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ABATE THE BARRIERS:
OPENING ELECTRICITY MARKETS
TO STORAGE AND RES

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Abstract

THE presented Thesis work considers the electricity markets in the presence of Battery Energy Storage Systems (BESS), Renewable Energy Sources (RES) and Distributed Energy Resources (DERs). It aims to provide a panoramic view of the possible regulatory evolutions of electricity markets, with particular focus on the Ancillary Services Markets (ASMs). The state-of-the-art of ASM and of the electricity balancing is reported, with focus on the standard balancing products for frequency control. The main stakeholders of the ASM are described: the System Operator (SO) and the Balancing Services Provider (BSP). A systematic review of sources is performed to assess the possible trade-offs in the ASM evolution, considering both the perspective of the SO and the BSP. The analysis qualitatively returns the compatibility of the ASM framework with DERs and BESS and detects the possible regulatory barriers for their effective participation.

To quantitatively assess the performance of BESS in the provision of ancillary services, a numerical model of BESS is developed. This is aimed to overcome a set of lacks found in the battery models present in literature, that makes them unsuitable to be used for testing ASM participation. The model is a multi-parameter empirical model based on an experimental campaign on a real-world asset. The model parameters return the overall performance of the system, included the impact of the power conversion system and of auxiliary systems.

The influence of the finite energy content of BESS on the provision of ancillary services is assessed. The importance of strategies for managing the energy content is highlighted, by proposing a comparative analysis among state-of-charge (SoC) management strategies. The analyzed strategies are defined “explicit” since they consider additional energy flows exchanged with the grid with the explicit purpose of restoring the SoC. The limitations of the explicit SoC management strategies enhance the interest for “implicit” strategies. A Multiservice Strategy is developed for providing SoC management via an additional (and remunerated) market service. The Multiservice Strategy exploits dynamic service stacking and guarantees revenue stacking. It is proposed and evaluated on two case studies. Then, the implicit SoC management strategy based on Multiservice is compared with the explicit ones.

The BESS model and the previously presented analysis on the evolution of ASM are used to estimate the optimal ASM arrangements for the provision of services by BESS. Two different services are tested along with a set of ASM parameters, recognized as potential regulatory barriers. The ASM arrangements are evaluated in terms of the flexibility that can be provided by the resources and the reliability of the provision. The optimal values of the ASM parameters for each type of service are returned.

Finally, to check if the BESS participation in electricity balancing brings advantages to the system, the provision of frequency response by BESS is tested with a power flow analysis tool. Dynamic simulations are performed and the results are appraised in terms of quality of service (i.e., frequency *nadir* after an incident) and system needs (i.e., needed regulating power) in case of frequency regulation by either conventional thermal power plants or BESS.

Keywords: *batteries, BESS, electricity markets, frequency regulation, ancillary services.*

Sommario

Il lavoro di tesi presentato considera i mercati elettrici in presenza di Battery Energy Storage Systems (BESS), fonti di energia rinnovabile (FER) e Generazione Distribuita (GD). Mira a fornire una visione panoramica delle possibili evoluzioni regolatorie dei mercati elettrici, con particolare attenzione ai Mercati per il Servizio di Dispacciamento (MSD). Viene riportato lo stato dell'arte dei MSD e del bilanciamento elettrico, con particolare attenzione ai prodotti di bilanciamento standard per il controllo della frequenza. Vengono descritti i principali attori dei MSD: il gestore del servizio (ad esempio, l'operatore della rete di trasmissione) e il Balancing Services Provider (BSP). Viene eseguita una meta-analisi delle fonti per valutare i possibili trade-off nell'evoluzione del MSD, considerando sia la prospettiva dell'operatore, sia quella del BSP. L'analisi restituisce qualitativamente la compatibilità del quadro del MSD con la GD e i BESS e rileva le possibili barriere regolatorie per la loro effettiva partecipazione.

Per valutare quantitativamente le prestazioni dei BESS nella fornitura di servizi ancillari, viene sviluppato un modello numerico di BESS. Questo ha lo scopo di superare una serie di carenze riscontrate nei modelli di batteria presenti in letteratura, che li rende inadatti ad essere utilizzati per testare la partecipazione al MSD. Il modello è un modello empirico multi-parametro basato su una campagna sperimentale su un sistema reale industriale. I parametri del modello restituiscono le prestazioni complessive del sistema, incluso l'impatto del sistema di conversione di potenza e dei sistemi ausiliari.

Viene valutata l'influenza del contenuto energetico finito dei BESS sulla fornitura di servizi ancillari. Viene evidenziata l'importanza delle strategie di gestione del contenuto energetico, proponendo un'analisi comparativa tra le strategie di gestione dello stato di carica o state-of-charge (SoC). Le strategie analizzate sono definite "esplicite" in quanto considerano flussi aggiuntivi di energia scambiati con la rete con lo scopo esplicito di ripristinare il SoC. Le limitazioni delle strategie di gestione esplicita del SoC aumentano l'interesse per strategie "implicite". Viene sviluppata una strategia Multiservizio per fornire la gestione del SoC con un servizio di mercato aggiuntivo (e remunerato). La strategia Multiservizio sfrutta lo stacking dinamico dei servizi e garantisce lo stacking delle entrate. Viene proposta e valutata su due casi studio. Poi, la strategia implicita di gestione del SoC basata sul Multiservizio è confrontata con quelle esplicite.

Il modello BESS e l'analisi precedentemente presentata sull'evoluzione del MSD sono utilizzati per stimare gli assetti ottimali del MSD per la fornitura di servizi da parte di BESS. Due diversi servizi sono testati insieme a una serie di parametri del MSD, riconosciuti come potenziali barriere regolatorie. Gli assetti del MSD sono valutati in termini di flessibilità che può essere fornita dalle risorse e di affidabilità della fornitura. Vengono restituiti i valori ottimali dei parametri del MSD per i vari tipi di servizi.

Infine, per verificare se la partecipazione dei BESS al bilanciamento elettrico porta vantaggi al sistema, la fornitura della risposta in frequenza da parte dei BESS viene testata con uno strumento di analisi di power flow. Vengono eseguite simulazioni dinamiche della rete e i risultati sono valutati in termini di qualità del servizio (cioè il *nadir* di frequenza dopo un incidente) e le esigenze del sistema (cioè la potenza regolante necessaria) in caso di regolazione della frequenza da parte di centrali termiche convenzionali o di BESS.

Parole chiave: *batterie, BESS, mercati elettrici, regolazione di frequenza, servizi ancillari.*

Contents

CHAPTER 1

Introduction

The World is committed to mitigate climate change. The awareness of human beings and governments on their own responsibility for the global warming has arisen. The single countries and the international organizations are pledging to reduce their burden on planet Earth [1], [2]. The main sources of the anthropogenic carbon footprint are known. They can be accounted in different ways. A widely adopted representation is proposed in Figure 1.1 [3]. This representation clusters four macro-groups of activities as the sources of greenhouse gases (GHG) emissions. A small portion, corresponding to around 3% of total carbon footprints is given by direct contribution of the waste. The organic matters and other residues we dispose of in the landfills or in wastewater produce methane and nitrous oxide while decomposing. 5% of the human-related GHG emissions are directly originated in the industrial processes: carbon dioxide is produced as a by-product of the cement production and of the production of chemicals. A wide share of GHG emission come from the agricultural and land use sector. This sector includes the use of soil for cultivation and for the livestock and the consequent deforestation. It accounts for around 20% of the pie. The remainder is energy. Energy is used in all sectors, including industry, agriculture, transport, buildings. The use of energy in all the sectors accounts for 73% of the anthropogenic burden on the climate. Each of the mentioned sector can improve its own environmental sustainability (thus shrinking its share of the red slice in Figure 1.1), mainly via energy efficiency. The energy sector must perform an ecologic transition to improve the sustainability of all the activities it feeds (thus shrinking the whole of the red slice). Apparently, the land use, land use change, and forestry (LULUCF) sector, including agriculture and farming, is the only relevant sector whose improvement in terms of carbon footprint is not largely influenced by the energy sector.

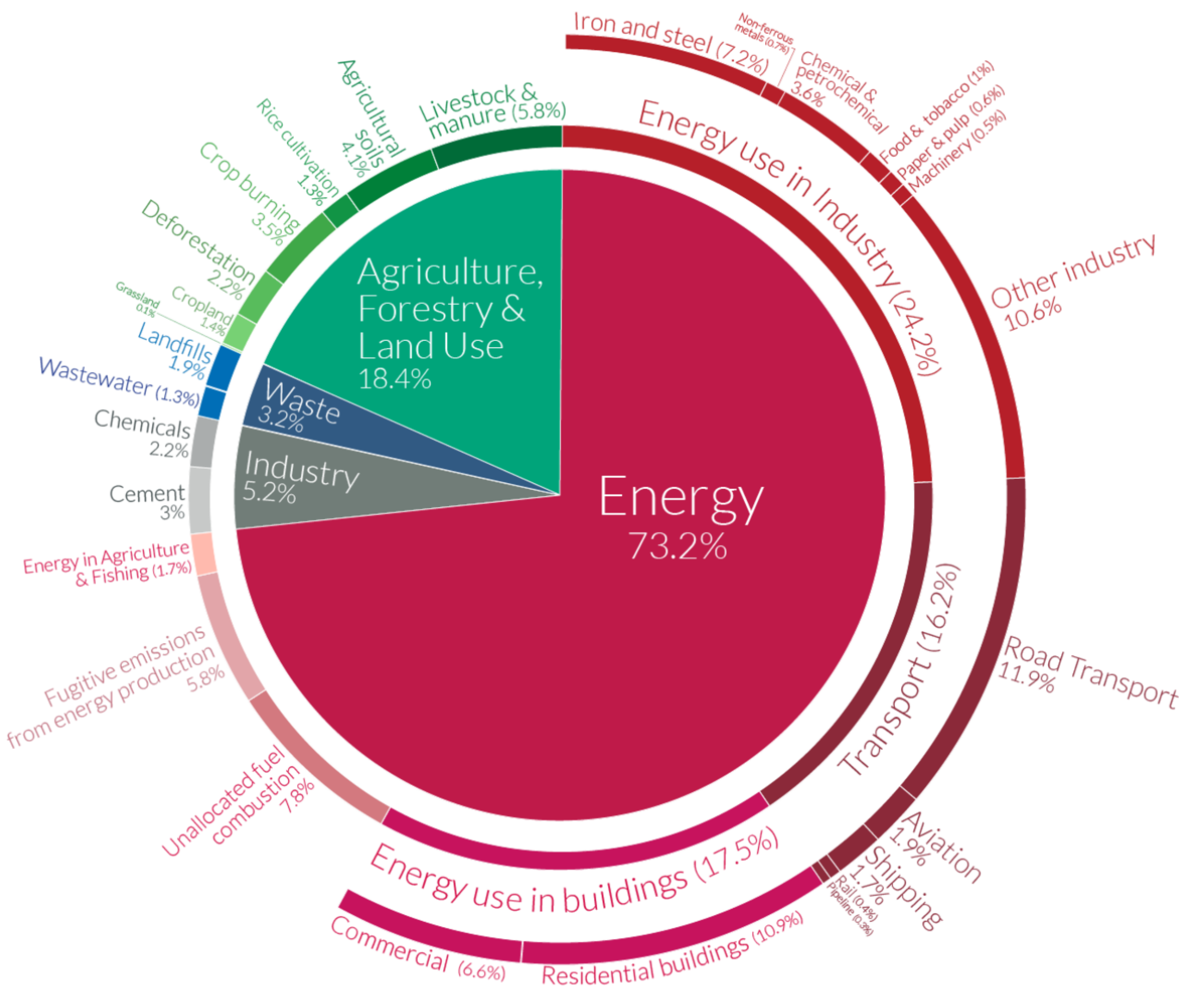


Figure 1.1 The breakdown of Greenhouse Gases emissions by sector [3].

To sharply reduce the climate-altering potential of the energy sector, the Renewable Energy Sources (RES) penetration as energy source should largely increase. The electricity is the form of energy that best suits RES [4].

If we analyze the RES impact on power systems, they present a set of issues for the power systems, such as their variability [5]. Another possible issue is the phase-out of conventional large-scale power plants and the massive deployment of (RES and non-RES) Distributed Energy Sources (DERs). Therefore, to increase the RES share in electricity, proper mechanisms for guaranteeing the correct functioning of the power systems must be foreseen. One of these include the provision of flexibility to the power system by reliable and fast resources [6]. The DERs are not usually involved in the flexibility provision. The electricity markets should evolve to welcome DERs flexibility since they will be the next main characters in the power system and in the electricity balancing [7].

In addition, the sketched evolution should be done fast enough to cope with pledges and targets. Focusing on EU the targets posed by the Green Deal are to reach in 2030 a GHG emission reduction of 55% with respect to 1990 [8]. For the power sector, a scenario compatible with this target is 75% of electricity from RES.

1.1 The evolution of the European generating mix

With the adoption of the European Green Deal [8], the EU will become the first climate-neutral continent by 2050. The roadmap to achieve this long-term target includes the EU target to have a 20% share of its gross final energy consumption from Renewable Energy Sources (RESs) by 2020, and 32% by 2030. The decarbonization in the energy sector will be led by the electricity sector. Figure 1.2 shows the EU gross production of electricity by source in the last 10 years [9]. As can be seen, RESs in electricity (RESs-E) passed 34% by 2020. Variable RESs (mainly solar and wind) largely increased their production in the last decade, reaching 20% of the overall electricity generation. The term variable refers to RESs that are characterized by a fluctuating nature, generally opposed to dispatchable and controllable sources, such as hydro reservoirs.

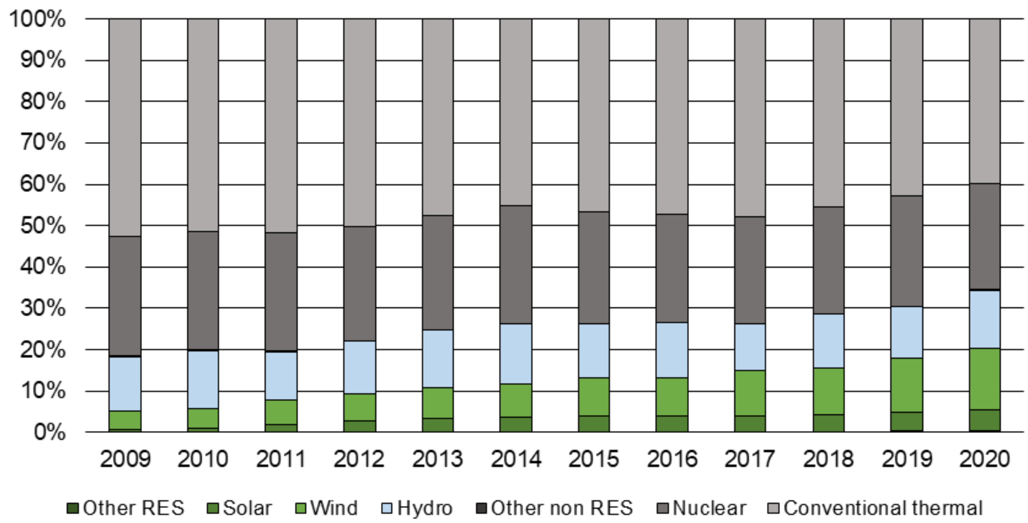


Figure 1.2 Total net electricity production of EU-27 by source [44].

Variable RESs are usually small or medium scale plants, thus connected to Low or Medium Voltage (LV or MV) networks (so-called Distributed Energy Resources, DERs). The penetration of DERs is rising in the EU thanks to the advent of new technologies and the rising interest towards decarbonization and energy efficiency [11][12]. Indeed, the largest share of DERs is based on RES plants and small high-efficiency thermal plants, often combined heat and power (CHP) plants. CHP plants share is 12% of total electricity generation in the EU as of 2018 [10]. The presence of CHP in the different Member States widely varies, as shown in Figure 1.3. In Germany, DERs represent more than 50% of the total installed power. Figure 1.4 shows the amount of German Distributed Generation powered by RES (DG-RES), shifting from 10 to 130 GW in 20 years [13]. Denmark shows similar trends, with wind power and small-scale CHP plants holding a large share of the total electricity production [14]. In Italy, in the decade 2008-2018, the DERs' yearly generation increased by more than 3 times: in 2008, only 15 TWh came from DERs; in 2018, around 55 TWh were produced by DERs out of 280 TWh of the overall electricity production [15]. Also, the numerosity of distributed plants is impressive: in Italy, the power plants with an installed capacity lower than 10 MW are more than 800 thousand in 2018 (see Figure 1.5). It is evident that a change in the generation mix is occurring in the direction of more distributed resources. In particular, the share of CHP is not rising, while the share of RES is increasing fast [10]. The importance of effectively dealing with RESs and DERs becomes even clearer considering long-term scenarios looking for the decarbonization of power systems in 2050 [16].

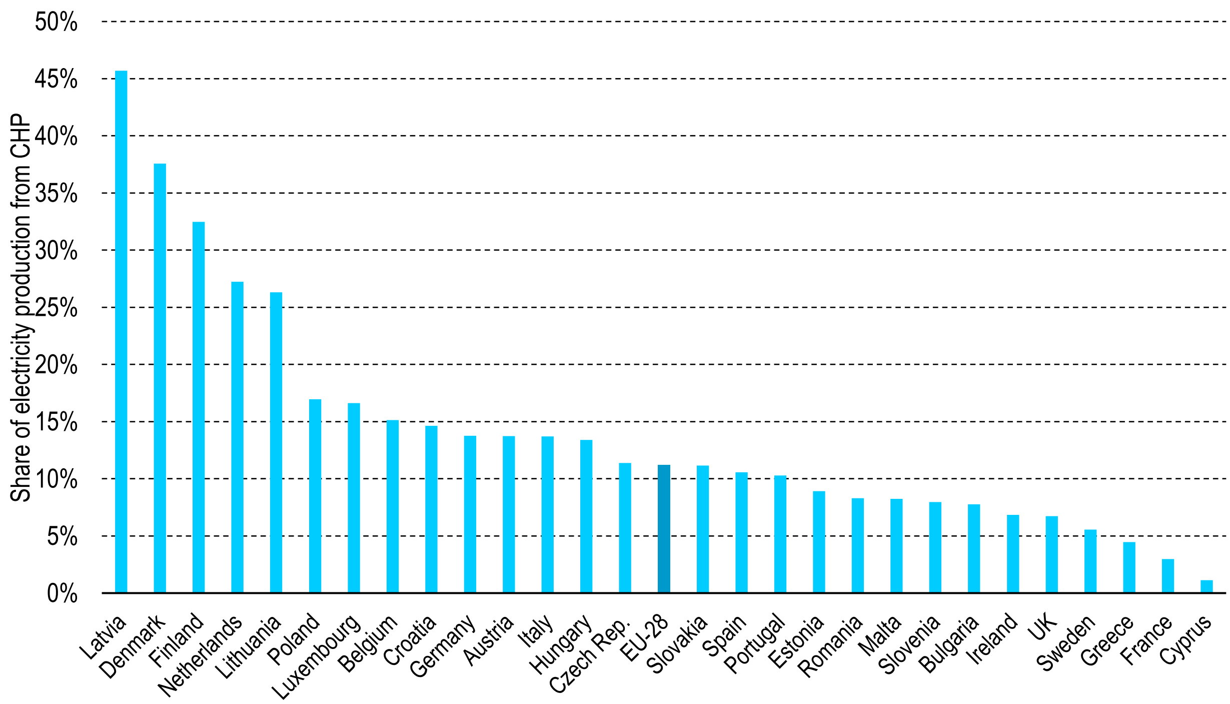


Figure 1.3 Share of electricity production by combined heat and power plants in each Member State in 2018 [10].

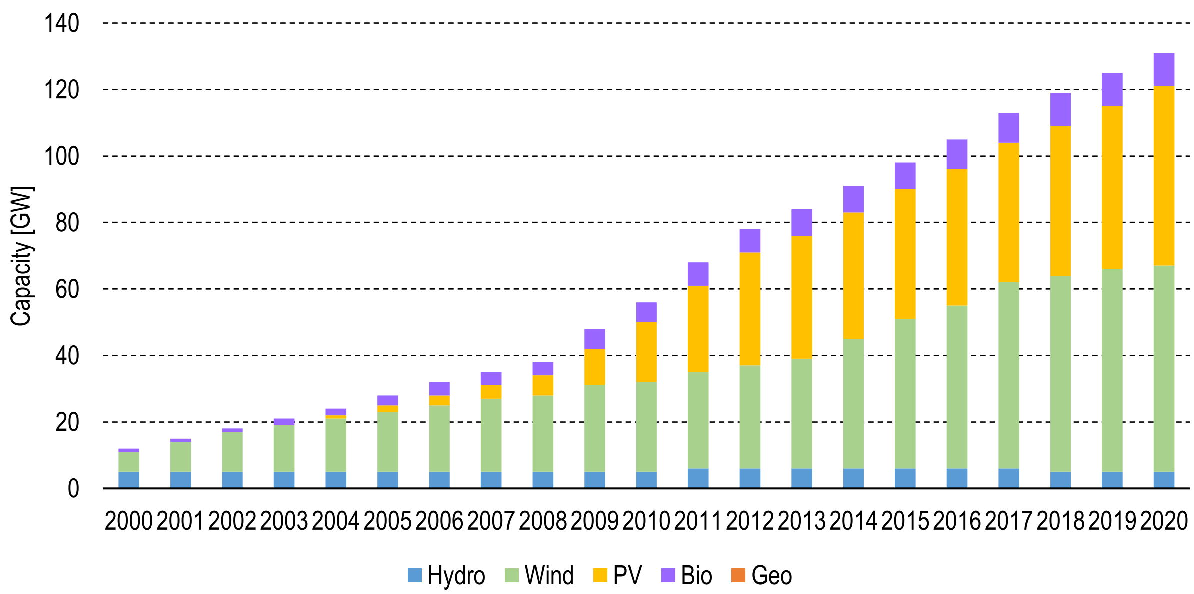
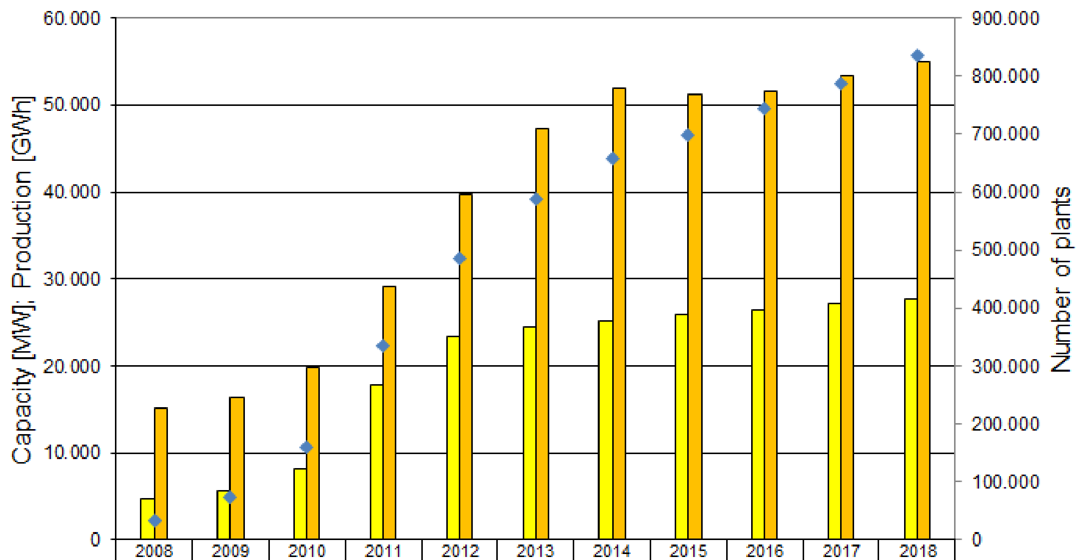


Figure 1.4 Installed capacity of DG-RES in Germany [13].



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Gross capacity [MW]	4.754	5.644	8.225	17.911	23.507	24.576	25.214	25.859	26.517	27.152	27.782
Gross production [GWh]	15.192	16.445	19.837	29.238	39.743	47.238	51.974	51.254	51.667	53.344	55.030
N° of plants	34.693	74.188	159.876	335.318	485.004	587.217	657.180	698.750	743.871	788.580	837.222

Figure 1.5 DERs gross production, capacity and number of plants trends in Italy. Only plants with capacity lower than 10 MVA have been considered [17].

1.2 The importance of energy storage systems

Energy Storage Systems (ESS) are recognized as an expanding technology that could enable the energy transition thanks to its multi-purpose nature. ESS, and in particular Battery ESS (BESS) can indeed both cope with the rising needs of balancing of the power systems and support the integration of variable RES, by decreasing their unpredictability [18]. On the contrary, the battery diffusion can lead to excessive exploitation of scarce material, such as rare minerals [19]: the development of a sustainable supply chain is a pillar [20]. Indeed, the larger economies are targeting to associate the increased production of BESS with a sustainable value chain leading to decrease the life-cycle impact of batteries in environmental and socio-economic terms: this is one of the goals of the European Battery Alliance (EBA) and other international economic forums [21], [22].

The speed of the BESS diffusion is strictly correlated with its cost. The BESS is a CAPEX-intensive investment. Nonetheless, the Levelized Cost Of Storage (LCOS) is increasingly used to compare the specific cost of cycling (in €/MWh) with the revenue streams associated to the available economic opportunities related to different applications. The LCOS varies largely considering the different applications. A proper model to represent all the BESS aspects and to consider the energy flows related to each application is needed to estimate it [23]. The LCOS majority is anyway related to the CAPEX. Therefore, a well-known recent estimation by a US institutional source of the Li-ion battery costs projections 2020-2050 is reported in Figure 1.6 [24]. BESS cost is rapidly decreasing, and this trend is expected to continue at least until 2030.

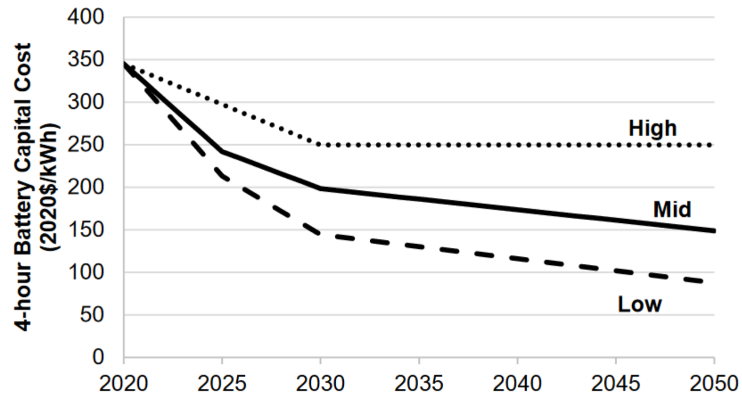


Figure 1.6 Cost projection for Li-ion batteries under three scenarios [24].

Two scenarios of market growth for BESS in 2030 are reported in Figure 1.7 [25]. Even in a decelerated scenario, BESS are growing significantly in terms of installed capacity. A large share of installations will be integrated with rooftop PV. Another relevant share is utility-scale BESS. Therefore, different applications can be foreseen for BESS: a combination of behind-the-meter and front-of-the-meter services, and a mix of standalone and RES-integrated installations. The possibility of service (and revenue) stacking is highlighted as a possible way of improving the economics of BESS [26].

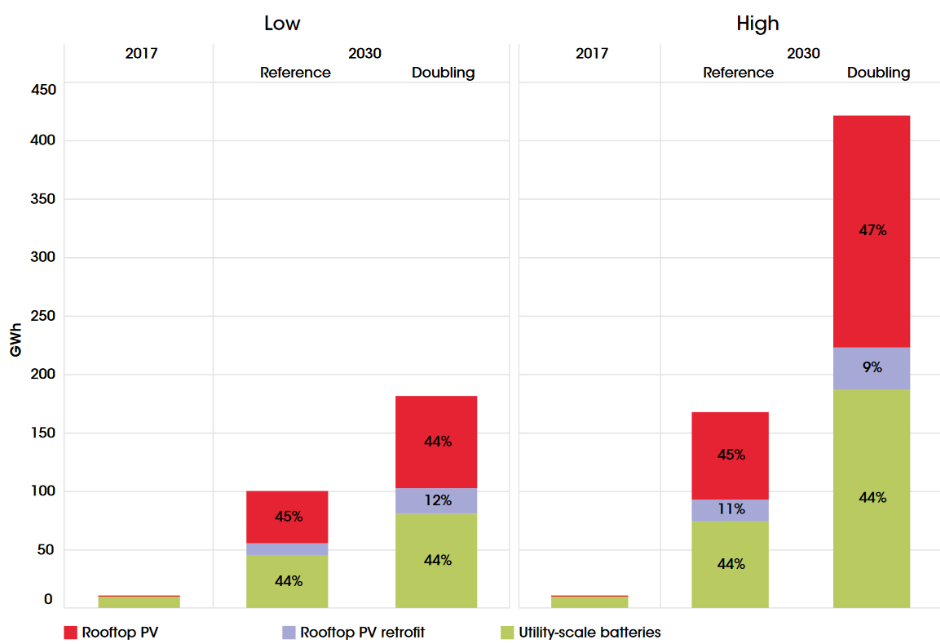


Figure 1.7 Market scenarios for BESS for 2030 [25].

The main application categories are presented in Figure 1.8. The installed capacity as of 2017 is largely devoted to the provision of frequency regulation. This is because BESS are inverter-based assets, capable of fast response to stimulus from the grid [27]. The provision of reserve capacity on the Ancillary Services Markets (ASM) is another major application, validating the possible central role of batteries on electricity markets. Today, the BESS installed capacity delivering behind-the-meter services, such as electric bill management, time shifting, and RES support represents a minor, but not irrelevant, share [25].

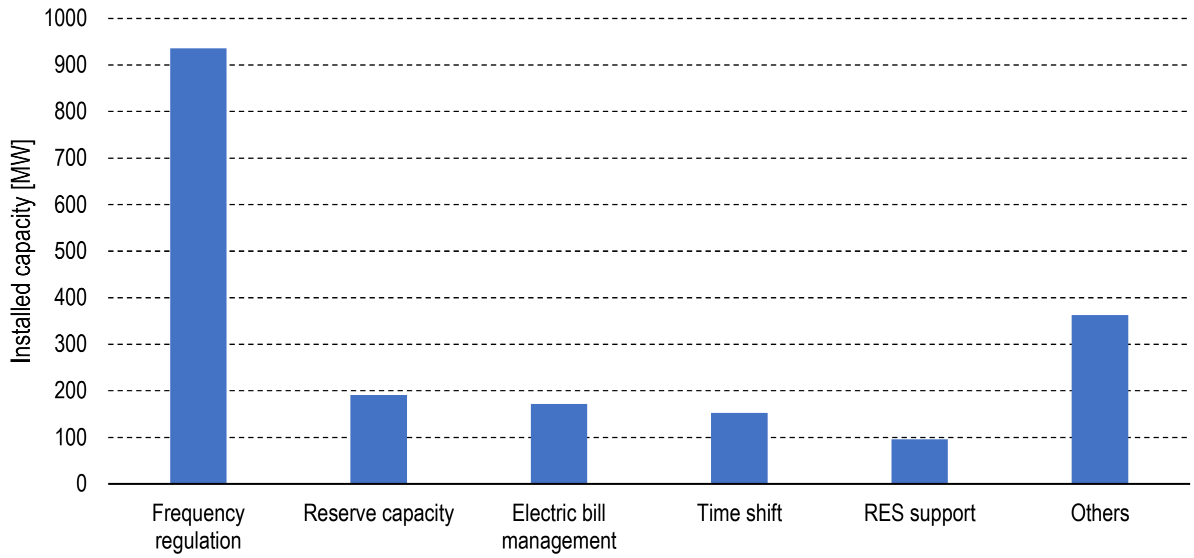


Figure 1.8 Electrochemical storage capacity installed by application (2017) [25]

In most of the applications seen before, BESS is aiding the power system and can provide a relevant support in the energy transition. Indeed, it either can satisfy a part of the needs for electricity balancing (thus keeping the system safe and secure) or it can support RES and reduce their variability (hence reducing the system needs for balancing).

1.3 The importance of regulating the change

The positive contribution of new resources (such as BESS) to the power system can only be exploited if the rules allow it. The Network Codes were developed in the last century considering the existence of conventional generation only (e.g., thermal, nuclear and hydro power plants). The regulation should update and evolve [28]. Specifically, the Ancillary Services Markets (ASMs) or Balancing Markets (BMs) are still partially (or totally) closed to DERs [7]. Their opening to new resources could be beneficial.

This can be done via a gradual transformation, based on the principles of the dynamic regulation [29]. Dynamic regulation involves the possibility for the National Regulatory Authorities (NRAs) to implement pilot regulations and pilot projects for testing either the provision of conventional services by new resources or the design of innovative ancillary services. Several examples can be found in the national frameworks. For instance, UK has developed a set of new services tailor-made for suiting some resources or some specific needs. Some of these services are then phased-out or reviewed in case the outcomes are different from the expectations [30]–[32]. Italy has launched a set of pilot project of limited duration aimed to test new services or to extend the provision of conventional services to new resources. This period is recognized as a transient period needed to fine-tune the services and products to be proposed on the ASM. The experiences gained by the pilot projects will converge in a final Integrated Grid Code of the Electricity Dispatch (TIDE), expected for 2023, that will close the transient period and propose a new stable regulatory framework [33], [34]. Germany proposed a different approach: it opened the conventional services to new resources, keeping the standard balancing products without creating new ones. Some reviews to better accommodate the peculiarities of DERs are implemented in the conventional services [35], [36]. Eventually, the US' system operator PJM regulated the change by splitting a single service in two different variants: one suitable for conventional generators (e.g., with slower dynamics), the latter suitable for ESS (e.g., with small or neutral energy requirements, compatible with the limited energy content of ESS) [37], [38].

Different approaches can be followed, but the mentioned countries show that it is important to regulate the change (in the technology mix and in the system architecture) to exploit the new capabilities and cope with the new needs.

1.4 The novelties of the study

The novelties of the study are summarized here. Nonetheless, a referenced analysis with respect to the state-of-the-art is presented in each Chapter: for the sake of readability, the relevant Paragraphs are referenced. Novelties are also summarized in Table 1.1.

We consider that the Thesis is novel starting from the approach: it both considers the perspective of the system and of the market participant, to better appreciate synergies and trade-offs. This is not usual in the studies investigating the power system and the electricity markets (in particular, ASMs), focusing either on the service provider or the systemic view. Instead, recognizing the possible trade-offs in the ASM evolution is of paramount importance to select and prioritize the regulation and policies. This Thesis work first expands on the state of the art to give a panoramic view of the trade-offs among the system operator and the service provider in the ASM. A wide set of regulatory barriers is analyzed and a priority ranking is returned: the evolutions that both bring a benefit for the operator and the market player are recognized with a systematic review and highlighted (Chapter 3, see Paragraph 3.1 for more details). Then, the proposed ranking is used to add a quantitative study returning the impact of each barrier on the DERs techno-economic performance (Chapter 7). These studies together increase the knowledge of the electricity balancing and the possible evolution for effectively welcoming DERs. The outcomes include the optimal range of parameters for two standard balancing products (aFRR and mFRR) to maximise the techno-economic performance of DERs by prioritizing the evolutions that represent win-win situation for the system and the resources. This can guide policymaking in updating electricity balancing for supporting the transition of the power sector towards more sustainable and distributed resources. The selection of standard balancing product allows to extend the results to a European perspective (even if the data for the simulation campaign come from Italian market).

The Thesis widely analyzes large-scale BESS and their operation by means of a BESS model. Two main categories of studies on batteries can be recognized in the literature. The first set concerns studies useful to the battery production, including the battery design and battery management system (BMS) emulation: these studies aim to represent with extreme accuracy the processes inside the cell or the electric quantities evolution in the battery, thus they make use of electrochemical or electrical models. They consider the electrochemical section of the battery only, and they are characterized by large computational effort. The second set of studies are useful for energy management and BESS operation within a power plant or an energy district, in particular for developing their control strategy: these studies usually model the BESS in a simplified way, since it is part of a larger system, and the computational effort should be limited. They make use of empirical models often based on a constant overall battery efficiency (see Paragraph 4.2 for more details). In the Thesis, the focus is on BESS management and operation. Therefore, an empirical model is selected. Nonetheless, the BESS is considered an enabling technology for supporting and enhancing the RES diffusion: it deserves accurate modelling, possible dealing with real-world situations (i.e., an experimental model). An accurate model, yet organic (i.e., considering the whole BESS) and fast (i.e., with lower computational effort with respect to models with comparable accuracy), is developed to improve with respect to the state of the art. A protocol for the development of an experimental multiparameter model is developed. A validation campaign is carried out to assess the accuracy of the model. A comparative analysis with respect to the state of the art is presented to clearly highlight the modelling advantages. The key features of the developed model are: to consider the dependency of the operational efficiency with respect to the main variables (i.e., power and state-of-charge); to include the auxiliaries demand, that represents a large source of losses when the battery is idle or operating at low power; to be fast enough for serial long-run simulation campaigns (Chapter 4).

BESS operating grid-connected need a proper strategy for managing the state-of-charge (SoC). While SoC management is analyzed by literature, the possibility of providing it implicitly while delivering a service is less explored. A detailed analysis, supported by numerical simulations (see Chapter 5 and 6) provides new knowledge on the topic. First, the explicit SoC management strategies are analyzed considering possible real-world implementation (see Paragraph 5.1 for more details), to evaluate them and define the most suitable strategies for a standard balancing product (i.e., FCR), once more considering both the perspective of the system (i.e., the reliability of the provision) and the participant (i.e., the additional operating costs for SoC management). Then, the possibility of service stacking is carefully assessed. Multiple services provision is considered as an effective mechanism for the provision of SoC management. A second service is added to the main one with the twofold aim of revenue stacking and (implicitly) managing the SoC (see Paragraph 6.2 for more details). While two case studies are proposed for the Italian framework, a final simulation on the standard product of FCR generalizes the outcomes and allow to compare explicit and implicit SoC management. A quantitative comparative analysis of the impact of SoC management strategies for the system and the market player is novel to the literature. In addition, the use of an organic BESS model and the inclusion of a market model (implementing the aleatory behavior of the market in the strategy) increase the accuracy of the study.

The impact (i.e., benefit) of the provision of innovative ancillary services to the power system is quantitatively analyzed in the literature. The possible impact on the system costs was assessed on a past study for the US case. The proposition of a similar analysis for a European case is considered of interest, and it is proposed in the Thesis work (Chapter 8). The literature shows system frequency studies assessing the short period following an incident such as an outage or a load ramp (i.e., some seconds to one minute, see Paragraph 8.1 for further details). When dealing with finite energy contents units as regulating units, analyses encompassing a longer period (e.g., minutes to hours) are beneficial to assess the evolution of the SoC and the consequent impact of the regulation of the depletion of the energy content. A novel methodology is proposed to assess the power imbalance during system operation based on electricity market data. Then, the developed BESS model is implemented in a tool for dynamic simulations of the system. This is done to reconstruct the real situation on the power network and to assess the impact of frequency regulation by BESS.

Table 1.1 Summary of the novelties of the work

Study	State-of-art	Novelties	Applicability
BESS modeling	Several models are present in literature. Some of them have high accuracy and high computational effort. Others presents low computational effort, but they are simplified (e.g., constant BESS efficiency). Even the complex models usually disregard auxiliary systems.	A multiparameter experimental model is developed, retrieved after a test campaign whose protocol is proposed in the Thesis. It features variable BESS efficiency and a model of the auxiliary systems. Its validation confirms it has high accuracy and its computational effort is lower with respect to competitors.	The proposed test protocol can be applicable to large-scale BESS, even in industrial and utility contexts since it does not require system disassembly. The retrieved model is applicable to Li-ion NMC BESS with a duration higher than 2.3 hours.
Control strategies for implicit SoC management	The stacking of services is presented in the literature also for providing energy and SoC management on a BESS. A comprehensive comparative analysis of SoC management strategies (including multiple services provision) is missing.	A Multiservice strategy for implicit SoC management is developed and checked against real-world SoC management strategies, showing better performance in terms of reliability and economics.	The strategy is tested over case studies based on Italian and German market. Nonetheless, it is compared with SoC management strategies for the provision of a standard product such as FCR. Therefore, the fundamental equations proposed can be applicable to a European context with slight adaptations to the products and the market structure (e.g., duration of the market sessions, distance from market closure to delivery time).
Systematic review of regulatory barriers	Several studies present a review of the regulatory barriers in ASM. They usually give qualitative indications. In addition, they are usually focused either on the provider perspective or on the system one.	The proposed analysis considers a large set of barriers, expanding on the previous literature. It considers both the perspective of the system operator and of the BSP. It returns semi-quantitative indications and a ranking to support policymakers prioritize interventions that outline a win-win situation.	The ranking considers the European regulation and several European case studies. Thus, the study can be of interest in the whole European framework and in Member States.
Best ASM arrangements	Some studies returned an optimal parameter range for DERs inclusion in a qualitative way.	A set of simulation assessed the techno-economic impact on BESS performance of different parameters of standard balancing products. An optimal range for the main parameters is returned.	The services are implemented as per the Italian Grid Code rules. Nonetheless, the use of the framework of the standard balancing product, coherent with Electricity Balancing Guidelines, allows the applicability of most of the results to the European framework.
System dynamic simulation on BESS providing frequency regulation during long-lasting frequency event	Dynamic simulation of power systems assesses the impact of different control strategies (also innovative regulation by BESS) on the frequency profile after an incident.	A methodology is proposed to test the system frequency during operation, over a time framework of several minutes to hours, in case of provision of frequency regulation by BESS, starting from electricity market data.	The adopted market data are from Italian market, as well as the strategy for the fast frequency regulation. With modifications, the proposed methodology could be implemented in countries where BESS are enabled for frequency regulation and power systems data are public or can be retrieved.

1.5 The layout of the work

The schematic presentation of the study is shown in Figure 1.9.

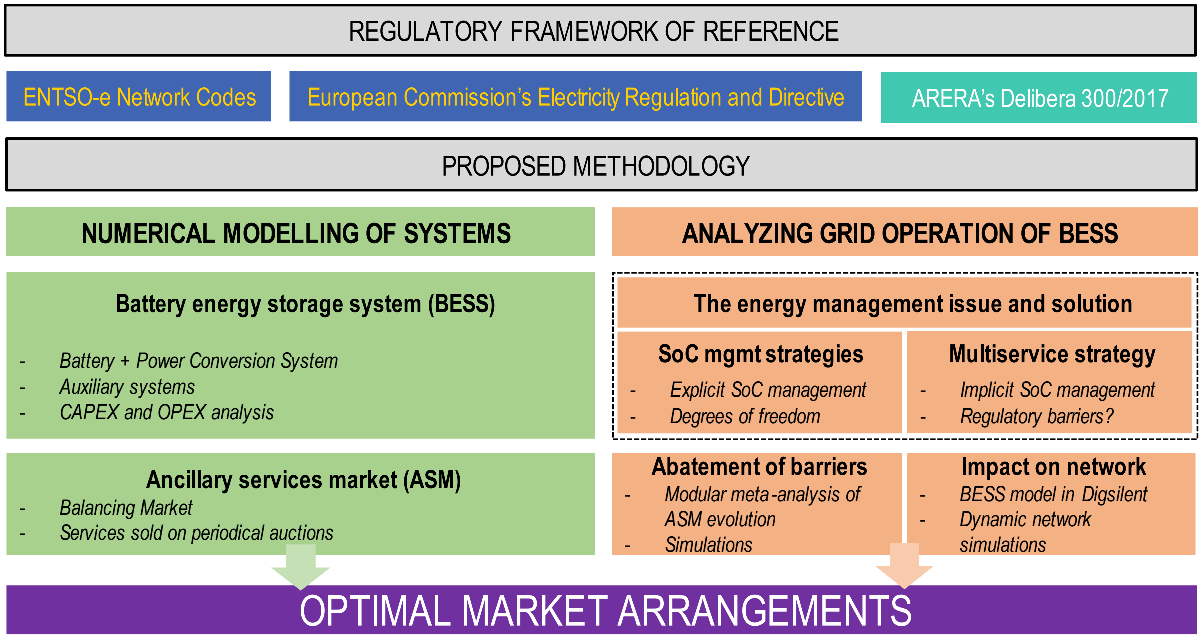


Figure 1.9 Modular presentation of the study.

The remainder of the work is structured as follows.

Chapter 2 describes the topic of electricity markets, with particular focus on the Ancillary Services Markets (ASM). A description of the system needs, of the services and of the products traded on ASM is given. The main stakeholders of the ASM are presented: the System Operator (SO) and the Balancing Service Provider (BSP).

Chapter 3 proposes a systematical review of sources on the evolution of ASMs. It allows to detail the process of evolution of ASM in Europe. Each recognized trend is described, and a semi-quantitative ranking is given as output to highlight the win-win evolutions and the possible trade-offs. Then, the developed framework is used to analyze some case studies of interest, including European national frameworks that present historically different backgrounds.

Chapter 4 introduces the topic of BESS and BESS modeling. Indeed, BESS are recognized as one of the fundamental players of the ASM of tomorrow, given their high accuracy in following power setpoints and fast response. A model able to organically estimate the BESS performance is developed, starting from an experimental test protocol, a campaign on a real asset and a verification and validation procedure. The model accuracy is assessed against the real BESS. Preliminary results are returned to show the capability and novelties of the model: for instance, the share of losses between the battery, the power conversion system (PCS) and the auxiliary systems on different BESS applications is estimated.

Chapter 5 to 7 presents three studies that make use of the developed BESS model to analyze the performance of BESS, also coupled with other production and consumption units, in the provision of ancillary services.

Chapter 5 focuses on the issue of the finite energy content of BESS and, consequently, the need for SoC management strategies: the reliable provision of ancillary services is subject to the available energy, beside the available power. Therefore, the regulation is recently implementing new degrees of freedom (DoF) in the grid codes and pilot projects, for instance in the provision of Frequency Containment Reserve (FCR). These allow to restore the SoC towards a target SoC without interrupting the service provision. A set of explicit SoC management strategies is proposed and a comparative evaluation is performed.

To overcome the limitations of explicit SoC management strategies (i.e., they imply additional costs, thus additional energy exchanges, and enhance the aging of the battery), an implicit SoC management strategy is proposed: the provision of a second market service beside FCR, with the scope of either buying or selling the power flows needed for SoC management at a convenient price and stacking the BESS revenues. Chapter 6 illustrates the development of a control strategy for the multiple services provision: the Multiservice Strategy. First, a general review of the approaches for service and revenue stacking is given. Then, the methodology for developing the Multiservice strategy is proposed. This is applied to two case studies: a domestic case where a battery provides both behind-the-meter and front-of-meter services; a utility-scale case, where multiple frequency regulation services are provided, including a fast frequency response. Eventually, the Multiservice strategy as an implicit SoC management strategy is quantitatively compared with the explicit strategies studied in Chapter 5.

The analyses of Chapter 6 make apparent the need for an ASM design that allows the effective exploitation of BESS and DERs. Chapter 7 considers the ASM evolutions in light of the ranking developed in Chapter 3 to propose a quantitative analysis of the regulatory trends that were recognized as win-win situations. The BESS model is used to check the provision of services under different regulatory parameters (e.g., the time definition of products, the type of services, the symmetry of procurement). The possible improvement in terms of reliability and economics given by a regulatory change is estimated. The outcome of the study is the optimal arrangement for different categories of standard balancing products traded in ASM: an optimized design of this product would increase the flexibility that can be gathered by the same resources and the reliability of the provision.

Chapter 8 changes the perspective: up to now, different ways of improving economics and performance of the provision of ancillary services by BESS have been assessed. Is this effort to evolve the regulation necessary (or useful)? To assess the impact on the grid that a faster and more precise regulation from BESS could have, the BESS model is implemented in a tool that allows to perform dynamic simulations of the power system. This tool is used to assess the benefit on the frequency profile of a fast frequency response from BESS. The analyzed case study is the provision of Fast Reserve in a region in Italy. The possible drawbacks of fast regulation provision are checked by carefully analyzing the control strategy, the connection topology, and other parameters. The results are given in terms of improvement of the frequency *nadir* after an event, or in terms of system costs (i.e., the size of the necessary power reserves for guaranteeing the same quality of supply).

Eventually, Chapter 9 summarizes the conclusions of the work.

CHAPTER 2

The Electricity Markets in Europe

Abstract

The power systems, historically vertically integrated, are nowadays liberalized. The demand (i.e., the electricity consumers) and the offer (i.e., the generation) meet on the electricity markets, where both energy, power and other services are traded. A detailed description of the market structure and principles, focused on Europe, is provided. The European Union is committed to develop a continental Internal Market for Electricity, with a set of common rules suitable for fostering cross-border trade, the participation of Distributed Energy Resources (DERs), targeting the decarbonization of the power system. The wholesale energy markets (the Day-Ahead Market and the Intraday Market) are described, considering the European framework. The Ancillary Services Market (ASM) is detailed, too. An analysis of the Italian ASM is given: Italian ASM is adopted as preferred market framework for the following analyses on the provision of services by BESS.

2.1 Introduction

In 20th century, the power systems were almost everywhere a vertically integrated system. A single body, usually a state agency, oversaw all the activities inherent to the generation, transmission, distribution and supply in a monopolistic regime [47]. In more recent years, the power system liberalization occurred. A market has been introduced for delivering some of the activities. The generation, the supply, and the delivery of ancillary services to the system are, in principle, competitive services. Instead, transmission and distribution are natural monopolies: competition in this sector would result in a duplication of the network. For a panoramic view of the activities on power systems, see Figure 2.1.

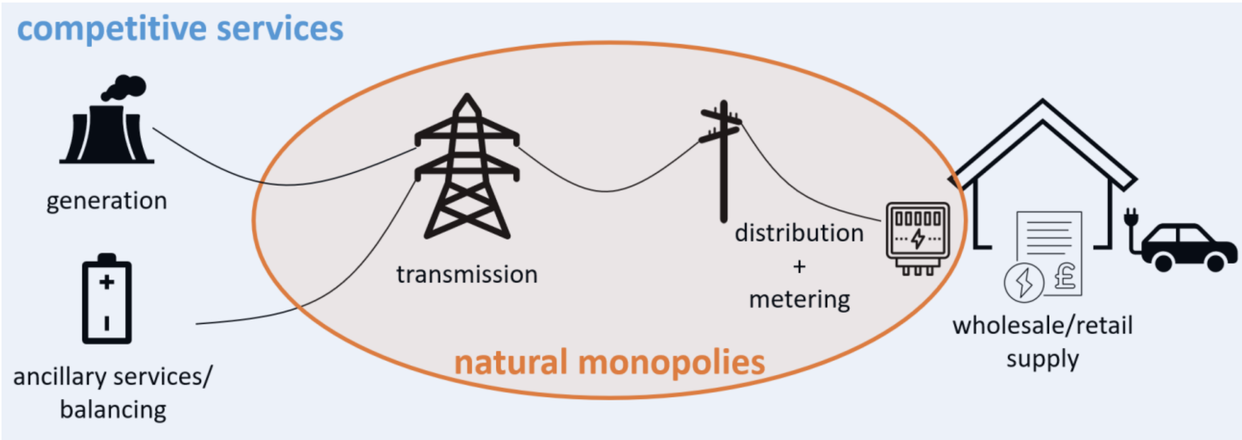


Figure 2.1 Visualization of the main activities in the power system.

For what concerns Europe, the liberalization started with the First Energy Package and the Electricity Directive [48]. The Directive was implemented in the following period in each Member State. To guarantee that the liberalized market and the natural monopolies work efficiently in an independent way, the unbundling process occurred: the agency, firm or institution operating in a market service cannot operate also as a monopolist in a regulated service. Therefore, the firms operating the transmission or the distribution network must be separate from the firms generating or selling electricity to customers [49]. This is to guarantee that there is no asymmetry of information between market players, and that none of them has access to more information on the status of the infrastructure, allowing it to behave differently on the market. To rule the regulated entities and to monitor the markets, National Regulatory Authorities (NRAs) were funded in each Member State [50].

The main product traded on the electricity markets is energy. In any case, the power systems have other needs beside the energy generation [47]. The electricity generation and consumption must always match: every surplus or lack in the energy generation with respect to the energy consumption would result in issues on the network (every imbalance results in a deviation from the nominal value of the network frequency). In addition, the network lines are characterized by load flow limits: a larger flow rate on a transmission line with respect to its maximum rate would result in a congestion. All these requirements can be satisfied only thanks to the provision of ancillary services to the power systems. These are generally traded on electricity markets, too.

The most important ancillary service is frequency regulation, also known as electricity balancing. Also, the provision of electricity balancing needs to evolve because of the evolution in the generating mix on power systems: indeed, the increase in system variability due to variable RES and the decrease in system mechanical inertia due to the rise of inverter-based systems drastically modify the frequency profiles [43], [44]. In general, to guarantee the instantaneous balancing between injections and withdrawals, it is necessary to:

- quantify the system needs (e.g., define the operating range for the network variables and sizing the power reserves);
- establish the tools for the regulation (i.e., the ancillary services), evaluating the rules and quantities needed for each of them;
- procure the resources for the provision (e.g., by means of the products of the Ancillary Services Market, ASM) [53].

Lately, the electricity markets have also considered the need for introducing a capacity remuneration mechanism (CRM) [54]. Indeed, energy-only markets have always remunerated the energy generated by each unit (in €/MWh). In any case, given the decarbonization of power systems, some of the production units could get out of the energy market. In case the working hours result lower than a certain threshold, there is no more convenience in running a generator, and it would be dismissed. This could generate scarcity hours: the power system has not enough capacity to cope with the peak load hours, resulting in loss of load or skyrocketing prices. To avoid this, the generating units that are out of the energy markets, could be remunerated to guarantee the availability of their capacity in the limited amount of scarcity hour. This could be done in a capacity market, with a remuneration in €/MW/period. As of today (2022), the European Commission must issue a positive opinion on a Member State's implementation plan before a CRM can be introduced in that State. This is to assess the efficiency of the energy market in that State and therefore avoid or limit the need for a CRM [55].

In the following, the electricity markets for energy and for the ancillary services will be detailed in their scope, structure, and functioning principle. The focus is on the Ancillary Services Markets (ASMs) that will be central in this Thesis work. The CRM will not be treated in this description and are only mentioned for the sake of completeness.

The structure of the remainder of the Chapter is the following. Paragraph 2.2 gives a panoramic view of the different market session, scope and timing. Paragraph 2.3 offers a detailed perspective on ancillary services, including the evaluation of the needs, the definition of the services and the conversion into products. A focus on the electricity balancing is given. Also, the main roles in the market are described. It is useful for introducing the systematic analysis of the evolution of ASMs presented in Chapter 3.

2.2 The electricity markets

The electricity markets are complex systems of subsequent markets, each one divided in several sessions. In each market, the demand (the electricity consumers) and the offer (the electricity producers) meet and trade the different products, i.e., energy, capacity, and services. Focusing on energy and services markets, the following paragraph will describe the main markets, defining for each one the scope and the timing.

The main market is the Day-Ahead Market (DAM). It is generally the market that manages the largest traded volumes (in GWh). In this market, the offer are production units generating energy, while the demand are electric users requesting to consume energy for their needs. The demand can procure electricity by bidding on the "electricity pool" or via bilateral contracts. Their working scheme is simplified in Figure 2.2.

In the electricity pool or power exchange, the market operator acts as a central counterparty:

- all the producers and consumers bid a quantity (in MWh) and a price (in €/MWh) for each hour of the next day;
- the market operator collects all the bids and builds the demand and the supply curve;
- the costumers (producers) that offer a price larger (lower) or equal to the system marginal price (SMP) are awarded, the others are not awarded;

- the outcomes are communicated to each participant well ahead of real time.

On the next day, the awarded customers (producers) will consume (produce) the awarded quantity.

In case of bilateral contracts, also known as over-the-counter (OTC), a single producer and consumer make a private contract for energy trading for a long period (typically some years). The contractors just need to communicate the exchanged quantities to the market operator.

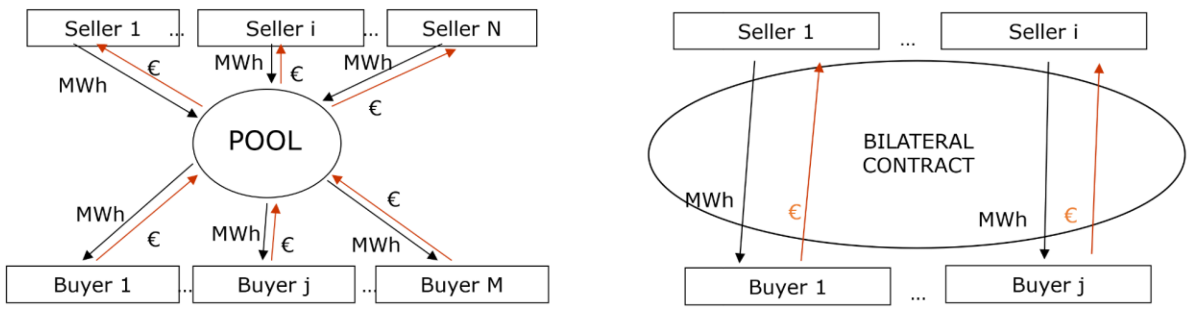


Figure 2.2 Simplified scheme of the electricity pool (to the left) and the bilateral contracts (to the right).

The volumes and shares of power exchanged energy and bilaterally contracted energy dramatically changes in different countries. For instance, in Germany, 60% of the energy volumes are bilateral OTC (2021 data) [56]. In Italy instead, 25% is bilateral, while 75% is traded on the power exchange (2020 data) [57].

Intraday markets (IM) present a gate closure nearer to real time. As this allows for a high level of flexibility, the participants use the IM to make last minute adjustments and to balance their positions closer to real time. In IM, the product is still energy, and the volumes are much lower than the ones in DAM (around a tenth) [58].

In both DAM and IM the trading is performed in market zones. Within the same market zone, congestions are not solved. In addition, both DAM and IM have a gate closure in advance with respect to real time. Therefore, the balancing is not guaranteed.

Ancillary Services Markets (ASM) are built to procure the necessary power reserves and to activate real time the resources able to guarantee the respect of the network parameters: frequency, voltage, lines' thermal rate, etc. To respect the requested performance, only more reliable resources are admitted to ASM. Power reserves are procured in advance with respect to real time, to cope with intrazonal congestions and to build the necessary margins for frequency regulation, both upward and downward. Reserves are generally procured in the scheduling session of ASM. In real time, the actual needs for balancing are satisfied by activating the resources in Balancing Markets (BM). The typical time framework is presented in Figure 2.3.

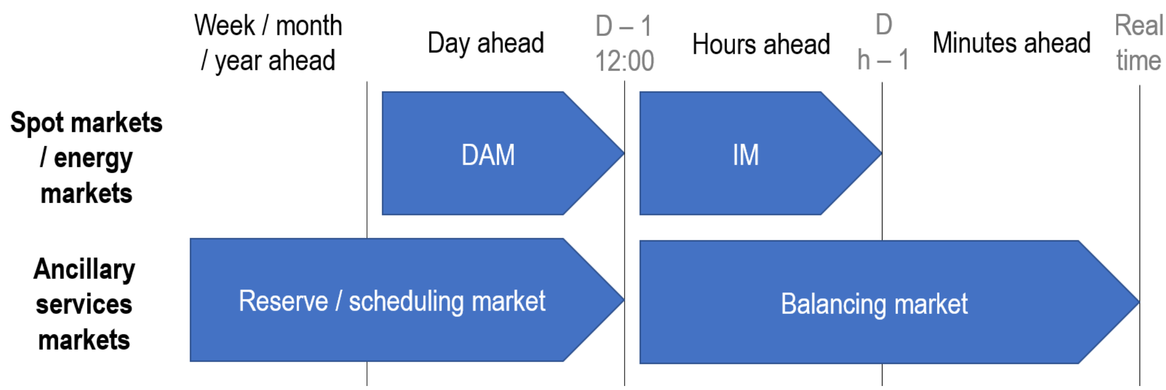


Figure 2.3 General time framework of gate opening and gate closure of Spot Markets and Ancillary Services Markets.

Prices in ASM are generally higher and the volumes are lower than in DAM [59]. ASM are increasing their importance with the rising penetration of DG and RES. Larger reserves must be procured to face a higher variability of RES and loads [60]. Innovative ancillary services could be introduced to provide a more precise control [61]. Regulation improvements could help reducing the needs for ancillary services [62].

While DAM and IM are homogeneous in different countries and cross-border projects are already live in Europe, ASMs present a higher degree of specificity. First, they differ in case of self-dispatch and central dispatch system, as will be better described in paragraph 2.3.4. Moreover, the payment can be energy or capacity based (or both). The distance from gate closure to delivery time widely varies: weekly, daily or hourly sessions can be present.

Electricity markets are evolving. For instance, the Single Intraday Coupling (SIDC) is live since 2018 in 14 countries, and within 2022 will be live in all the target area [63]. This will allow to trade resources intraday with continuous trading cross-border in all Member States. On the ASM side, many enhancements are ongoing. For instance, new services are introduced in UK, such as Enhanced Frequency Response (EFR) and Dynamic Containment [30]. Germany is introducing Degrees of Freedom (DoF) in the regulation to allow new resources, such as energy storage systems, to the ASM.

2.3 Ancillary services taxonomy

The market structures in place nowadays have been designed to suit the so-called conventional technologies: fossil thermal generation (including nuclear) and programmable hydro power plants. However, as previously described, the power system is drastically changing and, to further support the energy transition, demand, variable RESs and other DG facilities have to participate actively in the ASM and provide ancillary services. Variable RES are generally considered nonprogrammable [64], either in the sense that they lack the technological equipment needed to be dispatched or because the regulation does not require any adjustment to their schedule (they often benefit from dispatch priority [65]): historically, their production follows their fluctuating nature. With system decarbonization, their contribution to balancing becomes increasingly important.

To effectively redesign the ASM, the first step is to identify the criteria to quantify the electric system needs [47]. This includes the definition of standard conditions and the consequent estimation of necessary resources to keep the system running (e.g., the sizing of the power reserves for frequency regulation [66][67]), respecting both global and local requirements. There are also needs related to non-standard events, causing power networks to operate in emergencies, blackouts, and restoration states [68]. Regarding standard conditions, the main parameters that the system must keep in range are the system frequency (via the electricity balancing [69]), the voltage, and the power line limits. Instead, emergencies and restoration needs include all the resources helping to mitigate the emergency or to return the system to normal operation, e.g., the black start capability and the island operation capability. The total needs are quantified at the perimeter level; the perimeter represents the geographic area in which a service is procured and may be supplied indiscriminately by various units [70]. For example, concerning the Frequency Containment Reserve (FCR), the Continental Europe TSOs are jointly responsible for ensuring the availability of sufficient primary power reserves. The static requirement in this area was estimated in 3000 MW (for both upward and downward reserves); each involved TSO is obliged to provide a share of this overall requirement. It is worth noting that, in the case of a lower system inertia, the static requirement could be no longer enough to contain the frequency deviation [51]. For other power reserves (e.g., frequency restoration and replacement reserves), each TSO generally establishes the needs for its scheduling area [60].

2.3.1 Defining the services

After the quantification of the needs, the identification and definition of the services occur. The Electricity Directive [71] defines an ancillary service as a provision necessary for the proper operation of a transmission or distribution system. The ancillary services must satisfy the system's needs and ensure the security of the power system in normal and emergency conditions. The main clustering of ancillary services [71] splits them into frequency ancillary services and non-frequency ancillary services (e.g., voltage control, fast reactive current injections, inertia for local grid stability, short-circuit currents, black-start capability, and island operation capability), as shown in Figure 2.4. This division emphasizes the importance of frequency regulation (also called electricity balancing). For an overview of the various categories of frequency-related ancillary services, including timing and scope, from a European Member State grid code, see [60]. Namely, the balancing services considered hereinafter are the following: frequency containment reserve (FCR), automatic (aFRR), manual frequency restoration reserve (mFRR), and replacement reserve (RR). Additional (innovative) services listed in Figure 2.4 are Fast Frequency Response (FFR) and virtual inertia [72][45]. They are better addressed in paragraph 2.3.1.1. For a panoramic view of existing and innovative ancillary services, see [73]. The over- or underestimation of the needs of a certain ancillary service must be avoided: unreliability in the system must be prevented and, at the same time, the system cost for reliability must be kept acceptable.

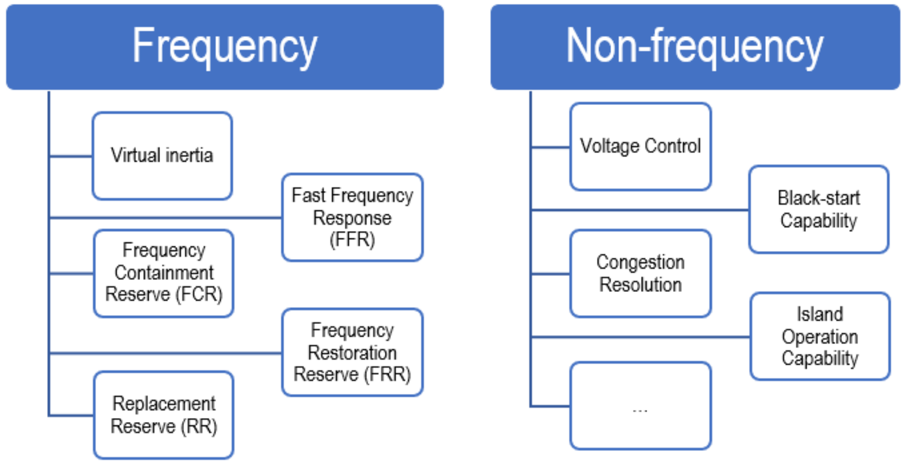


Figure 2.4 List of the main ancillary services.

Topologically speaking, ancillary services can be defined at a system or at a local level. At a system level, new services could be necessary to face changes of the needs [74] (wider variability or a loss of inertia) or suitable to exploit the peculiarities of new units (performance-based regulation). In this latter case, enhanced services could lead to a reduction of the needed quantities: studies [37][75] show that the provision of a single MW of fast frequency response implies a larger benefit for the system with respect to the provision of one MW of the standard service (i.e., the historically provided frequency response by conventional generators). Indeed, the standard frequency response was defined in the grid codes to be suitable for conventional resources (such as thermal power plants) that present a longer response time and lower ramping rates. Consider as an example the requirements of the Frequency Containment Reserve in the EU, requiring the supplier to provide full regulating power within 30 seconds [70]. In the case where there is a large share of fast-responding resources, the introduction of a faster service (e.g., response time of 1 second) can decrease the total MW of the contracted flexibility needed to guarantee the same quality of supply. On the other hand, local needs for voltage regulation and congestion management are increasing because of the ever-higher DER penetration [76]: the distribution networks are becoming increasingly active. Distribution System Operators (DSOs) are already aware of the evolution and of the more central role they will have [77], cooperating with Transmission System Operators (TSOs) [78] and, eventually, managing local ASMs [79].

Concerning the geographical aspect, the perimeter selected for each service must be coherent with the local or global nature of the need. From a global to a local perspective, there are services related to the whole Synchronous Area (e.g., Frequency Containment Reserve, as of art. 153 of [70]), to the Load-Frequency Control (LFC) Block (e.g., Frequency Restoration Reserve and Replacement Reserve, as per art. 157,160 of [70]), to the scheduling area (related to the aggregation perimeter of BSPs for provision of balancing capacity, as in art. 32 of [69]), or to a portion of the distribution network (art. 31 of [71]).

2.3.1.1 Frequency control

As previously introduced, the power systems must have a continuous balance between generation and consumption. In case there is imbalance, the system frequency is its best marker. For keeping the balancing, power reserves are always present and can be activated in due time to inject more (in case of underfrequency) or less power (in case of overfrequency) when needed, following a load-frequency control scheme.

The load–frequency control, the creation of technical reserves and the corresponding control performances are essential to allow TSOs' daily operations [70]. The system of control reserves and their activation is generally referred to as Electricity Balancing [69]. Three main frequency regulation reserves are defined at the European level, namely:

- Frequency Containment Reserve (FCR),
- Frequency Restoration Reserve (FRR), that splits in automatic (aFRR) and manual (mFRR), and
- Replacement Reserve (RR).

Their transposition into national market products is still heterogeneous among EU states, even if the implementation of standard balancing products is warmly suggested [69]. The use and activation of the reserves are generally referred to also as primary (FCR), secondary (aFRR), and tertiary (mFRR and RR) control. Figure 2.5 presents their technical characteristics of the frequency control, identifying the relevant activation time, the minimum required duration, and the main purpose. The adopted timing is coherent with Italian Network Code [80], but it can be extended generally to Continental Europe Synchronous Area.

Primary control is the fastest standard regulation (light brown line), aiming at stabilizing the frequency value; in general, it is automatically and locally activated by the velocity regulator installed on the production units. Its full activation is requested within 30 seconds from the start of the frequency event. Its required volume is defined, based on ENTSO-E prescriptions, with respect to the so-called "reference incident", where the contemporary loss of 3,000 MW of generation is supposed at EU level. The reserve needed from each control area (i.e., each Member State) is evaluated by multiplying the total EU need by a contribution coefficient. This is based on the ratio between the yearly energy produced in the control area with respect to the total production of Continental Europe (for Italy, it is equal to 9.6% as per 2018 data [52]).

Secondary control (in blue) is activated in a subsequent moment aiming at bringing the frequency back to its nominal value.

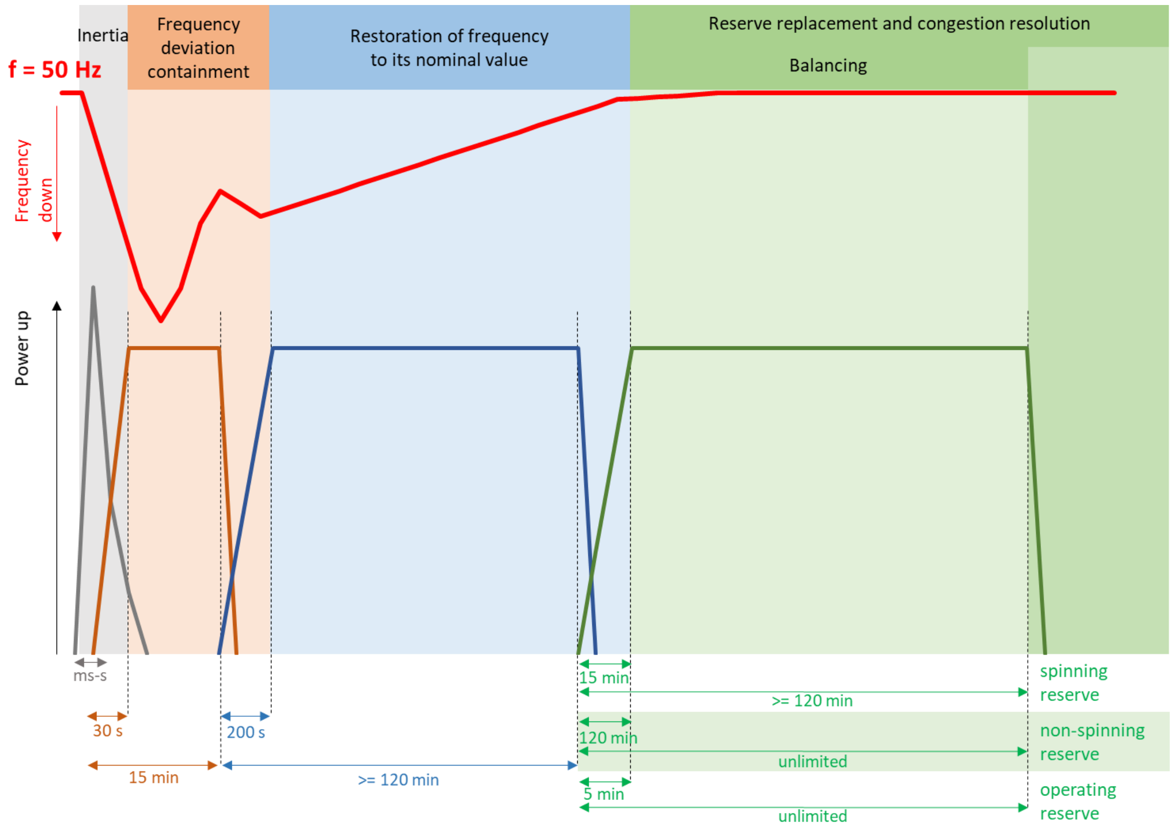


Figure 2.5 Schematic representation of frequency regulation services [60].

Frequency Containment Reserve (FCR) or primary control is the first response the system provides to a frequency deviation. The speed controller transforms frequency trends in power setpoints requested to each production unit providing the service. The dP/dF curve is usually represented in Network Codes via a droop control curve based on the following equation.

$$D = -\,(dF/F_n)/(dP/P_n) \times 100 \qquad (2.1)$$

where D is the droop value in percentage, dF is the frequency deviation in Hz, F_n is the nominal frequency (i.e., 50 Hz in Europe), dP is the power setpoint requested for FCR in MW, P_n is the nominal power of the asset in MW or the regulating power. Generally, the convention of generators is adopted, with power injected to the grid as positive power and power absorbed as negative. In addition, the curve usually features a dF dead band inside which dP requested is equal to 0 and a full activation dF over which the dP requested is equal to P_n. An example of droop curve is presented in Figure 2.6. It is an elaboration of the one in place in Italy for conventional thermal generators [80]. As can be seen, the dead band is 20 mHz as per the whole Continental Europe Synchronous Area. The dead band control power is recovered with the so-called recovery of the dead band: the control power just outside the dead band lies on the straight line starting from the origin and getting to full activation at the full activation dF.

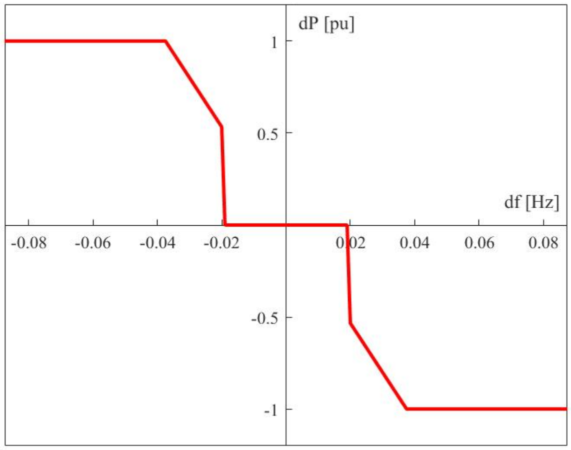


Figure 2.6 Droop curve for primary frequency regulation.

2.3.1.2 Fast frequency control

The advent of inverter-based systems poses a question on the need for faster and more precise frequency control. Some innovative ancillary services, mainly related to fast frequency regulation, are proposed in the countries that see larger frequency deviations or increasing share of variable RES. These experiences are still few and are seen as pilot projects to be implemented in the future regulation of electricity balancing [38], [81], [82].

For instance (as better described in paragraph 3.4.2), UK is reviewing its ancillary services and has introduced new frequency services, such as Enhanced Frequency Response (EFR). In 2016, the system operator NGESO ran a trial tender for EFR, namely a sub-second frequency regulation. It is based on a droop curve as the one shown in Figure 2.6. The innovative aspect is that the response is requested within 1 second, instead of the standard 30-second buffer for complying with FCR activation. Also, the service is based on two main operating strategies based on different dead-bands: a wide-band service and a narrow-band service. In the wide-band service, the dead-band is ±0.05 Hz, while in the narrow-band case it is ±0.015 Hz. This is both to propose a more dynamic service, able to suit different power network conditions, and for allowing strategies for exchanging power with the grid within the dead-band. This second point is related to the peculiarities of the resource that are likely providing the EFR. Indeed, the service requires high performance, not compatible with the dynamics of most of conventional generators [37]. Inverter-based systems are generally suitable for fast frequency response (FFR) in terms of dynamics [83]. In any case, most of inverter-based systems are variable RES such as wind and PV. There are studies on the provision of FFR by RES generators standalone (especially doubly-fed wind generators [84]). In any case, the ESS are often seen as either an enabler for the provision of FFR by RES plants or the standalone favorite provider of those services [85]. Thus, the dead-band cases proposed by EFR could be the room to cope with the finite energy content of ESS providers: while the frequency is in the dead-band, the ESS is authorized to charge or discharge within certain power thresholds to avoid depletion or saturation of its energy content [81]. Indeed, all the awarded resources in 2016 EFR's tender were ESS [86].

Another example of FFR is the Italian Fast Reserve [82]. It is a service promoted by the Italian TSO that is not trated on the ASM but it contracts resources for 5 years for providing frequency response within 1 second. The resources are contracted via a pay-as-bid auction where

- the offered quantity is the qualified power (P_{qual} in MW), and
- the offered price is the yearly capacity-based remuneration (in €/MW/year).

The P_{qual} of each asset is limited in the range 5-25 MW. The cap for the offers in the first auction (2020) has been set to 80 k€/MW/year. It is worth noting that the admitted resources are not only batteries. In any case, given the FR is a FFR service that require to provide full activation within 1 second, the admitted resources should be programmable power converter-based systems. Once the bid is accepted, the delivery period for the 2020 auction is 2023 to 2028 (the first and only auction occurred up to the time of writing). The delivery period only includes 1000 hours per year, split in a variable number of so-called “availability blocks”.

When inside an availability block, the resource must provide frequency response based on a control logic that is similar to FCR, with a droop curve. In addition, the service has a maximum uptime of 30 second: after that, the provider can stop following dynamically the frequency deviation and start a fade-out towards zero power output in 300 seconds. This is because the FR is a power-intensive service. In Figure 2.7, the droop curve and the fade-out are presented. The fade-out can only be activated in case the frequency deviation does not overpasses a threshold (soglia #2), neither in overfrequency nor in underfrequency. In that case, the emergency state activates, and the service must be provided for at least 15 minutes at the full activation. The fade-out strategy is aimed to create a service that is less energy-intensive and that can provide a fast and precise response in the first seconds of deviation (or in emergency). The dead-band (soglia #1), the full-activation threshold (soglia SAT) and the emergency threshold (soglia #2) are tentatively proposed in Figure 2.7. In any case, the Italian TSO has not yet disclosed the actual value for the service. Indeed, the delivery period for the service starts in 2023. The FR rules also include the possibility of managing the SoC to avoid depleting or saturating the energy content of limited energy reservoirs. The SoC management can be activated within the availability blocks, when the frequency is in the dead band: while the frequency deviation is within the dead band, the battery can offset its power setpoint by 0-25% of the P_{qual}, to get the SoC back to a target SoC (e.g., 50%). The energy flows for SoC management are valorized at the DAM price, both for charging (to pay) and discharging (to receive).

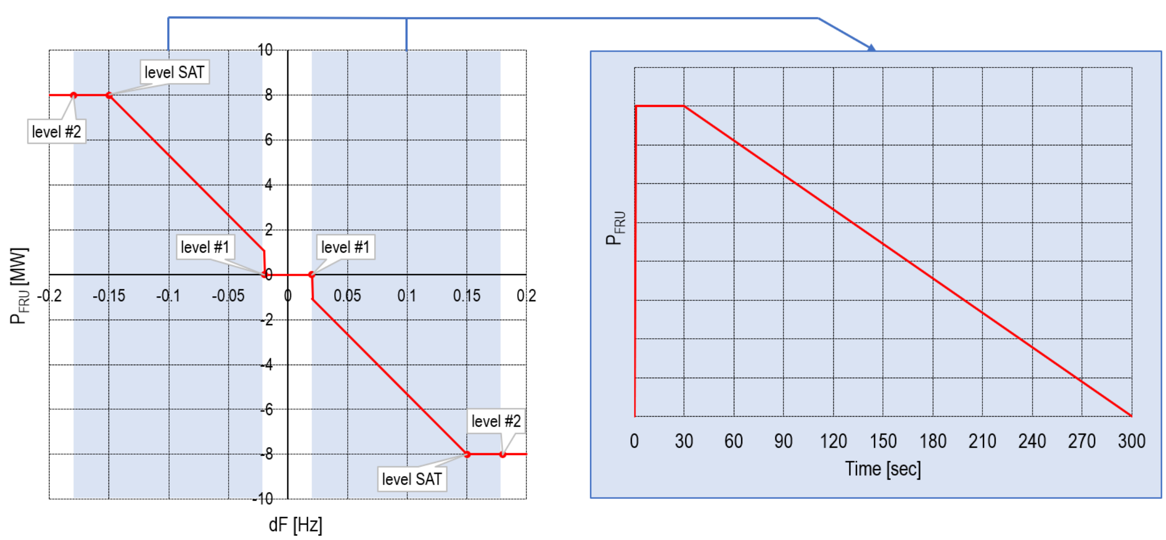


Figure 2.7 Droop curve (left) and fade-out strategy (right) for Italian Fast Reserve.

These services are likely to be present in the future of balancing, at least for power systems characterized by a large share of variable RES and inverter-based systems [30].

2.3.2 The layout of products

The ancillary services are procured by System Operators by means of market products [87]. Whenever possible, products are traded in the ASM and Balancing Markets (BMs) [71]. The ENTSO-E's Electricity Balancing guidelines (EBGLs) [61] foresee standard and specific products concerning frequency services. They describe a standard product as a harmonized balancing product defined by all TSOs for the exchange of balancing services. Instead, the addition of specific products is usually necessary since BMs are operated by state agencies: they are often based on country-related peculiarities and the products traded on them regarding the analogous services slightly differ. For instance, the procurement perimeter of the FCR products is usually the country, instead of the Synchronous Area: this could lead to specific products that sometimes better respond to needs [57].

A service is usually procured through a single product. Nonetheless, a single service can be procured by means of more products. This is done in case different units can provide different benefits if different rules are given [37]: in this case, a standard product is defined for conventional units; specific products are added for other providers, possibly excluded from the standard product (e.g., faster, shorter, or differently remunerated products). Another approach is establishing a set of Degrees of Freedom (DoFs) in the provision of the standard service so as to welcome a larger array of providers in the standard product [38]. This is to exploit the new resources without changing the market structure. The opening of the market to new resources, as previously mentioned, has a twofold target: to comply with EU regulation that requires no discrimination [61], and to exploit resources that can provide faster and more responsive regulation. Thus, a different (enhanced) performance can be requested to different unit types, coherently with their peculiarities: this is the principle of the performance-based regulation, which usually implements a different set of remunerations (and penalties) for respecting the performance standards [8].

The Electricity Balancing Guidelines introduced the concept of standard balancing product [61]. This is the preferred way for trading the aforementioned balancing services: frequency containment reserve (FCR), automatic (aFRR) and manual frequency restoration reserve (mFRR), and replacement reserve (RR). Where there are no impediments, national regulation must the use of standard products. Otherwise, the implementation of a specific product should be justified, showing that a standard product could not fit with the system needs or with the peculiarities of a resource, excluding this from the provision of the service. Once every two years, the persistence of the impediments should be re-assessed. The features of a standard balancing product can be summarized as shown in Figure 2.8, by including the prescriptions of art. 24 and 25 of the EBGLs. The ASM gate closure occurs in advance with respect to the delivery time. The distance to delivery time also includes a ramping period, inversely proportional to the ramping capability requested to providers [39]. Minimum and maximum delivery periods depict the time definition of the product. Minimum and maximum quantities (or bid sizes) are also established, defining the minimum and maximum power that can be offered by each provider. In the remainder of the thesis, these definitions are generalized and refer to each product traded in the ASM, not only to the balancing ones.

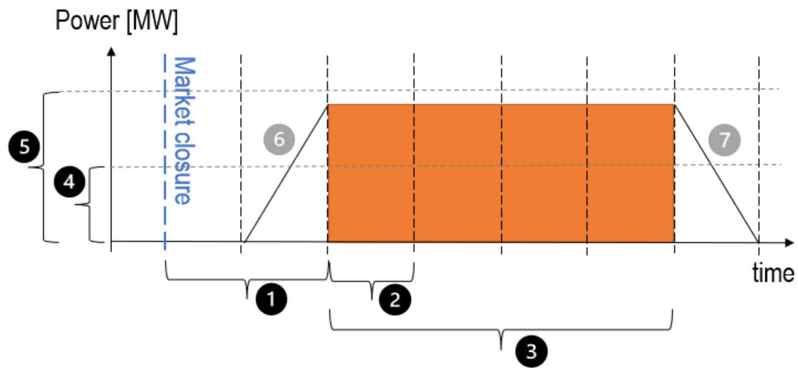


Figure 2.8. Schematic representation of a balancing product, highlighting 1) gate closure distance to delivery, 2) minimum and 3) maximum time definitions, and 4) minimum and 5) maximum bid sizes. Further requirements can be set for 6) ramping and 7) de-ramping rates.

The product is usually remunerated by a market with a System Marginal Price (SMP) or a Pay-As-Bid (PAB) mechanism. When a competitive market cannot be achieved, bilateral contracts between SO and BSP are usually defined. Alternatively, the provision of the service can be regulated by an obligation with (or without) remuneration.

Quantifying the needs, defining the services and designing the products, together, represent the whole of the design of the dispatching system. Figure 3.1 presents this process in a schematic view, highlighting the interdependencies between the levels and with the system structure and generation mix.

2.3.3 The implementation in a national framework: the case of Italy.

To give an example of a national implementation of electricity markets, the Italian case is presented in Figure 2.9. The liberalization in Italy started in 1999, with the Bersani Decree [82].

The market structure

DAM closes at noon of the day-ahead (D – 1). It contracts 24 hourly sessions for the following day. After DAM closure, IM opens. Italian IM is split in 7 sessions closing 4 hours before delivery. The ASM is split in scheduling (ASM ex-ante) and balancing sessions (BM). 6 ASM-ex ante sessions close at 5:30 PM of D – 1 and can activate resources in the following day every 4 hours as shown in Figure 2.9. BM sessions open at midnight of the delivery day and close 1 hour in advance with respect to real time.

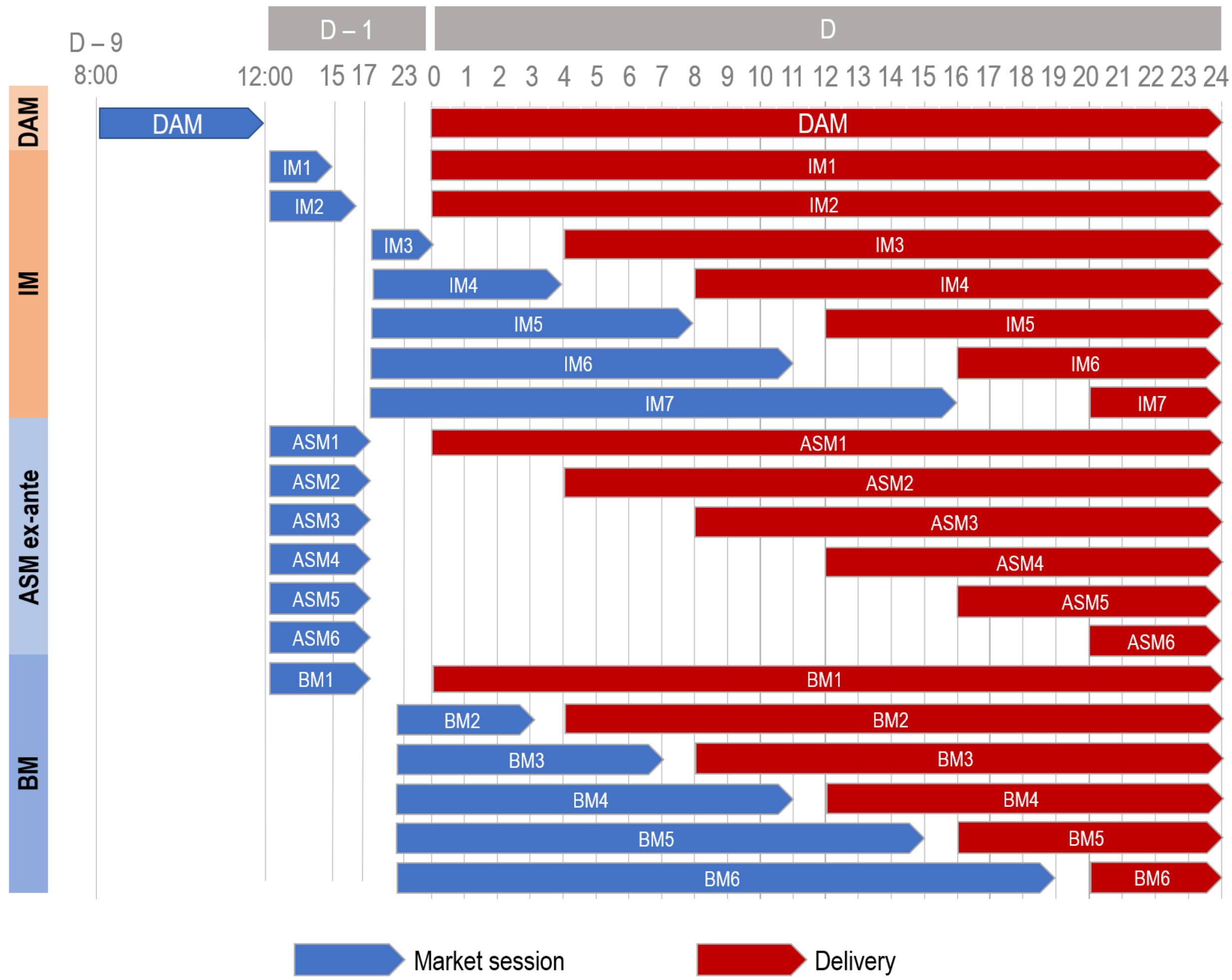


Figure 2.9 Market and delivery time periods for the Italian electricity markets, as of 2020.

Italian BM evolved in 2021 from the scheme depicted in Figure 2.9 to hourly sessions, to be compatible with the SIDC's gate closures: indeed, the BM sessions must close after cross-border intraday (XBID) market sessions.

The services

The ancillary services in Italy are coherent with the European framework and with the one shown in Figure 2.4. The main services are frequency services, including FCR, aFRR, mFRR and RR. The providers are historically large-scale thermal and hydro power plants. A new FFR service has been introduced, and it is detailed in Paragraph 2.3.1.2: Fast Reserve. Instead, there is no service for synthetic or virtual inertia. The emergency services, such as the Black Start Capability, are retained by large-scale production units that are located on the principal transmission lines [83].

The products

To understand that the conversion of services in products is not always straightforward, the example from Italian ASM is presented in Figure 2.10. As can be seen, there is a product for aFRR and a product that include mFRR, RR, and congestion resolution. There is no product for

FCR, since it is an obligation for programmable, large-scale power plants [73]. There are then other products related to non-frequency services, such as the startup and the shutdown of a production unit (PU), the layout change for a PU that holds multiple groups (e.g., shutdown of a group out of two), the reduction of the power setpoint to the technical minimum for that PU.

Figure 2.10 List of products in the Italian ASM. In brackets, the balancing service procured by the product.

As said, the ASM is likely to become more central in the electricity markets, given a larger amount of variable RES and a decrease in system inertia. This is not a rule, as for instance shown by [54] for the German situation where, thanks to improvements in system control, while the variable RES share rose, the traded volumes on ASM decreased. Data for the Italian ASM are reported in Figure 2.11 [84]. As can be seen, in Italian ASM a clear trend can be recognized from 2014 on: the overall yearly volumes (in TWh) increased by 64% in 7 years, approximately equally for upward and downward service. In 2020, the ASM volumes were 14.6% of the DAM in Italy [85].

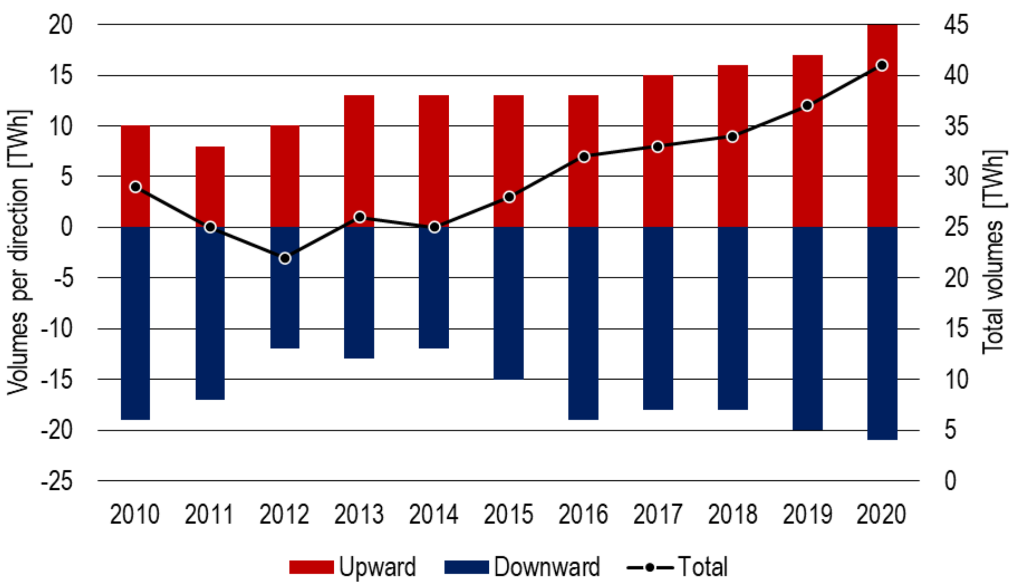


Figure 2.11 Yearly volumes exchanged on Italian ASM for upward and downward service (see left axis) and total (see right axis) .

2.3.3.1 Statistical analysis of market prices

In Italian ASM, production units offering upward capacity are paid energy-based in €/MWh to increase the injection. Oppositely, production units pay for decreasing the injection if they are awarded for downward regulation. A statistical analysis has been carried on considering the period 2017-2019 (before Covid-19 crisis, to depict the standard ASM behavior). This analysis considered the following bids:

- presented on the Balancing Market (BM);
- for “Other Services”, including mFRR, RR and congestion management;
- for the Northern market zone;
- awarded bids, both totally and partially awarded;
- split in holiday (including Saturday, Sunday, bank holidays) and working days (the remainder), and in downward and upward bids.

The statistical analysis allowed to define the distribution of the hourly marginal awarded prices for each service (upward and downward), for both working days (Monday to Friday) and holidays (Saturdays, Sundays and bank holidays). The average of the marginal hourly price for both regulation, for both working days and holidays, is shown in Figure 2.12. The Northern zone has been selected for the larger quantities and the larger number of resources competing in this market zone (i.e., the larger liquidity) [51].

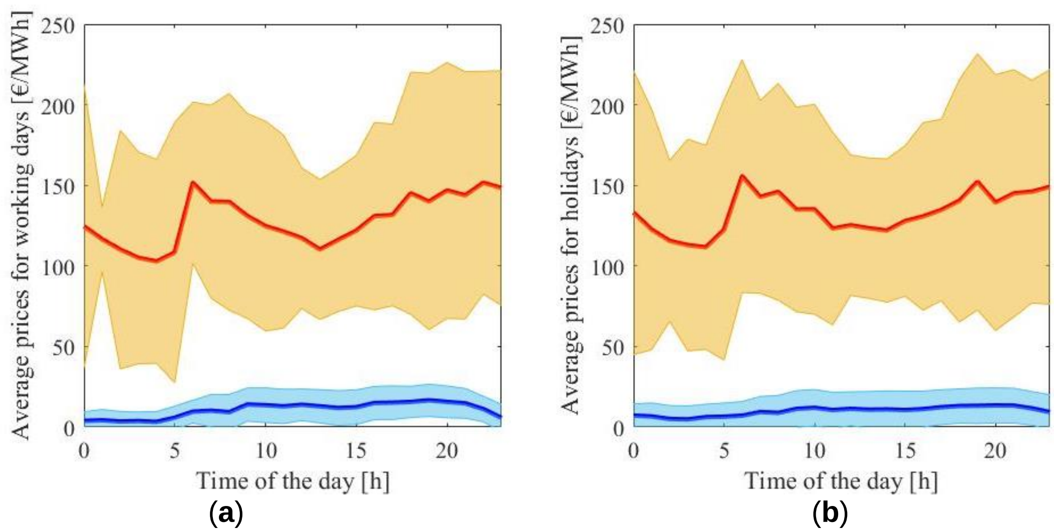


Figure 2.12 Average marginal prices for upward and downward regulation: (a) hourly prices during working days; (b) hourly prices during holidays. Red lines are the hourly average marginal upward prices, while blue lines are downward ones. The shaded areas represent the standard deviation of the average prices.

The upward prices are generally in the range 110-160 €/MWh, with two peaks in the morning (6 AM) and in the evening hours (7-10 PM). Nonetheless, the variability is very high, testified by the large range of the orange shaded area. For what concerns the downward prices, the marginal prices (the lower ones) indicate almost constant willingness to pay throughout the day. The average prices are in the range 5-20 €/MWh, with a smaller standard deviation (the light blue area) with respect to upward prices.

2.3.4 Stakeholders and roles of the electricity balancing

To transform the ASM in a suitable way, one must clearly bear in mind what the roles in the ASM are. The ASMs in Europe involve four main types of stakeholders: National Regulatory Authorities (NRAs), System Operators (SOs), Balance Responsible Parties (BRP), and BSPs. A description of the role of each one in the electricity balancing is given briefly in the following.

NRAs are in charge to promote competition by ensuring safe, secure, and sustainable energy supply at a reasonable cost.

The SO function may be owned by the Transmission System Operator (TSO), managing the transmission grid, or may be fully independent (ISO). In the EU, all SOs are TSOs. In [40], a TSO is defined as a natural or legal person responsible for operating, maintaining, and developing the transmission system in each area and sustaining the transmission demand over the long term. It also takes care of its interconnections with other systems. Therefore, the TSO is responsible for the safe operation of its balancing area. In particular, the TSO shall use ancillary services provided by third parties through a market-based procurement, when applicable [26]. As introduced before, DSOs have recently been increasingly involved in the ancillary services necessary to ensure the security of the distribution grids due to the increase of DERs. The Electricity Directive promotes a more explicit role for DSOs, establishing that they shall procure the non-frequency ancillary services needed for their systems in accordance with transparent, non-discriminatory, and market-based procedures [27].

By the side of the resources providing the services, two main roles are involved: the BRP and the BSP [25].

The BRP is responsible for the units' injection and withdrawal schedules and for their corresponding imbalances [25]. BRPs are financially responsible for keeping their own position (i.e., their injection or withdrawal schedules) balanced over a given timeframe (the imbalance settlement period). The eventual short or long energy positions in real time are described as the BRPs' negative or positive imbalances, respectively.

The BSP is the player of the ASM: in the EU Internal Electricity Market, it is a market participant with reserve-providing units (or groups of units) providing balancing services to the TSO [25]. Therefore, BSPs, with their assets (generators or loads), balance out unforeseen fluctuations on the electricity grid by rapidly increasing or reducing their power output. Therefore, they mainly cope with the imbalances that the BRPs could not avoid. To participate in the procurement process, BSPs' units must pass a pre-qualification test defined by the TSO, and, once qualified, BSPs have to submit bids to the TSO. BSPs that have been selected in the procurement of a service are then obliged to submit such service for the volume and time period for which they have been selected (following the rules of the product). To offer services, if permitted, BSP may aggregate DERs, such as demand facilities, ESSs, and power generating facilities in a scheduling area (the area where a product is traded) [25].

The Chapter 3 focuses on SOs (i.e., TSOs or DSOs) and BSPs, since they are the main active parts involved in the operation of the electricity balancing. BRPs are considered only with reference to their relationships with BSPs and TSO. The new role for DSOs, foreseen by the electricity Directive, is not discussed in this work, since it deserves a dedicated in-depth study, but some aspects potentially related to local services are considered.

It is worth noting that there are two opposite models for electricity balancing, depending on the role the TSO holds in the dispatching process: the self-dispatching model (decentralized coordination) or the central-dispatching model. According to Article 2(17) of the EBGLs [25], a self-dispatching system (SDS) is subject to a scheduling and dispatching model where the generation and consumption schedules, as well as the dispatching of power-generating facilities and demand facilities, are directly determined by the relevant BRP (self-determined). An SDS can be portfolio-based or unit-based. In the portfolio-based model, the aggregated generation schedules and consumption schedules for the whole portfolio are determined by the scheduling agents (BRPs) of these facilities. Within the respect of the aggregated schedule, the single units can be dispatched as preferred. In the self-dispatch unit-based model, each generating unit and demand facility follows its own generation or consumption schedule. Instead, according to the EBGLs, Article 2(18), a central dispatching system (CDS) is a scheduling and dispatching model where the generation and consumption schedules as well as the dispatching of power generating facilities and demand facilities (in reference to dispatchable facilities) are determined by a TSO within the integrated scheduling process. In other words, producers submit their detailed pricing information to the market, and the market operator decides how much should be produced in each plant. The dispatch is computed by minimizing the total cost of the serving demand at every node in the network, subject to network and production constraints. The map of diffusion of CDS and SDS in Europe is presented in Figure 2.13.

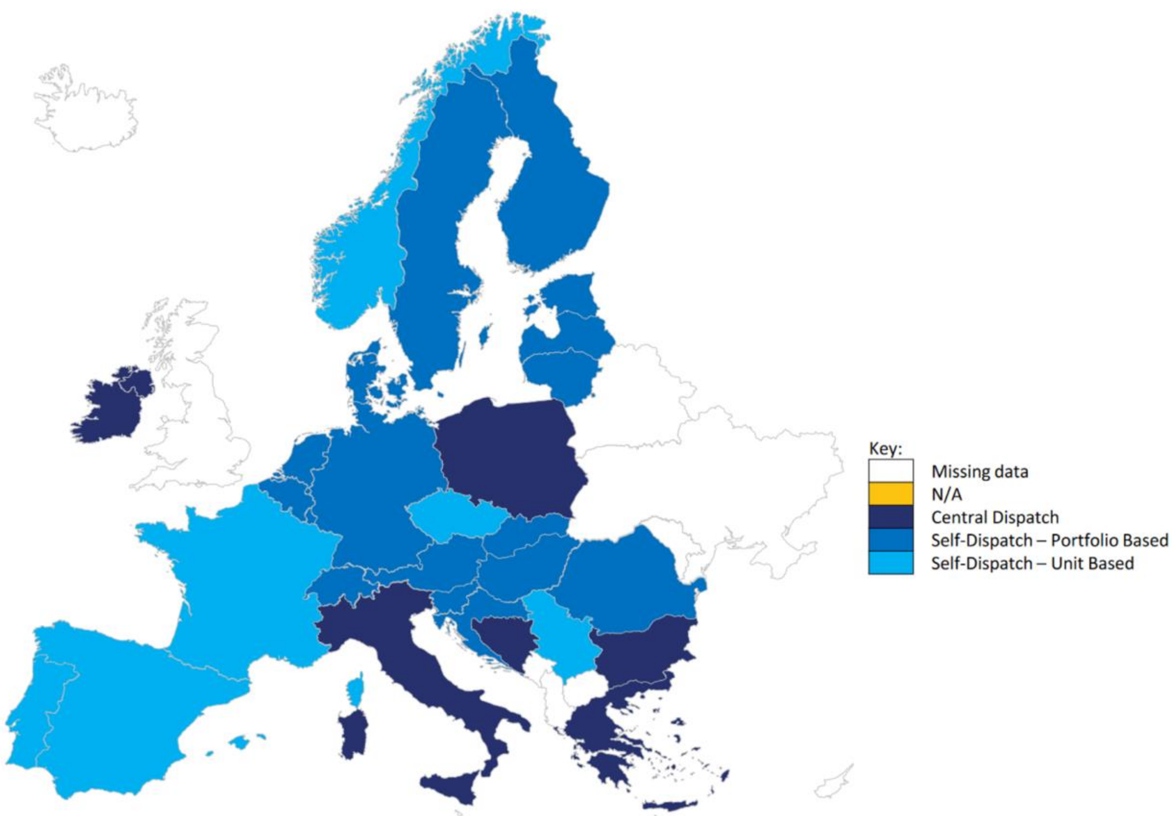


Figure 2.13 Self-Dispatch and Central Dispatch in Europe [41].

The main distinguishing feature of a CDS is that balancing, congestion management, and reserve procurement are performed simultaneously in an integrated process. From the SO's point of view, the main difference between central and self-dispatch is the procedure for dispatch decisions to secure and balance the system: in the CDS, security is guaranteed through simultaneous and coordinated markets (co-optimization); in the SDS, it is guaranteed through sequential markets (SO takes central control of balancing supply and demand only close to real time) and not necessarily optimized as a whole.

2.4 Conclusions

This Chapter presented the electricity markets, with a focus on ancillary services markets. The importance of the electricity balancing has been detailed, and the possible ways to provide the frequency control were described. It has been shown how the frequency control could evolve to face the new needs. The central role of energy storage systems in the innovative ancillary services provision has been shown, validated by the international experiences described. The need for the evolution of ASMs has been motivated. Even if the drivers of this evolution are the same (i.e., increased variability of the power system and decreased system inertia), countries could behave differently due to different current situation (e.g., a different share of variable RES in the generating mix, a different system inertia). An analysis to better understand the impact of the evolving generating mix on the ASMs, to recognized and evaluate the main trends for the market evolution, is necessary. It is fundamental to forecast the new possibilities for DERs, RES, and ESS of entering the electricity markets.

CHAPTER 3

Analyzing the Ancillary Services Markets evolution

Abstract

The generating mix has deeply changed in the last years. Especially in Europe, the electric systems are evolving towards a more decentralized architecture, widely penetrated by renewable and distributed energy resources. These resources usually present less predictability (e.g., variable RES) and less mechanical inertia (e.g., inverter-based systems). To avoid jeopardizing the power system, they should be effectively included in the Ancillary Services Markets (ASMs), which procure the resources for balancing and safely dispatching the system. While Chapter 2 gave a general description of the electricity markets (the architecture, the services, the products, the stakeholders), this Chapter presents a meta-analysis of the evolution of ASMs and the underlying regulatory trade-offs. The evolutions are analyzed modularly to clearly investigate the benefit of each one. The presented analysis aims to provide an evaluation of each trend regarding the architecture, the services, and the products of the ASMs, based on the level of agreement of the two main counterparties: the System Operator who manages the system and the Balancing Services Provider that delivers the service. The outcome is a ranking of the possible regulatory evolutions, with the win–win situations at the top and the cases that imply drawbacks for a counterparty at the bottom. The ranking can represent a guideline for regulatory authorities as well as market operators or players to prioritizing the evolutions towards the design of effective market arrangements. Also, in the framework of this work, it will be used as the basis for a quantitative analysis on the regulatory barriers, proposed in Chapter 7. Finally, a survey of some significant European countries describes the effort of each one towards each evolution.

3.1 Introduction

European power systems are undergoing important changes, driven by the realization of the harmonized European internal energy market, the rapid increase in distributed renewable generation and energy storage, and the dismantling of conventional thermo-electric power plants. The relevant data have been presented in Chapter 1 and 2, including the EU targets for decarbonization, the relative volumes of the markets, and the evolution in the generating mix, both for what concerns the energy sources (i.e., there is a gradual yet clear switch towards RES, in particular variable RES) and the distribution of production units (i.e., there is a trend towards the increase in Distributed Energy Resources).

In this context, the power system needs innovative solutions to continue keeping energy injections and withdrawals in balance instantaneously, ensuring a stable and secure operation. Historically, ancillary services have been only provided by conventional large-scale thermo and hydro power plants. Thus, keeping the system safe and secure is likely to become more challenging as the share of variable and intermittent generation increases [88], and many traditional providers of flexibility (such as large-scale gas and coal plants based on rotating generators) are phased out. This could cause more extreme events on power systems (e.g., large frequency deviations [89]) and larger costs for re-dispatching [90] and balancing [91].

A wide set of different services is therefore required to face this transition, whose impacts can be seen at different timescales. Indeed, the energy imbalance caused by intermittent Distributed Generation (DG) is more likely to require flexibility in the time scale of the hour. The change in the dynamic behavior of the system (i.e., the decrease of inertia) following the reduction of synchronous generation requires prompt flexibility services capable to react in seconds and lasting for a brief period [8].

To be fit with the European objectives inspired by the Climate and Energy Package [92], the market design should integrate flexibility services provided by the new assets. Even after this integration, an adequate security level of the electricity system should always be guaranteed [27][21][93]. A periodic review of all the ancillary services and products is necessary in order to follow the change in the generation mix: such a review is in charge to allow, by a regulatory perspective, all the generators and consumers to provide the services that they can, technically, provide [94]. To reduce the need for expensive back-up plants and infrastructural upgrades, the access to the market should be guaranteed to the new flexibility providers, such as final customers, energy storage systems (ESSs), new forms of flexible generation, and RESs [46]. DERs should be fully integrated in the ASM to answer the new needs (they are partially responsible for) in an economical and effective manner.

The amendment of an ASM can also be seen as a preventive measure for preserving the reliability of the EU power system. Indeed, a large effort has already been made to retrofit DG and prevent its early disconnection [95]. The ongoing next step for enhancing network security is to include DG in the electricity balancing and the ASM [96]: on one hand, DERs will increase unpredictability, but on the other hand, the increase of inverter-based systems will also provide faster and more precise services [37].

Many experiences have been seen in the first two decades of the 21st century for opening and redesigning the ASM [97][98][99], abating the existing regulatory barriers to have an effective participation [94]. These experiences are generally based on either the whole system redesign (e.g., passing from central to self-dispatch [100]), on the reform of some services (e.g., the introduction of fast frequency response services [101]), or on the market products evolution (e.g., a decrease in the minimum bid quantity of existing services to enable provision by DERs [102]). In electricity markets reforming, National Regulatory Authorities (NRAs) must operate cautiously since several regulatory trade-offs have to be properly evaluated [103]. Indeed, the market stakeholders have generally different perspectives [104]. For instance, the new units that aim to participate in the market are generally distributed and small-scale, so they can bid only a small power quantity. On the other hand, smaller bids imply a larger number of transactions on the market and consequently a higher effort by the system operator [94]. To correctly reform the market, one must be aware of the hidden trade-offs of the ASM and first focus on win–win options.

The literature analyzes the evolution of ASMs generally by a system perspective. In [105], the impact of DERs diffusion and the possible provision of services by them is analyzed considering evidences from the system costs. Possible evolutions are drafted in the discussion. Source [103] assesses the impact of different design variables on the possible ASM performance, focusing on the relationship with other electricity markets. It also introduces the concept of trade-offs in the evolution. The outcomes return qualitative indications of possible ranges of design parameters. Oppositely, the study [104] maps the European Member States and suggests welcome evolutions by the side of the BSPs, trying to give an evaluation of each country with a star system (i.e., from 0 to 5, considering the increasing effort towards an evolution). The two perspectives are considered qualitatively by [44], that considers the challenges in delivering a highly distributed system and proposes advantages and drawbacks of investing either in the network or in the flexibility by DERs. Eventually, study [94] adopts a modular framework for identifying possible barriers. Also, it clusters the regulatory barriers in different levels: design barriers preventing DERs aggregation, products barriers, and remuneration barriers. Then, different countries are compared to assess the effort level towards abating the recognized barriers.

This Chapter, after presenting in general the possible evolution of ASM, adopts and extends the modular approach by [94] to evaluate a set of barriers by the perspectives of the system and of the market participant. The barriers represent an exhaustive set of parameters, clustered in structural, technical, and economic parameters, either related to the services or the products traded on ASM. Each barrier is defined as a move either towards a direction or the opposite one. The evolutions that are welcomed by both the parties are considered win-win situations whose implementation should be prioritized. Oppositely, trade-offs are recognized if one of the parties does not agree with the proposed trend. The outcome ranks the recognized trends: the top results represent the win-win situations and the possible priorities to be targeted by policymaking. In addition, this ranking is the basis for a quantitative analysis on the impact of each barrier on the performance on ASM of a particular category of DERs: BESS. The quantitative analysis is the subject of Chapter 7.

The main goal of the following analysis is to provide the reader a clear view of the ongoing trends and their effectiveness in the DERs integration in ASM. Furthermore, this study can support the regulator in the difficult task of redesigning the electricity balancing and the ASMs. To do this, the trade-offs must be recognized and deeply analyzed to prioritize the regulatory action. There is a wide range of literature on the possible regulatory barriers, the evolution of the market in specific countries, and even the recognition of the trade-offs. The novelty of the proposed approach is to systematically analyze the available sources regarding the trade-offs to evaluate the existence and extent of the actual impediment posed by either of them. Indeed, at a time of such turmoil that is teeming with new regulatory implementations, moving in the wrong direction is a real risk.

In particular, a meta-analysis of institutional, industrial, and academic sources is performed to gather the perspectives of the Balancing Services Provider (BSP) and of the System Operator (SO) and return an evaluation of the level of agreement of each party to each evolution that markets are undergoing. This leads to discern situations with many obscure drawbacks from situations that organically contribute to improve the current scenario. The analyzed evolutions are selected based on the ongoing trends for electricity markets and systems in Europe. They are proposed to move from global to specific: starting from trends involving the system structure and moving towards the parameters of the ancillary services and then the single product. The trade-offs are analyzed in a modular framework [94], so that the reader can benefit of the analysis of each parameter per se.

The Chapter is organized as follows. Paragraph 3.2 describes the methodology proposed for a meta-analysis of the existing trade-offs in ancillary services and in the ASM. Paragraph 3.3 returns the outcomes of the meta-analysis, evaluating each evolution in electricity balancing and the ASM as either a win–win situation or a compromise between stakeholders. Paragraph 3.4 applies the modular evaluation to some national European case studies. Paragraph 3.5 summarizes some conclusions of the analysis.

3.2 A modular meta-analysis on the evolution of ancillary services markets

This work aims to illuminate a set of obscure trade-offs that exist in the evolution of an electricity system. A trade-off arises for the system when an evolution provides benefits for a stakeholder but, at the same time, represents an issue or a drawback for another one. This usually makes it difficult for NRAs to define a clear and effective strategy to make the system evolve. This work focuses on the perspectives of the provider of the service (usually referred to as a BSP) and of the counterpart operating the electricity system and procuring ancillary services (the SO). The BSP aims to be remunerated for providing a service, while the SO's goal is to economically and efficiently procure the necessary ancillary services to limit the system risks and to improve its reliability. It is widely known that the dispatch of future power systems will require a larger and more efficient role of the TSO; similarly, more interactions between TSOs and DSOs will be necessary for effectively integrating DERs [67][68][69]. Therefore, the evolution in the electricity balancing and the ASM can be in the direction of benefiting the BSPs, even if this implies a more challenging operation by the SO (i.e., the TSO or the DSO in a hypothetical local market). To analyze per se the effect of each parameter on a market, this study adopts a modular framework proposed by [94], generalizing it to include a wide list of economic, technical, and systemic evolution of the ASM. These evolutions are then analyzed one by one to assess the level of agreement for the BSP and the SO. The process of designing the ASMs is schematically summarized in Figure 3.1.

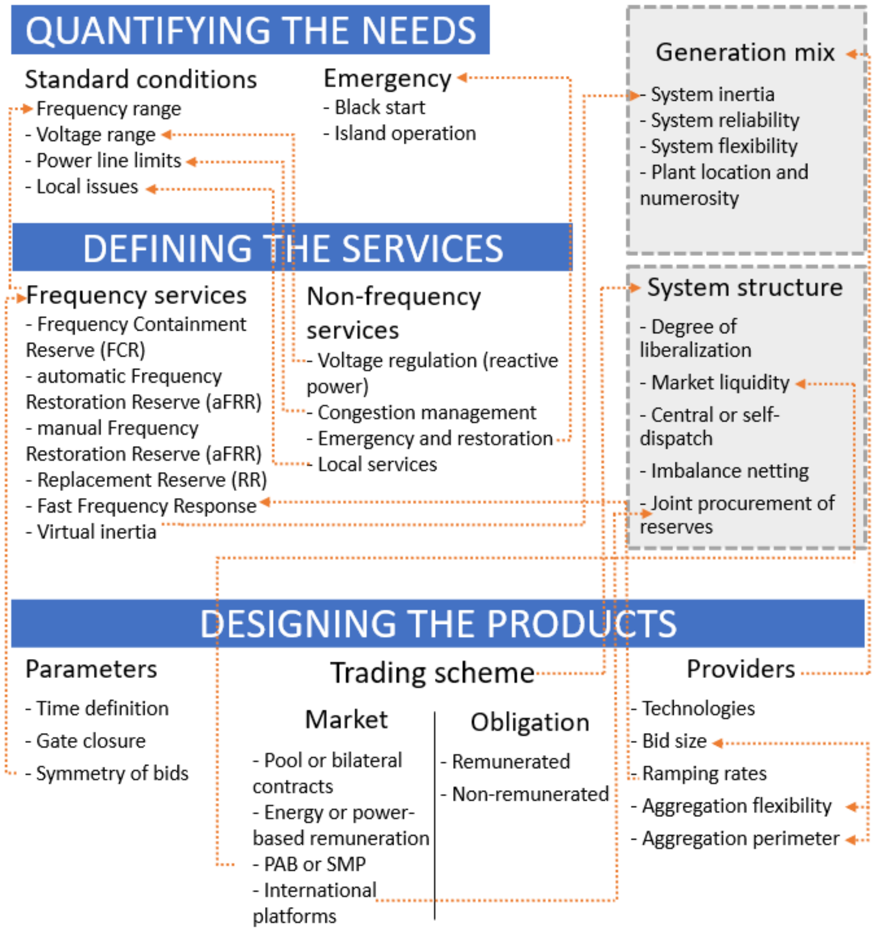


Figure 3.1. Non-exhaustive flowchart of the ancillary services design process, with the structural data in grey boxes and orange arrows to highlight interdependencies among levels: if the needs change, the services as well as the products could change.

As illustrated in Chapter 2, the process involves the estimation of the needs, the definition of the services and the design of products. All these phases require the analysis of a set of parameters. These parameters are evolving to suit the changing needs of power systems and to open the electricity markets to new resources. The main parameters are considered and translated in possible evolving trends by the proposed analysis.

Analyzed trends and features are very briefly described in the following and are listed in Figure 3.2. A range from general (i.e., related to the roles and structure of the market) to particular (i.e., referring to single services or products) trends is shown. Furthermore, both technical and economic parameters are analyzed. The order followed in the figure is adopted in Chapter 3.3 as well.

- Adopting an SDS or CDS.
- Separating the BSP and BRP role in the regulation.
- Ancillary services review: redefining the set of necessary services to answer the current needs.
- Moving towards the streamlining of products: decreasing the number of products associated with a service.

- Moving towards an increase of the procurement perimeter.
- Allowing an aggregation of different resource categories.
- Designing faster/steeper services. Generally, a faster/steeper service is one that requires either a larger ramping rate or a smaller response time.
- Decreasing the time definition (i.e., the minimum elapsed time for which a service can be delivered) of a product.
- Decreasing the distance to the delivery of a product: decreasing the time elapsed from the market closure (or the end of the procurement phase) and the delivery. Moving towards asymmetric products: relaxing the constraint on symmetric upward and downward calls (i.e., equal absolute value of power in the upward and downward bid for a product) by each providing unit.
- Decreasing the minimum bid size (i.e., the minimum quantity in MW or MWh that can be offered).
- Moving towards a System Marginal Price (SMP), e.g., abandoning a Pay-As-Bid (PAB) system or an obligation with (or without) a tariff.
- Moving towards the abolition of price limits. This means, for example, admitting negative prices or removing strike prices for a product in the ASM.

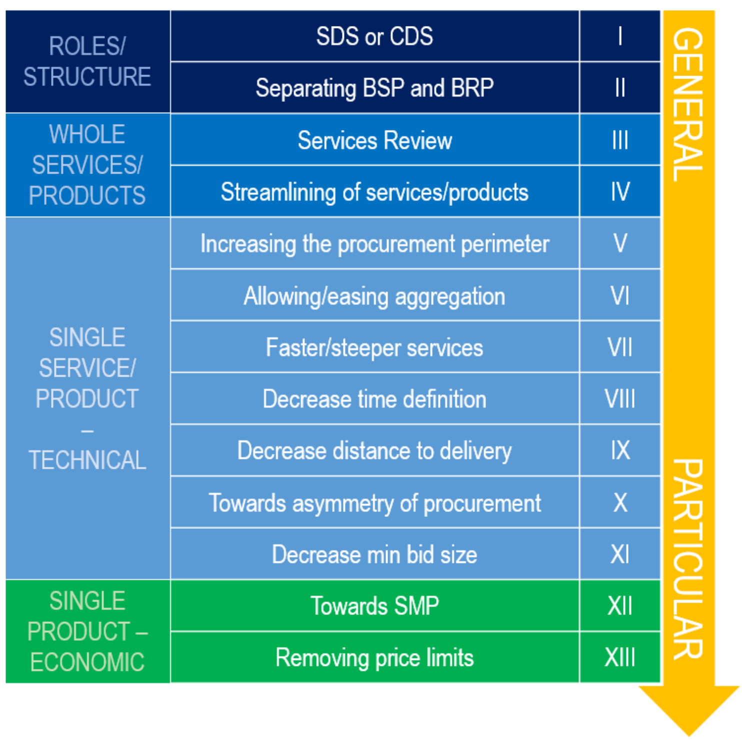


Figure 3.2. The list of analyzed trends in ancillary services markets.

We then investigated the level of agreement to each trend of the BSP and the SO. To do this, a meta-analysis of scientific, industrial, and institutional sources was performed [70]. The initial research was made on the Google Scholar portal, using the keywords “electricity," "ancillary," "services," "market," and the name of the feature. The initial studies led to additional literature and reports by two mechanisms. First, we scanned the document reference list. Second, we used the “cited in” function from Google Scholar to identify other relevant articles [71]. Most institutional and industry reports were found by these mechanisms. The level of agreement is estimated as follows. There is “strong agreement” (++) when more than one source expresses a positive opinion for the introduction of the feature by the perspective of the stakeholder (BSP or SO) and no source expresses a negative opinion. “Moderate agreement” (+) is for those features for which most sources express a positive opinion (at least two more than the negative ones). “Uncertain” (=) is for those features that are mentioned by almost the same number of sources with positive and negative opinions (with a spread of ±1). There is “moderate disagreement” (-) when the large majority of sources express a negative opinion (at least two more than the positive ones), while “strong disagreement” (--) is shown when all (and more than one) sources express a negative opinion. For a BSP, a positive opinion generally relates to the possibility of a larger turnout of resources to participate in the provision of ancillary services given by the considered evolution. A BSP also expresses positively in the case of a revenue increase or a cost reduction for the provision, and vice versa with respect to a negative opinion. The SO aims to guarantee the same or higher performance—measured as the degree of adequacy, operational security, and the quality of supply—with lower costs. Therefore, there is generally positive feedback in the case of performance enhancement, decreased reserve needs (fewer MW to guarantee the same performance), and the drop in costs per transaction. Otherwise, the opinion is negative. Some of the analyzed sources do not provide a clear opinion regarding the trade-off. In that case, the analyzed source is not selected for the systematic review. Thus, the supplementary materials of this study include a list of *Analyzed Sources* and a list of *Selected Sources* [72], a subset of the former. The outcome of the meta-analysis is a semi-quantitative evaluation of the harshness of the trade-offs: it results in a ranking of the possible evolution of markets in which the win–win situations are considered best.

3.3 Illuminating the obscure trade-offs in the market evolution

As described, this study aims to analyze the parameters implying the main trade-offs regarding the ASM evolution. This is performed by means of a systematic review of institutional, research, and industrial sources and highlights the perspectives of the BSPs and of the SO. The parameters are then ranked based on the agreement of both stakeholders towards a certain evolution. The results are shown in Table 3.1. The analyzed sources are 98, while the selected sources are 70. In the following, for each analyzed parameter, a discussion is proposed.

Table 3.1 The ranking for the ancillary services market evolutions.

Rank	Name	BSP agreement	SO agreement	Number of sources
1	Towards the asymmetry of products	++	++	10
2	Services review	++	++	9
3	Towards SMP	++	+	21
4	Increase of procurement perimeter—harmonization	++	+	16
5	Smaller time definition of products	++	+	12
6	Towards faster/steeper regulation	++	+	9
7	Smaller distance to delivery time	++	=	16
8	Allowing the aggregation of different resource categories	++	=	13
9	Removing price limits	++	=	9
10	Smaller minimum bid size	++	=	7
11	Towards a streamlining of products	=	+	8
12	Towards a separation of BSP and BRP	+	=	8

13	Adoption of SDS	+	-	5

Adoption of SDS

Article 14 of the EBGLs [25] states that each TSO shall apply an SDS model for determining generation and consumption schedules; TSOs that apply CDS shall notify it to the relevant regulatory authority to continue to apply a CDS model. According to ACER [73], an SDS is more in line with the European target model with zonal congestion management. In any case, both systems are admitted in the EU [25]. However, in the literature, there is no clear evidence showing that an SDS is more convenient than a CDS, or vice versa. The advantages and disadvantages of both dispatching systems are reported in [74]. According to this report, the main advantage is that a CDS makes sure that the day-ahead dispatch is technically feasible and (ideally) socially optimal; however, CDS markets present some issues since they are inflexible (a slow response to shocks that occur after the day-ahead market closure) and hard to scale up (difficult to optimize the entire system simultaneously within a given computational time). A further issue is that producers typically use multi-part bids made up by marginal costs and non-convex costs (such as start-up costs) and could have incentives to overstate their non-convex costs to avoid an economic loss. On the other hand, in an SDS, the SO takes central control of balancing supply and demand only close to real time, while BRPs are responsible for the balance of their units with respect to their self-defined injections or withdrawn schedules. SDS markets are generally based on a zonal representation of the network, and this leads to a standardization of the electricity, which can be traded with other market participants in the intra-day market. Intra-day markets can be also exploited by BRPs to manage RES variability. The main disadvantage of an SDS is related to the inefficiencies caused by zonal pricing: intra-zonal constraints are not properly accounted for in the day-ahead and intra-day markets, so real time adjustments could be unnecessarily large. In addition, different representations of the transmission constraints in day-ahead and in real-time markets result in partially different prices in the two markets. This gives producers an arbitrage opportunity: a producer in an export-constrained node can increase its profit by selling more in the DAM and then buy back power at a lower price in the real-time market (“increase–decrease game”).

According to [75] and [76], a centralized approach should lead to a more integrated treatment of generation units and transmission networks, and it could lead to significantly lower transaction costs. Indeed, a CDS model is generally adopted in congested electrical systems, such as in Ireland, Italy, Northern Ireland, and Poland [77]. Otherwise, a SDS could be preferable since it is generally more flexible. A CDS can be improved: centralized intra-day auctions should be introduced to increase flexibility. Moreover, a SDS model can also be enhanced by reducing the size of zones (or switching to a nodal system) or considering network constraints in more detail, e.g., in a German SDS, the four TSOs established the “German grid control operation,” which is a TSO's coordination based on a joint dimensioning and a joint tendering procedure for control reserves in order to cost-optimize the procurement of secondary and tertiary control reserve [78].

Thus, it is possible to state that moving towards an SDS from the CDS is preferable for BSPs since, according to them, a SDS improves their flexibility, while a CDS tends to be underdeveloped when it comes to the management of the latest technologies. From a TSO's point of view, instead, a CDS theoretically makes sure that the dispatch is technically feasible and allows for the minimization of the total cost, while a SDS, guaranteeing greater freedom to market participants (typically combined with a market model that is not able to represent all network constraints), could require more expensive interventions by the system operator close to real time.

Separation between the BSP and BRP

The independent aggregator has been introduced in the EU directives and regulations, since it is necessary to foster the flexibility and sustainability of DERs; therefore, the separation between the BSP and BRP no longer represents a choice, but rather a constraint for EU member states. Such a separation is welcomed by the BSP. However, the BRP, who is responsible for imbalances and, in the case of mismatches between power schedules and actual power exchanges, pays the imbalance fee, should not be penalized for the imbalances caused by the BSP. Therefore, an agreement with a BRP or a central settlement model (managed by an SO) is necessary [79]. Such an agreement is a barrier for BSP, as the BRP and BSP are potential competitors [80], so a central settlement model managed by the SO may be preferable. Moreover, introducing an independent aggregation might require changes in data processing, which in turn induces costs and requires a strong coordination by the TSO of the different providers [81].

Services Review

To address variability and uncertainty in the grid due to the new context of the electricity sector (characterized by an increasing amount of variable generation and fast frequency deviations), there is a need to redefine the existing ancillary services and create new ones, such as ramping products (i.e., a separate ramping or flexibility product created as part of the ASM to serve the net load ramping requirements), the fast frequency response, and the inertial response through power electronic-based systems [15]. In particular, faster-acting frequency response services are needed because frequency deviations are occurring more often and have a larger absolute value [82]. Instead, a review of requirements of existing ancillary services is necessary to remove technical and economic barriers for aggregation, as better described in the following. Such a review of existing ancillary services matched by the introduction of innovative services is quite important for BSPs, since new fast services (such as fast frequency control) can create more favorable market conditions [83]. The removal of existing regulatory barriers is also fundamental from a TSO's point of view to make use of DER flexibility for the system’s frequency control, achieving positive effects on frequency control and on market prices in all energy markets [84][85].

Towards the streamlining of products

Stakeholders highlight that a myriad of products does not attract new players in the market [66]. Therefore, moving towards the streamlining of products (i.e., decreasing the number of products associated with a service) can improve the liquidity of the market [86]. The abolition of technology-specific product requirements can prevent market inefficiency [87]. In any case, a certain number of products is needed for increasing market transparency and preventing the proliferation of bilateral contracts for flexibility [88].

Towards an increase of the procurement perimeter

The procurement perimeter is service-dependent. Indeed, the provision of voltage control must be local; on the other hand, the frequency regulation is not geographically dependent, but it could operate at the Synchronous Area level. In general, increasing the procurement perimeter can improve the competition, thus decreasing the system cost. Frequency control services are typically provided on a portion of the system equal to the scheduling area: moving towards a joint procurement over the Synchronous Area could be beneficial [26][25]. In this direction, the EBGL establishes a series of European platforms for the exchange of balancing energy from standard products (TERRE for a replacement reserve, MARI for a manual frequency restoration reserve, and PICASSO for automatic frequency restoration): these products can be delivered and shared across borders and between control zones, bringing benefits to consumers through increased competition plus a more efficient allocation of reserves between system operators [89][90][94]. However, as previously described, balancing approaches are very different across European countries: potential harmful interrelations of all national characteristics with harmonized balancing procedures are difficult to rule out [91]. Moving towards the point of view of BSPs, the creation of a common harmonized balancing market is an advantage since it entails numerous benefits for participating countries, such as the facilitated integration of RES and improvements in transparency and competition.

Allowing aggregation of different resource categories

DERs are usually admitted by aggregating small resources, to overcome a minimum bid size. Allowing a pooling of different assets (renewables, storage, and demand response) in a single virtual power plant is crucial for BSPs to always have the right answer to the system needs [92][66]. This should be an advantage also for TSOs since it entails an increase in the reliability of distributed resources in providing ancillary services: in fact, in the case of the unavailability of RES production, backup controllable resources (such as storage) can be used. Furthermore, easing the aggregation process can reduce investment in grids [93]. On the other hand, TSOs have to re-assess the prequalification tests [81]. In addition, a larger number of transactions (with lower quantity) implies larger costs of including DERs in the dispatching model [94].

Design faster/steeper services

The new needs can be satisfied by services requiring lower response times and larger ramping rates to balancing resources. As it has been shown, this can decrease the necessary power reserves, since 1 MW of enhanced (faster) regulation can better provide balancing than 1 MW of standard regulation [37]. In general, enhanced requirements for services provision improve balancing quality. Some argue that these requirements can hinder utilization efficiency, since they bring out of the market cheaper resources [65]. Since the DERs can usually respond to fast signals and show steep ramping rates, the evolution towards faster services is uniformly appreciated by BSPs. In any case, this evolution should be linked with a performance-based regulation aimed to recognize the value provided by the more responsive assets [94]. Therefore, the system cost will be in the end a compromise between the decrease in reserves and the increase in the remuneration for the single MW. Some TSOs are proposing a wider set of frequency regulation products to meet both the performance of conventional slower units and of new faster units [15]. This clearly poses another trade-off with the streamlining of products.

Decrease the time definition of a product

As introduced before, time definition is described generally as the minimum elapsed time in which a service can be delivered. It is unanimously recognized that, in a context of increasing

RES penetration in the generation mix, the decrease of the maximum delivery time enhances the certainty of provision and a larger integration of DERs in the electricity dispatch [95]. Moreover, from the perspective of the SO, this evolution generally decreases system costs and helps in giving the correct price signals to the resources, thus shifting the responsibility of balance towards them [86]. Some objections arise since a lower time resolution implies a larger number of transactions per day [96].

Decrease the distance to delivery of a product

A market closure nearer to the delivery time largely decreases uncertainties related to variable resources. Furthermore, the costs for the BSP decrease because of the lower effort needed for forecasting [96]. Instead, their opportunities are enhanced, since there is a possibility for a single unit to participate in more markets or to provide a larger set of services [65]. The SO can benefit from a general system cost reduction given by a larger turnout of market participants, balanced by the increased uncertainty of moving the commitment operation towards real time and the possibility of less coordination of the resources that are not reactive enough [97].

Towards asymmetric products

The procurement of reserves can be subject to the constraint that each awarded unit must provide the same amount of downward and upward capacity (e.g., in MW). This clearly hinders several categories of DERs and new units, e.g., variable RESs are usually only capable of providing a downward reserve [96]; ESSs present limited energy content, so symmetric provision could cause inefficiency in the state-of-charge management [98]. In general, it is uniformly recognized that the relaxation of the symmetry constraint allows for a wider level of optimization of balancing resources. From an SO perspective, asymmetric reserves are recognized to increase the efficiency of the market [96]. This is mainly due to the fact that symmetric procurement usually increases volumes to be reserved and consequently system costs [95]. To sum up, it can be said that all the analyzed sources agree on the fact that an open, efficient, and economically effective ASM should abandon the symmetric provision for creating more asymmetric products.

Decrease the minimum bid size

Generally, for a given product, SOs accept bids only larger than a certain threshold. The threshold can widely vary, from some hundreds of kW to some tens of MW [94]. A smaller minimum bid size increases market participation and allows aggregators to participate even if they hold smaller portfolios [80][99]. Smaller bids mean more transactions to be managed by the SO: this implies a cost and an increasing complexity for the operation. On the other side, allowing an increasing number of DERs to enter the market can decrease the average bid price [100]. There is likely an optimal trade-off for bid size to have the largest system benefit, perhaps slightly below 1 MW. Moreover, it is worth noting that an alternative to a drastic bid size decrease could be allowing more DoFs for the aggregation, e.g., to allow the unrestricted pooling of production and consumption units or to increase the pooling perimeter. In conclusion, this measure is highly desired by the BSPs, yet it implies a balanced mix of advantages and drawbacks for the SO. Thus, as an alternative, it may be preferable to ease the aggregation process as described before.

Towards SMP

Generally, there are two market remuneration mechanisms in electricity wholesale markets: pay-as-cleared, also known as the System Marginal Price (SMP), and Pay-As-Bid (PAB). With the SMP, all the successful providers are paid the price of the marginal accepted bid; with PAB, the supplier receives the price of its accepted offer. New market participants, such as aggregators, are disadvantaged under the PAB remuneration scheme since they have less information about the market itself. The SMP method, instead, ensures that service providers receive the full marginal value of the service they are providing. Furthermore, the SMP is more transparent since it reduces information asymmetry and consequently allows a reduction of forecasting costs incurred by market participants. This is a relevant aspect also for a TSO: PAB discourages competition and does not reflect the marginal costs of providers [101][102]. On the other hand, PAB can prevent potential market collusion [103].

However, there are services (such as voltage regulation or black start) that are not procured on a market basis since they are localized and, consequently, mandatorily supplied by few participants (often large producers). In this case, such ancillary services can be remunerated according to a regulated tariff or not remunerated at all (e.g., they can be set as a binding requirement for the connection by grid codes). A non-remunerated system is convenient for the SO, but it is not economically optimal because providers may reflect the incurred costs of provision in other products (e.g., in DAM or other market-based ancillary services). A regulated tariff is set by the regulator or the TSO, and it is usually the same for all providers. This form of remuneration is not efficient, as it is difficult to define a price that reflects the actual cost of providing an ancillary service. Both these forms of procurement are undesirable by BSPs because they inhibit competition [94].

Towards the abolition of price limits

Two main price limits are present in BMs and can be recognized as barriers by the providers: the maximum price cap for upward service provision and the prohibition of prices below zero for downward services (this rule does not admit that the SO pays the BSP for non-production). Regarding price caps, their removal would foster demand response [88]. Moreover, conventional generators, whose working hours are starting to decrease in modern power grids, could benefit from high prices during hours of scarcity [86]. Not only conventional plants, but also variable RESs can find a place for their business in providing upward reserves in the case of price spikes [102]. Negative prices can incentivize RESs to provide downward reserves. Otherwise, they are reluctant to offer such reserves given that their variable costs are close to zero. Price spikes have many political implications. Usually, the regulatory authorities do not admit overly high prices because they are barely tolerated by consumers. On the contrary, negative prices can lead to unfair conduct by RES producers in case of RES incentives, since the BSP can largely bid negatively to recover the lost subsidy in the case of a ramping down [104]. Moreover, negative prices for downward services can lead to exercise power market by conventional plants [105]. In general, an SO's opinion concerning price limits is uncertain, since there are also advantages: for instance, extreme prices give correct market signals for developing an adequate portfolio of dispatching resources.

3.3.1 Summary of the results

Table 3.1 shows that the most interesting evolutions are the relaxation of symmetry constraints and a general review of services. Regarding the symmetry of products, its presence implies for BSPs the need for power band reservation. On the other hand, no direct costs are foreseen for the SO given a relaxation of this constraint. Instead, the general concept of an ancillary services review is welcomed by each side, since the system and the generating mix are drastically changing, as described in the introduction. These two evolutions are clearly win–win situations for the stakeholders considered. There is a large interest (highlighted by a large number of retrieved sources) also towards the introduction of a SMP and the increase of the procurement perimeter (which implies an effort towards the harmonization of products). These two parameters also highlight drawbacks for the SO: e.g., the possible incompatibility of SMP with some market conditions and the large effort needed to harmonize different procurement processes and products. Focusing on the time parameters, decreasing the time definition of products is more acceptable than decreasing the market closure distance to delivery time from the SO's point of view. This is due to the enhanced uncertainty of closing the market very closely to the delivery: it implies less time for coping with unexpected events and even more stressful ramping rates (see Figure 2.8). Moving towards the bottom of the table, we see the streamlining of products and the separation of the BSP and BRP, for which the level of agreement is uncertain. The BSP generally prefers the SDS, but the TSO prefers the CDS, and this can generate friction among TSOs and the EU regulation, whose targets are more in line with the SDS [73].

The suggestions coming from the meta-analysis are to first focus on the upper part of the ranking, while more caution must be put in adopting the evolutions ranked lower. To explore the current framework, the following chapter describes some European case studies.

3.4 Survey of the evolution in European Ancillary Services Markets

The results of the study, applied to national frameworks, could lead to detect possible alternative regulatory strategies to open the ASM and to prioritize the efforts. The following case studies were selected among those that can be considered as advanced electricity markets in Europe. Denmark has been selected for the predominant amount of DERs (not necessarily RES), as shown in Figure 1.3. Germany, for the rapidly increasing share of distributed RES (DG-RES), as can be seen by Figure 1.4. UK has been considered since it is an island, and this influence the network parameters such as inertia and frequency deviations [30]. Italy has been selected to investigate a country that is not included in the European Power Exchange (EPEX) [144], but it is developing its own market evolution, via pilot projects and regulations that will shape the final ASM arrangement [34]. All the proposed case studies are relevant to an electric system with a large and increasing amount of DERs and NP-RESs. Therefore, they are already planning or running solutions for effectively integrating these in the ASM. The novelty of the following survey is to focus deeply and exclusively on the evolving parameter in the ASM (approximately over the period 2005-2021) and the recognized market trends. Thus, the existence and extension of the previously investigated changes in the national frameworks are described. This can be of support in assessing the actual implementation of the regulatory alternatives presented before. A general presentation of national markets is beyond the scope of this work. Where possible, the EU standard names for balancing products have been adopted, even if they do not correspond exactly to the national transliteration. Finally, for the UK, the larger array of services cannot be easily reconducted to FCR, aFRR, mFRR, and RR.

3.4.1 Italy

In Italy, the TSO (Terna S.p.A.) manages the electricity system by means of an integrated scheduling process (ISP), i.e., a CDS. Terna procures a wide set of ancillary services by means of the market, bilateral contracts, and obligations. Before the last introductions and evolutions, only relevant conventional plants connected to the HV grid and larger than 10 MVA provided ancillary services [106], mandatorily offering to the ASM the available upward and downward margins after DAM and IM schedules. These are traded in the ASM with remuneration in €/MWh with the PAB method. aFRR is symmetric, whereas mFRR and RR are procured by a joint asymmetric product. The services are paid-as-bid, while only the international platforms (e.g., TERRE, of which Italy has been an operational member since 2021) will be remunerated with SMP. According to [105], negative prices will not be introduced to the ASM, but only on the international platforms for the EU standard products. Since 2017, Italy has decided to gradually evolve the electricity dispatching by means of pilot projects [107]. The aggregation of resources has been introduced since 2019 within experimental initiatives, limited to mFRR and RR. According to the pilot project [108], the BSP can be different from the BRP, and the aggregation is relevant only for the provision of ancillary services, while it is not valid for schedules resulting from energy markets. Thus, a "baseline" schedule, as a generation profile presented by the BRP, is necessary. The management of a baseline curve, different from the schedules, represents an issue for BSPs [105]. The pilot projects also address a general decrease in the minimum bid size. The minimum bid size is 1 MW (a further reduction to 0.2 MW is under discussion [109]), which represents a large decrease with respect to the traditional 10 MW. The time definition has been reduced for congestion management, balancing, and replacement tertiary reserves. The distance to delivery decreased with respect to tertiary regulation traded in BM: indeed, after the entry into service of the TERRE platform at the beginning of 2021, the market sessions occur every hour, 1 hour ahead of the beginning of delivery time. Recently, the provision of aFRR has been extended to those units not already mandatorily enabled to provide it [110], including aggregated units, RESs, and storage, as conducted before for the mFRR. Asymmetric provision is extended to aFRR as well.

In addition to opening up the ASM, a new fast frequency response service is being introduced in Italy through another pilot project [111]: within the Fast Reserve first auction (12/2020), the TSO contracted 250 MW of fast resources at an average price of 30 k€/MW/year [112].

3.4.1.1 Insights from data on pilot projects in Italy

As described, the opening of ASM to DERs in Italy is occurring via pilot projects, fostered by the Italian NRA [33]. The pilot project on Enabled Virtual Mixed Units (UVAM, in Italian) started in 2018. In this project, DERs from a size of 1 MW on could participate to ASM for the provision of mFRR, RR, and congestion management. The UVAM framework introduced a capacity payment (in €/MW/year) for those unit guaranteeing the availability of upward reserve in the peak period (i.e., the late afternoon of working days). A set of auctions was issued for DERs to be awarded of the capacity price. The Italian territory was split in two areas: a Northern zone (Area A) and a Southern zone (Area B). A maximum contingent of 800 MW was available for Area A, while 200 MW were available for Area B. In the auctions, the lowest bid prices were awarded up to the saturation of the contingent. A price cap was established at 30 k€/MW/year. Some data on the outcomes of the project in the period 2019-2020 are given in the following. In Figure 3.3 and Figure 3.4, the awarded capacity of DERs for both Area A (including the Northern market areas of the Peninsula) and B (including the Southern market areas on the Peninsula, plus Sardinia and Sicily). As can be seen, Area A had a faster start, with the total contingent of 800 MW that was contracted for more than a half from the 2nd month of the project on. Area B had a smaller acceleration: up to the 6th month of the project, less than 70 MW out of 200 were contracted. Then, the available contingent was gradually saturated in both areas. In

Area A, from month 12, the yearly auction (that is the first auction carried out) was enough to reach the maximum capacity of contracted DERs (800 MW), thus no sub-yearly auction took place in 2020. For Area B, a small share (around 10 MW out of 200) were issued in intra-annual auctions. Also, the capacity prices decayed over time. For Area A, there was a reduction in the average price from 30 k€/MW/year (first 6 months of 2019) to around 26 k€/MW/year (for 2020). In Area B, the price decreased to 28 k€/MW/year.

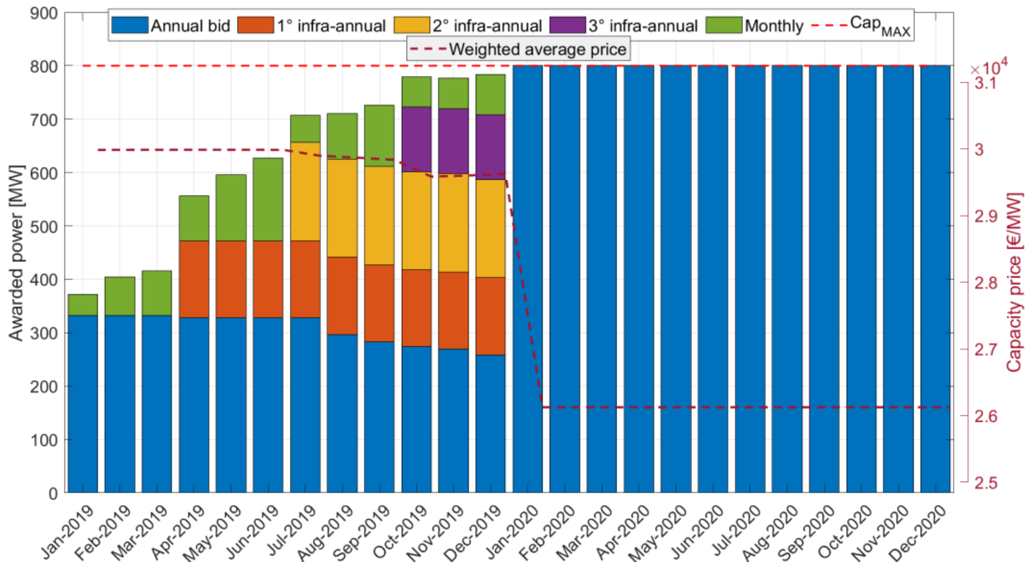


Figure 3.3 Awarded capacity and prices for area A (North and Centre-North market zones) [151].

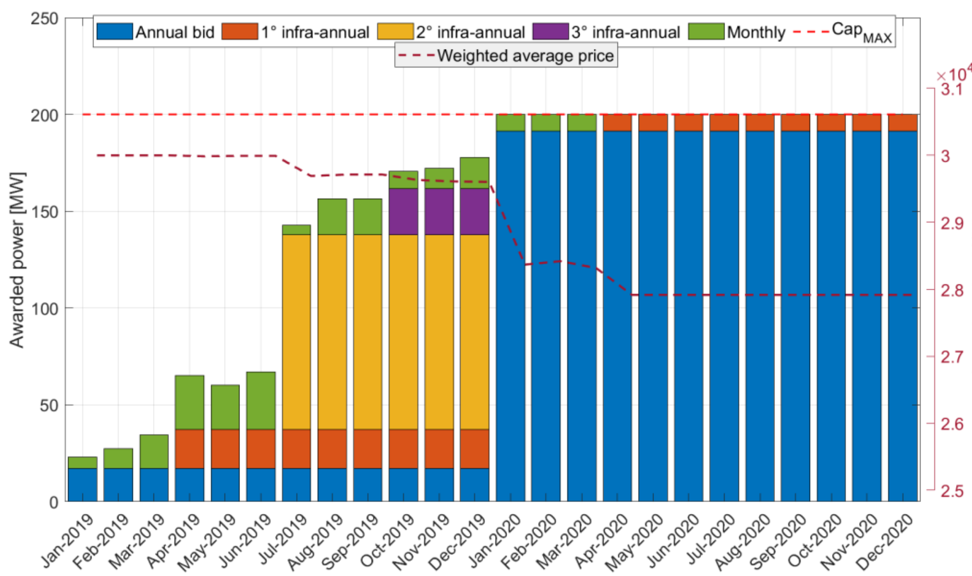


Figure 3.4 Awarded capacity and prices for area B (Centre-South, South, Sicily and Sardinia market zones) [151].

The previous data have shown the large interest towards the opening of the market and the wide turnout obtained by the project. The Figure 3.5 and Figure 3.6, instead, summarize the data on the activation of UVAM in the period from November 2018 to March 2020. As can be seen, the activated energy is just a minor part of the offered energy, both for upward reserve (Figure 3.5) and downward reserve (Figure 3.6). For what concerns upward reserve, the larger activated quantity was registered in 2018 (when a smaller contingent of UVAM was present) and in the spring/summer of 2019. In 2018, the strike price was around 200 €/MWh, as well as the awarded prices. In 2019, the strike price was moved to 400 €/MWh, while the activation prices reduced to 80-150 €/MWh averagely.

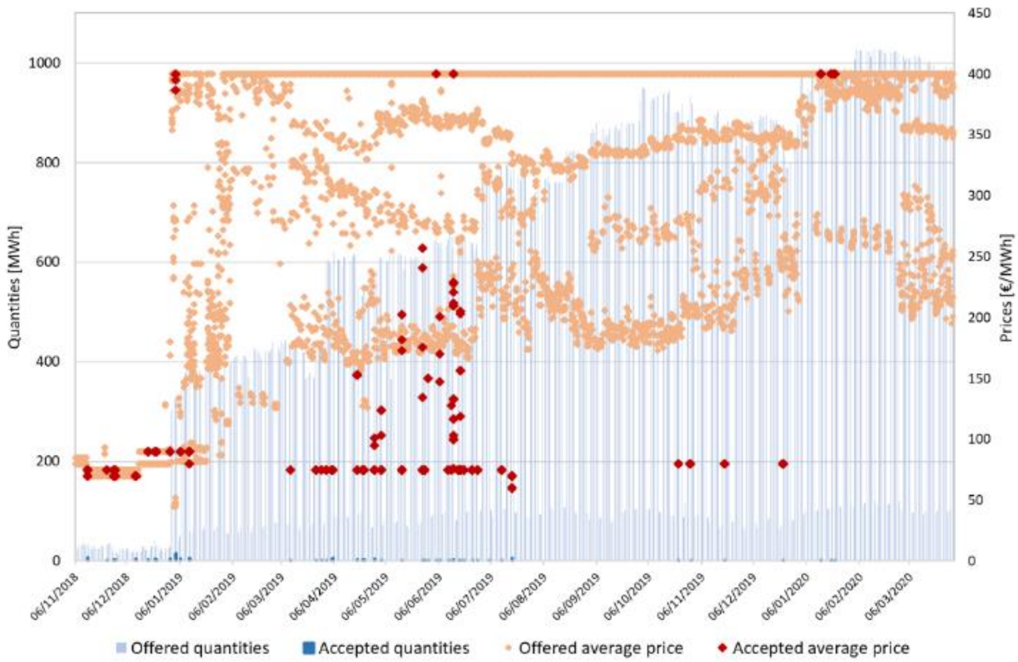


Figure 3.5 Activated energy quantities (in MWh) and prices (in €/MWh) for upward service [151].

For what concerns downward reserve (Figure 3.6), the awarded prices were always around 30 €/MWh, and the larger activation was registered towards the end of the examined period (March 2020).

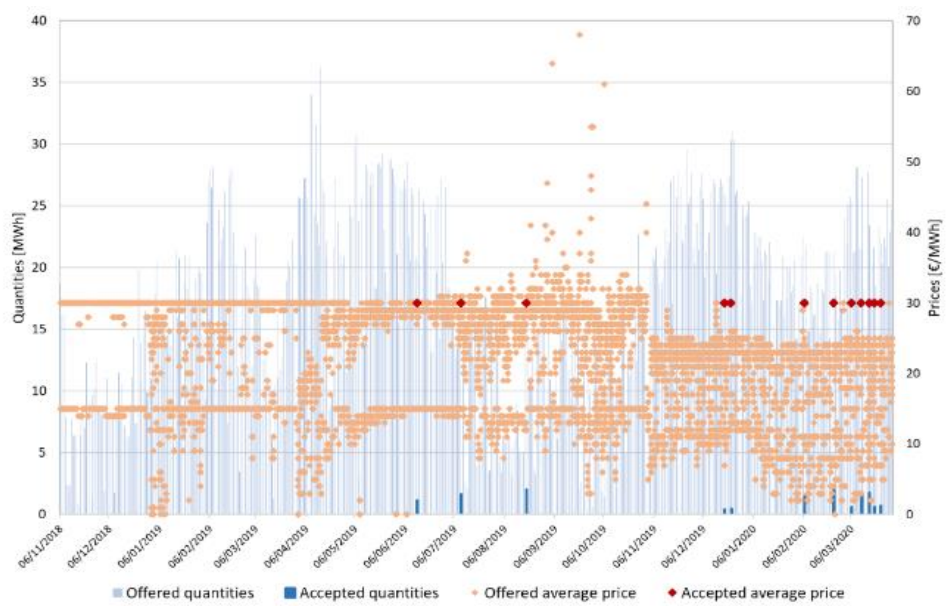


Figure 3.6 Activated energy quantities (in MWh) and prices (in €/MWh) for downward service [151].

While the upward offered quantities were always around 1000 MWh/h, the downward quantities were much lower (always lower than 40 MWh/h). Indeed, the capacity remuneration was tied to the upward offered quantity, while no requirement on the downward quantity was proposed.

The Fast Reserve pilot project had the first auction on December 2020, as previously presented [75]. This project contracted the provision of a fast frequency response service for 5 years, with the delivery period starting in 2023. The payment is capacity-based (€/MW/year). The bidders with the lowest capacity prices have been selected via an auction, that closed in December 2020. Single assets between 5-25 MW of nominal power could participate to the auction. A contingent of 230 MW was initially planned. The first FR auction saw the participation of more than 1300 MW of candidate Fast Reserve Units (FRU) [150]. The awarded FRU were 249.9 MW, split in different zones as per Figure 3.7. As can be seen, the whole initial quota has been awarded, plus some more capacity (each single bid awarded was awarded in its complete quantity). As said, the auction was a pay-as-bid with selection of least expensive bids. The average awarded prices were lower in continental zones, larger in Sardinia zone. In any case, the price was everywhere much lower than the price cap (80 k€/MW/year). Even if there was no technology discrimination in principle, it is believed that most of FRU are BESS, both standalone and integrated with other production units.

Zone	Initial quota [MW]	Awarded FRU [MW]	Weighted averaged awarded price [k€/MW/y]
CENTRO NORD	100.0	118.2	23.418
CENTRO SUD	100.0	101.7	27.279
SARDEGNA	30.0	30.0	61.016
TOTAL	230	**249.9**	

Figure 3.7 Fast Reserve capacity and prices for the 2020 auction.

3.4.2 The UK

The UK market consists of Great Britain's (GB) system and several of the surrounding islands. It is included in this survey, even if it is no more an EU case study after Brexit, since the particular frequency patterns (the UK is not synchronous with continental Europe) and the consequent attention towards enhanced services (the system inertia is in principle lower) are of interest. Since 2018, the figure of the independent aggregator as the BSP, separate from the BRP, has been introduced. The National Grid Electricity System Operator (NGESO) is reviewing the balancing services market to simplify the products and create transparency [19]: the balancing is characterized by a dynamic underwood of various services. To date, ancillary services in GB are divided into four categories: frequency response services, reserve services, reactive power services, and system security services. Firm frequency response (FFR) is an example of frequency response service. The minimum bid size for FFR was reduced from 10 to 1 MW in 2017 [113]. Mandatory frequency response (MFR) and FFR constituted the historical frequency response in the UK. A third response service has been recently added: in 2016, NGESO ran a trial tender for a sub-second Enhanced Frequency Response (EFR). There will be no more auctions dedicated to the EFR since NGESO aims to incorporate a faster response into the wider response products [114]. Meanwhile, a general review of frequency response is occurring: Low Frequency Static (LFS), Dynamic Low High (DLH), Dynamic Containment, Dynamic Moderation, and Dynamic Regulation are or will be added to the market-based services beside MFR and FFR. The minimum bid size of the new services is generally low, and the time to full activation is fast (e.g., 1 s).

Regarding reserves, NGESO has been rationalizing these products in the last few years, since there has been an abundance of them. The Balancing Mechanism is included among the reserve services. The single Balancing Mechanism Units (which are significant plants larger than 100 MW) and the Non-Balancing Mechanism Units (non-significant plants for which pools are possible) can participate in the market. The minimum bid size in the Balancing Mechanism has recently been reduced from 100 to 1 MW in accordance with the implementation of the European TERRE project. In general, both the availability and activation payments are present: the capacity-based remuneration for the availability is based on the PAB method; energy activated is paid as cleared.

The NGESO currently manages a reactive power using network assets (reactors and capacitors) and the mandatory provision of reactive power from generators in the balancing market, namely, an obligatory reactive power service (ORPS). In this latter case, generators are paid through a regulated tariff in £/MVArh. The remaining reactive volume needed is procured by means of an enhanced reactive power service (ERPS) [115], which should open the provision of reactive power to new resources. ERPS tenders are not very successful among operators mainly because they still refer to a system dominated by conventional plants.

Among system security services, a black start service has just been reviewed to improve transparency and remove barriers to entry [116].

3.4.3 Germany

The German electricity system is managed by four TSOs (50Hertz, Amprion, TennetDE, and TransnetBW), which refer to a single Grid Code and operate with an SDS. Balancing services are divided into FCR, aFRR and mFRR. The minimum bid size for balancing services is 1 MW: in detail, it is 5 MW for aFRR and mFRR, but there are derogations up to 1 MW. Since 2010, the German TSOs obtain supply resources for balancing services on a common platform (German Grid Control Cooperation), and they coordinate for the activation of those resources. This coordination has been extended to other TSOs of neighboring countries (International Grid Control Cooperation) [117]. FCR is procured in the coupled market area of Germany, Austria, Switzerland, the Netherlands, France, and Belgium, through daily tenders (weekly tenders until July 2019 [118]). FCR in Germany presents a set of Degrees of Freedom (DoFs), recently introduced, to allow for better exploitation in particular of energy storage and other units with limited energy content. These include the possibility of over-/underregulation, the possibility of exploiting the frequency deadband, and the possibility of superimposing a constant power setpoint to the regulation [38]. They are better described in Paragraph 5.3. Hundreds of MW of battery energy storage systems currently provide FCR in Germany [119]. The remuneration has been capacity-based (in €/MW) with an SMP method since July 2019 (before there was PAB). mFRR resources are supplied through daily tenders with four-hour blocks, whereas aFRR resources are supplied through weekly tenders, also with four-hour blocks. The weekly auction restricts the participation of various DERs, because it is procured well in advance with respect to real time, and most DERs cannot yet commit to provide a capacity so far from real time. The remuneration for aFRR and mFRR is based on the PAB method for both the available capacity (€/MW) and the activated energy (€/MWh). Negative prices for balancing energy are accepted and were introduced in 2009 [120]. Current providers of balancing services are conventional power plants, flexible controllable loads, and "balancing energy pools" (aggregating RESs and large-scale batteries) [121][122]. FCR product is symmetric, while aFRR and mFRR are asymmetric [37].

The other ancillary services are generally procured directly by the TSO by means of obligations, bilateral contracts, or margins of maneuver offered by DSOs.

3.4.3.1 Insights from data on market evolution in Germany

FCR market in Germany can be taken as a proxy of what happens in case of ancillary services review: indeed, Germany did not introduce a new service, but it regularly updates the rules of the existing FCR product. In particular, in the period 2017-2021 [38], the following process happened.

- The German TSOs have proposed (2017) and then organized the FCR Cooperation: an international platform for joint FCR provision among EU Member States, that now (2022) procures 1250 out of 3000 MW in Europe. The go-live occurred in July 2019, but further Member States are joining in the following (Slovenia and West Denmark joined the platform in 2021 [123]).
- The service has been updated to implement the DoFs previously mentioned.
- The tenders have been modified from a weekly tender to a daily one (in 2019) and then to a 4-hours one (in 2020).

The second and third bullet have allowed an increasing participation by BESS, that have widely influenced the market. Nowadays, BESS are the only technology considering the FCR as the primary market opportunity in Germany [124]. Indeed, even if there are 7 GW of prequalified resources for FCR (with 4 GW from hydropower alone) and only 450 MW of BESS, the BESS offer at a very competitive price with respect to other technologies. This is because conventional technologies primarily bid on DAM, and services represent a further revenue stream. Given the peculiarity of BESS and the evolution of regulation, instead, FCR market represents the best opportunity. Thus, the bid prices by BESS for FCR are very competitive and result in a high rate of acceptance on the ASM. Therefore, from 2019 on, they became the largest provider of German FCR [124]. This is testified also by the reduction of the average power per bidding: from 5 MW in 2015, to 3 MW in 2019.

The FCR tender builds an international supply curve with a Merit Order based on the capacity bid (in €/MW/period). The capacity remuneration for the awarded resources is at the SMP. The market gate closure is at 8:00 AM of the day ahead the provision. There are a minimum domestic share to be guaranteed (core share) and export limits: each country must procure a share of the FCR with national resources and cannot export more than a certain capacity. For instance, for 2022, the core share of each country is around 30% of its needed FCR, while the export limits widely vary [163]. The remuneration for energy activation is established by the single country: in Germany, no energy remuneration is present (being the service symmetric, the energy activation should counterbalance) [164]. As presented in Figure 3.8, the prices for German FCR dropped from a steady value of 3000-3500 €/MW/week to a minimum of 1250 €/MW/week in 2020, with a 60% reduction [125]. In the figure, the price drop is compared with the prequalified BESS capacity [126].

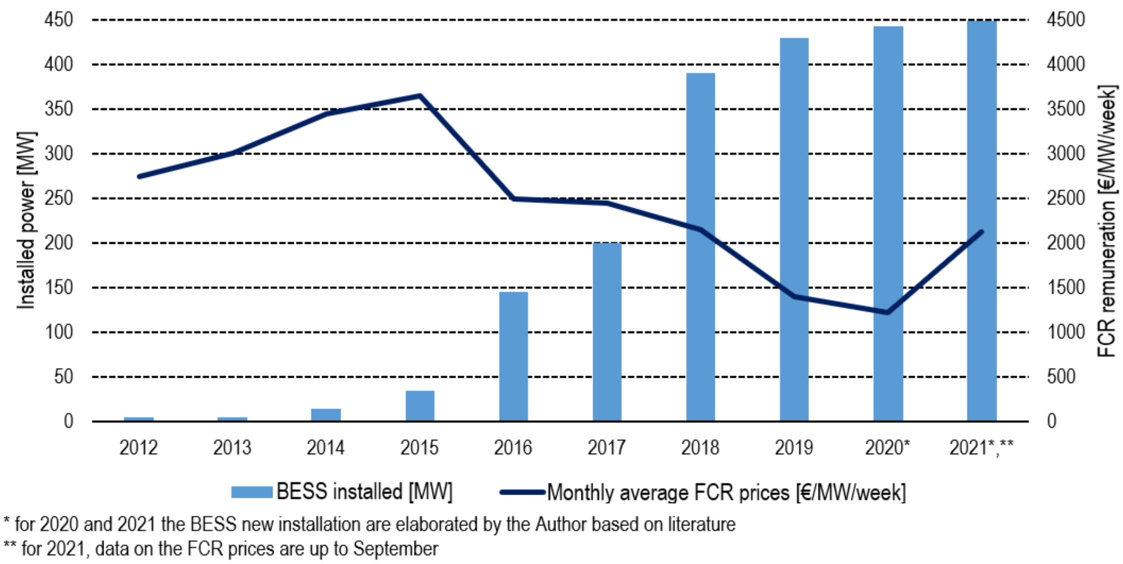


Figure 3.8 Historical trend of FCR prices in Germany and large-scale BESS providers.

Also, the other regulatory and market evolutions mentioned before must be taken in account as possible drivers. A zoom for period 2020-2021 is also proposed in Figure 3.9 to understand the separate effect of shortening the time definition of products and of the extreme high prices of energy markets in 2021 [127].

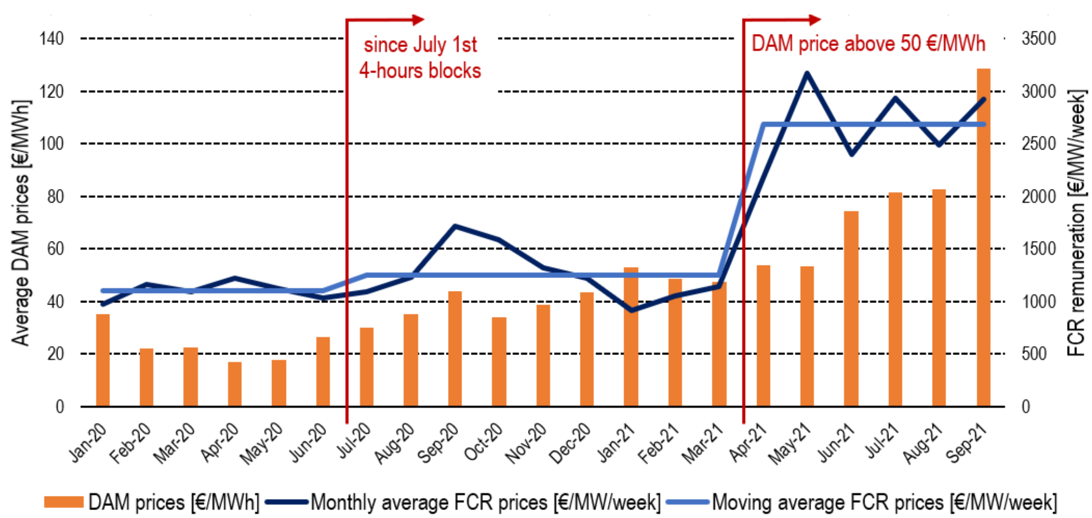


Figure 3.9 The influence of 4 hours-product introduction and of DAM prices escalation on FCR prices in the period 2020-2021.

3.4.4 Denmark

In Denmark, the share of electricity produced from variable RESs has been continuously increasing over the first two decades of the 21st century. In 2017, the share of the gross domestic electricity consumption covered by domestic variable RESs was 46%, of which 44% was wind and 2% was solar power. Increased interconnector capacity and enhanced power plant flexibility allowed for a curtailment limitation [128]. Ancillary services are procured by Energinet, the Danish TSO, from electricity generators and electricity consumers in Denmark and in neighbouring countries, in the framework of the central European shared platform. The SDS portfolio-based balancing system is implemented. In Denmark, the ancillary services provision and the imbalance discipline are interlaced, such that, even if in theory products are all open to independent BSPs, in practice the BSP almost always corresponds to the BRP. The lack of a clear aggregator framework and baselining methodology is an issue for independent aggregators accessing the market. A clear framework is also needed for storage participating in the market to avoid issues with classification. Two procurement areas are present: DK1 and DK2 [129]. DK1 is part of Continental Europe's synchronous area, and DK2 is part of the Nordic synchronous area. Traditionally, most ancillary services such as reserve capacity, inertia, frequency control, and voltage control were provided by large thermal power plants. Today, smaller CHP units and electric boilers deliver a significant share of regulating power. Wind turbines cannot submit bids on their own, so they may be included along with other production resources. FCR can be provided by pools of production or consumption units with the same BRP. DK1 joined the FCR Cooperation in 2021 [163]. The minimum bid size is 0.3 MW. The remuneration is in capacity (DKK/MW, where DKK is the Danish currency) adopting the SMP method for DK1 and PAB for DK2. The aFRR supply capability, explicit in DK2, is a temporary service since the TSO has not yet begun to procure aFRR (in DK1, aFRR procurement started in 2016). In this case, only symmetrical products are procured. Regarding mFRR, the minimum bid offer is 5 MW (it was 10 MW before 2017). The other services are characterized by a market with low liquidity and are mainly provided by conventional power plants, either by a market-based procedure or directly contracted. In terms of fast services, Fast Frequency Reserve was implemented in the Nordic Balancing Model to handle low-inertia situations in May 2020 [130][98]. It acts as a complement of FCR in DK2. To date, it is procured with a monthly capacity auction (an hourly capacity auction will be implemented). The Fast Frequency Reserve needs from the short-term forecast are specified on an hourly resolution two days before operation [131]. The minimum bid size is 0.3 MW. Pools of production or consumption units can provide the service.

3.4.5 Summary table: Assessment of the evolving ASM design in the analyzed European countries

The case studies are now analyzed in light of the previously presented ranking. We describe in Table 3.2 how each of these advanced countries (from a power system perspective) followed the trends in the evolution of the ASM in the period 2010-2021. The rows are ordered as in Table 3.1, from the most to the least appreciated by both the TSO and the BSP. Each cell of the table returns the action made by each country in the direction expressed by the corresponding row: a small or no effort ("◌◌"), a moderate effort ("●◌"), or a strong effort ("●●"). If not enough information was found or was available, the cell is "N/A". The systematicity of this second part of the study cannot be at the same level as the previous one, since there is not an equivalent amount of literature sources to be compared. In any case, the indication proposed in Table 3.2 can be considered to offer a reliable comparative evaluation of analyzed countries' balancing systems. Here below an analysis of the level of implementation of each trend, listed as in Table 3.1, is presented.

As described in the previous paragraphs, the symmetry of products and reserves is only gradually abandoned. In every country, there is a set of symmetric and a set of asymmetric services. Most of the countries are introducing asymmetry in some of the existing services, but no country is making the entire ASM asymmetric in a short period of time. A general review of the services is on the agenda for the UK, which shows a very dynamic ASM: new services are introduced, some pilot experiences are not renewed, and some conventional services are adapted to the new framework. Italy and Denmark are reviewing some of their services (especially to fit with international platforms) and introducing a fast frequency response service. Germany is more likely to maintain the conventional services: FCR was reviewed to integrate the DoFs, so that the conventional service is open to new resources. The system marginal price is of interest for those ASMs, showing larger liquidity, such as in Germany and Denmark, while Italy still widely adopts the PAB method. In general, the international platforms' (e.g., TERRE) implementation, which should occur in each member state according to [25], could push a shift towards the SMP. The increase of the procurement perimeter is already featured in Denmark and Germany, which procure FCR in the Nordic or Continental Europe synchronous areas' international procurement platforms. The implementation of European platforms, also in this case, could foster the process. The participation in the platform can apply to the UK as well, because Brexit started after the Regulation was enacted. As of 2021, the UK is a "non-operational member" of TERRE. Denmark and Germany are not yet participating in TERRE, while Italy is an "operational member." The interest towards the decrease of the time definition and the distance to delivery is shared by all countries. The barrier is potentially more sensible for those countries that procure the availability well in advance, by daily or even weekly auctions: in this case, the distance to delivery can represent an insurmountable problem for some resources, such as storage, variable RESs, and smart loads. The UK is reforming the frequency response services drastically to exploit the peculiarities of new units: indeed, faster services are implemented, requesting to respond to frequency deviations within 1 second. Dynamic regulation has also been adopted in the UK, with a piecewise linear droop curve, steeper in the case of larger frequency deviation (e.g., Dynamic Containment). The larger frequency deviations that the UK faces, due to the lower system inertia, have called for a tighter regulation. Denmark and Italy introduced a fast frequency response as well. Germany is still linked to the FCR, FRR, and RR layout. There is a very strong effort towards the easing of the aggregation process in every country, e.g., allowing for the aggregation of different resources. Nonetheless, the TSOs are usually facing increasing costs for including a pooling of different DERs in the dispatching. Furthermore, the aggregation of different resources is somewhat hindered by the lack of a clear separation between the BRP and the BSP in certain countries, e.g., in Italy, which presents a baseline for the BSP that differs from the schedule presented on the market, and in Denmark, where imbalance discipline and balancing provisions are closely related. An alternative to aggregation is a decrease in the minimum bid size, to allow for smaller portfolios of resources to enter the market. There is a large interest in this direction by Italy, Germany, and Denmark. Moreover, the UK shows this intention, even though, for some services, the minimum bid size is still high. Minimum values span from 0.3 MW in Denmark to 1 MW in the other countries. Italy could introduce a minimum bid size of 0.2 MW in the next period to ease the participation of electric vehicle supply equipment to the ASM by means of smart charging and vehicle-to-grid strategies. This reduction is not without drawbacks for SOs, since it enhances the complexity and the cost of running the ancillary services, dramatically increasing the number of transactions. Due to this, the decrease in the minimum bid size is shown among the least attractive alternatives in Table 3.1, despite the diffused effort in this direction by the analyzed countries. It is probable that a range from 0.2 to 1 MW is already more than reasonable for an open ASM, and barriers hide elsewhere. Price limits have been removed in Germany for years: negative prices as well as high prices are allowed. Negative prices remain forbidden in Italy, even if they will be permitted within the TERRE experience, as requested by the regulation. The possibility of streamlining and reducing the total number of products is considered by the UK only. Indeed, in the UK, there is historically a larger number of services, and there are several versions of similar products. As introduced before, a general review of the reserve products is ongoing in the direction of rationalizing the large number of products. Furthermore, new frequency response products have been proposed. All in all, it is not clear if the products are going to be streamlined. Other countries are adding fast frequency services to the traditional ones: they are therefore moving in the opposite direction with respect to streamlining.

A different argument must be made for the CDS versus SDS approaches. The CDS is adopted in Italy, while the other analyzed countries present the SDS. The Electricity Regulation has elected the SDS as the preferred model, but the CDS is allowed where it is requested by the TSO and justified by the NRA. The Italian stakeholders claim that the CDS allows for a better optimization of resources: analyzed sources agree. On the other hand, it is worth noting that the centralized approach is more opaque for the BSP, since the TSO retains the right of selecting the providers in the integrated scheduling process. A market that becomes more liquid could benefit by the joint adoption of SDS and, to some extent, of SMP: this would lead to a greater management flexibility of portfolios and simplify the bidding strategies (especially for newcomers). In any case, even if some member states are switching from a CDS to an SDS, this is not the case for Italy, at least in the short run.

In general, the correlation between Table 3.2 and Table 3.1 is only partial: the largest interest is not often towards the evolutions that entail a win–win situation. In addition, this survey highlighted that, even if the EU NRAs aim to direct the regulation towards the unique internal market for electricity, differences are still sensible, and fast and slow movers can be recognized: slow ones can learn from the pioneers' successes and failures [132]. The effort for following the trends can be empirically estimated by Table 3.2, considering the ratio of full dots "●" over the empty dots "○" for each analyzed country: the larger the ratio, the larger the effort of a country is (or, better, the faster the country is following the ASM evolution trends). The UK and Denmark show the greatest efforts: apparently, the evolution started first in countries with larger RES penetration (Denmark) or lower system inertia (the UK). Both of these regions have been able to keep the system secure while limiting RES curtailment, even if the frequency events have risen in magnitude [133]. This could suggest that the evolution of the ASM is necessary and could help in coping with the larger disturbances caused by the larger variability of the power system.

Table 3.2. Case studies summary table.

	ITA	UK	GER	DK
Towards the asymmetry of products	●○	●○	●○	●○
Services review	●○	●●	○○	●○
Towards SMP	○○	●○	●○	●○
Increase of procurement perimeter—harmonization	●○	●○	●●	●●
Smaller time definition of products	●○	●○	●○	●○
Towards faster/deeper regulation	●○	●●	○○	●○
Smaller distance to delivery time	●○	●○	●●	●●
Allowing the aggregation of different resource categories	●●	●●	●●	●●
Removing price limits	●○	N/A	●●	N/A
Smaller minimum bid size	●●	●○	●●	●●
Towards a streamlining of products	○○	●○	○○	○○
Towards a separation of BSP and BRP	●○	N/A	N/A	●○
SDS or CDS	CDS	SDS	SDS	SDS

3.5 Conclusions

This Chapter described and evaluated the ongoing evolution of ancillary services and Ancillary Services Markets (ASMs). The push towards a change is given by the quick shift of the generating mix towards a more sustainable and more distributed architecture, which, however, is partially composed by nonprogrammable sources. Many countries have started to open the ASM to Distributed Energy Resources (DERs) and to introduce faster services to respond to new system needs. The EU bound the Member States to develop an open and (up to a certain extent) harmonized market. National Regulatory Authorities (NRAs) are defining rules so that System Operators (SOs) can review ancillary services and products and that the necessary resources can be procured among a wider set of units. To do this, they must account for the different stakeholders' perspectives. A meta-analysis of the literature was proposed to evaluate the existing trade-offs between the points of view of SOs and Balancing Services Providers (BSP). Win–win situations, where a possible evolution presents advantages from both the sides of the BSP and the SO, have been identified, together with situations in which a trade-off is more evident. The goal of the resulting ranking is to provide a tool for NRAs and stakeholders to see the wider picture and determine which changes should be pursued first. In fact, while the power system already presents many technological solutions of interest for the energy transition towards a more sustainable future, system integration is not complete and still presents several elements of inefficiency and ineffectiveness. The evolution of the ASM and the inclusion of DERs as the core of the new dispatch could help in fostering a transition in a safe and secure way.

The first highlight of the analysis is that a general review of the services is necessary and welcome: the stakeholders largely agree that the system must evolve to integrate DERs and keep the quality of the supply and the cost of system operation at acceptable levels. Among the many trends analyzed, the one concerning the development of asymmetric products proved to be largely appreciated. All the analyzed sources highlighted a positive opinion, both by the BSPs and the SOs, for moving towards the asymmetry of downward and upward provisions. Moreover, many sources agree that the introduction of a system marginal price for remuneration could be effective for all the stakeholders.

Nevertheless, the outcomes of a survey of four European ASMs highlighted that the larger changes concern the aggregation criteria and the units enabled to the market: there is a strong, general effort towards easing the aggregation procedure and towards decreasing the minimum bid size. Moreover, the distance to delivery time of market gate closure is generally decreasing. European countries are also working towards the harmonization of products (e.g., by the means of international trading platforms) and the procurement of the resources on an increased perimeter (e.g., joint procurement by neighboring TSOs).

The focus of the Chapter has been on BSPs and TSOs. Since the BSP as an aggregator becomes important in the case of DERs' large diffusion, the point of view of the conventional generation is generally disregarded. This is justified by one of the scopes of the work, aiming to support policymaking in providing the ancillary services with the next production mix, increasingly dominated by DERs and pursuing the decarbonization of the system.

In conclusion, the proposed ranking is a term of reference to quantitatively test the impact of a new regulation on the system. Indeed, a further step could be to numerically analyze the effect of the variation of each parameter listed in the ranking, or at least the top-ranked ones, from a techno-economic perspective. This quantitative analysis is approached in Chapter 7, where it is useful to determine a set of ASM arrangements (based on a range of acceptable parameters for standard balancing products traded on the ASM) that are considered suitable to DERs, and specifically BESS, that are considered the quintessential enabler of the ASM for variable RES. To get to that result, a numerical model of BESS is necessary. Chapter 4 focuses on the BESS modeling.

CHAPTER 4

Modeling BESS for power grid applications

Abstract

As per what described in the previous Chapters, the electricity markets are opening and Distributed Energy Resources (DERs) are increasingly involved in electricity balancing and dispatch. Among them, Battery Energy Storage Systems (BESS) are crucial, and they are already providing frequency regulation and enhanced fast ancillary services. Therefore, the interest in modeling the operation of BESS for analyzing power grid applications is rising. BESS numerical models suitable for grid-connected applications must offer a trade-off between accuracy and computational effort. Moreover, they must consider the whole system, and not just be accurate in representing the electrochemical section. This Chapter presents a literature review on battery models: while there is a wide turnout of accurate model for the electrochemical section, a lack is recognized when it comes to consider the rest of the plant, for instance the auxiliary systems. A numerical model for the analysis of the grid-connected BESS operation is developed. The model is a BESS empirical multiparameter model obtained after an experimental campaign on a large-scale BESS. All the stages of the development are presented. First, a test protocol exploiting standard measurement equipment and based on charge/discharge cycles is proposed. An experimental campaign is carried out on a large-scale Li-NMC BESS. From the retrieved information, a multiparameter empirical BESS model is developed. The model undergoes a verification and validation process for testing its accuracy in simulating the provision of frequency regulation. Eventually, a set of case studies are presented for estimating the share of losses of the BESS on different applications: the relevant share of losses of auxiliaries provides a justification for the model developed. The procedure developed and validated is replicable in any other facility, due to the low complexity of the proposed

experimental set. This could help stakeholders to accurately simulate several layouts of network services.

4.1 The Battery Energy Storage System

The Battery Energy Storage System (BESS) is a versatile asset rising its importance and penetration in a large set of applications, as already detailed in Chapter 1. We talk of BESS since, beside the battery, other systems for the effective and safe grid-connected operation are necessary. The main involved systems are the ones depicted in the BESS layout presented in Figure 4.1:

- the battery pack;
- the power conversion system (PCS), generally made up by inverter and transformer;
- the auxiliary systems.

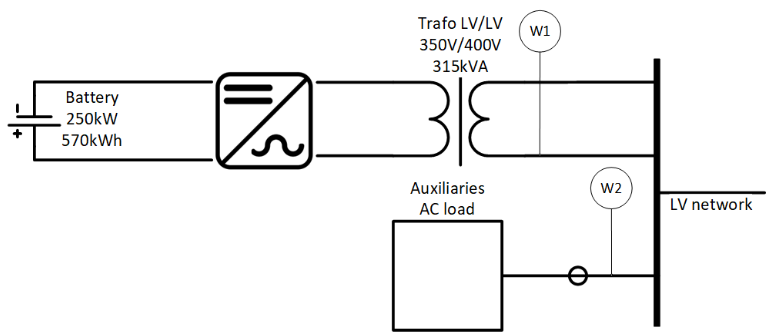


Figure 4.1 Battery energy storage systems (BESS) scheme with measurement boxes position [174].

4.1.1 The battery pack

In the battery pack, many batteries are inserted, electrically connected in parallel or in series to obtain the current and voltage of interest. The detailed description of a battery from electrochemical perspective is outside the scope of this text. We refer the Reader to [175] for this. From the energy perspective, the battery is a device able to absorb and inject energy. An available energy in the battery can be measured or estimated. There is a minimum energy content and a maximum energy content of the battery: the gap between these two thresholds is related to the nominal energy of the battery. The energy content available in each instant of the battery operation is commonly referred to as state-of-charge (SoC). Also, the name state-of-energy (SoE) is adopted. SoC is mainly related to the available capacity, while clearly SoE to the available energy content. In any case, the difference between SoC and SoE is shown to be always small [176], therefore the more diffused term SoC is always adopted in the framework of this study. The nominal energy (E_n) is related to the nominal capacity (C_n) via the following equation.

$$E_n = C_n * V_n \tag{4.1}$$

where V_n is the nominal voltage of the battery. Indeed, the minimum and maximum threshold are related to voltages in the battery. The battery cannot be subject to a voltage larger than a maximum voltage, namely the charging voltage limit (CVL), and lower than a minimum one, the discharging voltage limit (DVL). When the battery is idle, it experiences the open circuit voltage (OCV). OCV is a function of the energy content of the battery. It is known that for charging the battery we must impose higher voltages with respect to OCV (i.e., a positive overpotential), vice versa during discharging (i.e., a negative overpotential). The overpotential is proportional to the velocity of the reaction in batteries, usually measured as C-rate (in h^{-1}). A larger C-rate in the same battery means a larger power, either in charge or discharge. For a larger C-rate in charge, the cell voltage increases faster and reaches CVL before. Similarly, the voltage drops while discharging at higher C-rates [177]. The overpotential implies a larger effort for delivering the same energy. Therefore, even if the charge and discharge efficiencies of the battery are usually very high, they decrease at a larger power [178], [179]. The effect of the overpotentials on the available capacity at each C-rate can be seen in Figure 4.2: summarizing, the battery capacity is not a constant, but a function of the requested power. In other words, it could not be possible to reach the minimum and maximum SoC charging at constant power.

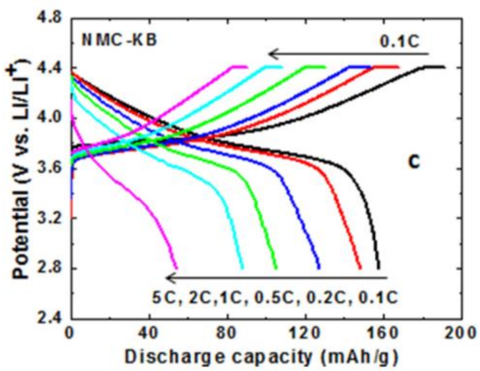


Figure 4.2 The effect of C-rate on the available capacity, both in charge and discharge [136]. The discharge capacity reduces moving from discharge at 0.1C to 5C, since the voltage drops faster from the maximum value to the DVL (approximately: 2.8 V). The same occur for charging, since at 5C (pink line) the CVL is reached at a capacity that is less than a half of the capacity for 0.1C (black line).

The reaching of the battery limits, as well as the depletion of its energy content, can result in power curtailments and, therefore, in decreasing of BESS reliability in operation. Indeed, the maximum power that can be requested to a battery changes with its energy content: at low available energy content, the discharge at high power can be impossible. Vice versa, the fast charging at high energy content can be prevented. What prevents the unsafe operation in a battery is the Battery Management System.

4.1.1.1 The Battery Management System

As already mentioned, the risk of depleting the energy content of BESS can decrease the reliability of these resources. Power curtailment can occur not only at minimum and maximum SoC since, as previously described, the operational limits are mainly given by the cell voltages [128]. The power curtailment in batteries is indeed given by hitting the boundaries of the Safe Operating Area (SOA) of the battery. This is a window between the maximum and minimum voltage each battery cell can be subject to in operation. In Figure 4.3, the SOA is highlighted by the white box. The horizontal lines identify the CVL and DVL.

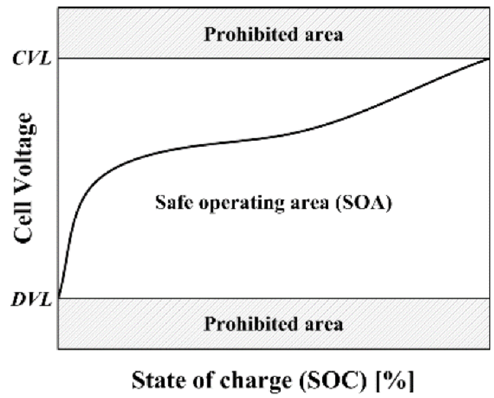


Figure 4.3 The Safe Operating Area of a battery cell, with the open circuit voltage curve depicted with a black line, and the charging (CVL) and discharging voltage limit (DVL) highlighted by the horizontal lines [180].

In charge, at a certain SoC, the battery voltage is always above OCV for that SoC (above the black line): the gap is proportional to power. The opposite occurs in discharge. The voltage thresholds are given by chemical reasons: outside this range, the decay of the cell enhances drastically. In any case, each manufacturer can partially modify the thresholds to privilege a larger lifetime or a better performance. The thresholds are implemented in the Battery Management System (BMS), that is the lowest layer of the battery control system, directly implemented by the technology provider. Whenever cell voltage hits CVL or DVL, the BMS acts to keep the voltage in the SOA: it can curtail the power, stop the battery, enhance the cooling of the battery (voltage is also proportional to temperature) [181]. To better understand the impact of the BMS on the operation, the following example is given, also making use of Figure 4.2. At low discharging power (e.g., 0.1C, black line), the battery reaches DVL at SoC close to 0%. Therefore, the battery can exploit almost the whole nominal energy at 0.1 per unit. In case battery is discharged at high power (e.g., 0.5C, blue line), the battery reaches DVL at SoC around 20%. Therefore, the energy content is not yet depleted, but the discharge can continue only at a lower power. It could be of interest, in some applications, to define the SOA to have the full activation power even at maximum and minimum SoC. Other applications could benefit by a larger capacity, even if it can be reached only at a very low power. Also, it is important to correctly model this characteristic of the BESS for understanding the actual performance on the markets.

4.1.2 Power conversion system

The battery pack delivers power in direct current (DC). As can be seen by Figure 4.1, a grid-connected application needs to inject and withdraw power from the power network in alternate current (AC). Therefore, a power conversion system (PCS) is needed. It is generally composed by inverter and transformer.

The inverter is a power electronic system able to perform the transformation AC to DC and vice versa. The transformation occurs at a very high efficiency, except for operation at low load with respect to inverter's nominal power, where the switching losses build up and the efficiency drops [182].

The transformer performs AC/AC conversion to the desired voltage (the grid voltage). Also, it provides galvanic isolation to guarantee the safe separation of the battery side and the grid side

[183]. Even in this case, at low power the efficiency of the transformer is limited, while it is generally high elsewhere [184].

For small-scale installation, just an inverter can be deployed. This decreases the investment cost, the complexity of the BESS and increases the efficiency. For mid to utility-scale installation, both the inverter and the transformer are deployed.

4.1.3 Auxiliary systems

As seen in Figure 4.1, each BESS must consider a set of auxiliary loads, generally AC, to ensure the safe operation of the BESS itself. These auxiliaries usually include safety systems (e.g., fire alarm), monitoring systems (e.g., a Supervisory Control and Data Acquisition or SCADA system), and an HVAC system. This last one guarantees the optimal ambient conditions, namely temperature and humidity, for the BESS operation. As previously introduced, the batteries must operate in a temperature range to prevent detrimental phenomena, decay and aging [185]. The HVAC is also the most energy-demanding among auxiliary systems.

4.1.4 Component efficiencies and qualitatively share of losses

For what said, while modeling a BESS, the PCS and auxiliary systems cannot be disregarded. Indeed, on a large-scale BESS, a share of losses can be imputed, beside the battery, to the PCS [186] and to the HVAC system [187]. A qualitative elaboration performed in Politecnico di Milano returned the values of share of losses presented in Figure 4.4, based on literature data and from measurements on real assets [188]. It is shown only for qualitative presentation purposes. Figures could vary considering the technology, the size, the application, and the geographical location of the BESS.

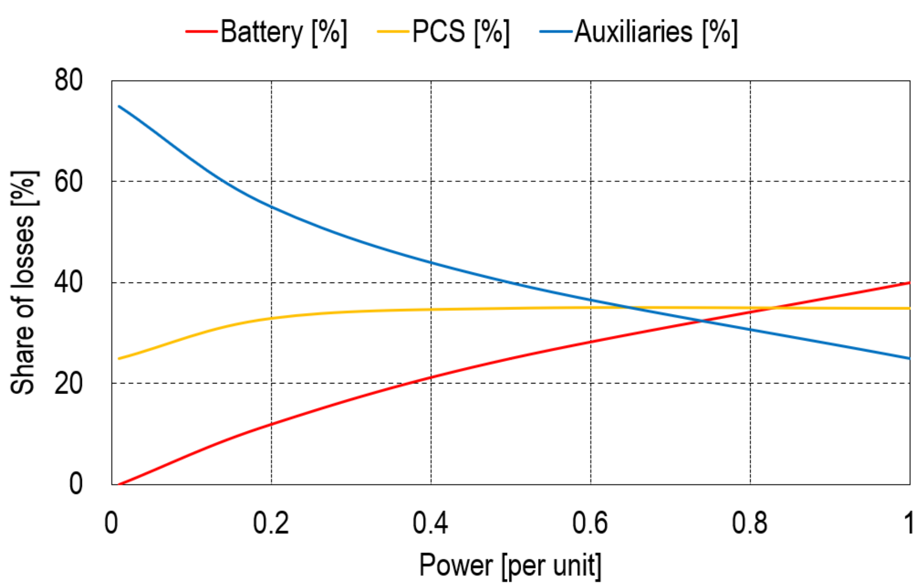


Figure 4.4 Qualitative share of losses on a Li-ion BESS.

As can be seen, the battery losses are prevalent only at power close to nominal power. Instead, at very low power, the auxiliary systems hold a larger share of losses: they work as a fixed operation cost that must be considered. The PCS has a medium weight on the losses at all the power ranges.

4.2 Battery and BESS modeling

Battery models are developed for several applications, but historically the main ones are the design of improved battery cells [189], and the online SoC estimation for implementation in the BMS [181]. For the design applications, the highest accuracy is necessary, while the computational effort is not a driver. Oppositely, for the BMS development, having a real-time SoC estimation is crucial, but the information on the relevant variable from the real asset (e.g., voltage and current measurement) are always available [181], [190]. The suitable models for these applications are electrochemical or electric models, more or less complex, dedicated to the battery. More recently, the study of BESS for grid applications, also included in smart energy districts, has become of interest [191]–[193]. In this case, model should have a decent accuracy, to avoid that high nonlinearity of the BESS leads to large errors [194]. Besides, the model should present a limited computational effort since market-related applications should be serially (e.g., varying the sizing of the BESS) tested on a long time-horizon [36], [195]. The following paragraph aims to bring a brief panoramic view on the modeling alternatives. Indeed, different models for various applications are available [196].

Electrochemical models deal with the reactions occurring in each cell, to model precisely the battery's nature. They feature extremely high accuracy and large computational effort [189]. They are usually based on nonlinear differential equations, representing the kinetic of the chemical and electrochemical reactions, as well as the transport phenomena occurring in the cell. Also inside this subset of models, there are less complex models, such as the single-particle model: it aims to consider a single particle with the same surface area as the electrode. This allows to simplify the large set of phenomena, focusing on the most relevant for the cell operation and neglecting others (e.g., the effect of the concentration of the particles in a battery cell). Moving towards more detailed models, either Pseudo-two-dimensional (P2D) models or Multiphysics models can be adopted.

A better compromise between accuracy and computational time can be offered by equivalent circuit models (ECM) [197], [198]. As the name suggests, they represent the battery as an electric circuit featuring a voltage source or a capacitor and a series of impedances. The more impedances are implemented (usually resistances or RC parallels), the better the phenomena happening in a cell during operation can be modeled. For instance, an ECM developed in Politecnico di Milano and CSEM [199] is schematically represented in Figure 4.5. This kind of model is used in a wider area of applications, among which it is worth mentioning battery management systems (BMS) [13]. BMS must deal with equivalent circuits since it works on-line and prevents batteries from detrimental operation by measuring in real-time both voltage and current at terminals.

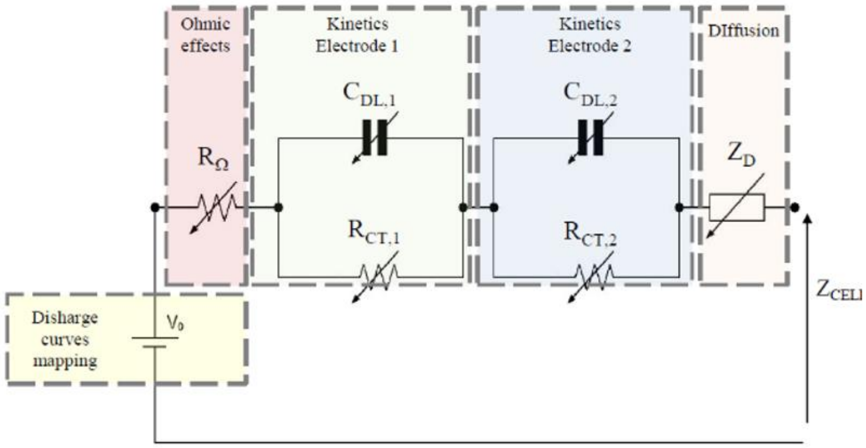


Figure 4.5 The equivalent circuit model of a battery from [199].

In case it is not necessary to deal with electric quantities, empirical models can be of interest. They employ functions correlating the energy quantities, not necessarily linked to the electrical or chemical nature of the battery device [189]. An empirical model represents, therefore, the nonlinear characteristics of a battery with reduced order polynomial or mathematical expressions [200]. For example, empirical models can exploit past experimental data for estimating the future behavior of BESS [201]. Empirical models have already shown a reduction in computational effort and an acceptable accuracy in predicting battery behavior [202]. Literature shows that the average relative errors in the SOC estimation are around 1%–4% for ECMs and of 5%–15% for empirical models [190], [203], [204].

In the modeling of energy districts, the BESS is usually considered in a wide set of assets, therefore modelled in a simplified way to keep a low computational effort compatible, for instance, with optimization problems. Valuable studies make use of a constant overall efficiency model for the battery [191], [193], [205]. The auxiliary systems demand is usually disregarded in these models, even if it accounts for a non-negligible share of losses, as highlighted by [187].

Since empirical models allow computational effort (and then simulating time) even 20–50 times lower [201], [202], [206], achieving a high accuracy with an empirical model is a target of large interest. Literature suggests that empirical model developed considering experimental data can have a high accuracy, but there is a risk of large bias in case the operating conditions get far from the experimented ones [201]. Usually, an experimental test with a complete coverage of the operating conditions is expensive and invasive (i.e., it cannot be performed on an already deployed system), since it is performed at the cell level [197], [207], [208].

Here below we summarize the results of the presented literature review on BESS modeling alternatives.

- There are several different models for different applications.
- They differ in terms of applicability field, accuracy, computational effort.
- Usually, accurate models require a high computational effort (electrochemical and electrical models). Oppositely, empirical models are faster (20-50 times faster), but imply larger errors.

- In studies where the BESS is included in an energy district, the empirical model is often simplified to a constant efficiency model, since the focus is on the whole control strategy and the computational effort of a complex BESS model is not compatible.
- To improve empirical models, model derived from experimental data on real batteries can be used. In any case, they show large errors in case the operating conditions are different from testing conditions. Furthermore, the experimental models proposed in literature are cell models: they disregard the rest of the plant, the experimental campaign are usually expensive, and they are invasive on the analyzed systems.

Concluding, there is a lack of models of the whole BESS, with low computational effort and high accuracy: a non-invasive experimental model testing the BESS instead of the cell could represent a useful novelty for testing grid-connected applications.

4.3 Developing a large-scale BESS model from experimental data

In this study, we propose the development of an experimental BESS model for SoC estimation. The model aims to consider the whole system quantitatively, by implementing on a Matlab Simulink tool the relevant empirical parameters describing the performance of the battery pack, PCS, and auxiliaries. The model is designed for the analysis of power grid applications: it aims to support the BESS manager in planning the operation and designing the control strategy (e.g., for optimal scheduling and market bidding). On the other hand, it could support policymaking in evaluating the suitability of an electricity market design for storage. It is not meant to substitute or emulate the battery BMS. The experimental campaign and the test protocol to characterize the model have been developed in the framework of this study. They are described in detail to be replicable in other facilities and for other systems. The validation and verification (V&V) process is performed to assess the accuracy of the model. A case study is included showing how BESS performance can be analyzed with the developed model. It deals with frequency regulation in the framework of an electricity market.

The model just described aims to overcome some weaknesses still present in BESS modeling highlighted in Paragraph 4.2. Indeed, this model implements the following main novelties.

- The entity modeled is the BESS (i.e., battery pack, PCS, and auxiliaries) and not just the battery. This is to conveniently retrieve all the losses of the system and to present the share of losses between the battery and auxiliary loads. As already mentioned, this is paramount for large-scale BESS operation but only partially present in literature.
- The proposed laboratory protocol for BESS characterization does not require expensive measurement set and allows to operate with probes at the switchboard level and not at the cell level, oppositely to the most widespread approaches (i.e., it is non-invasive). This allows a user to replicate the experimental tests in most facilities (i.e., with commercial power analyzers) and to repeat the procedure periodically to also evaluate the state-of-health (SoH) evolution of the battery (given obvious time constraints, it has not been possible to include SoH analysis and validation in this work).
- It shows accuracy in SoC estimation as high as state-of-art ECMs [190], at the same time the computation effort and the test effort (required to build up the model) are strongly decreased.

The proposed approach is summarized in Figure 4.6 and detailed in the following Paragraphs.

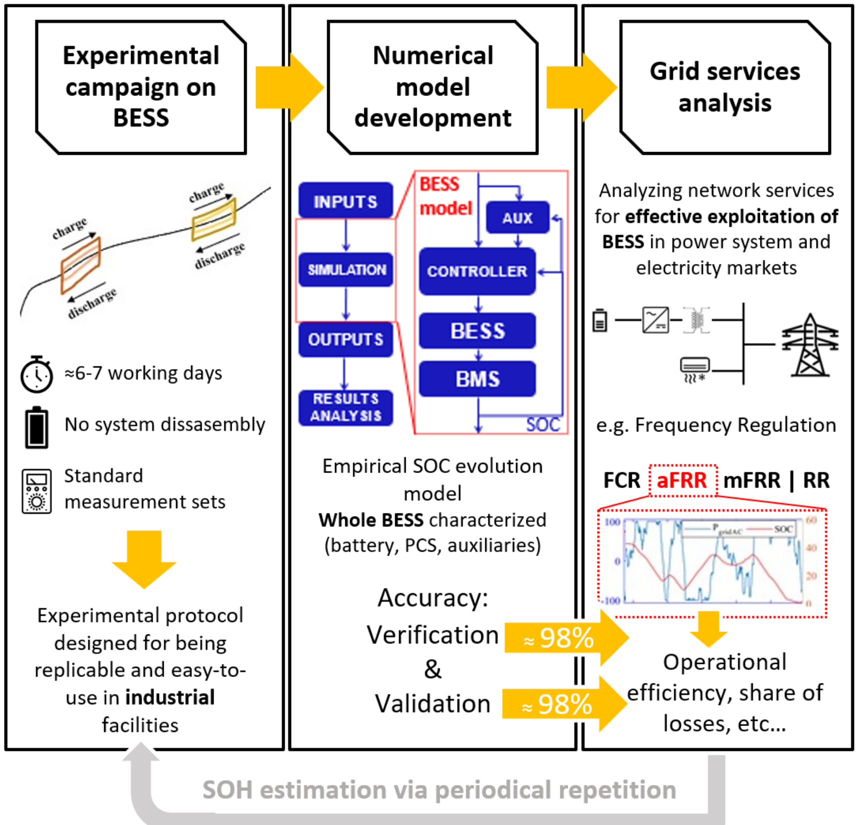


Figure 4.6 The proposed approach, including the proposition of a test protocol for an experimental campaign on BESS (left), the numerical model development (and validation) with the parameters obtained in the experimental campaign (mid), and the application of the model to typical use cases (right).

4.3.1 The experimental set-up

The BESS tested in the experimental campaign is a Li-ion BESS for stationary application present in JRC's Smart Grid and Interoperability Laboratory (SGILab) in Ispra (Italy) [174]. The BESS layout, shown in Figure 4.1, is described in the following. A Li-ion nickel-manganese-cobalt (NMC) battery pack of nominal energy (E_n) of 570 kWh and a nominal power (P_n) of 250 kW, whose datasheet is presented in Table 4.1, is used. The system was installed in an external container (see Figure 4.7a) and was made up of 144 battery modules clustered in 12 racks (Figure 4.7b). The system had a DC-side protection switchboard. At the end of life (EoL), the BESS is guaranteed for a minimum $E_{n,EoL}$ and $P_{n,EoL}$ of 450 kWh and 225 kW.

Table 4.1 Battery pack essential datasheet.

CELL	
Technology	Li-ion NMC
Capacity [Ah]	68
Voltage Range [V]	3.1–4.1
MODULE	
Capacity [kWh]	3.97
Voltage Range [V]	49.6–65.6
SYSTEM	
Design Capacity [kWh]	571.9
Nominal Power [kW]	250

Cells	2304
Modules	144
Racks	12
Minimum Voltage [V]	595.2
Nominal Voltage [V]	700.8
Maximum Voltage [V]	787.2
Nominal Current [A]	357.0

The laboratory contained an inverter featuring a nominal power of 330 kVA. It was employed for the DC/AC conversion in low voltage (LV) from max 1200 VDC to nominal 350 VAC. A three-phase transformer in the laboratory provided galvanic separation. Its nominal power was 315 kVA. It performed the LV/LV conversion from 350 to 400 V for the connection to a three-phase busbar. A set of auxiliary AC loads was used to enable the monitoring of the BESS (via SCADA, see Figure 4.7c) and keeping the setpoint ambient conditions stable (e.g., the air conditioning of the battery container). The battery container featured a commercial air conditioner and heat pump operating at a setpoint temperature of 18 °C. This was kept constant throughout the year. Therefore, batteries were kept in a constant, ideal ambient condition.

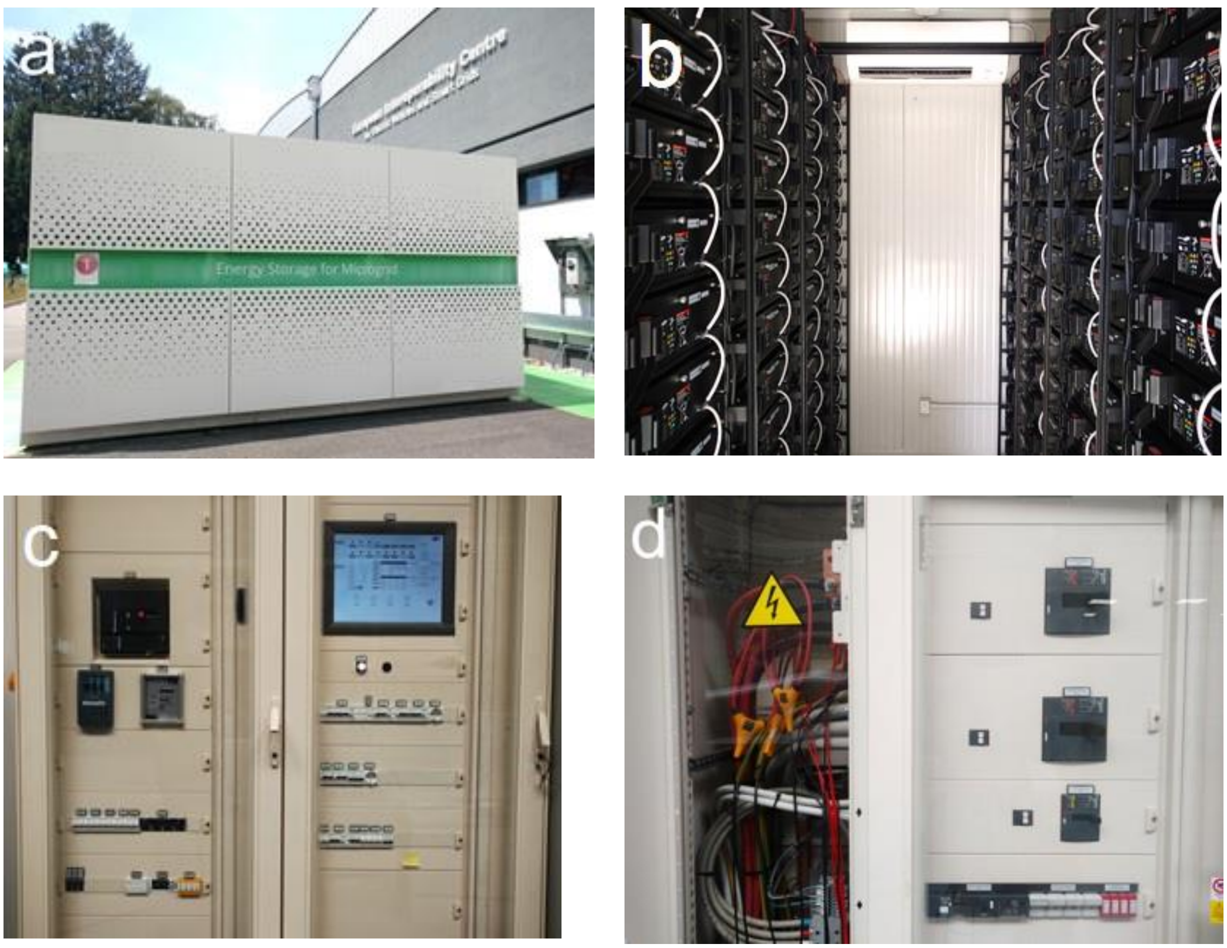


Figure 4.7 The BESS setup: battery container (a), racks (b), SCADA (c), switchboard and feeder (d).

The operation of the BESS was followed via the local SCADA, and by some specific measurement instruments that complemented the setup of the experiment. Within the framework of this study, the commercial BESS was used in its current state, without modifying its hardware configuration. The rationale behind this was being able to guarantee a certain degree of accuracy, suitable for the application, without requiring long or expensive procedures. The built-in SCADA of the BESS returned minute-based data logs of many DC-side quantities. Specifically, SoC estimation and voltages DC-side were reported. By datasheets, the measurements by the SCADA have low accuracy and thus were processed by proprietary algorithms developed by the manufacturers. The proprietary algorithm just mentioned, unknown by the authors in its entirety, estimates the SoC based on measurements of open-circuit voltages (OCV) and energy flows. We used a Fluke 437-II analyzer [209] for gathering the AC-side measurements with a second-based sampling rate and therefore higher accuracy than the original SCADA. The sensors were connected at the busbar level (see Figure 4.7d) to the main BESS feeder (between the transformer and the LV bus, see Figure 4.1, meter W1). Another analyzer, a Fluke 1732, measures the auxiliaries' feeder (see Figure 4.1, meter W2). The measurements are done with branded voltage and current clamps. A temperature probe measured the ambient temperature in the surroundings of the battery container. A summary of the equipment, measurements, and accuracies estimated is presented in Table 4.2. Such equipment has been selected as a standard measurement kit available in every facility, i.e., the goal of the paper is to propose an industrially viable approach to characterize a BESS and validate the accuracy of the procedure in a real-life implementation context.

Table 4.2. Metadata of relevant measured quantities [209].

Quantity	Source	Unit of Measure	Expected Range	Accuracy
Cell DC voltage	SCADA	V	[3.00–4.12]	±0.05 V
System DC voltage	SCADA	V	[595.2–787.2]	±10 V
System DC current	SCADA	A	[−400–400]	±1.0 A
SoC	SCADA	%	[0–100]	Estimation
AC voltage	Analyzer 1	V	[390–410]	±0.04 V
AC current	Analyzer 1	A	[−630–+630]	±1.0 A
AC power	Analyzer 1	kW	[−250–+250]	±0.5 kW
Auxiliaries' power	Analyzer 2	kW	[0–10]	±0.05 kW
Network frequency	Analyzer 1	Hz	[49.8–50.2]	±0.001 Hz
Outdoor temperature	PT100	°C	[0–50]	±0.1 °C

4.3.2 The test protocol

The experimental campaign took place between March and July 2019, with some additional tests in the 2019-2020 winter. The proposed laboratory protocol could be split in two different test sets.

4.3.2.1 Test set 1: complete charge/discharge cycles

The first one aims at retrieving the SoC curve with respect to the OCV of the system (SoC-OCV curve) and the capability curve of the battery. It features cycles of complete charge followed by complete discharge at constant power (DoD = 100%), as presented in Table 4.3. The estimation of SoC-OCV curve is fundamental to have a reliable reference term (i.e., a state variable as OCV) for defining SoC. This allows the ability to avoid being dependent on the algorithm of SoC estimation implemented in the system by the manufacturer, which is different for each technology provider and often proprietary (i.e., unknown). Furthermore, it is recognized that a dynamic (online) estimation of SoC hardly reaches the accuracy of estimation via OCV achieved after a convenient relaxation time [210]–[212], and the SoC-OCV curve is used as a reliable reference in most methods [213], [214]. Therefore, in the framework of this study, the SoC-OCV curve built as follows is used as an estimator of real SoC to be compared with SoC estimated by the model.

Table 4.3 The layout of Test Set 1

Cycle	SoC_{init} [%]	Explicit Power Setpoint [p.u.]	C-Rate [C]	DoD [%]	Estimated Elapsed Time [hours]
Cycle @ 22.5 kW	0	0.09	0.04	100	50.7
Cycle @ 45 kW	0	0.18	0.08	100	25.3
Cycle @ 90 kW	0	0.36	0.16	100	12.7
Cycle @ 135 kW	0	0.54	0.24	100	8.4
Cycle @ 180 kW	0	0.72	0.32	100	6.3
Cycle @ 225 kW	0	0.90	0.39	100	5.1

In the proposed protocol, the initial SoC (SoC_{init}) is set to 0%. To reach a SoC = 0%, the battery is discharged at constant current (CC) and then at constant voltage (CV), until the DC-bus minimum system voltage for safe operation (V = 623 V) is reached. Constant voltage discharge (that is equivalent to discharge at power decreasing up to 0 [215]) is then performed until reaching a minimum voltage with the battery idle (OCV = 623 V). It is worth noting that this voltage is higher than the minimum voltage proposed by the datasheet (see Table 4.1). This is because the BMS has a procedure for preventing detrimental phenomena while operating the battery. The procedure respects the requirement of a minimum settling time of 15 minutes before the beginning and after the end of each test. The BESS stays idle during the settling period. This ensures that the system voltage approaches a steady-state approximating OCV. After the settling time, the complete charge begins. When approaching the maximum system voltage, the BMS automatically stops the charging process. After a settling period (to identify the max OCV of the cycle), the discharging process at CC begins. When approaching minimum system voltage, BMS stops the process. Once more, a settling period is requested to reach OCV. To have a full battery cycle, the final SoC must be equal to SoC_{init}. Therefore, if by discharging at a constant current, the battery is not able to reach the SoC_{init} (the initial OCV), a constant voltage discharging process is applied. All the parameters set in this procedure (e.g., the settling time) comes from a trade-off between the accuracy and the low effort requested for the procedure so it can be adopted by a BESS operator. This selection is supported by literature analysis [216]–[218]. The test steps are described in detail in Table 4.4.

Table 4.4 Test steps for Set 1.

	Test Step	Charge/Discharge	Stopping Criterion	Explicit Power
0.1	Pre-test 1: complete discharge	Discharge (CCCV)	SoC = 0%	-
0.2	Pre-test 2: settling period 1	-	Steady voltage (OCV)	-
1	Complete charge at constant power	Charge (CC)	V max reached (BMS stops the charge)	As of Table 4.3
2	Settling period 2	-	Steady voltage (OCV)	-
3	Complete discharge at constant power	Discharge (CC)	V min reached (BMS stops the discharge)	As of Table 4.3
4	Settling period 3	-	Steady voltage (OCV)	-
5	Complete discharge to 0	Discharge (CV)	Initial SoC reached	-
6	Settling period 4	-	Steady voltage (OCV)	-

The test set includes six cycles with increasing constant power setpoints. The two tests at low power are then selected for building the SoC curve. They are presented in Figure 4.8.

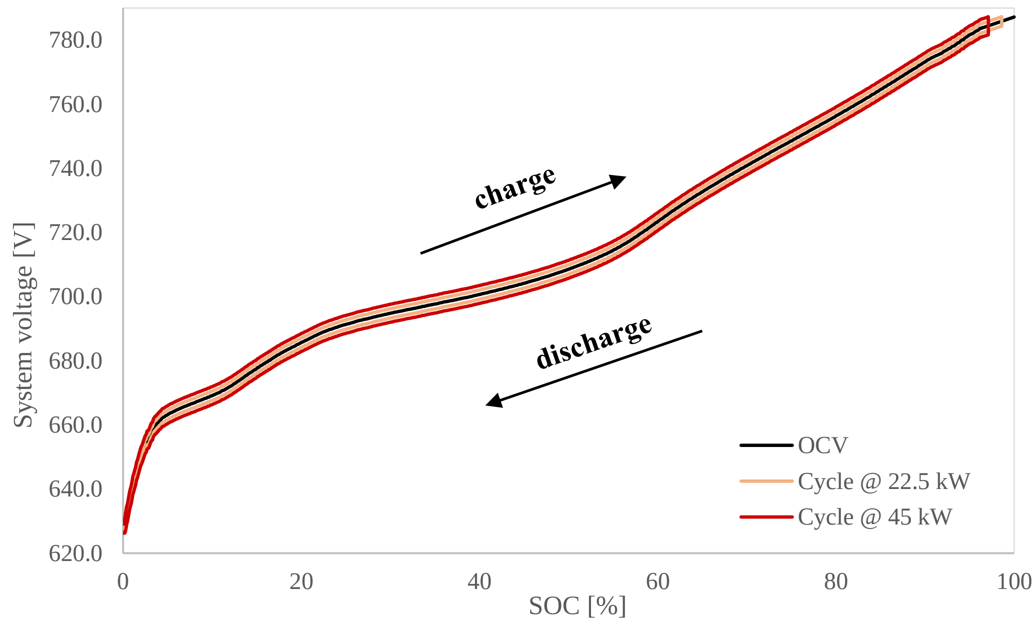


Figure 4.8 Qualitative voltage diagram for test Set 1.

4.3.2.2 Test set 2: short cycles at different SoC – C-rate combinations

The second test set, aimed at characterizing the BESS efficiency, is presented in Table 4.6. The aim of this second set is to cover a large span of the possible operating conditions in terms of SoC and power requested to BESS. Again, a set of tests featuring a cycle with a charging process followed by a discharging one at constant power is proposed. In order to have a rigorous evaluation of the efficiency, each cycle is bound to have a final OCV equal to the initial one. The depth of discharge (DoD) of the cycles is limited to have a proper check of the cell efficiency in different operating conditions; a 10% SoC variation has been identified as the optimal trade-off between numerical accuracy and proper estimation of the efficiency in selected working condition. The steps of each test in Set 2 are described in detail in Table 4.5. A certain degree of precision in getting back to SoC_{init} is requested. This is not always straightforward, especially at high power. Eventually, a further charge/discharge process at low power can be operated (step 4 in Table 4.5). Figure 4.9 presents a schematic layout of the cycles in a (SoC, V) diagram.

Table 4.5. Test steps for Set 2.

	Test Step	Charge/Discharge	Stopping Criterion	Explicit Power
0.1	Pre-test 1: getting to SoCinit	Charge/Discharge (CCCV)	SoC = SoCinit	-
0.2	Pre-test 2: settling period 1	-	Steady voltage (OCV)	-
1	Charge at constant power	Charge (CC)	Desired SoC reached (≈SoCinit + 10%)	As of Table 4.6
2	Discharge at constant	Discharge (CC)	SoCinit approached	As of Table

	power		(≈SoCinit)	4.6
3	Settling period 3	-	Steady voltage (OCV)	-
4	Eventual charge/discharge to exactly reach SoCinit	Charge/Discharge (CC)	SoCinit reached (=SoCinit)	0.09 p.u.
5	Settling period 4	-	Steady voltage (OCV)	-

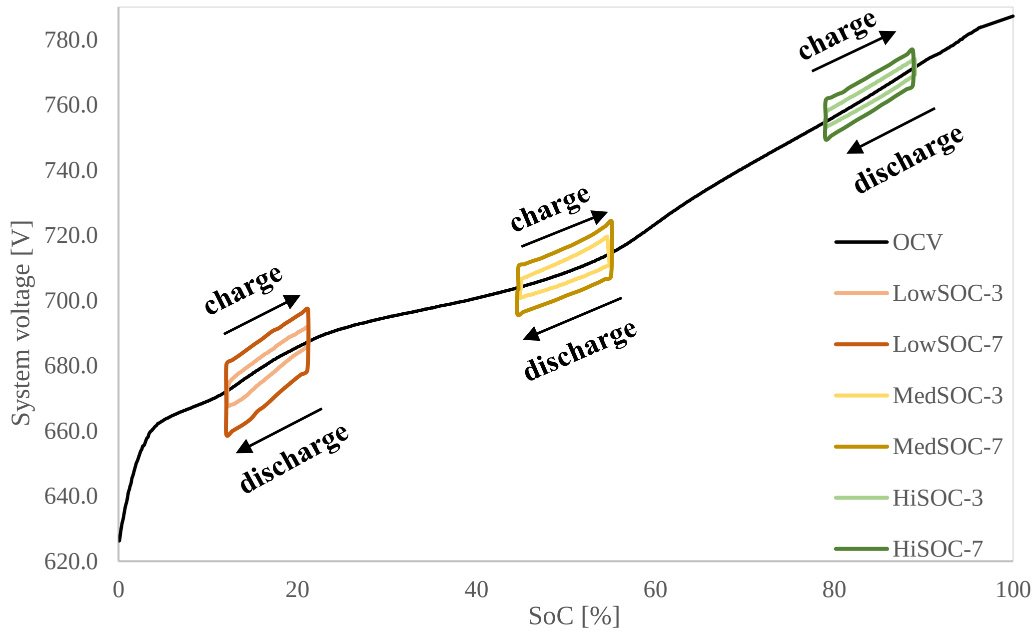


Figure 4.9. Qualitative voltage diagram for test Set 2.

The power setpoints are fractions of the BESS P_n, expressed in per unit through division by P_n. Each power level has been tested in three cycles, for different SoC_{init}: a high, an average, and a low SoC_{init}. The reached DoD of the cycles is approximately 10%. Exceptions (DoD lower) are made for very low power setpoints, to avoid the uncontrolled increase of the elapsed time. The minimum settling time of 15 minutes is also requested in this second test set.

Table 4.6. Layout of test Set 2.

Cycle	SoC_{init} [%]	Power Setpoint [p.u.]	C-Rate [C]	DoD [%]	Estimated Elapsed Time [minutes]
LowSoC-1	12.5	0.05	0.02	5	304
LowSoC-2	10	0.09	0.04	10	304
LowSoC-3	10	0.18	0.08	10	152
LowSoC-4	10	0.36	0.16	10	76
LowSoC-5	10	0.54	0.24	10	51
LowSoC-6	10	0.72	0.32	10	38
LowSoC-7	10	0.90	0.39	10	30
MedSoC-1	47.5	0.05	0.02	5	304
MedSoC-2	45	0.09	0.04	10	304
MedSoC-3	45	0.18	0.08	10	152
MedSoC-4	45	0.36	0.16	10	76
MedSoC-5	45	0.54	0.24	10	51
MedSoC-6	45	0.72	0.32	10	38
MedSoC-7	45	0.90	0.39	10	30

HiSoC-1	82.5	0.05	0.02	5	304
HiSoC-2	80	0.09	0.04	10	304
HiSoC-3	80	0.18	0.08	10	152
HiSoC-4	80	0.36	0.16	10	76
HiSoC-5	80	0.54	0.24	10	51
HiSoC-6	80	0.72	0.32	10	38
HiSoC-7	80	0.90	0.39	10	30

The analyzer measures the power during both tests Set 1 and 2. Set 1 and Set 2 guarantee a satisfactory coverage of the P_{gridAC} range and they are designed to test a large span of T_{amb} (i.e., they are carried out over some months, over two seasons and both during daytime and nighttime). Indeed, since the aim is to characterize the loads during real operation, it is important to measure P_{aux} for T_{amb} ranging from 0 to 40 °C and for P_{gridAC} ranging from 0 (battery idle) to P_n (maximum power injected or absorbed).

4.3.3 Estimation of the parameters

This section presents the methodology and results of the BESS parameter estimation following the experimental campaign. These results enable us to systematically describe the performance of the Li-ion large-scale BESS and the modeling tool developed for this study. The model parameters obtained as described in the previous paragraphs are E_n, P_n, the SoC-OCV curve, the capability curve, $\eta_{BESS,}$ and P_{aux}.

4.3.3.1 Nominal Energy and Power

For characterizing the BESS design, the actual battery capacity and rated power must be estimated. In the study, E_n (in kWh) and P_n (in kW) are used. This is to better adhere to power network terminology and quantities. Test Set 1 suffices for estimating E_n. Following the definition given in [219], the battery capacity E_n is defined as the energy that can be delivered to the grid when performing a complete discharging at 20-h-rated current EoL ($i_{20,EoL}$). The choice of low current is justified by the goal of maximizing the energy that can be delivered (it is known that battery capacity decreases with requested power [220]). The choice of using 20-h-rated currents at EoL highlights the interest to replicate the tests at different moments during the battery life. Therefore, the data from the Set 1 cycle at 22.5 kW (450 kWh/22.5 kW = 20 h) are used as follows to compute E_n.

$$\mathrm{E_n} = \int_{\mathrm{dis}} \mathrm{P_{gridAC}}(\mathrm{t}) * \mathrm{dt} \tag{4.2}$$

where P_{gridAC} is in the range of 22.5 kW (due to the selected cycle) and it is integrated on time during the discharge to obtain the maximum amount of energy that can be delivered continuously to the grid.

The nominal energy obtained as an outcome of test Set 1 is

$$\mathrm{E_{n,exp}} = 570.0\ \mathrm{kWh}, \tag{4.3}$$

available on the AC side discharging at 22.5 kW of constant power output. The value obtained is coherent with the declared E_n.

P_n is directly set by the BESS control system:

$$\mathrm{P_{n,exp}} = 250.0\ \mathrm{kW} \tag{4.4}$$

P_n is reached in both charge and discharge process.

4.3.3.2 State of Charge-Open Circuit Voltage Curve

The SoC-OCV curve is obtained from the Set 1's cycle at 22.5 kW and cycle at 45 kW. Useful data are DC current, DC voltage, and time elapsed. The SoC can be computed as follows.

$$\begin{cases} \mathrm{SoC(t) = SOC_{init}} & \text{if } \mathrm{t} = 0 \\ \mathrm{SoC(t) = SoC(t-1)} + \dfrac{1}{\mathrm{C_n}} * \displaystyle\int_{\mathrm{t}-1}^{\mathrm{t}} i(\mathrm{t})\mathrm{dt} & \text{elsewhere} \end{cases} \tag{4.5}$$

where i(t) is the DC current in the interval [t − 1, t], positive if the battery is charging, and C_n is the nominal capacity, obtained as follows.

$$\mathrm{C_n[Ah]} = \frac{\mathrm{E_n}}{\mathrm{V_n}} \tag{4.6}$$

where V_n is the nominal voltage (700.8 V). Therefore, we obtain a log of the SoC and the corresponding DC voltage (V_{DC}), from which we can build two curves of V_{DC} with respect to SoC while respectively charging ($V_{ch,cycle}$) and discharging ($V_{dis,cycle}$) at given powers. These two curves are reasonably close since the charge and discharge power are low. The SoC-OCV curve corresponding to the cycle is the average between $V_{ch,cycle}$ and $V_{dis,cycle}$ for each SoC.

$$\mathrm{OCV_{cycle}(SoC)} = \frac{\mathrm{V_{ch,cycle}(SoC) + V_{dis,cycle}(SoC)}}{2} \tag{4.7}$$

This is aiming to mitigate the hysteresis effect influence on OCV estimation that we would have in case of considering only one curve (charge or discharge) [210], [221]. The two SoC-OCV curves retrieved for the cycle at 22.5 kW and the cycle at 45 kW were combined to obtain the final SoC-OCV curve for the battery under testing.

$$\mathrm{OCV(SoC)} = \frac{\mathrm{OCV_{Cycle@22.5kW}(SoC) + OCV_{Cycle@45kW}(SoC)}}{2} \tag{4.8}$$

The use of both cycles decreases the possibility of transferring the inaccuracy of the DC measurements to the SoC-OCV curve. The use of cycles with lower power setpoints decreases the difference between V_{ch}, $V_{dis,}$ and OCV for each cycle.

The SOC-OCV curve of the BESS is presented in Figure 4.10. Two curves had been built (via the cycle at 22.5 kW and the cycle at 45 kW) and meshed to increase the overall reliability. Some obstacles were met while dealing with the SOC when close to saturation at 0% and 100%. The BMS sometimes acted in advance (triggered by transient voltages) and prevented the SOC from reaching the upper and lower boundaries. Therefore, the upper and lower tail of the OCV curve present a lower degree of accuracy. Figure 4.10 presents both the final OCV curve (black line) and the different experimental evidence for Set 1's cycles (pink + for 22.5 kW cycle and red triangles for 45 kW cycle).

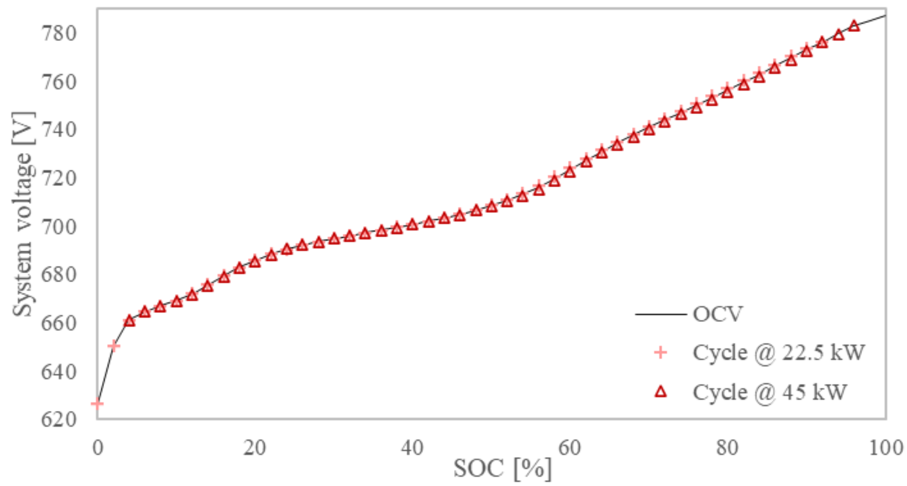


Figure 4.10 SoC-OCV curve experimentally obtained for BESS under study.

The experimental curves built are almost overlapping. Therefore, the estimation is considered reliable. Within the framework of this study, the real SOC is obtained by adopting the black curve as reference.

4.3.3.3 Capability Curve

Within the framework of this study, the capability curve is defined as the maximum explicit power that can be extracted or absorbed by the BESS at a certain SoC. The BESS under testing must work within 623.0 and 787.2 V. Therefore, the BMS curtails the power setpoints that can get outside this range (constant voltage charging/discharging). The capability curve is built by recording the OCV at the end of the charging/discharging processes in the test Set 1 (specifically, at the end of the CC process). When the BMS starts curtailing the power, the cycle is manually stopped and after the settling time, the OCV is recorded. Via the SoC-OCV curve, we can obtain the SoC corresponding to the OCV. This is the maximum (minimum) SoC at which a certain charging (discharging) power can be exploited. The capability curve is a way of expressing the operational battery capacity at a given power. This is different from the nominal capacity, that is the one used for the E_n estimation and is only valid at $i_{20,EoL}$.

The model implements a capability curve for BESS for active power only. The curve is presented in Figure 4.11. It represents the maximum charging and discharging power achievable for each SoC.

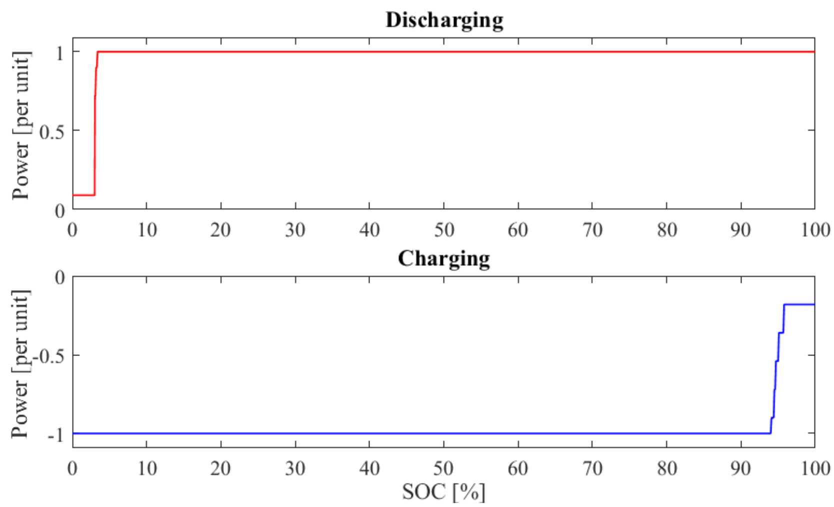


Figure 4.11 Capability chart as implemented in the model.

4.3.3.4 BESS Efficiency

The overall storage and conversion process efficiency is the main outcome of the experimental campaign. BESS efficiency (η_{BESS}) is estimated as a function of SoC and P_{gridAC}. The test Set 2 holds the data required for this. The BESS efficiency can only be computed for a whole cycle. Therefore, for each cycle of the test Set 2 we can obtain η_{BESS} as a function of the average power of the cycle and of the midpoint SoC of the cycle: (SoC_{init} + SoC_{max}) / 2. For each cycle of Set 2, efficiency is computed as indicated below.

$$\eta_{BESS}\,(SoC, P_{gridAC}) = \frac{E_{dis}}{E_{ch}} = \frac{\int_{dis} P_{gridAC,cycle}\,dt}{\int_{ch} P_{gridAC,cycle}\,dt} \tag{4.9}$$

where E_{ch} is the energy absorbed during charge and E_{dis} is the energy injected during discharge, computed as the integral of power measured on the AC-side while charging or discharging. The instantaneous charge or discharge efficiency can be obtained as the square root of η_{BESS}, since charge and discharge behavior are assumed equal. The surface of η_{BESS} is presented in Figure 4.12, obtained via the linear interpolation of the experimental outcomes on the domain. The surface is presented as a function of SoC and power requested in per unit.

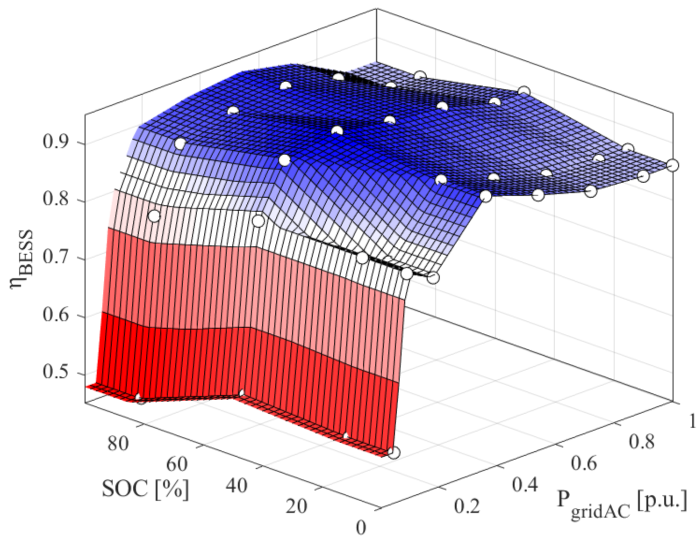


Figure 4.12 BESS efficiency.

The system efficiency is generally high (around 90%). η_{BESS} heavily depends on power requested to the battery—at low power, PCS losses become predominant and efficiency sharply decreases. At high power, the inefficiencies related to phenomena inside the electrochemical cells lead to mildly lower efficiency. Fixing the power, the SoCs close to 50% present a slightly higher η_{BESS}. Efficiency is implemented in the model as a lookup table (LUT). The LUT is presented in Table 4.7.

Table 4.7 BESS efficiency lookup table as implemented in the model.

η_{BESS}		**SOC [%]**				
		0	**15**	**50**	**85**	**100**
	0.00	0.540	0.540	0.550	0.480	0.480
	0.05	0.540	0.540	0.550	0.480	0.480
	0.09	0.842	0.842	0.842	0.787	0.787
P_{gridAC} [per unit]	**0.18**	0.818	0.818	0.931	0.896	0.896
	0.36	0.926	0.926	0.947	0.917	0.917
	0.54	0.895	0.895	0.931	0.927	0.927
	0.72	0.868	0.868	0.922	0.908	0.908
	0.90	0.861	0.861	0.896	0.859	0.859
	1.00	0.861	0.861	0.896	0.859	0.859

4.3.3.5 Auxiliaries' Power

A BESS relies on a set of auxiliary loads for operating. Conveniently estimating the weight of auxiliary power (P_{aux}) is fundamental for analyzing BESS operation and performance. Set 1 and Set 2 allowed the ability to measure P_{aux} in a vast range of operating conditions, in terms of ambient temperature (T_{amb}), and power requested to BESS (P_{gridAC}). P_{aux} is measured online. It is retrieved from the logs and correlated with temperature and delivered power. In the end, it is represented as an empirical function of T_{amb} and P_{gridAC}. To be sure of recording P_{aux} with a wide range of T_{amb}, measurements of the auxiliaries' load are performed both in daytime and nighttime for an extended time period including seasonal variations (March to July 2019, and winter 2019-2020). The measurements were processed to obtain a minute-based average P_{aux}.

The probability distribution of these values is reported in Figure 4.13. The total number of observations is 9466 (i.e., 9466 minutes of BESS operation were analyzed).

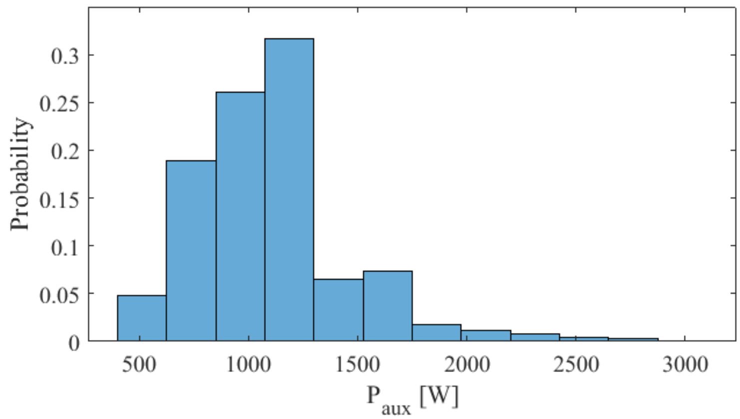


Figure 4.13 Distribution of experimental observations for auxiliaries' power.

Based on these measurements we built the 2-D LUT presented in Figure 4.14 and Table 4.8. The LUT includes both summer and winter loads, thanks to the extended measurement period [222]. In the LUT, we only reported the average value for the observation in the surrounding of each point (T_{amb} and P_{gridAC}). This was feasible since the model aims at representing the energy demand while disregarding the power profile. This latter is influenced by duty cycles of the appliances whose representation is out of the scope of this study. As can be seen, a slice of the auxiliaries' power (around 1000 W) is always present, feeding the components that are continuously operating in normal conditions and even with the battery idle (e.g., monitoring systems, SCADA, and alarms). In addition, there is a strong direct proportionality between P_{aux} and P_{gridAC}—parts of the loads are directly related to the BESS operation (e.g., PCS fans). Eventually, P_{aux} increases with T_{amb}, due to the need for the air conditioning of the battery container.

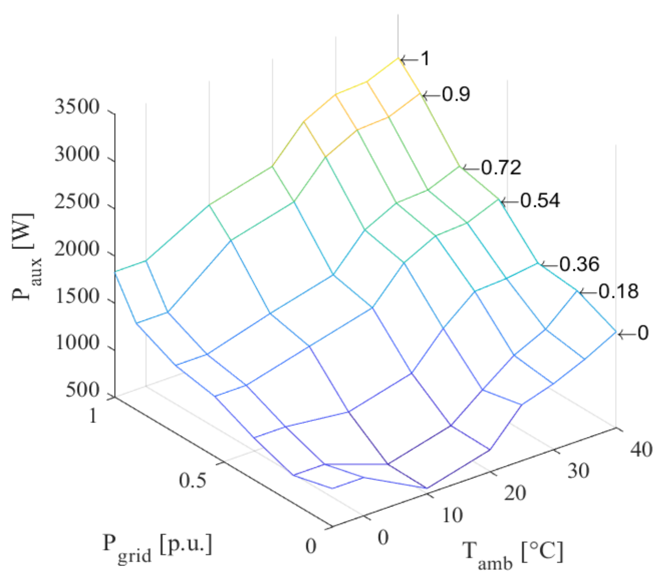


Figure 4.14 Auxiliaries' power.

Table 4.8. Auxiliaries' power lookup table as implemented in the model.

P_{aux} [W]		P_{gridAC} [kW]						
		0	**45**	**90**	**135**	**180**	**225**	**250**
T [°C]	**-10**	908	801	951	1143	1224	1423	1831
	0	908	801	951	1143	1224	1423	1831
	10	558	567	874	1322	1423	1950	2188
	20	733	742	1050	1497	1598	2125	2363
	25	1092	1004	1408	1856	1957	2483	2721
	30	1197	1253	1683	2024	2125	2652	2890
	35	1341	1412	1703	2045	2146	2672	2910
	40	1516	1704	1749	2180	2281	2807	3045

4.3.3.6 Adoption of the procedure for the evaluation of the State-of-Health

The experimental procedure developed is designed to be time effective and based on instrumentation that is normally available in each facility, i.e., it can be periodically repeated in order to take into account the state-of-health (SoH) evolution of the battery. The repetition of part or all of the procedure and the recording of new results may lead to the decision of updating the model parameters and to construct an aging model in a convenient manner. For example, just repeating the cycle at 22.5 kW in test Set 1 permits the user to analyze the capacity fade [223] of the battery: this test takes 1 working day. Repeating the entire procedure can also model the efficiency decay (i.e., the increase of internal resistance) over time [224] in approximately 6 working days. It is worthwhile to note that such tests are relevant to the evaluation of the overall BESS efficiency and capacity, moreover, they do not require the disassembly of any component (also, they do not allow to unbundle the aging phenomena leading to the decay). Once the procedure has been repeated, two actions are possible: if the experimental data show sensible aging, the numerical model is updated with the new parameters obtained; if the experimental data obtained are similar to the findings of the previous experimental campaign, the model does not need to be updated.

4.3.4 Implementation of the numerical model

The numerical model of the BESS based on the experimental parameters retrieved in Paragraph 4.3.3, characterized and implemented in a Simulink tool. The performed data processing is described in the following. The numerical model aims at accurately representing the operation of the BESS while providing grid services. The ancillary services for the electricity market of interest (such as RES support via time-shifting, frequency regulation and energy arbitrage) are real-world cases. Therefore, the model should be capable of receiving and conveniently processing real-world input data (such as electricity market prices and quantities, dispatching signals, and weather data). Timescales of the services vary from seconds (e.g., provision of the FCR [61]) to hours (e.g., energy arbitrage [225]). Hence a requirement for the model is to perform runtime simulations in all those timescales. The reliability of provision is of paramount importance when dealing with services to power networks. Therefore, the model must provide accurate estimates even when the BESS operates at its limits, i.e., power and SoC saturation limits. This will enable the coherent evaluation of the gap between the performance requested from the grid-side and the actual provision of the BESS (e.g., in terms of energy provided on energy requested). Given these premises, the proposed layout of the model is presented in Figure 4.15, to the left. Inputs are fed to the BESS model, featuring a controller implementing the control strategy for the provision of grid-related services. While developing the control strategies, the controller takes into account the presence of electric loads acting as auxiliaries of the operation. The output of the controller is a power setpoint fed to the BESS empirical model, which is characterized by the η_{BESS} (considering both the PCS and battery pack), the capability curve, and the SoC evolution model. The outputs are the power requested DC-side and the updated SoC. These are fed to a simplified battery management system (BMS) that modifies the inputs conveniently for staying within the operational boundaries (the SOA). The main outputs of the model are the SoC and the power provided AC-side. This process is repeated for each timestep of the simulation. The outputs are elaborated for supporting the analysis of the results. The model is implemented in the already described Matlab Simulink tool, whose zoomed-in flowchart for the BESS and BMS sections are presented in Figure 4.15.

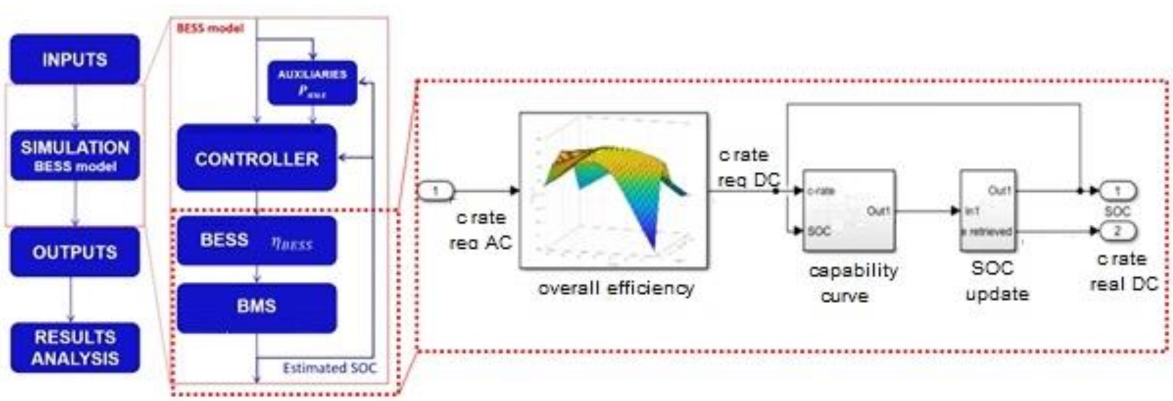


Figure 4.15 Simulation process flowchart and Simulink BESS + battery management system (BMS) representation.

The model implements the parameters obtained as outcomes from the experimental campaign. E_n and P_n are given as input to the model at the beginning of each simulation. They are useful in the construction of the control strategy since it is convenient to define the power setpoints as a function of P_n (in per unit). In addition, the model uses both power setpoints and c-rates, and the energy-to-power ratio (E/P) is used to transform between these two quantities. The auxiliaries' power demand is schematized in a 2-D lookup table (LUT) with P_{gridAC} and T_{amb} on the x- and y-axis. η_{BESS} is returned as a 2-D LUT with c-rate and SoC on x- and y-axis. The capability curve is returned as two 1-D LUT for charge and discharge, with SoC on the x-axis. The capability curve returns as output the maximum absolute value of power from the DC-side that can be delivered, for both charge and discharge.

4.3.4.1 The controller

The controller represents the model of the Programmable Logic Controller (PLC) of the BESS. In general, it contains the "intelligence" of the BESS and implements its control strategy. To do this, the controller must be able to:

- receive and process input signals, such as (but not limited to) market data, system status, ambient conditions, local or centralized orders and signals, position of the energy district assets, price signals, alarm signals;
- elaborate those signals via equations and transfer functions to obtain the power setpoints to be requested to the battery;

- send the power setpoints in the correct format to the battery.

An in-depth development of the controller is outside the scope of this Paragraph. Different implementations of the Controller are presented in Paragraph 4.4 and in Chapters 5, 6, and 7. Within this framework, the controller is only used for:

- directly receiving the power setpoints (P_{gridAC}) from input time-series. This occurs during the verification process, where the BESS model must operate on a cycle of user's choice;
- receiving and converting frequency deviation in a power setpoint via a droop control curve. This occurs during the validation process, where the BESS model is tested while performing frequency regulation.

The droop control curve is built in the model controller based on the curve controlling the operation of a real battery under study while providing frequency regulation. It is a simplified control curve, defined in Equation (7) and presented in Figure 4.16, featuring no dead-band and a droop value of 0.69%, computed as follows:

$$\mathrm{droop}\ [\%] = \frac{\frac{\mathrm{dF}}{\mathrm{F_n}}}{\frac{\mathrm{dP}}{\mathrm{P_n}}} * 100 \tag{4.10}$$

where dF is frequency deviation (in Hz), F_n is network nominal frequency of 50 Hz, dP is the power setpoint (in kW) and P_n is nominal power of BESS (in kW).

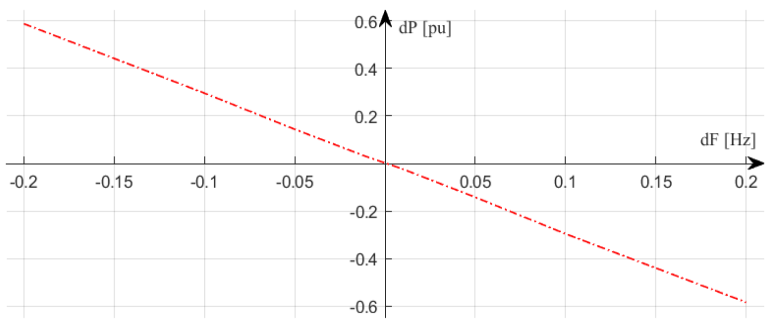


Figure 4.16 Droop control curve for frequency regulation as implemented in BESS under test.

4.3.5 Evaluating the model: Verification & Validation

The development of a model must include tests for verifying how accurately it represents the simulated system. The verification process verifies if the model is built using the correct equations and if there are no errors in its structure. The validation process aims to define if the model is appropriate for the foreseen application [226], [227]. Verification includes debugging the code for checking material errors and running tests capable of covering and checking the majority of the domain in which the model moves. This means, for the BESS model we are building, testing the behavior of the model with different couples of SoC and power setpoints requested from grid (SoC and P_{gridAC}). Indeed, the main parameter η_{BESS} is a function of these two variables. Validation includes testing the model on real-world data related to the model destination: grid-tie applications. Adopting typical timescales and power demand patterns of the phenomena under study is fundamental for validation.

4.3.5.1 *The verification procedure*

The rationale behind the proposed verification procedure is preventing all possibilities of error during coding and verifying that the model is simulating the system with proper accuracy on a large coverage of the possible operating conditions. These include different power demand to BESS (ranging from −250 to 250 kW) and several SoC conditions (ranging from 0% to 100%). We coded the Simulink tool using modular programming. Operating this way, we obtain functional units (i.e., separate blocks with input and output) where we can scope intermediate inputs and outputs, comparing them with manual calculations [227]. Furthermore, the verification includes running a test built based on the standard IEC 62660-1 taken from literature [228], [229]. The IEC standard applies to the performance testing of Li-ion batteries for the propulsion of electric road vehicles rather than for stationary applications. Despite this, it has been selected for its large coverage of the domain of interest. Some modifications were applied to the standard proposed in the framework of this study to better fit the application proposed. The power profile of the proposed cycle is shown in Figure 4.17. Indeed, it allows the development of a verification test on the BESS and the model under study, with DoD being almost 100% and the power profile ranging from −125 to 250 kW. An almost complete coverage of the operating conditions in terms of SoC and power requested to BESS are verified by this test.

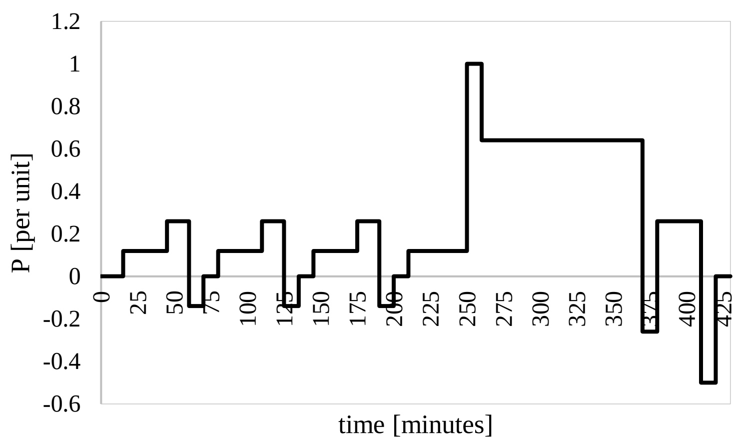


Figure 4.17 Power setpoints for the verification test proposed.

This power profile is fed to the real BESS. Then, the model runs a simulation cycle with the same profile. Initially, the SoC is in both cases 97.5%. Outcomes are evaluated using the following metrics. SoC estimation error during verification ($e_{SoC,V1}$) is defined as the difference between the real SoC (SoC_{real}) after reaching a stationary state (retrieved as a function of OCV using SoC-OCV curve) at the end of the test and SoC estimated by model (SoC_{model}) at the end of the simulation.

$$e_{SoC,V1}[\%] = SOC_{real} - SOC_{model} \tag{4.11}$$

This index provides an absolute figure of the error as a percentage of SoC. Energy estimation error during verification ($e_{E,V1}$) is defined as the ratio between $e_{SoC,V1}$ multiplied by E_n and the total absolute value of energy flown during verification test, obtained integrating on time the absolute value of power injected or absorbed AC-side.

$$e_{E,V1}[\%] = \frac{\left(\frac{e_{SoC,V1}}{100} * E_n\right)}{\int_{V1} |P_{gridAC}|\, dt} * 100 \tag{4.12}$$

This second index provides a dimensionless figure of the estimation error with respect to the total energy exchanged with the grid within a process.

The trend of SoC estimated by the model during verification is presented in Figure 4.18. As can be seen, the test included a large range of SoC values, from 92.8% to 9.8%. The large coverage of the model domain (in terms power and SoC) enhances the robustness of the verification test.

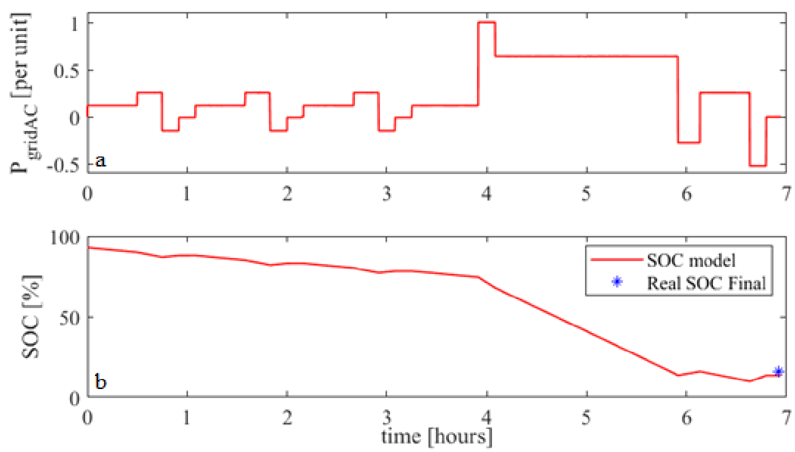


Figure 4.18. Power requested (a) and SoC evolution estimated by model (b) during the verification test.

A summary of the verification test is presented in Table 4.9. Both $e_{SOC,V1}$ and $e_{E,V1}$ are below 2.5%. The model estimates a final SoC approximately 2% lower than the actual one.

Table 4.9. Verification test summary.

TEST	
Starting date and time	July 4, 2019. 8:45 a.m.
Elapsed time	6h 48m
Initial OCV [V]	777.5
Initial SoC [%]	92.80
Final OCV [V]	679.0
Final SoC [%]	15.75
Total energy exchanged [kWh]	540.11
MODEL	
Simulating time	≈10 seconds
Initial SoC [%]	92.80
Estimated Final SoC [%]	13.46
$e_{SOC,V1}[\%]$	-2.29
$e_{E,V1}[\%]$	-2.42

4.3.5.2 The validation procedure

The validation process tests the BESS in a real-world use case, consistent with the model destination. Since the case under study is the analysis of the grid-tie application of BESS, the proposed validation process features the most widespread stationary application for a grid-connected BESS: as already mentioned, around 50% share of the total electrochemical storage stationary capacity installed as of mid-2017 performs frequency regulation [25]. Specifically, a primary frequency control or frequency containment reserve (FCR) provision is tested—such a frequency regulation requests fast response and has reduced timescales (power intensive) [230]. FCR is adopted for testing the model on the most stressful operating conditions. The droop control curve presented in Figure 4.16 is used for providing FCR. The choice of selecting a droop curve without a dead-band is meant to increase energy flows during the testing, thus decreasing the test duration. This is suitable for the validation process since its purpose is to investigate the estimation error rather than the effectiveness of the control strategy.

The proposed procedure includes several tests on the real BESS, then repeated using the BESS model. The real BESS measures the deviation of network frequency (f) in real-time at its connection point. It transforms frequency deviation into the power setpoint on the AC-side of the BESS via the droop equation proposed in Equation (2.1), with a droop value of 0.69%. For the validation test, the FCR is continuously provided for 24–48 hours. The BESS model is then fed with the frequency logs returned by the testing facility. The BESS controller implements the droop curve. Therefore, the real BESS and the model provide FCR following the same 24–48 hours frequency trends. Results are evaluated as for the verification process—the metrics obtained are the SoC estimation error during validation ($e_{SoC,V2}$) and the energy estimation error during validation ($e_{E,V2}$).

As said, the validation process was performed via a series of tests in which the BESS was providing FCR. We present the results of three of them and a general evaluation of the process. The three tests presented in Figure 4.19 are selected for analyzing SOC estimation when providing FCR starting from low, medium, and high SOC.

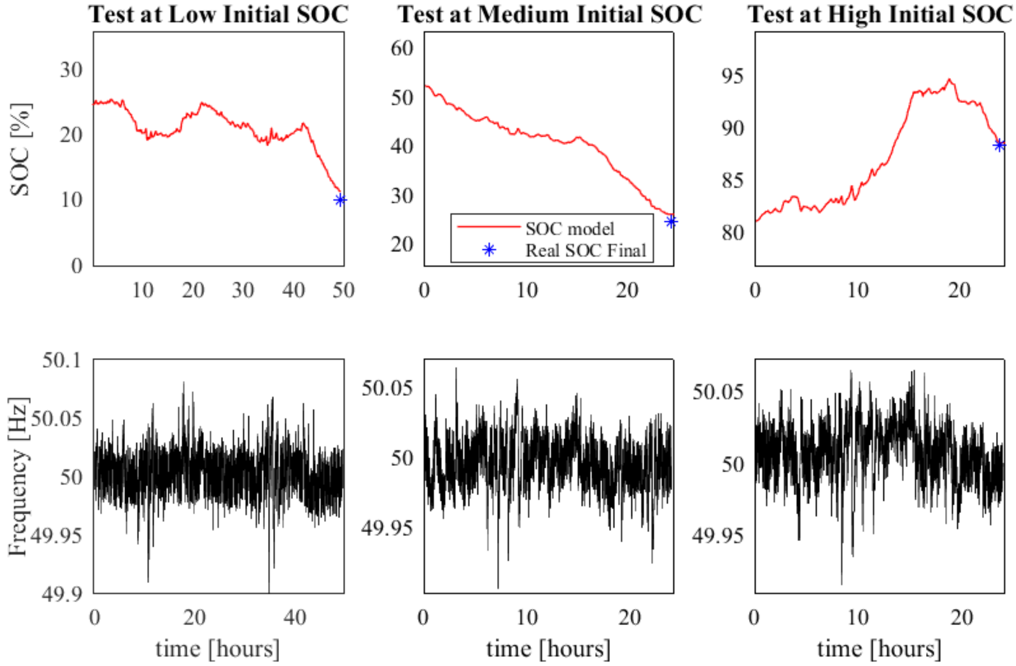


Figure 4.19 SoC estimation by model for FCR provision during validation tests.

Diagrams show the SoC evolution in the model and the comparison with respect to the SoC retrieved by the SoC-OCV curve at the end of the test (blue stars). It is worth noting that it is not possible to perform a comparison of SoC for the whole duration of the tests unless relying on SoC estimation proprietary algorithm of the battery. Since the OCV to SoC conversion is more reliable, only the comparison of final SoC is proposed. A summary of the results of validation tests is shown in Table 4.10.

Table 4.10. Validation tests summary.

TEST	Low SOC	Medium SOC	High SOC
Starting date	July 15, 2019. 12:23	June 14, 2019. 2:51	June 16, 2019. 2:34
Elapsed time	49h24m	24h40m	24h30m
Initial OCV [V]	690.90	710.80	757.90
Initial SoC [%]	24.40	52.10	80.95
Final OCV [V]	669.00	690.90	770.20
Final SoC [%]	**9.80**	**24.40**	**88.25**
Energy [kWh]	526.16	254.78	293.88
MODEL	Low SOC	Medium SOC	High SOC
Simulating time	≈20 seconds	≈15 seconds	≈15 seconds
Final SOC [%]	**11.14**	**25.79**	**88.43**
$e_{SOC,V2}$[%]	1.34	1.39	0.18
$e_{E,V2}$[%]	1.45	3.11	0.35

4.3.5.3 Summary of the V&V results

The errors in the 24-hours FCR provision tests are always lower than 5%, both in terms of absolute SoC error, and of error on total energy delivered.

As a final index, the V&V procedure proposes the average hourly SoC estimation error, obtained as follows.

$$\bar{e}_{h,SoC}[\%] = \frac{\sum_{i=1}^{N}\left(\frac{\frac{|e_{SoC,i}|}{100}}{t_i}\right)}{N} * 100 \tag{4.13}$$

where $e_{SoC,i}$ is the SoC estimation error of test *i*, t_i is the duration of test *i* in hours and N is the number of tests considered. This index represents the absolute value of the SoC estimation error the model could make on average during a 1-hour long simulation.

Within the whole V&V process, on a total of 10 tests (N = 10 in Equation (10)), we also computed the average hourly SOC estimation error $\bar{e}_{h,SOC}$, proposed in Table 4.11.

Table 4.11. Average hourly SOC estimation error.

	Average Value [%]	Standard Deviation [%]
$\bar{e}_{h,SOC}$	0.168	0.145

The general performance shown by the model is accurate. The accuracy (computed as 1 minus the error) is always more than 95% (with an average of 98%) both during verification and validation, in terms of estimation of energy flows, i.e., as complementary to one between $e_{E,V1}$ and $e_{E,V2}$. Regarding accuracy concerns in the SoC estimation, we focused on the average hourly error $\bar{e}_{h,SOC}$.

One feature of the developed model is not to disregard the auxiliary systems contribution to operational efficiency. Paragraph 4.4 gives an estimation of the weight of auxiliaries on the overall performance in different BESS applications.

4.4 The weight of the auxiliaries and the share of losses in BESS operation: three case studies

As previously described, the BESS plant layout usually presents an outdoor battery pack located in a container (see Figure 4.1). The container has dedicated HVAC system, plus other auxiliaries such as fire alarm and fans for the devices, not to be disregarded in modelling [231]. To estimate the operational efficiency of the BESS, losses can be disaggregated in two main categories: the losses due to unideal operation (e.g., joule effect in batteries, inverters and transformers) and the power requested by the auxiliary systems (e.g., SCADA, fans, fire alarms and HVAC). In the model previously presented, these two contributions are modelled respectively via the parameters η_{BESS} and P_{aux}. When analyzing scientific literature, plenty of models can be found simulating accurately the electrochemical section of the battery [232][233]. A model with exceptional accuracy the electrochemical cell is of paramount importance for researchers and engineers working for improving battery technology. Modelling the operation of the whole BESS is instead of interest for the asset owners and electricity market stakeholders. A lack can be found in literature when it comes to model the overall operation in grid-connected layout. The developed model aims to properly consider the demand of the thermal-related auxiliary systems in both winter and summer conditions. Auxiliary systems weight on total BESS losses depends on the service the BESS is performing. The products sold on balancing markets (BM) for frequency regulation widely differ for timescales of the response and for energy demand over time [234][37].

To assess the operational efficiency, three different kinds of real-world frequency control regulations are modeled. Specifically, these differ for the amount of MWh per period per MW qualified they demand to providers. A first case (CASE A) is related to a new service in which storage systems are integrated in a conventional production unit (PU) to support providing FCR: they provide FCR only when the PU is at its peak production. It has been introduced by the Italian TSO in the framework of a pilot project [235]: Unità di Produzione Integrate (UPI). The case of a BESS standalone providing FCR is then analyzed (CASE B). Tertiary regulation, including in Italy both manual Frequency Restoration Reserve (mFRR) and Replacement Reserve (RR) provided by BESS standalone, is eventually tested (CASE C).

Modeled services are, as said, three different kind of frequency regulation compliant with the Italian Grid Code [236]. They differ by the amount of energy requested (in absolute value) per unit of awarded power per period (MWh/MW/day), as can be seen in Table 4.12.

Table 4.12 Ancillary services considered in the study

CASE	Name	MW qualified	MWh/MW/day
CASE A	FCR in UPI pilot project	P_{nom}	2.31
CASE B	FCR – BESS standalone	$P_{nom}/2$	5.44
CASE C	Tertiary regulation – BESS	P_{nom}	6.71

MWh/MW/day is useful to identify the actual effort requested to a device for performing a service, after trading a unit of the product (in MW) on the market. In the framework of this study, since we aim to characterize the BESS performance and the weight of auxiliaries (working even when the battery is idle) on total, these three services are selected to compute BESS efficiency in a wide range of operation. The three CASES test a service for 24 hours both in a winter and in a summer day.

- CASE A tests the BESS providing FCR in an integrated plant layout with a conventional PU. In Italy, FCR provision is mandatory for conventional PU. This pilot project (active since 2018) allows the plant manager to provide FCR with BESS when the plant is at its peak power and it could not provide by itself [237]. Therefore, the effort requested to BESS is the provision of FCR as for Italian Grid Code, but only when integrated PU is peaking. Figure 4.20 shows the frequency trend for the selected day, coming from historical data of 2018 related to Continental Europe Synchronous Area. Figure 4.21 shows the Δf/ΔP curve in place in Italy used in this study, correlating the power requested on total awarded/qualified power (P/P_{awd}) to frequency deviation from nominal value (50 Hz) in Hz. The dead-band is ±20 mHz. Figure 4.22 shows the P_{grid} requested to BESS in CASE A (top chart) with $P_{awd} = P_{nom}$. As can be seen, PU is peaking in the morning (7-10 AM) and in the evening (5-10 PM). It is worth noting that we do not mean to generalize this time schedule: the pilot project is dedicated to PU that sell their peak power for a reasonable amount of time. For them, the opportunity of investing in a BESS to provide FCR for peak hours on their behalf represent a business. We consider a PU peaking for 8 hours a day. The only aim of the case study is considering a realistic application for a BESS that includes remaining idle for a large time every day (i.e., 16 hours).

- CASE B tests the BESS providing FCR as a standalone BESS. It differs from CASE A for the time of use (24 hours continuous) and for $P_{awd} = P_{nom}/2$ (see Figure 4.22, mid chart).
- For what concerns CASE C, it depicts the provision of mFRR by a standalone BESS on BM as for Italian Grid Code. Italian BM, such as other electricity markets, presents 15 minutes as reference contracted period [238]. Therefore, a signal of mFRR has been simulated by a series of constant setpoint lasting 15 minutes, ranging from -1 to 1 per unit (P_{awd}/P_{nom}). P_{grid} requested to BESS is presented in Figure 4.22 (bottom chart).

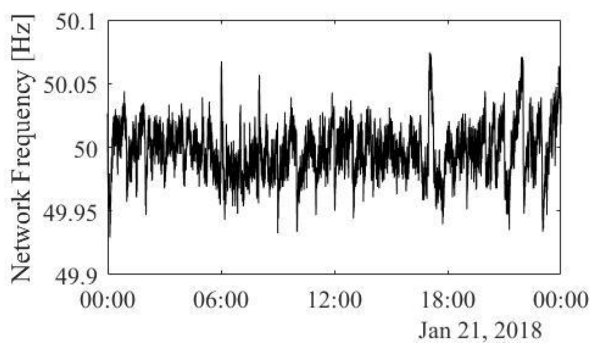


Figure 4.20 Frequency trend used for CASE A and CASE B.

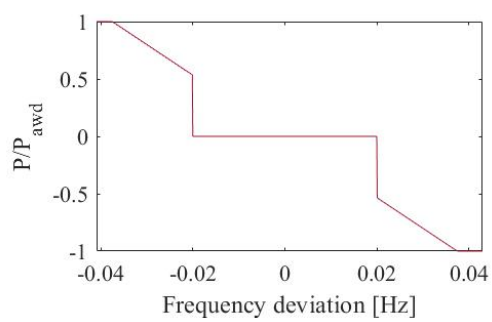


Figure 4.21 Droop curve for Frequency Containment Reserve used in CASE A and CASE B.

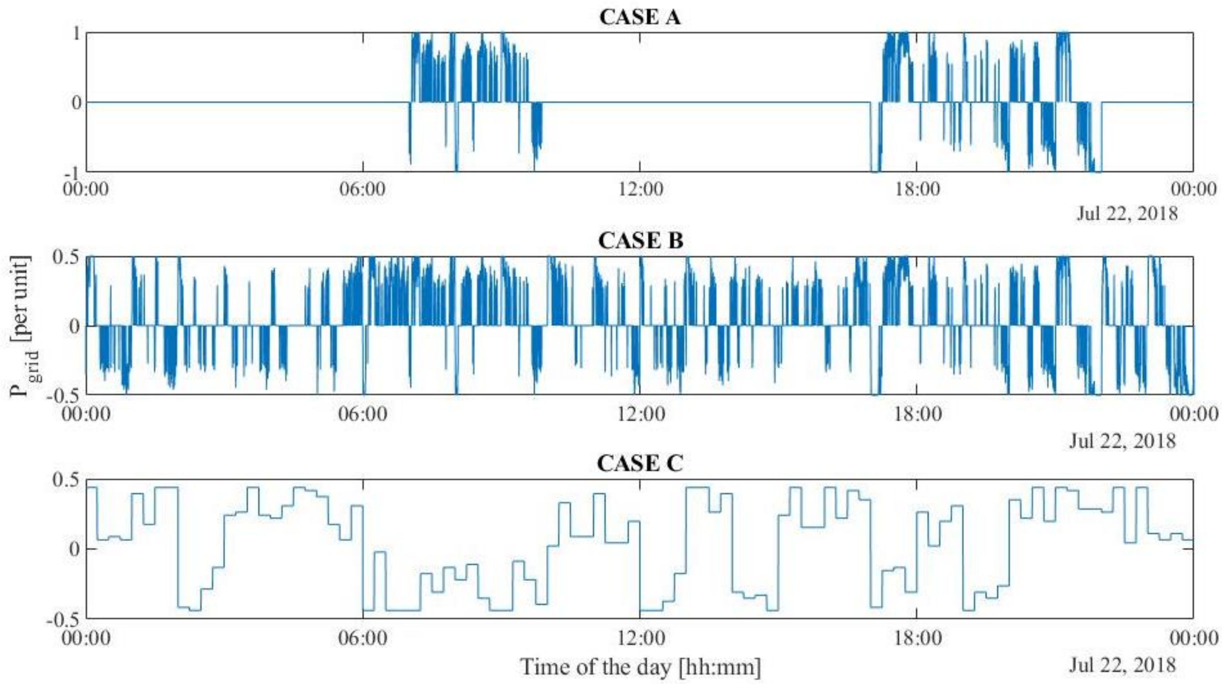


Figure 4.22 Power requested to BESS for 24 h provision of primary regulation in an integrated layout with a conventional plant (CASE A), primary regulation as a standalone BESS (CASE B), tertiary regulation as standalone BESS (CASE C).

Summer and winter temperatures are taken from direct measurements in Milan area, in northern Italy [239]. They refer to January 21 and July 22, 2018.

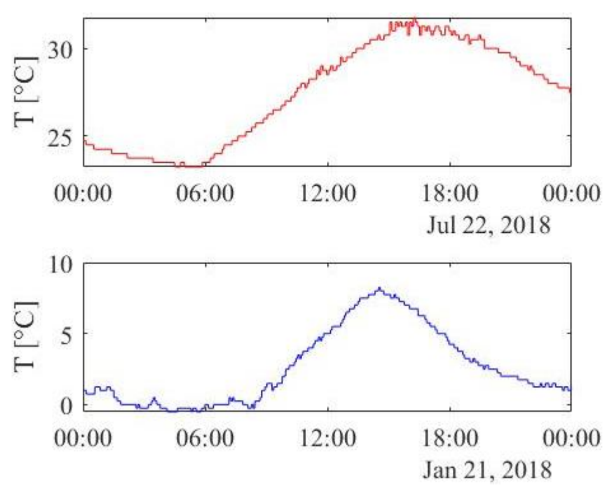


Figure 4.23 Temperature trends for summer (top) and winter (bottom) days.

The relevant KPIs in this case study are the efficiency of operation and the share of losses between battery and PCS, and auxiliaries. It is worth noting that, since we do not have a cycle (final and initial SoC are not coincident), the roundtrip efficiency cannot be used. Therefore, the real flowing power (P_{real}) is computed as the one associated to the real SoC variation in the model. P_{gridAC} and P_{aux} are still used as the requested power from the grid (for ancillary services provision) and from the auxiliaries. The KPIs are computed as follows. The energy requested to

BESS for service provision (E_{grid}), separately positive and negative, is computed as the summation of P_{gridAC} during the day.

$$E_{grid,dis} = \sum P_{gridAC}\left(P_{gridAC} \geq 0\right) * \Delta t \tag{4.14}$$

$$E_{grid,ch} = \sum \left|P_{gridAC}\left(P_{gridAC} < 0\right)\right| * \Delta t \tag{4.15}$$

Similarly, P_{real} is summed to get the energy (E_{real}) considering the efficiency and the auxiliaries' demand, which is correlated to SoC variation in charge and discharge.

$$E_{real,dis} = \sum P_{real}\left(P_{grid} \geq 0\right) * \Delta t \tag{4.16}$$

$$E_{real,ch} = \sum \left|P_{real}\left(P_{grid} < 0\right)\right| * \Delta t \tag{4.17}$$

The average efficiency during discharging and charging processes is obtained as follows.

$$\eta_{dis} = \frac{E_{grid,dis}}{E_{real,dis}} \tag{4.18}$$

$$\eta_{ch} = \frac{E_{real,ch}}{E_{grid,ch}} \tag{4.19}$$

To obtain overall efficiency, the weighted average of the two terms must be computed.

$$\eta_{overall} = \frac{\eta_{dis} * E_{grid,dis} + \eta_{ch} * E_{grid,ch}}{E_{grid,dis} + E_{grid,ch}} \tag{4.20}$$

Eventually, a generalized operational roundtrip efficiency is computed by elevating to the power of 2 the $\eta_{overall}$.

$$\eta_{RT} = \eta_{overall}^{2} \tag{4.21}$$

The efficiency η_{RT} is different from η_{BESS}: it can be said that it is its homologue, also taking in account the auxiliary demand. Indeed, it takes in account two macro categories of losses:

- internal losses due to non-ideal operation (and directly-fed auxiliaries' demand, that cannot be disaggregated if the measurement box is posed as in Figure 4.1, W1) related to η_{BESS};
- auxiliaries' system power demand related to P_{aux}.

To estimate the share between these two losses, a preliminary simulation for each CASE has been performed, neglecting the presence of auxiliaries. This is called reference (REF) simulation (100% share of losses due to η_{BESS}) because BESS models typically proposed in literature are limited to the electrochemical section and to the PCS [196], i.e., they do not properly evaluate the auxiliaries energy need. The results are then presented for both winter (W) and summer (S) scenario.

SoC profiles are shown for the 3 simulations of the 3 CASES in Figure 4.24. Largely different patterns show up. CASE A shows a long time with battery idle, in which battery slightly discharges only due to auxiliary demand. CASE B shows a hilly pattern, since FCR requests to absorb and then inject power to the grid for brief intervals. CASE C shows longer periods of discharge (1 hour or more), followed by charging periods. It can be seen how disregarding auxiliaries leads to outcomes more optimistic than real ones, especially in CASE A (larger difference between REF and the other two scenarios), where the MWh requested by the grid are less and battery sees long idle periods. Summer (S) is always more demanding than winter (W), but in both cases auxiliaries' demand is perceived.

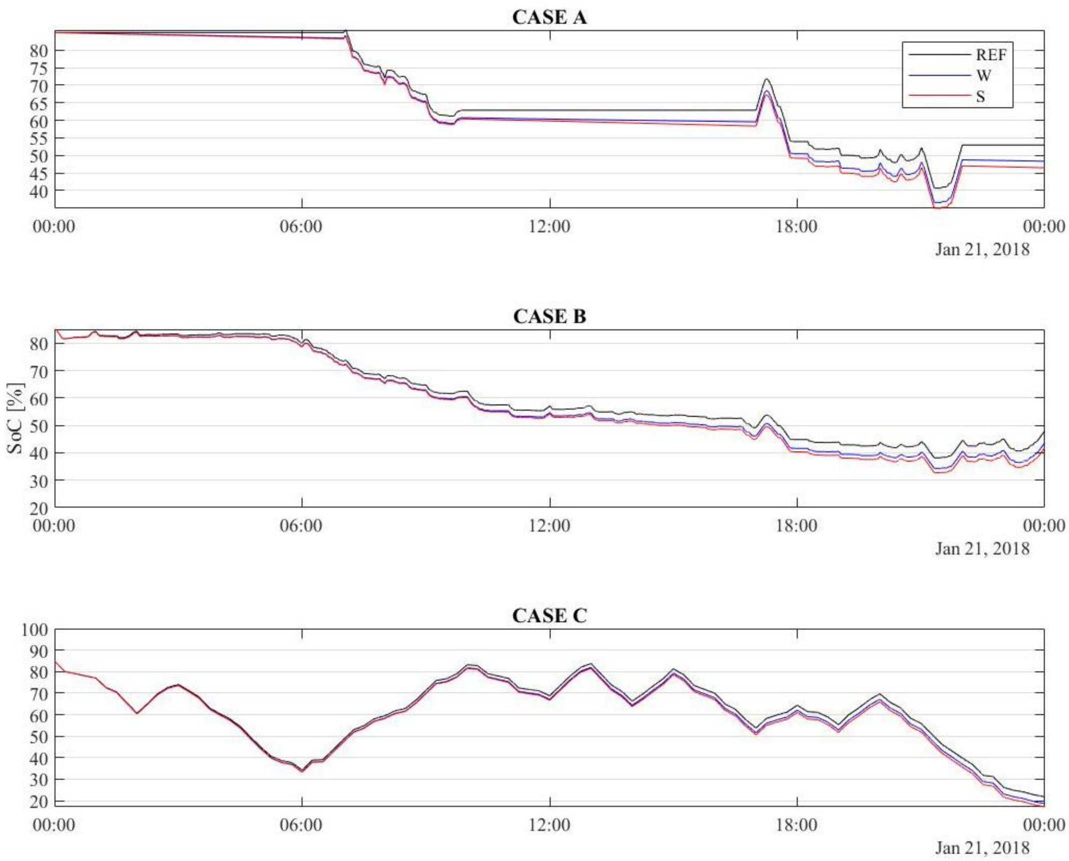


Figure 4.24 SoC trend for 24 hours of simulation of CASE A (top), CASE B (mid) and CASE C (bottom).

In Figure 4.25, η_{RT} and share of losses are shown. Operational efficiency is always greater than 80%. Scenario REF can be used to compare the performance of a standard numerical model similar to the ones nowadays used in literature. For REF scenarios, share of losses is 100% on internal losses. As can be seen, the distance between REF and the other scenarios in terms of efficiency is larger for services that have lower MWh/MW/day index. The bias caused by disregarding auxiliaries can lead to optimistic expectation of efficiency and to errors up to 10% in an optimistic way (see (A REF vs A S). This result is obtained modeling in the same way, the same battery, only disregarding the auxiliaries. Auxiliaries are responsible for more than half of the losses in CASE A and B. The share of auxiliary losses increases in summer. BESS better performs when the power absorbed/injected is higher. This is shown by the general higher efficiency of CASE C. Indeed, BESS efficiency is usually good even at high power, and auxiliary losses weight is by far lower.

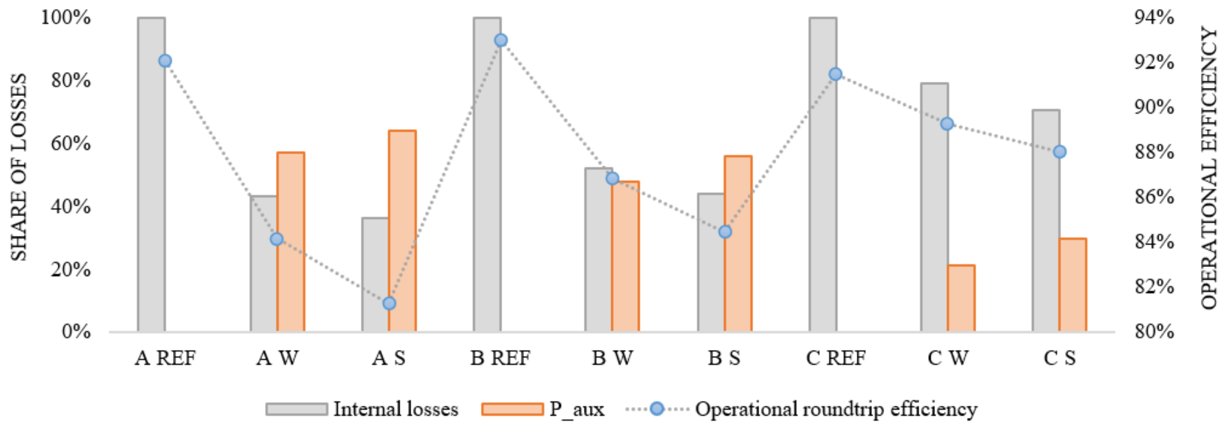


Figure 4.25 Share of losses and operational efficiency (η_{RT}) in the 9 case studies

The main takeaways can be summarized as follows. Achieving a larger accuracy while modelling the electrochemical section of the battery can be insufficient to correctly simulate the BESS operation. Indeed, for the same model, under some operating conditions, disregarding the auxiliary systems leads to errors in SoC estimation up to 10% (5% average error in the performed simulations). Therefore, since the gap between the real battery (only considering battery pack and PCS) and the previously presented model are in the range 1-3% (see Table 4.10), the auxiliary system model represents a fundamental part of the tool. On the other hand, some hints on the BESS management can be gathered. Indeed, the battery performance increases in case the battery flows more energy every day. Operational efficiencies are up to 7% larger in CASE C S (last point in Figure 4.25) than in CASE A S (third point in Figure 4.25). Some services are, anyway, requesting only a limited activation for the provider (e.g., power intensive services such as Fast Reserve in Italy, introduced in Paragraph 3.4.1.1). If this is the case, the possibility of providing more than one service with the same asset should be evaluated.

4.5 Conclusions

The Chapter presented the development, validation, and verification of an experimental BESS model. In addition, a detailed study on the importance of modelling auxiliary systems is proposed. The purpose of the numerical model is analyzing, for research and commercial purposes, the operation of BESS during the provision of services to networks in a grid-tie configuration. The possible services include, but are not limited to, ancillary services, energy arbitrage, and integration of RES in the electricity markets. Therefore, a good degree of accuracy is requested. At the same time, the proposed procedure aims at improving the efficiency—in terms of time and equipment—of the required experimental campaign. Some limitations or approximations are accepted in order to provide a procedure applicable by the BESS operator with reasonable timing and effort. Furthermore, the model offers a trade-off between precision of the estimation and limited computational effort. This latter point is of primarily importance when considering testing over long periods or in the case of serial testing of control strategies. The errors recorded during the verification & validation processes were always below 5% for a 24-hour test. The authors consider this result acceptable for the purposes foreseen and in line with examples from literature, mainly featuring equivalent circuit models (ECMs). Accuracy around 98% is shown by the model both in terms of SOC and energy flows estimations while validating it on frequency regulation provision. Usually, model accuracy is tested on standard charge/discharge cycles. This could hinder the investigation of BESS behavior in real-world operation—this issue is overcome with the approach proposed in this paper, with a strong validation campaign featuring frequency regulation provision. The high accuracy in SOC estimation during grid-connected operation is achieved by an empirical model with a low degree of complexity. The battery is characterized by two main parameters (efficiency and capability curve). This kind of model requires a simulating time that can be 20–50 times smaller than the simulating time for ECMs. In addition, this model encompasses the complexity of the BESS: the auxiliaries' power demand is modeled as a function of ambient temperature and power requested to the battery. This is an innovation for BESS modeling, since auxiliaries are poorly mentioned in scientific publications, as highlighted by [187]. Due to the previously mentioned characteristics, the model is suitable for being proposed to asset owners, electricity market players or institutions (e.g., TSOs or Regulatory Authorities) to estimate the performance and reliability of BESS providing ancillary services.

During the experimental campaign, issues deriving from the use of proprietary algorithms such as SOC estimation and safe operating area implementation by BMS were met. This led to some uncertainties when describing the battery operation at very high or very low SOC (0%–2%; 97%–100%).

Some case studies focused on the thermal management of large-scale stationary BESS, showing that larger operational efficiencies are obtained when the battery is constantly exploited, avoiding idle periods. Instead, if the service shows a lower energy demand per period (MWh/MW/period), then the weight of auxiliary systems' power demand overcomes all other kinds of losses (up to 65% of losses coming from auxiliary systems for a Li-ion BESS). The outcomes of the study highlighted high operational roundtrip efficiencies of the BESS: between 80 and 90% during provision of frequency regulation. Higher efficiencies can be estimated in case of disregarding the weight of losses related to auxiliary systems. This can lead to mistakes of up to 10%.

As of now, the performed simulations were shorter or equal to 40 hours. They were also studied to avoid SoC saturation at lower or upper limits (0 and 100%), to always be able to provide the requested power setpoints, both charging and discharging.

In general, it is not easy to keep the battery within SoC thresholds: the finite energy content is a potential issue. This is highlighted by Network Codes and Regulation, that specify requirements on energy, in addition to power, when dealing with services provided by Limited Energy Reservoirs (LERs) [62], [240]. For instance, a minimum activation time for the provision of a service must be established. Besides, the possibility of exchanging energy from/to BESS to restore the energy content must be guaranteed by the rules of the service provision. This can imply additional energy flows and costs for the BESS operator. Also, restoring the SoC towards a SoC target requires a non-trivial SoC management. Chapter 5 describes the regulatory opportunity to manage the energy content of an energy storage system providing ancillary services and compares different SoC management strategies in terms of economics and effectiveness (i.e., reliability).

CHAPTER 5

The finite energy content: a potential issue on markets

Abstract

The operation of Energy Storage Systems (ESS) does not only depend on the delivered power, but also on the requested energy. Indeed, the energy content of ESS is finite and to guarantee a high reliability in services provision, it must not be depleted. An eventual depletion or saturation would result in the impossibility of delivering or absorbing power. This would directly reflect on the reliability in the services provision. Two main categories of strategies are recognized for managing the energy content, thus the state-of-charge (SoC). Explicit SoC management is the restoration of SoC towards a target by exploiting dedicated energy flows. These require from regulation Degrees of Freedom (DoF) in the services provision, to superimpose to the provided power, the additional power flows for the management. Implicit SoC management is the restoration via the provision of a secondary grid service suitable to this. Explicit SoC management are analyzed in this Chapter. After an introduction on the effects of energy on the BESS operation, the change in the regulation and the DoF are described, starting from real world situations. Then, a detailed techno-economic analysis compares the explicit SoC management strategies. The main results are in terms of reliability in the provision of a frequency service, additional dedicated energy flows, and economics. The economics get worse in case of a SoC management strategy that requires large, dedicated energy flows to restore SoC. The outcomes and the highlighted limitations make necessary to analyze implicit SoC management, too. Indeed, Chapter 6 presents implicit SoC management via multiple services provision.

5.1 Introduction

The operation of BESS must consider the energy demand, in addition to the power demand. Indeed, BESS are Limited Energy Reservoirs (LERs) as per the definition of the European regulation [62]. The set of mechanisms for restoring the SoC towards a target are usually referred to as SoC management strategies, or energy management strategies [241]. SoC management strategies can be operated only in case they are allowed by the system, usually via degrees of freedom (DoF) guaranteed during asset operation [242]. The implementation of control strategies compatible with the DoF is presented in [243] and [244], both focusing on the UK regulatory framework for Enhanced Frequency Response (EFR). The first study assesses the SoC evolution and the economic outcomes considering two days of EFR provision. The battery and PCS models feature constant efficiency. The latter study provides a sensitivity analysis on a control strategy based on reinforcement learning. The results are provided with respect to a single frequency event and to a weekly simulation. The study [36] considers the utilization of multiple DoF from the German regulatory framework for improving the service provision over one month. The analysis if focused on the SoC distribution with the adopted strategy. The adopted model has a constant efficiency for battery and a variable efficiency for PCS. In [202], different strategies implementing one by one the DoF are compared. Only one strategy (adjustment of the power setpoint) proved to keep the non-performance of the service below 5%.

The proposed study extends on the comparative analysis just described to add some SoC management strategies exploiting more than one DoF and providing results by both the perspective of the system and of the market player.

5.2 The importance of regulating the change

The national Network Codes were developed in the 20th century, when only conventional generation – namely thermoelectric, hydroelectric and nuclear large-scale power plants – were connected to the power grid [158]. These large-scale generators guaranteed a large degree of reliability and took care of the electricity balancing. Also, the weight of the volumes (in MW) of the energy provision with respect to the grid services was of a different order of magnitude [52], [54]. Furthermore, the system was characterized by vertically integrated monopolists [246]. Nowadays, the power systems are liberalized in markets, where all the resources should compete for the generation and supply of energy and services [61]. In addition, the power system architecture is largely distributed, with many DERs entering the markets. Many of the new resources are variable RES: this increases the aleatory behavior of the power system, possibly rising the weight of the ASM with respect to the energy markets (see Paragraph 2.3.3 and Chapter 3).

All considered, the Network Code could need an update, to better exploit the capability of the new resources and avoiding disregarding some of their peculiarities, especially for what concerns ancillary services [37]. This could lead to an effective use and integration of all the technologies, to avoid technology discrimination on the markets and to better welcome the energy transition. If this is true, generally, for all DERs, it becomes apparent for BESS. Given the limited energy content they present, it becomes of utmost importance that the regulation establishes, in addition to power requirements, the energy requirements for each service or market. This has a direct impact on the required design of assets, and therefore on the economic attractiveness of an investment in BESS for grid-connected applications (bearing in mind that the BESS is a CAPEX-intensive asset, and that the CAPEX is mostly related to the nominal energy).

The update of network codes, in the form of pilot or permanent regulations, has already begun. At the national level, the German example can be presented. The regulation for the FCR or primary frequency regulation implements from 2015 a dedicated rule for BESS providing that service. It concerns the available energy reserve in the BESS that must be guaranteed for the entire tendering period, whenever the grid frequency is in the normal range. The BESS must be able to provide the entire amount of prequalified reserve power in both the positive and negative directions for at least 30-min: this is referred to as the 30-min criterion. This requirement comes from the System Operation Guidelines, that allow (art. 156) each Member State to define the preferred minimum time of full activation to be guaranteed by FCR providers with Limited Energy Reservoirs, within a maximum value of 30 minutes and a minimum of 15 [62]. The 30-min and 15-min SoC ranges are presented in Figure 5.1. They are estimated based on the following equation.

$$SoC_{lo} = \frac{P_{qual} * t_{min}}{E_n} \tag{5.1}$$

$$SoC_{hi} = 100 - \frac{P_{qual} * t_{min}}{E_n} \tag{5.2}$$

where SoC_{lo} and SoC_{hi} are the lower and higher acceptable SoC, P_{qual} is the qualified power in MW, t_{min} is the minimum full activation time in hours, E_n is the nominal energy in MWh, 100 is the maximum available SoC for the battery and 0 is the minimum.

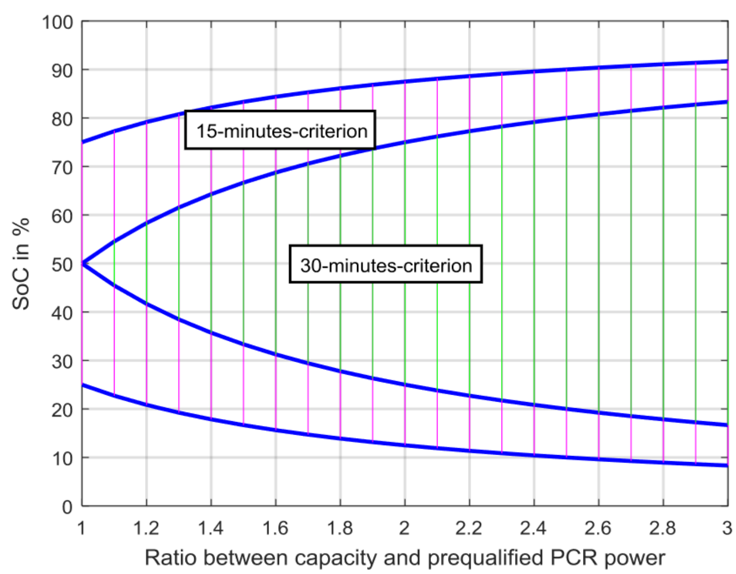


Figure 5.1 The 30 and 15-min criteria, with the BESS design on the x-axis, and the range of acceptable SoC on the y-axis [160].

Clearly, the suitable SoC range for guaranteeing the requested availability increases either for BESS whose ratio between capacity and power qualified to the service is larger or for lower minimum time adopted. For instance, considering the 30-min period, for the provision of FCR in symmetric mode (see Paragraph 3.3 for the definition of symmetric provision), a battery of 1

MW/1 MWh could only qualify 0.5 MW of FCR and provide it between 25 and 75% of SoC. The same battery could qualify 1 MW and operate between the same 25-75% SoC range in case 15-min criterion is applied. Doubling the battery capacity, a battery with 1 MW/2 MWh could either qualify 2 MW of FCR or qualify 1 MW and operate between 12.5% and 87.5% of SoC with 15-min criterion. It must bid less than 2 MW in case of 30-min criterion.

There requirements are posed for increasing the reliability of LER but, as seen, they have a direct implication on the ESS sizing [247]. Indeed, the n-minutes criteria imply that each BESS operator install some capacity that is not used for services provision but that is just available as a buffer, to prevent service interruption (e.g., the energy from 0 to 25% and to 75 to 100% of SoC of a 1 MW/1 MWh battery). Hence, the energy and SoC requirements have a direct influence on the operation and economics of the ESS.

To support national requirements for FCR in terms of minimum activation time (between 15 and 30 minutes), the System Operation Guidelines requested the ENTSO-E to develop a methodology for a cost-benefit analysis (CBA) to establish in an optimal way the minimum time for which the full-activation of FCR must be always guaranteed by LERs [240]. This CBA considers both the investment cost of the BESS operators and the system costs due to a possible depletion of LERs providing FCR. The optimal time (in minutes) should be the one minimizing both the costs: this means, requesting the LERs a decent degree of reliability, but avoiding over-estimating the energy content to avoid making the investment in energy storage largely unattractive.

Disregarding the peculiarities of energy storage systems can lead to detrimental consequences on the reliability of these systems. Instead, to exploit their fast response and precision, implementing rules that allow energy content management and avoid enhancing the sizing requirements for BESS providing services could be effective. One example, that is detailed in the following, are the Degrees of Freedom in the provision of FCR.

5.3 The Degrees of Freedom

Historically, the production units (PU) operating on the ancillary services markets (ASM) were only concerned about power requirements. Indeed, delivering the contracted power for a longer or shorter period is not an issue for a thermal generator. Grid codes were written bearing in mind these PUs. Therefore, for instance, FCR in European markets must be delivered continuously during the contracted period and for a minimum time at full activation (Article 156 of System Operation Guidelines) [62]. This is a problem for an asset featuring a LER (such as a battery): when it is completely charged or discharged, it can no longer provide a symmetric service (in both the directions of injection and withdrawal from grid) and faces penalties (that can even lead to exclusion from the market). Therefore, on the one hand, ENTSO-E defined the n-minutes criteria just discussed. The 15 to 30-min criteria are adopted by TSOs to cope with the greatest frequency perturbations. However, even considering the higher frequency deviation occurred in Continental Europe during the last years [248], frequency was restored in less than 8 min. Since full activation of FCR occurs only at very high frequency deviations, the time elapsed at a deviation equal to or greater than the one required for full activation of provision is even lower: these are the minutes of actual full activation requested by the harshest events in recent history, less than a half the minimum requirement.

On the other hand, some national TSOs identify some degrees of freedom (DoF) allowing for BESSs state-of-charge (SoC) management. For instance, these include:

- the possibility of varying the power setpoint within a range while frequency is in the dead-band (dead-band strategy);
- the possibility of over-under regulate;
- the possibility of superimposing a setpoint to the regulation when SoC gets closer to the thresholds;
- the possibility of trading (and exchanging) energy on other real-time markets while providing the service;
- the possibility of temporarily interrupting the provision of the service with no penalties.

In the UK, Enhanced Frequency Response (EFR) regulation sets a dead-band in which BESS can be freely operated with a power setpoint within a ±9% range with respect to the contracted power. In other words, while in dead-band the maximum export/import power must not exceed 9% of the BESS contracted power [74], this way EFR allows the development of a dead-band strategy for SoC management. In addition to the dead-band, a so-called envelope provides flexibility in provision devoted to supporting SoC maintenance. In this envelope, over or under-regulation is permitted. Thus, operators can manage the battery SoC by increasing or decreasing the control power demand indicated by the power-frequency characteristic by a fraction of regulating power. So, in the case of low SoC and frequency above the nominal value (or vice versa), the battery can over-regulate to charge faster and get back to target SoC. The envelope is presented in Figure 5.2.

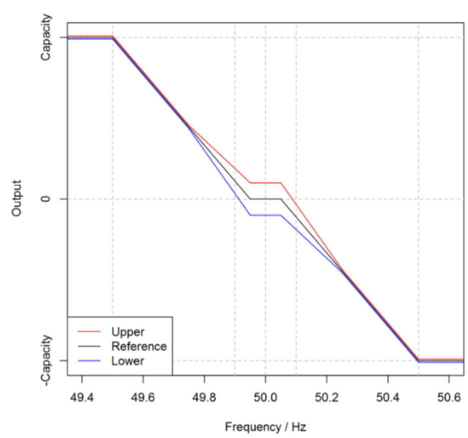


Figure 5.2 Enhanced Frequency Response envelope [162].

In Germany, several degrees of freedom (DoF) are allowed by the four German TSOs to keep the SoC within the permitted range [35]. As presented in Figure 5.3, in addition to the dead-band strategy, operators can: manage the battery SoC by providing over or under-regulation up to 20% of regulating power; trading energy on the electricity market and superimpose a setpoint to regulation; adjusting the gradient of the provided FCR power within certain boundaries.

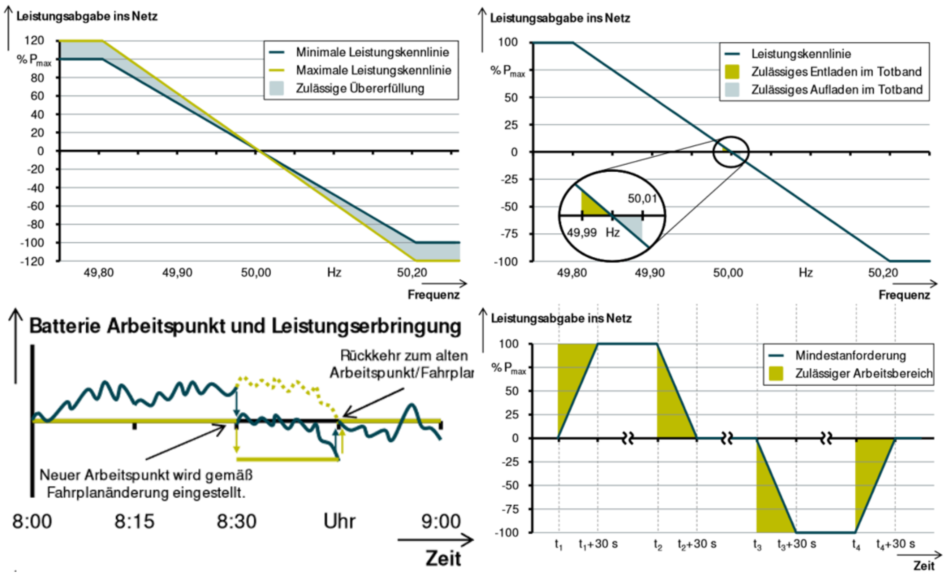


Figure 5.3 Degrees of freedom in German FCR: over-under regulation (top left), optional dead-band (top right), trading energy (bottom left), adjusting the response gradient (bottom right) [36].

In Italy, the UPI pilot project, which allows the use of BESSs integrated with conventional relevant units to provide FCR, is underway. During the provision of FCR, the SoC can be restored only by exchanging energy with the integrated programmable plant and not by exchanging energy with the grid [237]. In case SoC diverges, service provision must be interrupted and SoC restored.

In addition to what seen in the national regulations, a strategy compatible with the minimum full activation time foreseen by the System Operation guidelines could be the following. SoC management could operate when SoC gets above the SoC_{hi} or below the SoC_{lo}. In those cases, a setpoint for SoC management could be superimposed to the power requested for the service provision [202].

5.4 The explicit SoC management strategies

In general, the SoC must be kept as much as possible within the minimum and maximum thresholds to avoid hitting some limits posed by the BMS. Indeed, as previously described, the BMS keeps the battery within voltage thresholds. This translates, operatively, in a risk of power curtailment at SoC close to minimum (SoC_{min}) and maximum SoC (SoC_{max}), partial (capability chart) or total (SoC limits). In case of provision of grid services, the inability of respecting a power setpoint (e.g., a dispatch order) can lead to penalties. For instance, economic penalties include imbalances discipline, the non-performance penalties. Administrative penalties may exclude the provider from the service provision. A SoC management (or SoC restoration) strategy can be useful or necessary to keep the SoC closer to a target SoC and consequently far from power curtailment. Generally, target SoC can be:

- in the range of 50%, in case the service is a two-way service, that requires both upward (discharge) and downward (charge) provision;
- SoC_{max} (e.g., 100%), in case the service is one-way, only upward;
- SoC_{min} (e.g., 0%), in downward-only case.

In explicit SoC management, the dedicated energy flow is usually paid by the asset operator on the electricity market in several forms (e.g., day-ahead or intraday market, imbalance discipline). Different strategies can be recognized based on the method and time slot in which the energy is exchanged. The most common strategies exploit one or more of the DoF previously illustrated.

5.4.1 No DoF: SoC management with service interruption

Conventional ancillary services barely feature DoF to the droop curve shown in Figure 2.6. There is no need for conventional generators to exchange energy with the grid during the provision of the service to restore their energy content, since it is not limited. In case the regulation does not foresee any DoF, it usually inhibits the resource from the provision in the case of inadequacy (e.g., in the case of inadequacy of the available energy content). In the case of no DoF, the SoC management strategy can be implemented when the available energy content of BESS is inadequate. Maximum and minimum thresholds are implemented on SoC: above the first (e.g., 95%) and below the latter (e.g., 5%) service is stopped and SoC management towards target SoC (SoC_{target}) begins. Power for SoC management (P_{mgmt}) in the case of No DoF is generally high: indeed, all the power requested when service provision is interrupted is considered non-performance (NP). When SoC_{target} is reached, service provision restarts. The process is presented in Figure 5.4. Time is on the x-axis. In diagram (a) SoC evolution is presented; in (b), power requested for FCR before, during and after the service interruption can be seen; in (c), the power for SoC management is shown. Positive power means discharge. Red trend highlights that all the power requested while service is interrupted results in non-performance (NP): it is generally considered for NP penalty (NPP). Power is expressed per unit with respect to the nominal power of the battery.

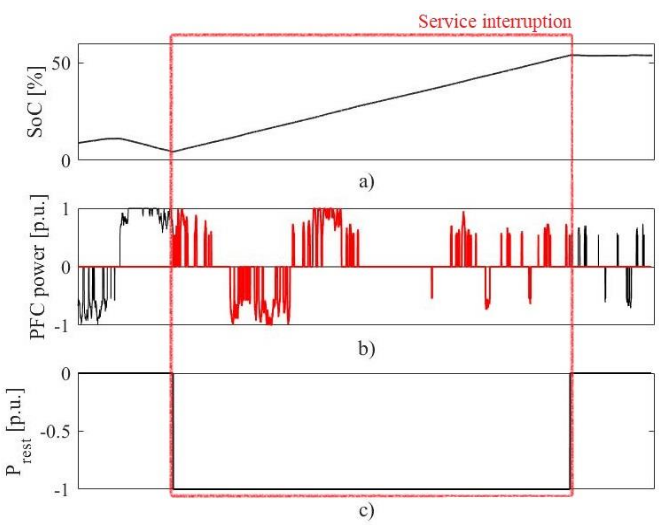


Figure 5.4 Schematization of SoC management strategy in case of no DoF

5.4.2 Over-under regulation exploitation

Some innovative frequency regulation schemes allow over or under-regulation as a DoF. In such a case, the droop D is no more a single value but an interval of values [D_{min}, D_{max}]. This means that the droop curve shown in Figure 2.6 is modified as depicted in Figure 5.5. The over/under-regulation admits different dP for the same dF within the pink area. dP that can be applied is in the following interval.

$$(dF/F_n) \times (P_n/D_{max}) \times 100 \le dP \le (dF/F_n) \times (P_n/D_{min}) \times 100 \tag{5.3}$$

where D_{min} is the minimum droop and therefore the steeper regulation, while D_{max} is the larger droop corresponding with the softer regulation. The flexibility offered by the variable droop in the pink area can be exploited to restore the SoC without incurring in NPP. Full activation dF varies between a minimum and maximum value. As previously described, this scheme is partially implemented, for instance, in one of the DoF for provision of FCR in Germany. Actually, that scheme only allows for over-regulation. Furthermore, in that scheme full activation varies between 100% and 120% of the contracted power, as can be seen in Figure 5.3.

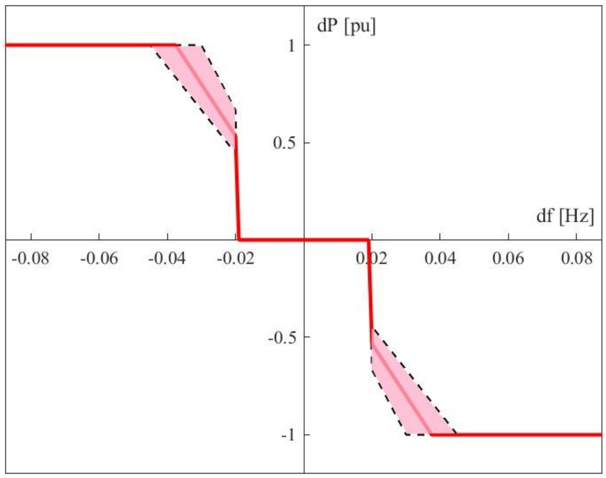


Figure 5.5 The variable droop that could be adopted in over/under-regulation schemes.

5.4.3 Dead-band strategy

When the frequency is in its dead-band, FCR does not require any dP. This circumstance is less critical for frequency control regulation in general. Thus, it is exploited in several control services [230] to allow SoC management. In this case, the DoF is represented as a share of regulating power that can be offset for charging and discharging while frequency is in its dead-band. An offset ratio (R_{offset}) is indicated as a maximum percentage of the regulating power: e.g., the Fast Reserve pilot project in Italy allows the SoC management exploiting 25% of the regulating power. Therefore, P_{mgmt} is computed as in Equation (5.4).

$$\begin{cases} P_{mgmt} = sgn(\Delta SoC) * R_{offset} * P_{nom} & \text{if } |dF| \le dF_{DB} \wedge |\Delta SoC| > \varepsilon \\ P_{mgmt} = 0 & \text{elsewhere} \end{cases} \tag{5.4}$$

where sgn(ΔSoC) is the signum function for $\Delta SoC = SoC(t) - SoC_{target}$ (positive power for SoC greater than SoC_{target}), dF_{DB} is the dead-band of ±20 mHz on frequency deviations and ε is a margin to depict an acceptable margin of tolerance on ΔSoC (a “dead-band” on SoC deviation). The resulting droop curve is shown in Figure 5.6, where the pink area represents the DoF in dead-band, therefore the range of offsets that can be adopted.

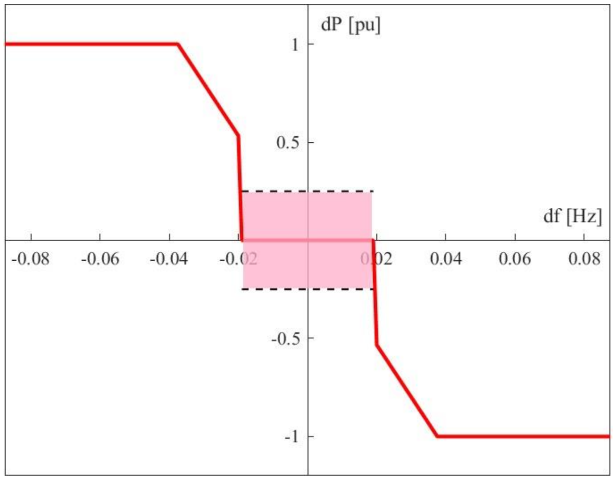


Figure 5.6 Droop curve for dead-band strategy.

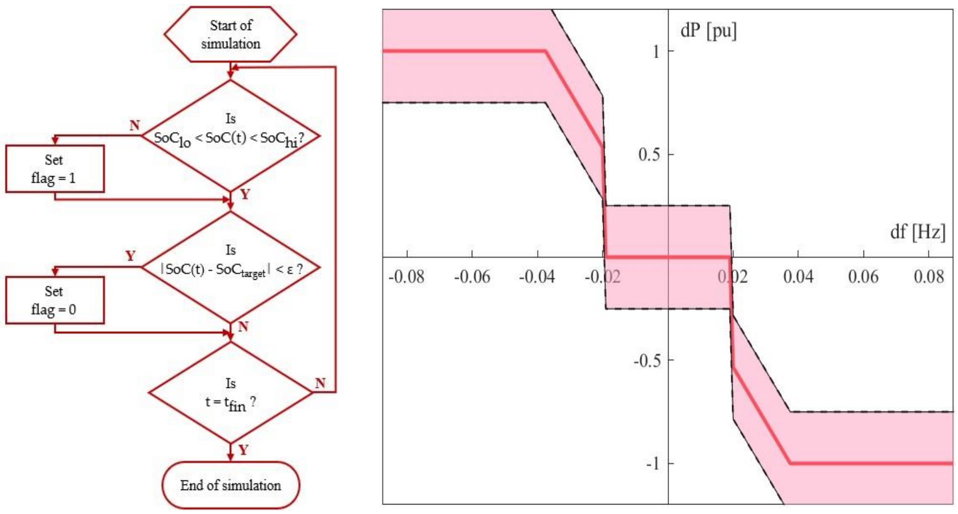
5.4.4 Available energy criteria

A further criterion for guaranteeing reliability in the case of devices with finite energy content is to require always a minimum amount of available energy (also in the form of equivalent available time at full activation). The available energy DoF implements the possibility of offsetting the delivery of service of R_{offset} times the regulating power, only if the available energy content approaches the minimum or maximum threshold and until the SoC is restored to SoC_{target}. In this time period, offsetting is admitted for every condition of frequency deviation. A requirement of wide use, as introduced in Paragraph 5.1, is that every device may always be available to provide 15 min of continuous full activation of the qualified power, both upward and downward: this is usually referred to as 15 equivalent minutes of available energy content. There is strong convergence towards this value since it relates to the contract durations for balancing products, the scheduling time for units and the imbalance settlement period in the EU [144], [249]. Other regulations adopt 30 min [36], [75]. Accurately establishing the required energy content is of utmost importance: a too low value can lead to frequent unavailability, while a too high value would imply larger capital costs for the providers, since the capital costs of a BESS are mainly related to its nominal energy.

In the case the SoC gets equal or greater than SoC_{hi}, the SoC management process is triggered and power requested to the battery (P_{req}) can be increased by R_{offset} multiplied by regulating power. This offset is kept until SoC_{target} is approached. On the other hand, for SoC equal to or lower than SoC_{lo}, power can be decreased to charge the battery. In this case, the offset remains until the battery reaches SoC_{target}. In the implementation of the algorithm, the activation of the offset depends on a flag variable whose role is shown in Equation (5.5) and whose use is described in Figure 5.7a.

$$\begin{cases} P_{req} = P_{FCR} + R_{offset} * P_{nom} & \text{if } SoC(t) \geq SoC_{target} \wedge \textit{flag} = 1 \\ P_{req} = P_{FCR} - R_{offset} * P_{nom} & \text{if } SoC(t) \leq SoC_{target} \wedge \textit{flag} = 1\,, \\ P_{req} = P_{FCR} & \text{elsewhere} \end{cases} \tag{5.5}$$

where P_{req} is the total power requested to the battery, composed by the contribution for FCR (P_{FCR}) and the power for management, and *flag* is the flag variable. The resulting droop curve is shown in Figure 5.7b. The red line is the reference droop curve without offset, to be kept while *flag* = 0. The DoF is represented by the pink area. Therefore, the pink area delimited by the black dashed lines represents the range of power setpoints that can be adopted in the case *flag* = 1. For a given dF, dP can vertically span within the pink zone between the black dashed lines. In the simulation, this is used to restore the SoC in the case of scarce or excessive energy content.



(**a**) (**b**)

Figure 5.7 The block diagram (a) and the droop curve, including the DoF area (b) of the available energy strategy.

5.4.5 Double threshold strategy

The latest explicit SoC management mechanism is a hybrid of the dead-band strategy and of the available energy strategy. The DoF that is exploited is the possibility of offsetting the P_{req} while the system frequency is in its dead-band. Therefore, the flag variable is triggered when SoC gets outside the interval [SoC_{lo}, SoC_{hi}] and stays on until SoC approaches SoC_{target}. In any case, the management process can only occur when the frequency is inside the dead-band. This is called the double threshold strategy. Therefore, both the conditions expressed in Equation (5.4) and (5.5) and (7) are reworked and result in Equation (5.6), that depicts the mechanism.

$$\begin{cases} P_{req} = P_{FCR} + R_{offset} * P_{nom} & \text{if } SoC(t) \geq SoC_{target} \wedge flag = 1 \wedge |dF| \leq dF_{DB} \\ P_{req} = P_{FCR} - R_{offset} * P_{nom} & \text{if } SoC(t) \leq SoC_{target} \wedge flag = 1 \wedge |dF| \leq dF_{DB}\ . \\ P_{req} = P_{FCR} & \text{elsewhere} \end{cases} \tag{5.6}$$

The resulting droop control curve with the exploitable DoF is the same as shown in Figure 5.6 for the dead-band strategy. The double threshold concept, thus the domain in terms of SoC and dF where the DoF can be exploited, is described in Figure 5.8.

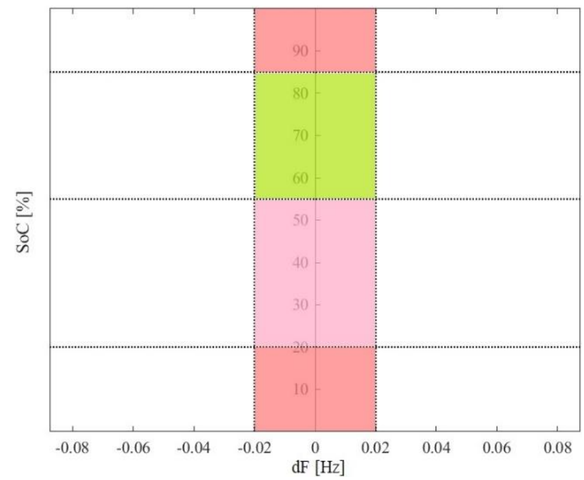


Figure 5.8 The double threshold domain for SoC management. The red area identifies the condition of (dF, SoC) for triggering the *flag* variable and starting SoC management. When the *flag* = 1, the pink area is where the offsetting can be exploited for charging towards SoC_{target}. The green area shows where P_{req} can offset to discharge.

5.5 A comparative evaluation of SoC management strategies

The previously described mechanisms are present in the regulation, and they can be considered the state-of-the-art for SoC management within ancillary services traded on market. To evaluate the effectiveness of each mechanism in overcoming the finite energy content issue and increasing BESS reliability, a comparative techno-economic evaluation is proposed in the following, exploiting the developed BESS model illustrated in Chapter 4. As described there, it is implemented in a Matlab Simulink tool for serial simulations. The model is fed by network frequency data. For this study, a proper Controller (see Paragraph 4.3.4.1) is developed within the Simulink tool. Two main blocks compose the Controller. The FCR controller block transforms frequency trends in power setpoints requested to BESS via the droop control curve based on the standard equation presented in Equation (2.1). The curve features a dF dead-band inside which dP requested is equal to 0 and a full activation dF over which the dP requested is equal to P_n. In the framework of the study, D = 0.075%. The relevant data for the curve can be seen in Table 5.1. The curve is the same shown in Figure 2.6.

Table 5.1 Droop curve data

Droop Value (D)	0.075%
Dead-band dF [mHz]	±20
Full activation dF [mHz]	±37.5

Besides the FCR controller, another block implements the SoC management strategy. It uses the same equations shown in Section 5.4. The power requested by FCR provision (P_{FCR}) and the one required for SoC management (P_{mgmt}) are summed up and represent the power setpoint demanded to the BESS (P_{req}).

$$P_{req} = P_{FCR} + P_{mgmt}. \tag{5.7}$$

The BESS model updates the power setpoint consistently with efficiency and capability charts, and consequently updates SoC value for each second of the analyzed year. The outcomes of the model are the SoC trend, the power and energy flows requested and actually flowing in the battery, the share of energy flows for FCR provision and for SoC management. The simplified block diagram of the BESS model is proposed in Figure 5.9.

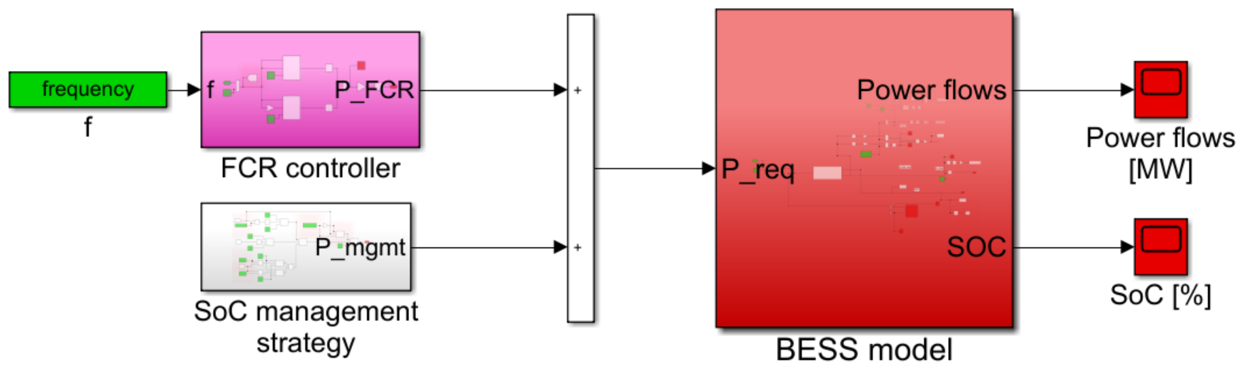


Figure 5.9 Simplified block diagram of the Simulink tool for the FCR provided by BESS.

A set of simulations provide the FCR on the same frequency trend (see Figure 5.10) and on the same Li-ion BESS, whose main sizing data are reported in Table 5.2. It is dimensioned as the battery studied in JRC (see Paragraph 4.3.1). Frequency data are from system frequency in Continental Europe Synchronous Area (CESA) for the year 2016, with 1 s sampling rate and a resolution of 0.1 mHz. Furthermore, data about the SoC management strategies are reported in Table 5.2. Given the steep droop curve used in this study (full activation at 37.5 mHz of absolute deviation), a 30-min threshold is adopted for the SoC management strategies including SoC thresholds. This corresponds, for the given BESS (E/P of 2.28 h), to the approximated SoC thresholds reported Table 5.2. These thresholds take into account the effect of BESS efficiency.

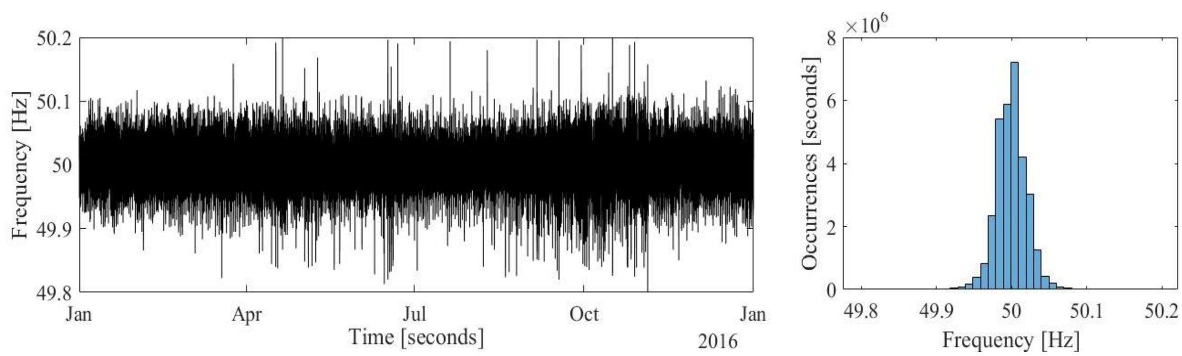


Figure 5.10 Yearly trend and histogram of frequency data used for simulation.

Table 5.2 BESS size and operation details for the simulations.

Key	Abbreviation	Value
Technology	-	Li-ion NMC
Nominal power (MW)	P_n	10
Nominal energy (MWh)	E_n	22.8
Energy-to-power ratio (h)	E/P	2.28
Maximum SoC (%)	SoC_{max}	100
Minimum SoC (%)	SoC_{min}	0
SoC target (%)	SoC_{target}	55
SoC management upper threshold (%)	SoC_{hi}	85

SoC management lower threshold (%)	SoC_{lo}	20
Full activation power for FCR (MW)	P_{fa}	1 (100% P_n)
Offset ratio for SoC management (with respect to P_{fa})	R_{offset}	25%
Air conditioning setpoint temperature (°C)	T_{in}	20

The regulating power for FCR provision is equal to the nominal power of BESS. The difference between the simulations only relates to the SoC management mechanism in place. Each SoC management mechanism is suitable for exploiting different DoF, and therefore, it could be possibly applied in different regulatory frameworks. The SoC management strategies tested are the same illustrated in Section 5.4, plus a Base case that does not implement any strategy. They are listed here below for the sake of simplicity.

- The **Base case** implements no SoC management strategy. FCR only is provided, and in case the SoC or power limits are hit, power is curtailed.
- The **No DoF case (NoDoF)** implements the SoC management strategy based on the interruption in service provision illustrated in Paragraph 5.4.1, with the minimum SoC for service interruption equal to 3% and the maximum equal to 97% and the P_{mgmt} = 100% of full-activation power (P_{fa}).
- The **Over/Under-regulation case (O/U)** implements the SoC management strategy based on variable droop, described in Paragraph 5.4.2, with D_{min} = 0.060% and D_{max} = 0.090%.
- The **Dead-band case (DB)** implements the SoC management strategy based on dead-band strategy, described in Paragraph 5.4.3, with R_{offset} = 25%, and therefore P_{mgmt} = 100% P_{fa}.
- **Available energy case (AE)** implements the SoC management strategy based on offsetting the regulating power when SoC is outside a window of acceptability [SoC_{lo}, SoC_{hi}] as shown in Paragraph 5.4.4, with R_{offset} = 25%, and therefore P_{mgmt} = 100% P_{fa}.
- The **Double threshold case (DT)** implements the SoC management strategy based on offsetting the regulation when SoC is outside the window of acceptability [SoC_{lo}, SoC_{hi}] and dF is inside dead-band, as illustrated in Paragraph 5.4.5, with R_{offset} = 25%, and therefore P_{mgmt} = 100% P_{fa}.

This set of explicit strategies presented are designed to be as coherent as possible with the ones adopted in the European experiences already mentioned. Except for the Base case, the other simulations feature a SoC management strategy conveniently exploiting the DoF that we assume are granted by the regulation. SoC management aims to bring back SoC towards a SoC_{target} equal to 55%. SoC_{target} is selected based on the assumption of symmetric provision of reserves for FCR: at SoC_{target}, indeed, energy content available (net of the efficiency) is approximately equal for upward and downward reserve.

$$(SoC_{target} - SoC_{min}) \times \eta_{avg} \cong (SoC_{max} - SoC_{target})/\eta_{avg}, \tag{5.8}$$

where SoC_{min} is the minimum SoC of the battery, η_{avg} is the average efficiency of the battery equal to 92%, based on the study developed on JRC's BESS [218].

5.5.1 Methodology for techno-economic analysis

The results of the model are analyzed in terms of energy flows and associated revenue streams. The energy requested for FCR (E_{FCR}) is computed as the summation of the absolute value of P_{FCR} in time. The energy for SoC management is computed from P_{mgmt} both for charge (E_{ch}) and discharge (E_{dis}). The energy nonprovided (E_{NP}), relevant for the estimation of non-performance penalty (NPP), is computed by the model. NP occurs when the battery is not able to provide with accuracy the energy requested for the regulation. In case the error between P_{FCR} and the power actually delivered (P_{del}) by BESS overcomes 5%, then all the power requested by FCR for that instant is considered as nonprovided (P_{NP}).

$$\begin{cases} P_{NP} = P_{FCR} & \text{if } |P_{req} - P_{del}|/P_{req} > 5\% \\ P_{NP} = 0 & \text{elsewhere} \end{cases}, \tag{5.9}$$

where P_{NP} is the non-provided power and E_{NP} is the summation of the absolute values of P_{NP}. NP is eventually E_{NP} expressed as a percentage of E_{FCR}. This index measures the reliability of the BESS as a provider of ancillary services. It represents the reliability on which the BSP is generally evaluated when providing services on the BM. The cash flows related to FCR provision, to SoC management and to NPP are computed valorizing the energy flows with the indexes reported in Table 5.3, mainly referred to the Italian market, except for FCR remuneration which is referred to the German market (in €/MW/week). However, according to [251], also in Italy FCR could be remunerated by means of availability payments in €/MW/week in the near future. By now, the FCR provision in Italy is instead based on an obligation. 2008-2016 prices were selected for German FCR, before the drop in prices occurred from 2018 and presented in Paragraph 3.4.3.1: this is to consider Italian market as less mature than German one. The energy necessary to charge BESS for SoC management is valued at the yearly average purchase price in the Italian DAM, whereas the discharging energy at the yearly average positive imbalance price. NPP is valued at the average yearly marginal price in the Italian BM (to date, NPP for FCR is not defined in Italy, since FCR is mandatory). The selected parameters aim to be representative of the current situation and possible evolution in Continental Europe.

Table 5.3 Economic indicators adopted in the study.

Cash Flow	Name	Value	Unit	Source	Notes
FCR remuneration	R_{FCR}	3310	€/MW/week	[252]	German scheme with capacity remuneration, likely to be adopted in Italy. Average price (2008–2016).
Charging cost	C_{ch}	−53.95	€/MWh	[253]	PUN (2017).
Discharging remuneration	R_{dis}	25.00	€/MWh	[254]	Average positive imbalance price (2017).
NPP	NPP	−140.00	€/MWh	[254]	For both upward and downward reserve a severe penalty applied, coherent with upward marginal prices on BM (2017).

The SoC management strategies allowed by the DoFs influence the return of the investment on BESS, too. To give a figure of this, the internal rate of return (IRR) for the investment at 5 y is computed as follows.

$$NPV = CAPEX + \sum_{i}^{N} \frac{NCF}{(1+IRR)^{i}} + \frac{RV}{(1+IRR)^{N}} = 0, \tag{5.10}$$

$$CAPEX = k_e \times E_n + k_p \times (P_n - E_n), \tag{5.11}$$

$$NCF = R_{FCR} + C_{ch} + R_{dis} + NPP, \tag{5.12}$$

where CAPEX is the cost investment for the BESS, based on the size of BESS and parameterized over k_e = 400 k€/MWh and k_p = 150 k€/MW [255]; N is the time horizon for the investment, set at 5 years; NCF is the net cash flow as the sum of the previously described revenue and cost streams (see Equation (5.12) and Table 5.3); RV is the residual value of the asset at the end of year N computed as in Equation (5.13).

$$RV = CAPEX \times (t_{EoL} - (N + 1))/t_{EoL}, \tag{5.13}$$

where t_{EoL} is the expected end of life (EoL) in years, hypothesizing linear RV decay with time. To estimate battery life, a SoH model was developed based on [256]. The SoH model considers both cycle aging and calendar aging in terms of capacity fade. SoH at EoL is 80% of SoH at Beginning of Life (BoL): since the model estimates capacity fade, EoL energy capacity is 80% of nominal energy (BoL). The yearly capacity decay due to cycle aging (C_{cy}) is computed as the summation of capacity decay in each step ($C_{cy}(t)$). This is the product of the equivalent cycle (cy) and cycle decay factor (cf) per each step t of the simulation.

$$cy(k) = |SoC(t) - SoC(k - 1)|/2, \tag{5.14}$$

$$C_{cy}(k) = cy(t) \times cf(t), \tag{5.15}$$

$$C_{cy} = \sum_{t}^{Y} C_{cy}(t), \tag{5.16}$$

where cf is a function of the operating conditions, and in particular of c-rate at step k as detailed in [256]; Y is the number of seconds per year. Yearly calendar aging (C_{cal}) is estimated based on capacity decay due to ambient conditions, in particular of the container indoor setpoint temperature T_{in}, as shown in Equation (5.17). Literature shows a clear correlation between temperature and calendar life (t_{cal}) of batteries.

$$C_{cal} = 1/t_{cal}(T_{in}) \times (E_n - E_{EoL})/E_n, \tag{5.17}$$

where $t_{cal}(T_{in})$ is 16 y. This is based on [185], [257], systematically reviewed in [258] for Tin = 20°C. The SoH is estimated summing up the yearly capacity decays as in Equation (5.18).

$$SoH(j) = 1 - (C_{cy} - C_{cal}) \times j, \tag{5.18}$$

where j is the time from the beginning of operation in years. t_{EoL} is obtained by dividing the total decay over life by the yearly decay as in Equation (5.19).

$$t_{EoL} = (1 - SoH(EoL))/(1 - SoH(1)), \tag{5.19}$$

with SoH(EoL) = 80% and (1 − SoH(1)) as the yearly variation in SoH.

5.5.2 Results of the comparison

The following Paragraph presents the results of the study. The market data selected come from Italian (for DAM and imbalances discipline) and German market (for ASM), so to have references that can be generalized to the Continental Europe Synchronous Area (SA). The adoption of Continental Europe SA's frequency decreases the applicability of these results to systems with less inertia and with larger frequency deviations, such as UK [101]. The adopted workstation features an Intel® Core™ i7-10510U CPU @ 1.80GHz, 2304 Mhz, 4 Cores, 8 Logical Processors. The approximate elapsed time is 1.5 hours per simulated year. The results of the simulations are provided in the following. We start detailing a sample of NoDoF case for better introducing what has been simulated. In Figure 5.11, the NoDoF case is described via four logs of 48 hours. The frequency log is presented in the top chart. The power for FCR is presented in the second top chart: positive power is delivered in case of underfrequency, and vice versa. As can be seen, the battery is idle in case the frequency is in the dead band. Just outside the dead band, a step power is provided due to the recovery of the dead band (see droop curve in Figure 2.6). The provided power then is dynamically following the frequency deviation up to full activation (1 p.u.). during the first half of the provision (left part of the diagram) the underfrequency is more recurrent than the overfrequency. Vice versa in the following period (right part). The second bottom chart shows the SoC management power. Positive power is delivered to discharge the battery in case the SoC hits the upper thresholds. In case the lower SoC limit is approached, negative power is delivered, to charge the battery towards SoC_{target}: when the underfrequency is more frequent, charging is more likely (left part), and vice vers. The bottom chart presents the SoC profiles consequent to the sum of FCR provision and SoC management power setpoints: SoC is restored towards 55%, either by charging (left part) or discharging (right part) the battery.

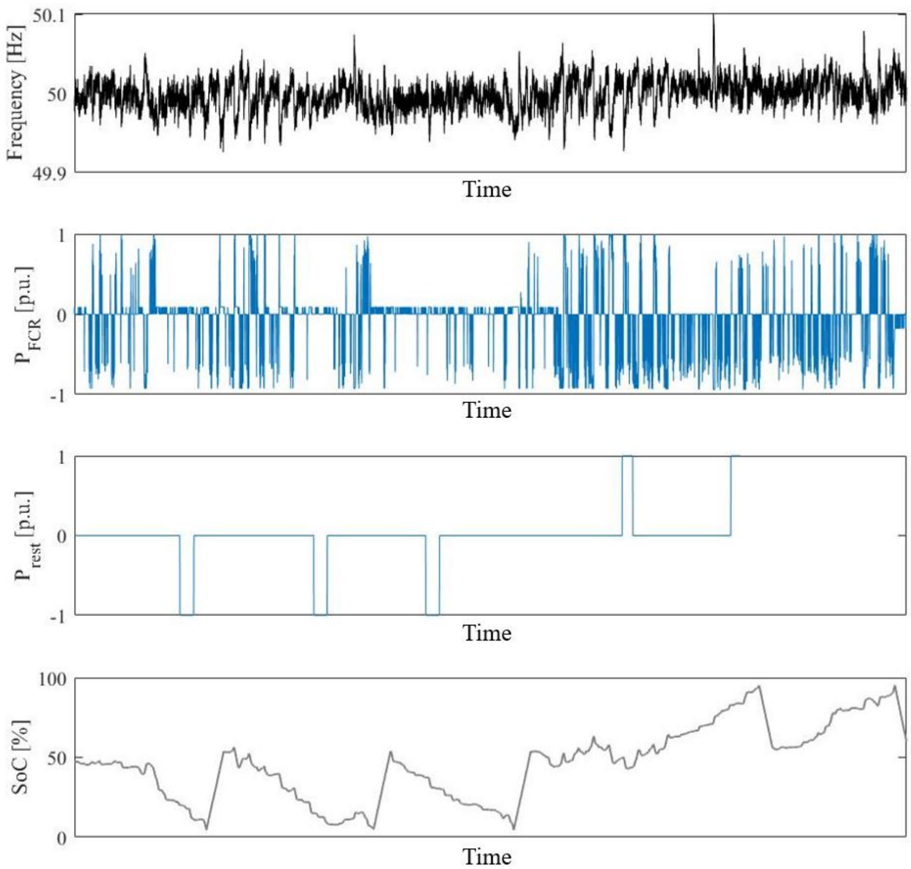


Figure 5.11 Frequency, power and SoC profiles for the NoDoF case

Now, let us compare visually all the stretegies. In Figure 5.12, the SoC profiles of the yearly simulations are shown. In addition, two events of some hours with SoC hitting the lower (see blue box of Figure 5.12) and upper thresholds (green box) are zoomed in. These can help better understanding how each strategy works. As can be seen, the Base case (in black) has no possibilities to get the SoC back on track in case of persistent frequency deviation in the same direction: indeed, no SoC management is implemented in the Base case. The NoDoF case (in grey) has the same behavior of the Base case up to the SoC limit (3 or 97%), then it shows a sudden path towards SoC_{target}: SoC is restored with the interruption of the service provision. O/U case (in brown) acts by decreasing the upward provision when the SoC is low, and vice versa. In any case, it is not capable to prevent saturation: the considered over/under regulation is not that effective for SoC management. DB strategy (in red) is usually really close to SoC_{target}, indeed the SoC is restored everytime the frequency is in the dead-band. This means, no matter how the SoC is already close to SoC_{target}, SoC management anyway starts. Nonetheless, the SoC saturates at 100% after an extended period of overfrequency (see green box in Figure 5.12). The AE and DT strategy have a similar path, with SoC restoring only when it departs from the SoC_{target}. For AE and DT case, saturation only occurs for a brief period (see green box).

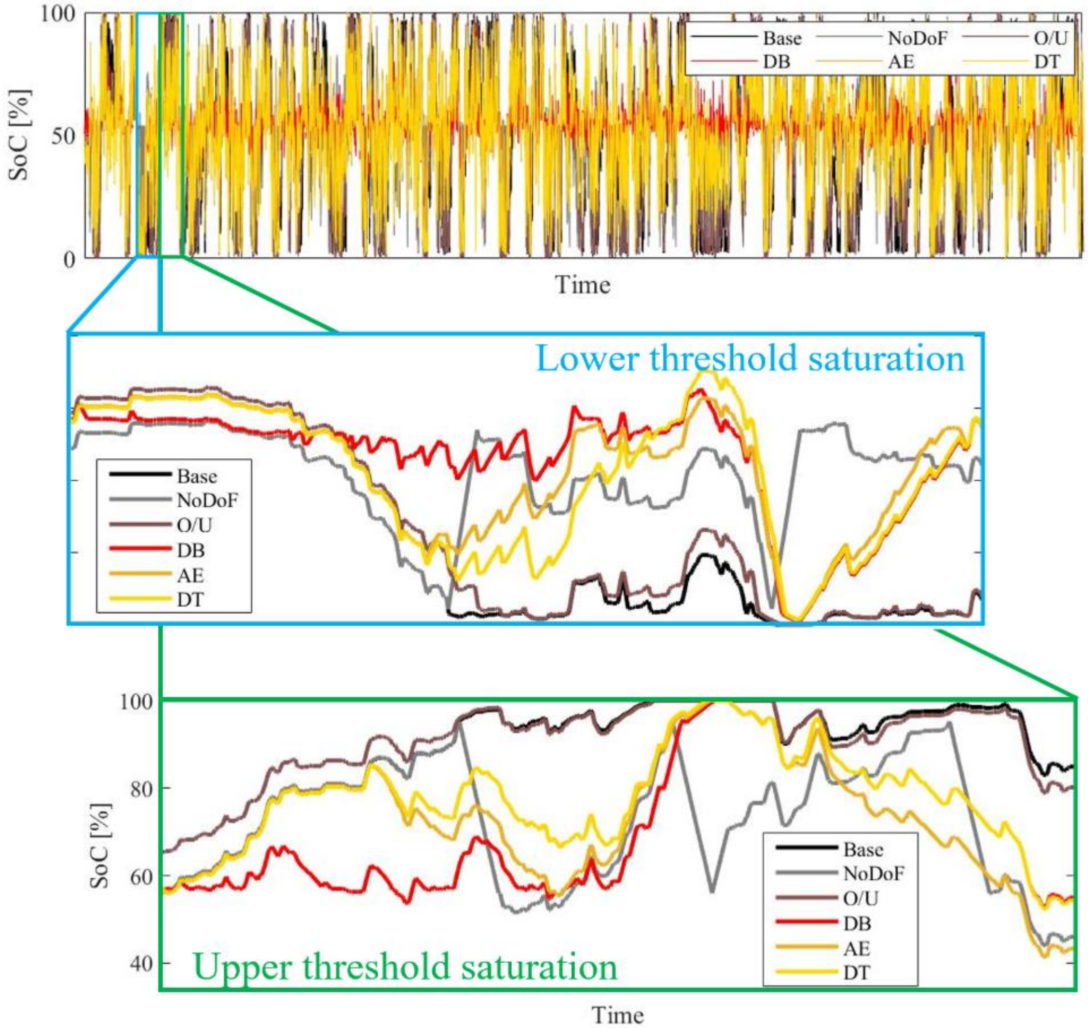


Figure 5.12 The SoC evolution profiles for FCR provision with different SoC management strategies. The top diagram shows the yearly profiles. The mid chart (blue box) zooms a contingency of some tens of hours with lower SoC limit saturation. The bottom chart (green box) shows an upper SoC limit saturation.

In Figure 5.13, the techno-economic comparison of the adopted strategies can be seen. The comparison is aimed to consider the amount of flexibility that is provided, the reliability of the provision and its cost. This can indicate if there are SoC management strategies able to improve the BESS operation and operating costs.

5.5.2.1 The energy provided for FCR

Each set-up can be evaluated in terms of the provided energy for FCR: the set of columns to the left of Figure 5.13 shows the energy provision in the framework of each SoC management strategy. The yearly provision is, for every strategy, between 14 and 18 GWh. Considering 10 MW of contracted flexibility, around 1400-1800 equivalent hours of FCR are provided by batteries. Obviously, as it can be seen, this energy is larger where the NP is lower. In any case, even considering 1800 equivalent hours (out of 8760 physical hours), FCR can be considered a power intensive service: the average energy requested is around 34 MWh/MW/week. This is a limited amount of energy per unit of provided flexibility. This is valid for Continental Europe Synchronous Area, whose frequency profile is adopted in this study. In addition, the droop value adopted for this study is very low: the provision is very steep, and the full activation of the service is at 37.5 mHz of absolute frequency deviation. For the usually adopted droop values (e.g., Fast Reserve in Italy is foreseen to be fully activated at 150 mHz of frequency deviation), the energy requirements could be even lower. This makes FCR an interesting opportunity for BESS and leave room also to multiple services provision and revenue stacking [259].

5.5.2.2 The energy for SoC management

Energy for SoC management widely varies among strategies. Base and Over/under-regulation (O/U) case (in black and brown) present no energy flow for the sake of restoration: indeed, SoC management is performed with the provided energy for FCR, offering itself some degrees of flexibility. Oppositely, DB case features 7.8 GWh for restoring SoC against 18.2 GWh provided for FCR: energy flows for management are 43% of provided energy. This is because the SoC management takes place every time the frequency is outside the dead-band. In the NoDoF case, the need of energy flows for management is lower (27%) since SoC management takes place (and service provision stops) only when SoC reaches the maximum or minimum thresholds; however, the NP is significant (7.3%) since service provision restarts only when SoC reaches its target value. In the other strategies, the portion of energy flown dedicated to SoC management varies between 27% and 32%.

5.5.2.3 BESS lifetime

The energy for SoC management increases the total energy flowing in the battery over a period. This is related to battery aging. BESS lifetime (t_{EoL}) estimated via the SoH model is generally very low: it ranges from 6.8 y for the Base case to 5.0 y for the DB case. BESS lifetime is usually inversely proportional to the overall absolute value of energy flown: it is well known that limiting the equivalent cycles decreases the cycle aging. Therefore, limiting the energy flows that do not imply a consistent revenue stream should be a target of the asset owner to preserve the BESS. On the other hand, following the lesson learnt in Chapter 4, the BESS cannot be idle for long time: we cannot avoid a battery gets old, but it is always better to use it intensively for well-remunerated services than to preserve it, because in the latter case cycle aging decreases but calendar aging prevails. In general, even in the ideal ambient conditions, a Li-ion battery can last no more than 20 years [260]. Therefore, the provision of multiple services is investigated in Chapter 6.

5.5.2.4 Nonperformance

As better investigated in Chapter 2, two main parties are involved in the electricity balancing: the system operator (which procures services) and the BSP (the service supplier). The two clusters of columns on the right part of Figure 5.13 can be investigated to evaluate the perspective of these two actors. The system operator aims to increase (or not to decrease) the reliability of provision: the reliability can be considered the opposite of NP. Therefore, NP must be kept as low as possible. NP below 5% can be taken as a conventional threshold to define an acceptable provision of service [75]. From this standpoint, the best result is obtained via DB (3.1%), while the other acceptable cases are AE (4.8%) and DT (4.9%). With respect to the case of a standard FCR provision (Base case), 87% of non-provided energy is avoided in the DB case. Furthermore, nonreliability avoided via DB is 57% with respect to a case in which no DoF are in place (case NoDoF) where the only possibility is interrupting the service provision for restoring SoC.

5.5.2.5 *Internal rate of return*

On the opposite side, the BSP is interested in the economic return on the investment. The IRR computed on a five-year business case ranged from 0.3 to 6.9%. Hypothesizing a real-world discount rate around 4% for the investment in energy systems [261], the economically positive cases are AE (4.1%) and DT (6.9%). In any case, even AE and DT cases feature an IRR slightly lower than hurdle rates adopted in generation companies (e.g., 10% [262]). Dead-band strategy, given the large amount of SoC management energy involved, is much less economically attractive for BSPs, with IRR equal to 1.2%.

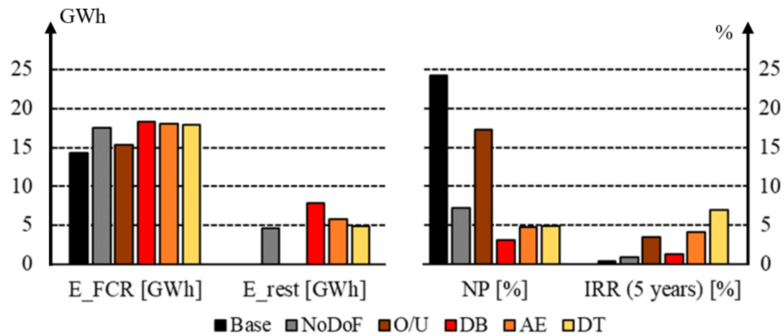


Figure 5.13 Summary of the results of the yearly simulations. Absolute value of energy for FCR (E_FCR), absolute value of energy for SoC management (E_rest), the ratio of NP with respect to total energy requested for FCR, and the IRR at 5 y are shown for each of the Cases.

5.5.2.6 *SoC probability distribution*

As stated at the beginning of this Chapter, the reliability is related to the finite energy content of storage, and specifically to hitting the upper and lower SoC limits. Distribution of SoC has proven important for guaranteeing reliability and the effective use of BESS [263]. Let therefore have a zoom into NP with the SoC probability distributions shown in Figure 5.14. The comparison is useful to understand how effective a strategy for restoring SoC is. An effective control strategy would prevent the battery from SoC saturation (at 0% or 100%) and keep SoC close to SoC_{target}. Therefore, the histogram of an effective strategy should feature higher probabilities for SoC around 50%–55%, and much lower probabilities for SoC largely diverging from 50%. In particular, the SoC_{target} in this study is 55%: this should be the taller bin for an effective SoC management strategy. This is achieved by all but Base and O/U cases (in black and brown). On the other hand, a too stressful SoC management strategy would prevent a large part of the energy content of the battery from being exploited, by keeping SoC always close to SoC_{target}. This is the case of the dead-band strategy (in red), featuring more than half of the year between 50% and 60% of SoC. In Figure 5.14, the orange area represents range between 10^{th} and 90^{th} percentiles: SoC stays within 42 and 66% of SoC for 80% of the time in DB case. It means that the rest of the energy content of the battery (76% of the E_n) is exploited only the 20% of the time. In cases AE and DT, SoC stays within 25 and 75% of SoC for 80% of the time, while the remaining 50% of the energy content is exploited in the remaining 20% of the time. This could give a better balance between reliability and effective exploitation of the asset. As seen before, DB allows to achieve a very high rate of reliability, but at the expenses of a building up of the dedicated energy flows: this leads both to a lower useful life of the storage (–36%) and to a largely lower economic benefit.

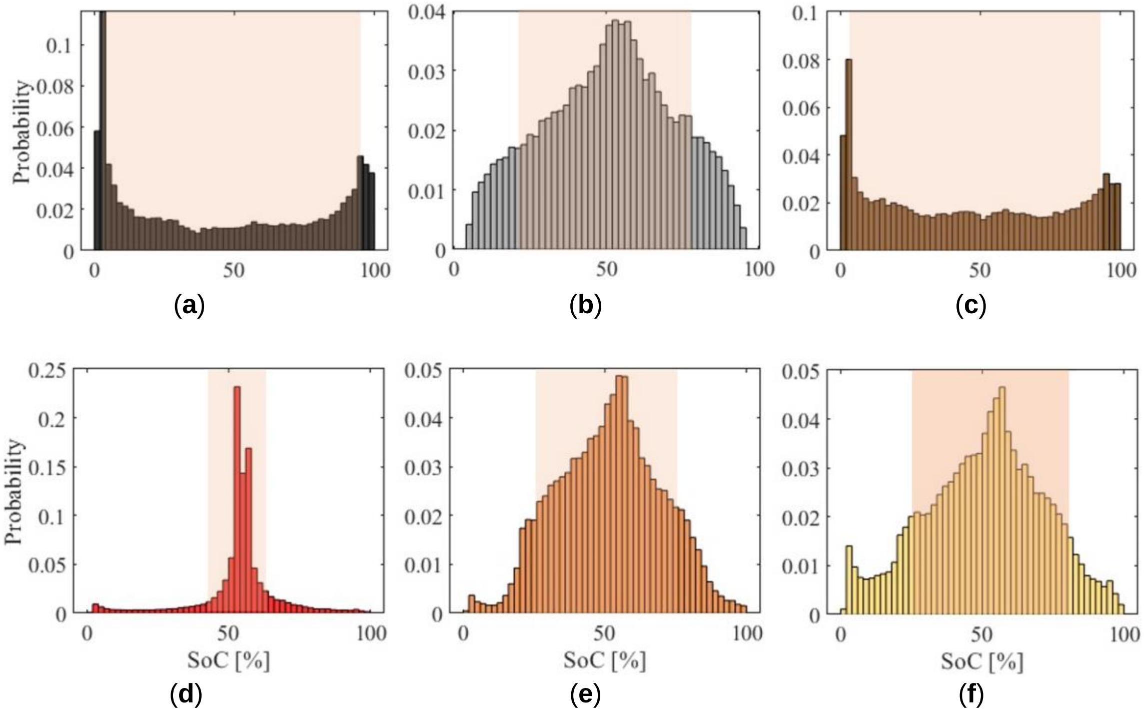


Figure 5.14 SoC distribution during the yearly simulation for the explicit SoC management strategies studied: (**a**) Base case; (**b**) No DoF case; (**c**) O/U case; (**d**) DB case; (**e**) AE case; (**f**) DT case. Y-axis represents the fraction of time in the year in which SoC is at a particular level (each bin represents 2% SoC range). The light orange area represents the SoC range for 80% of time (the interval between 10^{th} and 90^{th} percentile).

5.6 Conclusions

The finite energy content can be a potential issue for BESS operation in the provision of grid services. It is the duty of the Regulator to propose rules that guarantee reliability without preventing the business opportunities for the BESS operator and the BSP. The proposed analysis is aimed to give some numerical indications for the development of the rules for conventional and innovative ancillary services: for instance, the possibility to achieve an acceptable reliability with different SoC management strategies has been evaluated, highlighting best practices and possible improvements. Indeed, among the explicit SoC management strategies, some proved themselves able to guarantee reliability above 95% (DB, AE and DT cases). A subset of these were also capable to limit the additional (paid) energy flows for SoC management, therefore increasing the economics and showing an IRR over 4% (AE and DT cases). In case a regulator wants to foster the adoption of a SoC management strategy, a coherent degree of freedom in the service provision must be foreseen. As seen, the provision of FCR alone can leave room to the provision of additional services: FCR is in fact a power intensive service, with a limited amount of energy provision. As an alternative to explicit SoC management, an implicit SoC management can be proposed: it exploits a further grid service, provided simultaneously with the FCR, with the purpose of performing SoC management. Implicit management could provide SoC management while cutting the costs for the energy flows exchanged on that purpose. The applicability of implicit SoC management can be hypothesized if the BESS is enabled for multiple services provision. The development of a "Multiservice strategy" for provision of implicit SoC management is detailed in Chapter 6.

CHAPTER 6

The Multiservice strategy

Abstract

The explicit SoC management strategies compared in Chapter 5 showed some limitations: they imply additional costs due to additional energy exchanges and enhance the aging of the battery. Therefore, an implicit SoC management strategy is proposed: the provision of a second market service beside the primary application, with the scope of exploiting the available energy and power margins to manage SoC and introduce additional revenues. In this Chapter, the development of a control strategy for the multiple services provision is presented. First, a general review of the approaches for service and revenue stacking is given. Then, the methodology for developing the Multiservice strategy is proposed. This is applied to two case studies: a domestic case where a battery provides both behind-the-meter and front-of-meter services; a utility-scale case where multiple frequency regulation services are provided, including a fast frequency response. Eventually, the Multiservice strategy as an implicit SoC management strategy is quantitatively compared with the explicit strategies studied in Chapter 5.

6.1 Introduction

As shown in Chapter 5, the limited energy content of BESS is a potential issue for the provision of grid services. The Regulation can play a role introducing new rules and considering the peculiarities of new resources. In addition to this, a proper SoC management strategy must be developed and implemented. A comparison of explicit SoC management strategies showed that each of them increases the energy flows from and to the BESS, therefore the operating costs (i.e., the additional energy is usually traded on the energy markets) and the cycle aging. Since the Levelized Cost of Storage (LCOS) increases in case of higher operating costs [264], it is possible that the economic attractiveness of BESS is at risk, unless other revenue streams are considered. Indeed, the stationary BESS are recognized as multi-purpose technologies, that can create value in several applications [18]. The turnout of services that BESS can deliver include Behind-the-Meter (BtM) and Front-of-the-Meter (FtM) services, that have already been mentioned in Paragraph 1.2. The provision of multiple services, simultaneously or sequentially, with the same BESS, is referred to as service stacking.

6.2 The service and revenue stacking

The service stacking on stationary BESS is therefore something that can improve the economics, allowing the revenue stacking [26]. There are different possibilities for stacking services.

- Static stacking (or parallel stacking) is when the energy and power content of a BESS is split among two or more applications for an indefinite time. For instance, half the power and half the capacity could be devoted to a service (e.g., the qualified power for a frequency regulation is 50% of the nominal power, and the service can be offered for a finite time). This increases the reliability of the battery provision, since conflicting applications could not lead to the unexpected depletion of the energy content or of the power capability for the other service, that is allocated separately [265]. On the other hand, the splitting of the battery capabilities reduces the opportunities for each service, thus reducing the overall profitability of the BESS [26].

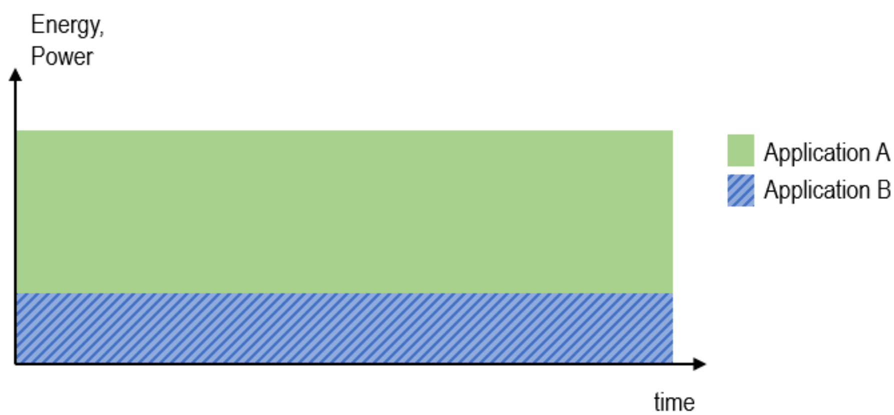


Figure 6.1 An example of static stacking of BESS power and energy considering two applications.

- Dynamic stacking is when multiple applications can be served simultaneously, varying the capacity allocation in time. This requires a complex Energy Management System (EMS) for the BESS, for dealing with the dynamic allocation of resources coping with the conflicts. Also, dynamic stacking can arise regulatory complications, for instance in case unbundling requires the value streams in different stages of the electricity supply chain to be separate [26]. Nonetheless, this can increase the economic profitability of the provision, due to the better exploitation of the asset [191], [266].

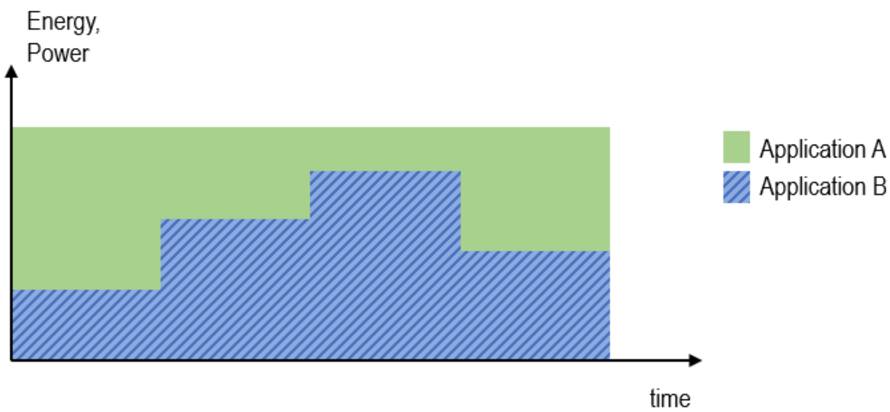


Figure 6.2 An example of dynamic stacking of BESS power and energy considering two applications over four time intervals.

- Sequential stacking can be seen as an extreme case of dynamic stacking: in case the regulation allows it, the battery can provide, not simultaneously yet sequentially, different services over a time period [265].

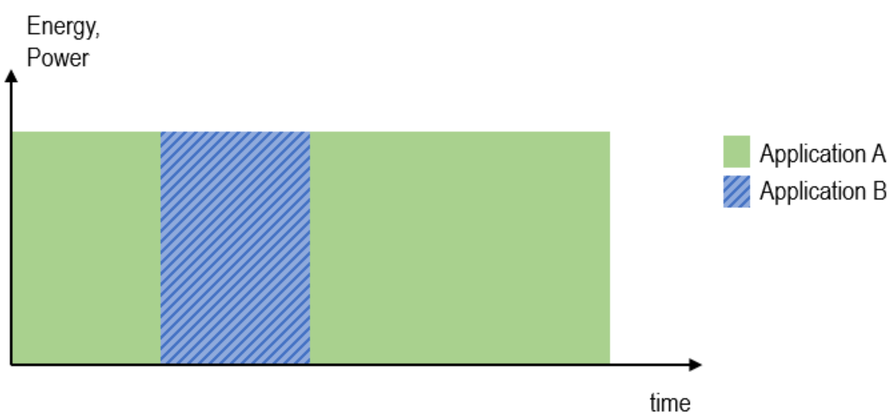


Figure 6.3 An example of sequential stacking of BESS power and energy considering two applications over four time intervals.

Often, the stacking is performed focusing on a primary application and one (or more) secondary applications [267]. The primary application is usually the more remunerative, while the secondary one is exploited in the remaining time or in case it is particularly suitable in certain situations [18]. Literature shows how, being stationary ESS a multi-purpose technology, the multiple revenue streams should be considered for increasing profitability, but usually there is a single application that features a lower profitability gap: it should be favoured [18]. Combination could be evaluated if the profit of providing two services overcomes the additional cost for complexity of the provision. This rationale could lead, on the one hand, the BESS operator in focusing on more, but not many, applications to be provided by an effective strategy. On the other hand, this could steer the policymaking in supporting first the single application that has a lower profitability gap. These would induce (at the lower cost) the deployment of the technology (e.g., with demand-pull policies [268]) and therefore drive the technology cost down the learning curve. This is possibly what happened, for instance, in UK and Italy, where a service for large-scale BESS has been proposed (respectively, EFR and Fast Reserve [74], [75]) in the area of frequency regulation, usually recognized as the one with lower profitability gap [18].

The development of an effective strategy for services provision with grid-connected BESS could start by the previously presented motivations: define a primary service based on its higher profitability, adding then one (or more) secondary services with the purpose of improving the economics, limiting the conflicting services and possibly fostering synergies.

6.3 Developing a strategy for reliable multiple services provision

As already introduced, the multiple services provision could be adopted for improving economics and for the implementation of an implicit SoC management strategy. In the following, a “Multiservice strategy” is sketched, implemented, and applied on some case studies relevant for the Italian market. Given what said in Paragraph 6.2, dynamic and sequential service stacking would be evaluated, compatibly with regulation, omitting parallel stacking since one of the aims is improving the economics.

The Multiservice Strategy proposed is a strategy where there is a primary service that is provided with priority. The secondary service is constrained to the remainder of the BESS capability: it is performed to exploit the remaining power and energy (i.e., SoC) bands of the BESS. Given this, the performance of the strategy and the suitability of the secondary application are evaluated based on the effectiveness of the implicit SoC management provided by the secondary service. The Multiservice Strategy can be applied to different frameworks and applications. The selected applications should respect the principles stated in the following Paragraphs 6.3.1 and 6.3.2.

6.3.1 The primary application

The primary application is adopted based on the estimated profitability. A brief analysis of the opportunities for BESS on Italian market is presented in the following. We consider applications related to electricity bill management, frequency regulation and participation to ancillary services markets. The summary of this analysis is returned in Figure 6.4. It is aimed to provide a general (qualitative, before than quantitative) analysis of business opportunities to motivate the development of the strategy and the selection of the case studies.

Electricity bill management includes the possibility of arbitrage, peak shaving and increasing self-consumption. We consider the economic opportunity of arbitrage based on the spread between peak and off-peak prices in Italy. We consider the average spread from the Italian Nominated Electricity Market Operator (NEMO) for 2019 [269], to omit the impact of Covid-19 and of electricity and gas prices rise of 2021 [270]. The spread in Italy is generally limited, given the predominance of thermal production units (namely coal and CCGT) as marginal technology fixing the zonal price [271]. This returns marginal prices generally ranging from 35 (off-peak) to 60 €/MWh (peak) for the considered year. The average spread for 2019 is 14 €/MWh. Therefore, forms of BtM services should be evaluated to manage the bill prices.

Self-consumption maximisation provides economic benefits related to the spread between the withdrawal price – namely the cost of the bill – and the injection prices. Italy is phasing out the net metering scheme in 2022 [272], hence, a preliminary estimation of the avoided cost for self-consumption of a prosumer is given by the difference of bill cost and the zonal price for injection. Considering the average indexes in Italy for 2019, the bill cost for a standard residential user is 206.8 €/MWh [273]. For an industrial user (class of consumption of 2000 to 20000 MWh per year), the average bill price is 158.0 €/MWh [274]. The DAM price as the average on the Italian market zones is 52.4 €/MWh [275]. The industrial and domestic self-consumption average profitability are estimated as the difference of these prices.

As per the Italian bill design, the peak shaving is only of interest for large-scale consumers, that have a power quota of the electricity bill based on the monthly maximum withdrawal. The peak shaving opportunities are disregarded in this brief analysis, but they could in principle improve the performance of the industrial self-consumption.

As described in Paragraph 2.3.3, Italy presents only secondary and tertiary frequency regulation traded on ASM. There is a product for secondary regulation and a product including mFRR, RR, and congestion management. Both these products are pay-as-bid in energy, both for the upward service (the provider injects energy and is remunerated in €/MWh), and the downward service (the provider absorbs energy and pays for it in €/MWh). The spread between upward and downward prices can be adopted as preliminary estimation of profitability of the participation to ASM. The average spread for both the secondary and tertiary product on Italian BM sessions for 2019 is considered [51]: 110 €/MWh. This is coherent with the prices presented in the Italian BM analysis (see Figure 2.12).

A recent opportunity for BESS is Fast Reserve, presented in Paragraph 3.4.1.1. It contracts resources for 1000 hours in a year, and the payment is in capacity (€/MW/year), based on auctions. The results of the first auction are presented in Figure 3.7. The weighted average remuneration is 29.5 k€/MW/year. The energy request is not given. Since the Fast Reserve is a fast frequency response service, we consider approximately an energy demand coherent with the steep FCR proposed in the previously presented study and highlighted in Paragraph 5.5.2.1: 34 MWh/MW/week. Possibly, this figure is overestimated, since the Fast Reserve is presented as a power intensive service with respect to FCR [75]. Reporting this energy demand on 1000 hours, the average energy remuneration for Fast Reserve can be estimated dividing the capacity payment by the total energy requested: 146 €/MWh.

In addition, it is worth noting that providing frequency regulation means responding to the native needs of the power system, as described in Paragraph 2.3 and better investigated in [52]. The needs for these services (and thus, the cost opportunity of providing these) is intrinsic in the power systems and cannot be depressed by policies. Oppositely, the large interest towards self-consumption is given by the regulatory framework and by the tariff: the large gap between the withdrawal cost and the injection one (considering the case with no incentives) is only marginally given by the grid costs. For instance, in Italy, grid costs represent historically less than 20% of the bill (around 0.04 €/kWh) and recently less than 10%, given the 2021 price rises [273]. The electricity bill also generally includes taxes, general system charges and other components that are not directly related to the network usage. A foreseen tariff evolution in Italy, also driven by high market costs [273], can drastically reduce the profitability of self-consumption increasing the interest towards flexibility provision.

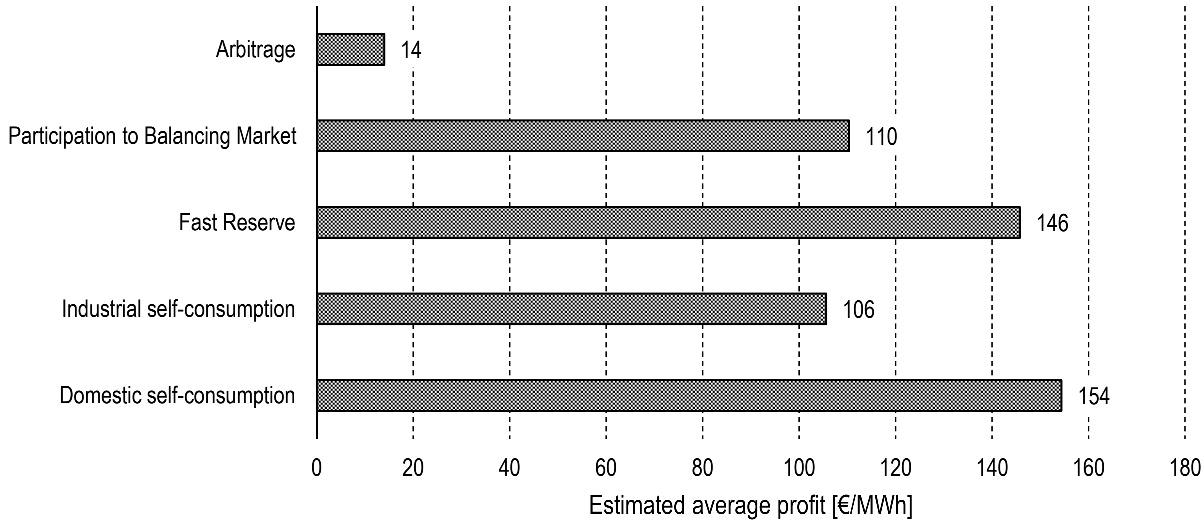


Figure 6.4 Estimated profitability of services available to BESS in Italy, considering average economic indexes in 2019.

Bearing in mind the limitations of this preliminary analysis, what can be seen is that

- the domestic self-consumption and
- the Fast Reserve provision

seem to represent the most profitable services, with an extra profit of +30% with respect to the next applications (participation to BM). Therefore, these two applications are considered as primary service for the Multiservice strategy under development.

6.3.2 The secondary application

The secondary application is necessary to improve the economics and provide SoC management. To provide SoC management, the service should be suitable to both charge and discharge the battery (or, better, to superimpose a power setpoint to the provision of the primary service [276]), with the aim of restoring the SoC toward a target. The target SoC is usually around 50%, unless the application requires differently. In addition, an effective SoC management strategy should predict the battery SoC evolution for the following period [244]. Willing to provide the SoC management with a market service, literature shows that for optimizing the use and the revenues, asymmetric bidding is an opportunity [17], [277]. As presented in Paragraph 3.3, asymmetric procurement entails the possibility of simultaneously bidding different quantities (in MW) for upward and downward directions of a service (up to the extreme case of offering flexibility only in one direction, either upward or downward).

Among previously considered market services, only the provision of tertiary frequency reserve on the Italian BM offers the possibility of the provision of an asymmetric service. Indeed, the FCR is not traded on the market and it is, in any case, symmetric. The aFRR is traded on the ASM but only via symmetric provision [73]. A pilot project is under approval for the provision of asymmetric aFRR, with explicit rules for the provider ESS [278], but its go-live is still not disclosed (as of early 2022).

In addition to the asymmetric nature, other features for selecting the secondary service can take advantage of the indications of the analysis proposed in Paragraph 3.3, related to the characteristics of the market and of the balancing products. In particular:

- the minimum bid size must be compatible with the considered resource;
- the time definition of product preferred by BSPs is generally short (1 to some hours);
- there is a slight preference for a small distance from market closure to delivery time.

6.3.3 The structure of the Multiservice Strategy

Once the applications are defined, the Multiservice strategy can be structured. The steps of the procedure are described in the following paragraphs and summarized in Figure 6.5. Several categories of input data are requested, both from datasheet, from real-time measurements and from preliminary analysis. Data are processed and some of them are fed as input to forecast models (see Paragraph 6.3.3.1). Based on data and forecasts, the available power band for the provision of the secondary service are estimated (see Paragraph 6.3.3.2). Eventually, a bidding strategy considers the already described statistical analysis on ASM to return a pricing rule for the bid, also based on the real-time measurement of the SoC (Paragraph 6.3.3.3).

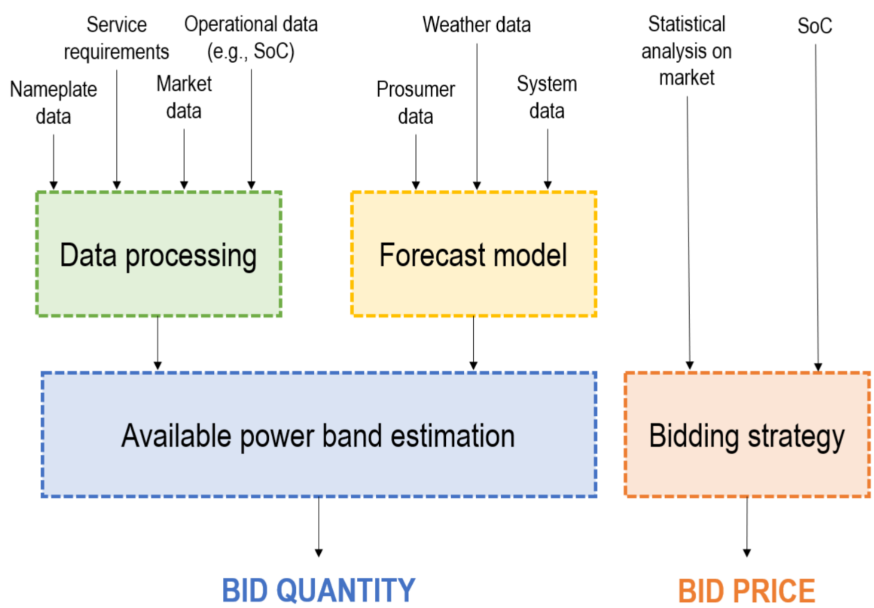


Figure 6.5 Flow diagram detailing the steps of the Multiservice Strategy.

6.3.3.1 Data management and forecasts

First, a phasis of data collection and forecast is necessary. Since the development of the Multiservice Strategy has the goal of providing a battery-centred and application-oriented Energy Management System (EMS), a complete set of system data are necessary. These include:

- the battery nominal power and energy, plus additional information useful to characterize the BESS;
- nameplate information of the other system components (e.g., load, PV, other production units);

- eventual requirements on the minimum and maximum qualified power for each application (i.e., eventual limitation to the dynamic stacking);
- market data, including prices and market structure;
- the operational data, such as the real-time SoC of the BESS, the eventual unavailability of some assets, the previously contracted ASM services.

Beside these data, a proper architecture for forecasting the energy flows in the system (or district) are necessary. The necessary forecasts model can be based on the following methodologies (but they are not limited to these).

- Persistence models.
- Data-driven models.
- Statistical models.

These models are needed for estimating the generation of variable RES, the load of the involved users, the market prices, the system frequency trends. They are fed as input to the strategy for estimating the available power bands for the secondary service.

6.3.3.2 Estimation of available power bands

The core of the strategy is the estimation of the available energy and power bands on the BESS for the provision of the secondary service. The estimated band is adopted as bid quantity for BM.

The forecast gathered are used to estimate the operation of the BESS in the next relevant period. The relevant period is usually the market period (if the secondary application is a market service). Referring to Figure 2.8, the relevant period considers the time slot between the market gate closure and the end of the delivery period. Indeed, the estimation of the bands must be performed before submitting the bid and must evaluate all the energy flows occurring up to the end of the delivery time. The energy flows that the BESS will experience in the relevant period will change its SoC. The SoC at the end of the period can be estimated, knowing the initial SoC and estimating the energy variations in the relevant period. The margin between the SoC at the end of the period and the upper SoC threshold (SoC_{max}) is the available energy for the provision of downward service (to charge the battery). Vice versa, the margin between the final SoC and the SoC_{min} is the available energy for upward service (to discharge). A schematic representation of the available energy estimation process is given in Figure 6.6 and Figure 6.7. The SoC_{min} and SoC_{max} shown in the figures are not necessarily 0 and 100%. Indeed, usually the BMS of real-world batteries prevents the battery to work at extreme SoC.

Figure 6.6 represents the domestic case characterized by:

- a behind-the-meter (BtM) service, namely maximization of self-consumption (SC), as the primary application, and
- a front-of-the-meter (FtM) service, namely the participation to ASM, as the secondary application.

The magnitude of the available energy contents is likely to change due to the moment of the day when the market session occurs and the previous outcomes on the ASM. For what concerns the SC, the battery is likely to charge in the daylight (top row of Figure 6.6), due to the excess PV, while it is likely to discharge for the rest of the time to satisfy the load (bottom row). The ASM contribution considers instead the possible superposition of the relevant period with the previous market session: in that case, ASM products contracted in the previous session generate an energy flow that must be considered. Battery discharges in case of upward provision contracted (left column of Figure 6.6), charges in case of downward provision (right column). Auxiliary systems demand (AUX) is always implying a battery discharge, since the battery directly feeds that load. The possible combinations lead to different sizes of upward (E_{avUp}) and downward available energy (E_{avDn}) estimated. Indeed, the availability of upward energy (and consequently the maximum feasible upward bid) is usually larger in daytime and in case in the previous market session the BESS downward bid was awarded (top right of Figure 6.6). Oppositely, downward available energy is larger in nighttime and following a previous upward call (bottom left).

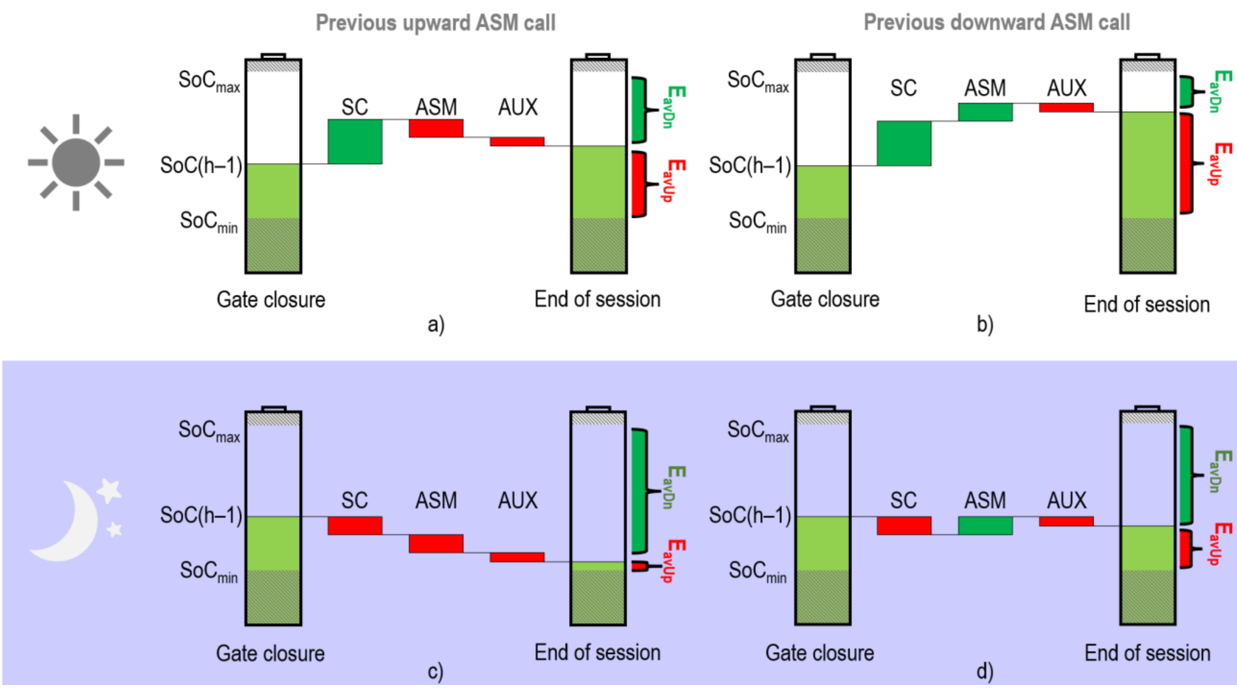


Figure 6.6 Schematic representation of the available energy in the BtM + FtM case. At the market closure, the energy variation for self-consumption (SC), ASM participation and auxiliary demand in the next 5 hours is estimated and available energy is computed. Four cases are shown: a) daytime and upward call in the previous market session; b) daytime and downward call; c) nighttime and upward call; d) nighttime and downward call.

Figure 6.7 represents the possibility of a standalone battery providing two FtM services to the system. The frequency regulation or specifically the Fast Reserve (FR) is the primary application, while the remainder of the available energy is bid on ASM. As before, the top left of Figure 6.7 represents a situation in which the primary application charges the battery, due to estimated overfrequency in the relevant period, while the previous ASM bid discharges the battery. To the top right, both the services are charging the battery (overfrequency adds to previous downward ASM bid). The bottom row shows the case of estimated underfrequency, with either upward (bottom left) or downward call (bottom right).

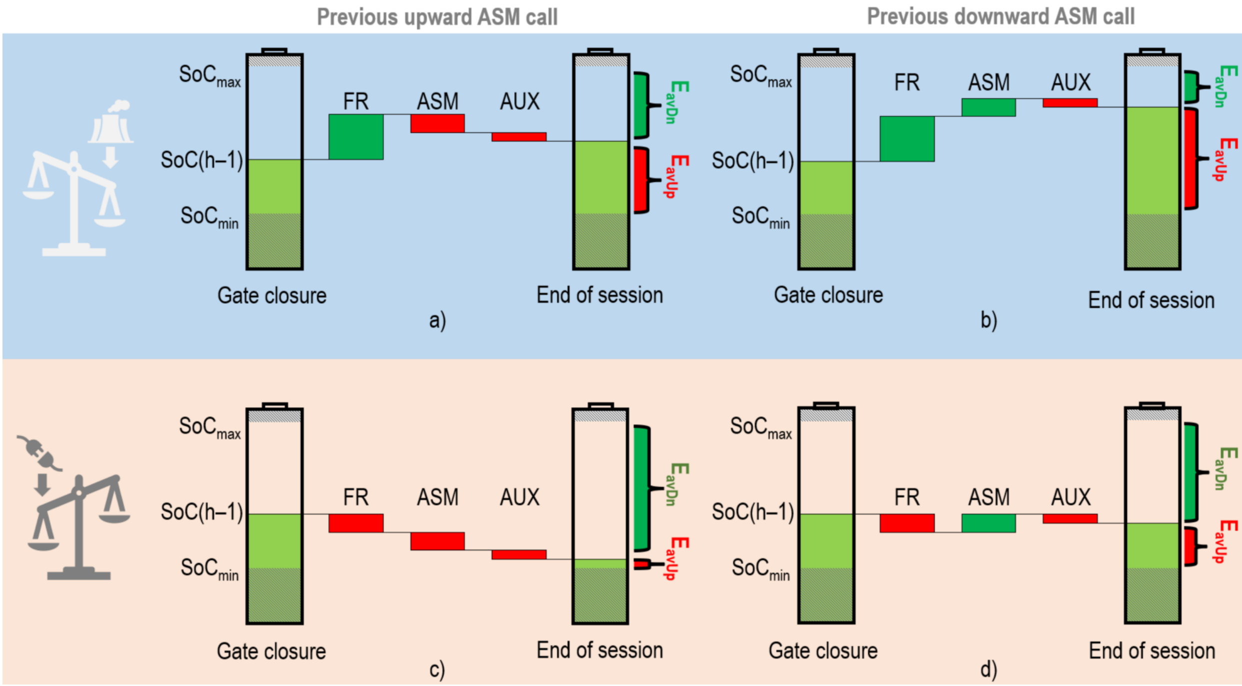


Figure 6.7 Schematic representation of the available energy in the FtM + FtM case. At the market closure, the energy variation for Fast Reserve (FR) or in general Frequency Regulation, ASM participation and auxiliary demand in the next 5 hours is estimated and available energy is computed. Four cases are shown: a) predicted overfrequency and upward call in the previous market session; b) predicted overfrequency and downward call; c) predicted underfrequency and upward call; d) predicted underfrequency and downward call.

While the primary service (SC or FR) is always the priority of the battery in Multiservice strategy, the secondary service exploits the available band estimated, that are converted in power bids on the ASM. To select the suitable secondary service and market, we refer to the indications provided in Paragraph 6.3.2: feasible minimum bid size, and preferably short product's time definition and distance to delivery.

Italian mFRR (and RR) is considered the most viable alternative in the Italian ASM (see Paragraph 2.3.3). For what concerns the minimum bid size, after the implementation of the UVAM project, the provision of mFRR is open to DERs down to 1 MW of qualified power and to aggregated virtual power plants (VPPs): this does not represent an obstacle to service provision. For what concerns time definition and distance to delivery, the most favourable scheme is presented in Figure 6.8, that conveniently updates Figure 2.9. The Multiservice strategy bids on all the BM sessions (BMn). Before gate closure for session BMn (blue arrows), a bid for all the 4 hours of delivery time (dark red stripe) occurring before the starting of delivery time for session BM(n+1). Therefore, the relevant period of Multiservice Strategy in each market session is the 5-hours period from h-1 to h+4.

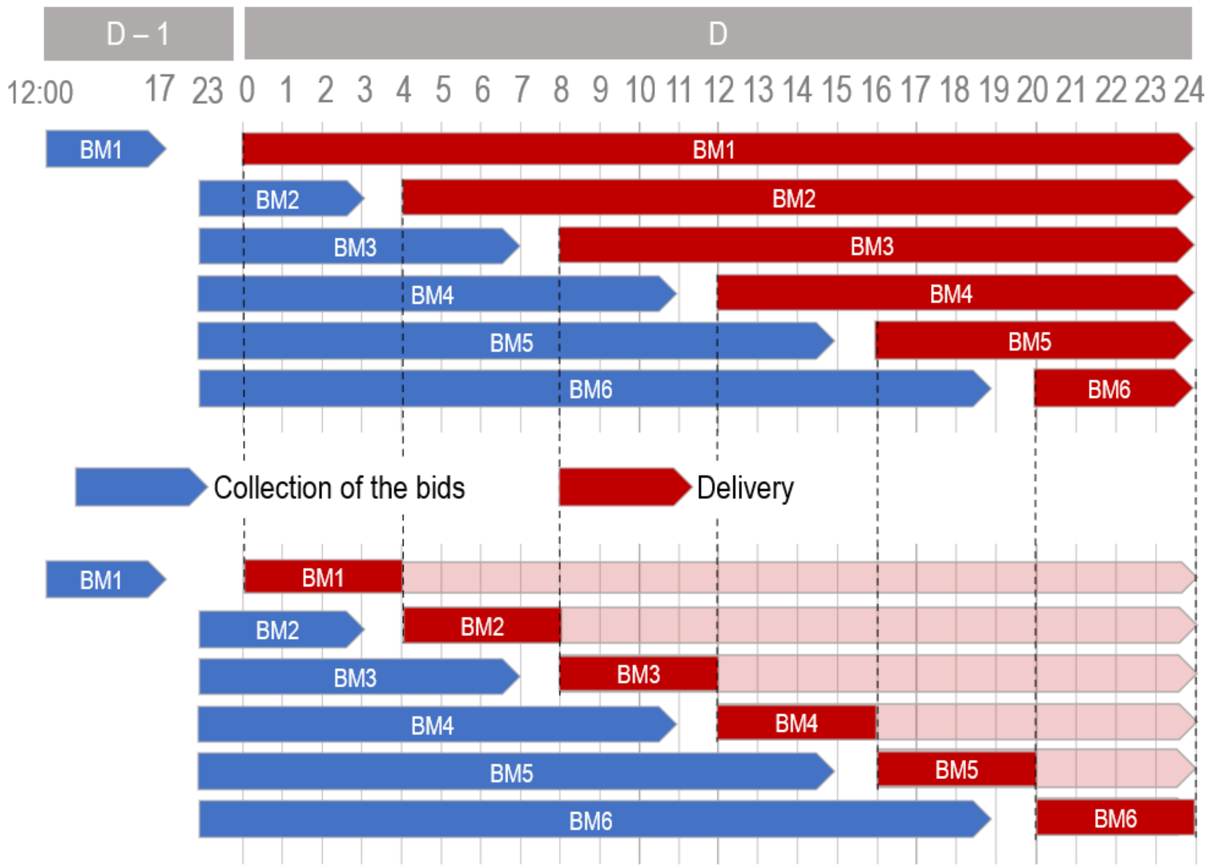


Figure 6.8 Elaboration of Figure 2.9 to detail the BM relevant periods for the Multiservice Strategy.

The BM sessions of Italian ASM present a distance to delivery of 1 hour, that is the shortest in the Italian panorama and it is coherent with the Electricity Balancing Guidelines [61]. The granularity of the BM bids is one hour (i.e., a different offer for upward and downward provision can be proposed each hour) but considering the gate closures (at h-1) each session is the last one for proposing bids on hour h to h+4.

It is worth noting that, from 2021, the BM in Italy is moving towards a hourly market. The following case studies will consider the situation depicted in Figure 6.8, relevant as of 2020. Chapter 7 elaborates instead on the evolution of the ASMs, including the new Italian structure.

The bid quantity on BM comes directly from the available energy estimation of the previous Paragraph: since the energy must be provided for *n* hours (e.g., 4 hours), the quantity offered is either the available energy upward or downward in MWh, divided by *n* to get the power offered in MW. The outcome is checked against the nominal power, to avoid offering an unfeasible quantity. In addition, a safety coefficient ($k_{safety} > 1$) can be divided to arbitrarily reduce the obtained quantity for reliability reasons (oppositely, a $k_{safety} < 1$ can be introduced for an aggressive market strategy).

6.3.3.3 Bidding strategy

The bidding strategy defines the prices to be offered for BM participation. Given the twofold aim of increasing the economics and improving the reliability of the provision, the bid price is estimated based on the available energy content at the moment of the offer, i.e., the SoC(h-1).

The further the SoC is from target SoC, the higher is the willing to be awarded on the BM in the direction of restoring the SoC. Indeed, in case of rejection, it is more likely to saturate or deplete the energy content, thus decreasing reliability of provision. Two strategies are therefore developed. One sets the bid price at the market closure (B(h)) proportionally to the distance of SoC(t) from target SoC (SoC_{target}), considering the average marginal price (μ(h)) and standard deviation (σ(h)) for that hour coming from the statistical analysis of BM as in Figure 2.12. Equation (6.1) illustrates the methodology for upward bids.

$$B(h) = \mu(h) - \sigma(h) * (SoC(t) - SoC_{target}) / 100 \tag{6.1}$$

The price B(h) results lower than μ(h) in case SoC(t) is above SoC_{target}, therefore increasing the probability of being awarded. Vice versa, B(h) is high in case SoC(t) is low, hence in case the provision of upward service is awarded, the risk of nonperformance is balanced by the high remuneration. The same approach can be adopted for the downward price.

A simplified version of this strategy is the Merchant/Reliability bidding strategy. The bid price is, in this case, selected between two prices: a convenient one (reliability) and a competitive one (merchant). The reliability price is bid in case SoC(t) is further than a certain threshold from SoC_{target}, vice versa the merchant price is used. Clearly, if the reliability price is adopted for a bid (e.g., upward), the merchant price is adopted for the opposite one (e.g., downward). This simplified strategy is based on the consideration that Italian ASM is a pay-as-bid market with imperfect economic efficiency (as confirmed by previous analyses [279]), i.e., a bid that present in the same session and market zone a lower price with respect to an awarded bid, is not surely awarded. Indeed, other variables (e.g., grid topology and congestions) play a role. Therefore, a simplified two-prices strategy can be anyway effective and be applicable also to a small-scale case where many resources with many operating conditions should bid together via an aggregator or BSP. It is not allowed by a regulatory perspective to submit a myriad of micro-bids at tailor-made prices. Instead, the BSP could propose on the markets two quantities (the first at a reliability price and the latter at a merchant price).

The Merchant/Reliability bidding strategy is applied to a domestic case study, while the SoC-dependent strategy is used for a utility-scale case study.

6.3.4 Two case studies for Multiservice provision

The previously developed Multiservice Strategy is tested on two case studies.

First, a dynamic stacking on a domestic, small-scale framework. A BtM + FtM Multiservice is proposed. It comes from an extended experience in the H-2020 project inteGRIDy [280], where both numerical model and on-field tests were developed and performed.

The second case study considers a sequential stacking involving FtM + FtM services: the provision of Fast Reserve and the participation on the ASM. The stacking is sequential, exploiting the rules of the Fast Reserve that require the provision of this service for 1000 hours over a year. The remainder is dedicated to provision of flexibility on the ASM.

The case studies are provided for being as close as possible to the real opportunities open on Italian context. Thus, they extensively consider the limitations posed by the regulatory framework. This makes them suitable to anticipate the analysis of Chapter 7, where all the constraints on the provision of standard balancing products will be relaxed to allow the definition of the optimal BM arrangements for providing services by BESS.

6.4 Small scale, behind-the-meter and front-of-meter Multiservice

In the following, we show how a domestic BESS can provide multiple services with a high degree of reliability and with suitable economic performance in a real market context. This means developing a control strategy able to bid on a market and perform the service minimizing the non-performance, even considering that each bid has a certain probability of being rejected on the balancing market. For doing so, a BM model is developed.

6.4.1 The H2020 inteGRIDy project and the San Severino Marche Pilot

The following study has been developed in the framework of the H2020 project inteGRIDy [280]. The project was a 4-year project (2016-2020) aimed to develop pilot cases centered on four pillars: demand response, smartening the distribution grid, energy storage, electric vehicle integration. Ten pilot projects around Europe focused on one or more of the pillars were proposed. San Severino Marche pilot project has been developed by Politecnico di Milano in cooperation with the local DSO and technology providers. The proposed solutions deal with the optimization of the medium-voltage network topology and the provision of flexibility by domestic prosumers aggregated and coordinated. The flexibility solution involved 4 domestic prosumers equipped with PV and a high-temperature BESS, plus 2 installations in laboratories for serial testing. A central project workstation was deployed to act as the counterpart of the market (e.g., the BSP gathering the DERs). The field communicated with the central workstation, receiving commands (e.g., power setpoints) and returning feedbacks (e.g., SoC, real power). The inteGRIDy framework offered the testing layout for some on-field tests of the procedure, that complemented the numerical simulations to assess the suitability of the control strategy also with the real-world application.

6.4.2 Testing layout

The simplified scheme of the testing layout of San Severino pilot project is presented in Figure 6.9. The Pilot Project's workstation in San Severino Marche hosts the batteries' scheduler and the project database. On the scheduler, 3 main routines are running. The Real Time BESS Control receives the indications from the ASM outcomes and translate it in setpoints for the batteries. Also, it gives indications on the strategy to be operated by each battery (e.g., self-consumption only or Multiservice strategy). The Multiservice Strategy gathers all the relevant data and performs the bid, in terms of price (€/MWh) and quantity (kW), both for upward and downward regulation. The Market Simulator contains all the ASM data to check the award/rejections of the bids proposed by the Multiservice Strategy. The market data are returned by the developed BM model. Each of the routines reads and writes on the database only (each routine is a functional unit) and is launched by the scheduler: the Real Time BESS Control runs each minute; the Multiservice Strategy runs each 4 hours; the Market Simulator runs before the Multiservice Strategy.

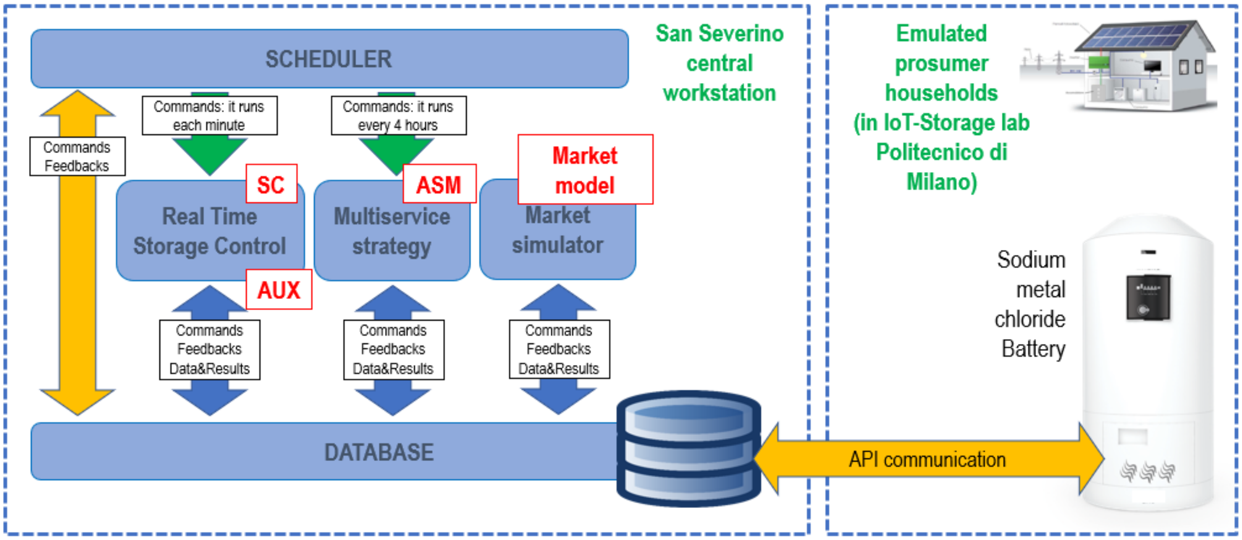


Figure 6.9 Testing layout for the San Severino Marche Pilot Project. To the left, the central workstation, that hosts the scheduler and the database. To the right, the prosumer equipped with battery and PV, emulated in the Politecnico di Milano's IoT-Storage Lab [281].

The Central Workstation communicates via web Application Programming Interface (API) with the assets. On the left part of Figure 6.9, the system in the Politecnico di Milano’s Lab [281] is presented. In the lab, the prosumer is emulated thanks to a resistive load and a DC supply, respectively simulating the user’s load and the PV production. The main device is the domestic battery, that is a high-T Sodium Metal Chloride (SMC) battery whose main data are summarized in Table 6.1. It accesses via API the database and reads its own control strategy and power setpoints. The battery features an internal self-consumption (SC) logic, too. Therefore, in case Multiservice strategy is active, the internal self-consumption logic is superimposed to the ASM power setpoints communicated via API. In case the SC only logic is selected (or in case the communication with the workstation interrupts), only the internal logic keeps running.

Table 6.1 San Severino Marche Pilot Project battery data

Key	Value
Nominal Power (P_n)	3 kW
Nominal Energy (E_n)	8 kWh
Operating temperature	260°C
Technology	Sodium metal chloride

The whole architecture is considered suitable for the provision of aFRR, mFRR and RR, since their dynamics are in the timescale of 1 minute to 1 hour. This architecture is replicated in a numerical model: the battery is represented by a variable efficiency model, equipped with a controller that implements the control strategies, including the market model and the bidding strategy. The numerical model is used to develop the Multiservice strategy and to serially test the provision of services via a domestic battery with 1-month simulations. Then, the developed strategies are implemented in the routines, and they are tested on the real asset, too.

6.4.3 The BESS models

Two BESS models are adopted. A Sodium metal chloride (SMC) simplified battery model is considered to emulate the actual San Severino project's battery. The Li-ion NMC BESS model presented in Chapter 4 is then adopted since it is a validated model that showed a high accuracy in representing grid- connected BESS operation.

The high-T BESS model representing the SMC battery under test in the inteGRIDy project is a multiparameter simplified model with nominal power of 3 kW and nominal energy of 8 kWh, that features:

- a constant battery efficiency, different for charging (74.0%) and discharging (83.3%);
- a constant auxiliary power demand, different for charging (225 W) and discharging (120 W);
- a capability chart, showing the maximum available power for both charging at discharging at each SoC, presented in Figure 6.10.

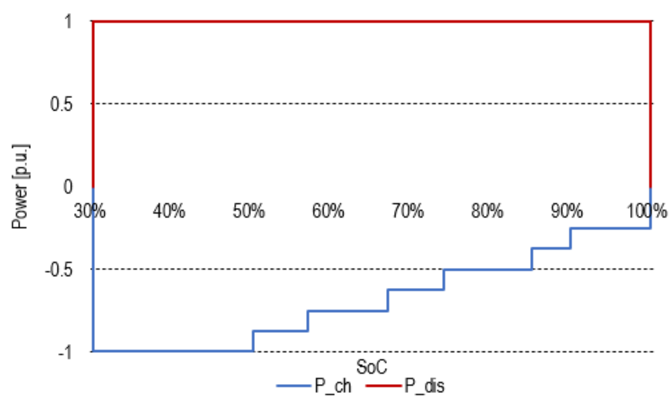


Figure 6.10 Capability chart for discharging (P_dis) and charging (P_ch) of the SMC model.

Figure 6.10 also shows the minimum and maximum SoC characterizing the NMC BESS. This model is adopted to emulate the actual prosumer's layout in the San Severino pilot project. Hence, the outcome of the models can be compared with the results of the on-field tests. To tune the model, some lab tests on the SMC battery have been performed, included a verification test based on the IEC cycle presented in Paragraph 4.3.5.1. The considered efficiencies and auxiliaries demand are retrieved from the measurements. To justify the great difference between charge and discharge, it is worth noting that the measurements provided the aggregated of the losses (including efficiency and auxiliary demand): the parameters were estimated based on some battery cycles, to fit the actual SoC evolution of the battery. The obtained accuracy was considered adequate for the model application.

The Li-ion NMC battery (LiB) model (see Chapter 4) is adopted to test a case where the auxiliary systems demand is less relevant since LiB is a low-T technology. The adopted models are both BESS model: they do not consider the battery only, but also the Power Conversion System (PCS) – mainly composed by the inverter – and the auxiliary systems.

6.4.4 Behind-the-meter control strategy

The tested BESS has a built-in proprietary self-consumption algorithm. Its logic is implemented in the controller of the numerical models, too. The tool receives as input the SoC, the P_{pv} and P_{load} in each instant. The P_{grid} is computed as

$$P_{grid}(t) = P_{load}(t) + P_{aux}(t) - P_{pv}(t) \tag{6.2}$$

where injected power is positive and absorbed power is negative. The SC logic aims to always keep as close as possible to 0 the power P_{grid}, so to minimize the exchange with the grid and, therefore, enhance the SC. Therefore, the power setpoint to the battery is always equal to P_{grid}, net of the efficiencies. As can be seen, the BESS always feeds its auxiliary systems. Therefore, it charges in case the PV is producing more than what is required from the loads and the auxiliaries, otherwise it discharges. Then, the model considers the BESS efficiency.

$$\begin{cases} P_{req}(t) = \dfrac{P_{grid}(t)}{\eta(t)} & if\ P_{grid}(t) > 0 \\ P_{req}(t) = P_{grid}(t) * \ \eta(t) & if\ P_{grid}(t) \leq 0 \end{cases} \tag{6.3}$$

where P_{req}, as the power requested to the BESS, is larger than P_{grid} if it is injected and lower than P_{grid} if it is absorbed. Next, the P_{req} is evaluated in front of the capability chart as follows.

$$\begin{cases} P_{real}(t) = \min(P_{req}(t), P_{max}\big(SoC(t)\big) \ if\ P_{real}(t) > 0 \\ P_{real}(t) = \max\ (P_{req}(t), P_{min}\big(SoC(t)\big) \ if\ P_{real}(t) \leq 0 \end{cases} \tag{6.4}$$

where $P_{max}(SoC(t))$ and $P_{min}(SoC(t))$ are the values of the capability chart for the instantaneous SoC, respectively for discharge and charge. Thus, the P_{real} absolute value is diminished to the maximum admitted. The P_{real} is the power actually flowing in the battery and updating the SoC as in the following.

$$SoC(t) = \max\left(SoC_{min}, min\left(SoC_{max}, SoC(t-1) - \frac{P_{real}(t)}{E_n * S * 3600} * 100\right)\right) \tag{6.5}$$

where SoC(t) is in %, SoC(t-1) is SoC at the previous step and S is sampling rate in Hz. Multiplying S by 3600 seconds per hour, we generalize the transformation from kW to kWh. E.g., if S is 1 Hz we have 3600 values of P_{real} per hour, so we divide P_{real} by 1*3600 to have the exchanged energy per second; if S is 1/60, we have one value of P_{real} per minute, so we divide P_{real} by 1/60*3600 = 60 to have the exchanged energy per minute. Then, exchanged energy is divided by E_n and multiplied by 100 to have the SoC variation for each step. Finally, the estimated SoC is compared with the SoC_{max} and SoC_{min}, that are the upper and lower boundary of admitted SoC. In case one of the SoC boundary is hit, P_{real} is updated as follows to take in account of the real power flow in the battery.

$$\begin{cases} P_{real}(t) = (SoC(t-1) - SoC_{max}) * E_n * S * \dfrac{3600}{100} & if\ SoC(t) = SoC_{max} \\ P_{real}(t) = (SoC(t-1) - SoC_{min}) * E_n * S * \dfrac{3600}{100} & if\ SoC(t) = SoC_{min} \\ P_{real}(t) = P_{real}(t) & elsewhere \end{cases} \tag{6.6}$$

P_{real} is relevant for DC side. To have the actual power delivered (P_{del}) AC side, the efficiency is applied once more as follows.

$$\begin{cases} P_{del}(t) = P_{real}(t) * \eta(t) \; if \; P_{real}(t) > 0 \\ P_{del}(t) = \dfrac{P_{real}(t)}{\eta(t)} \; if \; P_{real}(t) \leq 0 \end{cases} \tag{6.7}$$

$P_{del}(t)$ represents the power that can be measured AC side. This power should be equal to $P_{grid}(t)$ in each instant t. This occurs whenever the BESS is providing all the requested power to provide self-consumption. In case the battery is not able to inject or absorb all the necessary power, the prosumer must exchange power with the grid. Injected power (P_{inj}) and withdrawn power (P_{with}) are computed as follows.

$$P_{inj}(t) = \min(0, P_{grid}(t) - P_{del}(t)) \tag{6.8}$$

$$P_{with}(t) = \max(0, P_{grid}(t) - P_{del}(t)) \tag{6.9}$$

where $P_{inj}(t)$ is negative in case injection in grid occurs, 0 elsewhere; $P_{with}(t)$ is positive in case withdrawal from grid occurs, 0 elsewhere.

6.4.5 Multiservice strategy for BtM + FtM applications

The Multiservice strategy described in Paragraph 6.3 is implemented in the model.

The power that must be provided to the grid is updated as follows.

$$P_{grid}(t) = P_{load}(t) + P_{aux}(t) - P_{pv}(t) + P_{ASM}(t) \tag{6.10}$$

where P_{ASM} is the power exchanged with the grid for the provision of ancillary services (RR mainly, to consider the UVAM framework illustrated before).

The domestic BESS is bidding on BM, providing the product related to mFRR and RR. Each day, six pairs of bids (i.e., upward and downward bids) are proposed at the BM gate closures, for the relevant period of each BM session (see Figure 6.8, bottom part). Each bid contains the quantities (in kW) and the prices (in €/MWh) for hour *h* to *h+4*.

6.4.6 Available energy estimation and bid quantity

The bid quantity is the estimated available energy in the next market session. To compute the available energy in the battery, the energy content at the market closure and the estimated energy variation in the next period must be defined. Considering the operation of the battery under study, the following elements are of interest.

- The gap between SoC at market closure (SoC(h-1)) and SoC_{min} represents the energy content upward (ΔE_{up}) at the market closure. Furthermore, the gap between SoC_{max} and SoC(h-1) represents the energy content downward (ΔE_{dnEst}).

$$\Delta E_{up} = \frac{SoC(h - t_{adv}) - SoC_{min}}{100} * E_n \tag{6.11}$$

$$\Delta E_{dn} = \frac{SoC_{max} - SoC(h - t_{adv})}{100} * E_n \tag{6.12}$$

  where t_{adv} is the time advance of gate closure with respect to delivery time of 1 hour.
- The estimated energy exchange due to the self-consumption (E_{SCest}) in the next 5 hours is computed with two separate prediction models for PV and load. E_{SCest} can be either positive (if load is larger than generation) or negative. It can be estimated as in (6.13).

$$\begin{cases} E_{SCest} = \sum_{i=0}^{4}\left(P_{predLi} - P_{predPVi}\right) * \dfrac{t_{adv} + t_{mkt}}{\eta_{avgDis}} & if \sum_{i=0}^{4}\left(P_{predLoad} - P_{predPV}\right) \geq 0 \\ E_{SCest} = \sum_{i=0}^{4}\left(P_{predLi} - P_{predPVi}\right) * (t_{adv} + t_{mkt}) * \eta_{avgCh} & if \sum_{i=0}^{4}\left(P_{predLoad} - P_{predPV}\right) < 0 \end{cases} \quad (6.13)$$

where P_{predLi} and $P_{predPVi}$ are the estimated average load and PV production for hour *i* in kW; t_{mkt} is the time definition of the product of 4 hours, so that the total time of the estimation is 5 hours (4+1); η_{avgDis} and η_{avgCh} are constant values for taking account of the efficiency.

- The energy exchange for the provision of market services (E_{ASMest}) in the latest hour of the previous market session (thus, between *h-1* and *h*) must be computed. A unit providing RR can be awarded either for upward or downward service each hour. Therefore, E_{ASMest} can be computed as in (6.14).

$$E_{ASMest} = \frac{P_{terUp}(h - t_{adv}) * t_{adv}}{\eta_{avgDis}} - P_{terDn}(h - t_{adv}) * t_{adv} * \eta_{avgCh} \quad (6.14)$$

where $P_{terUp}(h\text{-}t_{adv})$ and $P_{terDn}(h\text{-}t_{adv})$ are the awarded power respectively for upward and downward tertiary regulation for the period [*h-1*, *h*]. As per what said before, either the first or the latter term is zero for each hour.

- The auxiliary system demand (E_{auxEst}) is computed as the average auxiliary demand multiplied the t_{adv}+t_{mkt} hours.

The available upward and downward energy content (see Figure 6.6) are respectively computed as in (6.15) and (6.16).

$$E_{avUp} = \max\left(0, \Delta E_{up} - E_{SCest} - E_{ASMest} - E_{auxEst}\right) \quad (6.15)$$

$$E_{avDn} = \max(0, \Delta E_{dn} + E_{SCest} + E_{ASMest} + E_{auxEst}) \quad (6.16)$$

where the maximum value is selected to avoid negative quantities are offered. Since the bid quantity is in kW, E_{avUp} and E_{avDn} are divided by 4 hours and checked against the maximum power that can be dedicated to ancillary services provision (P_{maxASM}) as in (6.17) and (6.18). For the sake of reliability of provision, P_{maxASM} is 50% of P_n for both upward and downward provision. Furthermore, the bid is only offered in case the power is above a minimum threshold (P_{minASM}), to avoid micro-bids. P_{minASM} is 200 W.

$$\begin{cases} P_{bidUp} = \min\left(\dfrac{E_{avUp}}{t_{mkt}}, P_{maxASM}\right) \; if \; \dfrac{E_{avUp}}{t_{mkt}} > P_{minASM} \\ P_{bidUp} = 0 \qquad\qquad\qquad\qquad elsewhere \end{cases} \quad (6.17)$$

$$\begin{cases} P_{bidDn} = \min\left(\dfrac{E_{avDn}}{t_{mkt}}, P_{maxASM}\right) \; if \; \dfrac{E_{avDn}}{t_{mkt}} > P_{minASM} \\ P_{bidDn} = 0 \qquad\qquad\qquad\qquad elsewhere \end{cases} \quad (6.18)$$

6.4.6.1 The pricing strategy

The bid price depends on the SoC at the gate closure and follows the Merchant/reliability strategy whose rationale is illustrated in Paragraph 6.3.3.3. In case the SoC is between a lower and an upper threshold (SoC_{lo} and SoC_{hi}), the bid price is the merchant price (€$_{upMer}$, €$_{dnMer}$). In case the SoC is above SoC_{hi}, the bid price is the reliability price for upward reserve (€$_{upRel}$) and merchant price for the downward reserve. Eventually, if the SoC is below SoC_{lo}, the price is merchant for upward reserve and reliability price for downward (€$_{upRel}$). The possibilities are shown in Equation (6.19).

$$\begin{cases} [€_{up}, €_{dn}] = [€_{upMer,}\ €_{dnMer}] & if\ SoC_{lo} < SoC(h-1) < SoC_{hi} \\ [€_{up}, €_{dn}] = [€_{upRel,}\ €_{dnMer}] & if\ SoC(h-1) \leq SoC_{lo} \\ [€_{up}, €_{dn}] = [€_{upMer,}\ €_{dnRel}] & if\ SoC_{hi} \leq SoC(h-1) \end{cases} \tag{6.19}$$

Merchant and reliability prices and SoC thresholds are shown in Table 6.2.

Table 6.2 Merchant/reliability strategy summary table

Key	Value
SoC_{hi}	75%
SoC_{lo}	50%
SoC_{max}	95%
SoC_{min}	30%
€$_{upMer}$	100 €/MWh
€$_{upRel}$	70 €/MWh
€$_{dnMer}$	20 €/MWh
€$_{dnRel}$	30 €/MWh

6.4.6.2 The Balancing Market model

As described, the Italian ASM is a pay-as-bid market based on hourly contract periods. A simplified market model is implemented to define if the bid is awarded. A maximum accepted price for upward reserve (€$_{upMax}$) and a minimum accepted downward price (€$_{dnMin}$) are defined for each hour: these represents the marginal prices for the market. They are estimated based on the statistical analysis on the Italian ASM described in Paragraph 2.3.3.1, performed on BM data for the period 2017-2019, for the product “Other Services” including the mFRR and RR provision. €$_{upMax}$ and €$_{dnMin}$ are the less convenient (by the system perspective) prices that are awarded on the market for a specific market session. In the simplified BM model, an upward bid is completely awarded if the offered price is lower than €$_{upMax}$ for that hour, it is completely rejected elsewhere (i.e., no partially awarded bids are considered). Oppositely, a downward bid is completely awarded if price is higher than €$_{dnMin}$ (the willingness to pay of the bidder is higher than the marginal awarded one), rejected elsewhere. The average marginal prices and standard deviations coming from the statistical analysis of ASM shown in Figure 2.12 are adopted to define a normal distribution of the hourly marginal awarded prices for each regulation, for both working days (Monday to Friday) and holidays (Saturdays, Sundays and bank holidays). Then, these outcomes are elaborated to feed the model with a random value per hour coming from the probability distribution for that hour of the day. The distribution of the marginal prices fed to the model are reported in Figure 6.11. The probability distributions come from a normal distribution that has been cut to avoid unrealistic (or unfeasible) prices: the upward prices cannot be lower than 60 €/MWh (to be equal or greater than DAM prices [162]), while downward prices cannot be lower than 0 €/MWh (no negative prices are admitted on Italian ASM to date).

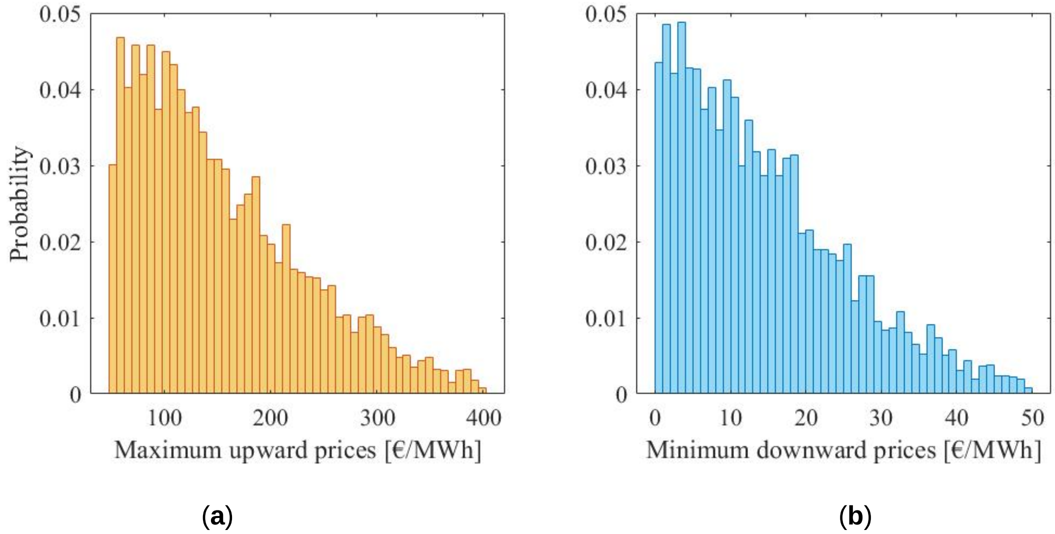


Figure 6.11 Marginal prices fed to the model in case study with implicit SoC management via RR provision: (a) probability distribution of maximum upward prices; (b) probability distribution of minimum downward prices.

The market model receives as input the marginal prices $€_{upMax}$ and $€_{dnMin}$, and the bid prices $€_{up}$ and $€_{dn}$ only in case the respective bid quantity is larger than zero. An upward bid is awarded in case the marginal price $€_{upMax}$ is larger than the bid price, as represented in Figure 6.12. Vice versa, a downward bid is accepted if the marginal price $€_{dnMin}$ is lower than the bid price (the bid price is a willingness to pay).

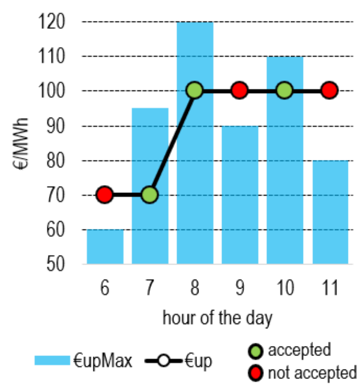


Figure 6.12 Award/rejection of an upward bid by the ancillary services market model

In case no bids are accepted, the BESS does not provide any ASM service for the relevant period. In case only one bid is accepted, this is automatically awarded, and the corresponding quantity must be delivered by the BESS for that hour. In case both bids are accepted, only one can be awarded. In this case, the awarded bid is decided based on the spread between the DAM price and the ASM price.

$$€_{upSpread} = €_{upMax} - €_{DAM} \tag{6.20}$$

$$€_{dnSpread} = €_{dnMin} - €_{DAM} \tag{6.21}$$

where €$_{upSpread}$ is the upward spread, €$_{dnSpread}$ is the downward spread, €$_{DAM}$ is the DAM price. €$_{DAM}$ is equal to the constant value 50.9 €/MWh, representing the average DAM price in Italy for 2019 for South zone [275]. If the upward spread is larger than downward spread, then the upward bid is awarded. Otherwise, downward bid is awarded. This is justified by the assumption that a larger spread is a symptom of a larger need of that regulation by the market. The bids are either awarded completely or rejected, i.e., no partial (in terms of awarded quantity in kW) award is considered.

The outcomes of the Multiservice strategy are the bid quantity and price for each BM session. It is worth noting that the P_{ASM} is always lower than P_n, therefore is in the order of some kW: we assume the prosumer's battery is part of a VPP that bids a larger quantity (e.g., larger than 1 MW) at the price coming from the Merchant/Reliability strategy and it is awarded coherently with the bid price.

6.4.7 Techno-economic evaluation

The energy flows related to all the provided services are estimated. The total absolute energy exchanged (E_{exch}) is the gross summation of the injection (P_{inj} is negative) and withdrawal (P_{with} is positive), as can be seen in Equation (6.22).

$$E_{exch} = \sum_{t=1}^{N} \left| P_{with}(t) - P_{inj}(t) \right| * \frac{1}{60} \tag{6.22}$$

where P_{load}(t) and P_{PV}(t) are respectively the load and the PV production in kW at the time t. Since the sampling rate for both the tool and the lab measurement set is 1 minute, the power is divided by 60 to get the E_{SC} in kWh. Then, the energy flows for the provision of tertiary regulation are computed separately for upward and downward regulation. The requested energy for downward regulation (E_{dnASM}) is the sum of the negative values of P_{ASM}, while for the requested energy upward (E_{upASM}) we must sum the positive ones.

$$E_{upASM} = \sum_{t=1}^{N} |P_{ASM}(P_{ASM}(t) > 0)| * \frac{1}{60} \tag{6.23}$$

$$E_{dnASM} = \sum_{t=1}^{N} |P_{ASM}(P_{ASM}(t) < 0)| * \frac{1}{60} \tag{6.24}$$

Then, the total absolute value of the requested energy for ASM trading (E_{ASM}) is the sum of the absolute values of E_{upASM} and E_{dnASM}. The reliability of the provision is assessed by means of the nonperformance (NP). NP is the amount of energy that is not provided on the total E_{ASM}. To compute the power provided on the ASM (P_P), the power for self-consumption and the auxiliary demand are subtracted to P_{grid}.

$$P_P(t) = P_{grid}(t) + P_{pv}(t) - P_{load}(t) - P_{aux}(t) \tag{6.25}$$

Then, there is non-provided power (P_{NP}(t)) only in case there is a gap between P_{ASM}(t) and P_P (t) when P_{ASM}(t) is not null. P_{NP}(t) is computed as in Equation (6.26).

$$\begin{cases} P_{NP}(t) = P_{ASM}(t) - P_P(t) \quad if \dfrac{|P_{ASM}(t) - P_P(t)|}{P_{ASM}(t)} > 5\% \; and \; P_{ASM}(t) \neq 0 \\ P_{NP}(t) = 0 \qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad elsewhere \end{cases} \tag{6.26}$$

where a 5% of inaccuracy in the provision is tolerated and does not entail penalties. NP (in %) is then obtained as the integral of $P_{NP}(t)$ over the E_{ASM}, as in Equation (6.14).

$$NP = \frac{\sum_{t=1}^{N} |P_{NP}(t)|}{E_{ASM}} \tag{6.27}$$

Finally, the integral of the auxiliary demand P_{AUX} is computed to have the total energy demand by auxiliary systems (E_{AUX}).

Then, a comparative analysis between SC only provision and the Multiservice strategy is proposed. The avoided costs thanks to the increase in self-consumption (R_{SC}) are the net sum of bill cost and injection price with SC only subtracted of the bill cost minus the injection price under the Multiservice strategy framework.

$$R_{SC} = \left(C_{bill} * E_{withSConly} - P_z * E_{injSConly}\right) - \left(C_{bill} * E_{withMultiservice} - P_z * E_{injMultiservice}\right) \tag{6.28}$$

where C_{bill} is the bill cost, P_z is the DAM zonal price (no incentive for RES injection), E_{with} and E_{inj} are the withdrawal and injection in the SC only and Multiservice case.

The gross ASM remuneration is given by the hourly bid price times the provided energy. It is a positive number (a revenue) for upward provision and a negative number (a cost) for downward provision.

$$R_{ASMup} = \sum_{t=1}^{N} €_{up} * P_{ASM}(P_{ASM}(t) > 0) \tag{6.29}$$

$$R_{ASMdn} = \sum_{t=1}^{N} €_{dn} * P_{ASM}(P_{ASM}(t) < 0) \tag{6.30}$$

The net ASM remuneration is obtained subtracting the penalties for NP to the gross remuneration. The penalty (correlated with ASM prices in Italy), is arbitrarily set to a high constant value ($€_{fee}$) of 140 €/MWh. This is multiplied by the absolute NP energy (disregarding downward and upward), to obtain the NP overall penalty (NPP).

$$R_{ASM} = R_{ASMup} + R_{ASMdn} - NPP \tag{6.31}$$

Also, CAPEX of a LiB is considered for a multi-year project analysis comparing the Reference Case with no BESS to the Multiservice case with LiB. All relevant economic parameters and the adopted sources are presented in the following Chapter.

6.4.8 Data acquisition and forecasts

The main economic parameters are presented in Table 6.3, along with the considered sources. Most of the data are consistent with Italian data for first half of 2021, to consider data not subject to the European rise in energy prices experienced from summer 2021 [270]. ASM market prices come from a statistical analysis on a longer period, ending in 2019 not to consider the peculiar behavior of 2020 and the effects of COVID-19 on energy demand and prices [282]. The BESS

CAPEX considers both the battery pack and the PCS. They are based on commercial sources available for Italy at the moment of writing [283], [284] and they also include the incentives in place nowadays in Italy: a 50% invoice discount based on the Ministry Decree [285].

Table 6.3 Economic parameters

Key	Value	Source
C_{bill}	204.5 €/MWh	Italian domestic customer's data for H1 2021[286]
P_z	66.9 €/MWh	Average zonal price for Italian DAM for H1 2021 [269]
ASM marginal prices	Variable	From a statistical analysis on Italian BM for 2017-2019, presented in [287]
$€_{fee}$	140 €/MWh	Italian ASM upward average price for H1 2021 [165]
k_e (CAPEX)	400 €/kWh	Commercial sources [283], [284], also considering 50% discount on CAPEX from [285]
k_p (CAPEX)	150 €/kW	Institutional sources [24]
OPEX	5 €/kWh/y	Institutional sources [24]

The PV and load data are collected within the inteGRIDy project, considering 30 spring days starting from the last week of April up to the third week of May, 2021: four prosumers are considered with different consumptions patterns and energy intensity. The power profiles of 1 week are presented in Figure 6.13 for User 1 (top left), User 2 (top right), User 3 (bottom left), User 4 (bottom right). This layout and time interval will be adopted for all the following diagrams investigating the BESS performance for the prosumers.

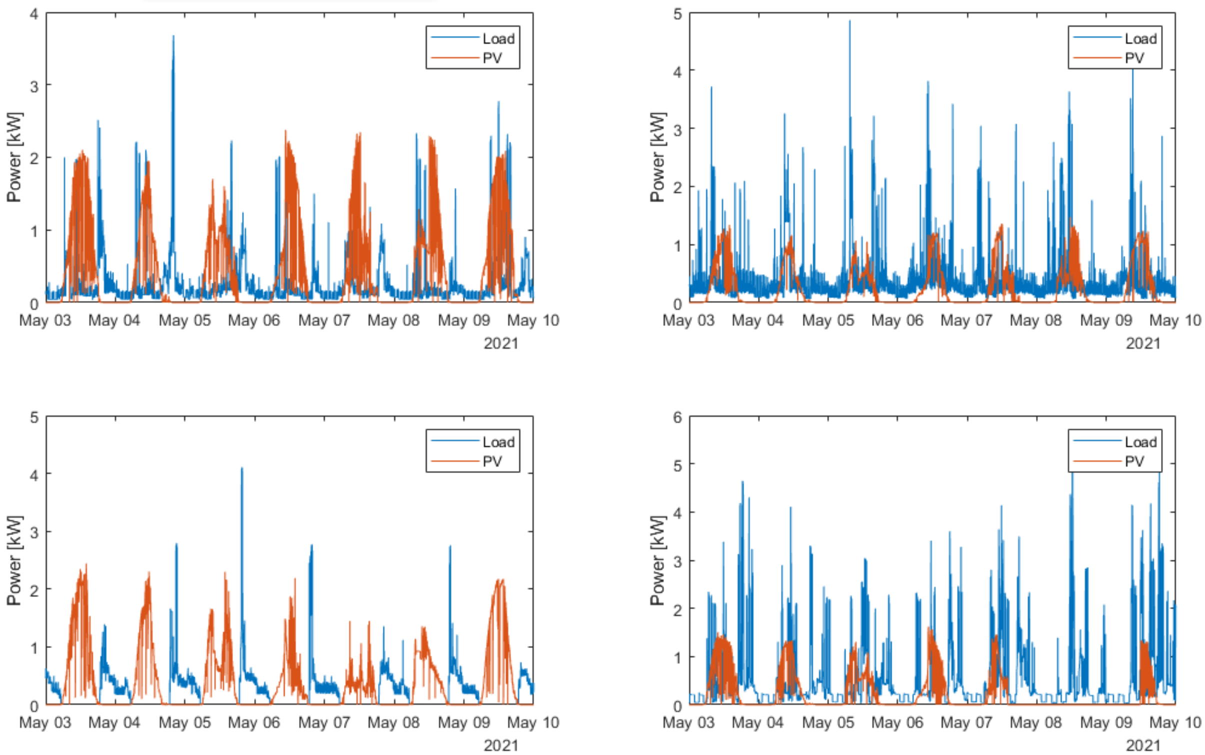


Figure 6.13 Load and PV power profiles for the 30-days period and for the 4 analyzed prosumers.

The load and PV forecast are intentionally based on standard models: the aim of the procedure is validating the Multiservice strategy as a robust control strategy, applicable to a large set of use cases. Therefore, the interest towards the achieved results increases if they are obtained in combination with standard algorithms.

The load forecast works with a simplified approach: it is based on a moving average (MA) forecast. The MA is performed on the previous 40 days, split in weekdays and weekends. Due to investigating each single user, the statistical noise in the results is larger leading to a slightly larger error in the forecast.

For what concerns the PV forecast, the adopted algorithm is a moving-window random forest coming from a study developed in Politecnico di Milano [288] and using 21 days of historical data for training. This is considered a preferred technique for PV forecast [289], [290]. The features used are the hour of the day and the forecasted Global Horizontal Irradiance (GHI). These two features are then correlated to the historical production by the random forest algorithm to obtain an accurate estimate of the future's production. The random forest is generated by 150 decision trees, whose average outcome is adopted as final prediction. Other feature and parameters were investigated, and the presented combination resulted the most suitable for this application. To evaluate the algorithm performance normalized root mean squared error (NRMSE) was adopted. It was normalized on the maximum power produced by the PV plant. The NMRSE for short-term forecasts (i.e., below 6 hours in advance) is in the range 12.8-14.3%.

6.4.9 Results

To assess the performance of the developed model and control strategies (in particular to check the benefits of the Multiservice strategy with respect to the standard control algorithms), some simulations are performed on the previously illustrated 30-days period starting from the beginning of the last week of April 2021.

6.4.9.1 Self-consumption

The first set of simulations concerns the provision of BtM services only: the batteries are increasing the self-consumption of the 4 prosumers. A zoom of the weekly power and SoC profiles of the batteries for the 4 users is proposed in Figure 6.14. As can be seen, battery is subject to a daily cycle, with a charging path during the daytime (negative requested power) and a discharging path for the rest of the time (positive requested power). Often, the lower SoC threshold is reached, and the battery is no more able to provide power to cope with the user's load. In this case, a gap can be seen between the actual and requested power profile (see the bottom part of the diagrams in Figure 6.14, with the actual power in black and the requested one in green). In some cases, a gap can be seen also during charging: this is the case if the PV production excess is larger than the nominal battery power.

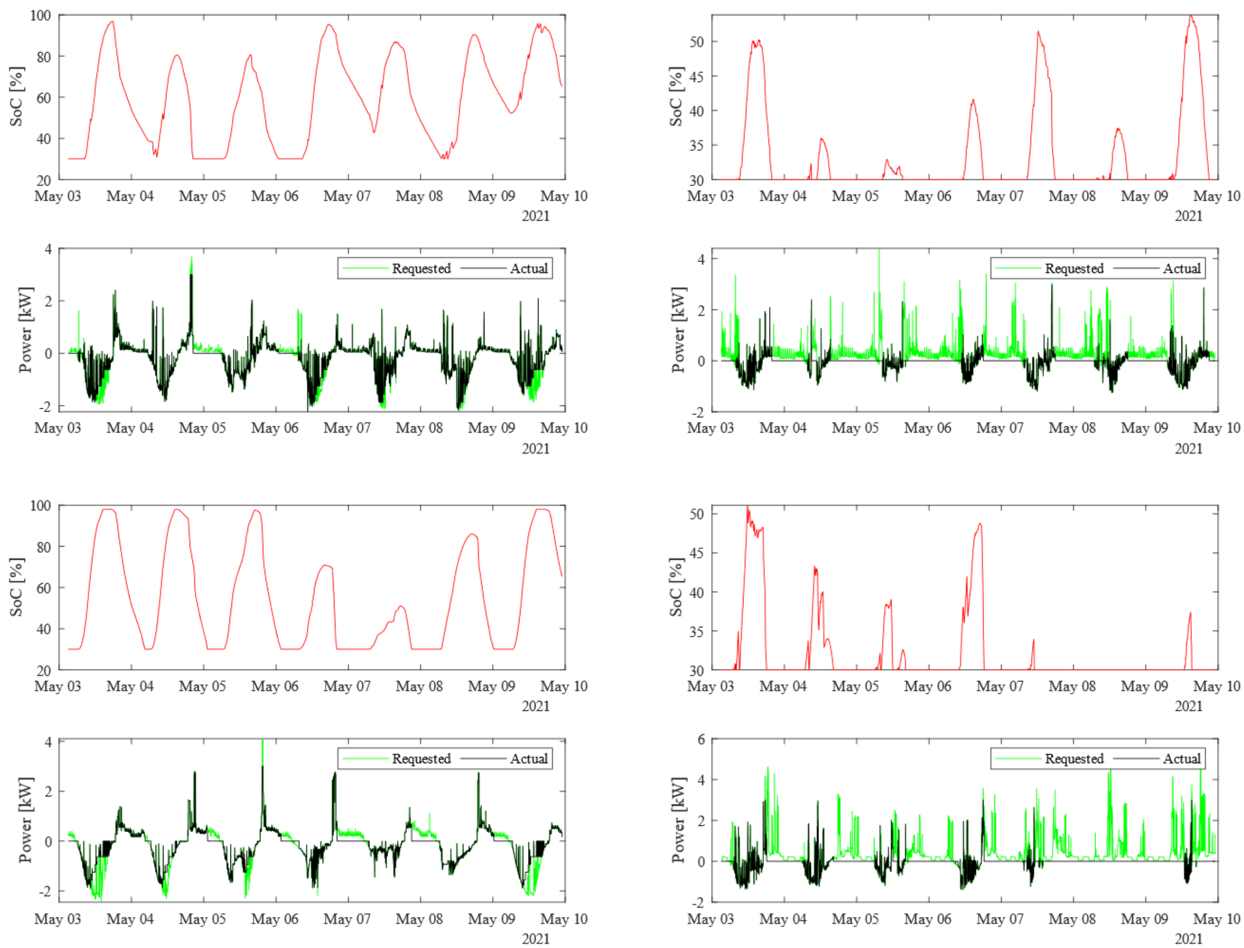


Figure 6.14 Self-consumption only profiles for SoC (top red lines) and power (bottom black and green lines) for the 4 prosumers.

The SoC evolution is depending on the ratio between the installed PV and load: the larger is the load with respect to the PV, the larger will be the time at minimum SoC. This will lead to large energy exchange with grid. For instance, Users 2 and 4 feature a larger load, and the SoC saturates to minimum SoC for most of the time, obliging the prosumer to withdraw from the grid. This can be inspected in top part of Table 6.4. Indeed, the energy exchanged with the grid spans from 100 to 330, highlighting how the considered users have different consumption patterns and only a limited superposition of production and consumption (i.e., a limited self-consumption).

6.4.9.2 Multiservice

A second case study implements simultaneous maximization of self-consumption and ancillary services provision. The control logic exploits the expected available power and energy bands (before SoC saturation) to bid on the market. The SoC and power profiles are shown for the 4 users in Figure 6.15. As can be seen, the SoC trends become spikier, with SoC increasing and decreasing more times with respect to the previously seen daily cycle associated to self-consumption only. The provision of RR requires either to charge or discharge at a constant power for some hours. Also, the SoC saturation is almost always avoided. As a consequence, the requested and actual power profile are almost perfectly overlapping. This is because the Multiservice strategy acts as a passive SoC management strategy [291]: the available band should be larger downward in case the battery is close to minimum SoC (or it is discharging due to self-consumption), and vice versa. Therefore, the RR provision requests power setpoints generally opposite with respect to self-consumption, bringing back SoC to the target SoC (generally around 50%).

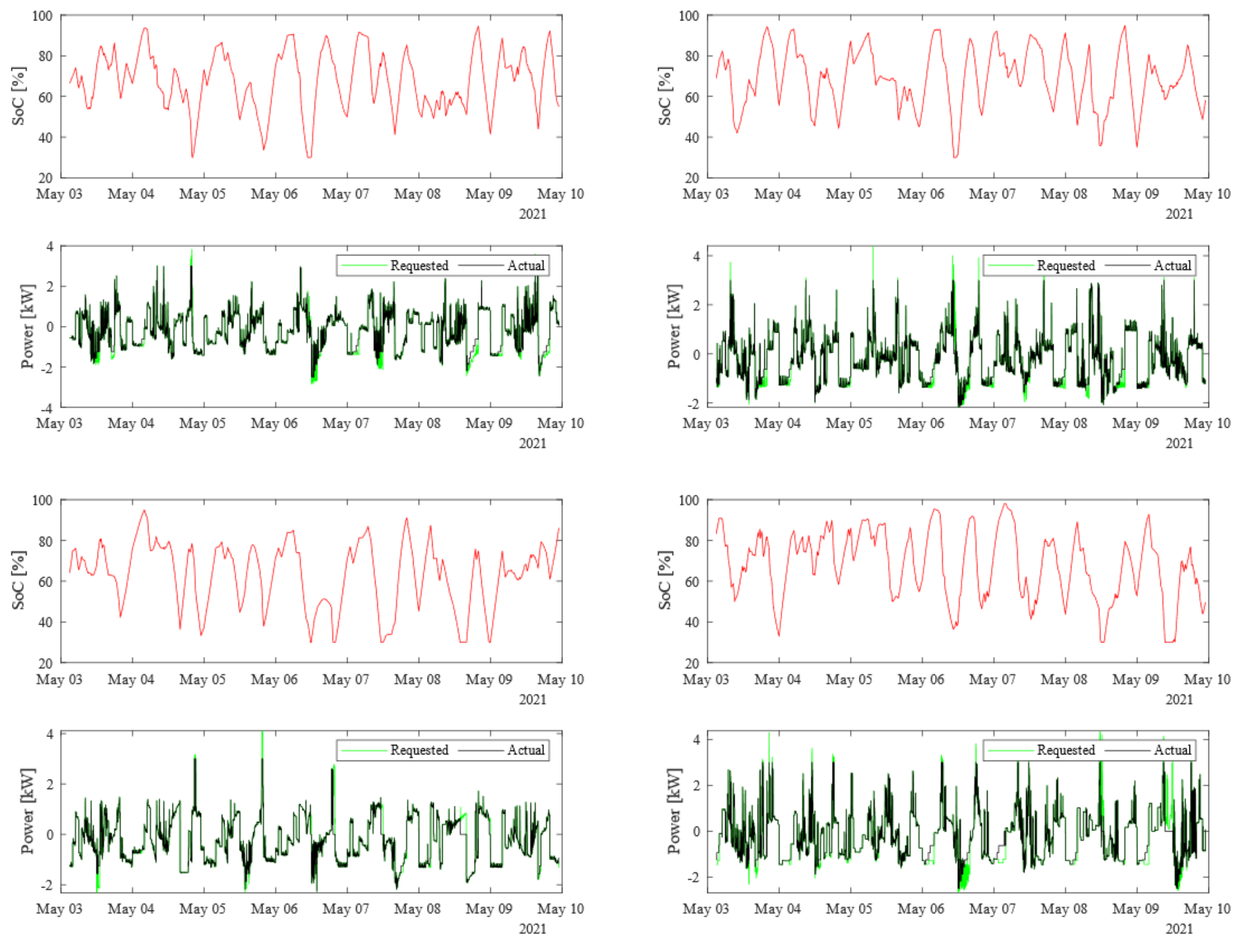


Figure 6.15 Multiservice profiles for SoC (top red lines) and power (bottom black and green lines) for the 4 prosumers.

The SoC profile generally manages to avoid saturation for all the Users, despite their different consumption intensity: indeed, in case the consumption largely overcomes the production, more downward service is offered by the Multiservice strategy, and vice versa. This can also be investigated in Table 6.4, where User 2 and User 4 (energy-intensive users, characterized by long time at minimum SoC in SC only case, as seen in Figure 6.14) show around 50% more downward energy traded and half upward energy with respect to User 1 and 3. A relevant amount of energy is traded on ASM by all the users (more than 500 kWh per month), with a nonperformance (NP) on ASM almost always below 5%. This means that a large amount of flexibility can be offered by distributed systems and provided with a decent level of accuracy (accuracy is seen as the complementary to 1 of NP). On the other side, the exchange with the grid is drastically decreased, meaning that the Multiservice also improves self-consumption.

Table 6.4 Energy flows

Case	User	Exchange with grid [kWh]	TR up [kWh]	TR dn [kWh]	TR tot [kWh]	NP [%]
SC only	User 1	102.6	-	-	-	-
	User 2	272.2	-	-	-	-
	User 3	103.8	-	-	-	-
	User 4	338.9	-	-	-	-
Multiservice	User 1	9.1	209.5	327.3	536.8	5%
	User 2	5	100.8	422.2	523.0	4%
	User 3	16.3	280.5	317.2	597.7	3%
	User 4	8.4	85.5	506.3	591.8	11%
Multiservice - LiB	User 1	14.3	271.4	224.6	496.0	2%
	User 2	7	150.4	300.7	451.1	2%
	User 3	9.9	383.0	244.6	627.6	3%
	User 4	23.9	156.6	392.5	549.1	7%

Table 6.5 summarizes the economic outcomes. For the SC only case, the cash flows are only related to the bill and the DAM revenues. Bills are estimated by considering the average bill cost for a domestic user in Italy in first half of 2021: 20.45 c€/kWh [286]. The injection value takes in account the direct selling of DAM in the same period: 66.9 €/MWh (or 6.69 c€/kWh) [269]. As can be seen, all the users need to withdraw much more than they can inject, and the overall net cash flow (NCF) is always negative.

Multiservice case also involves ASM net cash flows: the provision of upward service is associated to a revenue coherent with the awarded prices, estimated based on the statistical BM model developed. Oppositely, downward calls entail costs for the prosumer: battery is charging (or consumption is satisfied) by the energy absorbed via RR provision. Also, a penalty for NP (NPP) is considered (140 €/MWh). The net revenues are either positive or negative according to the amount of upward and downward provision. In any case, the bill cost shrinks thanks to the drastic withdrawal reduction. In the end, the NCF improves for all the users.

Finally, Multiservice – LiB case considers the presence of a LiB modeled as described before, using the model developed in [250]. While SMC batteries are under study for a future generation of more sustainable batteries [292], the LiB presents generally higher efficiency and lower auxiliary demand. This enhances the quantity of upward service that can be provided on ASM. As can be also inspected by Table 6.4, this allows to shift the traded energy on ASM towards upward energy, entailing a larger ASM net revenue with respect to previous case (generally, +10 € on the 30-days period). In any case, despite the technology, Multiservice strategy always generates a benefit on the exchange with the grid and on the net revenues with respect to SC only.

Table 6.5 Cash flows

Case	User	Bill cost [€]	Inj value [€]	ASM up rev [€]	ASM dn cost [€]	ASM NPP [€]	ASM net rev [€]	NCF [€]
SC only	User 1	18.14	0.93	-	-	-	-	-17.21
	User 2	55.66	-	-	-	-	-	-55.66
	User 3	10.47	3.52	-	-	-	-	-6.95
	User 4	69.31	-	-	-	-	-	-69.31
Multiservice	User 1	0.82	0.34	19.15	9.62	3.57	5.96	5.48
	User 2	0.49	0.17	10.94	12.80	2.81	-4.67	-4.99
	User 3	0.53	0.92	23.64	9.29	2.34	12.01	12.40
	User 4	0.39	0.43	9.41	16.13	9.09	-15.81	-15.76
Multiservice - LiB	User 1	1.31	0.53	23.82	6.70	1.68	15.44	14.66
	User 2	0.35	0.35	15.71	8.51	0.98	6.22	6.23
	User 3	1.08	0.31	31.37	7.54	2.81	21.02	20.24
	User 4	1.90	0.98	14.35	12.31	5.17	-3.13	-4.05

To assess the effectiveness of bidding strategy and market models, Figure 6.16 shows the violin plots of acceptance on the market. On the x-axis, the offered price, while on the y-axis, the awarded quantity. as can be seen by the left part of the picture, a lower price is offered for downward service in case there is less available quantity (SoC is high). In this case, the “merchant” strategy is adopted and the possibility of being rejected increases (i.e., the bid price is often lower than the minimum awarded price for that market session). Instead, in case of “reliability” strategy (second violin of left picture), the bids are always awarded, and the awarded quantity is around 1.2-1.5 kW (on each 3-kW battery): this means that, in case SoC is low, the bidding strategy is willing to pay a high price to buy back energy, and the bid is usually awarded since it is very convenient for the system operator to accept that flexibility. Symmetrically, for upward reserve, the “reliability” strategy bids at 70 €/MWh when SoC is close to upward saturation limit: in this case, the bid is usually awarded, and the awarded quantity is generally high, as can be seen in the right part of Figure 6.16, first violin. In case of lower SoC (see the violin to the far right), the “merchant” strategy bids at a larger price and the market model returns very often a rejection of the bid.

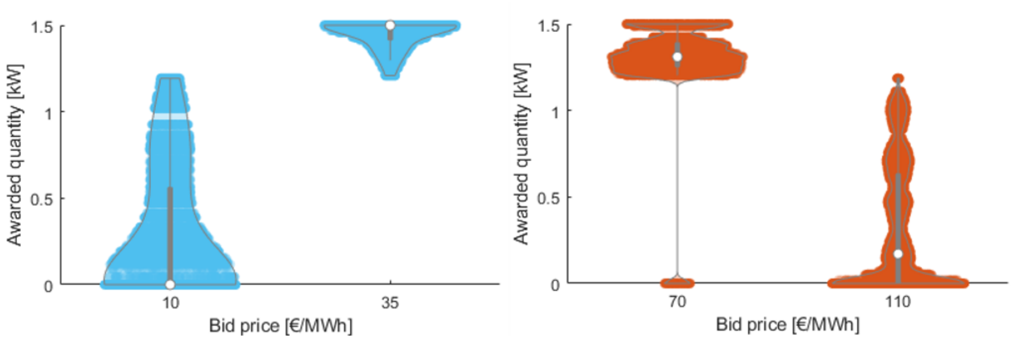


Figure 6.16 Violin plots for the awarded ASM bids. In blue, the downward bids, with price (x-axis) and quantity (y-axis) awarded. In orange, the upward price and quantity.

As suggested by the previous analyses, the Multiservice strategy seems to be feasible and to give economic benefits for different users. In any case, in Table 6.5, the NCFs for the prosumers range from positive to negative even in case a Multiservice strategy is adopted. To better understand the magnitude of each user's benefit, the analysis shown in Figure 6.17 is proposed. For each User, the NCFs of the three case studies are presented. From the SC only case, the Multiservice adoption always give the greater benefit. The impact is larger for those users who have a larger consumption with respect to the PV production: User 2 to the top right and User 4 to the bottom right recover around 50 € per month, mainly thanks to the drastic decrease in withdrawal. The switch towards a LiB then provides a marginal gain (around 10 € per month), homogeneous for all the users. In the end, the larger economic benefit is shown for the energy-intensive customers (even if the NCF keeps negative for User 4). It is worth noting that in this analysis only the differential cash flows are taken in account: i.e., no CAPEX and OPEX are considered, as well as the increase in BESS decay due to the more intensive use for Multiservice strategy.

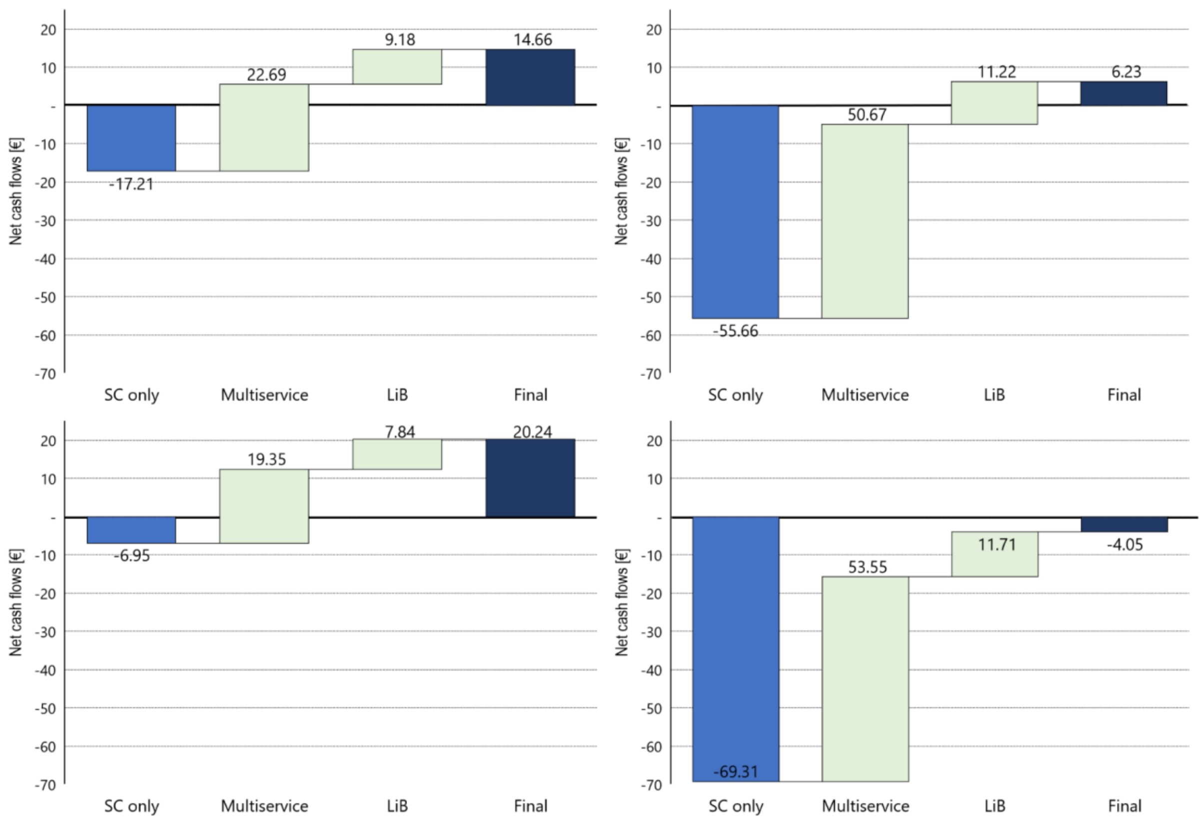


Figure 6.17 Comparative economic analysis of the three case studies.

6.4.9.3 Multi-year analysis on Multiservice – LiB case

To better cope with the mentioned limitations – such as the neglection of CAPEX, OPEX, and BESS life – a multi-year analysis is eventually given. The results are schematically presented in Figure 6.18. The multi-year analysis compares the Multiservice – LiB case with a Reference Case where no battery is present (only PV and loads are considered). In the reference case, if instantaneous production overcomes consumption, the energy is injected at the zonal price, vice versa the energy is withdrawn at the bill price. The study case is selected for the availability of a reliable aging model for LiB [256] and for the availability of up to date (2021) CAPEX data for domestic batteries in Italy. The CAPEX considered are the average of commercial sources [283], [284] for a battery with E/P equal to 1 hour, also considering the incentives in place in

Italy at the moment of writing (50% invoice discount on the total cost of the battery) [170]. The adopted equation is the following one.

$$CAPEX = E_n * k_e + (P_n - E_n) * k_p \tag{6.32}$$

where, as presented in Table 6.3: k_e is 400 €/kWh, coherent with what illustrated before; k_p is 150 €/kW, to take in account of a duration of the battery different from 1 hour and therefore of a larger or lower cost of inverter [293]. The OPEX are 5 €/kWh/year elaborating on data from [24].

Beside costs, the net revenues related to electric bill management and ASM are considered. For bill management, the difference between the net cost of exchanging energy with the grid in the Reference Case and in the case study is considered. By adding the battery, the injection value decreases, since the energy is absorbed and then released for self-consuming, reducing the cost of the bill, too: generally, the net economic impact is largely positive, especially for the energy-intensive users (see the green columns of User 2 and 4 in the right part of Figure 6.18). The ASM net value is the sum of the upward revenues and the downward costs: it increases in case the ratio between PV production and load is larger, as can be seen by the blue columns on the left part of the figure. Generally, the impact of increased self-consumption is larger and allows to recover the CAPEX in a brief time for energy-intensive users: as can be seen inspecting the black dotted lines, the payback time is around 5 years for User 2 and 4, much higher for User 1 and 3. It is worth noting that this level of self-consumption can only be achieved thanks to the Multiservice strategy: without it, the SoC saturation issues shown in Figure 6.14 would be present. BESS lifetime is considered only for replacement cost (i.e., no residual value at the end of year 5 is included): if the End of Life (EoL) occurs, a replacement cost proportional to CAPEX is paid. In this case, the BESS lifetimes are always larger than 5 years, ranging from 7.8 years (for User 4) to 9.2 years for User 2. All the economic evaluation considers 2% of actualization rate.

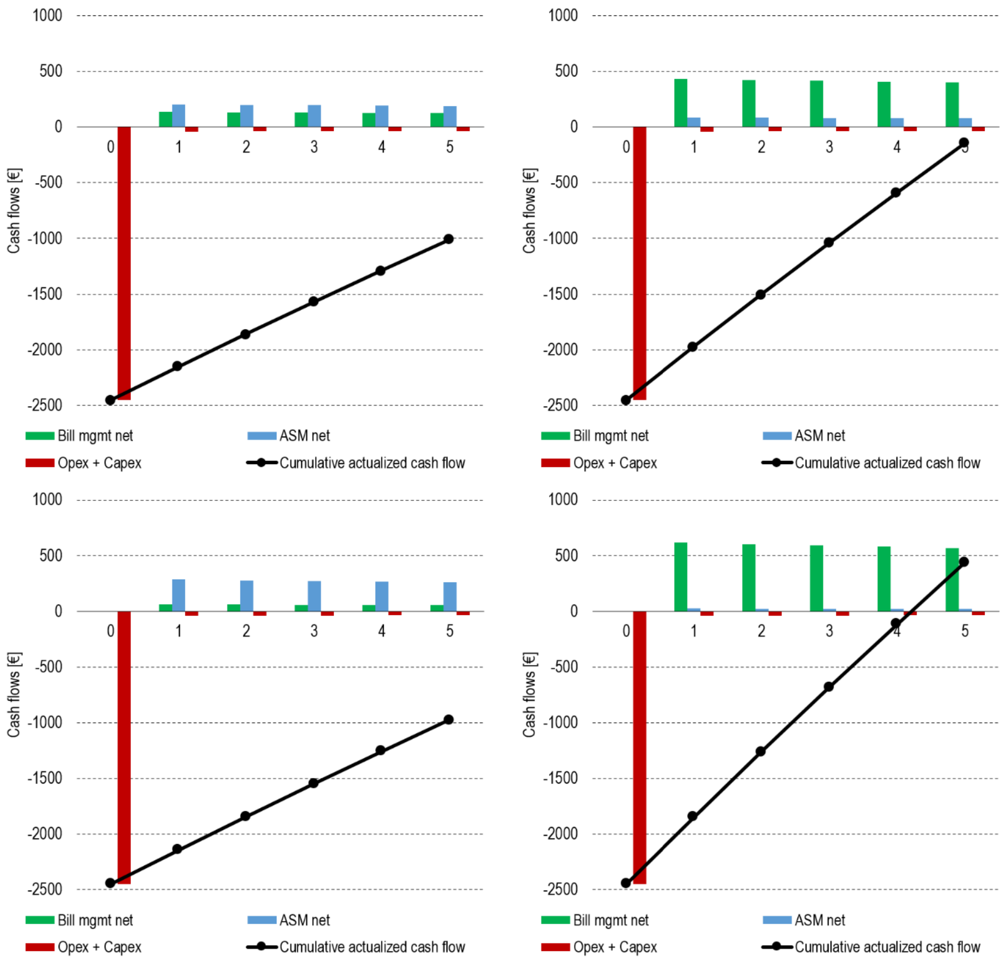


Figure 6.18 Multi-year project analysis on Multiservice – LiB case.

6.4.9.4 Extending the results: the flexibility from domestic BESS at Italian level

This paragraph briefly investigates the awarded quantities shown in Paragraph 6.4.9.2 to extend in a simplified way the results to the Italian system: this show what can be achieved in case of an extensive deployment of residential storage controlled by a Multiservice strategy. Considering the distribution of bid power in Figure 6.16, in case the domestic prosumer is involved in a VPP and the aggregated quantity is bid, for reaching the 1 MW thresholds (imposed as minimum bid size on the Italian BM), at least 1000 houses must be gathered. This would allow to present a bid on the market for the 20-30% of the time (i.e., when more than 1 kW per house is bid). Focusing on the upward flexibility, it can be delivered mainly on the daytime, since there is an excess of PV with respect to load. In addition, a larger VPP could increase the share of time in which a valid bid can be proposed. As alternative, the minimum bid size on ASM could be further reduced: in Italy, a reduction from 1 MW to 0.2 MW is discussed, with the purpose of opening the market also to low voltage users and electric vehicles [294]. Also, what can be seen is that a 3-kW battery is often able to propose 1 kW of flexibility on the ASM. In Italy, the mFRR needs are 500 MW at peak (i.e., during the daytime), 350 MW off-peak (i.e., night and Sundays) [52]. Therefore, at least around 1500 MW of domestic batteries should be installed to cope with the peak needs, while around 700 MW would be compatible with the provision of off-peak mFRR. As per 2020 data, already 170 MW of small-scale batteries are installed in Italy [172]: in the daytime, for a relevant share of the time, they could provide around 11% of the peak needs for mFRR, if controlled with a Multiservice strategy (see Figure 6.19).

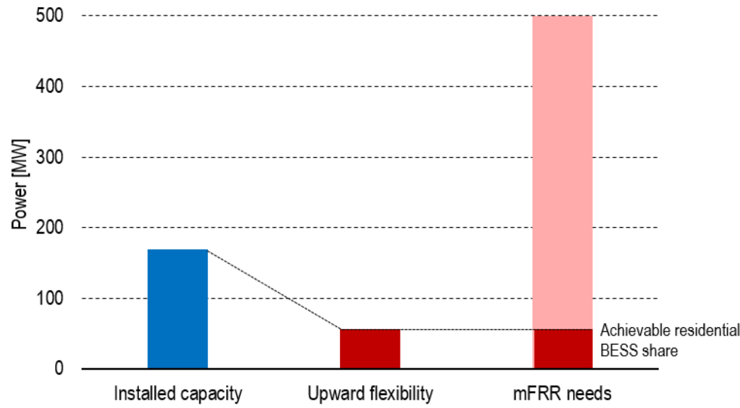


Figure 6.19 Daytime flexibility by residential BESS installed capacity (2020) with respect to Italian mFRR needs.

6.4.10 On-field test

We report in the following paragraph the outcomes of a real test of Multiservice strategy adopting the asset deployed in the inteGRIDy project. The test is a 2-days test. The domestic battery is a 3 kW – 8 kWh battery located in the Politecnico di Milano's IoT-Storage Lab and connected with the project workstation. As previously illustrated, the battery local controller has a built-in self-consumption routine that aims to keep null (if possible) the exchanges with the grid. The operating data are sent real time to the central workstation (one value per minute). The controller is on the workstation, and it implements the Multiservice strategy:

- it receives the on-field data;
- it forecasts the PV and load;
- it estimates the available energy based on the forecasts and on the battery SoC;
- it bids following the "merchant/reliability strategy";
- it receives the outcomes from the market model (i.e., awarded or rejected);
- it computes the setpoints related to ancillary services provision;
- it sends the setpoints to the battery.

The battery receives the setpoint and it superimpose it on the self-consumption strategy. The resulting profiles in terms of SoC (upper diagram) and power (lower diagram) are presented in Figure 6.20. As can be seen, the battery starts the test around 55% of SoC. It is awarded for downward provision from 6PM to midnight. In that time period, indeed, the load is foreseen to be larger than the PV production. During the nighttime, the self-consumption (SC, light blue line) request is always to inject energy to feed the load. In any case, the downward provision (ASM_{dn}, in blue) of around 1.5 kW allows a negative requested power (P_{req}, green line) and the SoC gets close to 100%. At 11PM, a positive availability is computed and the bid is awarded, so that the battery provides upward regulation (ASM_{up}, in red). Then, SoC gets steady around 50% and increases around 2PM of October 20. Therefore, in the next period, an upward bid is proposed. The combined request of the upward bid and of the increasing net load (we are in late afternoon) brings the SoC very close to minimum saturation (30%). Therefore, a "reliability" downward bid is performed, and the battery starts a long charging period, getting closer to maximum SoC. As can be seen, above 80% the capability of providing positive power decreases: there is NP around 3-4AM, since the battery can provide just partially the requested power and the real power (P_{real}, black line) departs from P_{req}.

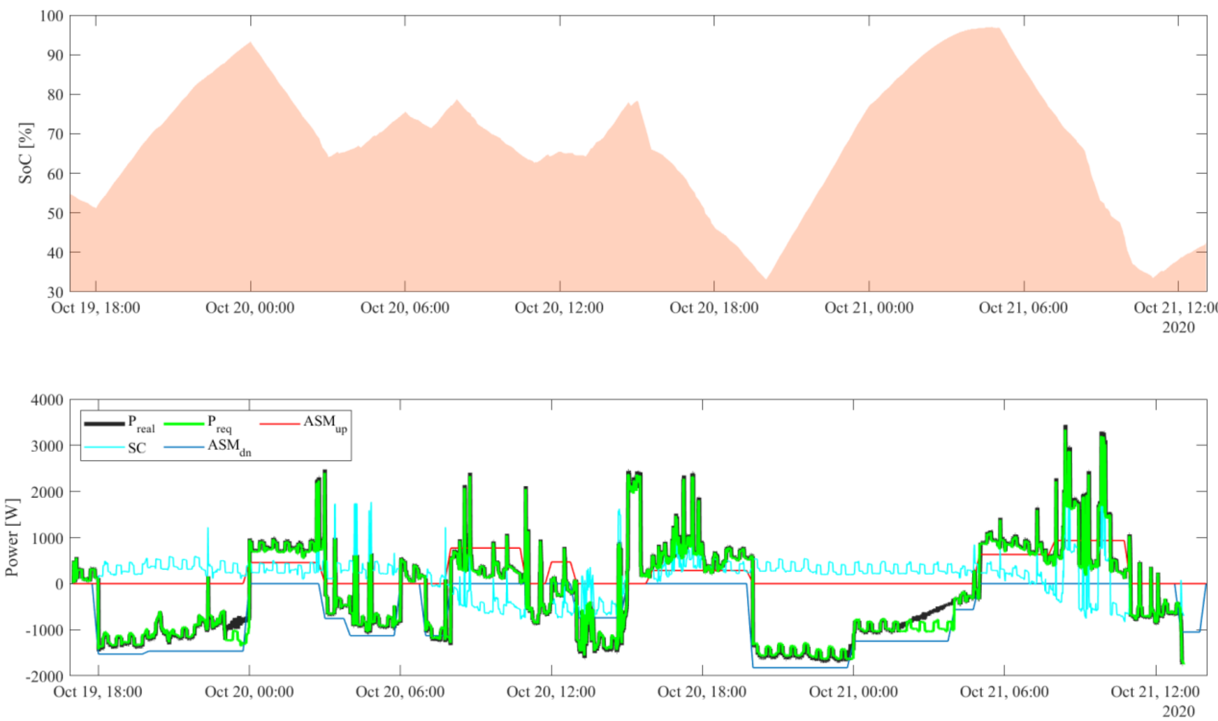


Figure 6.20 SoC (upper part) and power log from the 2-days test on the real domestic battery.

The outcome of this on field test is generally positive, since it allowed to check that the whole architecture is suitable for the reliable provision of Replacement Reserve and the Multiservice strategy avoids (or limit) SoC saturation.

6.5 Utility scale, front-of-the-meter Multiservice

The second case study is focused on the provision of multiple FtM service by a utility-scale BESS. For what said in Paragraph 6.2 and 6.3, in case it is admitted by the regulation (and it has a dedicated SoC management strategy), a sequential service stacking could imply benefits since it can maximise the exploitation of the most profitable service. The secondary service is provided either when it is not possible to deliver the primary application, or when the SoC management requires it. In the Italian panorama, the most profitable application for utility-scale BESS (i.e., 5-25 MW of qualified power) is Fast Reserve (FR) provision. It is contracted for 5 years with an initial auction, but it is requested for 1000 hours yearly only. Within the 1000 availability hours, the BESS qualified power should be dedicated exclusively to Fast Reserve. For the rest of the time, the BESS has no duties for Fast Reserve and can be dedicated to other applications. Therefore, given the analysis proposed in Paragraph 6.3.1 considering the profitability of opportunity for BESS in the Italian framework, the most remunerative strategy would be qualifying as much as possible the BESS power for FR (thus, dedicating it exclusively to FR in the availability hours), and then provide a service that allows implicit SoC management for the remainder of the time: i.e., sequential stacking. For a better description of the FR context and control strategies, please refer to Paragraph 2.3.1.2. Two case studies are tested, to compare the benefit of Multiservice with respect to the standard control strategy.

- The reference case is aimed to provide FR only (case “FR only”). The BESS provides FR in the availability blocks (1000 hour per year) and stays idle for the rest of the time. The battery gets to target SoC (55%) 1 hour before the starting of each availability block. This strategy could work for guaranteeing the best performance and reliability for FR. In any case, a long time idle and the devotion to a single service could decrease efficiency and economic profitability of the provision [26], [222]. It is worth noting that, since the auxiliary systems deal with the HVAC system, they cannot be shut-off in the idle period: this would lead to uncontrolled temperature trends in the battery room. This cannot be accepted by the BESS operator, since unexpected calendar aging could occur, decreasing BESS lifetime.
- A Multiservice strategy is then proposed (case “Multiservice”), including the provision of Replacement Reserve (RR) or tertiary frequency control on the Italian balancing market (BM). It is provided outside the availability blocks, up to 1 hour before entering the blocks. The bids are offered based on the estimated available capacity of the BESS, computed in the RR controller of the BESS model. The acceptance of the bids is based on a BM model fed with statistical data of the Italian market.

The procedure is implemented in a Simulink tool, gathering the control strategy-related algorithms and the BESS model, that is an update of the one presented in Chapter 4. The single parts will be detailed in the following sections, while the overall simplified block diagram is shown in Figure 6.21. The scheduler is updated based on the considered case study: the FR only case only includes SoC management and FR control blocks; the Multiservice case also include the RR control and the BM model.

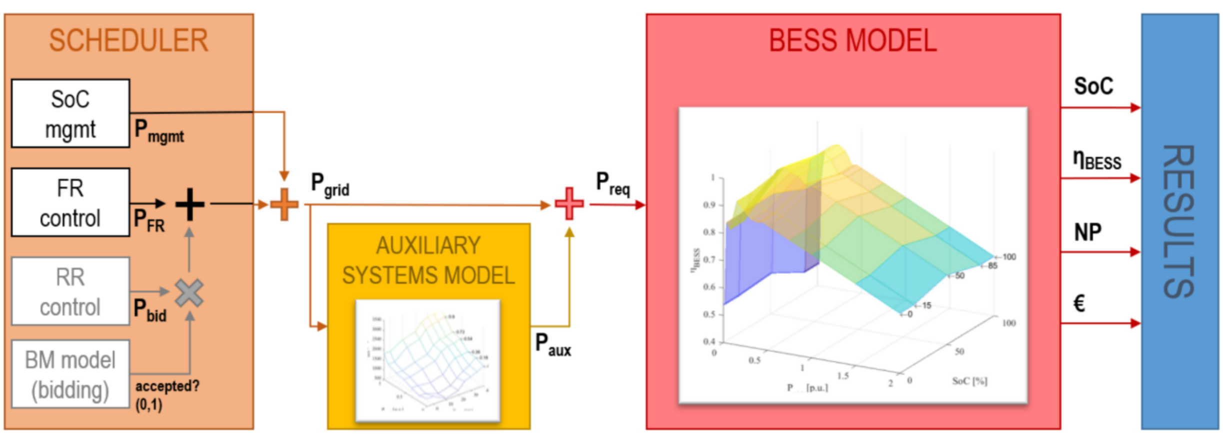


Figure 6.21 Block diagram of the proposed simulation tool.

6.5.1 Updating the BESS model

The model presented in Chapter 4 is updated on purpose for this study: coherently with a power-intensive service, the energy to power ratio (E/P ratio) of the batteries included in Fast Reserve Units (FRU) is generally very low (down to 0.5 h), the efficiency lookup table has been extended to the domain not covered by the experimental campaign. In detail, for what concerns c-rates above 0.439C, the efficiency follows a linear decreasing trend coherent with the behavior shown for c-rates between 0.316C and 0.439C. The updated lookup table is presented in Figure 6.22. The measured portion is the same presented in Figure 4.12. Adopting a linear trend, the right part of the lookup table has been added.

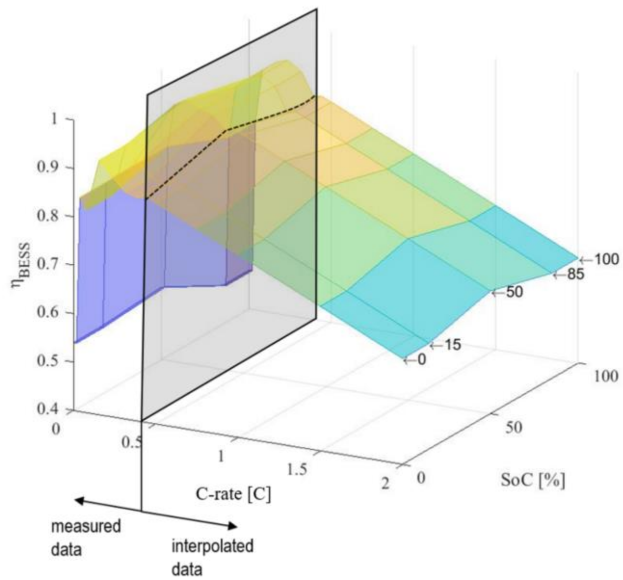


Figure 6.22 The updated lookup table, showing the measured data and the interpolated portion.

The BESS sizing for the study is presented in Table 6.6. It is coherent with the prescriptions of the FR pilot project previously illustrated. Specifically, the relation among P_n, P_{qual} and P_{mgmt} is described in the following. FR rules include the possibility of SoC management, following a dead band strategy: while the frequency deviation is within the dead band, the battery can offset its power setpoint by the power devoted to SoC management (P_{mgmt}) – limited between 0-25% of P_{qual} – to get the SoC back to a target SoC (e.g., 55%). In any case, the P_{mgmt} and the P_{qual} must be available separately on the asset: i.e., its P_n must be the greater or equal to the sum of them. The energy flows for SoC management are valorized at the Day-Ahead Market (DAM) price, both for charging (to pay) and discharging (to receive) phases.

Table 6.6 BESS sizing for utility-scale Multiservice

Key	Value	Unit
Nominal energy E_n	5	MWh
Nominal power P_n	10	MW
Qualified power P_{qual}	8	MW
SoC management power P_{mgmt}	2	MW
Target SoC SoC_{target}	55%	%

6.5.2 The Scheduler

The controller of the BESS model is developed in the framework of this study to host:

- the FR control;
- the SoC management strategy (a dead-band strategy coherent with prescriptions);
- the RR control;

- the bidding strategy on BM for RR provision, including the BM model.

The listed components of the scheduler are described in the following.

6.5.3 Fast Reserve control

This block implements the control strategy for the FR. It is schematically presented in the flowchart of Figure 6.23. A local power system frequency measure (taken by own data referred to Continental Europe Synchronous Area), with a sampling rate of 1 second, is used to calculate the frequency deviation with respect to the target value of 50 Hz; this is converted into a power setpoint through the droop curve presented in Figure 2.7, and it is imposed to the BESS as reported by Algorithm 1.

It is possible to see that the fade-out, induced after 30 seconds of non-critical frequency deviation, is interrupted if critical conditions are reached (deviation above level #2) or if frequency deviation changes its direction (from over to underfrequency or vice versa).

Algorithm 1: *BESS* FR *set point management*

Input: Frequency deviation Δf_t with respect to 50 Hz, measured each second

Output: Power set-point of the BESS for each second within the simulated period *TimePeriod*

counter = 0, j for underfrequency levels, i for overfrequency levels

for *t* **in** *TimePeriod* **do**

$P^t_{FRU} \leftarrow$ Apply droop curve

if *counter == 30* **do**

    Start BESS fade-out from current power set-point P_{FRU} to 0 in 300 seconds

    $P^t_{FRU} \leftarrow P^{t-1}_{FRU} - P_{FRU} / 300$

else if Δf_t **isin** $[level\ \#1_j, level\ \#2_j] \cup [level\ \#1_i, level\ \#2_i]$ **do**

    Increment the counter

    counter ← counter +1

else *counter = 0*

if $\Delta f > level\ \#2_i\ (level\ \#1_j)$ **or** $\Delta f > level\ \#2_j\ (level\ \#1_i)$ **do**

    $P^t_{FRU} \leftarrow$ Apply droop curve

    counter = 0

return *BESS power set-point* P_{FRU}

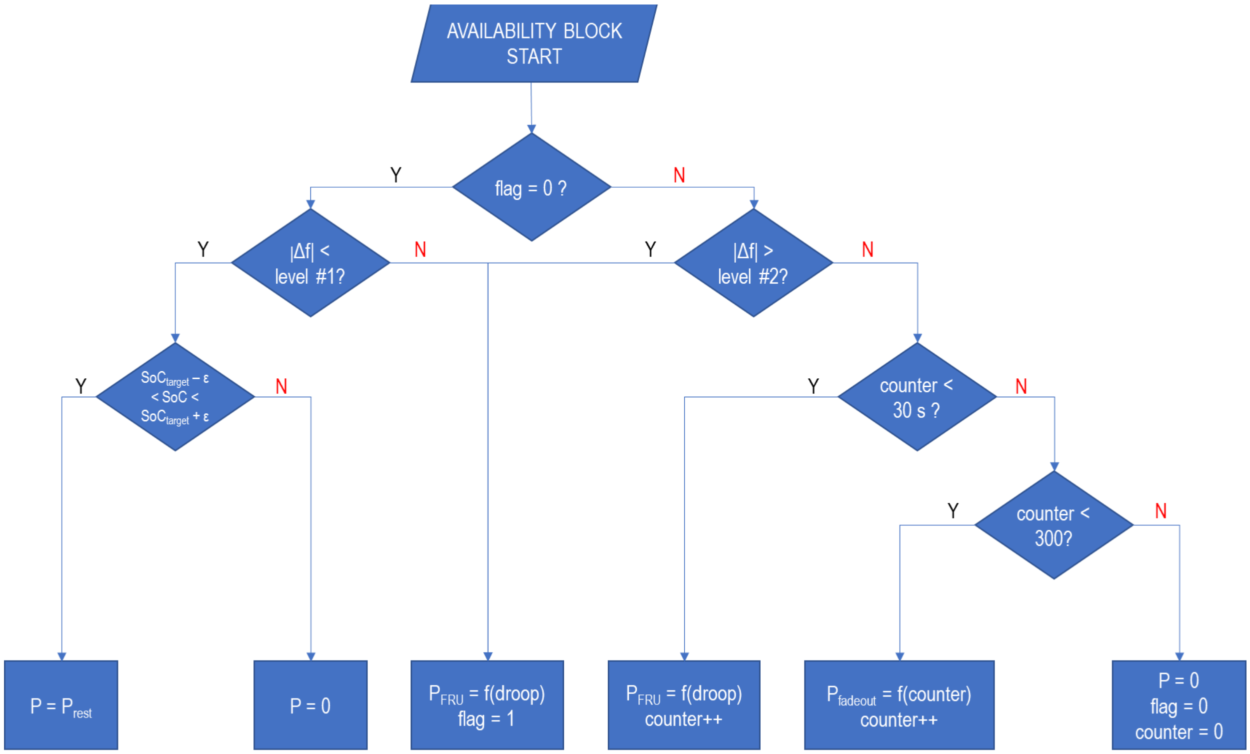


Figure 6.23 FR BESS scheduler flowchart.

With respect to the service duration (i.e., the minimum amount of time the BESS is asked to guarantee the service, resulting in a constrain to the minimum BESS energy content), FR rules require a minimum provision of 15 minutes at the qualified power for each service session, which lasts for two hours. For values above this energy requirement, the FRU is authorized to suspend the FR provision. This is to limit the required energy content, coherently with the power-intensive nature of FR. Also, this mechanism is replicated in the scheduler. The main values for BESS dynamic response are detailed in Table 6.7.

Table 6.7 Fast Reserve requirements influencing BESS dynamic response.

Key	Value	Notes
Dead band (level #1)	±20 mHz	
Full activation (levelSAT)	±150 mHz	
Emergency threshold (level #2)	±180 mHz	Above this threshold, fade out is disabled.
Fade-out trigger	30 s	In case the Δf remains this time within level #1 and #2, a deramping of power starts.
Fade-out duration	300 s	
Maximum energy delivered	15 equivalent minutes	In 2 hours, this is the maximum energy content that can be requested to the FRU.

With respect to the identification (and the simulation) of the FR blocks, i.e., those 1000 hours per year where the TSO will ask the activation of the FR service, a probabilistic analysis has been performed. In particular, the frequency profile registered for Continental Europe

Synchronous Area in 2016 has been considered. Supposing that the TSO would ask for the FR service when it needs it the most, hence in the most demanding frequency conditions for the system, availability blocks have been determined selecting the 100 non-overlapping most demanding 10 hours intervals, as described by Algorithm 2. This results in a set of availability blocks for which there is the largest cumulative frequency deviation in 2016.

Algorithm 2: *FR availability blocks selection*

Input: Cumulative hourly frequency deviation with respect to 50 Hz in 2016 (*ΔF2016*)

Output: Set of 100 availability blocks for FR provision (*FRΔF*), each one lasting for 10-hours

CΔF: 10-hours cumulative frequency deviation blocks

for *t* **in** *ΔF2016* **do**

Compute the 10-hours cumulative frequency deviation

$C\Delta F^t \leftarrow \sum_t^{t+10} \Delta F^t 2016$

return 8774 blocks of 10-hours cumulative frequency deviation

List the blocks in descending order: $C\Delta F^t \rightarrow C\Delta F^t\downarrow$

$FR\Delta F^1 \leftarrow C\Delta F^1\downarrow$, $s = 2$

for c **in** $C\Delta F^{2\rightarrow 8774}\downarrow$ **do**

while *s <= 100* **do**

  if $C\Delta F^c\downarrow$ **is not** *overlapping* **with** $C\Delta F^{1\rightarrow c-1}\downarrow$ **do**

    $FR\Delta F^s \leftarrow C\Delta F^c\downarrow$

    $s \leftarrow s + 1$

return *100 availability blocks of 10 hours FRΔF*

The yearly frequency profile for 2016 and the availability blocks are reported in Figure 6.24. In the top part of the diagram, the frequency trend is shown. In the bottom part, the availability blocks are the vertical red bars. As it can be seen, they are spread all over the year, with a larger concentration in January and October.

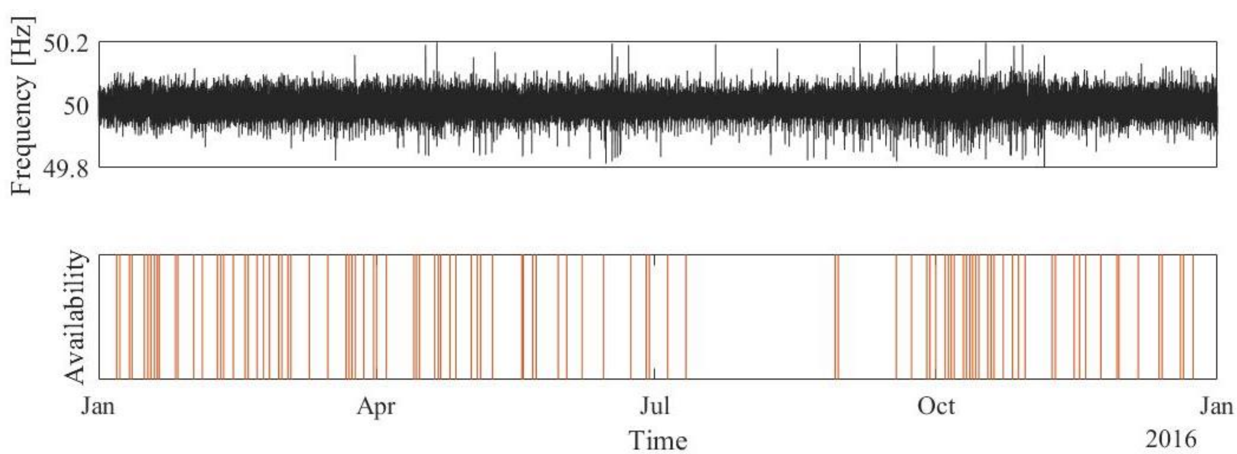


Figure 6.24 Yearly frequency profile (2016) (top) and corresponding FR availability periods selected (bottom).

6.5.3.1 SoC management strategy

The SoC management strategy is necessary to avoid saturation at minimum or maximum SoC limits (0 and 100%). As per the technical rules of the pilot project previously illustrated, the SoC management strategy is a dead-band strategy that is activated whenever the battery has less than 15 remaining equivalent minutes either in the upward or in the downward direction during the whole duration of the availability blocks. Therefore, it has a double threshold [291], since it activates if:

- the dF is in the dead-band and
- the SoC is outside a safety window.

The safety window is computed on SoC, considering the upper (SoC_{hi}) and lower SoC (SoC_{lo}) limits coherent with 15 minutes of service provision as follows.

$$SoC_{hi} = SoC_{max} - P_{qual} * \frac{15}{60} * \frac{1}{E_n} * \eta_{avg} = 63.2\% \tag{6.33}$$

$$SoC_{lo} = SoC_{min} + P_{qual} * \frac{15}{60} * \frac{1}{E_n} * \frac{1}{\eta_{avg}} = 43.5\% \tag{6.34}$$

where SoC_{max} is maximum SoC of 100% SoC_{min} is 0% and the η_{avg} the average efficiency of the battery [250], considering the actual SoC variation for delivering the full activation power for 15 minutes. Furthermore, the SoC management block activates 1 hour before the beginning of each availability block. The SoC management strategy is summarized in Algorithm 3.

Algorithm 3: *SoC management procedure*

Input: Frequency deviation Δf_t and availability blocks of 10 hours *FRΔF*

Output: Power set-point for SoC management P_{mgmt}

$FR\Delta F^s_h$ *with h from 1 to 10: hours composing the availability block s*

for *t* **in** $[FR\Delta F^s_0 ; FR\Delta F^s_{10}]$ **do**

if Δf_t **is in** *dead-band* **and** *(SoC>56%* **or** *SoC<52%)* **do**

P_{mgmt} = 2 MW

$SoC^{t+1} \leftarrow SoC^t \pm P_{mgmt}/(3.600 * E_{nom})$

return *SoC management set-point* P_{mgmt}

6.5.3.2 The RR control strategy

The Multiservice strategy considers the provision of RR on the Italian BM [144] while the FRU is outside the availability blocks. The RR, as an asymmetric service, has been selected and the Multiservice (MS) case has been set-up as follows. Asymmetric quantities of regulating power can be offered on the market, based on the available energy content (therefore, based on SoC). The BM implementation is the same presented in Paragraph 6.4.6.2. for the estimation of the available bands, it must be considered that there are no contribution for the primary application (due to the sequential stacking). Therefore, the bid volumes are returned as in Algorithm 4.

Algorithm 4: *BESS RR set-point management*

Input: SoC(h-1) where h is the first hour of the next BM session

---

Output: Bid volume (power set-point) for RR provision

if *SoC(h-1) < SoC_{target}* **do**

$P_{RR,up} = 0$

$P_{RR,dn} = min\left(P_n\, ; \frac{SoC_{max} - SoC(h-1)}{100 * t_{mkt}} * \frac{E_n}{k_{mkt}}\right)$

if *SoC(h-1) > SoC_{target}* **do**

$P_{RR,up} = min\left(P_n\, ; \frac{SoC(h-1) - SoC_{min}}{100 * t_{mkt}} * \frac{E_n}{k_{mkt}}\right)$

$P_{RR,dn} = 0$

return *Bid volumes $P_{RR,up}$ and $P_{RR,dn}$*

The parameter k_{mkt} is added as a safety margin to arbitrarily decrease (in case it is greater than 1) the bid quantity and give priority to reliability reducing market participation. The award/reject rule is based on the previously illustrated BM model (see Paragraph 6.4.6.2). the bid price is computed as in equation (6.1), therefore adopting the SoC-dependent bidding strategy proposed in Paragraph 6.3.3.3.

6.5.3.3 BESS power control logic

Finally, the output of the blocks described above provides a power set-point associated. The requested power (P_{req}) is the following.

$$P_{req} = P_{grid} + P_{mgmt} + P_{aux}, \tag{6.35}$$

where P_{grid} is the power for the provision of grid services, summing the power for FR (P_{FR}) and RR (P_{RR}); P_{mgmt} is the power for SoC management; P_{aux} is the demand of the auxiliary systems as implemented in the BESS model presented in Chapter 4.

6.5.4 Multi-year techno-economic analysis

Two case studies are considered. The first one only implements FR (FR only). The latter implements a Multiservice strategy with FR provision and BM participation outside the availability blocks. The cases are compared in terms of energy flows, technical performance, and economics.

6.5.4.1 Technical performances evaluation

For what concerns energy exchanges, and in coherence with the project rules [296], the following flows are considered.

- The energy provided for FR is associated to P_{FRU} as the absolute energy delivered during the availability hours as of the droop curve, including the deramping strategy. This energy is not explicitly paid, but the high reliability of the provision is a requirement for being awarded with the capacity-based remuneration obtained in the auction (k€/MW/year).
- The energy for SoC management, related to positive and negative P_{mgmt}, during the availability hours. This energy is valorized at the DAM price, both for charging (to pay) and for discharging (to receive), following the FR rules.

- The energy provided for RR is remunerated at the awarded price, coming from the developed market model. In this case, the reliability of provision is important, too. A fee for non-performance is implemented, energy-based (€/MWh).
- The energy for auxiliary systems, related to their power consumption (P_{aux}) is estimated by the model. This demand is fed either by the battery itself (that self-discharges) or by withdrawal from the grid (this in case the battery is exhaust).
- The energy withdrawn is related to the withdrawal outside the availability hours. The withdrawal (P_{with}) is paid at the bill price. This is a conservative choice since the framework in Italy is updating to guarantee that all the energy that is withdrawn for a next reinjection can be paid at the zonal price, as per [297]. The operational performance could aim to reduce the withdrawal by the provision of downward services, instead.

The operational performances are evaluated based on both the non-performance (NP) parameter and the operational efficiency. The NP-related power for FR ($P_{NP,FRU}$) is computed by (6.36).

$$\begin{cases} P_{NP,FRU} = P_{FRU} & \text{if } |P_{req} - P_{del}|/P_{req} > 5\% \\ P_{NP,FRU} = 0 & \text{elsewhere} \end{cases}, \tag{6.36}$$

where P_{del} is the power delivered by the BESS AC-side. It is equal to P_{req}, unless some limitations on power or SoC are hit. The same computation is performed on NP-related power for RR to obtain $P_{NP,RR}$. The 5% threshold value is considered in both cases since it is the dynamic precision requested by the pilot project for BESS power output. The integral on time of the absolute value of $P_{NP,FRU}$ and $P_{NP,RR}$ results in the NP-related energy for the two services ($E_{NP,FR}$ and $E_{NP,RR}$). The NP share (NP_{FRU} and NP_{RR}) is computed by dividing E_{NP} by the total energy requested for the services (E_{FRU} and E_{RR}). The NP must be kept low, since it can be considered the complementary to 1 of the reliability. Generally, a NP below 5% is welcomed [149]. The efficiency, instead, is estimated by the BESS model for each sample. The average efficiency is considered as a KPI for the study: it is the average of the charging/discharging operational efficiencies experienced by the BESS in each instant of the simulated period. It includes both the battery efficiency and the PCS efficiency. A better management of the BESS could lead to increase the overall efficiency. For instance, by avoiding idle periods when only the auxiliaries are active [222]. As stated before, auxiliary systems are up and running even if the battery is idle, since they take care of the air conditioning of the battery room.

6.5.4.2 Economic performances

On the economic side, the costs and revenues are considered. Capital expenditures (capex) include the cost of the whole BESS. It is well known that the cost of BESS is related to both nominal energy (the cost of the battery pack mainly) and nominal power (the cost of the PCS) [251]. Nominal energy (E_n) and power (P_n) are linked with the E/P ratio, namely the ratio between E_n (in MWh) and P_n (in MW). Considering the specific cost k_e (in k€/MWh) for a standard battery with E/P = 1 h, the total capex can be assessed as follows.

$$\text{CAPEX} = k_e * E_n + (P_n – E_n) * k_p, \tag{6.37}$$

where k_e is equal to 300 k€/MWh – that is coherent with sources from literature and from commercial insights for a BESS to be commissioned in 2022 [24], [298] – and k_p is equal to 150 k€/MW, and it is the cost of the PCS following commercial and institutional sources [298]. Following the Equation (6.37), for a fixed E_n, the capex increases in case of a P_n larger than E_n

(E/P lower than 1, higher c-rates requested) and decreases vice versa (larger E/P, lower c-rates). The operating expenditures (opex) are set to 5 k€/MWh/year, based on commercial and institutional estimations [24], [299]. Further operating costs are related to the energy flows for SoC management (within the availability blocks) and energy withdrawn (outside the availability blocks). As previously described, the SoC management within the availability blocks is always valorized in €/MWh at the DAM price, both for charging (to pay) and discharging (to receive). For the remainder of the time, the energy is bought by an electric customer that pays the bill price. In case there is energy injection towards the grid, for instance for restoring SoC before the availability block starts, it is valorized by the market at 0 €/MWh, considering it as imbalance and considering the minimum downward price to have a severe penalty [51]. The fees for NP are related to the auction bid in the FR: in case x% of energy is non-provided, x% of the capacity-based payment is not delivered. In case of FR, the imbalances discipline that usually applies in case of failure in following dispatching orders is worsened to have a strongly penalizing case: indeed, the NP holds a fee of 100 €/MWh to be paid both in case of downward and upward NP, equivalent to the average maximum awarded price for upward provision in BM [51].

For what concerns revenues, the BM-related revenues are equal to the energy requested for RR provision times the awarded prices in the BM model. Indeed, the Italian BM is pay-as-bid. On the other hand, FR revenues are based on the bid in the auction. A summarizing table of input can be found in Table 6.8.

Table 6.8 Economic indexes for utility-scale Multiservice

Key	Value	Unit	Reference
Capex on nominal energy (k_e)	300	k€/MWh	[24], [298]
Capex on nominal power (k_p)	150	k€/MW	[298]
Opex	5	k€/MW/year	[24], [299]
DAM price	60	€/MWh	[275]
Bill cost	200	€/MWh	[300]
Injection price	0	€/MWh	Worse case based on [51]
FR revenues (R_{FR})	Based on auction bid	k€/MW/year	
BM revenues (R_{BM})	Based on market model	€/MWh	
Fee on FR nonperformance	% of capacity-based payment	k€/MW/year	[75]
Fee on BM nonperformance	100	€/MWh	[51]
Actualization rate (r)	5	%	

The economic analysis is carried out based on an investment time horizon of 5 years, coherent with the duration of FR project. At the end of the FR project, the net present value (NPV) of the investment is requested to be zero. NPV is computed as follows.

$$NPV = CAPEX + \sum_i^N \frac{NCF}{(1+r)^i} + \frac{RV}{(1+r)^N} = 0, \tag{6.38}$$

$$NCF = R_{FR} + R_{BM} + R_{dis} - C_{ch} - C_{bill} - NPP_{FR} - NPP_{BM}, \tag{6.39}$$

where the NCF are the net cash flows for each year from 1 to 5, considering: positive revenues from FR (R_{FR}), from BM (R_{BM}); the SoC management cost for charging (C_{ch}) and revenues for discharging (R_{dis}); energy withdrawal at the bill cost (C_{bill}); the NP penalties for FR (NPP_{FR}) and BM (NPP_{BM}). The residual value (RV) is based on the remaining life of the asset, and it is linearly decreasing with respect to initial capex. The estimated BESS lifetime is computed based on the aging model proposed in [256] updated with [260]. In particular, capacity fade is considered: EoL is when the available energy is 80% of nominal energy. RV is computed as follows.

$$RV = CAPEX * (t_{EoL} - t)/t_{EoL}, \tag{6.40}$$

where t is the considered time horizon for the investment. To get NPV = 0 at year = 5, the FR bid is selected accordingly. The economic analysis will therefore be aimed to define the best bid for the FR auction in both the cases of FR only and the Multiservice.

6.5.5 Results of the utility-scale case study

The results for two case studies (FR-only and Multiservice) are presented in the following. For each case, a first analysis of the BESS operation and of the power and energy flows is given. Then, the evaluation of performance and reliability is presented. After that, the economic analysis is proposed, also estimating the optimal bid for FR auction.

6.5.5.1 FR only case outcomes

In the Italian scenario, as detailed in section 2, the provision of FR implies 1000 hours of response to frequency deviations, divided in a number of availability blocks. In the presented simulations, 100 blocks each lasting for 10 hours are supposed to constitute the FR availability blocks. Outside of these availability blocks, the BESS is idle. As in Figure 6.25, a spiky power profile is requested during the availability blocks; this is coherent with the provision of FR. Also, the SoC does not deviate largely from target (55%), due to the SoC management strategy that is activated whenever the SoC is above or below the reliability thresholds previously described. On the other hand, the battery SoC decreases during idle periods due to auxiliary systems consumption. In these periods the only relevant power is related to the auxiliary demand, which imposes a BESS discharging at a rate function of the ambient temperature and of the requested power. Even if this power is negligible compared to BESS size, being the battery idle, it often leads to approach the minimum SoC. When this happens, auxiliaries are fed by the power withdrawal from the grid.

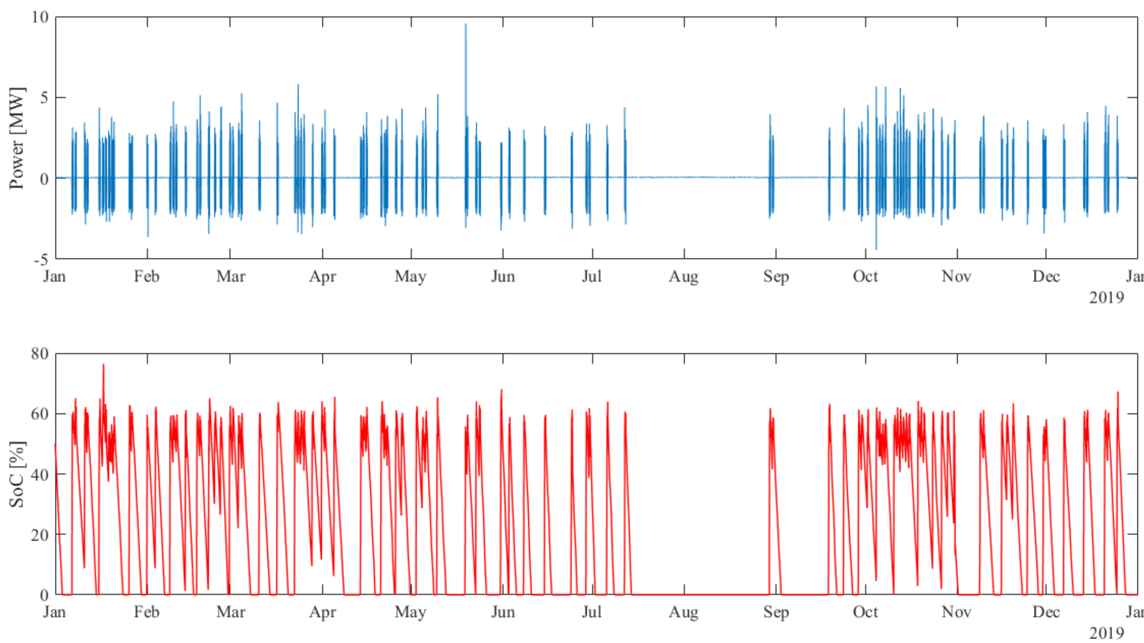


Figure 6.25 Power (top) and SoC (bottom) simulation results for FR-only case.

Even if the qualified power (P_{qual}) to FR is 8 MW (see Table 6.6), the requested power hardly gets over 4-5 MW. This is because the full activation threshold (level #2 - ±150 mHz) is larger than the observed frequency deviations. A focus on FR provision is reported in Figure 6.26. The frequency profile for some minutes is presented in the top diagram: Δf remains inside the dead band for the first minutes (frequency within 49.98 – 50.02 Hz); therefore, the scheduler checks the SoC: if it is outside the reliability thresholds (52-56%), the management starts and tries to restore it towards the target SoC (55%), discharging or charging (as in the figure case) the battery. The negative (charging) power for SoC management can be seen in pink in the mid chart: it is equal to 25% the P_{qual}, thus 2 MW. The SoC steadily increases in that time interval. Just after 9PM (21:00 in Figure 6.26), frequency gets outside the dead band, stopping the SoC management procedure; the FR dynamic response is activated (in orange in mid chart), following the underfrequency event by injecting power into the grid: this is performed respecting the droop curve, proportionally to the frequency deviation. Since the frequency deviation does not get outside emergency thresholds (level #2 - ±150 mHz), after 30 seconds a fade out starts, bringing back the FR provision to 0 in 300 seconds.

The grey line refers to auxiliaries' consumption. The auxiliary power demand is always present, even if its size is relatively small (the maximum requested power is around 74 kW). Over the whole simulation (8760 hours), the total energy demand for auxiliaries is 283.4 MWh, representing 34.6% of the absolute energy provided for FR. A large part of this power is withdrawn from the grid, since BESS is often exhausted.

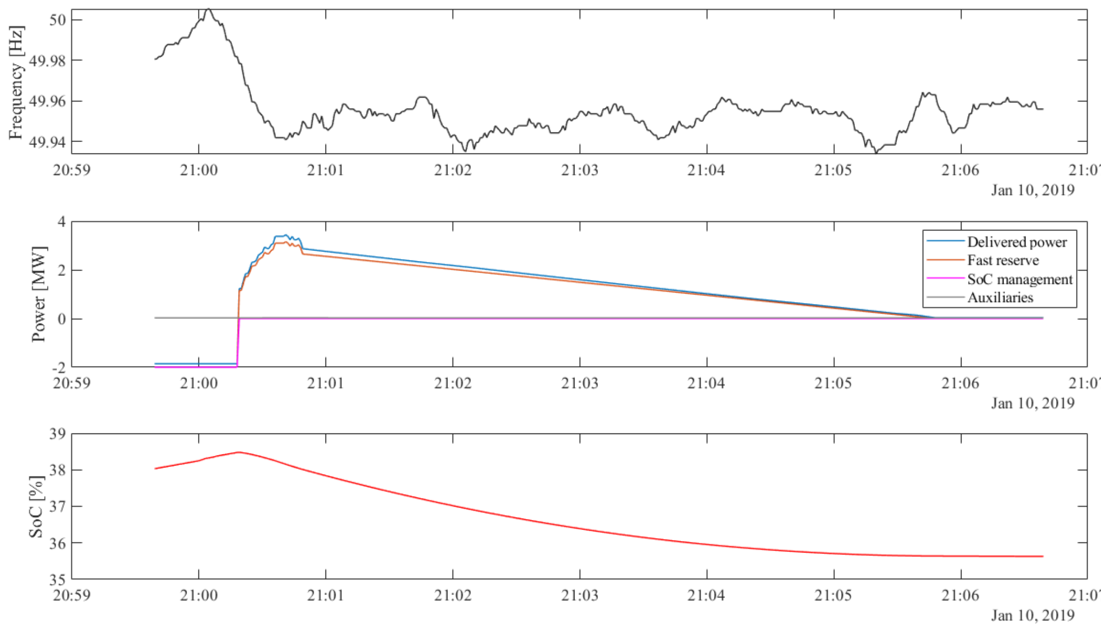


Figure 6.26 Detail on FR BESS management, including frequency variation (top), power management (middle) and SoC evolution (bottom).

The main technical data for evaluating the FR provision are reported in Table 6.9. They relate both to energy flows and technical performance. The energy cycled by the BESS (5 MWh – 10 MW, with 8 MW of FR qualified power) is 1150 MWh per year, around 115 yearly equivalent cycles.

There is no NP_{FR}, since the power requested is always provided: no limitations due to SoC saturation or capability chart are present. This means that the reliability of the provision is 100%. It is worth noting that this reliability only relates to BESS operation: no failures of the equipment are hypothesized. BESS estimated lifetime is 11.6 years, obtained considering the aging model from [256]. BESS efficiency (averagely 75.1%) is very low compared to general values of Li-ion NMC BESS performances [24]: this is because for a large amount of time the battery delivers a very low power with respect to the BESS nominal one. In this efficiency analysis the impact of auxiliaries is not included, whose demand is explicitly computed as previously reported.

Table 6.9 Technical results from FR-only case study

Key	Value	Unit
Total energy cycled	1166.9	MWh/y
FR provision	819.1	MWh/y
SoC management (charging)	168.6	MWh/y
SoC management (discharging)	85.6	MWh/y
Auxiliary demand	283.4	MWh/y
Energy withdrawal	237.7	MWh/y
NP_{FR}	0.0	%
BESS estimated life	11.6	years
Average efficiency	75.1	%

On the economic side, data are proposed in Table 6.10, where revenues are positive, and costs are negative. Capex are paid at year 0, with an investment above 2.2M€ according to Equation (6.37). Opex are estimated around 25k€, not considering the energy flows for SoC management and auxiliaries. Indeed, the SoC management implies a yearly net cost around 5k€, with all flows valorized at DAM price. The energy withdrawn outside availability blocks is instead paid at the bill cost, thus more than 3 times the DAM price. The total cost for energy withdrawal is therefore 47.5k€. There is no penalty for NPFR, since there is no NPFR. At the horizon time of the investment (5 years), still more than half of BESS value is residual, giving a BESS residual value of 1.3M€.

Table 6.10 Economic results from FR-only case study

Key	Value	Unit
Capex (year 0)	-2250.0	k€
Opex	-25.0	k€/y
NPP_{FR}	0.0	k€/y
SoC management costs (charging)	-10.1	k€/y
SoC management revenues (discharging)	5.1	k€/y
Bill total cost	-47.5	k€/y
Residual value (end of year 5)	1282.7	k€

To assess the economic attractiveness of the investment, the FR auction bid for having NPV = 0 at the end of year 5 is estimated. As can be seen from Table 6.11, a bid of 47.0 k€/MW/year allows recovering the investment in 5 years (assuming the monetization of the residual value). The total yearly FR revenues are obtained by multiplying the qualified power times the awarded bid. It is worth noting that the auction cap for 2020 has been 80 k€/MW/y.

Table 6.11 FR revenues requirement for having a NPV=0 at year 5.

Key	Value	Unit
FR auction bid	47.0	k€/MW/y
Qualified power	8.0	MW
FR revenues	376.1	k€/y

A schematic diagram of the cash flows is given in Figure 6.27. As shown, the capex paid at year 0 gives a largely negative actualized net cash flow (aNCF). Then, the cumulative aNCF (cumANCF in Figure) increases due to the net revenues coming from FR provision. At the end of year 5, the RV is considered and the final cumulative aNCF is 0 as the NPV.

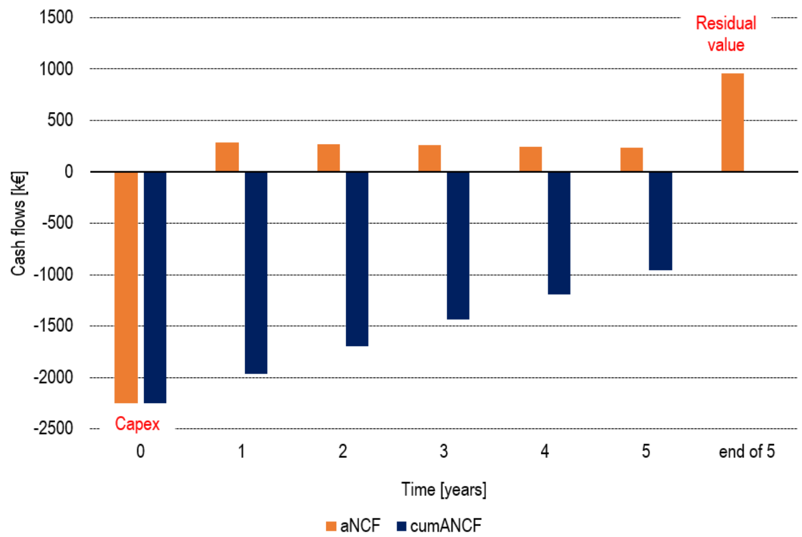


Figure 6.27 Actualized net cash flow of the investment with the targeted FR remuneration (NPV=0 at year 5).

As it has been shown, the long idle periods and the consequent large amount of energy withdrawn have a negative impact on the economics and the operation. As previously stated, shutting off the auxiliaries when the battery is idle (or, in any case, drastically reducing them) is not a viable option in BESS operation: the HVAC system must operate to prevent the early decay of BESS [301], and its power demand is not negligible when BESS is idle (check the auxiliary systems' model in Figure 4.14). A Multiservice strategy is proposed for sequential service stacking.

6.5.5.2 Multiservice case outcomes

In the Multiservice case, BM participation is foreseen outside the FR availability blocks. This aims at increasing both economics and the operational efficiency. In Figure 6.28, the power and SoC profiles for the Multiservice simulation are shown. The power profile is always dynamic, with very scarce idle intervals; indeed, the BESS is participating to BM for the provision of RR when it is not available for FR. In particular, some short periods with larger power spikes can be recognized: these are the availability hours of FR. Instead, the remainder of the time is characterized by power setpoints generally equal or lower than 1.5 MW: this is the RR provision. Given the fact it represents a constant power setpoint for 1 or more hours (contracted on 4-hours market sessions) and considering an E/P ratio of 0.5 hours, RR power is always limited.

This leads to a different SoC evolution too. The SoC profile gets more uneven, but it hardly gets to saturation (100% or 0). This is because the implemented control strategy only bids the available energy content on BM: if the BESS is awarded, it is usually able to provide for the whole contracted time the awarded power, getting close to SoC limits without hitting them.

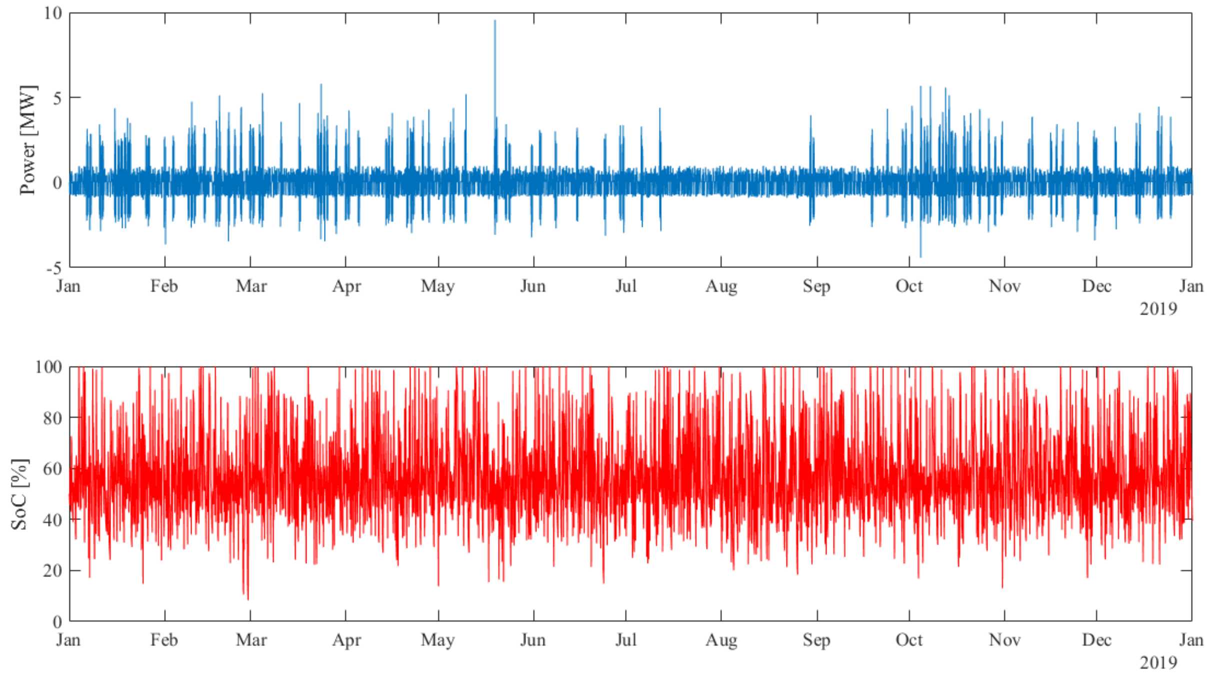


Figure 6.28 Power (top) and SoC (bottom) simulation results for Multiservice case.

A zoom on some working hours is presented in Figure 6.29. Analyzing the mid chart, a time interval outside availability blocks can be seen. In that period, BESS participates to the BM and is accepted for the downward provision of RR for 4 consecutive hours, from 12:00 to 16:00, with a PRR around 1 MW. The energy content increases by almost 4 MWh, therefore SoC rises towards 100%. In the last 30 minutes of provision, the SoC gets above 96% and the capability chart limits the absorbed power: only 0.5 MW can be absorbed. All the requested power for RR in the limited period is considered as a non-performance (NP) and is subject to a penalty.

At 4PM, a buffer period occurs before the starting of the availability block. In this period, SoC is restored towards target SoC, having the battery, injecting power towards the grid (at 0 €/MWh). As can be seen, even outside availability blocks, SoC management takes place only in case the frequency is within the dead band, otherwise it stops. Finally, at the end of the mid chart, the availability block starts. Some spikes followed by fade-out are shown due to over-frequency. When the frequency is within the dead band, still SoC management occurs (SoC is still around 60%).

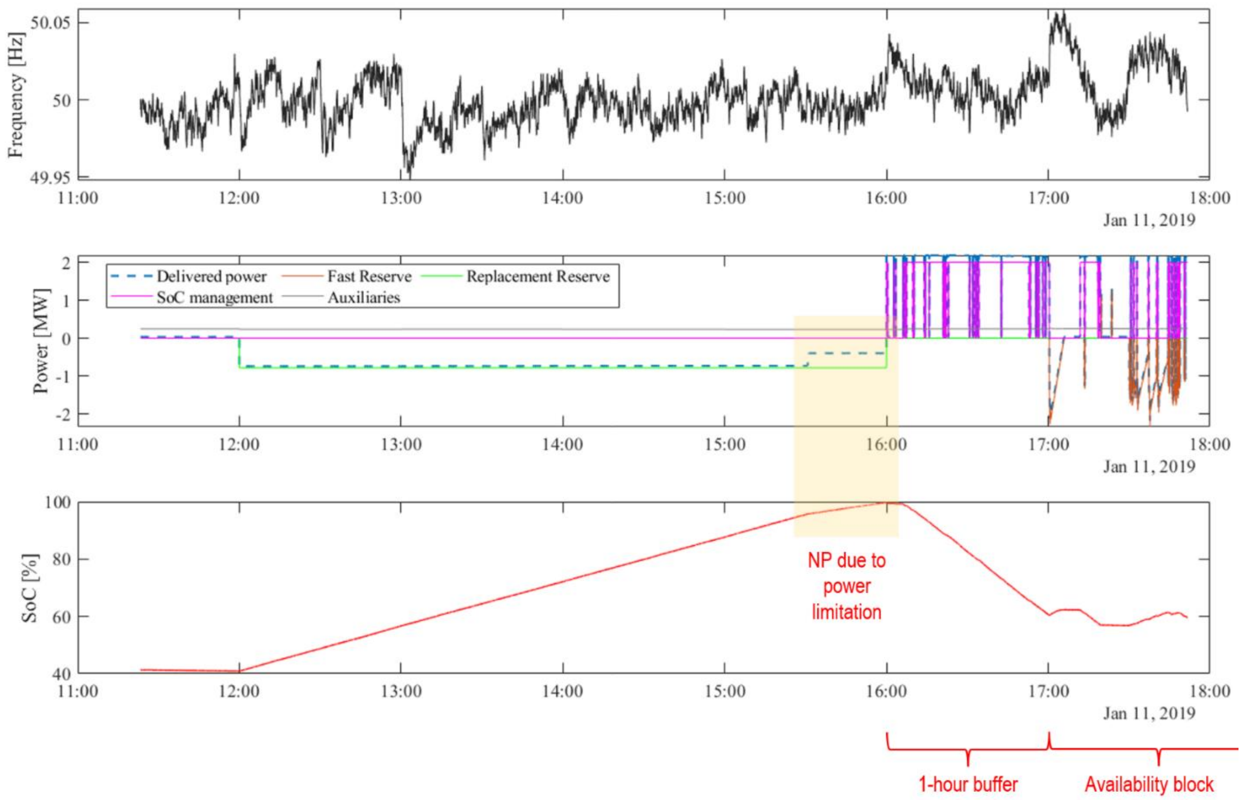


Figure 6.29 Detail on Multiservice BESS management, including frequency variation (top), power management (middle) and SoC evolution (bottom).

A highlight on the BM performance and on the market model is given in the following. The BESS bids either upward or downward every hour, except the 1000 hours of availability for FR, split in 100 blocks, and the 1-hour buffer before each block: 7660 hours. It is awarded for 1557 hours (20.3% of time) for upward provision, and 1693 hours (22.1%) for downward provision: the overall award rate is 42.4%. This means that for the remainder (57.6% of time), the BESS offers at a price that is either higher than the upward maximum accepted on the market or lower than the downward minimum.

For what concerns the technical performance, Table 6.12 presents the yearly energy flows. The total energy cycled by the BESS is almost 3 times that of FR only Case, due to the large requested energy for RR provision. Thanks to the RR provision, the BESS obtains a further revenue stream and drastically reduces the energy withdrawn. Indeed, the withdrawal is less than 30 MWh, decreasing by a factor 9 with respect to the previous Case. The reliability in the provision of RR is high (98.2%): only 1.8% of requested energy is NP. The NP_{RR} depends on the limitations posed by the capability chart and by the maximum and minimum SoC thresholds. Because of the large increase in energy flows, BESS estimated lifetime is reduced to 7.8 years. On the contrary, BESS efficiency improves (83.6%), but it is still low since the RR provision usually requests power around 10-20% of the nominal power.

Table 6.12 Technical results from Multiservice study case.

Key	Value	Unit
Total energy cycled	3199.7	MWh/y
FR requested	819.1	MWh/y
RR requested	2304.2	MWh/y
SoC management (charging)	111.9	MWh/y
SoC management (discharging)	98.6	MWh/y
Auxiliary demand	282.5	MWh/y
Energy withdrawal	29.2	MWh/y
NP_{FR}	0.0	%
NP_{RR}	1.8	%
BESS estimated life	7.8	years
Average efficiency	83.6	%

The main data for the economic evaluation are presented in Table 6.13. The capex and opex do not change, as well as the NPP_{FR}. New cash flows are added for what concerns the RR provision. The impact of BM participation is twofold: on the one hand, it adds some net revenues, given by the algebraic sum of revenues for upward provision (discharging), costs for downward provisions, and penalty for NP_{RR}; on the other hand, RR provision decreases the risk for the BESS energy content of being depleted outside the availability blocks, and therefore the energy withdrawal at bill cost. The first net revenue stream represents an additional yearly cash flow of around 80 k€. The avoided bill costs represent around 40 k€ of positive cash flow. Oppositely, the BESS life decrease implies a reduction of the residual value: it decreases by 1/3 with respect to the previous Case.

Table 6.13 Economic results for Multiservice case study

Key	Value	Unit
Capex (year 0)	-2250.0	k€
Opex	-25.0	k€/y
NPP_{FR}	0.0	k€/y
RR revenues (upward provision)	88.3	k€/y
RR costs (downward provision)	-4.3	k€/y
NPP_{RR}	-4.2	k€/y
SoC management costs (charging)	-6.7	k€/y
SoC management revenues (discharging)	5.9	k€/y
Bill total cost	-5.8	k€/y
Residual value (end of year 5)	809.5	k€

The opposite contribution of the additional revenue streams and the increased aging of the BESS lead to the FR auction bid presented in Table 6.14. The auction bid to have a null NPV at the end of year 5 is 41.5 k€/MW/year. This means either that the attractive offer is 13% lower with respect to the previous Case or that in case of presenting the same offer on the auction (the one detected in Table 6.11), the internal rate of return (IRR) of the investment would rise from 5.0% (in FR only Case) to 7.4%.

Table 6.14 Multiservice revenues requirement for having a NPV=0 at year 5.

Key	Value	Unit
FR auction bid	41.5	k€/MW/y
Qualified power	8.0	MW
FR revenues	332.1	k€/y

The cash flow for the Multiservice strategy is presented in Figure 6.30. As it can be seen, the same capex applies, while from year 1 to 5 a slightly higher aNCF are able to recover steeply towards a null NPV. In any case, the lower residual value at the end of year 5 brings to 0 the NPV. It is worth noting that the capacity-based premium related to the eventual provision of RR in the UVAM context is not considered [33].

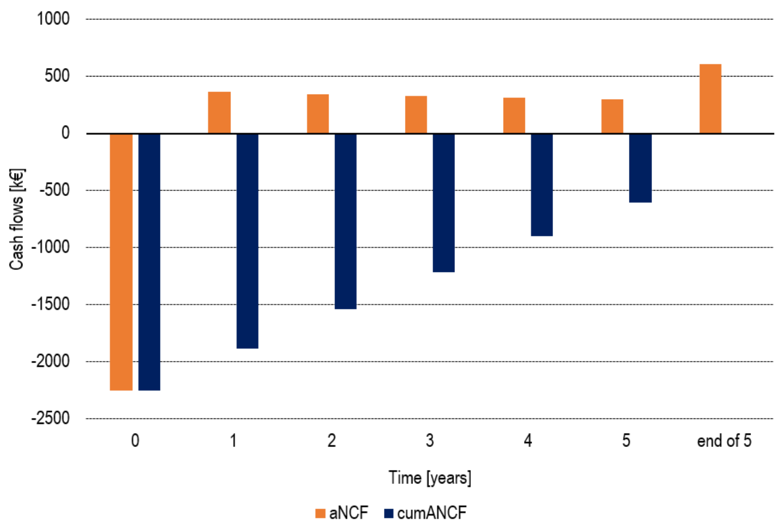


Figure 6.30 Actualized net cash flow of the investment with the targeted FR remuneration (NPV=0 at year 5) in Multiservice case.

The results reported above clearly indicate that there is a net advantage in adopting a Multiservice strategy for revenue stacking. Beyond the economic results shown in the previous section, some other elements are highlighted in the following.

- In case of a Multiservice strategy, the energy withdrawn from the grid is drastically reduced, thus the BESS needs fewer exchanges with the grid for SoC management and for its load. This is an advantage both for the grid operator and the users, and can fit with energy management strategies, for instance in the context of microgrids and smart energy districts [302].
- Considering Q3-Q4 2021 prices in both DAM and ancillary services markets (ASM), the possible economic outcome of the Multiservice strategy would be even more positive: indeed, both the avoided cost (related to DAM price) and the BM revenues (related to ASM prices) would have been larger and with a larger gap with respect to FR only Case. These high prices are not considered in the simulations since they are not expected to remain in the long period [270]. In any case, the persistence of high prices, now expected to last at least until 2023 [303], represents a further driver for decreasing the exchanges with the grid, i.e., increasing the self-consumption.

- The aging model considered estimates short BESS lifetime. This is also because it considers both cycle and calendar aging, and calendar aging is fixed and based on own elaboration from average data retrieved from [260]. Anyway, it is known that calendar aging highly depends on SoC operating conditions: it decreases faster in case of storage close to 100% of SoC, in particular for what concerns NMC cells [185]. The proposed application minimizes the time at very high SoC, thus probably decreasing the aging rates more than what the adopted model can depict and increasing the BESS lifetime.

6.5.6 Sensitivity analysis on the efficient FR auctioned price

Paragraph 3.4.1.1 presented the results of the 2020 auction for Fast Reserve. The average awarded price was generally lower than the estimated results using the BESS model just described, with a gap of 13-17 k€/MW/year. This gap could be given by several reasons, included differences in: capex; economic assumptions (longer investment time horizon); considered technologies or sizing; foreseen service stacking. To better analyze the benefit of Multiservice, the following sensitivity analysis is proposed. The IRR at the end of year 5 is proposed for different input parameters:

- an energy-based specific capex (k_e) ranging from 200 to 500 k€/MWh;
- a FR auction bid ranging from 20 to 70 k€/MW/year.

The results are shown in Figure 6.31. The Multiservice approach allows a slight switch towards green, therefore towards larger IRR. It is worth noting that a discount rate of 4% is generally applied to investments in the energy sector, while an IRR of 10% is the hurdle rate for energy firms [261], [262]. This becomes apparent for lower capex: if at capex around 350-450 k€/MWh the gap between the strategies in terms of IRR is around 0.2-1.6%, the distance increases for capex lower than 300 k€/MWh (2.0-4.9%). This means that it will be more and more important to select the best BESS control strategy to improve economics with future BESS costs. Considering actually awarded bids and likely capex for FRU, a focus on the subset within the dashed area of Figure 6.31 is proposed. For bids around 30 k€/MW/year and capex around 250-300 k€/MWh, the Multiservice strategy makes the difference between a negative and a positive IRR. For instance, IRR equal to 2.0% is shown for Multiservice case, considering 30 k€/MW/year and a low capex of 250 k€/MWh. For the same values, the FR-only IRR is negative.

FR ONLY CASE

FR bid [k€/MW/y] \ CAPEX [k€/MWh]	200	250	300	350	400	450	500
70	20.6%	16.8%	13.9%	11.5%	9.6%	8.0%	6.7%
60	15.6%	12.4%	10.0%	8.1%	6.5%	5.2%	4.0%
50	10.6%	8.1%	6.1%	4.6%	3.3%	2.3%	1.4%
40	5.6%	**3.8%**	**2.3%**	**1.2%**	0.2%	-0.5%	-1.2%
30	0.7%	**-0.5%**	**-1.5%**	**-2.2%**	-2.8%	-3.4%	-3.8%
20	-4.1%	**-4.7%**	**-5.2%**	**-5.6%**	-5.9%	-6.1%	-6.3%

MULTISERVICE CASE

FR bid [k€/MW/y] \ CAPEX [k€/MWh]	200	250	300	350	400	450	500
70	26.2%	21.2%	17.2%	14.0%	11.3%	9.1%	7.2%
60	20.9%	16.4%	12.9%	10.1%	7.8%	5.9%	4.2%
50	15.5%	11.7%	8.7%	6.2%	4.3%	2.6%	1.2%
40	10.0%	**6.8%**	**4.3%**	**2.4%**	0.7%	-0.7%	-1.8%
30	4.5%	**2.0%**	**0.0%**	**-1.6%**	-2.9%	-3.9%	-4.8%
20	-1.1%	**-2.9%**	**-4.4%**	**-5.5%**	-6.4%	-7.2%	-7.9%

Figure 6.31 IRR with respect to FR remuneration and CAPEX obtained in the sensitivity analysis.

To explain the gap between simulations and the real-world bidding strategies, the following consideration can be done. Possibly, in the first FR auction in 2020, there has been a sort of “crowding in” effect [304] given by the high auction base proposed by the Italian TSO for FR: the auction base (or, better, cap) was indeed 80 k€/MW/year. This proposed cap could have made the market players imagine large investments, from now on, for involving BESS in balancing and innovative ancillary services in Italy. Therefore, even a partial return on the investment on a BESS is accepted, with a view to future expected opportunities. The same conclusions were also proposed by some analyses on the awarded prices of 2016 EFR's auction in UK [79].

6.6 Comparative analysis: explicit SoC management versus Multiservice

Chapter 5 presented a comparative analysis of explicit SoC management strategies based on the real-world operating strategies in the provision of FCR. The previous sections of Chapter 6, instead, aimed to validate the service stacking and specifically the developed Multiservice Strategy as an effective implicit SoC management strategy. To coherently evaluate the Multiservice performance, the comparative analysis of Chapter 5 should be extended to the Multiservice (MS Case). Indeed, in the following Paragraphs, the provision of FCR as primary application and or RR as secondary application is simulated adopting the same framework already proposed in Paragraph 5.5. The outcomes should compare explicit and implicit SoC management in terms of technical (e.g., nonperformance) and economic (e.g., IRR) performance. In the following, the indications for the adaptation of the Multiservice strategy to the framework presented in Paragraph 5.5 are given.

6.6.1 Multiservice strategy as implicit SoC management strategy

The FCR is provided as primary applications. The rules are the same of the Base Case described in Paragraph 5.5. The FCR is therefore provided continuously without an explicit SoC management mechanism. In addition to FCR provision, the participation on BM to provide RR is considered. The market structure considered and the award/rejection rules are the same described in Paragraph 6.4.6.2. The bid quantity and prices are defined below.

- The upward and downward bid quantities are coherent with the amounts of energy respectively available between SoC(t) and SoC_{min} and between SoC_{max} and SoC(t) (see Figure 6.7). The available energy is divided by 4 hours to obtain power. A margin (k_{FCR}) is considered to take in account of the estimated energy flows (and consequently SoC variation) due to the FCR in the relevant period (in the 4 hours of the market session, plus the 1 hour-distance from market closure to delivery time). The FCR margin comes from a statistical analysis on the energy variation for FCR in 4-hour periods for 2016. The resulting equation is the following.

$$\begin{cases} P_{RR,up} = \min\left(P_n, \dfrac{SoC(h-1) - SoC_{min} - k_{FCR}}{100 * t_{mkt}} * E_n\right) \\ P_{RR,dn} = \min\left(P_n, \dfrac{SoC_{max} - SoC(h-1) - k_{FCR}}{100 * t_{mkt}} * E_n\right) \end{cases} \tag{6.41}$$

  where $P_{RR,up}$ is the upward bid and $P_{RR,dn}$ is the downward one; SoC(h-1) is the SoC at the market closure; t_{mkt} is the duration of the total market session of 4 hours. In this conservative strategy, indeed, it is considered that even if the bids are awarded for 4 consecutive hours, the SoC threshold should not be reached. In this strategy, either upward or downward power is offered: it SoC(h-1) is larger than SoC_{target}, upward power is offered, vice versa downward power.
- The bid price is coherent with the SoC-dependent bidding strategy proposed in Paragraph 6.3.3.3. It is therefore estimated as in equation (6.1).

Power for RR (P_{RR}) is considered in the model as P_{mgmt}, so that (5.2) is modified as in (6.42).

$$P_{req} = P_{FCR} + P_{RR}, \tag{6.42}$$

where P_{RR} substitutes P_{mgmt} as the responsible for SoC management strategy.

In order not to require power higher than nominal power, the regulating power for FCR provision (P_{fa}) is in this case 80% of P_n (instead of 100%, as reported in Table 5.2).

6.6.2 Results analysis

The MS Case is tested over 1 year of combined provision of FCR and RR and evaluated techno-economically as per the explicit SoC management Cases. To have a general view of its functioning, Figure 6.32 can be inspected. It shows approximately 50 hours of BESS operation, the same time interval depicted in Figure 5.11 for NoDoF case. The upper diagram shows the frequency. The second diagram shows power for FCR. The third diagram reports the P_{RR}, that is at the same time the provided power for RR and the P_{mgmt}. The fourth diagram is the SoC. As can be seen, when the SoC approaches lower limits, downward power is offered (negative, to charge) on the RR market. The smaller the initial SoC (actually, the smaller the SoC at the market closure), the larger the offered power. If awarded, P_{RR} is superimposed to P_{FCR} and should help restoring SoC. Vice versa, if SoC gets above SoC_{target}, upward power is offered (positive power).

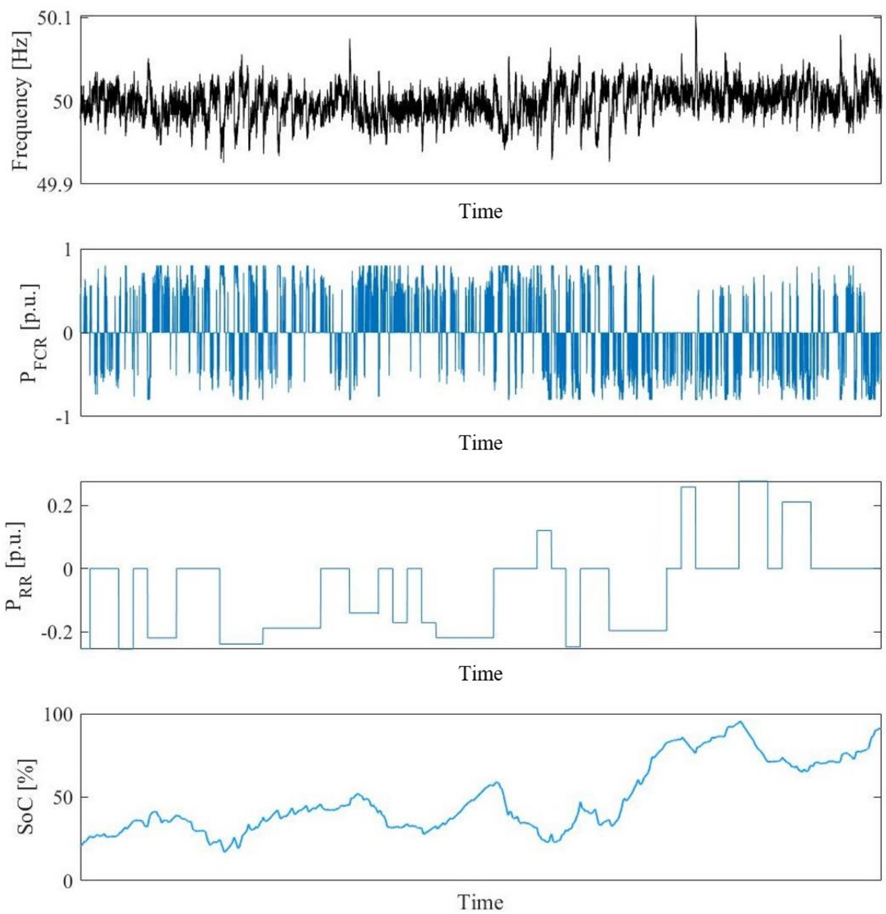


Figure 6.32 Frequency, power and SoC profiles for Multiservice case

In Figure 6.33, the updated version of Figure 5.13, also including MS case, is presented. As can be seen, the MS case delivers less energy for FCR: around 80% FCR is provided with respect to DB case, since the FCR band for the MS case is 80% the one adopted in the other cases. This is necessary since the RR provision is not tailor-made for providing SoC management, therefore it can require a power that, summed to FCR request, gets outside the capability of the battery (i.e., larger than P_n). Furthermore, energy for SoC management represents 47% of energy for FCR provision. Nonetheless, this energy is energy dedicated to RR provision: therefore, a net revenue stream is associated to SoC management energy flow instead than a net cost. This allows to get an IRR at 5 years for the MS case equal to 8.9%. This result is better than every explicit SoC management strategy tested. Indeed, the RR provides an additional revenue stream of around 20% the FCR revenues. This result is achieved with around 45% of the bids that are awarded on BM, either upward or downward. The achieved IRR is comparable with hurdle rates adopted in generation companies [262]. The reliability is not put at risk: indeed, the FCR nonperformance is 3.4%.

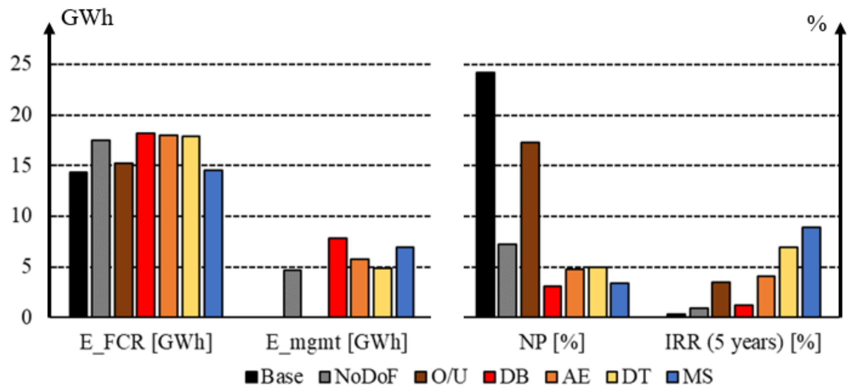


Figure 6.33 Updated summary of the results of the yearly simulations, including both explicit and implicit SoC management Cases. Multiservice (MS) case is shown in blue.

Figure 6.34 shows SoC distribution for MS case. The 10th percentile is SoC at 28%, while the 90th is 81%. With respect to the other SoC management strategies (see Figure 5.14), the BESS has a shorter time at low SoC.

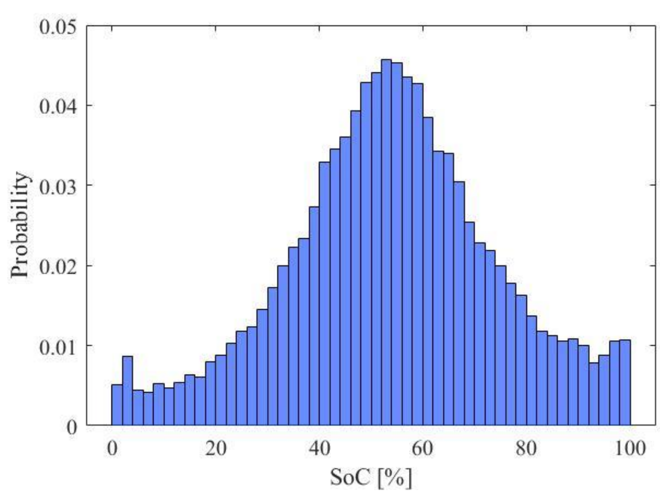


Figure 6.34 SoC distribution during the yearly simulation for Multiservice case based on a implicit SoC restoration.

6.7 Conclusion

The presented Chapter included the development of a reliable multiple service provision strategy, defined as the Multiservice strategy. A literature analysis allowed to recognize the interest towards revenue stacking by multiple services provision. Indeed, the stationary BESS are multi-purpose technology, able to create value on a wide range of grid-connected applications. Different ways of performing service stacking are analyzed, including static, dynamic, and sequential stacking. Dynamic and sequential stacking are recognized to bring the larger benefits and are considered as the basis for developing the Multiservice Strategy.

The Multiservice Strategy developed is an advanced control strategy for BESS based on the provision of two simultaneous services: a primary application, selected for its higher economic profitability, and a secondary service, selected since suitable to provide an implicit SoC management as well as further revenues. The Multiservice strategy could be applied to Balancing Markets, with predilection for asymmetric products with a small minimum bid size, short time definition and limited distance from gate closure to delivery time. It is exemplified starting from Italian BM. It estimates the bid quantity considering the available energy before saturation or depletion of the energy content. It estimates the price following bidding strategies based on the battery state-of-charge, thus compatible with the twofold aims of preserving reliability and improving the economics. The Multiservice strategy is then tested on two case studies: a domestic and a utility-scale application.

For what concerns the small-scale application, the work was aimed to test Multiservice strategy with respect to standard self-consumption strategies at the domestic prosumer's scale. The strategy adds the provision of manual Frequency Restoration Reserve (mFRR) and Replacement Reserve (RR) beside the maximization of self-consumption. This drastically reduces the energy exchanged with the grid, thus decreasing the weight of the domestic user on the distribution grid. In addition, it increases the economics with respect to the self-consumption only case. This is valid for different users tested (adopting real-world data gathered in the H2020 inteGRIDy project).

The utility-scale application considers the provision of Fast Reserve (FR) only, in comparison with a sequential stacking of FR with mFRR and RR. The outcomes show that the Multiservice case increases the profitability of the provision, maintain a very high accuracy for both services, and improves the BESS management in general (e.g., avoiding idle periods). The obtained economic results are compared with the results of the first auction of Fast Reserve, carried out in 2020. This case study described the provision of fast frequency regulation (FFR) from the perspective of the BESS operator. Further studies could focus on the analysis of the impacts of provision of FFR from BESS on the power system, so to better understand the opportunity of introducing innovative ancillary services such as FR. Chapter 8 deals with a quantitative analysis of the FR impact on the power system.

Eventually, the Multiservice Strategy is evaluated as an implicit SoC management strategy by comparing its performance on the same case study proposed in Chapter 5. The same service and techno-economic assumptions that have been considered for comparing the explicit SoC management strategies are applied to implicit SoC management via Multiservice. An analysis on Frequency Containment Reserve in dynamic stacking with RR provision is proposed. Results show that the Multiservice strategy guarantees the same level of reliability of the best explicit SoC management strategies (reliability above 96%) and can improve the economics of the provision (IRR of 8.9% with respect to 2-6% for the explicit strategies). This result should increase the interest of the regulator for providing the regulatory framework to allow the dynamic (or sequential) stacking of services. Indeed, this would allow to exploit reliable flexibility by BESS giving room to sustainable business models.

It is worth noting that the case studies proposed are based on a BM structure that is evolving towards an hourly market in Italy, also coherently with the implementation of international platforms for the cross-border trading of standard balancing products [61]. The next Chapter is aimed to analyse the effect of this and other evolutions in the standard balancing products. This allows to give quantitative feedback to the qualitative analysis on the ancillary services markets evolution and trade-offs presented in Chapter 3.

CHAPTER 7

Abate the barriers: evaluating the compatibility of market and storage

Abstract

The evolution of ancillary services markets (ASM) and balancing products is ongoing. The aim of the evolution is to integrate the products over the national boundaries and to open the ASM to distributed energy resources (DERs). Among DERs, battery energy storage systems (BESS) are increasing their importance. In this Chapter, we investigate by means of numerical simulations the effect of different evolutions in the regulatory framework on the performance of a BESS providing ancillary services. The analyzed regulatory barriers include some of the trends illustrated in Chapter 3. The following parameters are involved: symmetry of procurement, different types of services, time definition and distance to delivery. The considered case study is a BESS associated to a large-scale energy district including load, a cogeneration plant and a PV plant. It is aimed to provide maximization of self-consumption and simultaneously automatic (aFRR) or manual Frequency Restoration Reserve (mFRR). Results are given in terms of energy flows, economics and reliability of performance. The correlation between the techno-economic performance and the analyzed parameters leads to the definition of optimal ranges for the definition of ASM arrangements able to abate the barriers and effectively include DERs.

7.1 Introduction

Beside the high capital cost that generally characterize battery technology (and others), the regulatory barriers represent a major issue. A regulatory barrier in the power system is generally a rule, a code, a law that hinders or prevents the exploitation of an asset for the provision of a service. As reported by literature [305], [306], barriers are not always explicit obstacles to the deployment of a technology or prohibition to enter a market. Instead, they can rely in a missing definition, in the disregard of a peculiarity of a technology, in effective impossibility in capturing different revenue streams. This is apparent when dealing with Ancillary Services Markets (ASM) and Electricity Balancing. In Chapter 3, it has been shown how some of the barriers to entry in ASM are generated by Network Codes written when only conventional generators provided the balancing to the system. A general review and update of these codes is necessary to exploit the distributed energy resources (DERs). Also, the trade-offs lying behind some of the market evolutions have been unveiled and systematically reviewed in a qualitative way, from both the perspectives of the System Operator (SO) and the Balancing Service Provider (BSP). The peculiarity of the BESS among DERs have been also highlighted in Chapters 4 and 5. Indeed, beside the requested power, their performance is intimately linked with the energy requested by the services provision. As shown by Chapter 6, the BESS can guarantee a high reliability and offer flexibility to the system in various frameworks (from small to utility-scale), if they are given the opportunity of accessing dynamically multiple services. The multiple services are compatible with an increase of the technical performance and allow to access multiple revenue streams, improving the economics and decreasing the time to market of stationary BESS. In accordance with the performed simulations, the extensive access of BESS to the provision of ancillary services as already demonstrated its ability to decrease the system costs in real-world contexts (e.g., Frequency Containment Reserve in Germany, see Paragraph 3.4.3.1). The BESS, indeed, see the ASM as the core business [25], hence they are interested in offering flexibility at a competitive price, lowering the system prices [157]. Oppositely, in case less business opportunities are available and the batteries should respect more stringent requirements, their economics can provide a positive return only in case of high remuneration (see the results of Chapter 5).

7.1.1 The problem statement

Still, literature lacks a clear identification of the optimal market arrangements for the inclusion of BESS (especially integrated with RES) in ASM and for exploiting the flexibility that can be guaranteed by these inverter-based resources. This identification, to be reliable, should be supported by quantitative analyses and evidence. Indeed, a systematic review of the market structure, of the proposed services and of the traded products have already been developed in Chapter 3, highlighting the possible evolutions to be prioritized in a qualitative way. A quantitative study could better and more specifically address the integration of BESS in the markets.

To assess quantitatively the discovered barriers and check how much they can limit the battery business, a modular analysis is proposed in the following. It aims to depict a real-world setting as generalizable as possible: this is to produce results that are actually applicable, yet general. Two standard balancing products are tested over a serial campaign of simulations, relaxing one by one the constraints in their provision that can represent a barrier. The analysed barriers include the top part of the ranking previously developed and presented in Table 3.1. The considered products are selected since they feature different characteristics in terms of dynamics, aleatory behaviour and energy-intensity. They are standard products to provide results that can be extended to EU. The same would not be possible in case of testing a specific (e.g., Fast Frequency Response) product. The considered plant layout is an energy district, to consider a case where BESS works as enabler of ASM for RES and DERs.

The outcomes return the acceptable (or optimal) ranges of the analysed parameters for the integration with BESS. These can be returned to the SO, to the National Regulatory Authorities

(NRAs) and to international institutions as indications for the development of the optimal arrangements of an open ASM and electricity balancing.

7.2 The proposed methodology

The analysis proposed in Chapter 3, provided the qualitative basis for this study. The methodology proposed here analyses the provision of standard balancing products by BESS in light of the regulatory barriers and possible evolutions of ASM. The BESS model is used to test a month of ASM participation, adopting the Multiservice Strategy to provide behind-the-meter (BtM) and front-of-the-meter (FtM) services in an energy district. Two FtM services are considered, namely the automatic Frequency Restoration Reserve (aFRR) and the Replacement Reserve (mFRR) as per the Italian rules. As already introduced, these can be recognized as standard balancing products in the Italian ASM. The framework of the standard balancing product is used to vary a set of parameters that could entail the regulatory barriers highlighted in the systematic review. The results are analysed considering several techno economic KPIs to check the performance of the BESS and possible correlation with the range of tested parameters. In case correlations are found, the range of acceptable or optimal parameters for enhancing BESS performance is recognized.

The plant layout is a typical grid-connected smart energy district layout [307]–[309]. It considers an electric load that must be satisfied using local energy production or withdrawal from grid. The generating assets are a combined heat and power (CHP) plant and a PV plant. A BESS is also present. The considered energy flows only focus on electricity, while heating needs are disregarded. This choice is to have a general case study, whose outcomes could be immediately applicable to a large share of DERs and extended easily.

The Reference Case logic considers maximisation of energy self-consumption. Priority is given to PV production, that is consumed as it is available (see equation (7.1)). The CHP follows the residual electric load ($P_{residual}(t)$) as in equation (7.2) (i.e., the heat is a by-product and it is disregarded for the sake of the study).

$$P_{residual}(t) = P_{load}(t) - P_{pv}(t) \tag{7.1}$$

$$P_{CHP}(t) = \min\left(P_{nCHP}, max\left(P_{tmCHP}, P_{residual}(t)\right)\right) \tag{7.2}$$

where: $P_{CHP}(t)$ is the CHP setpoint also considering its nominal power (P_{nCHP}) and its technical minimum (P_{tmCHP}), i.e., the power below which the CHP cannot operate safely and should shut off; $P_{load}(t)$ is the load demand; $P_{pv}(t)$ is the PV generation. Therefore, the CHP is never shutting off. The BESS activates if the difference between the CHP setpoint and the residual load is not null.

$$P_{SC}(t) = P_{residual}(t) - P_{CHP}(t) \tag{7.3}$$

where $P_{SC}(t)$ is the BESS power for self-consumption. Since the CHP is not shutting off, the $P_{SC}(t)$ can be:

- positive (discharge) in case the residual load is larger than the CHP nominal power;
- negative (charge) in case the residual load is smaller than the CHP technical minimum;
- null elsewhere.

While the PV and CHP detailed modeling is disregarded, the BESS model is the one developed and described in Chapter 4 (the same nomenclature for the power flows adopted in Chapters 5 and 6 is used). Therefore, $P_{SC}(t)$ is added to the auxiliary systems' demand and is requested to BESS ($P_{req}(t)$).

$$P_{req}(t) = P_{SC}(t) + P_{aux}(t) \tag{7.4}$$

The real power delivered AC side ($P_{del}(t)$) depends on the BESS nominal power, on its SoC and on the possible limitations of the capability chart. The power exchanged with the grid ($P_{exch}(t)$) is therefore the difference between request and delivery.

$$P_{exch}(t) = P_{req}(t) - P_{del}(t) \tag{7.5}$$

It is positive in case of withdrawal, negative in case of injection. To assess the performance of self-consumption, the total energy requested for self-consumption in MWh is estimated (E_{SCreq}).

$$E_{SCreq} = \sum |P_{SC}(t)| \tag{7.6}$$

Therefore, the E_{screq} is the absolute integral of the power requested for self-consumption (to have it in MWh, the sampling is considered: for instance, if 1 value per minute in MW is given as input to the model, the value of E_{SCreq} is divided by 60). The power non-provided for self-consumption ($P_{SC,NP}(t)$) and as a consequence the total non-provided energy ($E_{SC,NP}$) is considered as follows.

$$P_{SC,NP}(t) = \min\left(P_{SC}(t), P_{exch}(t)\right) \tag{7.7}$$

$$E_{SC,NP} = \sum |P_{SC,NP}(t)| \tag{7.8}$$

And the actual energy delivered for self-consumption is therefore:

$$E_{SC} = E_{SCreq} - E_{SC,NP} \tag{7.9}$$

In addition, a self-consumption provision ratio (SC%) can be estimated as follows.

$$SC\% = \frac{E_{SC}}{E_{SCreq}} \tag{7.10}$$

This control strategy is optimal in case the PV generation cost is considered lower than the CHP marginal cost, that is considered lower than the BESS cycling cost, that is considered lower than the spread between bill cost and injection value. The plant layout and the energy flows are proposed in Figure 7.1. for the Reference Case just depicted, only the black dashed lines are of interest.

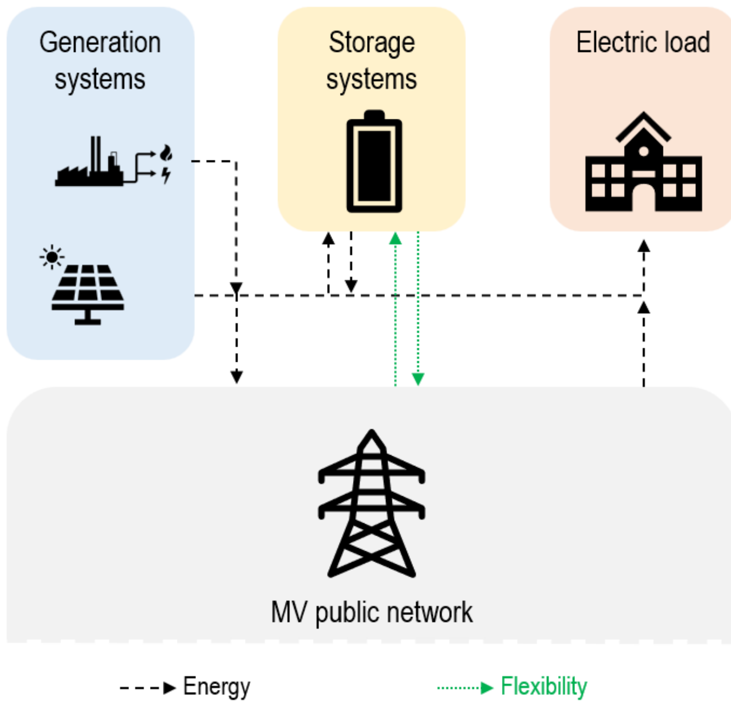


Figure 7.1 Plant layout with energy (black) and flexibility flows (green).

For what concerns the case studies, a Multiservice Strategy BtM + FtM (see Figure 6.6) is adopted. The primary application is the self-consumption maximization (SC), while the secondary is the provision of standard balancing product on the Ancillary Services Market (ASM). Two different services are selected and the already illustrated ASM model based on the Italian BM is adopted (see Paragraph 6.4.6.2). The procedure of the Multiservice strategy is as structured in Paragraph 6.3.3, where the available power for the secondary application are estimated as in Paragraph 6.3.3.2: they are a function of the SoC at the market closure, and the estimated energy flows in the market period (from the considered market gate closure to the next one). Differently from the domestic Multiservice case, the pricing strategy is the SoC-dependent strategy based on equation (6.1). The power requested to the BESS considering ASM ($P_{req+ASM}$(t)) is updated from equation (7.4) as follows.

$$P_{req+ASM}(t) = P_{SC}(t) + P_{ASM}(t) + P_{aux}(t) \tag{7.11}$$

The nonprovision of self-consumption is still based on the equation (7.7), where P_{exch} does not involve the ASM provision. Instead, the nonprovision (NP) for ASM is estimated as follows.

$$\begin{cases} P_{NP}(t) = P_{req+ASM}(t) - P_{del}(t) - P_{SC,NP}(t) \quad if\ \dfrac{|P_{del}(t) + P_{SC,NP}(t)|}{P_{req+ASM}(t)} > 5\%\ and\ P_{ASM}(t) \neq 0 \\ P_{NP}(t) = 0 \qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad elsewhere \end{cases} \tag{7.12}$$

where a 5% of inaccuracy in the provision is tolerated and does not entail penalties, as per what said in Chapter 6. NP (in %) is then obtained as the integral of P_{NP}(t) over the E_{ASM}, as follows.

$$NP = \frac{\sum \ |P_{NP}(t)|}{\sum \ |P_{ASM}(t)|} \tag{7.13}$$

7.2.1 The provided ancillary services

The BESS is tested on the provision of two different services, based on the Italian rules. The first is the automatic Frequency Restoration Reserve (aFRR). As illustrated in Paragraph 2.3.1.1, the aFRR is activated after the Frequency Containment Reserve (FCR). Therefore, it has a slower dynamic with respect to FCR. In Italy, that is taken as model for the service definition, it is activated on 1-minute setpoints. AFRR requires a bid quantity each hour for upward and downward ($P_{bidUp}(t)$ and $P_{bidDn}(t)$). If awarded, the bid quantity constitute the power availability for the provision of the service. The activation of aFRR follows a 1-minute Regulating Signal (*S*) ranging from 0 to 100. The power to be provided each minute is defined by the following equation.

$$\begin{cases} P_{ASM}(t) = P_{bidUp}(t) * \dfrac{S-50}{50} & if\ S \geq 50 \\ P_{ASM}(t) = P_{bidDn}(t) * \dfrac{S-50}{50} & if\ S < 50 \end{cases} \tag{7.14}$$

Therefore, upward service is provided if *S* > 50, elsewhere the downward provision is requested. Full upward bid power is delivered when *S* = 100; no power is delivered if *S* = 50; the full downward bid power is delivered with *S* = 0. Each minute, the value of the Regulating Signal can change. A statistical study shows that its variability is limited (i.e., the next value is in the neighbourhood of the previous one), so that a limited ramp is requested to the providing units each minute. The Regulating Signal valid for the first week of 2021, used in the study, is presented in Figure 7.2.

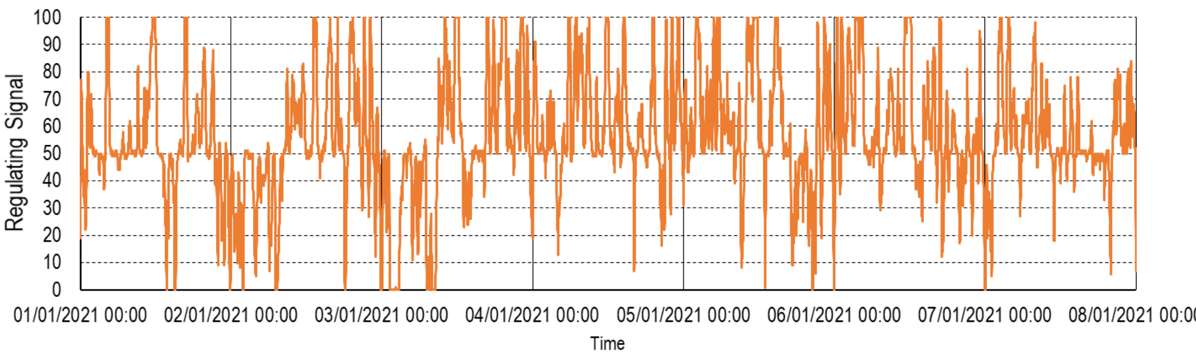


Figure 7.2 Regulating Signal for aFRR in the Italian peninsula for the first week of 2021 [310].

The second ancillary service considered is the manual Frequency Restoration Reserve (mFRR). It requests a power setpoint constant for 60 minutes, coherent with the bid quantity.

To better understand the difference between the provision of the two services and therefore the interest for the comparison, Figure 7.3 represents some hours of aFRR provision, while Figure 7.4 represents mFRR. In both cases, the resource bids a quantity (dashed lines) for upward and a quantity for downward provision. In case the bid is awarded (shaded areas), the resource must provide the requested power. For aFRR, the requested power varies each minute based on the bid quantity and on the Regulating Signal (see Figure 7.3). For mFRR, the power is constant and it only depends on the bid quantity (Figure 7.4). In both cases, asymmetric provision is depicted. In Italy, the mFRR is provided asymmetrically, while aFRR is still symmetric. A pilot project is introducing (2022) the asymmetric provision of aFRR [278]. As said (see Paragraph 3.3), symmetry of bids can be a regulatory barrier for ESS. Therefore, it is treated in this study among the analyzed barriers. In particular, in case of asymmetric provision, the bid quantity is estimated as in Paragraph 6.4.6. If the provision is symmetric, the upward and downward bid quantities must be equal: in a conservative strategy they are reduced to the minimum between upward and downward available quantities.

$$P_{bid}(t) = \min\left(P_{bidDn}(t), P_{bidUp}(t)\right) \tag{7.15}$$

Instead, to consider the different ratio of energy requested with respect to awarded power of the two services, the bid quantities of aFRR are updated as follows.

$$P_{bid,aFRR}(t) = P_{bid}(t) * \frac{1}{r_{\frac{E}{P}}} \tag{7.16}$$

Where $r_{E/P}$ is the result of a statistical analysis on the gross energy requested for the provision of aFRR (both upward and downward) in each period of 4 hours of 2019 with respect to the awarded power. The ratio is averagely 33.5%: this means that for 1 MW awarded, the hourly energy provided is 0.33 MWh. To be coherent with mFRR (that requires 1 MWh/MW), the $P_{bid,aFRR}$ is increased as in equation (7.16).

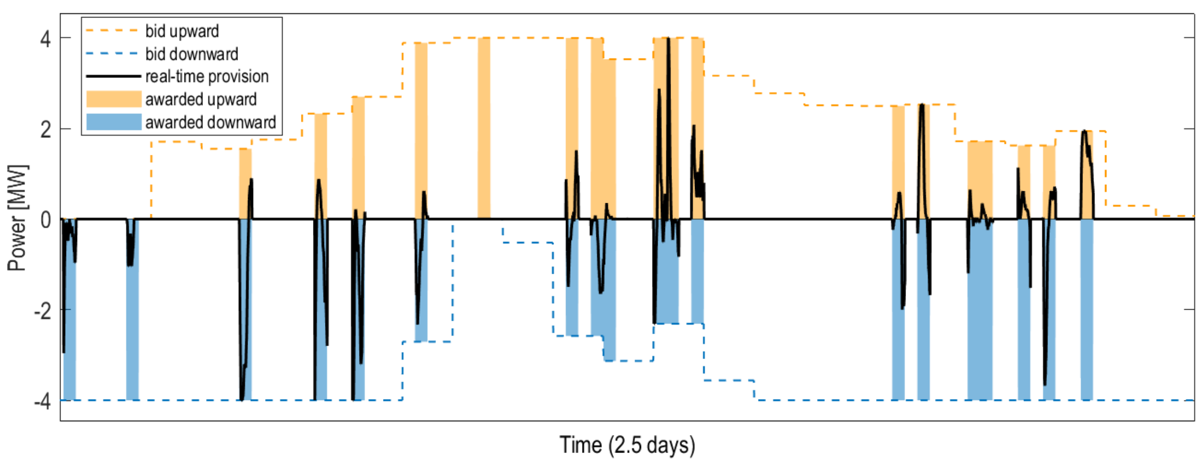


Figure 7.3 A sample of the provision of aFRR, upward (orange) and downward (blue). The dashed lines depict the bid quantities, the shaded areas represent the awarded bids, the black line is the power requested in the real-time provision.

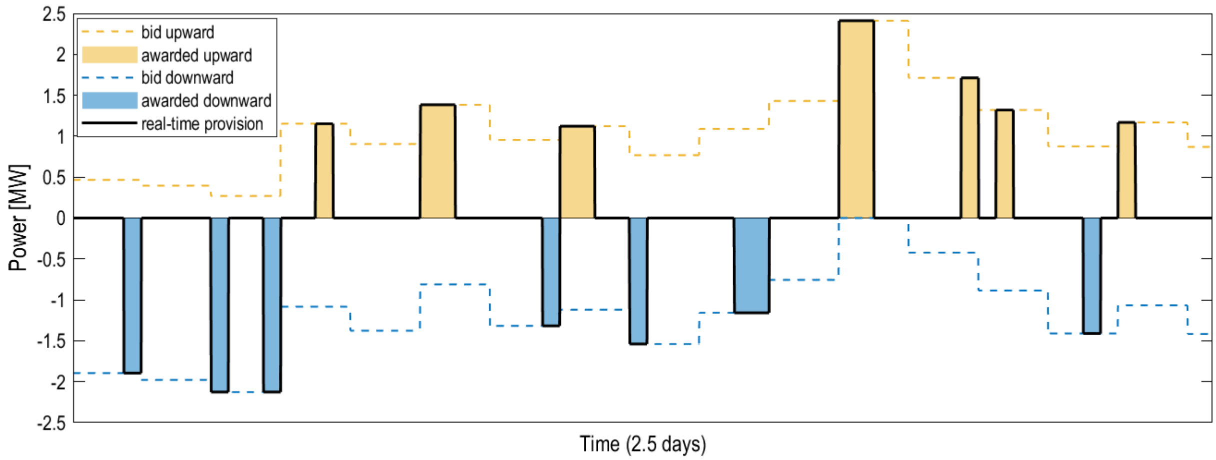


Figure 7.4 A sample of the provision of mFRR, upward (orange) and downward (blue). The dashed lines depict the bid quantities, the shaded areas represent the awarded bids, the black line is the power requested in the real-time provision.

7.2.2 The analyzed barriers

The framework of standard balancing products is considered when dealing with the mentioned services. This is to be as generalizable as possible and to have a flexible design, based on the parameters illustrated in Figure 2.8. As introduced, the aim is assessing the performance in the provision of a service, varying the parameters that could entail regulatory barriers. To identify the critical parameters, the ranking developed in Chapter 3 is considered. Some of them are not suitable for a quantitative analysis with the BESS model. The list of considered parameters is depicted in Figure 7.5. A list of the considered/not considered variables and some considerations are given in the following. We move top down in the ranking presented in Table 3.1.

The symmetry of products is considered in the study. The aFRR and mFRR will be proposed in a set of simulations in both configurations, as shown in Figure 7.5.

The services review is partially considered comparing two different standard products (i.e., aFRR and mFRR). A further quantitative analysis is difficult to propose in the developed format.

The effect of System Marginal Price (SMP) cannot be assessed with the proposed market model, that is based on a statistical analysis of real-world data concerning the Italian BM, that is pay-as-bid (PAB). Further studies on that would be of interest, since SMP is generally considered fairer with newcomers. Yet, it is contested, for instance in late 2021, given the high marginal prices of the electricity markets with respect to the low marginal prices of RES technologies [167].

The increase of procurement perimeter cannot be depicted by the BESS model, yet some quantitative analyses on the topic have been delivered in Paragraph 3.4.3.1. It is perceived as a valid alternative to the decrease in minimum bid size in case it is associated with the increase of aggregation perimeter.

The variation in the time definition of the products is tested by the study as depicted in Figure 7.5. Shorter or longer time definitions are considered in the simulations. This directly reflects on the length of the relevant period of each ASM bid, also known as the delivery time (t_{mkt})

The provision of steeper regulation, by the side of the BESS operator, entails attractiveness since it decreases the competition: a large share of the resources traditionally involved in electricity balancing cannot provide steep/fast regulation with a degree of precision as high as the inverter-based systems [37]. The real question is whether steeper services are needed for the power system. The Chapter 8 attempts to give some quantitative answers.

The distance from market closure to delivery time is assessed by the simulations. Different time intervals between the instant of the bid proposal and the start of the delivery period are tested in the simulations, as shown in Figure 7.5. This means, different time advance (t_{adv}) for estimating and bidding the flexibility.

The assessment of the parameters ranked at the bottom of Table 3.1 is outside the scope of this study. Indeed, given the rationale behind the analysis presented in Chapter 3, the evolutions to be focused are the ones ranked at the top of that table. They present less critical trade-offs, therefore an action in that direction should be prioritized.

Summarizing, the different simulations are performed to provide either aFRR or mFRR under different regulatory frameworks, tuning the following parameters:

- symmetry of products;
- time definition of products;
- distance to delivery.

Specifically, the bid quantities offered on the ASM are obtained by equations (6.11) to (6.18), thus they relate on the parameters t_{adv}, variable with the distance to delivery, and t_{mkt}, variable with the time definition, that can be substituted in the equations.

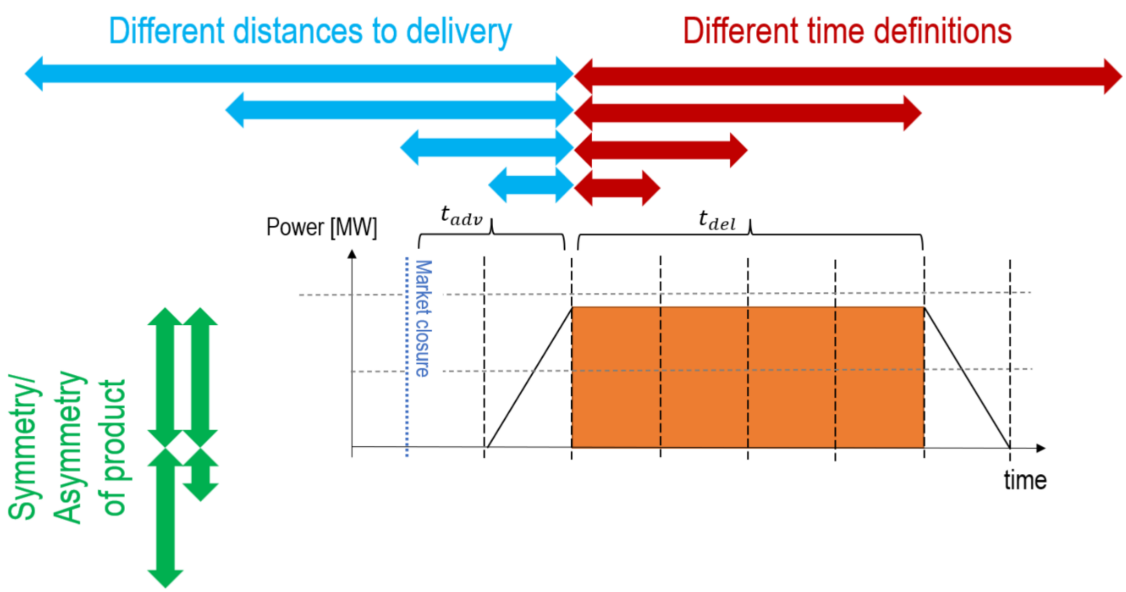


Figure 7.5 The framework of the standard balancing product with a highlight on the tested parameters.

7.2.3 Assessing the optimal ASM arrangements for opening to DERs

The scope of the work is to define a possible correlation between each parameter and the BESS performance. If correlations are found, the optimal range of parameters should be adopted by the regulation when developing the ASM design to be suitable for the BESS (associated with RES and DERs, as in the proposed plant layout) and increase the portfolio of resources competitively offering flexibility. The performance should be evaluated under different perspectives. The adopted Key Performance Indicators (KPIs) are listed in the following. The reference case (REF) is the provision of self-consumption only, without participation to ASM.

The energy that can be provided for both the services delivered by the Multiservice strategy is considered. The self-consumed energy (E_{sc}) in MWh is evaluated with respect to the E_{sc} in the REF case. This is to avoid that some peculiarities of the system layout could influence the self-consumption rates: here we compare the situation with and without the participation on ASM. All the contributions to self-consumption given by the CHP and by the PV are disregarded, and we only assess if the ASM participation improves the results with respect to a standard BESS control strategy, only devoted to self-consumption. This is considered coherent with the analysis, that aims to return the optimal ASM design for maximising the system and the operator benefits with respect to no participation. It is worth noting that the self-consumption creates not only a value for the energy district in terms of avoided costs, but also for the network in terms of reduction of exchanged energy, as also shown by Paragraph 6.4.9. In general, this can be of interest for reducing variable grid costs [311] and for increasing the quality of supply for users subject to shortage [312]. It is worth noting that self-consumption does not reduce to zero the use of the grid and can lead to unfair tariff costs for the users that are not self-consumers [313].

The participation to ASM is directed to make available and then sell flexibility to the system. By the side of the BESS operator, the outcome of interest is the sold quantity. By the side of the system operator, it is important to create the conditions for having enough flexibility made available by the resources. The flexibility sold to the system is therefore a KPI. The energy sold on ASM (E_{ASM}) is estimated as the gross total of awarded energy for downward and upward provision. We consider energy since the remuneration on the Italian market is energy-based (€/MWh). Nevertheless, given the importance it has for the system operator, the power available for providing flexibility should be considered, too. To do so, the average power that is bid on the ASM in both upward and downward direction ($P_{bidASMup}$, $P_{bidASMdn}$) is estimated. It is worth noting that the Multiservice strategy considers the ASM participation as a secondary application. The bid quantity, as deeply illustrated in Paragraph 6.3.3.2, is the total available power band, considering the battery limitations and the energy flows devoted to the provision of the main application, that has the priority. Therefore, the P_{bidASM} can be considered the flexibility that can be made available by the DERs, constrained by the market arrangements, and causing no further effort to the energy district. E.g., if the market sessions are longer, in principle the bid quantity is lower, since the same available energy band should be split in more time. Hence, P_{bidASM} is a measure of the available flexibility, given an ASM arrangement. Being able to increase the offered MW on ASM with a fixed installed capacity of resources is something to be pursued by an effective market design [314].

The reliability of provision is a KPI of interest for the system. The provided flexibility should be delivered by keeping as small as possible the distance between the requested energy and the activated energy. The reliability of provision (*Rel*) is estimated as the complementary to 1 of the NP, as follows.

$$Rel = 1 - NP \tag{7.17}$$

A higher reliability could foster the penetration of the DERs in ASM, since these resources would be considered trustable as an alternative to reliable conventional generators, traditionally involved in electricity balancing.

By the operational side, the provision of services requests the battery to absorb some energy to be delivered when necessary. In principle, the absorbed energy is larger than the delivered energy due to losses. As seen in Paragraph 4.1.4, the BESS is generally a high-efficiency system, whose share of losses depends on the operation. Indeed, in case of operating at very low power (or being idle for long periods) the BESS decreases its operational efficiency due to auxiliary systems' losses. Oppositely, up to a certain extent, working for long periods close to nominal power can decrease the efficiency due to battery losses. The larger amount of absorbed energy related to lower efficiencies entails an additional cost stream for the plant manager. The BESS efficiency becomes therefore a KPI for the operator. In this study, the BESS efficiency ($\eta_{BESSavg}$) is estimated as the average roundtrip efficiency during operation.

The ASM participation has the goal of improving the economics of BESS operation. To have a general estimation of the BESS net revenues (i.e., providing conclusions that are not bound to a specific regulatory and market framework), the following statements can be proposed.

- The economic attractiveness of the project increases if the self-consumed energy increases since it is correlated with avoided costs. This could not be the case if a strong feed-in-tariff is implemented and/or net metering is considered: indeed, these incentive schemes have shown to decrease the economic interest towards a BESS integrated with PV [315]. In any case, the high E_{SC} is considered in this study as a driver for economic attractiveness of investments in BESS.
- The flexibility sold on the market is directly correlated with the economic attractiveness of the investment in BESS. As shown by Figure 6.4, indeed, ASM participation is one of the most remunerative applications for BESS, in Italy as well as in other frameworks. The E_{ASM} is therefore considered a main driver for improving the economics.
- The non-performance (NP) is generally associated to penalties (NPP) that shrink the net revenues on the ASM. Below a certain threshold, the lack of reliability can lead to exclusion from the provision (or from the remuneration). Therefore, a high reliability is considered a main driver for the economics.
- BESS inefficiencies are responsible for additional operating expenditures, as previously described. Therefore, BESS efficiency is a driver for the economic attractiveness for investment in BESS.

A qualitative economic KPI is included in the results of the study as a combination of the drivers listed above.

All the described KPIs identify the goodness of an ASM arrangement for the inclusion of DERs.

7.3 The case study: an energy district in the tertiary sector

A wide set of 1-month simulations are performed. They have the same inputs, except for the market structure, that varies as illustrated in Paragraph 7.2.2. To characterise the case study with real-world data, the Politecnico di Milano's "Leonardo" Campus is considered. It is the headquarter of Polimi, characterized by 21 main buildings and more than 20 thousand students and researcher hosted every day, with classrooms, labs, offices, and shops (see Figure 7.6).

Data on this Campus are recorded and kindly made available by the "Commissione Energia", a technical and research group based in Politecnico di Milano [316].

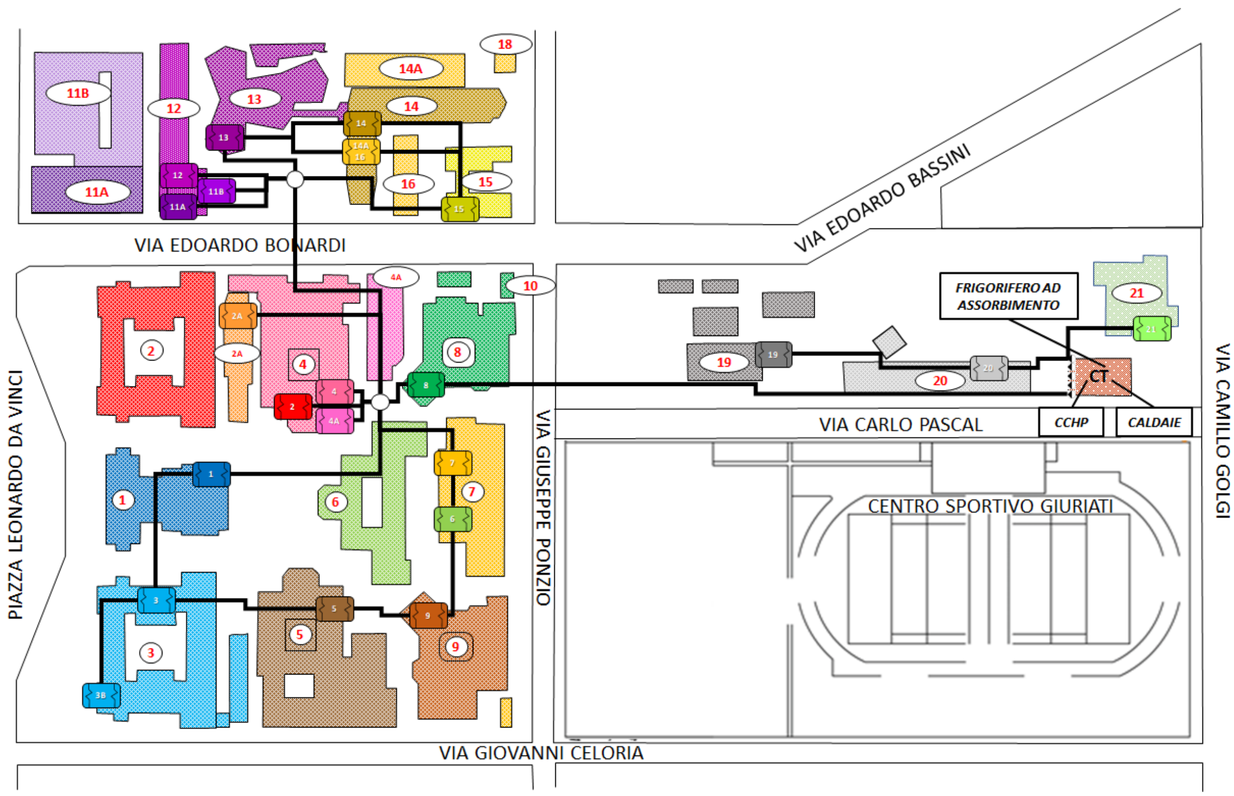


Figure 7.6 The map of Leonardo Campus, with the electricity grid and assets highlighted [316].

The energy district of Leonardo Campus can be described as follows:

- a total load of 4000 kW,
- a CHP plant of 2750 kW of nominal power, with a technical minimum of 1375 kW.

A PV generator of 1600 kWp is added in the case study, even if it is not yet deployed in Politecnico as of early 2022. This is because the massive deployment of PV systems is foreseen in the sustainability plans of the university. In the case study, the CHP operates following the electric load. In addition to this layout, a BESS and the power grid must be considered, as seen in Figure 7.1. The BESS data are given in Table 7.1.

Table 7.1 Energy district's BESS data

Key	Value	Unit
Technology	Li NMC	
Nominal power	4	MW
Nominal energy	10	MWh

The reference operating strategy for the BESS is to cope with the residual self-consumption requested by the plant, as described in Paragraph 7.2. The power flows in some standard weekdays and holidays are shown in Figure 7.7. The PV generates power during daytime (in yellow). The electric load (in red) is higher during the daytime but is not null during the nighttime (around 2000 kW). To the left part of the figure, two weekdays are depicted (peak load around 3500 kW). To the left part, Saturday and Sunday are shown (similar pattern, with peak slightly above 2000 kW). The PV production is primarily serving the load. For limited periods, it is injected towards the grid, e.g., in the weekends. The CHP is always on, ranging between the technical minimum and the nominal power, to cope with the residual load (i.e., the difference between the red and yellow curve. Due to the fact (as it is usual) the CHP also provides Quality of Supply improvements (e.g., it is involved in logics of intentional islanding [317]) and to the high startup costs also in terms of additional aging, the CHP is never shut off. Therefore, if the residual load is lower than the technical minimum, the district features an excess in production (e.g. in the morning of weekdays and during the daytime of weekends). The BESS operates to maximize the self-consumption (see green and purple lines): it is requested to charge when production exceeds the load, it is requested to discharge when the generation lacks.

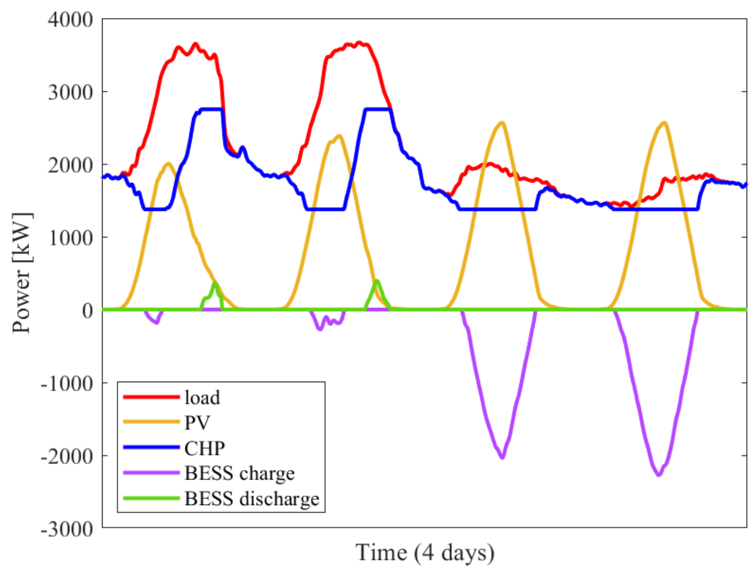


Figure 7.7 A sample of the considered power flows in the energy district.

7.3.1 Energy and power profiles and forecasts

The load and PV profiles of the district for the considered month (June 2021) are presented in Figure 7.8. They are retrieved from 15-minutes average data.

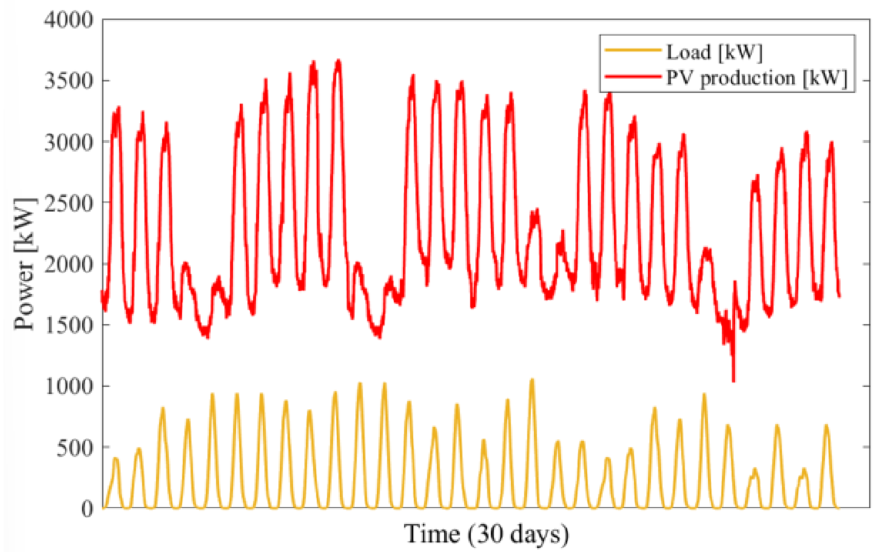


Figure 7.8 The load and PV profile for the considered 30 days.

As well as actual power profiles, forecasted profiles must be fed to the model for the estimation of the available bands. It is performed with a data-driven model based on classification trees. Two different models are trained for PV and load prediction. The main metadata of the models are given in Table 7.2, they refer to the prediction of the quantities in per unit with respect to their nominal power (thus, they are given in %). It is worth noting that the adopted models are standard: this is once more for having more generalizable results with respect to an enhanced prediction model.

Table 7.2 Metadata of the PV and load prediction models.

Key	PV model	Load model
Method	Bagged Tree	Least-square Boosted Tree
Features	*Hour of the day, PV production at h – 24 (i.e., the day-ahead).*	*Hour of the day, day type (i.e., weekday, holiday), Load at h – 168 (i.e., the week ahead).*
Root Mean Squared Error (RMSE)	5.2%	3.6%
Mean Absolute Error (MAE)	2.9%	2.8%

The actual and forecasted power profile are given as input to a Simulink tool, where the BESS model is implemented as well as the model of the district as per the equations presented in Paragraph 7.2.

7.3.2 Setup of the simulations

The study performs 25 simulations, starting from the REF case (self-consumption only), then testing different layouts for the assessed parameters. The summary of the performed simulations is provided in Table 7.3. Both aFRR and mFRR are tested both symmetrically and asymmetrically. The time definition (TD) ranges from 24 hours to 1 hour. The Distance to Delivery (DtD) ranges from 24 hours to zero (immediate delivery). The several simulations performed are necessary to have a modular analysis. Between a simulation and the next one, only a parameter (i.e., service, symmetry, TD, or DtD) changes: this allows to detect the specific effect of each parameter on the KPIs. The considered ranges are coherent with the provision of ancillary services in several analysed markets: indeed, markets are generally characterised by either asymmetric or symmetric procurement, by daily to hourly products, contracted from the day-ahead to real time.

Table 7.3 Layout of the simulation campaign.

Case	Service	Symmetry? [Y/N]	TD [h]	DtD [h]
REF	-	-	-	-
1	aFRR	Y	4	1
2	aFRR	N	4	1
3	mFRR	Y	4	1
4	mFRR	N	4	1
5	aFRR	Y	24	1
6	aFRR	Y	8	1
7	aFRR	Y	2	1
8	aFRR	Y	1	1
9	aFRR	N	24	1
10	aFRR	N	8	1
11	aFRR	N	2	1
12	aFRR	N	1	1
13	mFRR	N	24	1
14	mFRR	N	8	1
15	mFRR	N	2	1
16	mFRR	N	1	1
17	aFRR	N	4	24
18	aFRR	N	4	4
19	aFRR	N	4	0.5
20	aFRR	N	4	0
21	mFRR	N	4	24
22	mFRR	N	4	4
23	mFRR	N	4	0.5
24	mFRR	N	4	0

7.4 The outcomes of the evaluation of the ASM parameters

The reference (REF) case is simulated, providing self-consumption only. A set of 24 further simulations are then performed modularly relaxing some constraints or testing a range of different parameters. The summary of the resulting KPI is given in Figure 7.9.

One first consideration is on symmetric mFRR. In case of the mFRR provision (as per the proposed rules), it is meaningless to test the symmetric service: it would result in a simultaneous provision of two constant setpoints of the same magnitude, a positive and a negative one. This is tested in Case 3, where the obtained results are the same as in Case REF since there is no provision on ASM: the results of this test are not proposed in Figure 7.9 for avoiding confusion, and no more tests with symmetric mFRR are proposed.

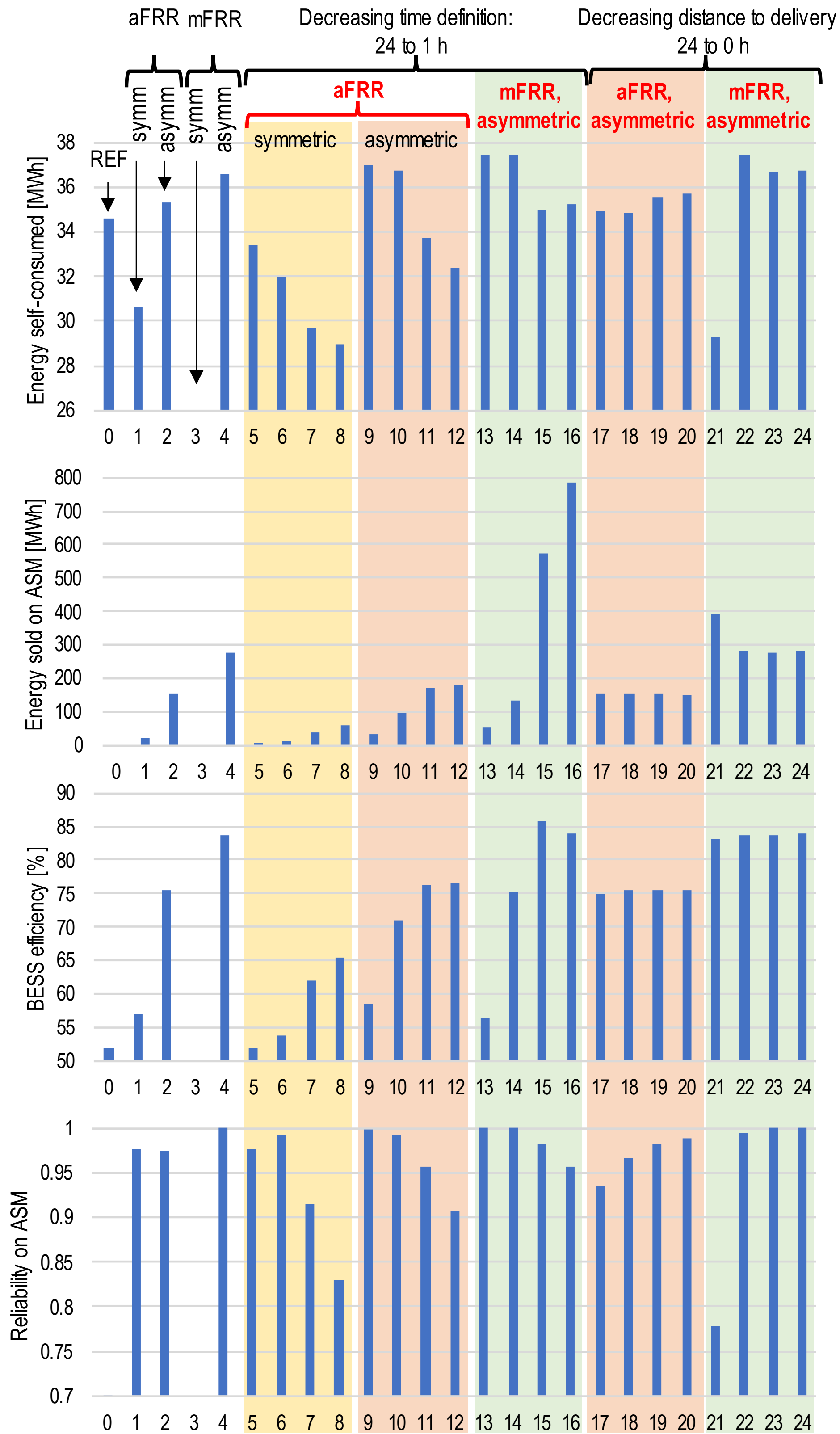


Figure 7.9 Main results of the simulation campaign on the ASM arrangements.

7.4.1 Self-consumption

For what concerns the self-consumed energy (E_{SC}), most of the cases show a higher value with respect to RES case. This confirms the results obtained in Chapter 6: the Multiservice strategy allows to increase the self-consumption with respect to the standard control strategy focused on self-consumption only. The provision can be investigated based on the SoC profiles proposed in Figure 7.10. The provision of self-consumption more largely requests the BESS to inject power, while the battery charge occurs rarely (e.g., during weekend daytime). The main result is that the battery suffers of self-discharge due to the auxiliary systems and depletes its energy content. The addition of aFRR and even more of mFRR allows to increase the battery cycling, avoiding the depletion of SoC and increasing the availability to self-consume.

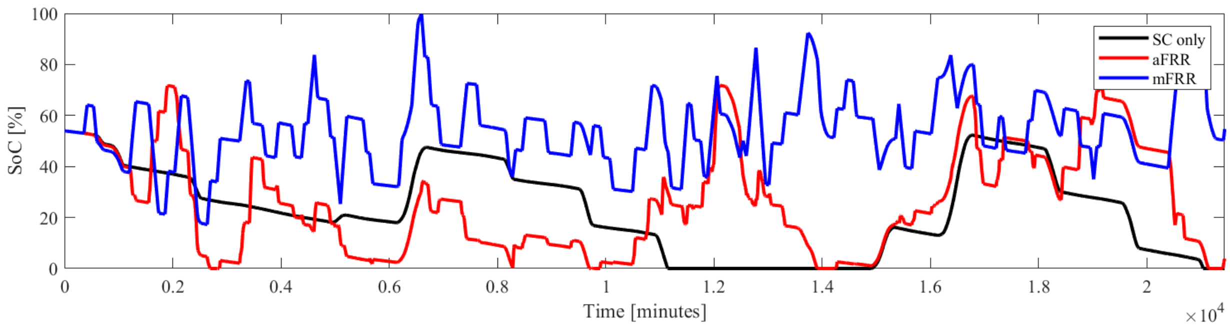


Figure 7.10 Some days of SoC evolution during service provision for self-consumption only (REF case in black), for aFRR (Case 2 in red) and mFRR (Case 4 in blue).

The increase of self-consumption with respect to REF case always occurs except for Case 1, 3, 5-8. These Cases feature symmetric provision of services. The symmetric provision of aFRR do not allow to perform effective implicit SoC management: the combined effect of the aleatory behavior of aFRR (given by the variable Regulating Signal shown in Figure 7.2) and the reduced bands according to equation (7.15) lead to an ASM participation that do not usually support the BESS to restore SoC towards the target. While providing an asymmetric service, the self-consumption is generally high: it is higher for mFRR than for aFRR. In general, neither TD nor DtD have strong influence on the self-consumption: self-consumption slightly decreases for small TD, since a larger quantity of energy is offered on the ASM and this leads to competition between the provision of the two services, in the end reducing both the self-consumption and the reliability on the ASM.

7.4.2 Flexibility

In this paragraph, we analyze both the energy sold on ASM and the flexibility made available on it.

The E_{ASM} is the gross amount of energy awarded on the market, for both upward and downward provision. As presented in Figure 7.9, all simulated Cases improve the performance of the REF case, where no energy is sold for the provision of ancillary services. Among the different cases, the energy that can be offered largely changes. The simulation 1-4 in the second top diagram highlight that a small amount of energy is sold in case of provision of symmetric services: as said, the provision of mFRR in symmetric way is meaningless as per the Italian rules; nevertheless, also symmetric aFRR only sells 16 MWh of monthly flexibility. The E_{ASM} increases to 148 MWh in case of asymmetric aFRR, and a further step up to 273 MWh sold occurs in case of asymmetric mFRR. In general, there is a strong inverse correlation between the energy traded on ASM and the time definition of products. Indeed, a shorter delivery time allows a limited energy reservoir to increase the bid power. An hourly time definition, with respect to a time definition of 4 hours, allows to trade from 1.8 (for aFRR, simulation 10 vs 12) to 5.7 times (for mFRR, simulation 14 vs 16) the E_{ASM}. The energy sold for mFRR is larger with respect to a coherent provision of aFRR by 1.5 to 4.6 times (comparing simulations 9-12 to 13-16). This is not because the mFRR is more energy-intensive than aFRR (see equation (7.16), the aFRR bids are larger to balance the lower energy request) but because of the aleatory behavior of aFRR. Indeed, as can be seen by Figure 7.11, comparing SoC distribution of aFRR (left) and mFRR (right) provision, mFRR better spans the SoC range. The mFRR allows to better exploit the energy content of the BESS: e.g., the SoC gets high after a delivery of services, thus the P_{bid} is high for upward service, and if awarded, it gets close to minimum SoC, thus allowing offering a large amount of downward reserve for next session and increasing the daily cycles. This is a virtuous circle, since the large energy provision increases the BESS efficiency, thus leading to a SoC distribution considerably shifted towards high SoC.

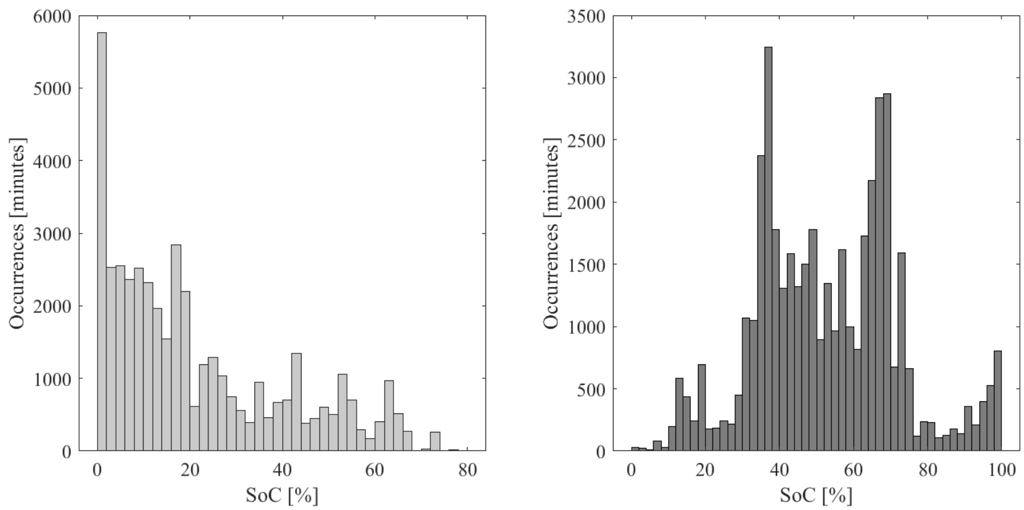


Figure 7.11 SoC distribution for aFRR (Case 11, left part) and mFRR (Case 15, right part).

As said, a requirement for an ASM arrangement to be defined efficient is the possibility to exploit a large amount of flexibility even by a limited installed capacity of resources. The KPI to evaluate this is the average power (P_{bidASM}) that is offered on the market in the simulated month (P_{bidASM}). As per the Multiservice Strategy, this power is represented by the available margin left after providing the primary service (self-consumption, in this case). Focusing on the asymmetric provision, Figure 7.12 shows the trend of bid power for aFRR (in red) and mFRR (in blue). The awarded power depends on the SoC. Nonetheless, the services show differences: at the same SoC, the aFRR can bid a sharply larger power. This is because of the smaller energy requirements of aFRR with respect to mFRR, considered by the Multiservice strategy. In case of a time definition of 4 hours, the $P_{bidASMup}$ for aFRR is 1.6 MW, while the $P_{bidASMdn}$ is 3.8 MW (Case 2). For mFRR, the values are respectively 1.0 and 1.2 MW (Case 4). Reducing the time definition to 1 hour, the pair ($P_{bidASMup}$, $P_{bidASMdn}$) for aFRR increases to (2.3, 4.0) MW, and (3.0, 3.5) MW are the values for mFRR (Case 12 vs 16). Therefore, the bid power is inversely proportional to time definition, too. For aFRR it is generally unbalanced towards downward power. This is because of the lower real-time power flows and the consequently lower efficiencies (and larger weight of auxiliaries) bringing down the SoC. mFRR is instead able to provide a balanced mix of downward and upward flexibility. It is worth noting that for low time definitions (e.g., 1 hour), in both cases we have 2.4-4.0 MW of flexibility averagely available on the ASM for a BESS of 4 MW of nominal power: this means that 60 to 100% of the installed power can be regularly devoted to flexibility.

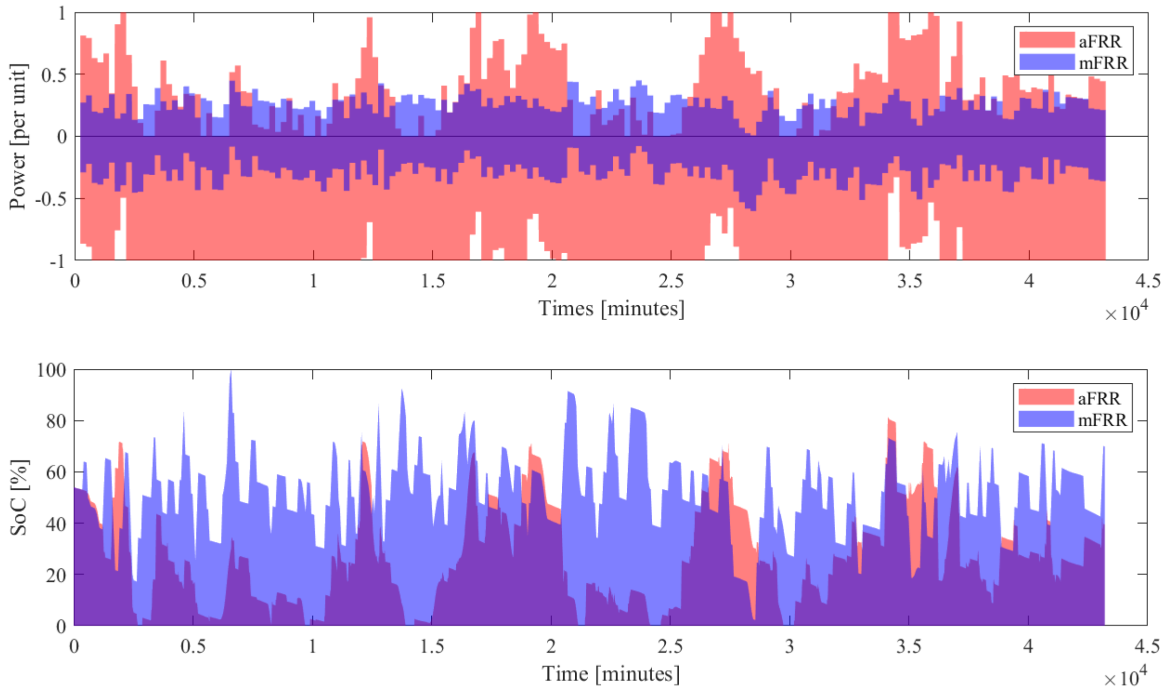


Figure 7.12 Bid power (top chart) and SoC (bottom chart) profiles for aFRR (Case 2) and mFRR (Case 4)

7.4.3 Reliability of ancillary services provision

The reliability of the provided services is generally high: reliability is above 90% for 20 out of 22 relevant Cases (see bottom chart of Figure 7.9). This is given by the effectiveness of the Multiservice Strategy, only bidding what can be provided. In addition, this is proving the trustworthiness of BESS and DERs on ASM, thus backing their larger exploitation. The reliability is above 97% for large time definitions (4 to 24 hours) and relatively small distances to delivery (<24 hours for mFRR, <4 hours for aFRR). This is due to the significantly lower E_{ASM} in these cases. For small time definitions, the traded energy increases, leading sometimes to impossibility of providing all the energy, e.g., due to SoC saturation. This reduces reliability to smaller, yet acceptable values: around 90% for aFRR and 95% for mFRR in case of 1 hour of time definition. The effect of the distance to delivery is clearer on the aFRR, since its behaviour is aleatory: the provision of aFRR itself can lead SoC to diverge between the commitment (the market closure) and the delivery time, thus leading to unreliability. This is a drawback, for instance, for products contracted on the day-ahead [318].

7.4.4 BESS efficiency

The simulations showed a wide range of average roundtrip BESS efficiencies. Efficiency is very low (down to 45%) where the energy provided on the ASM is low or absent. In the REF case, for instance, the minimum efficiency is recorded since the battery is often subject to self-discharge (see Figure 7.10), hence increasing the auxiliaries' share on losses. The efficiency rises to 85%

in case of massive participation to ASM. As highlighted in Chapter 6, too, there is interest in exploiting the BESS as possible, to avoid calendar aging to become predominant.

7.4.5 Comprehensive economic evaluation

To achieve generalizable results, the economic analysis evaluates a set of previously described KPIs that are considered drivers of the economic attractiveness of the investment. The main drivers are the energy traded on the ASM and the reliability of the provision of the ancillary services. Indeed, the more energy is sold on ASM, the more additional revenues with respect to the REF case can be assumed (in case of energy-based remuneration). On the contrary, a large reliability guarantees avoiding the financial penalties usually associated to non-performance. Besides, the increase of self-consumption is positively evaluated, nonetheless its economic value is uncertain since it is subject to the tariff scheme (e.g., the presence of net metering), as previously highlighted. Eventually, a high efficiency indicates generally less variable operating costs for BESS management. The economic evaluation performed considering these KPIs is presented in Figure 7.13.

Case	Service	Symmetry? [Y/N]	TD [h]	DtD [h]	Economic evaluation
REF	-	-	-	-	Poor
1	aFRR	Y	4	1	Poor
2	aFRR	N	4	1	Good
3	mFRR	Y	4	1	Poor
4	mFRR	N	4	1	Excellent
5	aFRR	Y	24	1	Poor
6	aFRR	Y	8	1	Fair
7	aFRR	Y	2	1	Poor
8	aFRR	Y	1	1	Poor
9	aFRR	N	24	1	Fair
10	aFRR	N	8	1	Good
11	aFRR	N	2	1	Fair
12	aFRR	N	1	1	Poor
13	mFRR	N	24	1	Good
14	mFRR	N	8	1	Excellent
15	mFRR	N	2	1	Excellent
16	mFRR	N	1	1	Good
17	aFRR	N	4	24	Poor
18	aFRR	N	4	4	Fair
19	aFRR	N	4	0.5	Good
20	aFRR	N	4	0	Good
21	mFRR	N	4	24	Fair
22	mFRR	N	4	4	Excellent
23	mFRR	N	4	0.5	Excellent
24	mFRR	N	4	0	Excellent

Poor Fair Good Excellent

Figure 7.13 Economic evaluation of each case.

A poor to fair economic interest is recognized for REF case and for the symmetric provision of services. More positive outcomes are shown for asymmetric provision, in particular of mFRR.

aFRR hardly gets an excellent evaluation: a good outcome is achieved for 4-8 hours of time definition and for distance to delivery equal or lower than 1 hour. The asymmetric mFRR provision returns excellent economics for 2-8 hours of time definition and for distance to delivery lower than 4 hours.

7.4.6 The optimal ASM parameters

The previous analysis allows to define an optimal range of parameters to be adopted when defining standard balancing products. They are shown in Figure 7.14. They are coherent with the adopted ranges in the Cases achieving the highest grade of evaluation in Paragraph 7.4.5.

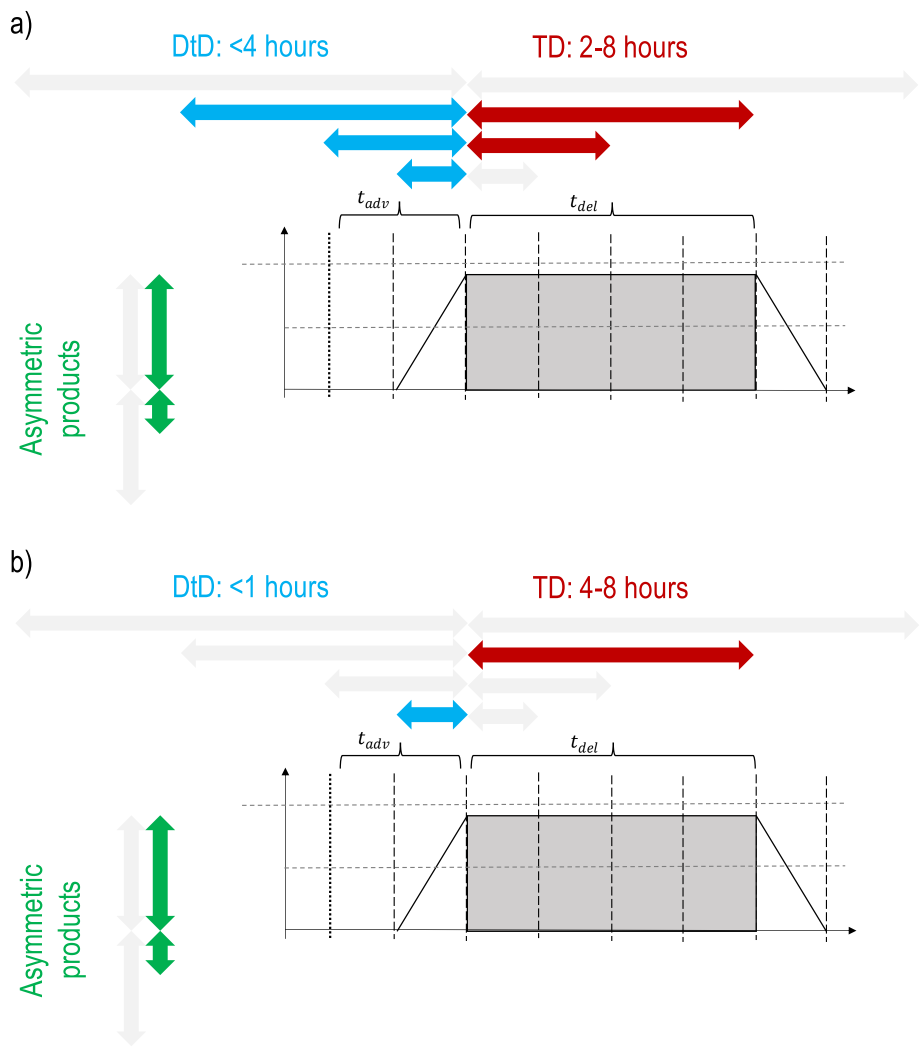


Figure 7.14 Optimal ranges for the provision of a) aFRR (top chart) and b) mFRR (bottom chart).

The aFRR gets a good evaluation for asymmetric provision with a distance to delivery (DtD) equal or lower than 1 hour and a time definition generally long. This result can be generalized, up to a certain extent, to all the services showing an aleatory behavior and a low energy intensity. For instance, frequency response services (including Fast Frequency Response) and the services responding to the Area Control Error (ACE). They need to be contracted closer to real time. They can be provided for a generally long period, since they do not require an intense energy provision.

For what concerns the mFRR (bottom part of Figure 7.14), its asymmetric provision offers an excellent outcome in terms of techno-economic performance when provided for 2-8 hours and when contracted less than 4 hours in advance. These results can be generalized to the provision of Replacement Reserve, congestion management, balancing and other slow dynamics services. The ranges are larger in this case, and the achieved results are better. Nonetheless, BESS face larger competition when providing services characterized by a static setpoint or by slow dynamics. Indeed, these can be provided by a larger turnout of resources, not only inverter-based systems [37].

It is worth noting that, within the study, a sensitivity analysis has been performed on the BESS sizing, to check the results with an E/P ranging from 1.5 to 3. It resulted that the provided outcomes on the optimal BESS arrangement are generally independent from E/P within this limited range.

7.4.7 Discussion and application to national frameworks

To better address the obtained results and gather some takeaways, the following discussion is proposed and the evaluation of real-world examples is provided.

As previously introduced, since 2021 the Italian BM changed from a setting with six 4-hour market sessions a day, towards hourly market sessions. Therefore, the provision of mFRR (previously represented by Case 4) is performed as in Case 16. The expected performance of the energy district could qualitatively change as follows. The offered flexibility and, consequently, the energy traded on the ASM is expected to sharply grow. The self-consumption could remain the same, as well as the BESS operational efficiency. The reliability of the provision could slightly decrease, maintaining high values (e.g., 95%). Therefore, the evolution is in the direction of further including DERs in the electricity balancing and increasing the flexibility that can be provided by each resource.

For what concerns the provision of aFRR, a pilot project for its asymmetric provision has been presented in 2020 [278], but still its go-live is undisclosed. This change would modify the way aFRR is provided from the one depicted in Case 1 to Case 2. This would drastically improve the techno-economic performance of BESS, increasing the energy traded on ASM by even 7 times – with no expenses on the reliability (see Figure 7.9) – and enhancing the self-consumption rates. In the case of aFRR, a decrease in time definition would not bring additional flexibility, whilst it could decrease reliability (see Case 2 with respect to Case 11 and 12). Oppositely, a decrease in distance to delivery would increase reliability (see Cases 18-20). The economic evaluation would benefit by the asymmetric provision, too, switching a poor evaluation into a good one (see Case 1 vs Cases 2 and 20 in Figure 7.13).

The proposed analysis clearly showed a performance decrease in case the gate closure time is too far from the delivery time. Considering the German FCR, the gate closure time is on the day-ahead, as described in Paragraph 3.4.3.1. The time definition is 4 hours since 2019 and the provision is symmetric. There is not a dedicated Case representing this provision. Nonetheless, a symmetric provision of an aleatory service is described in Cases 1 and 5-8: these show that, up to a certain extent, the decrease in time definition improves the provision. As already described, the switch to an asymmetric service works better. Next, the decrease in distance to delivery time can be of utmost importance in the case of an aleatory service. Cases 17 to 20 support this statement: the reliability increases by 15%, as well as the self-consumption (+21%) and the overall economic evaluation (from “poor” to “good”).

The same rationale can be applied to different standard balancing products. The analysis can be extended to evaluate different conditions (e.g., weekly auctions, steeper provision) given the flexibility and low computational effort of the adopted BESS model.

7.5 Conclusions

In this Chapter, a study on the regulatory barriers for BESS in the provision of ancillary services is presented. The BESS is implemented in a simplified energy district based on the Politecnico di Milano’s Leonardo Campus microgrid. It is selected to be general and to have results that could be applied to a wide range of frameworks. The BESS is providing self-consumption and ancillary services adopting the Multiservice Strategy described in Chapter 6.

The provision of services shows generally high reliability. Changing the Ancillary Services Market (ASM) parameters in serial simulations, the techno-economic performance of the BESS on market improves. A larger amount of energy traded on the ASM is not in conflict with the provision of self-consumption, on the contrary it improves as well thanks to synergies exploited by the developed control and bidding strategy.

These outcomes strongly support a gradual yet fast penetration of DERs in the electricity balancing and in ASM participation.

The fine-tuning of parameters allows to retrieve general principles. The asymmetric provision of services (i.e., the asymmetric procurement of reserves) drastically improves performance, reliability, and economic attractiveness of the ASM participation. The different nature of services can influence the performance. A static service (i.e., requesting for a constant power) allows a more reliable provision and larger economic benefits. Oppositely, there is larger competition in its provision since also conventional resources can provide static services with high precision. A service requesting to follow an aleatory and dynamic signal slightly reduces reliability and sharply shrinks the energy traded. Yet, it is less energy-intensive, therefore it allows to offer more flexibility (in terms of power) with the same installed capacity. Eventually, a fast response service would decrease the competition and easily elect BESS as the preferential provider. Energy-intensive services benefit of lower time definitions: BESS can offer larger flexibility since it is less constrained by the energy requirements, and the techno-economic performance improves. Aleatory services benefit also of a lower distance from gate closure to delivery time: it is difficult to forecast the available flexibility on a long-term horizon.

The indications and data gathered in this Chapter could be of use for stakeholders (e.g., regulators, policymakers, transmission system operators) aimed to abate the barriers of ASM.

The possible applicability of the analysis to recent or foreseen changes in real-world market (or product) designs has been showed, too. The Italian and German evolutions of balancing products have been treated.

When talking about including BESS in the ASM, the major interest is in the provision of innovative, enhanced, fast services necessary for facing the new needs of power systems dealing with decarbonization. Until now, we showed what is the effort to be done for including

BESS in ASM. Is it worth the effort? To answer this question, Chapter 8 presents an analysis on the possible impacts on the grid and the market of a relevant penetration of BESS providing enhanced services. The results are analyzed in terms of quality of supply and system costs.

CHAPTER 8

Why opening the markets? The impact of BESS on grids

Abstract

Chapter 8 aims to preliminarily assess the impact on the grid that a fast and precise regulation from BESS could have. To do so, the BESS model is implemented in a tool for power flow analysis of the power systems. This tool is used to perform dynamic simulations and assess the potential benefits of a frequency response service provided by BESS. The proposed methodology for adapting the BESS model to be suitable for dynamic simulations of power systems is described. Then some analyses are performed on test grids. A case study of a fast frequency response service following a real-world control strategy is built up. The analyzed case study is the provision of Fast Reserve a market zone in Italy. The estimated benefits and the possible drawbacks of fast regulation provision are checked by carefully analyzing the control strategy, the connection topology, and other parameters. The results are given either in terms of improvement of the frequency *nadir* after an event, or in terms of system costs (i.e., the size of the necessary power reserves for guaranteeing the same quality of supply).

8.1 Introduction

The increasing penetration of inverter-based systems and variable RES increases the variability of the power system and decreases its inertia (given by the rotating mass of conventional generating units: the synchronous machines). This acts sooner where the energy transition is faster and where the power system has intrinsically lower rotating mass: for instance, this is the case of the islands, such as UK and Ireland, generally connected via High Voltage Direct Current (HVDC) interconnections to the mainland [319]. Where inertia hits a minimum value, the direct consequence is the increase in the frequency deviation derivative (*df/dt*), namely the Rate of Change of Frequency (RoCoF). Indeed, the lower inertia increase the steepness of frequency events. Given the characteristics of frequency control and of Frequency Containment Reserve (FCR) described in detail in Paragraph 2.3.1.1, the higher RoCoF generates in the end a larger transient frequency deviation, namely a larger frequency *nadir*: RoCoF and *nadir* are correlated (and both increase with a larger penetration of non-synchronous machines) because there is a delay between the frequency event and the full-activation of the FCR [320].

Two main response strategies are considered for the evolution of the frequency control: synthetic inertia (SI) and Fast Frequency Response (FFR) [65], [321]. A Virtual Synchronous Generator (VSG) is an inverter-based system that implements SI and possibly FFR as follows.

$$P_{VSG} = P_0 + k_{SI} * RoCoF + k_{FFR} * \Delta f \tag{8.1}$$

where P_{VSG} is the overall power output of the VSG, composed by: P_0, that is the initial power of the asset; the power for SI, proportional by a factor k_{SI} to the RoCoF (in Hz/s); the power for FFR, proportional by a droop coefficient k_{FFR} to the frequency deviation (in Hz). A single asset can provide both or either. It is known that, depending on the reaction time [322], FFR can reduce both the *nadir* and the RoCoF of a frequency event [323]. Instead, SI does not significantly influence the *nadir* [321].

To cope with the evolution of the power systems, prompt and reliable services will likely become fundamental to maintain the quality of supply [54]. Also, they can reduce the total amount of necessary reserves and thus the system costs [37].

BESS are considered among the main provider of enhanced ancillary services [53]. BESS are Limited Energy Reservoirs (LERs), meaning that their energy content is finite. The reliability of the provision of ancillary services by LERs depends on the effective management of the energy content, as the provision of power for a certain time can lead to the depletion of the energy content. If the energy content depletes, the LER can no longer provide regulating power. Traditional analyses may fail to assess the reliability of LERs contribution to electricity balancing in real operation. For instance, a long-lasting small frequency deviation (e.g., 5-15 minutes) can be harsher for these assets than a larger but shorter frequency event [240], [324]. These analyses often rely on dynamic simulations aimed to replicate an accident (e.g., step disturbance, load ramp) and check the frequency profile in the following seconds (e.g., 15-30 seconds) [325], [326]. Possibly, this interval is too short to assess the effect of the frequency deviation on LER energy content: new methodologies for system frequency analysis must be developed to assess the effectiveness of new frequency controls by LER. For instance, they should not only analyse an incident but also the system frequency during system operation (intervals of some minutes to hours) and during system contingencies. These analyses can be therefore used to assess the effect of innovative, flexible services with respect to conventional ones. Dynamic simulations for this “new normal” system deployment, which considers LERs as a relevant provider of frequency regulation, should adopt a convenient LER model. The model of the LERs should be a detailed energy model, confirming that the energy content does not deplete (or saturate) during the service provision [324].

Thus, a study on the impact on the grid and on the system of BESS providing innovative ancillary services is of interest as a corollary study with respect to the previous ones, dedicated to defining the best arrangements for the markets for welcoming BESS. FFR is selected as subject of this study for what said before. After a general presentation of advantages and drawbacks of FFR, the methodology for the study is proposed: it includes the update of the BESS model for its implementation in a tool for performing dynamic simulations of power networks.

8.2 The Fast Frequency Regulation

Fast Frequency Regulation (FFR) is generally a control strategy based on the frequency deviation and aimed to contain it. It differs from the Frequency Containment Reserve (FCR) for the response time, the full activation time and the dynamic precision. If the FCR must provide its full activation within 30 seconds from the beginning of an event (see Paragraph 2.3.1.1), the different FFR strategies diffused in the power systems request to dynamically follow the frequency with less than 1 second of delay. In addition, they request a high dynamic precision (e.g., an error lower than some percentage points with respect to the requested power). Therefore, they are usually suitable for power converter-based systems, such as BESS or wind generators [101].

The FFR control strategies are usually characterized by small droop values (i.e., steep response to frequency deviations), small frequency deviations for full activation, and tight precision thresholds [38], [74], [75].

The positive characteristics of the FFR derive from the advantage of the precision in dynamically following the frequency deviation. Therefore, a single MW of FFR can in principle provide the same impact of several MW of conventional frequency regulation. The results of an assessment of the value of regulation resources based on their dynamic response characteristic was first provided in 2008 by institutional sources [327]. The main results are reported in Table 8.1. According to that study, 1 MW of FFR can substitute around 1.5 MW of hydro power plants providing conventional regulation, and even more than 20 MW of steam turbines providing conventional regulation.

Table 8.1 The value of Fast Frequency Regulation with respect to conventional regulation [327].

Technology	Regulating capacity replaced by 1 MW of FFR
Hydro	1.43
Gas Turbine	2.24
Steam Turbine	24.04

By a system perspective, this means that a share of FFR can reduce the total reserve needs in a region, thus probably reducing the system cost. Nonetheless, a high-performance resource should be better remunerated in case of providing a better service. This is the principle of performance-based regulation: a score is estimated for the provision of the service by each provider, and the score influence its remuneration. The score sets a prize for the higher precision: a service requiring a significantly variable power output (namely, requiring a larger mileage), deserves a larger prize. This is the rationale behind the remuneration of RegD, a FFR service procured by PJM [328].

FFR provision by BESS faces the duration challenge: their limited energy content requires either SoC management or the provision of a balanced service, i.e., requesting the same upward and downward energy each short period. For instance, RegD is a balanced service, that entails a high mileage but features energy neutrality. It is backed by RegA, a slower service for conventional resources that can sustain energy deviations [328].

Another possible drawback of FFR are the local frequency deviations. If a fast regulation is imposed in a network node poorly interconnected, the large resistances on the lines can originate local frequency deviations from the average regional frequency. This was shown for instance in case of Enhanced Frequency Response in UK [31], as shown in Figure 8.1.

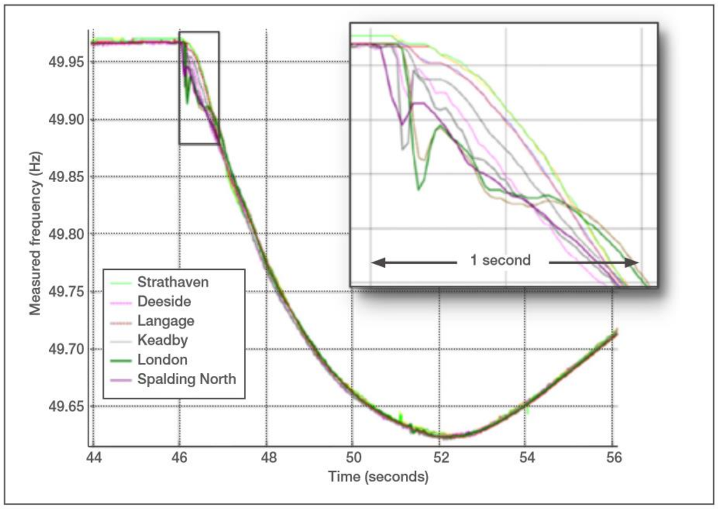


Figure 8.1 The frequency variation after an event as measured in different locations [31].

In summary, there is evidence that a share of FFR in the mix can decrease the system cost and provide valuable regulation. Above a certain threshold, there can be drawbacks given by the limited duration of the FFR provision by BESS, by the necessity of creating energy-neutral services, of by the existence of local frequency divergence. Therefore, a study substituting a share of FCR by FFR can allow to quantify the advantages in terms of either system costs or quality of supply.

8.3 The proposed methodology

To analyze a power system, the most common tool is the power flow analysis. This allows to estimate the bus voltages and currents in a system in steady-state. Therefore, it depicts a steady situation of the power system in a specific condition. To assess the dynamics of the power system, included its frequency profile, dynamic simulations can be performed. An initial power flow is computed, and then the dynamics of the system is estimated based on differential equations such as the swing equation, whose formulation is reported in Equation (8.2), highlighting the frequency behaviour.

$$\frac{df}{dt} = \frac{f_n}{2H} * \Delta P \tag{8.2}$$

where: df/dt is the frequency derivative; ΔP is the mechanical power subtracted of the electric power (P_m – P_e); f_n is the nominal frequency of 50 Hz; H is the inertia of the system. When analyzing a power system, the P_m represents the supplied power by synchronous generator, while the P_e represents the net load of the system. Therefore, the system frequency derivative (the RoCoF) is proportional to the imbalance between generation and load, while it is inversely proportional to the system inertia.

The swing equation is a simplified equation only valid under a set of assumption, for instance it considers the angular velocity and the synchronous velocity equal (i.e., the rotational speed of the machines always equal to the system frequency) [329]. Therefore, the state-of-art tools for dynamic simulations use multiple load flows over a limited time step, adopting differential equations in quasi-steady state [330].

A dynamic simulation is proposed for a power system including BESS providing frequency regulation. The first simulations implement the same FCR droop curve on conventional units and on BESS, to check the performance in the provision of conventional FCR by different units under harsh frequency events. Then, the detailed control strategy of Fast Reserve (FR) as per Italian rules, already described in Paragraph 6.5.2 and following ones, is implemented for a real-world case study based on a 15-minutes frequency profile from historical data. The adopted case studies include standard test networks [331] and the real-world case study concerning the provision of FR in a portion of the Italian network [150]. The FR control strategy data are provided in Table 8.2.

Table 8.2 Fast Reserve control strategy information.

Key	**Value**
Dead-band (level #1)	20 mHz
Full-activation threshold (level SAT)	150 mHz
Emergency threshold (level #2)	180 mHz

Two main KPIs are considered in the simulations, as previously introduced.

- The *nadir* of the frequency after frequency events in case of FCR and FFR provision is assessed (both in case of a standard incident and considering operational frequency profiles coming from historical data).
- The power reserve size necessary to return the same *nadir* in case of FCR and FFR is adopted as an estimation of the possible system needs and costs with the two schemes.

A state-of-art tool for dynamic simulations is adopted [330], and the BESS model illustrated in Chapter 4 is updated and included in the tool for delivering the same degree of accuracy in representing the BESS.

8.3.1 Implementing the BESS model in the network analysis

The BESS model is implemented in the model for assessing the technical performance of a battery providing FFR. The BESS envelope is a static generator. It is connected to the network at low voltage (LV) or medium voltage (MV) depending on the case study. The BESS model includes all the parameters described in Chapter 4, its block diagram is show in Figure 8.2. The BESS receives the frequency data from the network model and return the BESS active power delivered (top chart). The BESS model presents the capability chart and the efficiency lookup table, based on these the power delivered can be estimated and the SoC can be updated (bottom chart).

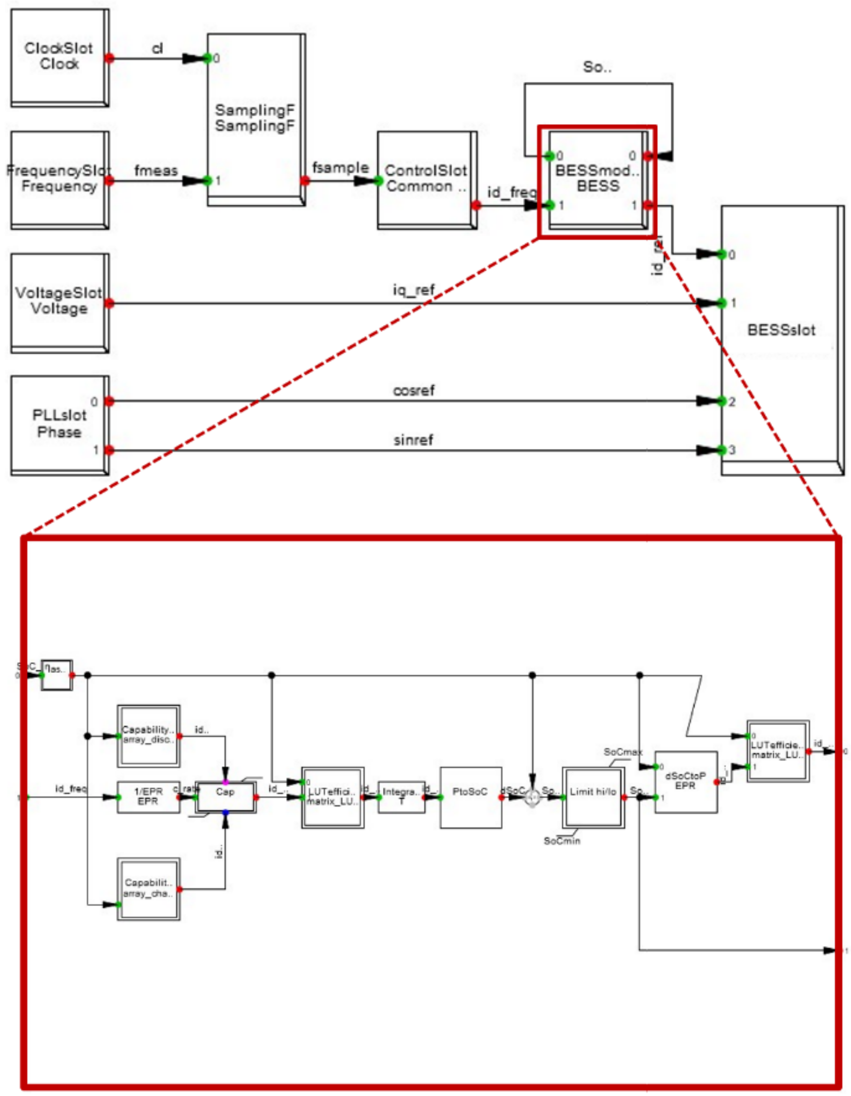


Figure 8.2 The block diagram of the BESS model implemented in the power system analysis tool.

In addition to this, a block with an integrator is added to include in a simplified way the dynamics of the BESS response. The BESS is represented as a first order system with a time constant (τ) of 40 ms, coherent with the time for completing a transient that is considered of 200 ms (5τ) for batteries [332], [333]. Therefore, the transfer function between the requested (P_{req}) and delivered power (P_{del}) is represented by equation (8.3).

$$P_{del} = \frac{P_{req}}{1 + \tau s} \tag{8.3}$$

In addition to this, the frequency in input to the BESS controller is sampled each 0.5 seconds.

This model is considered suitable to assess the provision of FFR in a dynamic simulation. Indeed, it retains the accuracy in representing the operational performance already validated, and it adds the dynamic behavior of a standard BESS coherent with literature estimations.

8.3.2 Testing a long-lasting frequency event

As introduced, a BESS could be more challenged by a long-lasting frequency event, than by a harsher event, but shorter [324]. Thus, the goal of the procedure implemented and presented in Case Study 3 (see Paragraph 8.4.3) is to test the system frequency over an extended period characterized by a long-lasting frequency deviation. In this perspective, the following procedures are implemented.

The transmission network model of one of the Italian market zones is adopted. To consider a real-world operation contingency, the historical frequency data are investigated, and the harsher contingencies are extracted: the adopted criteria for the selection of a harsh contingency both consider the total continuous time outside the dead-band and the absolute value of the frequency deviation (this is to consider a large and long-lasting frequency event as a worst case for a BESS). After the selection of the frequency event (i.e., 15 minutes of frequency profile), the grid scenario must be reconstructed.

The electricity market data for the same period are considered. They show the total production and consumption, the interzonal exchanges and the active assets. They are used to characterise the network model with the operating production units, the regulating power, and the main system dynamic. In addition, the interzonal flow exchanges are considered for the analysis. A non-exhaustive list of the necessary data is summarized in Table 8.3.

Table 8.3 List of the adopted data

Data	**Provider/source**	**Notes**
Frequency profile (in Hz)	Direct measurement, phasor measurement units (PMU), from public repositories.	The sampling rate should be comparable with integration time.
Asset data: technology, control strategy (regulating or non-regulating units), nameplate data (e.g., nominal power in MW).	Public repositories of Producers and TSO.	The control strategy for the delivery of FCR is generally available on the Grid Code.
Day-ahead (DAM) and intraday market (IM) data: active power setpoints of production units and consumption units (in MW or MWh), zonal transits (in MW or MWh with sign).	Nominated Electricity Market Operator (NEMO) website or other public repositories.	DAM and IM data are necessary to retrieve the injection and consumption schedules of the assets of the market zones. These data are used to characterize the initial state of the power flow.

The regulating assets are used to transform (by reverse engineering, using an equivalent small grid) the frequency profile into a coherent active power imbalance profile. This power imbalance is then equally shared between the loads in the network and the selected frequency profile recreated. A dynamic simulation of the system with the reconstructed imbalance profile is performed and compared with the frequency profile coming from historical data to validate the method.

Then, a case study also including FFR provision by LER is tested. To do so, the BESS model is implemented in the network model. One or more BESS are located in the grid coherently with real assets.

Figure 8.3 shows the flowchart of the proposed approach.

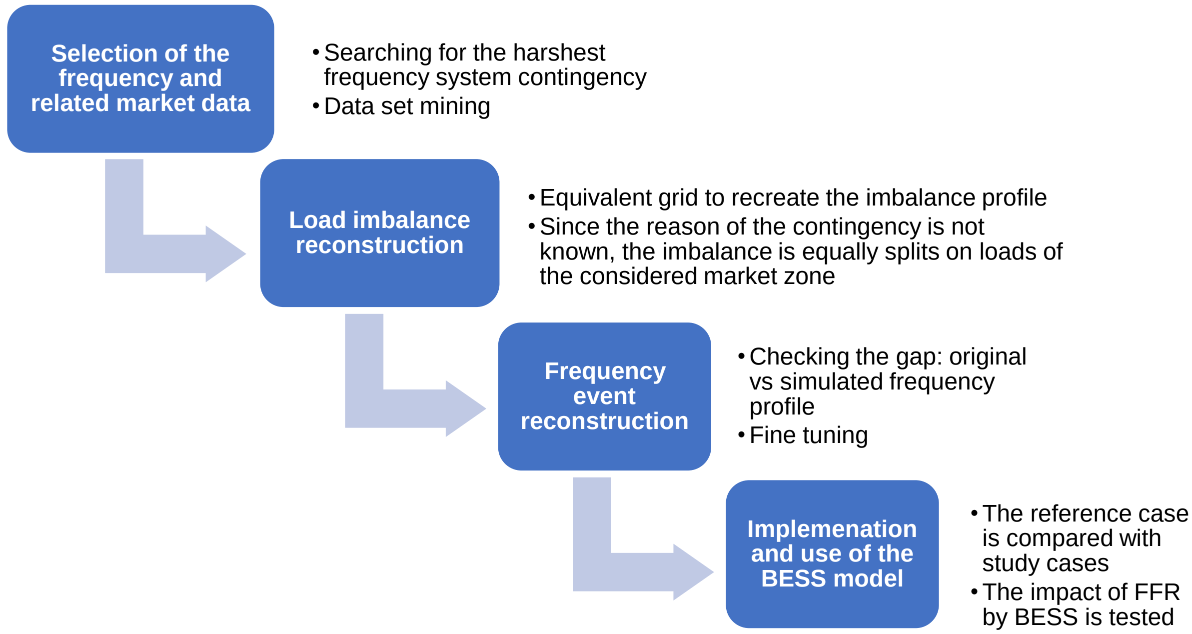


Figure 8.3. The main steps of the proposed methodology.

Following the presented procedure, different contingencies coming from historical data can be reconstructed, and different control logics can be tested. The obtained results concern the quality of supply (e.g., the frequency *nadir* or the duration of the frequency event with and without FFR), the reserve needs (e.g., the maximum activation of FCR or FFR), and the estimated system costs (considering reference costs for 1 MW of FCR and FFR). Thanks to the BESS model, the procedure can also give details on the SoC evolution: they are of paramount importance to consider the possible depletion of the energy content of LERs.

8.4 Analysis of the BESS impact on the power grid

8.4.1 Case study 1: reducing the *nadir* after an incident

The first tests are carried out on the IEEE 39 Bus New England System [331]. A first test considers a load event: an electric load is subject to a step increase of +50%. The event occurs 5 seconds after the start of the simulation. The main results are shown in Figure 8.4. A reference case is obtained by adding no more regulating units with respect to the synchronous generators already present in the system. Then, 120 MW of gas turbine (GT) power plant are installed in a central bus of the network, providing conventional FCR with full activation at 200 mHz (in the diagram, 0.996 p.u.). The GT can reduce both the *nadir* (-25%) and the final steady state frequency. In any case, the maximum power is provided more than 10 seconds after the incident and it is lower than the maximum requested: indeed, reaching the full activation frequency deviation at *nadir*, the resource would be expected to provide the full 120 MW of regulating power, but this is not the case. Next, 120 MW of BESS regulating power is installed instead of the GT at the same bus, with the same FCR control strategy based on a droop curve with full activation at 200 mHz. BESS use results in a further reduction of *nadir* (-33% with respect to the GT case) even in case BESS is devoted to the conventional FCR. This is because BESS can dynamically provide with precision the power requested to cope with the sudden frequency drop. Indeed, the maximum power is provided within 4 seconds from the incident. Being the deployed regulating power the same in GT and BESS case, the final steady-state frequency is the same. The frequency is measured in two different buses, a bus close to the installation feeder and a farther one. No locational differences are seen.

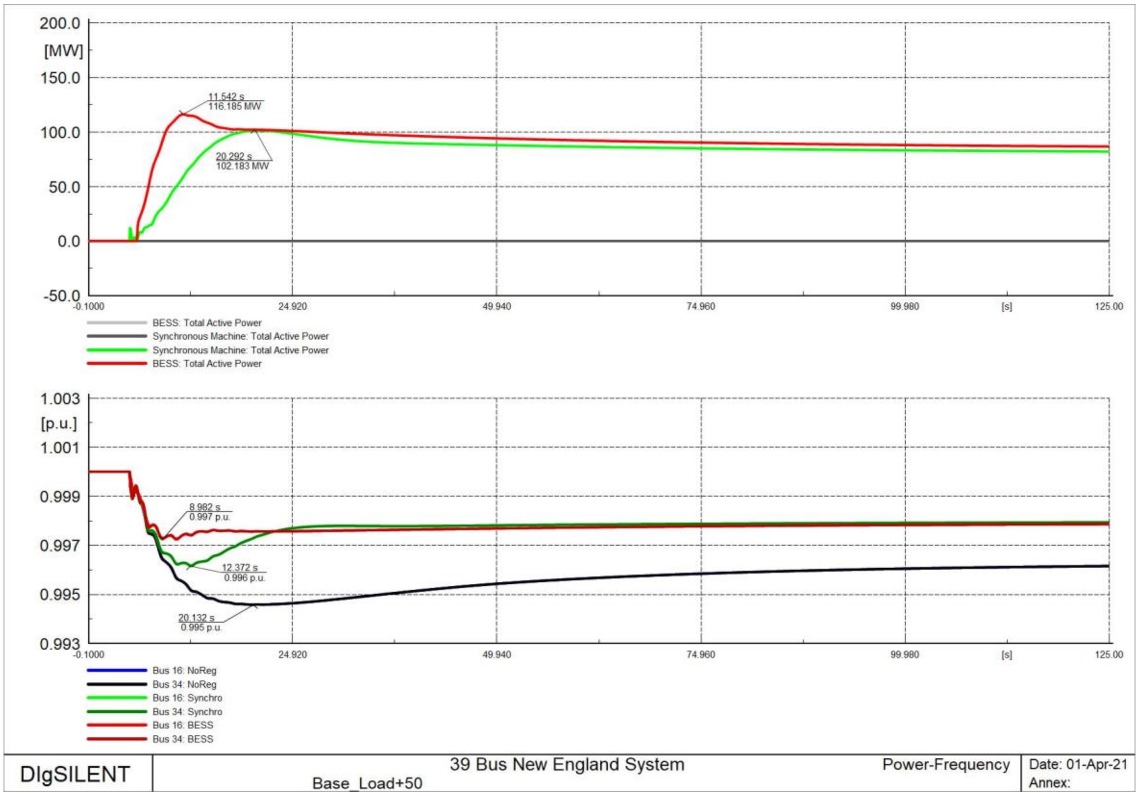


Figure 8.4 The regulating power profile (top chart) and the frequency profile (bottom chart) after a load event in the 39 Bus New England System, considering three regulating scenarios: no additional regulation (black-blue), additional regulation with 120 MW of gas turbines (green), additional regulation by BESS (red).

The BESS seems to be useful to improve the quality of supply after a harsh and sudden frequency event. This is because its performance is precise in dynamically following the frequency drop in the first second after the incident. On a meshed network, no local frequency distortions are detected.

8.4.2 Case study 2: reducing the necessary reserve for the same quality of supply

The nowadays frequency profiles can be considered suitable for the efficient operation of networks. One goal for the RES-penetrated power grid could be to be able to provide the same quality of supply, keeping an equal or lower cost for the balancing. A study on the possible reduction of necessary power reserve is carried out on the so-called Kundur’s Two-Area System [334]. This poorly meshed network is considered to check if the fast response of BESS can enhance the inter-area oscillations usually experienced on this system. Once more, a GT or a BESS is added to provide frequency response to a step increase of load (occurring 3 seconds after the beginning of the simulation). In this case, a GT regulating power is fixed (i.e., 300 MW), and a set of iterative simulations are performed to obtain the same *nadir* with BESS. As in the previous case study, the BESS is substituting the GT and hosts the same FCR control strategy with full activation at 200 mHz. With respect to the previous case, a reference case is not provided since this is the only regulating power considered in the network. The results of the test are provided in Figure 8.5. The *nadir* is equal in the two cases: 49.825 Hz: this is obtained with 160 MW of BESS or 300 MW of GT. The steady-state frequency is closer to the nominal one for the GT case (in green) with respect to the BESS case (in red). This is due to the lower regulating power for the BESS case. As can be seen, the power delivered by the GT is larger at the end of the simulation. Instead, the BESS can ramp faster and provides the requested power in less than 3 seconds after the incident. Please note that the BESS does not present an inertial behaviour, differently from the GT. Therefore, its regulation starts some tenths of second after the frequency drop (see the different length of the horizontal red and green lines to the left part of the bottom chart of Figure 8.5).

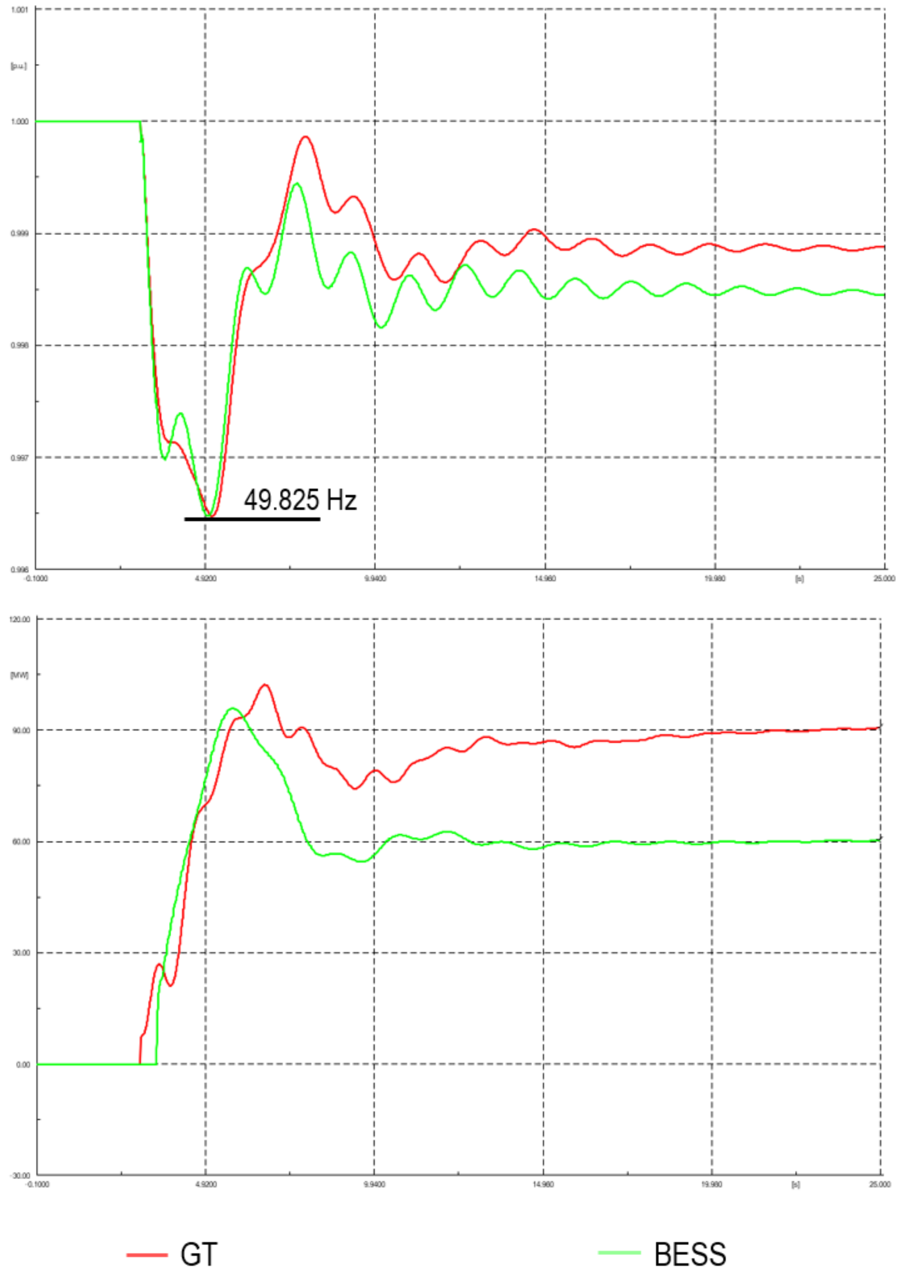


Figure 8.5 Frequency profile (top chart) and regulating power profile (bottom chart) after a load event in the Two-Area System, in two scenarios: with 300 MW of GT (red lines) and with 160 MW of BESS (green lines).

BESS can significantly reduce the reserve needs in a power system, thus possibly leading to decrease the system cost. It is worth noting that, as per the results of this case study, the 1 MW of BESS has the same value of 1.88 MW of GT, considering the obtained *nadir*. This is much lower than the estimation shown in Table 8.1. This can depend on several reasons, including the fact that FCR (that is tested in this case study) is slower than FFR, and that the cautious assumptions made in modelling the dynamics of BESS could be conservative. Eventually, the BESS shows no significant impact on the frequency oscillations, that seem to be comparable with the GT case.

8.4.3 Case study 3: Fast Reserve by BESS in an Italian market zone

To estimate the impact of FFR on grid, the case of the deployment of Fast Reserve Units in a market zone is considered. In the considered zone, 30 MW of FR units are expected to be installed to start the delivery of FR in 2023. The available data include the winner of the auction and the nominal power of the installation. The location is still undisclosed. Therefore, some assumptions are done in this study, considering the known location of already deployed installations of the same energy firm. As just mentioned, the qualified powers are coherent with public data, while the locations are estimated. For each BESS, the qualified power is equal to nominal power. The E/P (i.e., the ratio between nominal energy and nominal power) is 0.6 hours: these data are not public yet assumed according to the FR rules on the minimum energy content.

8.4.3.1 The analyzed frequency event

The case study considers a period of system operation of 15 minutes (the “imbalance settlement period” for Terna, the Italian TSO). This analysis aims to check the BESS operation over time and verify its energy content (since BESS are limited energy reservoirs). The frequency profile is selected from the Italian 2018 frequency log for the studied market zone. In particular, the profile is selected based on the magnitude and duration of the frequency event: the selected time is September 27th, 2018, at 6:00-6:15 PM.

To better characterize the power system analysis and the power flows between the zonal market regions, the market data are retrieved from the NEMO platform [295]. Specifically, the quantities awarded on the DAM and IM are used to define the operating production units (PUs), the zonal transfers and estimate the regulating power of conventional FCR.

Concerning the FCR, in Italy, it is nowadays mandatorily provided by programmable PUs larger than 10 MVA. In addition, it is also provided by HVDC interconnectors. By analysing the awarded quantities and the zonal transfers, it is possible to identify the power plants and interconnections in service. Then, knowing their nominal installed capacity and assuming a droop equal to 4-5% (according to the Italian Grid Code), it is possible to estimate the regulating capacity available in the zone on the selected quarter of hour.

The retrieved data are summarized in Table 8.4. As can be seen, the extracted period is characterized by a very low regulating power. This is due to the fact that the HVDC is performing the flow inversion (from export to import), therefore its regulating power is unavailable for the minutes of the underfrequency (the exact duration of the unavailability is not known, approximately 5 minutes from 6:04 PM). This condition makes the grid unstable and favors harsh frequency events.

Table 8.4 Selected power system data: September 27th, 2018, 6 PM.

Key	Value	Notes
Consumers	1115.5 MWh	Equally split among the primary substations of the market zone.
Producers	1164.2 MWh	Mainly thermal and hydro plants.
Net Zonal production	+48.7 MWh	Zonal surplus/deficit
Regulating power	210 MW/Hz	Combined Cycle Gas Turbine (CCGT), hydro plants and interconnections with other zones

8.4.3.2 *The imbalance reconstruction*

The selected frequency event is reconstructed by feeding the zonal loads with an active imbalance profile of the 15-minutes period. The imbalance profile that generated the frequency deviation is recreated as a response by the regulating units and the interconnection links as follows.

An ideal microgrid is first developed in the analysis tool (see Figure 8.6), composed by:

- an AC voltage source that imposes the recorded frequency profile;
- the regulating units and interconnection links (represented by equivalent units) in service in the relevant period, generating/absorbing the power awarded in the DAM and IM. A droop value (σ) of 5% (4% for hydro power plants), coherent with the Grid Code, is considered [73]. The droop control law is the one presented in Equation **Error! Reference source not found.**.

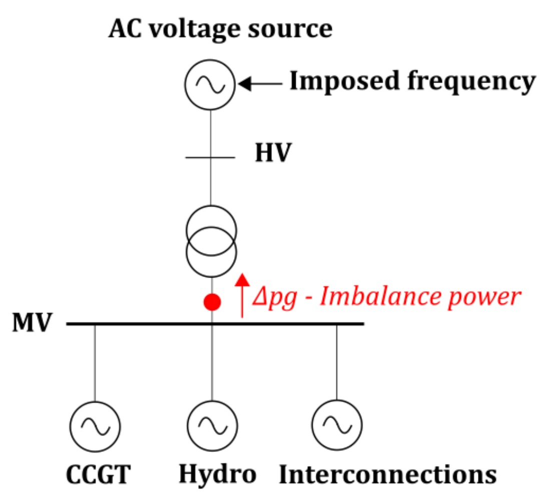


Figure 8.6. The block diagram of the grid developed for generating the imbalance profile, considering an interconnected market zone with a CCGT and a hydro power plant.

The desired active power imbalance (P_{imb}) is considered equal to the opposite of the sum of the variation of the generated power of the considered units.

$$P_{imb} = -\left(\sum_{i}^{N_t} \Delta P_{FCR,i} + \sum_{j}^{N_h} \Delta P_{FCR,j} + \sum_{k}^{N_i} \Delta P_{FCR,k}\right) \tag{8.4}$$

where ΔP_{FCR} is the FCR power setpoint for each unit, included a certain number of thermal units (N_t), of hydro plants (N_h) and of interconnectors (N_i). Interconnectors can be either HVDC or AC lines. This imbalance profile is then shared equally (p.u.) on the loads connected to the primary substations of the selected market zone.

8.4.3.3 *The validation of the network model*

As a validation, a simulation without BESS providing FR is performed to check the performance of the approach:

- the imbalance profile is fed to the loads;
- the only provided regulation is the FCR by the active assets;
- the frequency returned as output is expected to resemble the historical data.

The results of the simulation are shown in Figure 8.7. The trends are qualitatively coherent, and the quantitative error is considered acceptable for the application (e.g., the error at frequency *nadir* is 6% in excess).

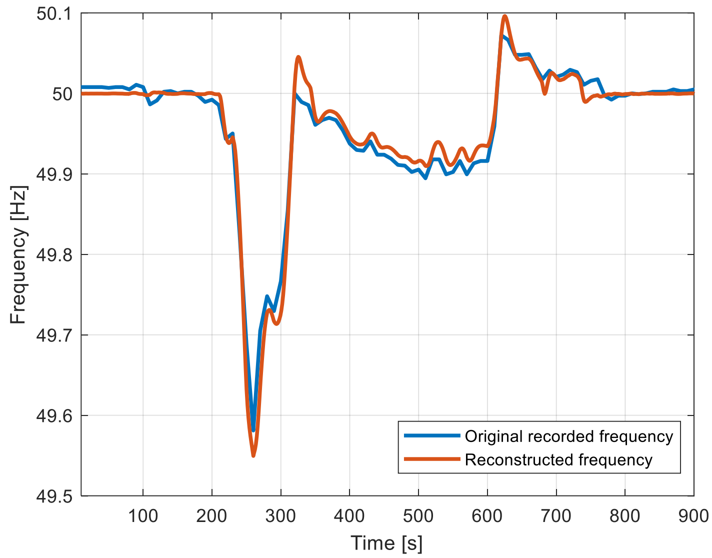


Figure 8.7 Validation of the model: frequency from historical data (blue line) and from the model (orange line).

8.4.3.4 The impact of BESS on the Italian network frequency

Once validated, the model is used to assess the BESS impact on network frequency. The BESS providing FR are added: four assets with a total regulating power of 30 MW. The results of the simulation are presented in Figure 8.8 and are explained in detail in the following. The frequency is initially in the dead-band: no FR is provided. After 200 seconds, a sudden frequency drop occurs: the FR reacts and there is a positive power response from the FR units (top chart), proportionally to frequency and the qualified power. It is worth noting that the recovery of the dead-band is implemented in FR droop curve (see Figure 2.7): hence, the power drop is steep when the frequency gets outside the dead-band (210 seconds). The FR units dynamically follow the frequency until the full-activation threshold is reached. The frequency reaches the emergency threshold (level #2), obliging the FR units to provide regulation for more than 30 seconds. The power output in this period is equal to the nominal power of each asset. As can be seen, the four assets present different power according to public data of FR auction. Then, the frequency deviation is contained, and the profile gets back towards nominal value (270 seconds). After 30 seconds from the end of emergency state, the fade-out starts (300 seconds). The fade-out suddenly drops when the frequency deviation changes sign, to avoid contributing to an overfrequency event (330 seconds). Frequency gets once more outside the dead-band, and positive power is provided (350 seconds). Since the frequency does not get to level #2, the fade-out starts (410 seconds). It drops when overfrequency is reached (600 seconds). Negative power is provided until the frequency gets inside the dead-band (740 seconds).

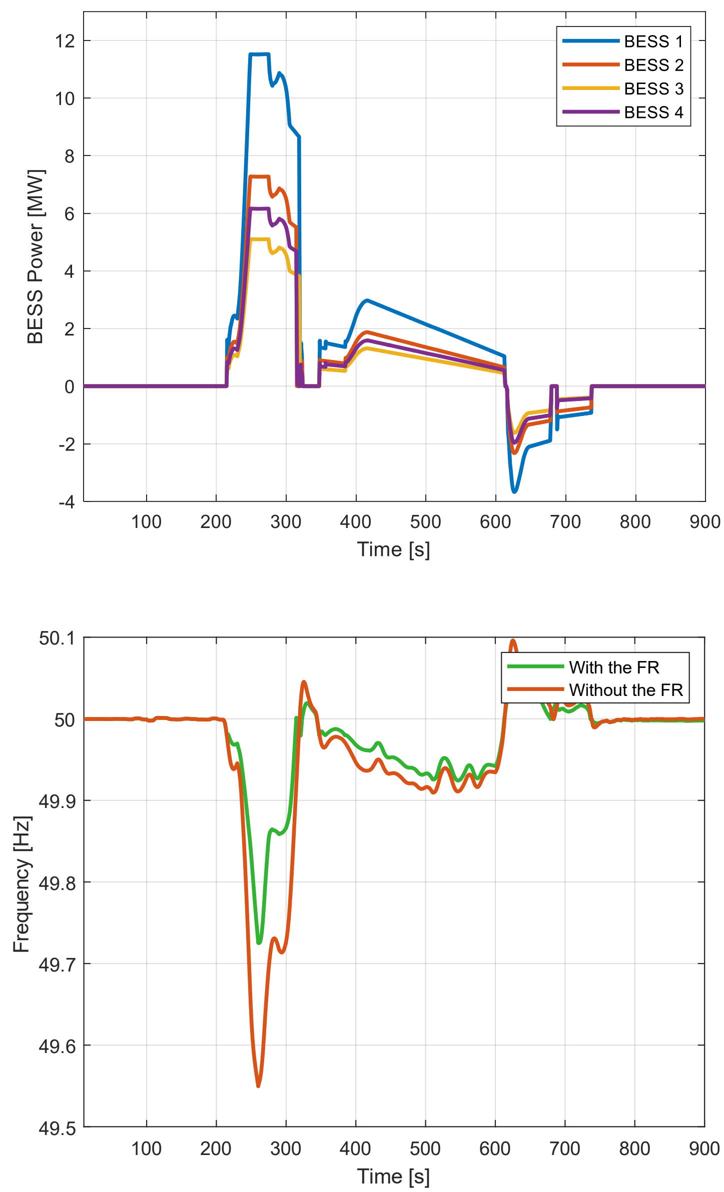


Figure 8.8 The impact of Fast Reserve provision (top chart) on the frequency (bottom chart).

The frequency *nadir* resulted 49.73 Hz in the scenario with FR, with respect to 49.55 Hz without FR. The *nadir* is reduced by 40% with 30 MW of FR. It is worth noting that the frequency trend is assessed on 10 network buses distributed over the region, to avoid disregarding local frequency distortion. No local distortions are detected, and the frequency profiles are close to the plotted one.

Eventually, an analysis of SoC evolution in the FR units is performed: the SoC remains in the range 40-50% even at the end of the frequency event. This result is achieved even if one of the harshest long-lasting events is considered, as per the selection procedure illustrated before. This analysis shows that a FFR service is a power-intensive service with a limited impact on the energy content of the BESS.

8.4.3.5 Discussion and possible further studies

The FR provision shows a significant impact in reducing the frequency *nadir* over a large underfrequency event reconstructed by historical data. The obtained result is considered positive, but also provided some further research questions that could lead future studies. For instance, the sudden power rise and drops given by the recovery of the dead-band and by the dismission of the fade-out should be cautiously analyzed. Further simulations performed within the study detected some oscillations in case the installed FR power is larger (e.g., 100 MW) and the frequency is around the dead-band. In these cases, avoiding the adoption of the recovery of the dead-band can provide stability at the cost of a slightly larger *nadir* (around +5%). The proposed droop curve is on the right of Figure 8.9, substituting the one coherent with Italian grid code (to the left) [73].

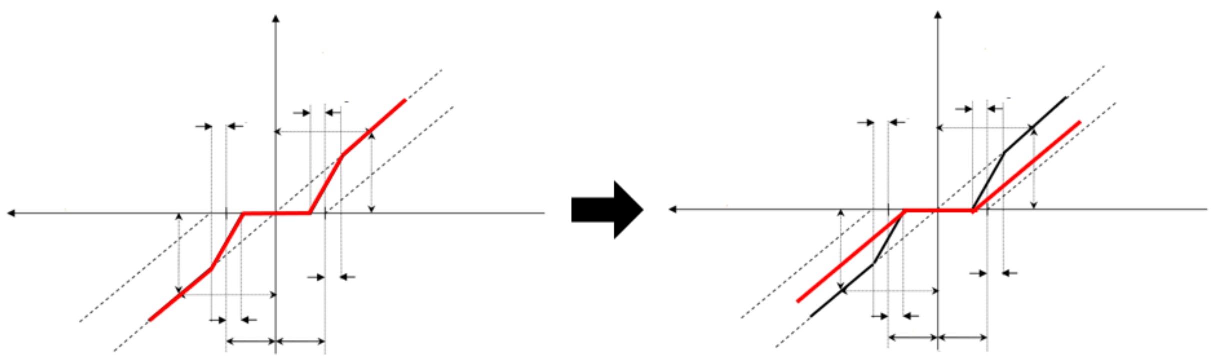


Figure 8.9 In red, the droop curves coherent with Italian Grid Code (left part) and the proposed one, without the recovery of the dead-band (right part) [73].

In addition to this, the control strategy of FR (and in general of FFR) could be reviewed to add an integral term beside the proportional control. This would avoid that a sudden variation of measured frequency leads to a spike in provided power. Alternatively, the possible implementation of a centralized control (e.g., based on Area Control Error) is adopted instead of a frequency response based on local frequency measurements.

For what concerns the other case studies, they show how a share of BESS as FCR provider can either sharply improve the quality of supply (i.e., reduce the *nadir* after a frequency event) or reducing the system costs for the FCR. Recent studies show how an updated computation of the reserve needs, considering the performances of new resources such as BESS, could be beneficial to the system [52], [99].

The previous ones are examples of the applications of the developed model supporting the regulation and the design of FFR control schemes.

8.5 Conclusions

The previous study assessed the possible impacts of BESS providing Frequency Containment Reserve (FCR) or Fast Frequency Response (FFR) on the power system. These impacts include: an enhancement of quality of supply; the possibility to cope with a decreasing system inertia avoiding jeopardizing the system; the reduction of system costs for the procurement of reserves.

To do so, the BESS model previously developed is implemented in a tool for the load flow analysis on the power network. It is updated by adding simplified dynamics, coherent with recognized BESS dynamic performances.

The BESS, both when providing FCR and FRR, brings either an improvement in frequency control (reduction of frequency *nadir* of 33-40%) or a reduction in the size of power reserves for guaranteeing the same quality of supply (1 MW of regulating power from BESS provide the same impact that 1.88 MW of a conventional gas turbine). Fast Reserve (FR) is analyzed to provide a real-world case study on FFR. There are positive outcomes and some indications for the system operators on possible improvements in the control strategy.

This Chapter closed the circle with the previously analyzed evolution of the market. The research question was: is it worthy to rearrange the ancillary services and ancillary services market design to better accommodate provision by BESS? It seems that BESS can bring a crucial advantage if adopted for frequency regulation in addition or in substitution of conventional generation. They can be fundamental in keeping the balancing of a system widely penetrated by variable RES and with a reduced system inertia given by the phase-out of fossil-based thermal power plants. All of this can be done at a reasonable (even reduced) cost, considering nowadays CAPEX and OPEX, considering an improved market arrangement able to abate the barriers, updated methodologies for power system needs estimation, and effective control strategies for new resources.

Conclusions

The presented Thesis work returns a wide view of the provision of ancillary services on the markets (ASM) by Battery Energy Storage Systems (BESS), also integrated with variable Renewable Energy Sources (RES). The analyses carried on focus on several perspectives.

- The technology perspective considered the suitable modelling of BESS for analyzing grid-connected applications.
- The economic perspective was investigated to assess the most attractive market opportunities for BESS, with a special interest for analyzing those BESS application that either directly support RES integration or improve the electricity balancing even in presence large RES penetration (i.e., with reducing system inertia and larger variability).
- The regulatory framework is necessarily linked to the effectiveness of ASM/BESS interaction. Indeed, the main goal of the Thesis was to propose optimal ASM arrangements for BESS and DERs exploitation.
- The power system perspective allowed to investigate the eventual benefits of providing high-quality frequency control and innovative ancillary services.

It is the conviction of the Author that these perspectives together allow to bring a systemic view and propose solutions that are effective and positive for all the involved parties, abating the trade-offs that each systemic and disruptive evolution features. The declared objective of the work is assessing the role of BESS in making a larger penetration of RES possible and feasible in the power systems. Most of the proposed analyses show that even a limited quantity of BESS can be beneficial. Therefore, the outcomes of the Thesis do not support a massive deployment of BESS (not desirable both for economic and environmental reasons related to the use of scarce materials), yet an effective and coherent deployment in association with fostered RES penetration and substitution of conventional thermal power plants. This is seen, for instance, in Chapter 7, where a BESS featuring only 2.5 hours widely improves the performance of a complex energy district, and in Chapter 8, where some tens of MW are added in a zone with more than 1 GW of load to improve significantly the frequency profile. The good results in terms of reliability of provision should encourage the stakeholders of the power system to abandon the anxiety towards its evolution, often expressed by policymakers, and foster a gradual but fast substitution of conventional generation with RES-based resources.

The wide set of case studies is aimed to support the idea that the actors of the new energy markets can be several: from citizens (or communities), to districts, to utilities.

The focus on the regulation relies on the belief that policymaking must lead the evolution and that the State can pick the winners and the direction in a (regulated) market environment. Indeed, it is possible that many technologies can support achieving a target, each one having advantages and drawbacks. The policymaking should be aware of its role, clearly depict a goal, and then the roadmap to achieve it using the tools it holds. If it clearly selects a sound mix of technologies and solutions, implementing effective regulations and incentives, it can foster the transition even in a market environment.

A better detail of the main qualitative and quantitative outcomes of the Thesis is given in the following.

The developed BESS model represents a virtuous trade-off between accuracy and computational effort. With respect to the state of the art, either it decreases by one order of magnitude the simulation time of models with comparable accuracy (i.e., of equivalent circuit models), or it halves the error of models with comparable speed (i.e., empirical models). This allows a wide set of studies that can support BESS operators, utilities, and system integrators. Indeed, the model achieves a high accuracy not only in representing the battery section, but also the power conversion and the auxiliaries, giving a complete picture of the system.

In addition, the proposed experimental protocol updates the literature since it allows to characterize the BESS without disassembling the battery pack (and even by measuring only in AC). A limitation of the study is that the BESS model is characterized on a single asset, and only represents that asset (i.e., the combination of the battery pack and the power conversion system). Its generalization would imply the loss of model validation.

The analysis of the possible arrangements of ASM to have an effective opening to DERs brings new knowledges. First, it illuminates a wide set of possible trade-offs between the interests of the system (e.g., of the TSO) and of the market participants (i.e., of the BSP also aggregating DERs). By analyzing the recent trends of some European countries in light of the analysis, it is clear that the largest efforts are often towards directions that entail trade-offs. Both the qualitative and quantitative analysis suggest that the wide deployment of asymmetric services (i.e., each provider can offer a different power upward and downward) would bring substantial benefit and would permit the effective participation of BESS also integrated with RES.

Finally, the analysis on the system frequency during operation presents a novel methodology to reconstruct the grid condition from market data (i.e., public data), and test the effect of imbalance on the frequency profile with different mixes of FCR and FFR over a long period. The provided results show the significant impact of the precise regulation by BESS. In terms of sizing of reserves and system costs, an estimation of the value of BESS precise regulation is provided: 1 MW of BESS regulation has the same effect on frequency containment as 1.88 MW of GT-provided regulation.

9.1 Advice to regulators and policymakers

The Thesis highlights the high reliability (even on the long run) of BESS in a set of different conditions (with different degrees of freedom, with one or multiple services). Also, the simulations have been built on standard balancing products and using historical frequency profiles for the Continent, to be generalized at least at European level (i.e., Continental Europe Synchronous Area). In addition, a sensitivity analysis has been performed to set the optimal range of many balancing product of the parameters, returning the range that allows high reliability and a decent return on the investment. This set of analysis should support the regulators and policymakers in an informed redesign of standard balancing products to maintain the quality of supply at the minimum system cost. Indeed, as it is already occurring in some Member States where batteries are already enabled to ASM (e.g., Germany), BESS are providing an increasing share of the regulating power, showing a significant decrease in operating costs of regulation and reserves. This trend will likely continue in the next future.

Therefore, a redesign of the structure and products of (for instance) the international platforms (e.g., FCR, TERRE, MARI, PICASSO) by prioritizing the parameters that both decrease system costs and increase the participation and reliability of BESS (the so-called win-win evolutions described in the Thesis) and by considering the proposed optimal ranges, could be beneficial for the electricity balancing and represent an effective opening to DERs. Additionally, this would not favor BESS over other assets: first, the BESS are presented inside an energy district with RES generators, non-RES generators, and load; second, the other assets do not deal with the energy limitations featured by BESS and the change in design parameters would not greatly influence their possibility of providing services.

For what concerns the sizing of the reserves, some institutional and academic studies suggest that updated methodologies could reduce the estimation of necessary reserves, hence decreasing the system costs. The presented work adds the estimation of the effectiveness of precise frequency regulation with respect to conventional regulation. The recommendation is to review the reserve sizing considering all the updates regarding resources reliability and performance. Indeed, efficiently sizing the reserves can lead to manage system costs in a significant way, preventing the likely increase of the volumes due to RES variability. The Italian ASM saw in the past 12 months a great reduction of the volumes traded for the reserves (e.g., -81% upward and -64% downward considering the year-on-year ratio of April ‘22 versus April ’21 [335]).

9.2 Recommendations for future works

For what concerns BESS modeling, further studies are already ongoing. The proposed experimental protocol, lasting 5-7 working days and requiring the BESS to be offline from its primary application, could be an obstacle to its applicability in industrial or utility contexts. The improvement of the protocol could include lowering the number of test cycles or adopting a semi-electric model to infer a trend in the lookup table without covering all the operating conditions in terms of SoC and power. A further step would include the possibility of gathering the necessary data while the battery is online, building the model parameters without dedicated tests.

When it comes to the control strategy for Multiservice, one of the limitations of the study is that it does not make use of optimization algorithms. A possible work is testing in a linear optimization problem a simplified version of the developed model (i.e., compatible with the linear nature of the problem). This would allow to use an accurate BESS model in a detailed Energy Management System (EMS) for the planning and operation of energy districts.

Eventually, the proposed methodology for modelling system frequency during system operation can be adopted on a set of activities assessing the potential of decarbonization of the power system. This is particularly of interest, nowadays, concerning the decarbonization of small and large islands that have a limited interconnection towards the mainland. Comparative studies assessing the impact of network reinforcements vs BESS deployment for frequency regulation and balancing could be of interest.

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