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Bidding strategy for battery storage systems in the secondary control reserve market

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HIGHLIGHTS

- Automatic Frequency Restoration Reserve market description.
- Operating strategy for a generation pool comprising a Battery Energy Storage Systems (BESS)
- Bidding strategy to derive optimal bids and to evaluate economic feasibility.
- BESS market participation not economic feasible in 2019 but possibly in 2025.

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ABSTRACT

In continental Europe, automatic Frequency Restoration Reserve (aFRR) is one of three control reserve services to counteract imbalances in the electrical grid. The market is dominated by a few operators of conventional power plants since the auction design is complex and new players face various entrance barriers. In order to stabilize the electrical grid in the future, renewable generation technologies need to enter the market. To encourage operators (and traders) of renewable generation facilities to enter the market, this paper presents a bidding strategy based on an optimization approach for deriving an optimal bid and for estimating the revenue potential on this market. The focus is on the participation of Battery Energy Storage Systems (BESS) either in standalone mode or in conjunction with a virtual power plant (VPP). An in-depth cost breakdown and battery ageing model support the derivation of earning potentials. With current costs of containerized BESS, an operation is not economically viable. However, with a predicted cost breakdown for the year 2025 and a pooled operation, profits can be generated. But even for the reduced-cost scenario, profits were found to be lower than on the Frequency Control Reserve (FCR) market.

1. Introduction

In order to limit the global temperature rise, the energy supply must shift away from conventional power plants towards a high degree of renewable sources. As for Germany, the nuclear and coal-fired phase-out is politically agreed. With fewer conventional power plants being active, services for stabilizing the electrical grid must increasingly be provided by other technical units. In continental Europe, various country-specific services are harmonized in order to benefit from a joint service procurement and a collaborative delivery. Of the three major control reserve services, Frequency Control Reserve (FCR) has the smallest activation time and first responds to grid imbalances. Battery Energy Storage Systems (BESS) already make up a significant share among all FCR providers because the procurement process is easy and the business model is validated [1,2]. However, this is different for subsequently activated control reserve services which are dominated by a small number of conventional power plant providers [2,3]. Despite recent design changes, automatic Frequency Restoration Reserve (aFRR) and manual Frequency Restoration Reserve (mFRR) suffer from entrance barriers. Aside from technical requirements, the auction process is complex and revenue potentials are difficult to estimate. This work presents a novel bidding strategy for estimating the earning

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Nomenclature

aFRR	automatic Frequency Restoration Reserve
BESS	Battery Energy Storage System
EPF	Electricity Price Forecasting
FCR	Frequency Control Reserve
mFRR	manual Frequency Restoration Reserve
PV	Photo Voltaic
SARIMA	Seasonal Autoregressive Integrated Moving Average
SBP	Secondary Balancing Power
SCR	Secondary Control Reserve
SoC	State of Charge
TSO	Transmission System Operator
VPP	Virtual Power Plant

potential of a BESS participating on the aFRR market. Battery aging and a BESS cost breakdown are integrated in the derivation of an optimal bid. Both, the standalone operation of BESS and the integration into an existing virtual power plant (VPP) are considered. Despite a focus on the German/Austrian market, the presented methodology can easily be adapted to comply with the market rules of other countries, also outside Europe. This work further compares the earning potentials on the aFRR market with the earning potentials on the FCR market and earning potentials due to arbitrage operation.

Section 2 briefly describes the aFRR market design, Section 3 presents an overview of literature related to bidding strategies followed by open research questions answered by this work, Section 4 explains the methodology for calculating an optimal bid, Section 5 presents the results for various scenarios, and Section 6 summarizes the findings of this work.

2. Automatic Frequency Restoration reserve (aFRR)

Since this work is closely related to a publicly funded stationary battery storage research facility located in Aachen, Germany, the German/Austrian electricity market is considered in this work [4]. However, due to an ongoing market harmonization and coupling in continental Europe, the results are more widely applicable.

Three different types of control reserve are procured by the TSOs: Frequency Control Reserve (FCR) must be fully activated within 30 s, automatic Frequency Response Reserve (aFRR) within 5 min and manual Frequency Response Reserve (mFRR) within 15 min after an imbalance causing event [5]. The focus of this work is on the aFRR market, also referred to as Secondary Control Reserve (SCR).

A prequalified technical unit for the aFRR market must be able to generate a measurable power output after 30 s, deliver the full tendered power within 5 min and provide the full tendered power for at least 4 h. On a quarterly basis, the TSOs adjust the total aFRR demand (in MW) for their respective control zone [5].

The total aFRR demand is procured in a multi-unit, open, pay-as-bid, anonymous and transparent auction process. Only prequalified units which fulfill the technical requirements are allowed to participate in the auction process. As illustrated in Fig. 2-1, separate daily auctions are held for 6 different time slices and both positive (“POS_xx_xx”) and negative (“NEG_xx_xx”) delivery directions.

For each product type a participant must submit a bid tuple comprising the capacity (MW), capacity price (€/MW) and energy price (€/MWh). Awarding of the submitted bids is either solely based on the capacity price or on the mixed price. As defined by Eq. (1), the mixed price for one product (B_{MP}) is based on the submitted capacity price (B_{C}), the submitted energy price (B_{E}) and a factor (a_{M}) published quarterly by the TSOs.

$$B_{\mathrm{MP}} = B_{\mathrm{C}} + a_{\mathrm{M}} \cdot B_{\mathrm{E}} \tag{1}$$

Over the past years, the market and auction design has frequently changed. Due to the simulation period of this work (see Section 5), the mixed price auction scheme is of primary interest for this work.

After auction closing, all bids are collected by the TSOs and arranged ascendingly by mixed price (merit order). Starting from the lowest mixed price bid, consecutive bids are accepted until the total aFRR demand is met. The last accepted bid marks the marginal mixed price.

If grid imbalances require aFRR intervention, participants are activated starting with the one with the lowest energy bid until the power demand is met. The relative height of an energy bid determines the position in the merit-order list. Participants with low energy price bids are therefore activated more frequently than those with high energy prices.

3. Literature review

This section provides an overview of literature related to bidding strategies for the electricity market with a special focus on the aFRR market. Predominant foundations for building a bidding strategies are either based on fundamental market simulations, multi-agent models or game-theoretic derivations.

Fundamental models assume an efficient market and complete information for all market participants. The system load is covered at minimal overall costs since the distribution of resources can be optimized [6]. However, under the assumption of complete information, strategic bidding or exploitation of market power cannot be investigated. For latter effects to be considered, a multi-agent or game-theoretic based simulation is more suitable.

A multi-agent based simulation of the German control reserve and day-ahead market was conducted in [7]. The aim of the research was to find bidding strategies which simulate the behavior of market participants in aforementioned markets as close to reality as possible. An analysis revealed that a bidding strategy is influenced by the auction design, price development expectations, the portfolio of the individual market participant and the repeated procurement process. In case of the day-ahead market, bidding strategies offering prices close to the marginal generation costs revealed the most realistic results. Offers at the marginal costs increase the awarding probability of market participants and in most cases contribute to covering fixed costs as well. The contribution to the fixed costs is due to a unit market price (market clearing price) on the day-ahead market which is usually higher than the offered price. Strategic bidding plays a minor role. In control reserve markets such as the aFRR market, participants are payed-as-bid. Offers at marginal costs therefore do not cover fixed costs. The research revealed, that strategic bidding strategies which learn from previous auction outcomes produce the most realistic results. Offered prices were above the marginal costs.

Another detailed multi-agent based model was presented by [8] and

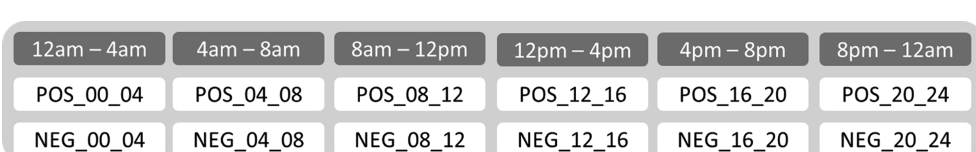

Fig. 2-1. Time slices in the new aFRR market design.

is able to simulate the day-ahead as well as the intraday market. Major agents in these markets are modelled individually. Aside from short-term simulations, the model also allows to derive investment decisions by analyzing multiple years [9].

In order to extend the country-specific balancing power markets to a European-wide solution, the auction design must be harmonized. Compared to the German/Austrian market design, the European Commission aims at implementing two design modifications [10]. First, the pay-as-bid awarding scheme is to be replaced by uniform pricing and second an additional energy-price based market is planned. A game-theoretical model for both auction designs was implemented by [11]. Both market designs were found to theoretically provide efficient auction outcomes and competitive prices. However, imperfections were also revealed in historical market data. Empirical evidence was presented which suggests that market participants coordinate on non-competitive price levels (collusive bidding behavior) and take into account previous auctions results [3,12]. The collusion and abuse of market power was in part explained by only a few participants providing most of the aFRR capacity in Germany. Historical market data does therefore not match with game-theoretic predictions. Based on above findings, [13] proposes a bidding strategy which integrates the results of previous auctions in order to derive optimal capacity and energy price bids. A subjective acceptance probability and demand probability was derived from historic prices. It was found that the capacity and energy price depend on each other. Validating the bidding strategy on real market data revealed a high correlation to bidding strategies actually used in the market.

A two-player competitive market model was developed by [14]. The first player represents a single market participant whereas the second player represents the remaining market. The simulation environment implements a power market, ancillary services and corresponding auction processes. From a defined combination of bidding strategies, game theory techniques developed in this research can locate optimal Nash equilibrium solutions. Also the dominant bidding strategy which maximizes the revenues for a single market participant can be derived.

In [15], bidding strategies on the German aFRR market are derived by analyzing the historical capacity and energy prices. A two-stage bivariate modelling process is presented which first analyses the influence of exogenous data sources to the aFRR prices. In the second stage, the influence of the lagged predictors is modelled in a multivariate vector autoregressive model. Based on the findings from the time series modelling, two dominant bidding strategies were derived and explained by game-theory.

In order to allow wind power farms to provide ancillary services to the grid, [16] implemented a probabilistic generation forecast model. Based on the forecast, an offering strategy was developed which accounts for the market rules, operational capabilities of the turbines and the joint market participation. The research revealed that the provision of control reserve provision by wind farms is technically feasible but does not always generate more revenues. Related research estimates the amount of aFRR capacity which can reliably by provided by a renewable generation plant consisting of wind and photovoltaic [17,18]. Multiple strategies are derived which either optimize for maximizing revenues or for minimizing the risk of underfulfilment. The research used aFRR price forecasting techniques and is evaluated on real aFRR market data.

Only a few investigations are published which deal with BESS participating on the aFRR market. Lithium-ion and sodium Sulphur based grid-scale energy storages were analyzed in [19]. For the British market, an arbitrage algorithm was extended to also allow participation in control reserve services. Both a stand-alone operation as well as a joint operation with a wind farm was considered. Despite a tripling of profits, the high investment costs of BESS were found to prevent an economic viable operation. A revenue potential analysis of BESS offering congestion relief services and providing arbitrage trading was conducted by [20]. However, ancillary services were not considered. Various research suggests that BESS which provide aFRR in a standalone mode cannot be operated economically beneficial [21,22]. According to this research, the energetic capacity costs of BESS are too high for meeting the 4-hour minimum operating criterion of aFRR.

3.1. Research questions

Based on the currently published literature, the authors identified the following open research questions, which are addressed in this work:

1. Various aFRR market models have been presented to analyze and explain the bidding behavior of market participants. However, an in-depth earning potential analysis supported by historical data is missing. What are the earning potentials for new technologies, such as renewables, entering the aFRR market? See Section 5.1 for results.
2. In particular, is it economically viable to operate a BESS on the aFRR market? How do the various battery aging mechanisms impact the business model? See Section 5.2 for an analysis.
3. The aFRR request frequency and aFRR energy provision strongly depends on the submitted energy price bid in the auction. Which energy price bid is optimal for a BESS and how does the energy price bid impact the battery aging? See Section 4.6 for a detailed overview of the optimization approach.
4. The focus of this work is on the aFRR market. But how do the earning potentials of arbitrage and the FCR market compare to the earning potentials of the aFRR market? See Section 5.3 for a comparison.
5. Considering a heterogeneous pool of generation units, this work presents a methodology, based on an optimization approach, for deriving the optimal market participation. See Section 4 for a detailed overview of the methodology.

4. Methodology

The objective of the bidding strategy presented in this chapter is to evaluate the benefits of adding a BESS to an existing VPP. Revenues on the aFRR market strongly depend on the submitted bid tuple. The methodology presented in this chapter maximizes the profit for a particular pool by deriving the optimal bid tuple. It relies on the aFRR market prediction methodology as described in [23]. Section 4.1 presents the underlying data sources of the simulation, Section 4.2 describes various pool configurations analyzed in this work, Section 4.3 describes the operating strategy of a pool, Section 4.5 describes the battery model used for estimating aging effects and Section 4.6 describes the optimization approach.

4.1. Input data

This section describes the various input data sources used for running the simulation described in this chapter.

All aFRR market related data is published on a web-based platform (regelleistung.net) operated by multiple European TSOs [5]. The data is open-access and includes anonymized bids of all successful market participants for each aFRR product type and day. Bids above the marginal mixed price are not qualified for aFRR provision and are not published. For each submitted bid, the corresponding capacity price (€/MW), energy price (€/MWh) and offered capacity (MW) is included in the data set. A historical aFRR request time series is published in both 1-sec and 15-min resolution. For each instance in time, the series states the total power requested by the TSOs. If a unit must respond to a request depends on the position in the merit order list. A quarterly changing mixed price factor a_M (Section 2) is published as well.

Day-ahead and intraday market data is obtained from the European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Power Exchange (EPEX) [24,25]. Data for both markets is used by the operating strategy described in Section 4.4. The day-ahead and intraday prices (€/MWh) are published in 15-min or 1-h resolution corresponding to the individual market block size.

Various different generation types and corresponding properties such as generation profile time series, marginal costs or idle capacities are considered by the simulation framework used in this work. Among the included types are various wind parks (onshore and offshore), solar parks, biomass generation, nuclear power plants, fossil gas power plants and lignite power plants. This work, however, does not use specific generation facilities at individual locations but instead uses scaled profiles of the overall generation in Germany. The corresponding time series were obtained from the freely accessible ENTSO-E web platform which provides the data in a 15-min resolution [24]. To obtain for example the wind onshore profile of 100 MW nominal capacity, the overall German wind onshore generation time series is scaled accordingly. A few advantages arise from scaled generation profiles for this investigation. Outages of individual generation units due to failures or maintenance measures do not impact the results. Also, depending on the data source, individual generation profiles are often at a resolution of less than 15-min (e.g. 1-h resolution) which does not match the simulation time base. Furthermore, individual generation profiles are often not freely available which would make this work not reproducible.

4.2. Pool configurations

This section describes multiple pool configuration (VPP) scenarios which differ in the types and capacities of generation facilities. The particular pool configuration influences the generated revenues since it influences the total capacity which can be offered on the aFRR market (Section 4.4.2). For all pool configurations considered in this work, one dispatch and trading unit controls all generation facilities and the BESS.

Table 4-1 provides an overview of the considered pool configurations in this work. On purpose, the configurations do not reflect the generation units of any specific trading, administration and dispatch facility. Instead, the used configurations could be part of any utility-scale or municipal-scale trading facility portfolio. A BESS is operated in stand-alone mode, coupled with onshore wind, coupled with onshore wind and PV and coupled with onshore wind, PV and a lignite power plant.

For this work a common, as of 2019 in Germany, stationary BESS size with 20 MWh storage capacity was assumed. In case the BESS is operated in standalone mode, 20 MW of inverter capacity is considered whereas in the pooled operation mode, 30 MW of inverter capacity is considered. The difference in the energy to power ratio arises from the fact that in standalone mode a BESS must be capable of providing the full tendered aFRR power for 4 h. In pooled operation, the BESS can recharge from other generation units during aFRR provision and therefore requires a lower energy to power ratio (see Section 4.4.2). In theory the BESS in standalone mode would only require 5 MW of inverter capacity. However, this setup would prevent the BESS of participating in other markets such as the FCR market.

Both the PV and onshore wind park have nominal capacities of 100 MW. The lignite power plant has a nominal capacity of 400 MW.

Table 4-2
Utility-scale cost parameters of BESS in the year 2019.

Component	Costs
Battery system	189 €/kWh [28]
Bi-directional Inverter	70 €/kW [26]
BOS	81 €/kWh [26,27]
EPC	55 €/kWh [27]
Soft Costs	60 €/kWh [27,28]
Maintenance and Operation	1% of hardware invest per year
Contingency	3% of invest [28]

4.3. System cost breakdown

In order to evaluate the economic performance of stationary BESS, a financial analysis is necessary. Detailed cost breakdowns are rare in this area because system integrators often keep information of individual components confidential. Prices strongly depend on the ordered quantities. Parameters used in this work are largely based on an utility-scale BESS benchmark provided by the U.S. National Renewable Energy Laboratory [26], a BESS analysis conducted by McKinsey [27] and data derived from the stationary BESS located in Aachen, Germany.

Container based solutions are currently the most cost effective approach in building BESS. As mentioned in Section 4.2, this work focuses on a utility-scale 20 MWh lithium-ion based container system. Table 4-2 provides an overview of the components and corresponding costs of the BESS. The battery system includes all cells, modules, cell state monitoring devices, racks, DC circuit breaker, DC bus bar, DC connection point and the battery management system (BMS). The balance of system (BOS) encompasses the container, all mounting structures, cabling, transformers (e.g. to medium voltage), electrical components, documentation, installation works, fire suppression system, gas extinguishing system (if available) and the HVAC (heating, ventilation and air conditioning) system. Due to the increased availability of container-scale components, design advances and efficiency gains in manufacturing, BOS costs decreased by 78% between 2012 and 2017 [27]. EPC (engineering, procurement and construction) reflects costs associated to project management, procurement, permissions, site preparation, construction and commissioning. Similar to BOS costs, EPC costs decreased by 75% in aforementioned range [27]. This decline is attributable to increased standardization, enhanced design and installation techniques, increased competition and gained experience of the EPC companies. Soft costs include customer acquisition, land acquisition, permitting and interconnection among others. By standardized processes and an increase in experience, soft costs have decreased over the past years as well.

Based on the cost parameters provided by Table 4-2, Fig. 4-1 illustrates a cost breakdown for the 20 MWh BESS with a 30 MW inverter size. At this scale, the total costs amount to 13,350,610 €. All battery system related costs contribute 28% to the total costs. The second highest positions are taxes and inverter costs. Dividing the total costs by the energetic capacity reveals specific costs of 668 €/kWh. If only the hardware costs (battery system, inverter, BOS) and taxes are considered, specific costs of 482 €/kWh are obtained. The latter is in line with the entries of a BESS database provided by [29]. The database offers free access to BESS data provided by various manufacturers and

Table 4-1
Generation Pools.

Confi-guration	BESS Power Capabilities P_{Nom} [MW]	BESS Energetic Capacity E_{Nom} [MWh]	Wind Onshore – Nominal Capacity [MW]	PV – Nominal Capacity [MW]	Lignite-Fired Power Plant – Nominal Capacity [MW]
1	20	20	0	0	0
2	30	20	100	0	0
3	30	20	100	100	0
4	30	20	100	100	400

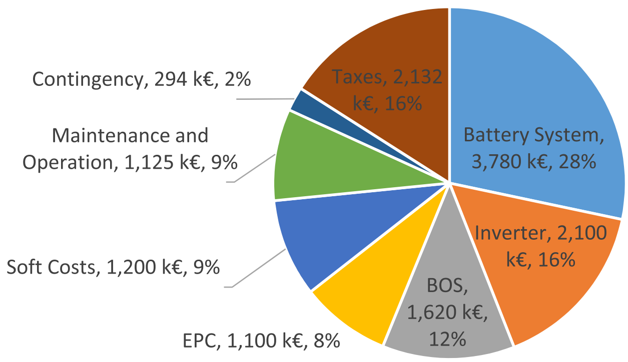

Fig. 4-1. Cost Breakdown of a 30 MW, 20 MWh BESS.

system integrators. Aside from technological information and multiple system size ranges, the database offers pricing information. Aside from the battery system (Section 4.5), all components are simulated with a lifetime of 15 years.

4.4. Operating strategy

For a pool comprising different generation units and a BESS, the operating strategy handles the dispatch and trading of energy at each instance in time. Generation capabilities are either placed on the day-ahead or on the intraday market. Other trading channels aside from aforementioned markets are possible but due to the complexity are not further considered in this work. Here, any unpredictable aFRR request is instantly provided by the BESS. By the use of a reserved power band, the generation units are capable of recharging the BESS after an aFRR request. This power band is a part of the projected generation of a VPP which is not sold on the day-ahead market to serve as recharge opportunity for the BESS. The operating strategy assures that in each instance of time, the aFRR requirements of the TSO are met and the energy trading generates maximum revenues. Section 4.4.1 investigates time parameters relevant for the operating strategy, Section 4.4.2 derives the maximum possible aFRR capacity (MW) a pool can offer, Section 4.4.3 describes the handling of time slices in which aFRR must be provided and Section 4.4.4 describes the handling of time slices without aFRR obligation.

4.4.1. Continuous intraday market rules

The smallest quantity which can be traded on the continuous intraday market is a 15-min block (t_{Block}) and the minimum lead time is 5 min (t_{Lead}). In order to give trading partners an opportunity to consider and buy a certain block, some arbitrary time > 0 must be taken into account (t_{Sale}). This work assumes a sale opportunity time of t_{Sale} = 30 min. Fig. 4-2 illustrates aforementioned time constants for an exemplary 15-min block (hatched area). The decision point marks the instance in time at which the sell decision for the hatched block must be made.

Aside from the intraday market prices, additional expenses apply when exchanging energy. These additional expenses are country-specific and consist of for example various taxes, network charges, metering costs, concession fees, renewable energy surcharges and various apportionments. It is a fixed charging fee which applies independently of the market. For each MWh of energy fed into the grid, the revenue is equal to the market price since the final consumer is charged for all additional expenses. If, however, energy is withdrawn from the electrical grid to e.g. charge the BESS, above specified expenses apply. For all calculations, this work uses the same fees which apply for the stationary M5BAT BESS located in Aachen. In total, 12.01 €/MWh are charged for each MWh obtained from the grid. This includes among others concession fees and multiple apportionments (power-heat coupling, §19 StromNEV [30], etc.).

4.4.2. Determination of maximum aFRR capacity

Units prequalified for aFRR are required to deliver up to 4 h of the accepted capacity (MW). Based on discussions with grid operators, an aFRR prequalified VPP must not rely on intraday recharging during a 4-h aFRR provision period. It cannot be guaranteed that an energy seller is available which in consequence means that the VPP must be capable to fulfil the 4-hour criterion without external market recharge. The maximum capacity a standalone BESS can offer on the aFRR market is therefore given by Eq. (2):

$$P_{\mathrm{aFRR\_Standalone}} = \min\left(P_{\mathrm{Nom}}, \frac{E_{\mathrm{Nom}}}{4\mathrm{h}}\right), \tag{2}$$

where P_{Nom} represents the maximum power capabilities and E_{Nom} represents the energetic capacity (in MWh) of the BESS.

If, however, the BESS is operated in conjunction with a generation pool as described in Section 4.2, more capacity can be offered on the aFRR market. This work only considers positive aFRR as this is generally more profitable and, if combined with other generators, can be realized without a derating of generators. Fig. 4-3 illustrates how energy can be recharged from the pool while the BESS provides aFRR. The total pool generation power (P_{Pool}), as the sum of all units (e.g. PV + Wind + Thermal), is given by the continuous line. Some of the total pool generation power is traded on various channels, e.g. on the day-ahead market as indicated by the hatched blue area. Another share

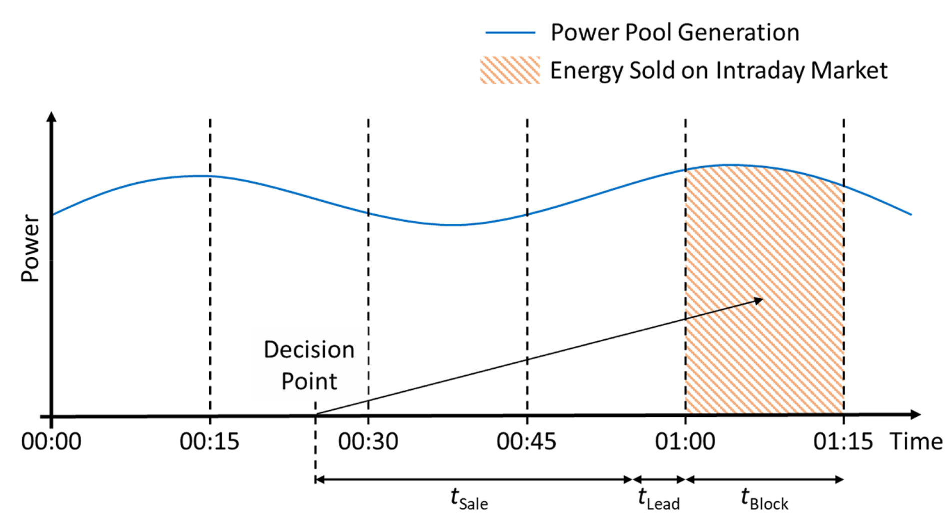

Fig. 4-2. Time Constants of the Intraday Market.

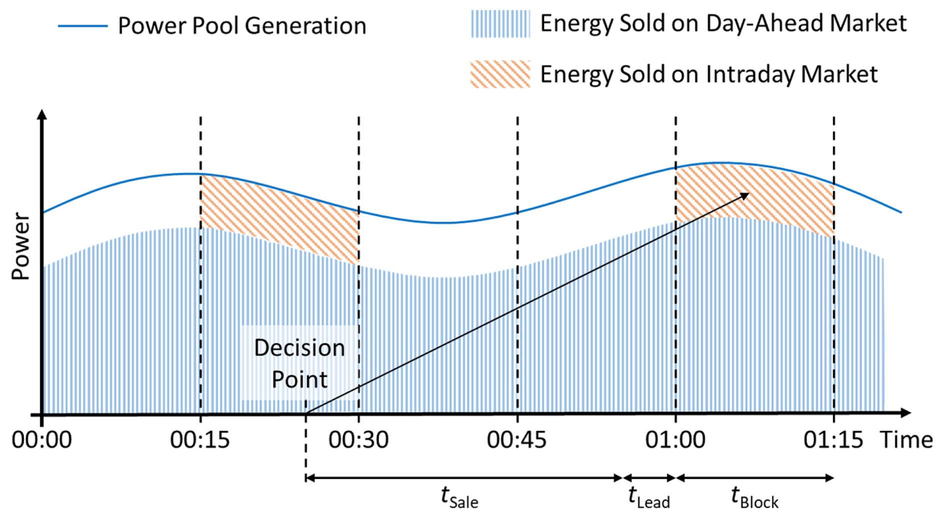

Fig. 4-3. Recharge strategy for positive aFRR Provision.

of the total pool generation power is reserved for recharging the BESS after an aFRR request. The reserved power is equal to the accepted aFRR capacity. If no aFRR energy is requested from the BESS, the reserve band can continuously be sold on the intraday market. The latter is indicated by the hatched red area. If, however, an aFRR request discharged the BESS, the reserve band can be used for recharging. Prediction uncertainties in the wind and PV generation are not particularly considered in this work. However, uncertainties could be compensated by the reserved power band or an extension of the reserved power band.

According to Section 4.4.1, the decision to either sell or not sell a quarter-hour block on the intraday market must be made $t_{Sale} + t_{Lead}$ before the start of the block. If in the worst case scenario, a full and continuously lasting aFRR request is triggered right after the decision to sell a block, the BESS must at least be able to provide the delivery duration ($t_{Delivery}$) as indicated by Eq. (3):

$$t_{Delivery} = t_{Sale} + t_{Lead} + t_{Block} \quad (3)$$

If the pool continuously provides a reserve band over the aFRR product duration, the maximum possible aFRR capacity to offer ($P_{aFRR\_Pool\_max}$) is given by Eq. (4):

$$P_{aFRR\_Pool\_max} = \min\left(P_{Nom}, \frac{E_{Nom}}{t_{Delivery}}\right) \quad (4)$$

In case the generation profile of the pool does not continuously provide the possibility to recharge the BESS, the aFRR capacity to offer on the market is less then$P_{aFRR_Pool_max}$. To give an example, Fig. 4-4 illustrates a generation pool scenario for the POS_04_08 aFRR product type (4 am to 8 am). From the start of the product type at 4 am until 6:30 am, in this example, no pool generation power is available to support the BESS in case energy must be recharged due to an aFRR request.

The BESS therefore must provide enough energy to answer a continuous full power aFRR request over that period. Due to energetic capacity limits of the BESS, the amount of aFRR capacity (MW) to offer on the market must be reduced. This research implements an algorithm to determine the maximum possible aFRR power as a function of the pool's generation profile, the power capabilities of the BESS and the energetic capacity of the BESS.

4.4.3. *Active aFRR period*

For periods in which aFRR must be provided (auction success), this section describes how energy is dispatched within the pool and traded on the electricity market.

Each aFRR request triggered by the TSOs is instantaneously fulfilled by the BESS. Based on the merit-order position of the individual energy price bid, the set point power and request duration is derived. Since only positive aFRR is offered, the BESS only discharges.

As explained in Section 4.4.2, a power band from the pool's generation profile is reserved to handle recharging the BESS. For each 15-min block within the reserve band, a corresponding decision point marks the instance in time at which the decision to trade the block on

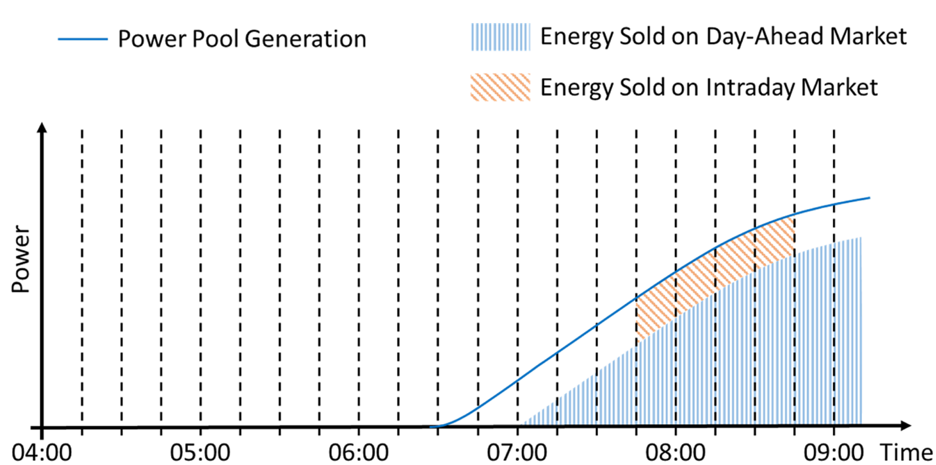

Fig. 4-4. Non-Continuous Pool Generation Profile.

the intraday market or not (Fig. 4-3) must be made. All energy discharged due to aFRR requests between two decision points will be recharged in the next possible 15-min block. As illustrated by the hatched blue area in Fig. 4-3, generation capabilities beyond the reserve band are traded on the day-ahead market.

Some generation types, such as thermal power plants, are at times operated below their nominal capacity. The leftover generation capabilities can be used to recharge the BESS. Arising marginal costs due to for example lignite consumption are considered in this work.

If the BESS is not connected to a VPP and provides aFRR in standalone mode, the only possibility to recharge is by buying energy from the intraday market. Since the BESS must not rely on intraday recharge, the BESS by itself is capable of providing the full tendered aFRR power for 4 h.

Depending on the location of the BESS, additional expenses, as explained in Section 4.4.1, apply for recharging energy. This applies for example in scenarios in which the BESS is not located on-site of a coupled unit such as a wind farm. Recharging then involves using the public electrical grid which causes aforementioned expenses.

4.4.4. Inactive aFRR period

This section describes the dispatch and trading of resources in time periods of no aFRR obligation (e.g. lost auction).

As illustrated in Fig. 4-5, all power capabilities of the generation units are traded on the day-ahead market. As before, other trading options would be possible but are not subject to investigation in this work. The decision to trade all energy on the day-ahead market can be taken after the results of the aFRR auction are published. Market closing for the day-ahead market is at 12 pm and results of the aFRR auction are published at 9 am the day before delivery.

If an active aFRR period is followed by an inactive aFRR period, the SoC of the BESS can be below 100% at the start of the inactive aFRR period. In such a case, recharging from the pool is not possible since all energy is already sold on the day-ahead market. To bring the SoC of the BESS back to 100%, energy is bought from the intraday market.

In order to utilize the otherwise unused capacity of the BESS, the operating strategy considers arbitrage trading on the intraday market. The arbitrage algorithm implemented in this work is based on [31,32] and has been extended to handle the properties of BESS. It was shown, that the algorithm reaches the global optimum for profit [19,31]. Within a predefined time period, the algorithm identifies pairs of charging/discharging periods. The first pair consist of the quarter hour block with the lowest and the quarter hour block with the highest intraday price. To be considered a potential pair, the price spread must be above a predefined threshold. In this work, the price spread is forced to be higher than the sum of the cyclic ageing costs of the battery (Section 4.5) and the applying recharge taxes (Section 4.4.1). Calendric ageing costs are not considered since this type of ageing occurs anyway, independent of arbitrage operation. The second pair covers the second highest price spread of all remaining quarter hour blocks, and so on. According to the identified pairs, a schedule is created which maximizes the revenues. In the second step of the algorithm, the schedule is adapted in order to not violate the SoC boundaries of the battery. Only SoC values between 0% and 100% are possible. The least economic beneficial charging/discharging blocks are reduced accordingly. At the end of each inactive aFRR period, a target SoC must be reached. The target SoC assures that the requirements for providing e.g. aFRR in the next block are satisfied. In the third step of the arbitrage algorithm, the schedule is again adapted to meet the target SoC requirement.

4.5. Battery model

In order to estimate the costs associated with battery aging, this work implements a battery model based on [33]. The model provides sufficiently accurate results for this work, is not computationally demanding and can be applied on arbitrary operating profiles. Also, the proposed model was fitted to a lithium ion manganese oxide (LMO) cell chemistry which matches the largest battery technology used in the BESS located at the RWTH Aachen University. By combining theoretical battery degradation analysis with experimental observations, the model is described as semi-empirical. Battery deterioration is divided into a calendar component given by Eq. (5) and a cyclic component given by Eq. (6).

$$f_{\mathrm{cal}} = S_t(t)\cdot S_\sigma(\sigma)\cdot S_T(T) \tag{5}$$

$$f_{\mathrm{cyc}} = S_\delta(\delta)\cdot S_\sigma(\sigma)\cdot S_T(T) \tag{6}$$

Each factor represents a specific stress model, where $S_T(T)$ denotes a stress model for temperature based on Arrhenius' equation [34], $S_t(t)$ denotes a linear time stress model, $S_\sigma(\sigma)$ denotes a SoC stress model originating from [35] and $S_\delta(\delta)$ denotes a DoD stress model. For a more detailed description, reference is made to [33]. Battery degradation further depends on the current state of life, with a significantly higher rate during the early cycles than during the later cycles. A major cause of the early degradation is rooted in the formation of the Solid Electrolyte Interphase (SEI) film [36,37]. To correctly model the aging behavior, the proposed model implements a linear and non-linear component. The high accuracy of the proposed model was demonstrated on mixed-cycle operations (Dynamic Stress Test Cycling) data provided by the manufacturer of the LMO cell [33].

The model is adaptable to different types of lithium-ion batteries by fitting the coefficients to either specifications provided by the manufacturer or to conducted cell measurements. Depending on the cell-chemistry, each stress model can be replaced with a suitable alternative.

In order to cope with the irregular charging/discharging pattern resulting from the operating strategy (Section 4.4), the frequently used Rainflow algorithm has been implemented [33,38].

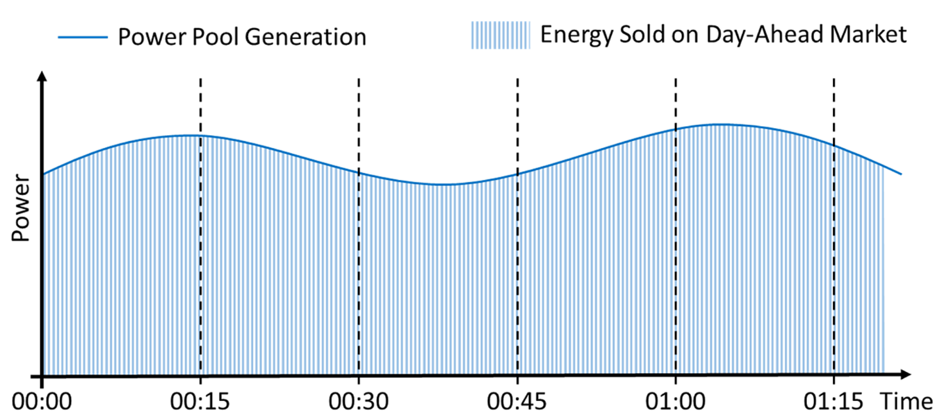

Fig. 4-5. Trading of Pool Capabilities during Inactive aFRR Period.

In this work, the fast capacity decline within the first around 500 cycles is not considered. The latter is justified by this work's simulation time range of less than one year which corresponds to a few hundred cycles. Taking the non-linearity into account would overestimate the battery ageing.

Based on the charge/discharge time series resulting from the operating strategy, this work derives the differential loss in capacity. The implemented battery ageing model considers cyclic operations as well as standby periods to estimate the differential capacity loss. As described in Section 4.3, a battery system price of 189 €/kWh is assumed. Together with the differential capacity loss, the monetary loss can be estimated.

4.6. Optimization

The economic viability of the proposed pool configurations (Section 4.2) strongly depends on the submitted capacity bid and energy bid prices. This section presents the optimization approach of finding the most economic bid tuple for an individual pool configuration. Section 4.6.1 calculates the boundaries passed to the optimizer, Section 4.6.2 derives an aFRR request time series based on a prediction of the total request duration and Section 4.6.3 describes the objective function.

4.6.1. Boundaries

For each aFRR product type under consideration, the search space of the optimization problem consists of a capacity price and an energy price. Both optimization variables are subject to certain boundaries applied in this work.

Currently, the aFRR regulations do not limit the capacity price which in theory allows price offers between $\pm\infty$. In practice, however, capacity prices have not been negative and a capacity price of 0 €/MW corresponds to a very high acceptance probability in the auction process. This work sets the lower boundary to 0 €/MW and the upper boundary to 100 €/MW.

Due to energy price gambling in the past, the energy price has been regulated to be within ± 9999 €/MWh. This work further restricts the energy price to be not lower than the minimum intraday price payed during the aFRR period under consideration. If more revenues can be generated on the intraday market, there is no incentive to participate in the aFRR market. Also the energy price is forced to be higher than the cyclic ageing costs of the battery. Based on a full cycle analysis, the differential costs for charging and discharging 1 MWh of energy are derived from the battery model presented in Section 4.5. Calendric ageing costs are excluded in the lower boundary since economic benefits can be achieved even if the full calendric ageing costs are not compensated. The upper boundary of the energy price is set to the highest energy bid of the past month.

4.6.2. Estimation of the aFRR request time series

Since the accurate aFRR request time series is unknown at the time an aFRR bid tuple must be submitted, this section derives a strategy to predict an exemplary time series which can be used by the optimizer to estimate the revenues. The first step in deriving a time series is to obtain a prediction for the total expected aFRR request duration.

A prediction methodology for deriving key quantities of the aFRR market was presented in [23]. In order to obtain a prediction of the total aFRR request duration, the list of successful bids is first sorted ascending by energy price (merit order) and then grouped into 10 blocks of equal capacity (MW). If the total tendered capacity is e.g. 1880 MW, each block covers 188 MW. For each of the 10 blocks, two prediction models are trained with data of the past. The first model is used to predict the mean energy price and the second model is used to predict the mean total aFRR request duration. Both models return a prediction for the next day. This work uses SARIMA prediction models [39,40]. Fig. 4-6 illustrates the prediction methodology for an exemplary day and aFRR product type. Each value marked with a cross represents the mean energy price prediction and each encircled value represents the prediction of the mean request duration. For an arbitrary choice of energy price, the corresponding request duration is graphically obtained as follows:

1. All energy price predictions are linearly interconnected (dashed line in Fig. 4-6). Every possible energy price is located somewhere on the dashed interconnection line. Possible positions are between two predicted energy prices, left from the first block mean value or right from the last block value.
2. All request duration predictions are linearly interconnected (continuous line in Fig. 4-6). Starting from the position of the energy price, a vertical line is drawn until the continuous request duration line is crossed. The intersection point marks the desired request duration corresponding to the energy price.

In short, the predicted request duration is obtained by linearly interpolating between the energy price predictions and the request duration predictions.

After having obtained a prediction for the total request duration, a

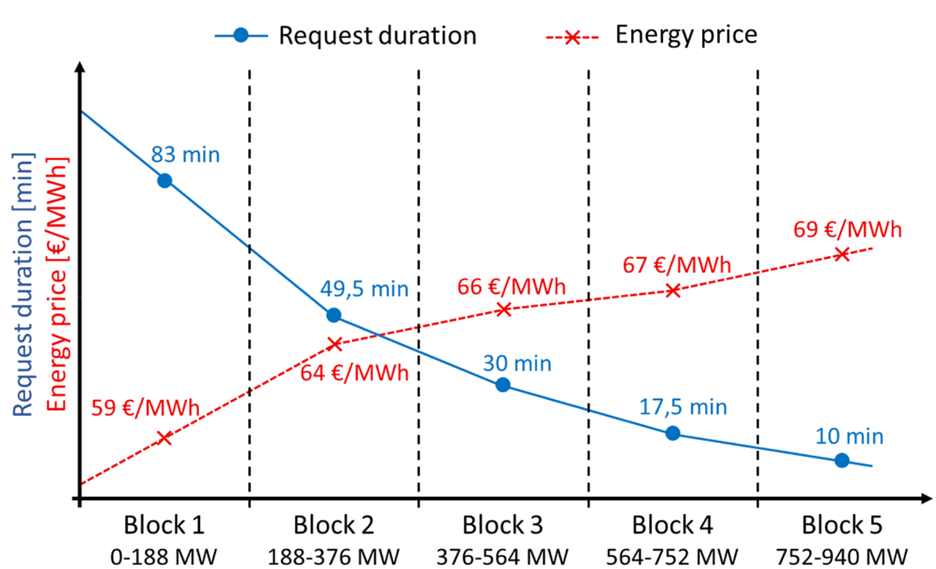

Fig. 4-6. aFRR prediction methodology: Total request duration and energy price.

high resolution time series must be generated which can be fed into the operating strategy. The process of mapping one value to a high resolution time series involves many degrees of freedom. It is impossible to accurately predict the future request time series. However, the pattern of the time series influences the battery ageing. Long lasting continuous requests correspond to deep cycles and an increased capacity loss whereas many short requests correspond to less stress on the battery. In this work the following approach was conducted: The first hour of the total request duration is assumed to be continuously requested. All remaining time is assumed to be requestes in multiple small cycles for the battery. Therefore, this approach follows an average case scenario.

4.6.3. Objective function

For each possible combination of capacity and energy price, the objective function calculates the expected revenues by applying the operating strategy as described in Section 4.4. As opposed to the approach presented in [22], a separate optimization process is conducted for each aFRR product type. This reduces the number of optimization variables to two (capacity and energy price). Aside from the significantly reduced computation time, a minor drawback is that arbitrage trading can only be considered within one aFRR product type range. However, when evaluating the overall profit based on the true auction outcome, arbitrage trading spanning multiple aFRR product types is considered.

In search of the maximum revenues, the optimizer samples various combinations of capacity and energy prices. The acceptance probability$G(B_C, B_E)$, derived in [23], depends on the choice of capacity price B_C and energy price B_E. For each combination, either the aFRR bid tuple gets accepted or not. Eq. (7) states the objective function which calculates the total expected revenues E_{Total} as a function of P_C, B_C and B_E. Table 4-3 describes each component of the objective function.

$$\begin{aligned} E_{Total}(P_C, B_C, B_E) &= G(B_C, B_E)\cdot(E_{CaFRR}(P_C, B_C) + E_{EaFRR} \\ &(P_C, B_E) + E_{DA} + E_{ID} - C_{IdleGen} - C_{BESSAge}) + (1 - G(B_C, B_E))\cdot \\ &(E_{DANoaFRR} + E_{Arbitrage} - C_{BESSAgeNoaFRR}) \end{aligned} \tag{7}$$

The first summand of the objective function describes the case in which a successful bid tuple was submitted. All revenues generated from the operating strategy in Section 4.4.3 are multiplied by the expected acceptance probability. The second summand covers the opposite case by multiplying the inverse probability with the earning potential if no aFRR obligation exists. In this work, the Covariance Matrix Adaption Evolutionary Strategy (CMA-ES) Optimizer is used to search for a bid tuple which maximizes the total expected revenue E_{Total} [41].

5. Results

This section presents the results of applying the bidding strategy presented in chapter 4 on real market data. All simulations are conducted for the time period between October, 30th 2018 and July 31st, 2019. In the latter time period the aFRR mixed price auction scheme was in effect. At the time of writing this work, above time period is the longest time period in which the new market design with a 4-h block size was in place. All forecasts required for running the bidding strategy are obtained from applying the prediction framework presented in [23].

Section 5.1 first reveals the earning potential of a BESS participating on the aFRR market in standalone mode. Subsequently, a wind park with a nominal capacity of 100 MW is considered. The earning potentials for an operation with and without BESS are revealed. Appendix A investigates a virtual power plant comprising both wind and PV generation. In Appendix B a configuration comprising wind, PV and a thermal power plant is considered. A sensitivity analysis is conducted in Section 5.2. Revenue potentials yielded on the aFRR market are compared to earning potentials on the FCR market in Section 5.3.

5.1. BESS in standalone operation and in conjunction with a VPP

This subsection presents the results of seven different scenarios. In the first scenario, a BESS with a nominal power output of 20 MW and an energetic capacity of 20 MWh is operated in standalone mode without a supporting VPP (configuration 1, Section 4.2). The second and third scenario correspond to configuration 2 of Section 4.2. A wind park is operated with and without a supporting BESS (30 MW, 20 MWh). The fourth and fifth scenario correspond to configuration 3 of Section 4.2. A wind and PV park each with a nominal capacity of 100 MW is operated by itself and in conjunction with aforementioned BESS. The last two scenarios correspond to configuration 4 of Section 4.2. A wind park, PV park and lignite-fired thermal power plant is operated with and without a BESS.

Table 5-1 summarizes the simulation results for all scenarios. Each value in the table represents the daily average over the simulation period.

The sold energy and revenues on the intraday market (row 10, 11) correspond to the reserve band described in Section 4.4.3. If no energy is needed for recharging the BESS, the reserve band can be sold on the intraday market.

All table entries denoted by “Arbitrage” (row 12–15) correspond to the following intraday market activities triggered by the BESS. Firstly, the BESS increases its revenue by buying energy at times of low prices and selling energy at times of high prices (Section 4.4.4). Secondly, the BESS recharges energy to reach its target SoC. The latter occurs in BESS standalone mode or in aFRR inactive periods in which the power capabilities of all generation units of the VPP are sold on the day-ahead

Table 4-3
Components of the objective function.

Variable	Meaning
$G(B_C, B_E)$	Acceptance probability for a specific bid tuple in the aFRR auction. Depending on the auction design this is a function of B_C only or of B_C and B_E (mixed price).
P_C	Offered aFRR capacity in MW
$E_{CaFRR}(P_C, B_C)$	Capacity based aFRR revenue based on P_C and B_C.
$E_{EaFRR}(P_C, B_C)$	Energy based aFRR revenue based on P_C and B_E.
E_{DA}	Revenues raised on the day-ahead market for trading some of the generation capabilities of the pool (Section 4.4.3).
E_{ID}	Revenues raised on the intraday market resulting from trading the reserve band as explained in Section 4.4.3. In times, the BESS needs to recharge, the reserve band is not sold on the market. Towards the end of an aFRR period, the BESS is recharged to meet the requirements of the next aFRR period. Any BESS recharge reduces the revenues on the intraday market.
$C_{IdleGen}$	Sum of marginal costs for activating the idle capacities of generation units (Section 4.4.3).
$C_{BESSAge}$, $C_{BESSAgeNoaFRR}$	Differential ageing costs for the BESS. This includes ageing of the battery cells due to calendar and cyclic ageing (Section 4.5) as well as ageing of all other components in the system (Section 4.3).
$E_{DANoaFRR}$	Revenues raised on the day-ahead market for periods without aFRR obligations (Section 4.4.4).
$E_{Arbitrage}$	Arbitrage earnings yielded on the intraday market for periods without aFRR obligations.

Table 5-1
Result summary of seven scenarios: Each value represents the daily average over the simulation period.

Row		BESS Stand-alone	BESS + Wind	BESS + Wind + PV	BESS + Wind + PV + Thermal
1	aFRR Capacity Price Revenue [€]	303	560	638	692
2	aFRR Energy Price Revenue [€]	353	778	917	934
3	aFRR Total Revenue [€]	657	1339	1556	1627
4	POS_00_04: Accept Cap. [MW]/Accept. rate [%]	5/66	20/24	20/24	23/22
5	POS_04_08: Accept Cap. [MW] /Accept. rate [%]	5/55	19/24	19/26	23/22
6	POS_08_12: Accept Cap. [MW] /Accept. rate [%]	5/47	17/19	21/22	23/19
7	POS_12_16: Accept Cap. [MW] /Accept. rate [%]	5/38	19/19	22/18	24/17
8	POS_16_20: Accept Cap. [MW] /Accept. rate [%]	5/30	18/19	19/18	24/16
9	POS_20_24: Accept Cap. [MW] /Accept. rate [%]	5/73	18/17	18/16	23/15
10	Intraday Market: Sold Energy [MWh]	0	60	67	73
11	Intraday Market Revenue [€]	0	2070	2420	2782
12	Arbitrage: Bought Energy [MWh]	6.6	3.5	3.4	3.4
13	Arbitrage: Costs [€]	367	127	100	103
14	Arbitrage: Sold Energy [MWh]	1.4	1.8	3.4	1.5
15	Arbitrage: Revenue [€]	140	163	108	104
16	Day-ahead Market: Sold Energy [MWh]	0	447	672	6,187
17	Day-ahead Market: Revenue [€]	0	17,996	26,588	279,128
18	Recharge Taxes [€]	0	125	148	148
19	Battery Deterioration [%]	0.0049	0.0053	0.0054	0.0054
20	Battery Deterioration [€]	1111	1189	1215	1224
21	Differential Inverter Costs [€]	304	456	456	456
22	Differential BOS Costs [€]	352	352	352	352
23	Differential EPC and Soft Costs [€]	500	500	500	500
24	Differential Maintenance and Operation Costs [€]	222	245	245	245
25	Differential Contingency Costs [€]	59	64	64	64
26	Total Cash Flow incl. Degradation BESS Costs [€]	−2118	18,511	27,592	280,549
27	Total Cash Flow without BESS [€]	0	20,410	29,420	282,330

market. For this reason, the arbitrage buying costs can exceed the arbitrage selling costs. All arbitrage activity is based on real market data for the respective day. The prices used in the simulation correspond to the real quarter-hour average prices of the continuous intraday market.

As described in Section 4.4.1, various fees and apportionments apply if the BESS recharges energy from the generation pool via the electrical grid. The row “Recharge Taxes” covers all costs associated with the energy exchange between the generation units and the BESS (row 18). It is assumed, that the BESS is not located on the same premises as the generation units. If that was the case, a private grid could be used for energy exchange to circumvent the recharge fees. Both calendric and cyclic ageing effects (row 19, 20) are included in the battery deterioration (Section 4.5). The percentage value states the average decrease in capacity per day. If the total capacity decrease is above 20%, the battery cells are considered to have reached their end-of-life. All other BESS components are expected to have a lifetime of 15 years (Section 4.3). Their daily differential cost impact is stated in row 21–25. This work does not incorporate any fixed or variable costs related to the generation units of the VPP. If the generation units are operated without the BESS, the total cash flow only accounts for the revenues of having sold the generated energy on the day-ahead market (row 27). This work only answers the questions, if a BESS is economically beneficial for an existing VPP. For a BESS to be economically beneficial, the total cash flow of the VPP with BESS (row 26) should be higher than without BESS (row 27).

As shown in Table 5-1, the average daily total cash flow of the BESS in standalone mode is negative (row 26). This indicates an uneconomical operation. Neither on the aFRR market, nor on the intraday market is the price spread between charging and discharging sufficient to cover all costs. Due to the 4-hour criterion on the aFRR market, the BESS is only capable of offering 5 MW of capacity to the aFRR market.

Across the aFRR product types (row 4–9), the acceptance rate of the submitted bids varies between 30% (POS_16_20) and 73% (POS_20_24). The low aFRR acceptance rates can have multiple causes. First, the prediction model predicts a mixed price which deviates from the real auction outcome. If the mixed price is overestimated, the optimizer of the bidding strategy overestimates the acceptance probability as well. Second, the cyclic ageing costs of the battery set a lower threshold to the offered aFRR energy price. Bids below the threshold would generate higher costs on the battery side than the yielded revenues. Consequently, the bidding strategy must choose an energy price which covers the arising costs but does not necessarily have a high acceptance probability. Third, a too high energy price does not only reduce the acceptance probability but also decreases the aFRR provision duration (merit order effect). With a decreased aFRR provision duration, the energy earnings might decrease as well. Fourth, the expected arbitrage earnings due to high price spreads on the intraday market might exceed the expected earnings on the aFRR market. In this case the bidding strategy submits a very high capacity price (€/MW) which is unlikely to be accepted. Consequently, the acceptance rate as of Table 5-1 decreases and this is desired behavior.

On average, the standalone BESS recharges 5.2 MWh per day from the intraday market and trades 1.4 MWh in arbitrage (row 14). The intraday recharge costs therefore exceed the revenue from energy sold on the intraday market. Under consideration of the 80% end-of-life criterion, the battery model estimates the battery life to be 11.1 years. If the prediction framework is replaced by perfect knowledge of the simulation day (prices and request duration), the total cash flow amounts to −1959 €/day on average.

5.1.1. BESS with wind generation

In case the BESS is operated in conjunction with the wind park, the total revenue on the aFRR market is more than doubled. Depending on the aFRR product type the average offered capacity is between 17 and 20 MW. Compared to the BESS standalone operation this aFRR capacity offer increase arises from the possibility to recharge from the pool. However, the average offered capacity is lower than the theoretical maximum of 24 MW because the wind generation profile does not always provide sufficient reserve power to recharge the BESS (see Section 4.4.2 for explanation). Arbitrage trading does not provide significant profits. Depending on the day, either the price spread is lower than the cyclic ageing costs of the BESS or the earning potential on the aFRR market is higher. The battery model reveals an estimated lifetime of 10.4 years and therefore a slightly higher ageing than for the BESS standalone operation.

As explained in Section 4.4.4, the revenue potential of generation units without a coupled BESS are estimated by trading all generation capabilities on the day-ahead market. The wind park by itself yields an average revenue of 20,410 €/day whereas the wind park in combination with the BESS yields 21,441 €/day. However, the total cash flow of the pooled operation (18,511 €/day) is lower than in the wind only scenario. The additional revenues do not compensate for the costs of the BESS. Adding a BESS to an existing wind park is not economically beneficial. Fig. 5-1 illustrates the daily total cash flow for both the wind and BESS + Wind configuration over the simulation period. Because of varying wind generation and day-ahead prices, the total cash flow fluctuates significantly. In only 9.9% (27/274 days) of the days, the total cash flow of the BESS + Wind configuration is higher than for the wind only configuration. If the prediction framework is replaced by perfect knowledge of the simulation day (prices and request duration), the total cash flow amounts to 18,872 €/day on average.

For an exemplary day, Fig. 5-2 provides detailed time series of the BESS + Wind operating strategy and prices on the various markets. The operating strategy strictly follows the methodology presented in Section 4.4 and is the unaltered output of the simulation framework. As illustrated in the uppermost chart (SoC), the BESS undergoes two full cycles and one quarter cycle at that specific day. The VPP participates in the aFRR market between 12 am and 8 pm with offered energy prices as indicated in the bottom chart. All offered aFRR energy prices are at any time above the day-ahead and intraday prices. During the aFRR delivery period, a part of the pool generation capabilities are traded on the day-ahead market and another part is reserved for recharging the BESS. In time periods of no aFRR requests, e.g. between 9 am and 8 pm, the reserve band is traded on the intraday market. All intraday market activity conducted by the wind park is denoted by “Intraday Market Power Pool” whereas all intraday market activity triggered by the BESS is denoted by “Intraday Market Power BESS”. The BESS intraday market activity includes all arbitrage trading and necessary recharge operations. If an aFRR request is triggered by the TSOs, the BESS provides the required power by discharging its battery cells. The discharged energy is at a later time recharged from the reserve band of the pool (“Reserved Recharge Power”). At times of recharge, the pool cannot sell the reserve band to the intraday market. Between 8 pm and 12 am, the BESS does not provide aFRR but instead conducts arbitrage. At 8 pm, energy is sold for 53 €/MWh and at 11:45 pm, energy is bought for −4.6 €/MWh (negative energy price on intraday market). The target SoC of 100% is reached at the end of the day.

5.1.2. BESS with wind- and PV-generation

If the BESS is operated in conjunction with the wind and PV farm, on average, between 18 MW and 22 MW of capacity were offered to the aFRR market. Due to the availability of PV generation during the day, more recharge opportunities arise for the BESS than for e.g. a pool of only wind generation. Consequently, more aFRR capacity can be traded and more revenues can be generated. Earnings arising from arbitrage trading are minor. The battery model reveals an expected lifetime of 10.2 years. Due to the high costs of the BESS and the relatively low revenue margin on the aFRR market, the total cash flow with BESS is lower than without BESS.

Fig. A-1 in Appendix A illustrates the daily total cash flow for both configurations over the simulation period. For an exemplary day, Fig. A-2 provides detailed time series of the operating strategy and prices on the various markets for an exemplary day.

5.1.3. BESS with wind-, PV- and thermal generation

In the following the BESS is operated in conjunction with the wind farm, PV farm and thermal power plant. Since the BESS is capable of recharging from the generation pool at any time, the maximum possible aFRR capacity (24 MW) is offered to the market. Compared to the previous scenarios, the highest total aFRR revenues are yielded. The aFRR acceptance rate is similarly low and the arbitrage earnings are negligibly. The battery model reveals an expected lifetime of 10.1 years. As before, the total cash flow with BESS is lower than without BESS.

Fig. B-1 in Appendix B illustrates the daily total cash flow for both configuration over the simulation period. Fig. B-2 provides detailed time series of the operating strategy and prices on the various markets for an exemplary day.

In summary, none of the BESS scenarios above yielded an economic operation.

5.2. Parameter variation

Adding a BESS to the pool configurations as described in Section 5.1 caused a decrease of the total cash flows. However, all simulations were based on BESS cost parameters of the year 2019 (Section 4.3). This subsection presents an outlook into the future by running the same simulations with an altered set of parameters for the year 2025.

In order to grant the market an opportunity to react on bids placed on the intraday market, a sale opportunity time of $t_{Sale} = 30$ min was considered so far. As trading processes are increasing in speed, this subsection considers a sale opportunity time of $t_{Sale} = 15$ min. With this measure, BESS can offer more aFRR capacity (MW) to the market, since less energy must be reserved for aFRR request fulfilments.

The previous subsections derived differential battery ageing costs by considering an end-of-life (EoL) criterion of 80% of the nominal capacity. However, various battery ageing measurements and research

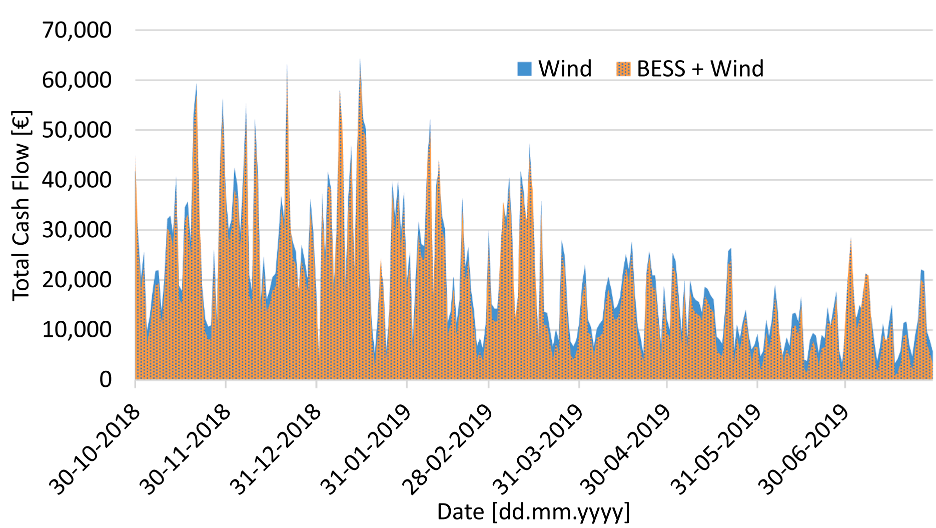

Fig. 5-1. Total cash flow per day for 2 scenarios: Wind and BESS + Wind.

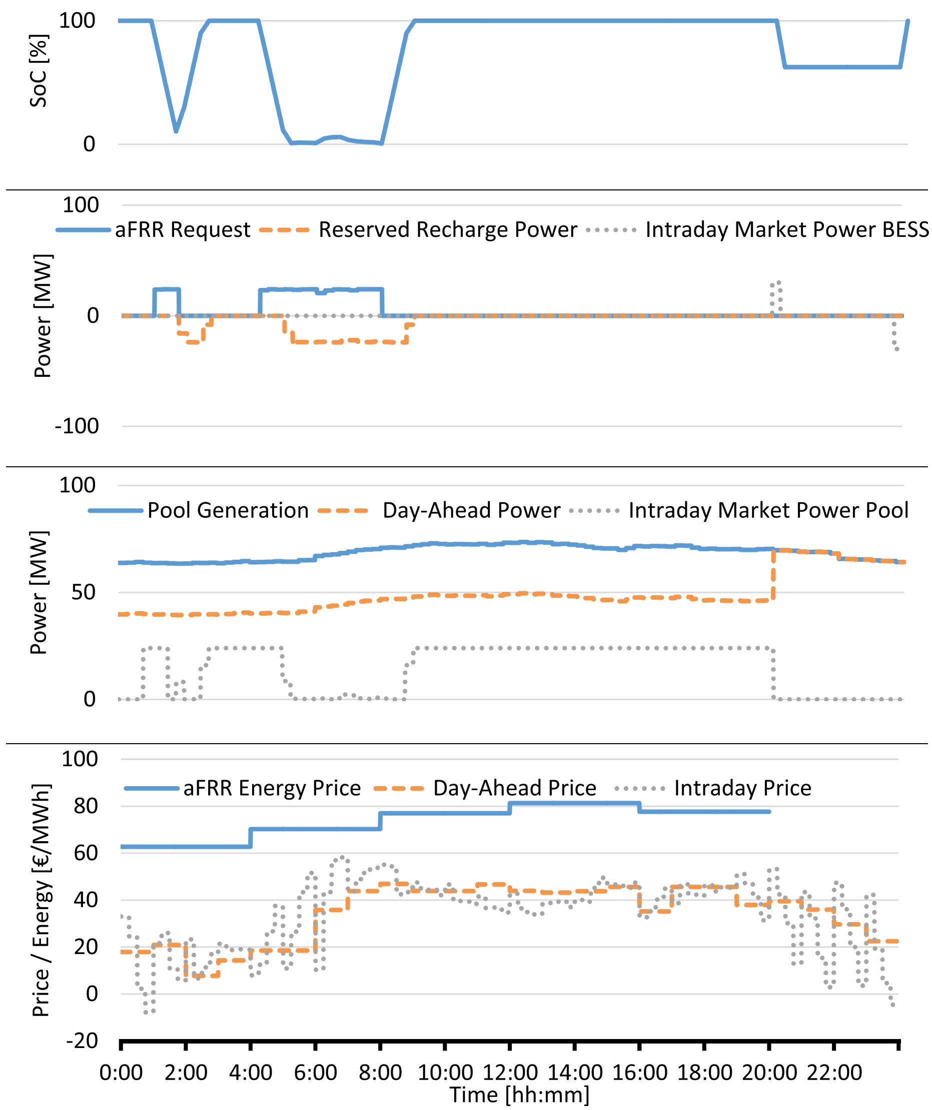

Fig. 5-2. Operation and trading of the BESS + Wind pool on January 8th, 2019.

articles suggest that batteries can be used beyond the predefined end-of-life criterion [42–44]. In particular, multiple investigations recommend a stationary usage after the battery cells have been aged to the EoL criterion in a primary use case (e.g. electric vehicle). Results show that 2nd life battery lifespan can be multiple years [42]. The decrease in capacity beyond the end-of-life can be non-linear and the speed depends on the cell chemistry. For the simulation in this subsection, an EoL criterion of 75% was chosen and the capacity decline is assumed linear. Investigations beyond this point would require a more sophisticated and specialized battery model.

The highest cost influence on the total cash flow arises from the containerized BESS solution. Table 5-2 summarizes the predicted costs of the various components for the year 2025. The source of the prediction is stated behind each cost value. Due to economies of scale, all hardware component costs are expected to decline by more than 50 percent until 2025. Due to gained experience within construction companies and more standardized processes, the EPC and soft costs decline as well. Aside from the battery system, all components are simulated with a lifetime of 20 years.

Simulation results for the parameter set as described above are provided in Table 5-3. Four columns state the results for the BESS standalone scenario, the BESS + Wind scenario, the BESS + Wind + PV scenario and the BESS + Wind + PV + Thermal scenario. For comparison, the last row in Table 5-3 states the total cash flow of the pool without incorporating the BESS. Despite the cost reductions, a BESS cannot be operated economically in standalone mode. As in Section 5.1, the respective total cash flow is negative (−673 €/day). However, in all other scenarios, adding a BESS to the pool configuration increases the total cash flow. It is a key finding of this work, that a BESS in conjunction with an existing generation pool can in the near future be operated economically beneficial. This in particular applies to generation pools comprising only renewables.

Compared to the parameter set of the year 2019, the total revenues on the aFRR market have more than doubled. Due to the reduced

Table 5-2
Predicted utility-scale cost parameters of containerized BESS for the year 2025.

Component	Costs
Battery system	99 €/kWh [27,45]
Bi-directional Inverter	50 €/kW [45]
BOS	53 €/kWh [27]
EPC	40 €/kWh [27]
Soft Costs	35 €/kWh [27]
Maintenance and Operation	1% of hardware invest per year
Contingency	3% of invest [28]

Table 5-3
Result summary with an altered parameter set. Each value represents the daily average over the simulation period.

Row		BESS Stand-alone	BESS + Wind	BESS + Wind + PV	BESS + Wind + PV + Thermal
1	aFRR Capacity Price Revenue [€]	309	823	944	1126
2	aFRR Energy Price Revenue [€]	569	2083	2301	2841
3	aFRR Total Revenue [€]	878	2905	3245	3967
4	POS_00_04: Accept Cap. [MW] /Accept. rate [%]	5/69	23/36	23/37	30/35
5	POS_04_08: Accept Cap. [MW] /Accept. rate [%]	5/64	21/46	22/47	28/42
6	POS_08_12: Accept Cap. [MW] /Accept. rate [%]	5/50	20/25	25/29	29/26
7	POS_12_16: Accept Cap. [MW] /Accept. rate [%]	5/47	21/29	27/26	29/26
8	POS_16_20: Accept Cap. [MW] /Accept. rate [%]	5/39	21/30	22/30	29/27
9	POS_20_24: Accept Cap. [MW] /Accept. rate [%]	5/65	21/24	21/23	29/23
10	Intraday Market: Sold Energy [MWh]	0	102	118	143
11	Intraday Market Revenue [€]	0	3756	4503	5844
12	Arbitrage: Bought Energy [MWh]	11.7	12.2	11.5	10.9
13	Arbitrage: Costs [€]	626	495	433	371
14	Arbitrage: Sold Energy [MWh]	3.1	8.6	8.1	8.0
15	Arbitrage: Revenue [€]	226	574	498	477
16	Day-ahead Market: Sold Energy [MWh]	0	385	599	6085
17	Day-ahead Market: Revenue [€]	0	15,554	23,700	274,900
18	Recharge Taxes [€]	0	355	400	511
19	Battery Deterioration [%]	0.0054	0.0070	0.0072	0.0076
20	Battery Deterioration [€]	513	664	675	716
21	Battery Lifetime [years]	12.6	9.7	9.6	9.0
22	Differential Inverter Costs [€]	82	245	245	245
23	Differential BOS Costs [€]	173	173	173	173
24	Differential EPC and Soft Costs [€]	245	245	245	245
25	Differential Maintenance and Operation Costs [€]	115	148	148	148
26	Differential Contingency Costs [€]	25	30	30	30
27	Total Cash Flow incl. BESS Degradation Costs [€]	−673	20,421	29,599	282,751
28	Total Cash Flow without BESS [€]	0	20,410	29,420	282,330

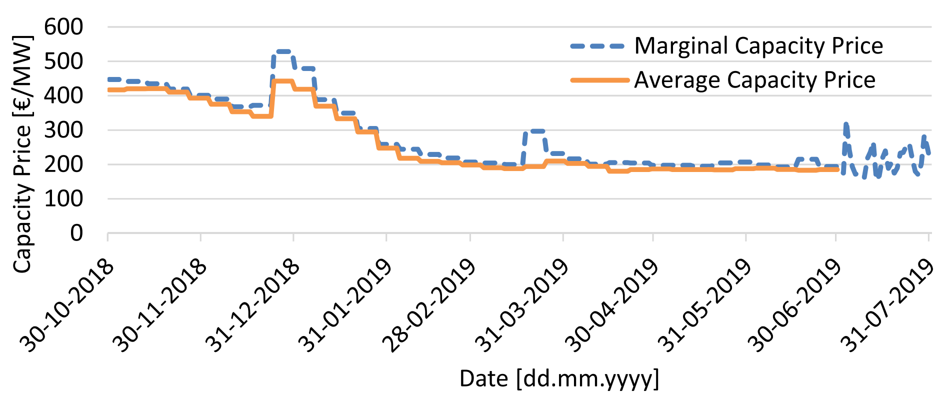

Fig. 5-3. Daily capacity prices of FCR in the German control zone [5].

battery system costs (in particular cyclic ageing costs), the bidding strategy can offer lower energy prices (€/MWh). Consequently, a lower position in the merit order list is obtained which then leads to an increased energetic throughput. The higher energetic throughput is reflected in an increased daily battery deterioration (row 19). Despite the lower EoL threshold, the estimated battery lifetime is around 1 year lower than with the parameter set of the year 2019. The arbitrage earnings are increased but as before do not substantially contribute to the revenue.

5.3. Comparison with FCR

The vast majority of stationary BESS located in Europe/Germany operate on the Frequency Control Reserve (FCR) market. As of November 2019, 380 MW of BESS capacity were prequalified for FCR provision [1]. This amounts to 5.5% of the total prequalified capacity. However, decreasing capacity prices lead to uncertainties in the business model for BESS [46]. This subsection provides a rough assessment of the revenue potentials for BESS and compares with the revenue potentials on the aFRR market. Reference is made to literature which more thoroughly analyses FCR provision with BESS [38,46–48].

Fig. 5-3 illustrates both the marginal capacity price and the average paid capacity price on the German FCR market over the simulation period. Before July 2019, FCR was auctioned in weekly blocks with a service compensation based on the individually submitted capacity price (pay-as-bid). Starting with July 1st, 2019, each day is auctioned independently and a uniform capacity price is paid to all successful participants. The daily average paid capacity price during the aforementioned time period is 258.55 €/MW.

Before May 2019, each FCR prequalified unit was required to provide the auctioned power for 30-minutes in both fulfilment directions. Following new regulations coming into place at start of May 2019, the minimum delivery duration was reduced to 15-minutes. In order to get prequalified, each BESS must be able to provide the minimum delivery duration and present a functioning recharge strategy to compensate for FCR calls as well as losses within the system. An in-depth analysis regarding the minimum required energy buffer per MW FCR offered was conducted by [49]. The analysis includes the application of a recharge strategy which is also implemented on a stationary, grid-connected BESS located in Aachen, Germany (M5BAT). Eq. (8) states the minimum required energetic capacity (E_{buffer}) a BESS should have for providing a FCR power of P_{FCR} [49].

$$\begin{aligned} &E_{\text{buffer}}(P_{\text{FCR}}, t_{\text{Lead}}, t_{\text{Idle}}) \\ &= 2\cdot(E_{\text{worstCase}}(P_{\text{FCR}}, t_{\text{Lead}}, t_{\text{Idle}}) + E_{\text{15MinCriterion}}(P_{\text{FCR}})) \\ &= 2\cdot\left(5\ \text{min}\cdot P_{\text{FCR}} + 10\ \text{min}\cdot\frac{1}{2}\cdot P_{\text{FCR}} + 5\ \text{min}\cdot\frac{1}{4}\cdot P_{\text{FCR}} + 15\ \text{min}\cdot P_{\text{FCR}}\right) \\ &= 0.875\cdot P_{\text{FCR}} \end{aligned} \tag{8}$$

The formula includes the lead time $t_{Lead}(=5\ \text{min})$, which accounts for the delay between triggering a recharge (set point adjustment) and the actual delivery. Further, an idle time $t_{\text{Idle}}(=15\ \text{min})$ which arises from the block size on the intraday market is considered. The capacity reserved for providing the 15-min minimum delivery duration ($E_{\text{15MinCriterion}}$) may only be used in a so called alert state. Three different conditions define when the alert state is active. A worst-case estimate of how much additional energy is required before the reserve capacity can be used, is provided by $E_{\text{worstCase}}$ [49]. Applying Eq. (8) on the 30 MW/ 20 MWh BESS considered in this work reveals a maximum FCR power (P_{FCR}) of 22 MW. The remaining 8 MW can be used for recharging during FCR operation (recharge strategy).

In total, the average daily revenue on the FCR market amounts to 22 MW·258.55€/MW = 5688.1€. The estimated FCR revenue is higher than the revenue potential on the aFRR market. This holds true for all considered aFRR scenarios including the reduced cost scenario of the year 2025 (Section 5.2), which yielded a daily aFRR revenue of 3967 €. Since large frequency deviations are very rare in the European integrated grid, the BESS has long idle times (~43% of the time) during FCR provision and mostly performs small cycles [49]. Battery ageing is dominated by calendar ageing [46]. For this reason the battery deterioration costs are lower when providing FCR than aFRR.

6. Conclusion

After a brief description of the automatic Frequency Restoration Reserve (aFRR) auction design, this paper introduced a bidding and operating strategy to derive a bid tuple which optimizes the earnings of a Battery Energy Storage Systems (BESS) on the aFRR market. Three different configurations of Virtual Power Plants (VPPs) with wind-, PV- and thermal generation were considered. A detailed operating strategy for a BESS participating on the aFRR market in conjunction with a VPP was presented. The aim of the operating strategy is to maximize the sale of generation capabilities while providing a recharge opportunity for the BESS in aFRR periods. During hours of no aFRR obligation, the BESS conducts arbitrage on the intraday market. The maximum possible aFRR capacity (MW) to offer on the market was derived as a function of the generation profile of the VPP and the energetic storage capacity (MWh) of the BESS. Section 4.6 presented an optimization approach for finding the optimal bid to submit in the aFRR auction process. The optimization approach is based on an aFRR prediction framework and the derivation of the acceptance probability as a function of the submitted energy and capacity price. A cost breakdown of a containerized BESS was provided and a battery model for estimating the ageing costs of a lithium-ion battery system was presented. Based on the investment costs and the ageing effects, differential costs for any BESS load profile could be derived.

Results indicate, that an economically feasible operation in the year 2019 is not possible. This applies to all VPP configurations considered in this work. The price spread between the optimized aFRR energy price and the intraday market price does not suffice to compensate the differential BESS costs. However, for a predicted cost parameter set of the year 2025, an economically feasible operation is possible. This applies to a BESS operated in conjunction with a VPP but does not hold true for a BESS in standalone mode. The economic feasibility is very sensitive as regards prices on the aFRR market and costs of the BESS. Small changes in either direction make a substantial difference. The future will show how a consolidation of the national European markets and fewer thermal power plants will impact the aFRR revenues.

Compared to the Frequency Control Reserve (FCR) market, profits on the aFRR market were found to be lower throughout the scenarios of this work. Due to falling prices on the FCR market and frequent design changes in the control reserve markets, the statements of this work are relatively short-lived. The authors suggest a continuous re-evaluation of the markets in the future.

6.1. Future work

The bidding strategy could be extended to a holistic approach which covers the participation in multiple markets. If for instance a bid on the aFRR auction was not awarded, a subsequent bid could be submitted to the manual Frequency Restoration Reserve (mFRR) auction. Market participation on the FCR market could also be implemented. The arbitrage algorithm could be extended to simultaneously trade on both the day-ahead and intraday market in order to find higher price spreads. For all simulations conducted in this work, the minimum end-of-life (EoL) criterion of the battery cells was set to either 80% or 75%. However, various measurements and research show that battery cells can be used beyond this point. Since deep ageing effects are not covered by the implemented battery model, a more sophisticated and specialized battery model could be used instead. A better usage of the battery lifetime would decrease the differential ageing costs and increase the earning potential. Various other battery cell technologies could be investigated which differ in the calendric and cyclic aging properties.

CRediT authorship contribution statement

Michael Merten: Conceptualization, Methodology, Software, Writing - original draft, Supervision. **Christopher Olk:** Validation, Validation, Writing - review & editing, Resources, Software. **Ilka Schoeneberger:** Validation, Writing - review & editing, Visualization, Project administration, Funding acquisition. **Dirk Uwe Sauer:** Validation, Writing - review & editing, Visualization, Project administration, Funding acquisition.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. BESS with wind- and PV-generation

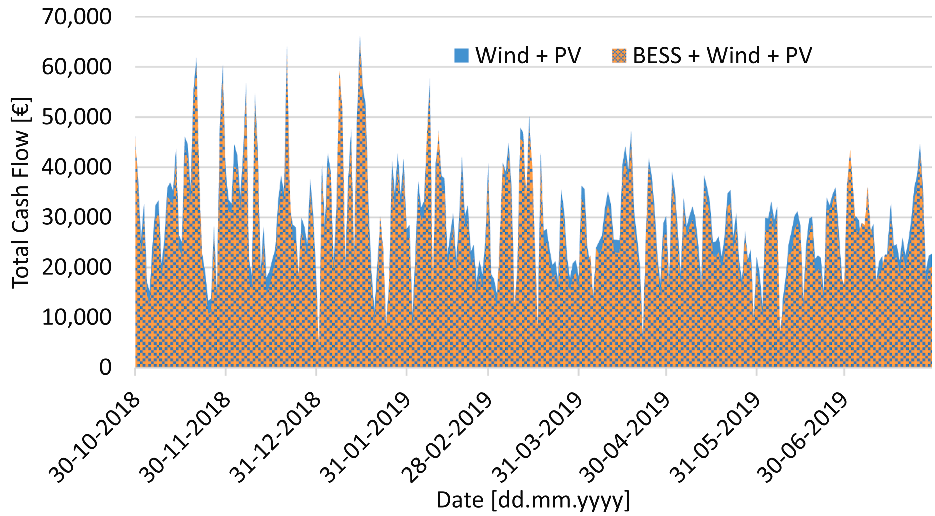

Fig. A-1. Total cash flow per day for 2 scenarios: Wind + PV and BESS + Wind + PV.

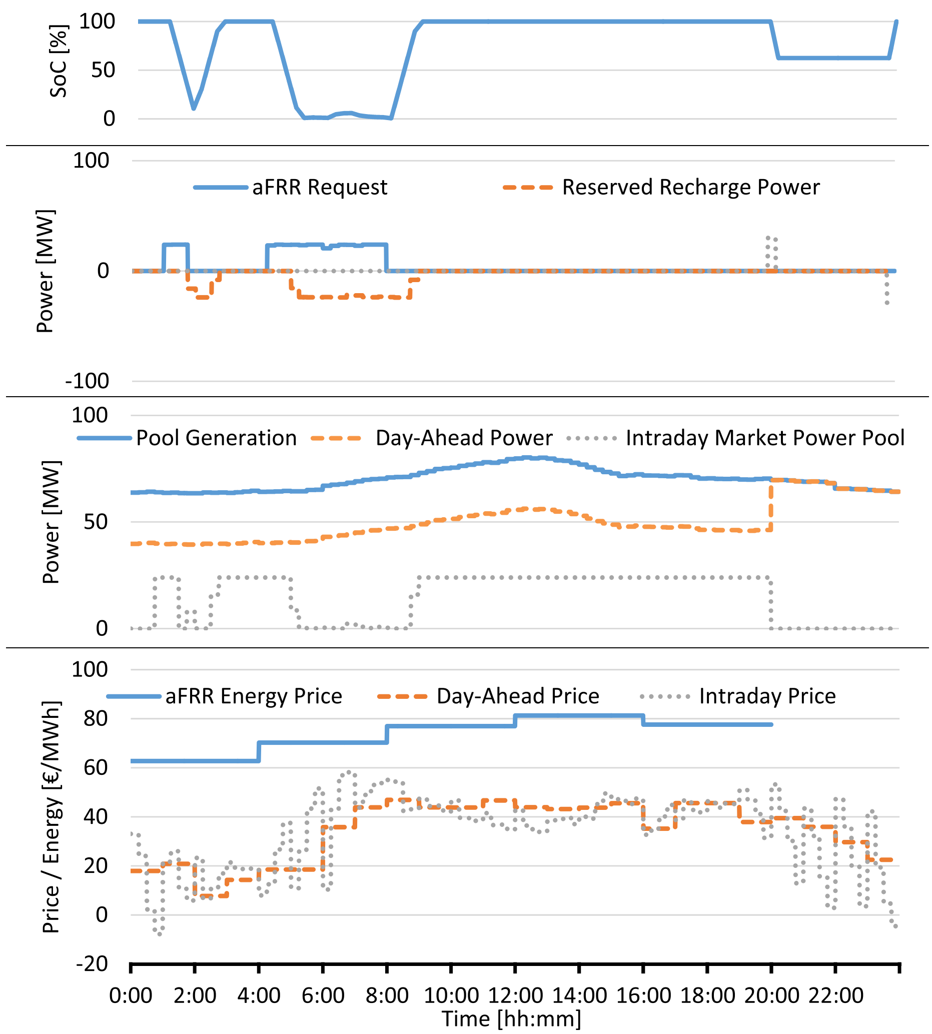

Fig. A-2. Operating and trading of the BESS + Wind + PV pool on January 8th, 2019.

Appendix B. BESS with wind-, PV- and thermal gen

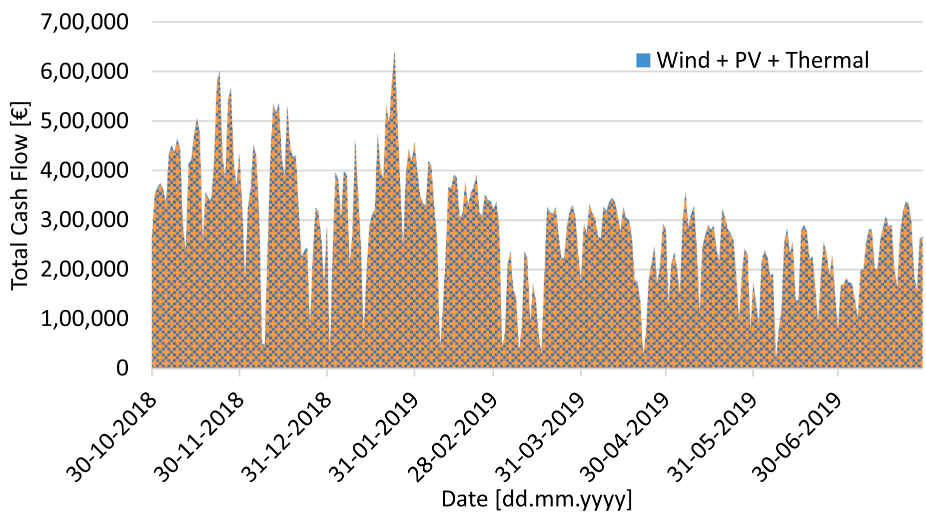

Fig. B-1. Total cash flow per day for 2 scenarios: Wind + PV + Thermal and BESS + Wind + PV + Thermal.

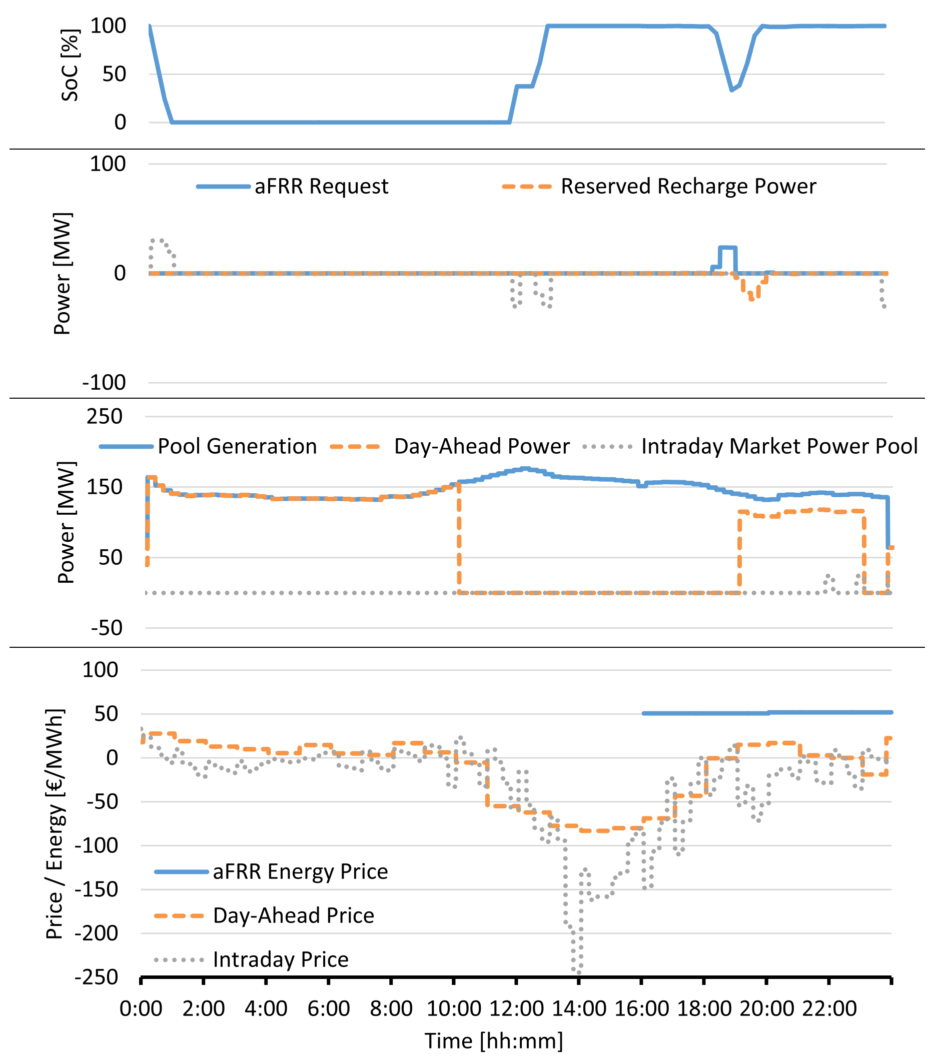

Fig. B-2. Operating and trading of the BESS + Wind + PV + Thermal pool on April 22nd, 2019.

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