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Reserve provision by CHP units and its impact on equilibria in spot and reserve markets

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Reserve Provision by CHP Units and its Impact on Equilibria in Spot and Reserve Markets

HEMF Working Paper No. 03/2018

by

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and

Christoph Weber

June 2018

UNIVERSITÄT
DUISBURG
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Abstract

There is a broad consensus that the energy transition planned in Europe, along with an increasing share of renewable energy sources, demands a sufficient number of flexibility providers. The established flexibility procurement mechanisms, notably the reserve markets, are expected to reflect the cost of flexibility provision. As more flexibility is needed – given a higher resulting uncertainty of residual load levels – prices for such provision are expected to rise. In recent years, however, reserve provision prices in Germany have shown a decreasing tendency, with overall reserve demand remaining constant.

This contribution proposes to analyse first the equilibrium pricing of reserve power against the electricity spot market in a stylized setting. A fundamental market model is used to analyse the price effects of reserve flexibility from Combined Heat and Power (CHP) entering both markets, using 2016 data as input.

Four cases are analysed to assess the effects of different reserve market characteristics. In Case 1, CHP plants may not provide secondary reserve for the reserve market and a stylized heat demand curve is considered as operating restriction of CHP plants in the spot market. Case 2 allows reserve provision by CHP plants, but models these plants without heat restrictions. Case 3 considers the combination of the stylized heat demand curve and reserve from CHP plants. Case 4 extends Case 3 by 100 small CHP power plant pools, analysing their additional effect on reserve prices.

From June 2018 on, secondary reserve in Germany will be auctioned in four-hour tenders, instead of the current weekly peak/off-peak auction design. We therefore compare the results to such an alternative auction regime with the same demand, but four-hour reserve provision tenders to reflect upcoming market design changes.

Our approach leads to spot prices at a similar mean level compared to historical data, with MAE values in a range from 5.91-6.64 €/MWh for all cases. The positive reserve price levels in this approach also compare to mean historical price levels. The price lowering effect of flexibility provision from CHP is clearly identifiable, underscoring the importance of explicit modelling of heat demand restrictions. A change of the reserve tender regime towards 4-hour tenders further lowers positive reserve prices in all cases. As a result, low reserve price levels may be expected to persist in the medium term despite the expected increase of intermitting generation.

Keywords: Equilibrium pricing, flexibility provision, reserve markets, combined heat and power, heat restrictions

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Content

Abstract	I
Content.....	II
1 Introduction	1
2 The marketplace for flexibility: relevant reserve market aspects	2
3 Literature Review	5
3.1 Endogenous Reserve Price Formation.....	5
3.2 Modelling of Reserve from CHP.....	6
4 Methodology.....	7
4.1 Endogeneous Modelling of Spot and Reserve Price Formation	7
4.2 Modelling of heat provision from CHP	12
4.3 A simplified model of the German market in 2016	16
4.4 Investigated Cases	17
5 Model Results	18
5.1 Results of Cases 1a-4a	18
5.2 Results of Cases 1b-4b.....	21
6 Conclusions	23
References	III
Appendix	VI

1 Introduction

The ongoing reform of many electricity systems towards a low emission generation mix and a higher renewable generation share is creating new challenges, notably a higher uncertainty of residual load due to a higher share of intermittent electricity generation. The uncertainty of generation and demand at a given point in time in electricity systems is commonly handled using reserve power, guaranteeing the match of physical electricity supply and demand at all times. While reserve power used to be provided from conventional generation units in the past mostly, new players like batteries, renewable producers, interruptible loads and, most notably, pooled small reserve plants have entered the German reserve market over the last years.

A significant subgroup of the latter group are combined heat and power (CHP) plants. These plants do not only provide electricity as an output, but also feed heat into heating networks and/or provide heat for local consumers and industry processes. CHP plants have entered the reserve markets to a significant extent in the last years – accompanied by a notable drop in reserve provision prices. Their special characteristics concerning reserve provision and opportunity cost structure in combination with their impact on overall reserve price levels have – at least to the knowledge of the authors – not been the focus of a thorough analysis yet (cf. below for a summary of related literature).

This paper therefore suggests answering the following research questions:

How does the opportunity cost structure for reserve provision from CHP plants differ from other, conventional power plants? As a result, what price impacts may be expected from their market entry, especially in reserve power pools? And, finally: In the developed setting, what is the expected price effect of a further market design change, shortening reserve provision timeframes from peak/off-peak hours to four-hour blocks, as put in place for secondary reserve in Germany in June 2018 (Federal Network Agency, 2017a)?

The design of the German reserve market is briefly described in section 2. However, it is not the intention of this paper to give a full description of the market regime employed, hence section 2 focuses on aspects of the market regime that are relevant for the following analysis. Besides discussing recent design changes, reserve price developments in the timeframe between 2013 and 2016 are described.

Section 3 gives a literature overview and derives theoretical findings concerning the price equilibria between spot and reserve markets (section 3.1) and flexibility provision by CHP (section 3.2). Section 4.1 extends the analysis by introducing a simplified model for an endogenous reserve price derivation (Section 3.1) and Section 4.2 investigates the opportunity cost structure of CHP plants. Section 4.3 and Section 4.4 describe the empirical analysis and

cases used to derive cost-optimal market results in the fundamental model implemented for investigation of reserve and spot prices. Section 5 states the obtained results. In section 6, conclusions regarding fundamental reserve modelling and the provision from CHP pools are drawn, as the expected and actual results are compared.

2 The marketplace for flexibility: relevant reserve market aspects

In the German reserve market, three different reserve products are auctioned, differentiated by their activation timeframe and response speed, namely primary (VDN, 2003), secondary (VDE, 2009) and tertiary (VDN, 2007) reserve¹ (www.regelleistung.net, 2017).

While there exists a bidirectional reserve product (positive and negative reserve provision²) for primary reserve, secondary and tertiary products are auctioned for positive and negative reserve separately. All auctioned reserve amounts are announced before the respective auctions by the TSOs³ and the market demand may therefore be considered common information for all market participants.

Primary reserve is auctioned in a multi-unit auction with each a bid comprising a provision price in [€/MW] and size of the bid in [MW]. There is a prerequisite that only integer value bid sizes greater than or equal to 1 MW may be bid. Secondary and tertiary reserve are auctioned using two-part bids in a multi-unit auction. Thereby a bid comprises besides the size of the bid its capacity (or provision or reservation) price and additionally the price to be paid on reserve energy activation in [€/MWh]. Bid sizes must be integer values greater than or equal to 5 MW.

The products also differ regarding the covered timeframe, during which the allocated capacity needs to be available. While primary reserve covers a whole week from Monday until Sunday (which amounts to a duration of 168 hours), secondary reserve is auctioned separately for peak periods (8-20 h from Monday – Friday, i.e. 60 hours per week) and off-peak periods (remaining

¹ Primary reserve (aka Frequency Containment Reserve, FCR) comprises spinning capacities that can reach full availability within 30 seconds. Similarly, secondary reserve (aka Automatic Frequency Restoration Reserve, FRR-a) plants need to reach full availability within 5 minutes. Tertiary reserve (aka Manual Frequency Restoration Reserve, FRR-m) plants need to reach their full availability within 15 minutes. Therefore, positive tertiary reserve also potentially comprises non-spinning, fast ramp-up capacities.

² Positive reserve denoting to withheld power bands for leaving the option to ramp up in case of residual demand increases, negative reserve denoting to guaranteed producing power bands for leaving the option to ramp down in case of residual demand drops.

³ Primary reserve auctions in Central Europe are staged jointly by the four German TSOs and the Swiss, Dutch, Belgian, Austrian and French TSOs. Secondary and Tertiary reserve auctions for the German market area have been jointly staged by the German TSOs. Since June 2016, Austria joins the secondary reserve auction if enough cross-border transfer capacity is available.

hours, i.e. 108 hours per week). Primary and secondary reserve are auctioned for the following week on Tuesdays and Wednesdays, respectively (both at 3 pm CET).

Tertiary reserve, however, is auctioned from Monday to Friday at 10 am CET⁴. Four-hour blocks are auctioned for the following day(s) up to and including the next working day. Per day, these amount to six products for positive and negative reserve each.

The submitted bids are ranked by their capacity price (“reserve provision merit-order”) and allocated starting with the lowest bid until the reserve demand is satisfied. The bidder with the highest allocated price might only be partly allocated, if his or her bid size exceeds the remaining demand. The reserve energy bid then only impacts on the reserve activation sequence (represented by the corresponding “reserve energy merit-order”) and is not impacting the reserve bid allocation – unless two provision price bids are exactly the same.

On allocation, respectively activation, bidders are awarded their bid price for reserve capacity, respectively reserve energy (“pay-as-bid”). Thus, on bidding, the bidders already know their payoff in case of allocation or activation.

In recent years, following the appendices to the Transmission Code of 2003 (VDN, 2003) (VDN, 2007) (VDE, 2009) and a reinforcing decision by the German Federal Network Agency (Federal Network Agency, 2011), new players have increasingly entered the market, including pooled resources, interruptible loads and emerging electric storage technologies (beyond pumped storage) like batteries. Pooling resources opens the reserve market towards small power plants that, due to minimum bid sizes, are not able to participate on their own.

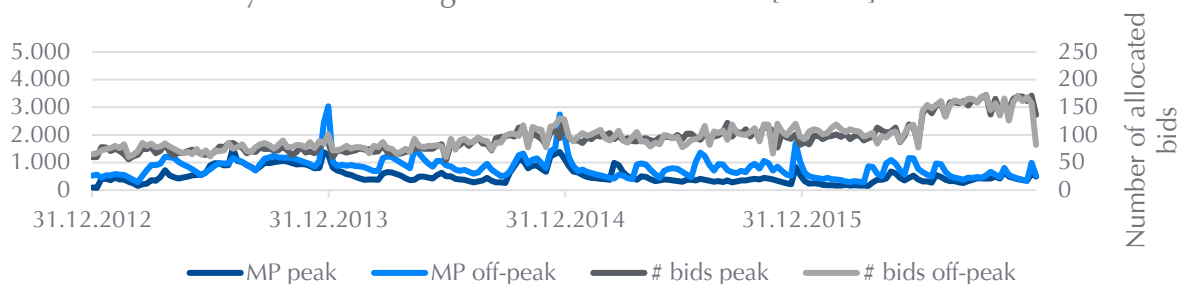
The number of prequalified market participants has been constantly rising over the last years (64 companies in July 2017 (www.regelleistung.net, 2017), compared to 32 companies in 2012 (50 Hertz, 2016). In September 2017, the overall capacity per primary energy source of all prequalified production plants has been published by the transparency platform of the four TSOs, www.regelleistung.net. At the end of June 2017, 22.32 GW have been prequalified for participation in the positive secondary reserve market, the largest part coming from pump storage and other hydro plants (www.regelleistung.net, 2017). About 60 more MW of capacity were prequalified for negative reserve.

The focus of the further analysis in this paper will be on secondary reserve, as there have been significant price changes in the recent past. The observed price level of allocated secondary reserve bids in the years 2013-2016 (www.regelleistung.net, 2017) is depicted in Figure 1. It is

⁴ The reserves for Saturdays, Sundays and Mondays are all auctioned on Fridays, so that there is no auction on the weekend. Similar procedures apply for holidays.

striking that the overall price level has decreased, while the number of allocated bids has risen disproportionately.

Positive Secondary Reserve Marginal Prices 2013-2016 [€/MW]



Negative Secondary Reserve Marginal Prices 2013-2016 [€/MW]

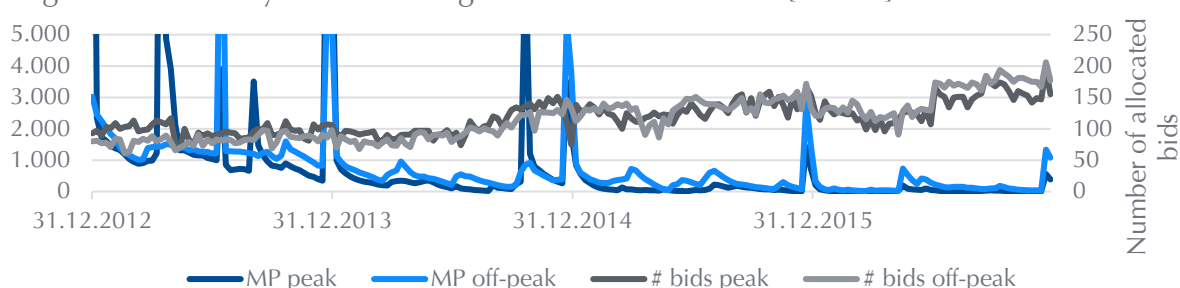


Figure 1: Marginal Prices of secondary reserve provision prices 2013-2016 (Data from (www.regelleistung.net, 2017a) and own calculations)

As reserve demand has been relatively constant between 2013 and 2016, this increase in allocated bids corresponds to a decrease in mean allocated bid sizes for the tendered secondary reserve products. The average allocated bids size has decreased by 50% over the mentioned timeframe. This development is depicted in Figure 2 and might at least partly be explained by a high number of small units entering the reserve market.

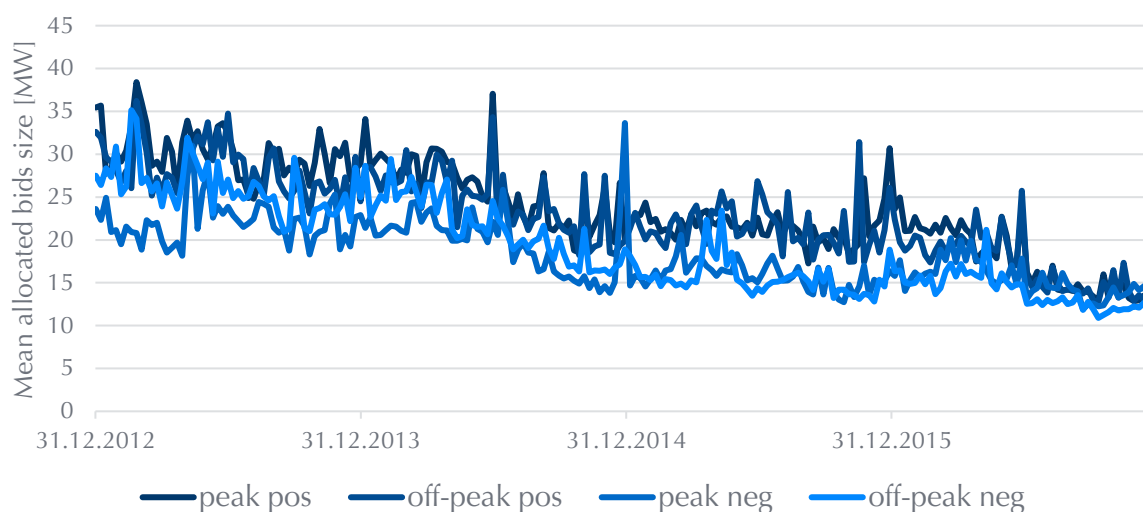


Figure 2: Average bid sizes of allocated secondary reserve bids 2013-2016 (Data from (www.regelleistung.net, 2017a) and own calculations)

In June 2017, the German Federal Network Agency has decided that several aspects of secondary and tertiary reserve procurement should be reformed taking effect from July 12, 2018. Most notably, secondary and tertiary reserve auctions are going to be held one calendar day⁵ ahead of reserve provision, at 8 a.m. CET and 10 a.m. CET, respectively. Secondary reserve switches from peak/off-peak tenders to 4-hour tenders. Although a minimum bid size of 5 MW remains in place, it is possible to only bid for 1 MW, 2 MW, 3 MW or 4 MW of secondary and tertiary reserve under the prerequisite that it is the bidder's only bid in this individual auction (Federal Network Agency, 2017a) (Federal Network Agency, 2017b). This further lowers the hurdles of reserve market participation for small participants.

3 Literature Review

While there is an eclectic body of literature with regards to price formation in general and endogenous reserve and spot price formation in particular, the investigation of CHP has been, apart from technical considerations, mainly focusing on the optimal combination of heat demand and spot marketing opportunities. Both strings of literature and their relevance for the subject of this paper are thus briefly discussed subsequently.

3.1 Endogenous Reserve Price Formation

Electricity wholesale markets and reserve power markets are closely linked, as every power plant marketer needs to choose between electricity production and withholding reserve capacity for sale in the different reserve markets described in section 2. As a result, the marketer faces opportunity costs in case he or she decides to provide reserve, based on his or her individual economic optimal bidding strategy.

Different endogeneous approaches exist to derive optimal bidding strategies and/or market designs. A game-theoretical discussion of the implemented market scheme for secondary balancing power in Germany and its decision-theoretic optimal bidding strategies is given by (Ocker, et al., 2015). Deriving the profit functions of individual market participants and assuming stylized Merit Order and probability curves, the first-order conditions of individual bidders are used to derive optimal bids. In another related working paper, (Belica, et al., 2015) focus on the adequate market design, i.e. pricing rules, in a harmonized European setting, extending previous findings by equilibria formulations.

In contrast, (Wieschhaus & Weigt, 2008) use two market equilibrium models, a Cournot model of spot and reserve markets, and a Bayesian approach for the modelling of the sequential market clearing process of spot and reserve markets. The authors analyse how a variation of the market

⁵ I.e. including weekends and holidays, contrary to prior design.

clearing rules in spot and reserve market, compared to the actual implemented scheme of uniform pricing for the spot and pay-as-bid pricing for the reserve market, would influence price levels in both markets.

The design of the reserve market is also considered by (Müsgens, et al., 2014), who discuss in more depth the technical necessities of central balancing power provision in face of increasing renewable production. They derive the cost-efficient reserve energy provision based on variable power plant costs, also considering the power plants' (partial) non-availability for the spot market in case of reserve marketing. Again, this approach aims to identify efficient market mechanisms for selecting the most cost-efficient reserve power plants at a given point in time and doesn't provide an in-depth quantification of its results. As their main result, Müsgens et al. make the case for a replacement of the existing "pay-as-bid" auction regime in favour of a combined scoring and uniform pricing rule.

A fundamental approach to reserve market modelling similar to the approach used in this paper has already been discussed by (Just & Weber, 2008), also with a special focus on the German secondary reserve market. They model the interdependency between spot and reserve markets by setting up an equilibrium model between reserve power provision and spot generation for conventional power generators. They then investigate the market outcome, given a hypothetical steadily increasing supply function curve and spot electricity and reserve power demand. Finally, a numerical solution algorithm is proposed and applied. The framework of said paper is also applied in (Just, 2011), where the implications of different contract durations of online reserve capacity are investigated.

A more recent work focussing on the derivation of welfare-optimal levels of spinning reserve provision is provided by (Baldursson, et al., 2017). They use an opportunity cost approach to identify optimal reserves capacities from a social planner's perspective, given stochastic residual demand and uncertain renewable electricity generation. The first-order conditions for determination of optimal positive and negative reserve levels are computed, additionally considering the disutility of a failure to meet electricity demand in real time by means of the procured reserve power, resulting in energy not served.

3.2 Modelling of Reserve from CHP

The literature on modelling of combined heat and power plants providing flexibility in reserve markets is relatively sparse compared to the available literature on reserve pricing discussed in section 3.1. However, the suitability of CHP for reserve procurement has been derived as a result in all papers discussed subsequently in this section, although their exact approaches and focus vary.

The provision of heat, electricity and reserve from single or multiple CHP units have so far mostly been discussed in the context of portfolio optimization. As a recent example, (Kumbartzky, et al., 2017) have discussed the optimal operation of a single CHP plant by the help of multistage stochastic mixed-integer linear programming, with a special focus on the German tertiary reserve market. Kumbartzky et al. also provide an extensive list summarizing the body of literature treating with CHP plant operation planning in two or all three of the aforementioned markets. They find that participation in all three markets leads to a significant decrease in net acquisition costs for CHP portfolio owners. Local heat demand restrictions of portfolio holders are modelled as equations and CHP plant operating ranges are modelled by the help of linearization of the possible electricity and heat production ranges.

A similar approach is followed by (Haakana, et al., 2017), except that the spot and reserve market in question here are Nord Pool and the Finnish Frequency Containment Reserve (FCR) markets, respectively. Haakana et al. also identify opportunities between electricity and reserve markets and argue that reserve provision from CHP bears additional economic potential; however, they also underscore the need for additional flexibility in the heating network such as the availability of heat storages to realize said potentials without risking missing heat delivery obligations. In the paper of (Hellmers, et al., 2016), a very similar approach is additionally complemented with the marketing of a stochastically operating wind farm, showing that there is additional benefit if both systems are jointly optimized, rather than marketing heat providing plants and renewable generation separately. However, their model includes a possibility to buy missing heat from other suppliers, relaxing the fixed heat demand restriction – even though heat is in this case provided at high costs.

However, none of the mentioned papers has simultaneously focused on an opportunity cost-based reserve provision from CHP plants and resulting reserve and spot prices in an endogenous reserve market model, suggesting that the following sections constitute a novel contribution to both strings of literature.

4 Methodology

In this paper, a simplified approach for endogenous reserve and spot price formation is combined with power plants acting at a third market, the heat market. The methodology, assumptions and modelling of this paper are presented in the following subsections.

4.1 Endogeneous Modelling of Spot and Reserve Price Formation

As mentioned in the previous section, marketers of power plants have different options to sell power in different markets, creating a rivalry and opportunity costs between these different marketing channels. Figure 3 depicts the impact of reserve marketing on plant operation and the

formation of these opportunity costs. In the following, we assume that spot prices result from an auction under a uniform price clearing. Bids are based on marginal costs of the individual power producers in the market, resulting in an aggregated spot market bidding curve (“the Merit-Order Curve”, MOC), reflecting the current market design in most existing liberalized energy markets.

Assume a simple conventional plant u with marginal costs of MC_u , that may modulate its production between 0, meaning the plant is switched off and P_u^{max} , the maximum power production capacity of this plant. The produced power output needs to be sold entirely in the spot market. Depending on the resulting spot power price p_{spot} , it is then optimal to either keep the plant shut off (in case $p_{spot} < MC_u$) or operate the plant at maximum capacity (in case $p_{spot} > MC_u$). When the marginal costs equal the spot price, the plant operator is indifferent between all possible production points, as he or she is realizing a profit of zero for all output levels. This all-or-nothing view, however, neglects costs and technical limitations associated with shutting down and restarting the power plant. It is thus common not to shut down a plant completely during a limited timeframe with low spot prices, but to rather operate at the minimum stable operation limit of the plant, P_u^{min} , to minimize losses. This operation point is marked by (X) in Figure 3.

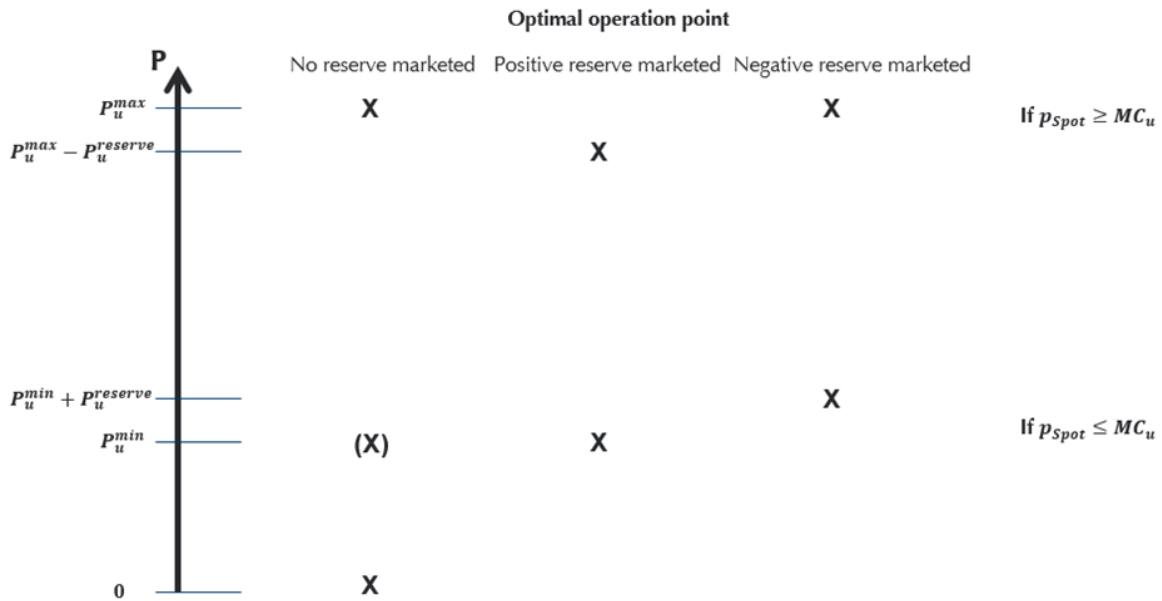


Figure 3: Optimal operation points of conventional power plants with and without reserve marketing for the case of secondary reserve.

In case of a prior decision to market positive reserve, the optimal operation points change. At the upper limit of the production range, the marketed positive reserve power $P_u^{reserve}$ needs to be withheld from the spot market, resulting in a maximum power output of $P_u^{max} - P_u^{reserve}$. The product of the withheld power and the actually obtained spreads in hours with $p_{spot} > MC_u$ thus describes the opportunity losses due to foregone profits compared to a pure marketing of power in the spot market. As a conventional plant committed to provide positive secondary reserve

already needs to be running to reliably deliver the provided reserve energy in case of activation, the plant needs to operate at least at minimum capacity in all hours t during the reserve provision period T . In hours with $p_{spot} < MC_u$, the product of minimum capacity and obtained negative spreads describes the opportunity losses due to this must-run-condition. The opportunity costs of positive reserve provision thus amount to

$$c_{opp,plant,pos} = \sum_{t \in T} \max(p_{spot} - MC_u; 0) + \sum_{t \in T} \max\left((MC_u - p_{spot}) \cdot \frac{P_u^{min}}{P_u^{reserve}}; 0\right) \quad (1)$$

during the reserve provision period. In contrast, in case of negative reserve, there is no inherent foregone profit, as the same power may be sold in the spot market as if there were no negative reserve provision. The minimum production capacity necessary, however, rises by the reserve amount provided, increasing must-run losses compared to the case of positive reserve. The opportunity costs of negative reserve thus amount to

$$c_{opp,plant,neg} = \sum_{t \in T} \max\left((MC_u - p_{spot}) \cdot \frac{P_u^{min} + P_u^{reserve}}{P_u^{reserve}}; 0\right) \quad (2)$$

during the reserve provision period. The reserve bid of a conventional plant owner should at least cover the sum of all expected opportunity costs during the reserve provision period – otherwise the provision of reserves would not be viable for this individual power plant marketer. This finding is also independent from the implemented auction clearing price scheme, i.e. meaning that in a “pay-as-bid” pricing scheme an individual bid should never be lower than the expected opportunity losses from the reserve marketing decision per MW of marketed reserve. If the reserve market is competitive and there are no incentives to underbid provision costs or (significantly) overbid the expected highest allocated bid under perfect competition, the market participants with the lowest opportunity costs of reserve provision should therefore always be allocated in an efficient reserve market⁶. However, bids are calculated with significant lead-time and under uncertainty regarding the actual mean spot price levels during the provision period.

Following the opportunity cost structure described above, the effect of shorter reserve provision periods should be the lowering of reserve prices due to a lower sum of opportunity costs. As an example, the replacement of one peak-hour reserve tender (60 hours per week, part of the secondary reserve regime until July 2018) by 15 four-hour reserve tenders (part of the secondary reserve regime starting from July 2018) results in only four instead of 60 hourly summands per

⁶ As mentioned in section 3.1, there are various game-theoretical approaches arguing that many reserve auction regimes that are implemented are not efficient. However, an in-depth discussion of these effects and arguments is beyond the scope of this paper.

reserve product, resulting in a lower absolute reserve price. Additionally, it may be expected that in many cases, four consecutive hours yield a lower spot price volatility than 60 non-consecutive peak hours over a whole week, which lowers the price spreads in formulas (1) and (2) within the individual hourly summands for plants with marginal costs close to the average spot price of the provision period in question. As a result, the system-wide sum of the reserve provision costs of allocated reserve plants over 15 four-hour tenders may on average be expected to be lower than the system-wide reserve provision costs for allocated reserve plants over one peak period – resulting not only in lower absolute reserve prices, but also in lower per unit reserve prices (cf. (Just, 2011)).

Furthermore, the marketing decision to provide reserves also influences a plant's spot market bidding: As a must-run obligation for plants arises when their reserve bids are selected, the plant's minimum capacity (plus marketed negative reserve capacity) needs to be sold at any resulting price in the spot market. The optimal spot market bid of reserve plants for its minimum capacity hence drops to the lowest possible price in the market to ensure spot market allocation. As a result, the shape of the spot market MOC is changed by reserve markets, as is thoroughly discussed in the paper of (Just & Weber, 2008). Consequently, a mutual dependency of reserve and spot marketing decisions exists, although marketing in both markets does not take place at the same point in time.

In the following sections, we are therefore examining equilibria between spot and reserve markets by the help of a fundamental MOC market model where individual power plant blocks are modelled as discrete units with unit-wise constant marginal costs resulting in a step-wise MOC. This contrasts to steady and differentiable MOCs as analysed by (Just & Weber, 2008) and other papers. We use the system cost-minimizing market result for joint reserve and spot marketing as a proxy of an efficient combined spot and reserve market scheme and derive marginal spot and reserve prices from the obtained results. The authors of this paper acknowledge that by this assumption of efficiency the results do not necessarily have to match obtained reserve market results from implemented reserve market mechanisms.

The following paragraphs describe the model formulation without heat constraints, which are investigated and modelled in the following Section 4.2.

The model objective function is the minimization of system production costs, calculated as the product of individual plant production $prod_{u,t}^{elec} \geq 0$ and marginal costs of electricity $c_{u,t}^{elec}$ per plant u of the power plant pool U and the hourly timestep t of the optimized weekly timeframe T with $|T| = 168$.

$$\min_{\substack{prod_{u,t}^{elec}, r_{ru,t}^+, r_{u,t}^-}} obj = \sum_{t \in T} \sum_{u \in U} prod_{u,t}^{elec} \cdot c_{u,t}^{elec} \quad (3)$$

The electric demand dem_t^{elec} is hereby required to be satisfied at all times, leading to the first equation constraint:

$$\sum_{t \in T} \sum_{u \in U} prod_{u,t}^{elec} = dem_t^{elec} \quad (4)$$

Positive and negative reserves are defined as positive integer values $r_{u,t}^{r+}$ and $r_{u,t}^{r-}$. These reserve amounts provided by individual reserve power plants $ru \in RU \subset U$ need to amount to the positive and negative reserve demand parameters dem_{td}^{r+} and dem_{td}^{r-} during each reserve provision period $TD \subset T$, resulting in the following equation constraints:

$$\forall t \in TD: \sum_{ru \in RU} r_{u,t}^{r+} = dem_{td}^{r+} \quad (5)$$

$$\forall t \in TD: \sum_{ru \in RU} r_{u,t}^{r-} = dem_{td}^{r-} \quad (6)$$

Every plant u may only produce within its feasible production range, described by a minimum stable production capacity share $cs_u^{min} \in [0,1]$, as well as a maximum capacity cap_u^{max} in [MW]. Minimum capacity requirements are modelled by use of a binary on/off-parameter $O_{u,t} \in \{0,1\}$. Also, positive and negative reserve provision $r_{u,t}^+$ and $r_{u,t}^-$ restrict feasible production outputs for reserve plants ru , whereas they are equal to zero for non-reserve providing plants.

$$\forall t \in TD: prod_{u,t} \geq O_{u,t} \cdot cs_u^{min} \cdot cap_u^{max} + r_{u,t}^{r-} \quad (7)$$

$$\forall t \in TD: prod_{u,t} + r_{u,t}^{r+} \leq O_{u,t} \cdot cap_u^{max} \quad (8)$$

The reserve provision decisions are as well modelled as binary constraints $O_{ru}^+ \in \{0,1\}$ and $O_{ru}^- \in \{0,1\}$. For secondary reserve, reserve provision implies a must-run condition:

$$\forall t \in TD: O_{ru,td}^+ \leq O_{u,t} \quad (9)$$

$$\forall t \in TD: O_{ru,td}^- \leq O_{u,t} \quad (10)$$

$$\forall t \in TD: r_{u,t}^{r+} \geq O_{ru,td}^+ \cdot bid_{SRL}^{min} \quad (11)$$

$$\forall t \in TD: r_{u,t}^{r-} \geq O_{ru,td}^- \cdot bid_{SRL}^{min} \quad (12)$$

bid_{SRL}^{min} amounts to 5 MW in the given setting.

Finally, each plant has its own maximum reserve capacity share $cs_u^{maxreserve} \in [0,1]$. This capacity factor amounts to zero for all non-reserve plants. For sake of simplicity, $cap_u^{maxreserve}$ is here assumed to be equal for both positive and negative reserve. The reserve bids per plant are hence subject to the following restrictions:

$$\forall t \in TD: r_{u,t}^{r+} \leq O_{ru,td}^+ \cdot cs_u^{maxreserve} \cdot cap_u^{max} \quad (13)$$

$$\forall t \in TD: r_{u,t}^{r-} \leq O_{ru,td}^- \cdot cs_u^{maxreserve} \cdot cap_u^{max} \quad (14)$$

Table 1 summarizes the assumptions concerning power plant parameters that are not derived from actual market data, as summarized in Section 4.3.

Table 1: Parameter values chosen for technology groups (based on (Buttler, et al., 2015) and own assumptions).

	Biomass	Coal	Natural Gas	Lignite	Nuclear	Oil	Run-of River
cap_u^{min}	0.3	0.3	0.3	0.4	0.3	0.2	0.0
$cap_u^{maxreserve}$	0.3	0.3	0.4	0.2	0.1	0.4	0.1

4.2 Modelling of heat provision from CHP

In this section, we extend the simplified opportunity cost-based reserve valuation by a third product – heat. CHP plants that produce both electric and heat energy are an important part of today's energy system and are expected to remain so despite energy transition efforts limiting the use of greenhouse gas emitting fuels – due to the reliability and efficient use of primary energy in CHP plants. There is a broad range of CHP plant types installed in heating grids. On the one hand, some provide both electricity and heat for industrial processes. Many of these are primarily intended to deliver heat and sell excess electricity on the spot market. On the other hand, heat from CHP units owned by municipal utilities or major generation companies is often used for district heating. Because of its diverse application contexts, there are different plant and portfolio layouts for CHP-fed heating systems (Weber, 2005).

Most notably, CHP units may be differentiated according to their possible operation modes. Some CHP plants such as small-scale units based on combustion engines or so-called backpressure turbines are only able to produce electricity and heat at a fixed ratio, leaving these plants with only one operational degree of freedom. In contrast, extraction condensing turbines may vary the electric and heat output independently from each other, only bounded by the technical limitations posed by its components. Figure 4 shows the feasible heat (x-axis) and electric (y-axis) production combinations for both turbine types in a stylized manner. The brown line demonstrates the remaining flexibility of the plant in case of a fixed heat demand condition; such a restriction is binding in case there is no second heat supply (or storage) unit in the respective heating grid. This operation mode is referred to as “heat-led CHP” in the following.

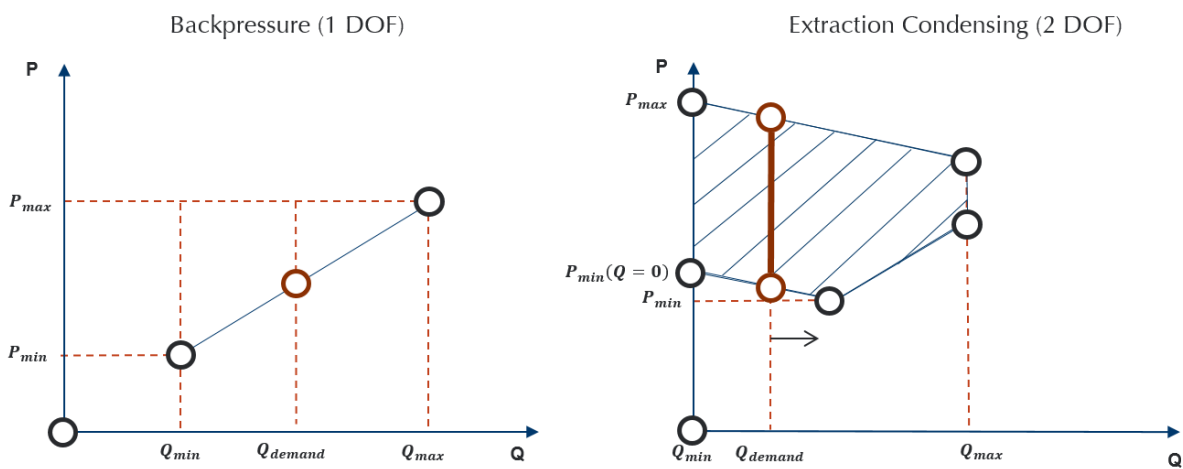


Figure 4: Types of CHP power plants by number of degrees of freedom (DOF) (based on (Weber, 2005), own depiction).

At first glance, backpressure turbines do not seem to differ very much from other conventional power plants regarding their reserve provision cost. Just like conventional power plants, in principle they may provide positive or negative reserve – however, this requires additional heat providing units in the same heating grid that are able to adjust their heat output accordingly to satisfy heat demand in a reliable manner. As a result, costs associated with alternative heat provision need to be considered at determination of reserve provision and energy bids of said units. However, must-run costs of CHP are only existent in case there is no heat delivery obligation of the plant. Opportunity costs of reserve provision may therefore be lowered significantly if reserve provision does not imply an *additional* must-run condition to the CHP plant.

This effect becomes even more pronounced for extraction condensing turbines. Operation of these plants is merely restricted by the maximum and minimum steam generation capacity, stable speed and pressure conditions in the steam cycle and maximum capacity of the heat extraction valve. Within the resulting restricted operational range, however, the plant will be able to realize

all possible electricity/heat output combinations (Weber, 2005). Given an optimization concerning an electricity spot market, however, the results of the prior section 4.1 suggest that the optimal operation point will again be located at the “upper” or “lower” electricity boundary of feasible operation points, the actual position depending on current heat demand and the costs of alternative heat provision.

Assessing the impact of marketing of positive reserve as indicated by the green arrow in Figure 5, we notice that this additional restriction may not necessarily imply opportunity costs. If we further assume that the optimal operation point, for example due to high local heat demand coupled with a high spot electricity price surpassing this plant’s marginal cost of electricity, is in the upper right corner of the feasible operation region – maximum heat output and maximum electricity output subject to maximum heat output – the marketing of positive reserves will not restrict the plant from choosing its optimal operation point. This implies foregone profits of zero, at least in this very instance. As it is the case for backpressure turbines, reserve-induced must-run costs of CHP are only relevant in case there is no heat delivery obligation of the plant. As a result, CHP plants with two degrees of freedom bear relatively lower opportunity costs of reserve provision and can participate in the reserve markets even at low reserve prices without lost opportunities.

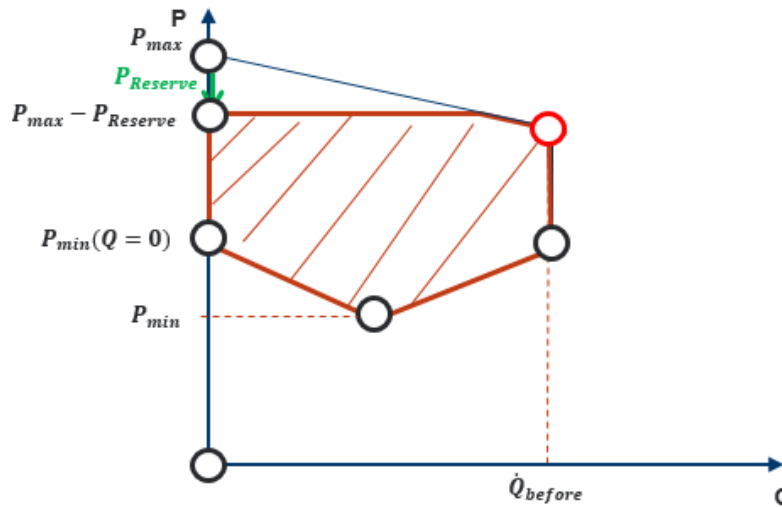


Figure 5: Operation range of an extraction condensing combined heat and power plant in case of positive reserve provision (based on (Weber, 2005), own depiction)

Heat restrictions implemented in the fundamental model include the restrictions enumerated in the next paragraphs.

In the objective function, the costs $c_{hb,t}^{heat}$ for alternate heat production $prod_{hb,t}^{heat}$ from back-up heat boilers need to be added:

$$\begin{aligned}
& \min_{prod_{u,t}^{elec}, prod_{u,t}^{heat}, prod_{bh,t}^{heat}, r_{u,t}^+, r_{u,t}^-} obj \\
& = \sum_{t \in T} \left(\sum_{u \in U} prod_{u,t}^{elec} * c_{u,t}^{elec} + \sum_{hb \in HB} \sum_{u \in U} prod_{hb,t}^{heat} * c_{hb,t}^{heat} \right)
\end{aligned} \tag{15}$$

Heat demand $dem_t^{heat} \geq 0$ needs to be satisfied within every local heating grid $hg \in HG$, comprising a CHP plant $chp \in CHP \subset U$ and a back-up heat boiler $hb \in HB \not\subset U$.

$$\forall hg \in HG: prod_{chp,t}^{heat} + prod_{hb,t}^{heat} = dem_t^{heat} \tag{16}$$

Every CHP plant and back-up heat boiler has a maximum heat output $cap_{chp}^{max,heat}$ or $cap_{hb}^{max,heat}$, respectively.

$$\forall chp \in CHP: prod_{chp,t}^{heat} \leq cap_{chp}^{max,heat} \tag{17}$$

$$\forall hb \in HB: prod_{hb,t}^{heat} \leq cap_{hb}^{max,heat} \tag{18}$$

As described above, the feasible electricity and heat outputs of CHP plants may be implemented by implementation of linear constraints displayed in Figure 4. For backpressure turbines $bt \in CHP$, this relationship is implemented by assuming a fixed ratio β_u^{bp} between heat and electricity output.

$$\forall bt \in CHP: prod_{chp,t}^{elec} = prod_{chp,t}^{heat} \cdot \beta_u^{bp} \tag{19}$$

For extraction condensing turbines, three inequalities are needed to model the boundaries of the feasible area. Let β_u^{ex} denote the power loss coefficient at the maximum steam throughput and β_u^{bp} the slope of the backpressure limit. Then the power loss coefficient may also be applied to the minimum stable operation limit and the feasible production range may be described by the joint application of the following three constraints.

$$\forall chp \in CHP: prod_{chp,t}^{elec} \leq cap_{chp}^{max,elec} \cdot O_{chp,t} - \beta_u^{ex} \cdot prod_{chp,t}^{heat} \tag{20}$$

$$\forall chp \in CHP: prod_{chp,t}^{elec} \geq cap_{chp}^{max,elec} \cdot cap_{chp}^{min} \cdot O_{chp,t} - \beta_u^{ex} \cdot prod_{chp,t}^{heat} \tag{21}$$

$$\forall chp \in CHP: prod_{chp,t}^{elec} \geq prod_{chp,t}^{heat} \cdot \beta_u^{bp} \tag{22}$$

Note that production boundaries from reserve provision, implemented by the inequality constraints (7) and (8), may further restrict the possible operation range.

4.3 A simplified model of the German market in 2016

In order to verify and quantify the price effects of reserve provision by CHP plants we use the defined fundamental MOC model based on data of the German power plant fleet, including notably actual block-wise availability data from the EEX transparency platform (EEX Transparency Platform, 2017) of the year 2016. Smaller generation units not reporting to EEX, i.e. small biomass and hydro plants, are modelled as technology groups with uniform characteristics and full availability. Load data, renewable generation data and cross-border exchange amounts are considered as an exogenous input and are derived from entso-e data (entso-e Transparency Platform, 2017). However, renewable generation from direct marketing under the Renewable Energy Act is not modelled as part of residual load, but as a technology class offering at the negative technology market premium valid in 2016. An estimation of the hourly production amounts from direct marketing of renewables is undertaken based on 2016 data by the German Federal Network Agency (Federal Network Agency, 2018) and the renewable generation pattern given by entso-e (entso-e Transparency Platform, 2017). Historical secondary reserve demands are derived from 2016 data provided by the German Transmission System Operators (TSOs) (www.regelleistung.net, 2017a). As secondary reserve is tendered in weekly auctions for the peak/off-peak hours of one calendar week at a time, only the 52 calendar weeks from January 4, 2016 until January 1, 2017 are considered in this analysis. Storages, i.e. pump storage hydro power plants, are not explicitly modelled.

Marginal costs of power plants per technology class are determined by using actual daily fuel prices from the examined weeks of 2016⁷, if available. Primary energy costs of nuclear and lignite plants are assumed to be constant⁸. Price differentiation within technology classes is achieved by randomly drawing plant efficiency parameters for each power plant, assuming a normal distribution of efficiency values in each technology class. A summary of used parameter values is given in Table 7 in the Appendix. Market premiums are displayed in Table 8 – with the corresponding negative values being used as marginal costs of renewable generation. Dispatchable renewables not subject to direct marketing are assumed to offer their capacity at marginal costs of zero. One slack turbine is implemented at highest current marginal costs in the market in each hour to keep the model solvable if electricity demand exceeds generation capacity.

⁷ Coal: API2, Natural Gas: OTC TFF, CO2: EEX, Oil: Brent, data from (Energate Messenger, 2017b) (Energate Messenger, 2017a)

⁸ at $2.09 \frac{\text{€}}{\text{MWh}_{th}}$ and $4.31 \frac{\text{€}}{\text{MWh}_{th}}$, respectively.

Reserve providing power plants are identified by merging ownership data from the EEX Transparency platform (EEX Transparency Platform, 2017) with the list of companies prequalified for the secondary reserve market (www.regelleistung.net, 2017). However, because of missing information about the actual reserve portfolio composition, we assume an individual reserve market participation by the power plants of this list. CHP plants are identified by merging EEX Transparency platform information with the power plant list of the Federal Network Agency, containing this information (Federal Network Agency, 2017c). The distinction of backpressure and extraction condensing turbines is based on a further internet research of the individual CHP plants. CHP plants are assumed to satisfy a stylized heat demand, depending on seasons. For simplicity reasons, it is assumed that every CHP plant serves an individual heating grid, and that there is a back-up heat generation unit (with natural gas as fuel and a capacity equalling 30% of the highest heat demand during the year) installed in every heating grid. Thus, it is possible in general to substitute parts of the heat provision from CHP by alternative heat in times of low spot electricity prices, relaxing heat-driven must-run conditions.

The implemented model optimizes joint secondary reserve and spot electricity provision with a rolling optimization window, optimizing one calendar week at a time. System overall electricity and positive and negative reserve demands need to be satisfied, as well as a local heat demand for each CHP portfolio. Reserve marketing induces a must-run condition to the respective plant, and each conventional plant is assigned a maximum and minimum operation capacity, as well as a maximum reserve share. Only integer values greater or equal to 5 MW are allowed as reserve sizes. On/off-states are modelled by a binary variable, turning the model in a mixed-integer-problem (MIP). The system-cost minimization model is solved by using GAMS 24.1.3 with the CPLEX 12.5.1.0 MIP solver.

Resulting spot and marginal reserve prices are identified as the shadow prices of the electric demand (4), respectively positive and negative reserve demand equation constraints (5) and (6), under the assumption that those may be interpreted as the cost or provision of the next electricity or reserve power increment.

4.4 Investigated Cases

We investigate four different case setups to assess their impact on reserve and spot prices:

In case 1a, reserve provision by CHP plants is allowed, but these plants are modelled without heat demand and restrictions, i.e. CHP plants are treated as conventional condensing power plants. As a result, only the spot and reserve market equilibrium is considered in a peak/off-peak reserve provision scheme, as it was implemented during the investigated 52 calendar weeks of 2016. In Case 2a, it is assumed that CHP plants may not provide secondary reserve and thus, primarily conventional power plants satisfy reserve demand; however, the stylized heat demand

is considered as an operating restriction to identify must-run conditions of CHP plants for the spot market.

Case 3a considers the combination of the stylized heat demand curve applied in case 2a and reserve from CHP plants as applied in Case 1a and their combined effect on both spot and reserve market results. Case 4a extends Case 3a by 100 small CHP power plant pools, analysing their additional effect on spot and reserve prices as a sensitivity.

The results of the four cases are finally compared to an alternative auction regime with the same demand, but four-hour reserve provision tenders to reflect upcoming market design changes in the German secondary reserve markets (Cases 1b, 2b, 3b, 4b) instead of peak/off-peak tenders.

5 Model Results

We obtain spot prices and positive and negative reserve prices for 8736 hours, as well as the marketed positive and negative reserves and marginal prices for every reserve plant during the respective reserve periods. The results are discussed in the following subsections.

5.1 Results of Cases 1a-4a

Table 2 shows the results of the hourly spot prices for all analysed cases with a peak/off-peak reserve tender. It shows that all four cases produce spot prices with Mean Average Errors (MAEs) in a 5.91-6.64 €/MWh range; a value that appears reasonable, compared to results of “pure” fundamental electricity price modelling approaches for the German market in the literature, especially as they are focussed on predicting spot electricity prices only. For example, (Beran, et al., 2018) obtain a MAE of 5.6 €/MWh over a range of five years (but not including 2016), (Kallabis, et al., 2016) obtain a MAE of 4.46 €/MWh for earlier years with a similar model, but focus on German Futures Prices. Spot prices are slightly over-estimated on average, which also stems from an under-estimated number of hours with negative prices. Overall accuracy increases when heat-induced must-run is considered, Case 4a yields both the lowest mean price level and the lowest MAE.

Table 3 displays the obtained results for positive reserve. The values of the error measures are not comparable to the spot market, and there is no similar approach in the literature, making it harder to assess the quality of obtained results. However, comparing MAE values between the cases, it becomes apparent that Case 2a, the case excluding reserve from CHP, differs most from historical results for reserve and electricity prices. While Case 4a shows the lowest mean error, Case 1a – the case not considering heat demand restrictions – yields the lowest MAE over the 52 weeks investigated.

Table 2: Spot price model results, compared to historical Day-Ahead prices (EPEX Spot, 2017) in Cases 1a-4a.

	Historical (2016)	Case 1a	Case 2a	Case 3a	Case 4a
Mean spot prices [€/MWh]	29.06	32.01	31.79	31.83	31.17
Correlation (Model/Hist.)	-	0.73	0.76	0.75	0.77
Mean Error (Model- Hist.) [€/MWh]	-	2.95	2.73	2.76	2.11
Mean Absolute Error (Model-Hist.) [€/MWh]	-	6.60	6.64	6.42	5.91
# negative hourly prices	96	42	82	49	51

The model shows highest electricity prices without consideration of heat production, which does not seem surprising, because lower spot bids of plants with a heat-induced must-run condition are not reflected in this Case. For positive reserve prices, however, Cases 1a and 4a seem to reflect historical observations best for the peak period. For the off-peak period, however, the assumptions of Case 4a lead to slightly lower prices than historically observed, while reserve prices are over-estimated for all other positive reserve products and Cases. The price lowering effect in reserve markets because of heat-induced must-run-conditions described in section 4.2 is confirmed by model results. However, in this approach, actually observable bid size patterns are not replicable without the assumption of participation of smaller pools bidding only low reserve volumes. Additionally, modelling of CHP reserve plants without heat restrictions influences the accuracy of spot price modelling more negatively than the accuracy of reserve price modelling. The slope of the MOC near to the resulting spot price drives reserve prices. As the MOC gets steeper in the relevant section of the MOC due to heat-induced must-run-capacities bidding at minimal price, reserve prices without consideration of heat restrictions may even yield lower reserve prices in the giving setting. This may occur if the effect of cheap reserve provision from CHP is over-compensated by a steeper MOC from including heat demand considerations.

Table 3: Positive reserve model results compared to historical reserve provision data (www.regelleistung.net, 2017a) and own calculations).

	Historical (2016)	Case 1a	Case 2a	Case 3a	Case 4a
Mean positive secondary reserve prices peak [€/MW]	353.31	483.17	707.46	596.43	497.97
Mean Error peak (Model-Hist.) [€/MW]	-	129.87	354.15	243.13	144.67
Mean Absolute Error Peak (Model-Hist.) [€/MW]	-	279.54	429.68	374.85	229.17
Mean allocated bid sizes peak [MW]	17.60	61.42	65.14	51.07	21.32
Mean positive secondary reserve prices off-peak [€/MW]	581.04	622.41	1,038.90	612.27	540.26
Mean Error off-peak (Model-Hist.) [€/MW]	-	41.36	457.85	31.23	-40.79
Mean Absolute Error off-peak (Model-Hist.) [€/MW]	-	279.37	574.71	338.01	316.92
Mean allocated bid sizes off-peak [MW]	17.37	66.54	66.78	54.07	21.27

For negative reserve, Cases 1a, 3a and 4a show smaller differences to historically observed price levels than Case 2a (cf. Table 4). Again, the inclusion of CHP plants in the reserve market leads to much lower and more realistic price levels, due to reduced reserve-marketing induced opportunity costs of reserve provision. However, negative reserve prices seem to increase through the inclusion of more CHP and heat restrictions, contradicting the intuition that more flexible reserve supply from CHP should lower reserve prices. On the other hand, the price increase of negative reserve is consistent with a dropping mean spot price, leaving less inframarginal power plants in the market. Furthermore, as most CHP plants in this model have marginal costs of electricity higher than the average spot price, it is not surprising that provision of positive reserve is cost-wise preferable to negative reserve provision from the same plants.

Table 4: Negative reserve model results compared to historical reserve provision data (www.regelleistung.net, 2017a) and own calculations).

	Historical (2016)	Case 1a	Case 2a	Case 3a	Case 4a
Mean negative secondary reserve prices peak [€/MW]	43.24	28.03	58.81	50.14	44.69
Mean Error peak (Model-Hist.) [€/MW]	-	-15.21	15.57	6.90	1.46
Mean Absolute Error Peak (Model-Hist.) [€/MW]	-	46.40	71.66	64.26	60.59
Mean allocated bid sizes peak [MW]	15.38	63.25	63.70	58.93	56.49
Mean negative secondary reserve prices off-peak [€/MW]	177.65	195.65	348.77	283.53	290.85
Mean Error off-peak (Model-Hist.) [€/MW]	-	18.01	171.12	105.89	113.20
Mean Absolute Error off-peak (Model-Hist.) [€/MW]	-	198.20	237.47	228.14	230.91
Mean allocated bid sizes off-peak [MW]	14.04	58.39	61.18	51.64	55.40

5.2 Results of Cases 1b-4b

This section describes the changes in model results if reserve market tenders are shortened to four-hour periods, instead of the peak/off-peak regulation implemented until July 2018. Changes of spot price levels are displayed in Table 5. Changes are most pronounced for the model without heat restrictions. With heat-induced must-run, the decrease in spot prices is clearly less pronounced. Yet a slight price lowering effect by the new auction regime is observable in each case.

The effects on positive reserve prices are much more pronounced. To enable a comparison between the obtained prices, all prices are displayed as prices in €/MW/h and the four-hour tenders of the new regime are matched to the corresponding peak/off-peak tenders of the old regime.

Table 5: Spot price deviations in case of four-hour reserve provision tenders.

	Case 1b-Case 1a	Case 2b-Case 2a	Case 3b-Case 3a	Case 4b-Case 4a
Mean Price Effect [€/MWh]	-0.17	-0.03	-0.10	-0.10
Median Price Effect [€/MWh]	0.00	0.00	0.00	0.00
Stand. Dev. of differences [€/MWh]	5.44	3.27	3.61	4.10

As expected, shorter reserve provision periods result in lower hourly reserve provision costs for all cases. The price-lowering effects are similar in all cases, with a range of 1.2-2.7 €/MW/h for positive reserve, and a range of 0.2-1.3 €/MW/h for negative reserve. Negative reserve continues to yield a much lower price level than positive reserve – regardless of the regime employed. As a result, a shortening of reserve provision tenders can be expected to lower the cost of reserve procurement substantially. From a power plant owner perspective, this obviously means that the market value of flexibility as observed in the reserve market decreases. Yet this does not imply that the value of flexibility is now under-valuated. Rather the flaws of an inefficient market design are reduced by moving towards shorter procurement periods (cf. also (Just, 2011) on this point).

Table 6: Mean Hourly Positive and Negative Reserve Provision prices with peak/off-peak and four-hour tenders

	Case 1a	Case 1b	Case 2a	Case 2b	Case 3a	Case 3b	Case 4a	Case 4b
Mean Price Positive Secondary Peak [€/MW/h]	8.05	6.12	11.79	10.20	9.94	8.73	8.30	6.75
Mean Price Positive Secondary Off-Peak [€/MW/h]	5.76	3.99	9.62	6.90	5.67	4.26	5.00	3.64
Mean Price Negative Secondary Peak [€/MW/h]	0.47	0.22	0.98	0.57	0.84	0.45	0.74	0.42
Mean Price Negative Secondary Off-Peak [€/MW/h]	1.81	1.04	3.23	2.18	2.63	1.35	2.69	1.46

6 Conclusions

In this paper, we analyse the opportunity cost structure of CHP plants and evaluate their impact on spot and reserve price levels by use of a fundamental model of the German electricity and secondary reserve market. We find that CHP plants differ from other conventionally fuelled power plants due to their heat delivery obligations, leading to lower reserve-induced opportunity costs for participation in the reserve markets. A higher market share of CHP is therefore not only lowering spot electricity, but also reserve price levels under a peak/off-peak market design. We find that fundamental price models benefit significantly from the explicit modelling of heat restrictions and reserve provision, leading to more accurate results concerning spot electricity prices. In comparison, we find that an increase in accuracy of fundamentally modelled reserve price levels is a lot more challenging. However, our fundamental model seems to reflect historically observed data reasonably well.

We further investigate the effects of a shorter reserve provision tender of four hours on projected reserve prices, finding that they lower prices significantly both with and without additional consideration of heat demand restrictions, a result in line with the findings of (Just, 2011). For negative reserve, this effect is on average less pronounced in absolute numbers, but as well observable.

The cheaper provision of flexibility from small plants, i.e. CHP plants, should at least in part explain the plummeting reserve price levels over recent years, as CHP provides a larger supply of very flexible capacity to the market. A further price decrease due to other new entrants in the reserve markets, like battery storages or flexible demand resources, seems likely in the short-term future. Combined with the upcoming changes in secondary reserve market design, values for flexibility on German reserve markets are likely to be under continued downward pressure – despite the projected increase in renewable intermittent generation in the coming years.

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Appendix

This section contains additional model input data.

Table 7 exhibits used parameter values of standard-normal distributions for the random draw of values for the power plant efficiencies necessary for calculation of the MOC.

The probability density function of the standard-normal distribution is:

$$f(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} \quad (23)$$

Random input numbers for x were created by help of the Excel method RAND().

Table 7: Overview of parameters for efficiency calculation in MOC (based on (Buttler, et al., 2015) and own assumptions)

Technology class	μ	σ	Lowest efficiency [%]	Highest efficiency
Hard Coal	0.41	0.03	32.4	51.1
Natural Gas OCGT	0.40	0.03	32.8	48.7
Natural Gas CCGT	0.60	0.02	54.9	65.1
Nuclear	0.33	10^{-6}	33.0	33.0
Lignite	0.39	0.01	36.0	41.7
Oil	0.30	0.04	23.3	39.7

Table 8 contains market premiums for renewable generation during the investigated year (2016).

Table 8: Overview of market premiums [ct/kWh] used as negative marginal costs of renewable generation (data from (Netztransparenz.de, 2017))

Month	Wind onshore	Wind offshore	Solar	Dispatchable RE
January 2016	2.407	2.637	3.224	2.904
February 2016	1.831	1.961	2.405	2.199
March 2016	2.106	2.138	2.314	2.431
April 2016	2.325	2.340	2.344	2.421
May 2016	1.800	2.009	1.887	2.254
June 2016	2.672	2.687	2.821	2.769
July 2016	2.391	2.408	2.67	2.719
August 2016	2.533	2.537	2.616	2.718
September 2016	2.748	2.806	2.978	3.049
October 2016	3.403	3.570	3.763	3.713
November 2016	3.266	3.455	4.046	3.822
December 2016 (and January 1, 2017)	2.403	3.111	4.352	3.748

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