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Felix Müsgens, Axel Ockenfels, Markus Peek

Chair of Energy Economics
Brandenburg University of Technology Cottbus
http://www.tu-cottbus.de/fakultaet3/en/energiewirtschaft/

Economics and Design of Balancing Power Markets in Germany[1]

by

Felix Müsgens, Axel Ockenfels, Markus Peek

Abstract:

This article analyzes the economic fundamentals that govern market design and behavior in German balancing power markets. Then, partly based on theoretical work by Chao and Wilson (2002), we illustrate the role of the scoring and the settlement rule as key elements of the market design. With sufficiently competitive markets, a settlement rule based on uniform pricing ensures efficient energy call in the balancing power market. A scoring rule based on capacity prices only ensures an efficient production schedule. Thus, both rules together with rational bidding ensure simultaneous efficiency on the balancing power market and the wholesale electricity market.

Key words: Electricity Markets, Balancing Power, Market Design

Addresses:

Prof. Dr. Felix Müsgens
University of Technology Cottbus
Institute of Power Engineering
Cottbus

felix.muesgens[at]tu-cottbus.de

Prof. Dr. Axel Ockenfels
University of Cologne
Department of Economics
Cologne

Ockenfels[at]uni-koeln.de

Markus Peek
r2b energy consulting GmbH

Cologne

markus.peek[at]r2b-energy.de

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INTRODUCTION

Balancing power is the electric power required to counterbalance short-term differences between generation and consumption of electricity in a grid. These differences can be caused by deviations from announced schedules both on the supply and on the demand side. The result of these deviations is either an unexpectedly insufficient supply of electricity (frequency drops below 50 Hz) or an oversupply of electricity (frequency rises above 50 Hz). In the case of insufficient supply, positive balancing power is required. It can be provided by the supply side in the form of an extra amount of generated electricity or by the demand side in the form of reduced consumption. In the case of an oversupply of electricity, negative balancing power has to be provided. Besides the distinction between positive and negative balancing power, the balancing power products in Germany are separated into three different qualities, namely primary control power, secondary control power and minutes reserve. Simply put, the quality determines the requirements regarding the maximum time span between the request and the delivery of balancing power.

The four German transmission system operators are responsible for the stability of the electricity grid in their respective control area. As a consequence, they are also responsible for procuring balancing power capacities to constantly balance electricity generation and electricity consumption in real time. A system operator has to procure a certain amount of balancing power capacity of each of the three qualities. The necessary amount is calculated with probabilistic models. Necessary balancing power capacities are procured in advance in an auction. In this auction, bidders submit two-part bids consisting of a capacity price bid and an energy price bid. Bids are selected based on the capacity price bid; successful bidders are paid their capacity bid ('pay-as-bid'). If balancing power is physically needed during a period, it is called from procured capacities. In case of a call, accepted capacity is called based on the energy bid – starting with the lowest. Once again, 'pay-as-bid' is used. Physically, a technical unit providing balancing power capacities has to increase or decrease its electricity generation or its electricity consumption in case of a call. Depending on the quality this has to happen instantly or within a few minutes.

In Germany, the procurement of balancing power by means of competitive auctions started in the year 2002. During the past years, several changes have occurred especially with regard to market and product design. The four originally separated markets in the different regional control areas were combined stepwise so that there is one common balancing power market in Germany today. However, the number of market participants, i.e. suppliers of balancing power, is still relatively small in many segments of the balancing power market. In addition, the complexity in the balancing power market makes it difficult to interpret market results – especially in the absence of a single market clearing price. This also makes it difficult to interpret price and cost developments on this market. For these reasons, the market and product design for balancing power is subject to an ongoing debate.

However, as of today, very little work – theoretical and empirical – is available on this topic. One important exception is Chao and Wilson (2002), which we use as a basis for our illustration how balancing power markets should be organized to increase market efficiency. We analyze the market design on balancing power markets in general and the German balancing power market in particular. Furthermore, specific recommendations for an improved market design will be given where appropriate.[2] We will concentrate the analysis on secondary control power and minutes reserve.

After a discussion of the necessity of centralized balancing power markets in section 2, section 3 describes the fundamental factors affecting the costs of balancing power suppliers. These costs consist of capacity costs to provide capacity and energy costs when provided capacity is called and therefore has to produce energy.

Section 4 covers two main aspects of balancing power market design. Firstly, the settlement rule is analyzed which determines how much successful bids are paid. Secondly, we analyze the scoring rule. The scoring rule determines which suppliers' bids are accepted. Designing these two rules properly is essential for an efficient market. Hence, both rules are analyzed with regard to market efficiency. Furthermore, we make propositions for improvements with regard to the scoring and settlement rules in the German balancing power market.

Finally, Section 5 concludes and summarizes our recommendations.

TECHNICAL BACKGROUND AND NECESSITY OF CENTRALIZED BALANCING POWER PROVISION AND DISPATCH

Generation of electrical power must equal consumption at any given point in time in electricity systems. However, electricity markets - without further measures - may not always ensure this. Hence, any resulting net difference is counterbalanced by positive or negative balancing power capacities.

In liberalized electricity markets, supply and demand of electricity meet on markets, where planned electricity generation and planned electricity consumption are matched. In Germany, this is mainly done on the day-ahead market, where power for the following day is traded until 12 a.m. (noon). There is also an intraday market, where deviations from planned generation or consumption can be balanced out.[3] Every balancing group operator is responsible for a balanced planned schedule with a temporal resolution of 15 minutes. However, differences between planned schedules and actual generation or consumption will occur. Such differences can be caused by load forecast errors, forecasting errors of renewable energy feed-ins, outages of power plants and deviations of scheduled average generation and consumption values within the time periods of 15 minutes. In such cases, balancing power is

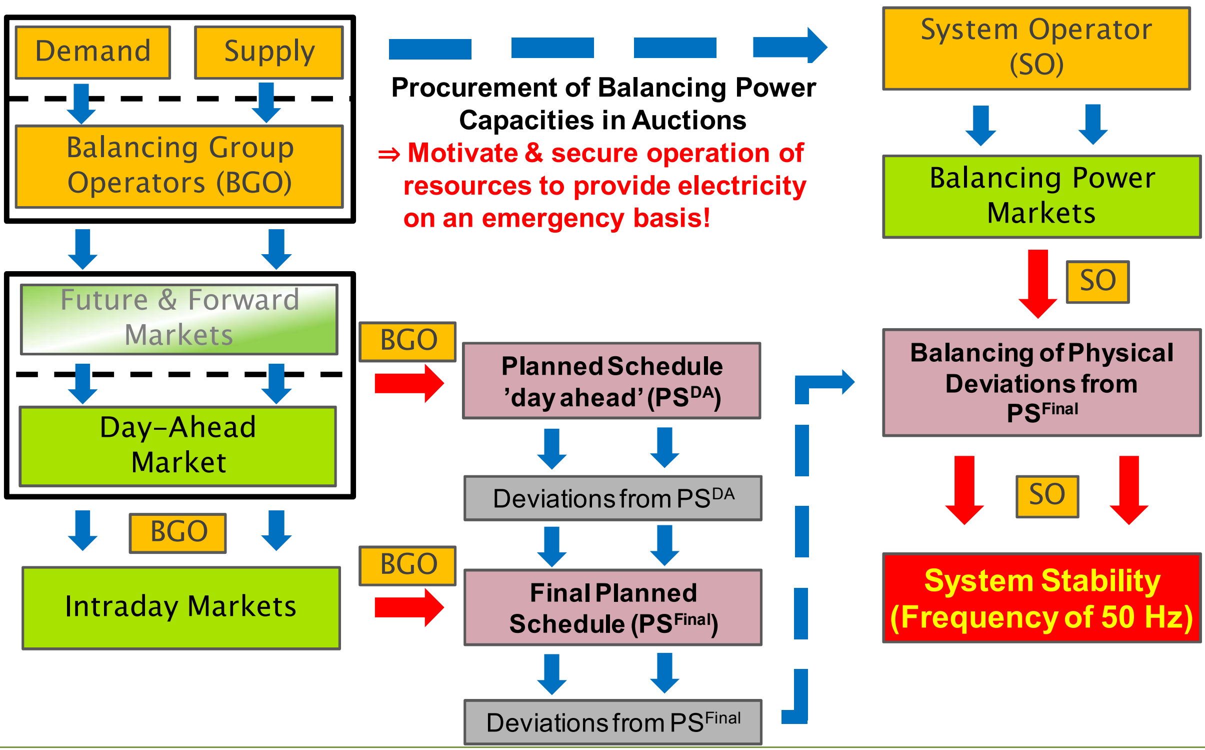
2 For an analysis of timing issues in balancing power markets, refer to Müsgens, Ockenfels and Peek (2011), and for an analysis of feedback policies in balancing power markets, see Müsgens and Ockenfels (2011). Cramton and Ockenfels (2011) address the long run perspective of reliability in electricity markets by analyzing the economics and design of capacity markets in Germany.

3 However, as today's intraday market shows little traded volume, the day-ahead market is currently referred to as spot market in Germany. We follow that notation.

required to adjust these short-run physical deviations after the closure of day-ahead and intraday markets.

Figure 1 shows the different electricity markets and their interaction in Germany. In addition, the figure shows whether the system operator (SO) provides a service centrally or different balancing group operators (BGOs) are responsible individually.

Figure 1: Electricity Markets and Responsible Parties in Germany



In theory, balancing power could be provided either decentralized by the responsible balancing group operators or as a centralized system service by system operators. In liberalized electricity markets, the latter is usually done for several reasons:

- In the short-run, the price elasticity of both demand and supply on electricity markets is close to zero. On the supply side this is due to technical restrictions of generation units. These can be start-up and shut-down times, load gradients and minimal technical loads, which constrain the short-term adjustment of electrical power output. On the demand side the low price elasticity is partly a consequence of insufficient incentives. In many cases this is due to the form of electricity supply contracts. Other reasons are restrictions in information, communication and metering facilities. Most consumers have neither the knowledge and the technical opportunities to benefit from short-term price volatility nor the incentives to adjust their electricity consumption in reaction to price signals on the markets in the short-run.
- The level of system reliability and quality of supply of electricity is a public good. It is ensured by the provision of an adequate amount of balancing power capacities in advance. In case of a difference between current generation and current consumption the frequency in the grid deviates from the target value of 50 Hz. Without an

adjustment by means of providing balancing power, fluctuations of the frequency in the grid can follow. In the end disruptions of electricity supply can be the consequence. Due to the grid dependence of electrical supply all customers and generators connected to the grid would be concerned to the same extent. In case of a decentralized balancing power system the costs of reliability of supply would be individualized. However, the costs of an insufficient balancing power provision caused by frequency fluctuations and blackouts would be borne by all grid users. Hence, in the case of a decentralized provision of balancing power the level of reliability of supply would be insufficient.

- In case of a centralized balancing mechanism, compensations between different balancing groups can be utilized. Individual deficits and surpluses can be neglected and only the aggregate deviations in the grid have to be balanced physically. As a result both the necessary provision of balancing power capacities and the call of balancing power is lower.

In the German electricity market, the four Transmission System Operators (TSOs) – Amprion GmbH, transpower Stromübertragungs GmbH, 50 Hertz Transmission GmbH and EnBW Transportnetze AG – are responsible for the procurement and dispatch of balancing power capacities. To maintain the reliability and quality of supply the responsible system operator procures balancing power capacities and dispatches the procured capacities to compensate short-run deviations between generation and consumption in real time. This is done in a three-stage process.

In a first step, deviations from the regular grid frequency are instantly balanced by calling on primary control power. This is done by decentralized primary controls, which are located inside the power plants. After a drop of more than 10 mHz or a rise of the same amount, these controls are automatically activated. If the deviation lasts for more than 30 seconds, secondary control power is activated in a second step to release the primary control power capacities. Capacity offering secondary control power has to be at its maximum load within 5 minutes after activation. In contrast to primary control power, secondary control power is not provided directly and instantly by the power plants. Instead it is automatically activated by centrally located controls. To release and supplement secondary control power capacities, minutes reserve can be used in a third step. After activation it has to be at its maximum load within 15 minutes.

COSTS AND EFFICIENT PROVISION OF BALANCING POWER

Knowing the cost structures of potential suppliers is one of the most crucial prerequisites for the evaluation of the market and product design on balancing power markets. The cost structure concerns both fundamental costs and interdependencies between balancing power markets and the electricity wholesale market. In this section, we identify the cost structures for providing balancing power capacities on the one hand and for delivering balancing power on the other hand. We will specify these costs in detail for exemplary potential suppliers, which is the basis for the analyses of market design in the following section. After that, efficient allocations of power plants for providing and delivering balancing power taking into account the electricity wholesale market will be investigated.

Technical and economical properties of power plants lead to highly complex costs of providing balancing power. Interdependencies between balancing power markets and electricity markets increase the complexity even further. One way to tackle this is the use of sophisticated fundamental electricity market models. These can be used to compute e.g. balancing power prices based on marginal costs and generate quantitative answers to other relevant empirical questions. [4]

In contrast to that, the aim of this article is to identify and illustrate basic economic principles, mechanisms and influencing factors that guide the design and behavior in balancing power markets. To achieve this goal and to reduce complexity, some simplifications and abstractions are made, partly following Chao and Wilson (2002). Important ones are:

- We investigate the market of positive balancing power only, i.e. positive secondary control power and positive minutes reserve.
- We limit our analysis of balancing power provision and generation to so called ‘spinning reserve’ from thermal power plants. These power plants have long start-up and shut-down times. Therefore, in order to be able to provide balancing power capacities, these power plants have to operate at least with minimal technical load. Produced electricity must be sold on the electricity wholesale market. We do not take into account pump storage plants, which can be used to provide secondary control power. Moreover, we do not consider so called ‘stand-by reserve’, such as OCGTs or emergency power generators, which are used to provide minutes reserve. We assume increasing opportunity costs for extra-marginal generators. Furthermore, electricity consumers as potential providers of balancing power are not taken into account either.
- We do not consider dynamic effects, which result from start-up or shut-down processes of power plants. For the sake of simplicity, we also assume levels of efficiency to be independent of operation points.
- We assume an identical probability of being called for all accepted bidders. That is, we assume that with a certain probability all reserve is needed and otherwise none.

While these simplifications limit the applicability of our results for quantitative estimation purposes, the assumptions help to understand and clarify the fundamental economics of balancing power markets. In fact, the simplifications should not influence the applicability of the *qualitative* results. For instance, our findings can easily be extended to negative balancing power.

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4 See e.g. r2b / consentec (2010). The study quantifies by how much increasing shares of RES increase the cost for balancing power based on complex electricity market models.

Cost Structure of Suppliers

If positive balancing power is called, it must be available on short notice. Start-up times of thermal power plants usually amount to several hours. Therefore, such power plants face restrictions when offering positive balancing power capacities. First of all, the power plant must be operating at least at minimal technical load during the bidding period, because it is not possible to provide balancing power from a thermal power plant when it is shut down. Furthermore, it must be possible to increase generation within a short period of time ('ramp up'). Balancing power from power plants running in partial load is called 'spinning reserve'. The maximal offered capacity is determined by the technical parameters maximal technical load (nominal capacity), minimal technical load and load gradient of the respective power plant. It is further determined by the time within which the offered balancing power capacity has to be fully available, i.e. the activation time. More specifically, the possible balancing power capacity of a thermal power plant is the minimum of the difference between maximal technical load and minimal technical load and the amount of capacity that can be ramped up during the respective activation time.

The latter factor can be described as the product of the load gradient in MW per minute [ΔCAP] and the activation time in minutes [t*], which is determined by the specification of the balancing power quality: $\Delta CAP \cdot t^*$. If for instance the load gradient of a power plant is 20 MW per minute, a supplier can offer 100 MW secondary control power, because the activation time for this product is 5 minutes. The supplier can offer 300 MW of minutes reserve, where the activation time is 15 minutes.

The other constraint for positive balancing power is that offered balancing power capacity cannot exceed the difference between maximal technical load [CAP^{Max}] and minimal technical load [CAP^{Min}]. Depending on which constraint is binding, the maximal offered balancing power capacity is either determined by the product of load gradient and activation time or by the difference between minimal and maximal technical load:

$$CAP^{\text{Reserve}} = \min\left\{\Delta CAP \cdot t^*; CAP^{Max} - CAP^{Min}\right\}.$$

In the next step we analyze the capacity costs of providing balancing power. Two cases have to be distinguished, namely whether a power plant is inframarginal or extramarginal. Inframarginal power plants have variable costs below the (expected) electricity price in the corresponding bidding period.[5] In contrast, extramarginal power plants are characterized by variable costs that are larger than the (expected) electricity price in the respective bidding period.

[5] For simplicity, here and in the following we often (implicitly) assume that marginal costs do not differ from variable costs, although these costs typically do differ. For a discussion of the subtle differences between the concepts in the context of electricity markets, see Stoft (2002), Ockenfels (2007), Kuntz and Müsgens (2007) or Müsgens (2006). However, for the purpose of our qualitative analysis, the difference is insubstantial.

For the present, we assume that there is no uncertainty with respect to the expected day-ahead electricity price. Furthermore, we assume that there is one and only one electricity price in the bidding period.[6]

If the variable costs [VC] of a power plant are below the electricity price [p^{DA}] within the bidding period - the power plant is inframarginal - the supplier would sell all the generated electricity on the electricity wholesale market when not taking into account the balancing power market. The supplier would earn a positive contribution margin equal to the difference between the electricity price and the variable cost. This margin determines the opportunity costs of shifting capacity from the wholesale to the to the balancing power market. That is, capacity costs [$CC^{Reserve}$] per MW for inframarginal units are equal to the difference between the day-ahead electricity price (which is considered the reference price of other wholesale markets due to arbitrage) and variable costs: $p^{DA} - VC$.

If a power plant's variable costs are above the electricity price at the wholesale market, i.e. the power plant is extramarginal, the supplier would not operate the power plant when not taking into account the balancing power market. It would not generate electricity, because it would make losses on the electricity wholesale market. However, to provide balancing power as 'spinning reserve', the power plant must be running at least with minimal technical load during the bidding period. This creates costs, because the generated electricity has to be sold at an electricity price below variable cost on the wholesale market. Losses per MW and hour are equal to the difference between electricity price and variable cost. The total amount of costs is the product of losses per MW of generated power at the wholesale market and the minimal technical load. This cost can be allocated to the (maximal) offered balancing power capacity.[7] Hence, the capacity cost of an extramarginal supplier is equal to

$$\left(VC - p^{DA}\right) \cdot \frac{CAP^{Min}}{CAP^{\text{Reserve}}}.$$

As a result, the capacity cost function for providing positive balancing power is asymmetric. It depends on technical parameters – minimal and maximal technical load and load gradient – and on the difference between electricity price and variable costs of the respective power plant. Summing up, the capacity costs for positive balancing power in EUR je MW are given by:

$$CC^{\text{Reserve}} = \begin{cases} \left(VC - p^{DA}\right) \cdot \dfrac{CAP^{Min}}{CAP^{\text{Reserve}}} & ,\text{if } VC > p^{DA} \\ p^{DA} - VC & ,\text{if } VC \le p^{DA} \end{cases}.$$

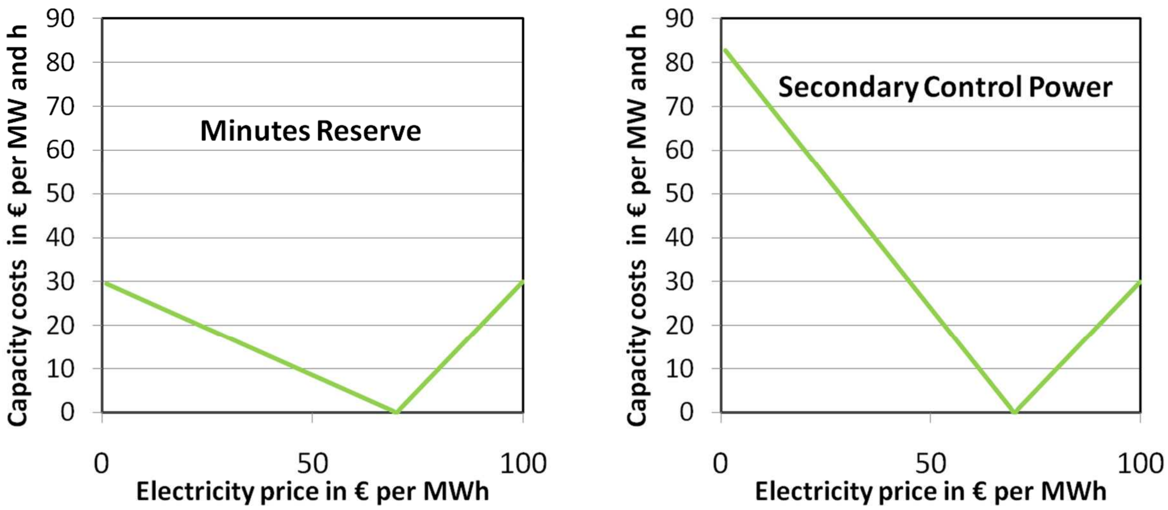
[6] The effects of uncertainty regarding the electricity price and bidding periods with volatile electricity prices are discussed in Müsgens, Ockenfels and Peek (2011).

[7] The current product design in Germany allows system operators to accept bids only partially. This increases the cost per MW of generation capacity, because the total costs can only be allocated to a smaller amount of balancing power capacity. However, in this section we assume that a bid can only be either fully accepted or rejected. The Bundesnetzagentur (the German regulator) recently decided to move into the direction of indivisible offers – at least for balancing power calls – thus reducing this problem.

In Figure 2, the shape of the capacity cost curves of an exemplary CCGT for secondary control power and minutes reserve are shown as a function of the electricity price in the day-ahead market. The power plant is assumed to have a maximal generation capacity of 400 MW, a minimal technical load of 30 % of the maximal capacity and a load gradient of 20 MW per minute. Moreover, its variable cost is 70 € per MWh. Hence, the capacity costs for the plant are zero if the electricity price in the day-ahead market is 70 € per MWh. For prices below 70 € per MWh, the power plant is extramarginal. Hence, it earns losses on the day-ahead market which must be compensated by revenues from the balancing power market. If the electricity price is above 70 € per MWh, the plant earns money on the day-ahead market and has opportunity costs when capacity is withdrawn to provide balancing power.

According to its load gradient, this power plant could provide 300 MW minutes reserve, since the activation time corresponds to 15 minutes. However, as the difference between minimal and maximal technical load is only 280 MW, the maximal balancing power capacity of this power plant corresponds to 280 MW. In the case of secondary control power, the amount of reserve capacity that can be provided is limited by the activation time of 5 minutes. Because of the load gradient of 20 MW it corresponds to 100 MW.

Figure 2: **Capacity Costs of a CCGT - Minutes Reserve & Secondary Control Power (Example)**



If a power plant is inframarginal, capacity costs in € per MW and hour are identical for secondary control power and minutes reserve. For each MW of provided balancing power, the supplier has to reduce generation of electricity in the same amount. If, however, a power plant is extramarginal, capacity costs in € per MW and hour are higher in the case of secondary control power than in the case of minutes reserve. In both cases, the supplier must sell electricity on the electricity wholesale market in the amount of the minimal technical load which creates losses. With minutes reserve, these losses can be allocated to 280 MW, whereas with secondary control power they can be allocated to 100 MW only. Thus, specific capacity costs are higher for secondary control power and the negative slope of the cost function is steeper.

In addition to capacity costs, costs occur for the actual delivery of balancing power. In both cases – secondary control power and minutes reserve – variable costs increase when balancing power capacities are actually called. The parameter *h* (0% < h < 100%) denotes the ex-ante probability that a power plant's accepted capacity is called.[8] Total costs [TC^{Reserve}] for both inframarginal and extramarginal power plants are then the sum of capacity costs and expected costs of actual delivery:

$$TC^{\text{Reserve}} = \begin{cases} \left(VC - p^{DA}\right) \cdot \dfrac{CAP^{Min}}{CAP^{\text{Reserve}}} + h \cdot VC & ,\text{if } VC > p^{DA} \\ p^{DA} - VC + h \cdot VC & ,\text{if } VC \leq p^{DA} \end{cases}$$

.

Efficiency on the Balancing Power Market and on the Electricity Wholesale Market

We will start this section by illustrating what constitutes an optimal allocation of power plants to balancing power markets if the goal is to minimize total balancing power costs. Here, we implicitly assume that a central planner has access to all relevant information to implement such an allocation (in the next section we illustrate how efficiency can be realized in a decentralized market system). Thereafter, we show that the allocation remains unchanged if we include the wholesale market in our computations such that we simultaneously minimize the total costs of electricity in wholesale and balancing power markets.

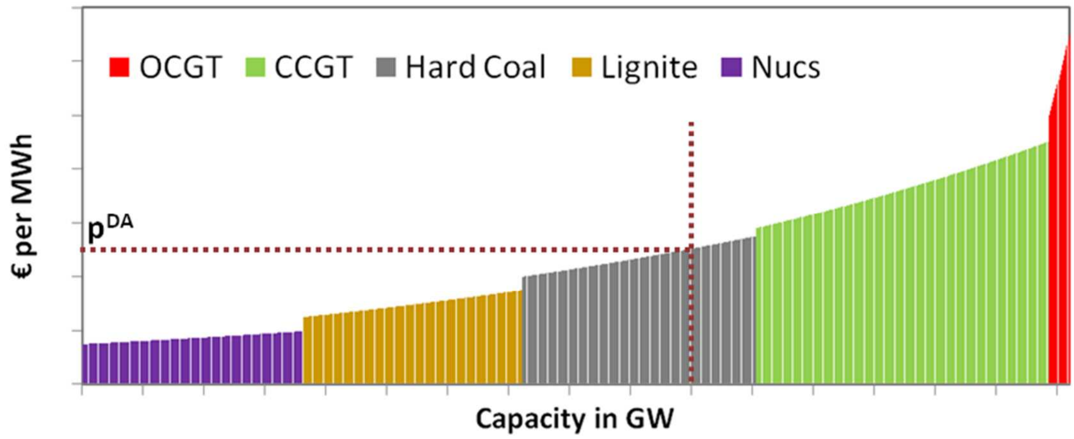
Cost Efficiency in the Balancing Power Market

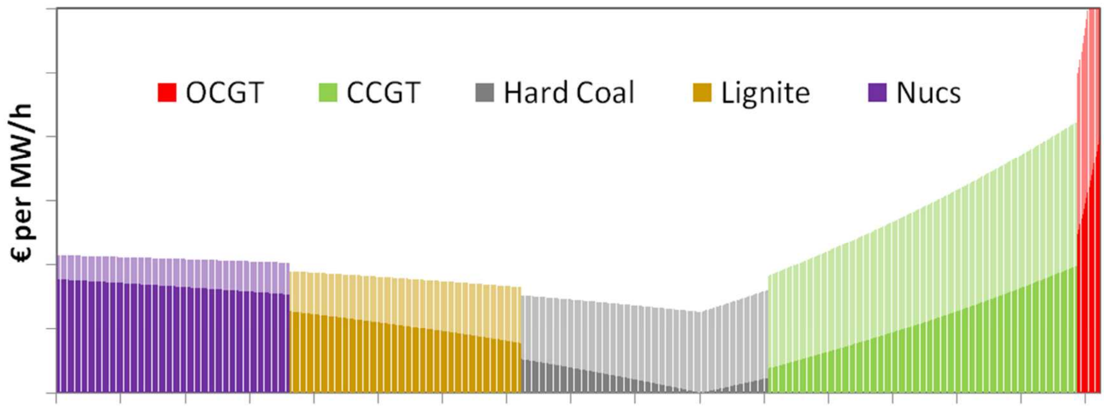
On the basis of all power plants' generation costs, minimal technical loads, maximal capacities and load gradients, it is possible to determine the maximal balancing power capacity to be provided by each power plant and both its capacity cost and its total cost. On this basis, we will now illustrate by way of example how the capacities that minimize balancing power costs *for a given electricity price in the wholesale market* can be determined.

The upper part of **Figure 3** shows the 'merit order' of a stylized thermal power plant system. On the basis of the technical parameters of each power plant and a probability of being called *h* – which in the example in **Figure 3** corresponds to 50 % for all plants - one can calculate the total costs of each power plant given an exogenous electricity price. This is shown in the lower part of **Figure 3**. The electricity price is set to the variable cost of a hard coal power plant and both capacity costs (fully colored bars) and expected energy costs of calls (partly transparent bars) are shown. The sum of both corresponds to the total (expected) costs of providing balancing power.

[8] As we have mentioned before, we assume an identical probability of being called for all accepted bidders

Figure 3: Merit Order on the Electricity Market And Total Costs on The Balancing Power Market





To minimize total costs on the balancing power market (and hence achieve efficiency on this market), it must be assured that the power plants with the lowest total costs are used for providing balancing power capacity. Recall that the total cost of a power plant when it provides balancing power is the capacity cost plus the expected cost of call. Thus, minimizing overall total costs requires that supplier *i* is favored over supplier *j* if and only if

$$CC_i + h \cdot VC_i < CC_j + h \cdot VC_j .$$

Simultaneous Cost Efficiency in the Wholesale and Balancing Power Markets

The provision of balancing power capacities affects generation costs on the wholesale electricity market. This was not taken into account in the previous example. An overall efficient allocation of capacities requires that aggregated generation costs (including both variable generation cost on the wholesale market and on the balancing power market) are minimized.

The two markets are interlinked for two main reasons: firstly, providing balancing power from inframarginal power plants reduces generation from these plants on the electricity market, which has to be replaced by power plants with variable costs above the spot price.

Secondly, extramarginal power plants providing balancing power replace electricity generation of inframarginal power plants due to the necessity of generation with minimal technical load in the case of providing positive balancing power. In both cases, the generation costs on the wholesale electricity market increase.

When inframarginal power plants provide balancing power and hence reduce their generation on the spot market, the generation of electricity must be increased from power plants which had not been generating electricity before. On the margin, this leads to additional generation costs p^{DA} - VC on the electricity market, if the variable cost of the (inframarginal) power plant is VC, because the variable cost of the 'new' power plant, which replaces the reduced generation, corresponds to p^{DA}.[9] That is, the replacement cost on the day-ahead market of withdrawing inframarginal capacity is p^{DA} - VC

On the other hand, we have to take into account the energy costs of actually delivered energy on the balancing power market by a power plant with variable cost VC, which is h·VC.

Hence, for the purpose of maximizing overall efficiency, an inframarginal power plant *i* with variable cost VC_i will be favored over power plant *j* for providing balancing power if the total costs (replacement costs on the wholesale market plus energy costs on the balancing market) are smaller for *i*:

$(p^{DA} - VC_i) + h \cdot VC_i < (p^{DA} - VC_j) + h \cdot VC_j$, which is equivalent to:

$VC_i > VC_j$.

The economic interpretation of this inequality is that balancing power from inframarginal power plants should be provided first from those with highest variable costs. A supplier's capacity costs increase by the same amount as variable costs decrease. Even though the costs of call decrease, this cost decrease cannot be fully compensated. The reason is that the probability of being called is below 100%.

Observe that we already know that CC = p^{DA} - VC. Hence, the inequality condition above is exactly the same as the one derived in the last section, in which we did not take into account the wholesale market. That is, those plants that minimize balancing power production also minimize the replacement costs on the wholesale market after withdrawing inframarginal units. In other words, opportunity costs on one market are real costs on the other market.

A similar argument holds when balancing power is obtained from extramarginal power plants, which generate electricity in the amount of their minimal technical load. On the one hand, this creates additional generation costs. These add up to the product of a power plant's minimal technical load and its specific variable cost in € per MWh. On the other hand, the variable costs of formerly inframarginal power plants are saved. Looking at marginal costs, these are again set by power plants with variable costs of p^{DA}. Hence, when balancing power capacities

9 In a competitive market, the price is determined by the variable (or, generally, marginal) cost of the marginal plant. At this price, additional capacity is available. Hence, p^{DA} is the marginal cost for additional supply (see also Chao and Wilson 2002).

are procured from extramarginal power plants, additional generation costs for electricity increase by VC – p^{DA} multiplied by the minimal technical load of the respective power plant. These additional costs can be allocated to the amount of provided balancing power capacity. Hence, the additional generation costs on the electricity market are identical to the capacity costs of an extramarginal power plant. As for inframarginal capacity, the costs for production on the balancing power - costs of call - of h·VC must be added.

In conclusion, an extramarginal power plant *i* is favored over an extramarginal power plan *j* if

$$(p^{DA} - VC_i) \cdot \frac{CAP_i^{\text{Min}}}{CAP_i^{\text{Reserve}}} + h \cdot VC_i < (p^{DA} - VC_j) \cdot \frac{CAP_j^{\text{Min}}}{CAP_j^{\text{Reserve}}} + h \cdot VC_j$$
.

Again, applying that the first part of both sides in the inequality above is equal to CC, this is the same optimality condition as for the balancing power market alone.

The reasoning above can be extended with regard to the optimality condition when inframarginal and extramarginal power plants are compared. The capacity costs providing balancing power equal real additional costs on the wholesale electricity market in both cases. Hence, the optimality condition considering the balancing power market alone and the optimality condition considering both markets are equivalent.

MARKET DESIGN

Chao and Wilson (2002) addressed the question whether efficiency can be reached in a decentralized market system applying results from economic incentive theory and mechanism design and assuming that the market is sufficiently competitive. We illustrate their theoretical results by way of example and also consider the impact of market power on market design, and of the proposed market design on market entry where possible.

Under the constraint that demand for balancing power in Germany is exogenously given and price inelastic, an efficient supply allocation is a sufficient condition for efficiency (there may be efficiency improvements from making demand price elastic, though). A supply allocation is efficient if overall costs are minimized. In the previous section, we have shown that overall efficiency in the case of balancing power markets requires the acceptance of the suppliers with lowest costs for the provision of balancing power capacities and expected energy call.

In most balancing power markets and also in Germany, bidders who want to provide balancing power offer a capacity price bid (indicating a commitment of capacity) and an energy price bid (for the energy actually delivered). A *scoring rule* is used to determine the winning two-part bids. The scoring rule in the current German market design accepts bids on the basis of capacity price bids only, starting with the lowest. During the bidding period, accepted capacities are called on the basis of energy price bids only, again starting with the lowest. The *settlement rule* determines how much winning suppliers are paid. Two different settlement rules are used on energy markets. 'Pay as bid' pays every accepted bid its own bidding price. In 'uniform pricing', all accepted bids are paid the same - market clearing -

price.[10] According to the current settlement rule in Germany, accepted suppliers are paid the amount of their own capacity bids. Hence, a 'pay as bid' rule is currently in operation. The same applies to the payment when energy from balancing power capacity is called: suppliers whose balancing power capacities are called are paid the amount of their own energy price bid. As energy can only be called from accepted capacity, these payments are made in addition to capacity payments.

There is an ongoing debate whether both settlement and scoring rule in Germany should be revised. Alternative settlement rules mostly favor 'uniform pricing' over 'pay as bid'. Alternative scoring rules discussed are scoring rules based on expected total costs, i.e. capacity cost plus expected energy cost. Based on the theoretical work of Chao and Wilson (2002), we will start with a discussion of the different settlement rules' advantages and disadvantages. According to the analysis, 'pay as bid' is not the preferred choice for balancing power markets. Instead, all accepted bidders should be paid the highest price of all accepted bids ('uniform pricing'). In a second part, we illustrate that scoring rules based on expected total cost do not lead to market efficiency. Instead, an efficient scoring rule implies that acceptance of bids should be based on capacity price bids only.

One implication of our analysis is that there are arguments to change the current settlement rule from pay as bid to uniform pricing, and to continue with the scoring rule in Germany and not change to a scoring based on expected costs. Furthermore, we will discuss the divisibility of bids. In the current product design in Germany a system operator may accept only parts of offered capacity, which can lead to higher costs for suppliers.

Settlement Rules

Theoretical and empirical studies have analyzed advantages and disadvantages of various settlement rules for different markets.[11] Usually, two different settlement rules are compared and discussed, 'uniform pricing' and 'pay as bid'.[12] It turns out that *under perfect competition and complete information*, both settlement rules lead to full efficiency and exactly the same procurement costs. For uniform pricing, this is easy to see. In sufficiently competitive markets, bidders will just bid their cost. The reason is that bidding variable cost always ensures (independent of the bidding of others) that one wins if and only if winning is profitable, that is if the market clearing price is above one's variable cost. In other words, uniform pricing reveals true costs.

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[10] 'Uniform pricing' is the more common settlement rule and is used for instance in the Germany day-ahead power market.

[11] Because most of the arguments are well-documented and understood in the literature, we confine ourselves here to a rather brief description; see e.g. Cramton et al. (2001) and Grimm et al. (2008) for a more detailed account.

[12] Another possible settlement rule is the so-called 'Vickrey auction'. Even though from a theoretical viewpoint this auction type guarantees efficiency in production, it is no relevant alternative in the practice of balancing power markets. This is because the rules are complicated, bidders may get paid different prices for the same service, large bidders are paid more on average than small bidders, and procurement costs may be very high. For a thorough discussion, see e.g. Grimm et al. (2008).

This is different under ‘pay as bid’, where bidding true cost is not optimal. In the context of California’s electricity wholesale market, Kahn et al. (2001, p. 70) wrote: ‘Any belief that a shift from uniform to as-bid pricing would provide power purchasers substantial relief from soaring prices is simply mistaken. The immediate consequence of its introduction would be a radical change in bidding behavior that would introduce new inefficiencies, […]’. The reason that bidding true costs is not optimal is that increasing one's bid leads to an increase of the profit as long as the bid is still accepted. If all suppliers have full information regarding both their own cost as well as the costs of the competitors, all suppliers submit a bid equal to the marginal supplier’s bid. The marginal supplier is the most expensive supplier needed to cover demand. As a consequence, with perfect competition and complete information, the winners and payments for ‘pay as bid’ are the same as for ‘uniform pricing’.

Now suppose there is uncertainty about the competitors' costs and strategies, but still perfect competition. With 'uniform pricing', one's bid is independent of others' behavior, so full efficiency is still reached. With 'pay as bid', however, efficiency is unlikely, because suppliers then have to guess the costs of their competitors and bid corresponding to these guesses. On the one hand, this is a challenge for the bidders that is likely to increase transaction costs. On the other hand, it might lead to an inefficient market outcome. The reason is that bidders with relatively low variable costs might overestimate the marginal plant’s costs and may hence submit a bid that is too high to be accepted. If at the same time other plants with higher variable costs are accepted, the result is inefficient. That is, while 'uniform pricing' still yields full efficiency, 'pay as bid' typically does not - even with perfect competition.

Now, finally, suppose there is imperfect competition. Here, with 'uniform pricing' suppliers with market power have incentives to reduce supply that could otherwise be profitably operated. The reason is that reducing supply may increase the market clearing price and thus the profitability of the inframarginal units. An analogous strategy is not possible with 'pay as bid', because bids on one unit cannot directly influence the payments for other units. However, with 'pay as bid' and market power, suppliers have incentives to increase bids beyond the variable cost of the marginal supplier. Theory does not find a unique ranking with respect to efficiency or procurement costs regarding the settlement rules (Ausubel and Cramton 2002).

That said, the literature has revealed a couple of arguments why 'uniform pricing' is typically the preferred settlement rule. For one, 'uniform pricing' is strategically very simple with competition; there is no need to guess others' costs and behaviors, so that the outcome is robust against wrong beliefs and uncertainty. Moreover, empirics seem to suggest that, even with less than perfect competition, the outcome with 'uniform pricing' quickly converges to full efficiency with the number of players. Second, with imperfect competition, 'uniform pricing' rewards low costs (because all winners get the same price) whereas 'pay as bid' rewards good guesses (because guesses determine the price). Third, and related, because with 'uniform pricing' the market price is a public good for suppliers, small players profit from the market power of large players. Exercising market power thus deteriorates the strategic player’s performance in comparison to other suppliers. In the long run, higher prices therefore promote market entrance of new suppliers. Finally, 'pay as bid' does not yield a unique reference price, complicating arbitrage and reducing market transparency.

In view of these advantages of the 'uniform pricing' rule, it seems understandable that relevant experimental research often finds that 'uniform pricing' performs better. As Tierney et al. (2008) put it when surveying the relevant literature: "Bidding behavior in experimental electricity markets designed to replicate real-world bidding situations suggest that pay-as-bid auctions would raise prices above uniform-price auctions."

We add that the specific complexities of balancing power markets tend to strengthen the case for 'uniform pricing'. In particular, it seems likely that inefficiencies under 'pay as bid' will arise for several reasons. Firstly, rational bidding strategies require empirical estimates of cost functions, which are challenging to compute. For example, market participants have to estimate details of technical units of their competitors to determine cost functions. This involves minimal capacities, load gradients and variable costs. Secondly, costs also depend on the energy price at the wholesale market, which is volatile. While forwards can be used as estimates for wholesale prices, volatility has to be estimated.[13] However, efficiency with 'pay as bid' strongly depends on the ability of all suppliers to estimate the costs of their competitors sufficiently precisely.

There is another argument increasing the complexity of optimal bidding on balancing power markets further. Bidders on the capacity market will take into account their expected revenues from calls on the energy market. This necessitates accurate estimates of the revenues from the energy market. These are difficult to determine under 'uniform pricing'. However, we will argue that they are even harder to predict with 'pay as bid'. Let us consider the situation under 'uniform pricing' first. Under uniform pricing, bidders can simply bid their variable cost on the energy market. However, the expected revenues from the energy market are needed when calculating the optimal capacity bid because bidders have to subtract these revenues from their capacity bid. Hence, suppliers have to estimate market prices on the energy market for different levels of calls and the associated probabilities.[14] It is especially challenging to estimate the probability function empirically. Yet these estimations are even more complex under 'pay as bid'. Recall that bidders do not reveal their variable costs on the energy market with 'pay as bid'. Instead, to simplify, bidders try to guess the most expensive accepted bid. The determination of the most expensive accepted bid requires an estimation of the probability distribution for calls of different energy levels, however. Bids on the capacity market depend on the expected profit on the energy market, which makes an accurate estimation regarding the energy market even more important. These estimates become harder when strategic bidding is an additional part of the equation.

Taking everything together, we conclude that 'uniform pricing' tends to be superior to 'pay as bid' on balancing power markets, both for the capacity and the energy part.

13 At least as long as there is no liquid options market which might provide market estimates for volatility.

14 As a side remark, this reasoning might be an argument for a high degree of transparency in these markets (if sufficiently competitive) because better predictions can increase efficiency.

Scoring Rules

Theoretical framework

Chao and Wilson (2002) show that a scoring rule for balancing power markets is efficient if the acceptance of bids is based on capacity prices only and accepted capacities are called on the basis of energy price bids. For this, it is assumed that markets are sufficiently competitive and beliefs about expected profits on the energy market are sufficiently accurate.

This result is based on two fundamental properties. Firstly, as the energy part of the bid is not part of the scoring rule for the acceptance of bids, there is no incentive for suppliers to adjust energy price bids to increase the probability of being accepted. In other words, the scoring rule does not interfere with the optimality of truthful bidding in the (competitive) energy market. Secondly, even though the energy bid is not part of the scoring rule, variable costs and expected revenues due to calls of energy from balancing power capacities are nevertheless taken into account. In the following, we will explain and illustrate this result by Chao and Wilson and the resulting incentives for market participants in more detail.

Given the decision about which capacities provide balancing power has already been made, and given a settlement rule, a supplier can compute an expected profit $E\left(R_i^{EM}\right)$ that is realized on the energy market. This expected profit is equal to the positive profit contribution, i.e. the difference between the energy market price p^{EM} and variable cost VC_i, which is adjusted by the probability of being called *h*. More formally, the expected profit on the energy market for supplier *i* is[15]

$$E(R_i^{EM}) = h \cdot \left(p^{EM} - VC_i\right).$$

This profit is made under the condition that the corresponding supplier's capacity bid has been accepted in the step before. Because the profit only materializes if the capacity bid is accepted, it is accounted for in the capacity bid - with a negative algebraic sign. That is, the supplier incorporates both capacity costs CC_i - which typically are the opportunity cost for not

[15] For simplicity, we have so far assumed a constant *h* for all capacity – regardless of variable costs. This might refer to the case where either all capacity is needed (with probability *h*) or none at all (with probability 1 - *h*). We provide just an example with heterogeneous *h* across firms. We assume that the bidding period is 10 hours, and balancing power demand is 1 MW in 9 hours and 2 MW in the remaining hour. There are two available technologies: a base (peak) load technology with capacity costs of 50 (0) per hour and variable costs of 20 (70) per hour. We assume that there are numerous suppliers who each own one MW of either baseload or peakload capacity. The efficient technology mix for balancing power is 1MW baseload and 1 MW peakload. The corresponding equilibrium balancing power prices in competitive markets are 20 in the 9 hours with low demand and 70 in the one hour with high demand. With these energy prices, it can be readily seen that there are no equilibria with either two baseload or two peakload winners. In fact, in equilibrium, the capacity bid of the winning peakload supplier is 0, the capacity bid of all baseload suppliers is 400 - (70 - 20) = 350, and the capacity bids of all losing peakload suppliers are - 9x(20 - 70) = 450. The latter bid reflects that - given the competitive market clearing prices - a (second) peakload supplier who wants to crowd out the baseload supplier could do this only by accepting losses in those 9 hours where the baseload supplier can more efficiently deliver electricity. As a result, with competitive bidding, the scoring rule selects one baseload and one peakload supplier, leading to an efficient market equilibrium in which different winners have different probabilities of being called.

bidding on the day-ahead market - and the expected revenues on the energy market in case of acceptance of the bid in the capacity market:

$$CC_i^{Bid} = CC_i - E(R_i^{EM}) = CC_i - h \cdot \left(p^{EM} - VC_i\right).$$

This capacity bid can be interpreted as the (opportunity) cost on the day-ahead market minus expected profits from called energy on the balancing power market. It indicates the smallest amount that a supplier is willing to accept for providing balancing power. With uniform pricing on the capacity part of the balancing power market and sufficient competition, it is easy to see that no other bid can improve profits: Like on the energy market, there is no incentive to increase this capacity price bid, because the probability of being accepted would decrease, whereas profits in case of acceptance would stay the same. On the other hand, there is no incentive to decrease this capacity price bid either, because this could lead to an acceptance of the bid in a situation where the market price is lower than the sum of capacity costs less expected profits on the energy market and hence to a situation where losses are made.

Note that even though the expected profit on the energy market is anticipated by the supplier, it is not an explicit part of the scoring rule on the capacity market. This is not necessary because the expected profit on the energy market is adequately priced into the capacity bid. As a result, a supplier *i* is favored over supplier *j* if

$$CC_i^{Bid} = CC_i - h \cdot \left(p^{EM} - VC_i\right) \leq CC_j^{Bid} = CC_j - h \cdot \left(p^{EM} - VC_j\right).$$

This formula can be simplified and leads to the condition for efficiency on the balancing power market:

$$CC_i + h \cdot VC_i \leq CC_j + h \cdot VC_j.$$

As we have shown in the last section, this is also the condition for overall efficiency. Each side of this inequality represents the total cost of the respective supplier, i.e. capacity cost plus variable cost times probability of being called. Thus, a supplier's capacity bid is favored if his total cost is lower than the other supplier's total cost. This is the condition for efficiency on the balancing power market and also the condition derived for overall efficiency. To summarize, as has been more formally derived by Chao and Wilson (2002), with sufficiently competitive markets, a settlement rule based on uniform pricing ensures efficient energy call in the balancing power market, a scoring rule based on capacity prices only ensures an efficient production schedule, and both rules together with rational bidding ensure simultaneous efficiency on the balancing power market and the wholesale electricity market.

An Illustrative Example

In this section, we present a stylized graphical illustration of the fundamental economic interrelationships between the balancing power and the day-ahead market. However, while graphical examples are sometimes more intuitive, we caution that significant simplifications have to be made. So, we recommend all readers to use our illustration only complementary to Chao and Wilson's (2002) work and our treatment above.

We start with an exemplary day-ahead market without the consideration of spinning reserve in **Figure 4**. There are five technologies: nuclear power plants, lignite and hard coal fired power plants, combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT). The load level is 55 GW. The resulting price in the day-ahead market is $p^{DA} = 40$ € per MWh if the balancing power market is not considered.

Let us now assume, without loss of generality, that we need 4.000 MW of balancing power capacity, that 20% of installed capacities can participate on the balancing power market,[16] that minimal load for all power plants is 50%, and that load gradients are sufficient to ramp up the remaining 50% in time to provide balancing power. Then, the colored bars in **Figure 5** depict total costs TC_i of providing balancing power for different technologies. The figure distinguishes between CC_i and costs for energy provision on the balancing power market. The (opportunity) costs CC_i are shown by the black line in the figure. Recall that $CC_i = p^{DA} - VC_i$ for inframarginal capacity and $CC_i = VC - p^{DA}$ for extramarginal capacity. The second part of total costs is the energy cost $h \cdot VC_i = 0.5 \cdot VC_i$. This is the difference between the black line and the upper limit of the colored bars in **Figure 5** (here we assume $CAP^{Min} = CAP^{Reserve}$).

We have pointed out that it is cost efficient to let those plants with minimal TC_i provide balancing power. In our example, these would all be inframarginal. However, this would mean that, ceteris paribus, inframarginal capacity reduces production by 4.000 MW. This cannot be an equilibrium because extramarginal capacity must then generate electricity to compensate for any capacity withdrawal from inframarginal capacity. Otherwise, load on the day-ahead market would not be covered. Hence, every MW from inframarginal capacity taken out of the day-ahead market must be replaced by one MW of extramarginal capacity and vice versa. However, at a price of 40 €, extramarginal capacity would not find it profitable to enter the market. Hence, the equilibrium price in the market without consideration of balancing power cannot be the equilibrium price in the market with balancing power. In this example, the electricity price p^{DA} must rise to motivate the production of capacity that was extramarginal when balancing power was not considered.[17]

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[16] This reflects the fact that not all capacity is prequalified to provide balancing power. It might help to assume that there are very many very small power plants in this example. Every fifth of these can provide balancing power with 50% of nominal capacity. Hence, 10% of nominal capacity in the market can supply balancing power.

[17] It is not necessarily the case that the electricity price on the day-ahead market has to rise when balancing power is considered. If mostly extramarginal capacity was called (e.g. at load level of 56 GW in the figure) the day-ahead price would have to decrease for an equilibrium considering balancing power.

Figure 4: **A Simplified Merit Order on the Electricity Market And the Equilibrium Price Without Balancing Power**

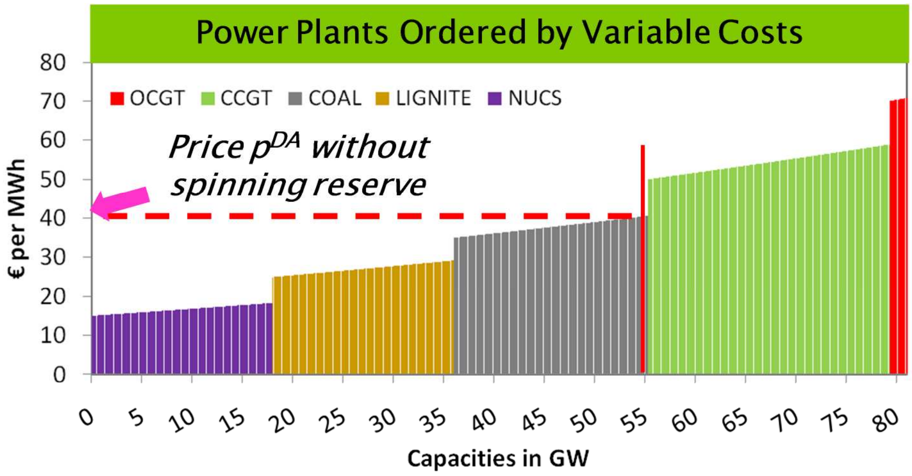


Figure 5: **Accepted Bids from Balancing Power Without Consideration of Day-ahead Price Adjustments – No Equilibrium**

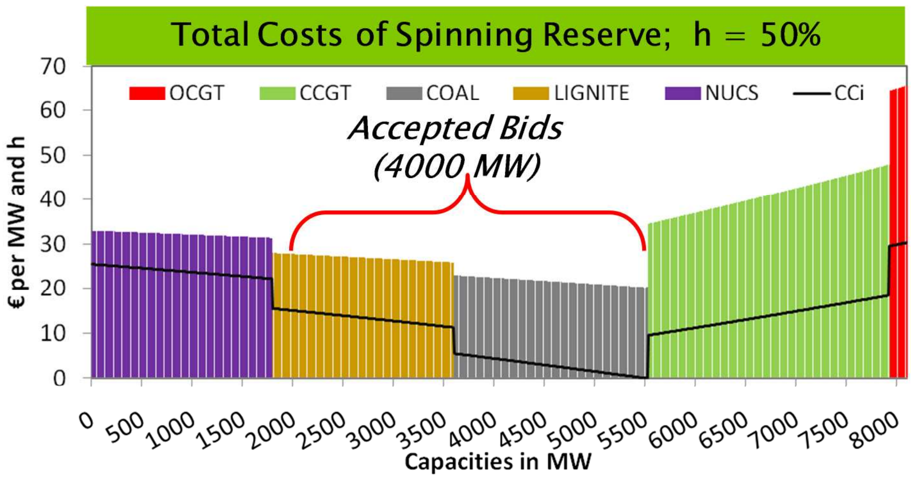


Figure 6 shows the resulting equilibrium price on the day-ahead market after price adjustments due to balancing power have taken place. In the inter-market equilibrium, p^{DA} is about 50 € per MWh; that is, 10 € per MWh above the day-ahead price if the balancing power market is not considered. Due to the higher price, 260 MW of formerly extramarginal capacity become inframarginal. [18]

Furthermore, the capacity costs CC_i for both infra- and extramarginal capacity are different (higher for inframarginal and lower for extramarginal capacity). This can again be seen in the black line in **Figure 7**. The figure shows which capacities provide balancing power in the inter-market equilibrium. The key to understanding this equilibrium is that the higher day-ahead price makes it cheaper (and more attractive) for extramarginal capacity to enter the balancing power market – and at the same time, the balancing power market becomes less attractive for inframarginal capacity due to higher opportunity cost. In equilibrium, both infra-

[18] We use 'inframarginal' for capacity with variable cost below the electricity price p^{DA} – not for capacity which in the merit order is to the left of demand.

and extramarginal capacities provide balancing power. The resulting allocation depicted in **Figure 7** is now cost efficient and physically 'feasible': 2.130 MW of inframarginal capacity and 1.870 MW of extramarginal capacity provide balancing power in our example.[19] Taking into account the 260 MW which became inframarginal due to the rise in p^{DA} (and in equilibrium provide 130 MW balancing power), a total of 2.000 MW capacity that was producing in the equilibrium without balancing power are now withdrawn from the day-ahead market (i.e. producing in partial load). They are replaced by 2.000 MW capacity that was not producing in the equilibrium without balancing power. Hence, electricity is now generated by formerly extramarginal power plants.

Figure 6: **A Simplified Merit Order on the Electricity Market After Price Adjustments**

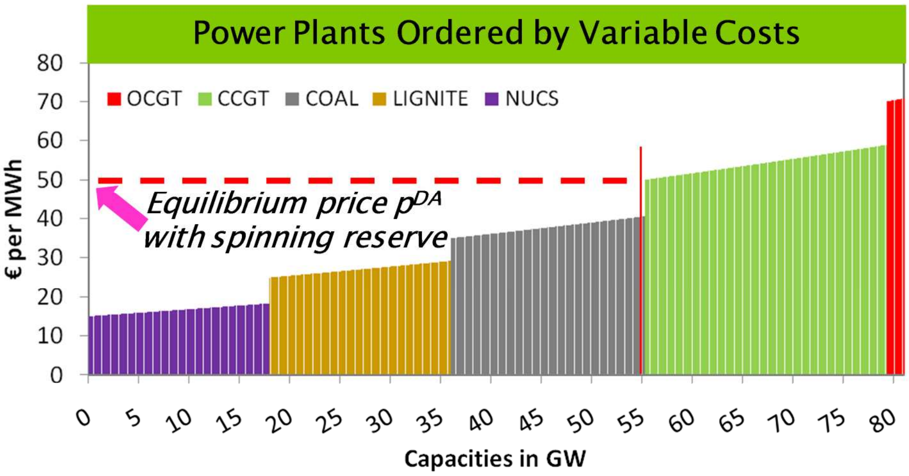


Figure 7: **Accepted Bids from Balancing Power Considering Day-ahead Price Adjustments – Equilibrium**

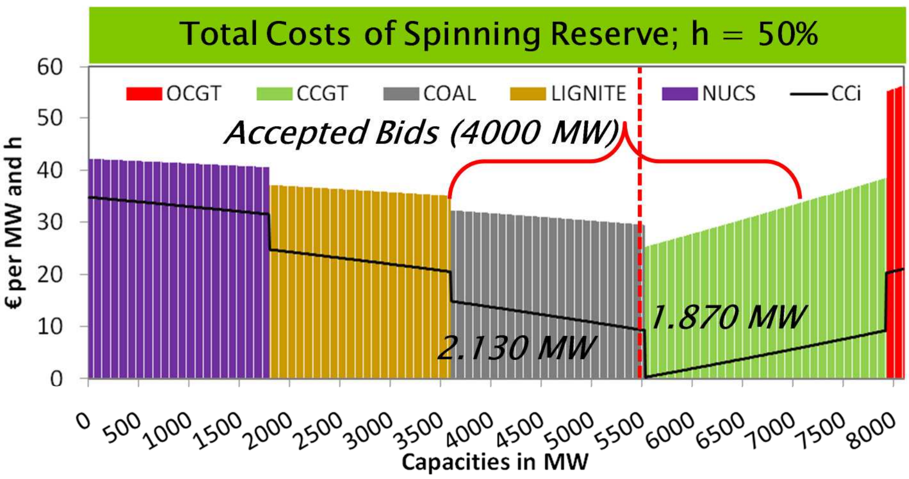
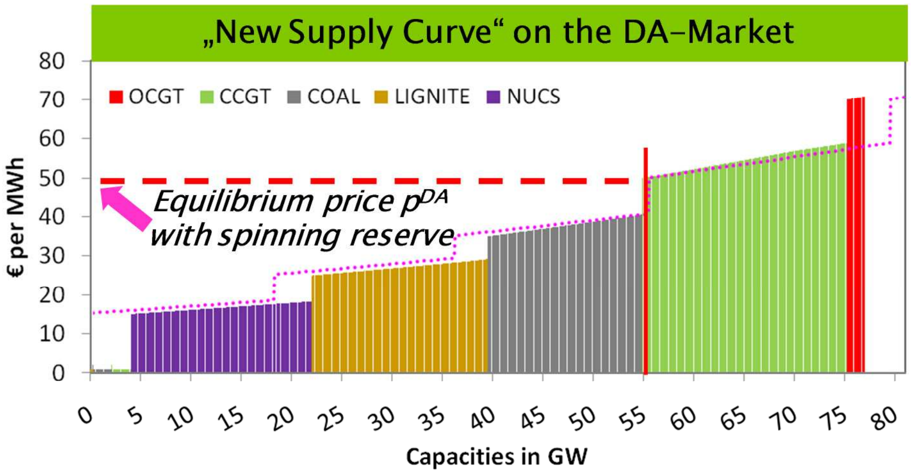


Figure 8 shows the merit order as bid on the day-ahead market taking into account the balancing power market, and compares it to the merit order without the balancing power market (dashed line). The figure takes into account that capacity bids accepted in previous

19 The reason why this is not 2.000 MW on both sides is the minimal load condition for extramarginal capacity which adds a factor to the calculation.

auctions for balancing power are mirrored by price-inelastic bids in the day-ahead auction because of the minimal load restrictions. Hence, 4.000 MW bid a day-ahead price of zero (or even negative).[20]

Figure 8: The New Merit Order on The Day-Ahead Market



Source: r2b energy consulting GmbH

While we made some simplifications in this example, it becomes clear that the day-ahead price and the merit order are usually different when balancing power is taken into account. In our example, the price rose but it may also be reduced – depending on the shape and slope of the merit order.

CONCLUSION

This article analyzes and illustrates the economic fundamentals that govern market design and behavior in German balancing power markets. Based on these economic fundamentals, we discuss the scoring and the settlement rule as key elements of the market design. The current settlement rule in Germany is pay-as-bid. However, there are discussions whether this should be changed to uniform pricing. While the theoretical auction literature cannot provide a general ranking with respect to efficiency and procurement costs regarding the settlement rules, we agree with many researchers who favor uniform pricing. Firstly, uniform pricing is strategically simple and relatively robust against wrong beliefs and uncertainty. Secondly, it reduces the impact of information and other asymmetries among firms. Thirdly, it generates unique market prices, increasing transparency. And last but not least, we present arguments that uniform pricing is superior to pay-as-bid in market power mitigation, both in the short run and in the long run.

The current scoring rule in Germany uses capacity bids as the only criterion for the selection of winning bids. As with regard to the settlement rule, there is a current debate whether that scoring rule should be replaced by a scoring rule based on expected total costs, i.e. capacity

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[20] Exactly 4.000 MW of capacity bid a price of zero in the day-ahead market because we assumed 50% minimal load in our example.

cost plus expected energy cost. However, total costs scoring can be gamed, even in competitive markets. We thus argue against changing the existing German scoring rule. The underlying rationale is that, when scoring is based on capacity bids only, these bids will reflect all relevant costs, including the variable costs of delivering balancing power. To be more precise, rational bidders' capacity bids in competitive markets equal the foregone expected profit on the wholesale electricity market *minus* the expected profit from called energy - this is the reserve price when offering balancing power.

Overall, following the theoretical analyses by Chao and Wilson (2002) we illustrate that, with sufficiently competitive markets, a settlement rule based on uniform pricing ensures efficient energy call in the balancing power market, a scoring rule based on capacity prices only ensures an efficient production schedule, and both rules together with rational bidding ensure simultaneous efficiency on the balancing power market and the wholesale electricity market.

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