Benefit and value of Li-ion batteries in combination with large-scale renewable energy sources.

Agurtzane Erdozia and Alessandro Ferraris

School of Engineering

Thesis submitted for examination for the degree of Master of Science in Technology.

Stockholm July 12, 2017

Thesis supervisor:

Prof. Peter Lund

Thesis advisors:

Prof. Mikael Amelin

M.Sc. Roosa Nieminen

Aalto University
School of Engineering

AALTO UNIVERSITY
SCHOOL OF ENGINEERING

ABSTRACT OF THE
MASTER'S THESIS

Author: Agurtzane Erdozia and Alessandro Ferraris

Title: Benefit and value of Li-ion batteries in combination with large-scale renewable energy sources.

Date: July 12, 2017 Language: English Number of pages: 18+128

Department of Mechanical Engineering

Professorship: Advanced Energy Systems

Supervisor: Prof. Peter Lund

Advisors: Prof. Mikael Amelin, M.Sc. Roosa Nieminen

Li-ion batteries have demonstrated to be a very flexible source with energy storage capability. Due to their scalability and wide range of power and energy densities, they are suitable for several applications. Li-ion storage can therefore provide different services, the remuneration of which depends on the electricity market of the country. In this work, two different case studies of combination of Li-ion batteries with large-scale renewable power plants have been investigated: batteries with solar PV in India and with wind power in Sweden. Simulation models have been developed to assess the operation and profitability potential of different services in these two case studies. The models have been built using control algorithms, linear optimization (LP) and stochastic programming techniques. The results show that the use of batteries for solar power output smoothing under a power purchase agreement can be a profitable business case in India. Moreover, batteries providing primary frequency regulation (FCR-N) in Sweden show to have a positive economic value. System breakeven costs to make the stacking of wind power production imbalance compensation and FCR-N services profitable have been found, which based on conservative price expectations should be achieved by 2022.

Keywords: Li-ion batteries, RES, power markets, India, Sweden, flexibility, energy modelling.

AALTO-UNIVERSITETET
HÖGSKOLAN FÖR INGENJÖRSVETENSKAPER

SAMMANDRAG AV DIPLOMARBETET

Författare: Agurtzane Erdozia and Alessandro Ferraris

Titel: Fördelar och värde av Li-ion-batterier i kombination med storskaliga förnybara energikällor.

Datum: July 12, 2017 Språk: Engelska Sidantal: 18+128

Institutionen för maskinteknik

Professur: Advanced Energy Systems

Övervakare: Prof. Peter Lund

Handledare: Prof. Mikael Amelin, M.Sc. Roosa Nieminen

Li-ion batterier har visat sig vara en mycket effektiv källa för lagring av energi. Tack vare deras skalbarhet och det breda utbudet av kraft och energidensiteter har de flera användningsområden. Li-ion batterier kan därför användas för att tillhandahålla olika typer av tjänster vars ekonomiska ersättning beror av landets elmarknad. Detta arbete undersöker två fallstudier av Li-ion batterier i kombination med storskaliga kraftverk som drivs av förnybara energikällor: batterier i kombination med solkraft i Indien och vindkraft i Sverige. Simuleringsmodeller har utvecklats för att undersöka driften och lönsamhetspotentialen för olika tjänster i de två fallstudierna. Modellerna baserar sig på kontrollalgoritmer, linjär optimering och stokastisk programmeringsteknik. Resultaten visar att användningen av batterier för utjämning av solenergi enligt ett kraftköpavtal kan vara lönsamma i Indien. Dessutom har användningen av batterier för primärreglering (FCR-N) visat sig ha ett positivt ekonomiskt värde i Sverige. Breakeven kostnaderna för att göra kombinationen av vindkraftsproduktionens balanskompensering och FCR-N tjänster lönsamma har hittats, vilket ska uppnås senast år 2022 baserat på en konservativ prisprognos.

Nyckelord: Li-ion batterier, förnybara energikällor, elmarknader, Indien, Sverige, flexibilitet, energimodellering.

Preface

This Master Thesis is the result of the combined work between Agurtzane Erdozia and Alessandro Ferraris, who have mainly worked together but have also taken responsibility for and developed some parts individually.

The first, Agurtzane, has been in charge of the literature study on Li-ion batteries and their applications as well as the development of the mathematical models for constant power output, power output smoothing and time-shifting in IEX Day-Ahead market for the case study of solar PV and batteries in India. The latter, Alessandro, has carried out the study on modelling techniques together with developing the mathematical models for the demand following, demand following considering curtailment possibility and power output smoothing following SECI's requirements applications in India. The economic assessment and conclusions parts for the Indian case study have been performed by both authors together.

Regarding the Swedish case study, Agurtzane has developed the wind power production imbalance compensation model and has also taken part in building the stochastic model for simulating the battery operation for primary frequency regulation. On the other hand, Alessandro has adapted and developed the power time-shifting in Elspot and the primary frequency regulation models. The economic assessment of all the different services and conclusions have also in this case been done between both authors.

This work has been possible thanks in first place to *Fortum Sverige AB*. Special thanks to Anna Vidlund, for believing in us from the very beginning and helping us as much as possible in the Stockholm office. Big thank you also to all the people in Finland, the members of the Solar Technology team (Eero, Heikki and Jan in particular), Sebastian Johansen and Roosa Nieminen, who followed and guided our work.

Furthermore, we are very grateful for all the help and support from all the TAO people sitting in the sixth floor and control room. Such a supportive, enriching and at the same time friendly working environment, which has given us the opportunity to learn from the greatest and nicest experts.

We also wanted to thank Mikael Amelin for the opportunity we had to conduct our Master Thesis within the School of Electric Engineering at KTH. We feel lucky for having had Mikael and Dina as part of this project, who provided us their guidance and support when needed. At the same time, we wanted to thank Peter Lund for providing us inspiration during our studies at Aalto University and for being our examiner in Finland.

Moreover, to all the awesome *kompisar* from the Nordic Master and all the friends we have made during these two years, thank you for all the hours we shared at the hub, energy garage and having *fika*. For the Sundays joint training sessions. For the dinners with Mario. For the amazing trips to Lapland and Russia, and for much more.

Last but not least, we thank each other for the great collaboration and team work. We are both convinced we could not have had a better partner for this project.

Tack, kiitos to everyone who made these two years in Finland and Sweden unforgettable!

Stockholm, July 12, 2017

Agurtzane Erdozia
Alessandro Ferraris

Contents

List of Figures

List of Tables

Glossary

ABT Availability Based Tariff. 22

ACF Autocorrelation Function. 73

ACP Area Clearing Price. 20

aFRR Automatic Frequency Regulation Reserve. 54–56, 62

ARIMA Autoregressive Integrated Moving Average. 72, 73

ARMA Autoregressive Moving Average. 73

BESS Battery Energy Storage Systems. 2, 5, 6, 11–15, 17, 23, 26, 36, 42, 49, 61, 68, 78, 84, 85, 89, 104, 107

BOS Balance of System. 42, 46, 84, 89

BRP Balance Responsible Part. 53–58, 60, 61

CAES Compressed Air Storage Systems. 7, 15

CAPEX Capital Expenditure. 30, 45, 46, 83–85, 89

CUF Capacity Utilization Factor. 19

DISCOM Distribution Companies. 19, 22, 23

DoD Depth of Discharge. 8, 9, 36, 45, 46

DSO Distribution System Operator. 11, 22

EES Electrical Energy Storage. 7

Elbas Electrical Balancing Adjustment System. 51–53, 57, 60, 62

ENTSO-E European Network of Transmission System Operators. 11, 55, 103

ESS Electrical Storage System. 15

FCR Frequency Containment Reserve. 16, 54, 55, 60

FCR-D Frequency Containment Reserve in Disturbed Operation or Controlled Disturbance Reserve. 54, 56, 62

FCR-N Frequency Containment Reserve in Normal operation. 54, 56, 62, 68, 69, 71, 73–75, 78–81, 83, 84, 87–89

FiT Feed-in Tariff. 19

FoK Fill-or-Kill. 53

FRR Frequency Restorement Reserve. 54, 60

IBO Iceberg Order. 53

IEX Indian Energy Exchange. 19, 20, 22, 24, 27, 39, 40, 44, 46, 47

INR Indian Rupee. 19, 44, 45

IoC Immediate-or-Cancel. 53

IPP Independent Power Producer. 20

IRES Intermittent Renewable Energy Sources. 1, 14, 80, 84

IRR Internal Rate of Return. 44–46, 83, 86

ISR Imbalance Settlement Responsible. 60

JNNSM Jawaharlal Nehru National Solar Mission. 17–19, 36

LCO Lithium Cobalt Oxide. 9

LFP Lithium Iron Phosphate. 9

Li-ion Lithium Ion. 1, 2, 5–10, 13–15, 23, 34, 76, 78, 87, 89, 90

LMO Lithium Manganese Oxide. 9

LP Linear Programming. 63, 68

LTO Lithium Titanate. 9

MCP Market Clearing Price. 20

mFRR Manual Frequency Restoration Reserve. 55–57, 62

MGA Metering Grid Area. 60

MPP Major Power Producer. 20

NAPCC National Action Plan on Climate Change. 17

NBS Nordic Imbalance Settlement. 60

NCA Lithium Nickel Cobalt Aluminum Oxide. 9, 14

NMC Lithium Nickel Manganese Cobalt Oxide. 10

NPV Net Present Value. 15, 44–46, 83, 84

O&M Operation and Maintenance. 83

OPEX Operational Expenditure. 83

PACF Partial Autocorrelation Function. 73

PCC Point of Common Coupling. 36, 37, 87

PHS Pumped Hydro Storage. 7, 15

POSOCO Power System Operation Corporation Limited. 22

PPA Power Purchase Agreement. 19, 20, 23, 44, 45, 89, 90

PX Power Exchange. 19, 20, 22

PXIL Power Exchange India Limited. 19

REC Renewable Energy Certificates. 22, 23

RES Renewable Energy Source. 9, 11, 13–15, 17, 22, 62, 89

RLDC Regional Load Dispatch Centre. 22

RPM Regulation Power Market. 55

RPO Renewable Purchase Obligation. 19, 22

RR Replacement Reserve. 60

SEB State Electricity Boards. 18

SECI Solar Energy Corporation of India. 19, 24, 35, 36, 39, 44, 46, 47

SEK Swedish Krona. 55

SLDC State Load Dispatch Centre. 20

SMES Superconducting Magnetic Energy Storages. 7

SOC State of Charge. 9, 15, 69, 83, 87

SvK Svenska Kraftnät. 53–56, 60, 66, 68, 77, 103

T&D Transmission and Distribution. 12

TSO Transmission System Operator. 11, 22, 50, 52, 53, 55, 57, 60, 87

UI Unscheduled Interchange. 22

WACC Weighted Average Cost of Capital. 42, 44, 83, 86

1 Introduction

Motivated by the need to act against global warming, the energy sector is immersed in a decarbonisation process in which the Paris Agreement at COP 21, the 2015 United Nations Climate Change Conference, was a milestone. In this transition towards a low-carbon future, greenhouse gas emissions must drop and externalities such as air, water and soil pollution must be reduced, so as to improve social and economic welfare. Regarding this transition process, the electricity generation sector has experienced significant changes and solar and wind power generation have, among others, played a significant role [1].

In spite of the fact that solar and wind power technologies are booming globally, with more than 762 GW installed worldwide at the end of 2016 and offering low-carbon power with competitive costs, their share in total power generation is still low or even negligible in many countries [2]. Nevertheless, countries such as Denmark, Germany, Italy, Portugal and Spain have boosted solar and wind power shares well above 10% of their electricity generation capacity fleet [3], and countries like China, Germany and USA are currently leading the Intermittent Renewable Energy Sources (IRES) investments, with China counting for 34.1% (145.4 GW) of the global installed wind power capacity in 2015 and 25.8% (78.1 GW) of the global installed solar PV capacity in 2016 [4, 5]. At the same time, the average size of wind turbines is constantly growing, with single units rated over 8 MW available [6]. Also solar farm capacities have been increasing significantly during recent years, being a 1.5 GW plant in China the largest installed in the world [7].

However, solar and wind power are variable electricity sources, which depend on the solar or wind resource at any given time, and thus not dispatchable. This poses special grid integration and flexibility challenges for considerable shares of IRES, exceeding 20-25% of total capacity [8], as these sources increase the generation side variability and uncertainty, displace some conventional dispatchable capacity and increase the balancing requirements [9].

Different solutions can be employed to increase the system capability to react to contingencies and thus allow higher penetration of IRES. These solutions are generally classified in the following four groups: strengthening of grid and interconnectors, flexible generation, demand-side management and energy storage [10]. The availability of low-cost, distributed energy storage could play a key role in the decarbonisation of the power sector by solving many of the renewables integration issues.

In this context, in the present work the benefits and value of energy storage in combination with utility-scale solar PV and wind plants are studied.

Due to the current relevance and fast market growth of Li-ion batteries [11], this is the technology chosen for the study. The interest in a hybrid IRES with storage system is then analysed in the light of its technical and economic performance.

The profitability of Li-ion batteries has been shown to be very dependent on the market framework and investment costs [12], and previous research has been carried out [13, 14] regarding the profitability of different singular services or combinations of them, also together with wind and solar power generation [15]. In this context, the potential of Li-ion batteries strongly depends on their applications and market framework in which they operate.

Due to the big potential and relative fast growing business of Battery Energy Storage Systems (BESS) together with the fact that their economic interest is very project specific, this work analyses the value of Li-ion batteries for two different case studies: in combination with solar power generation in India and wind power in Sweden.

In first place, India has one of the fastest growing solar markets worldwide [4], with clear and ambitious targets for the near future [16]. On the other hand, Sweden has a considerable share of wind power capacity [17] and the target to achieve 100% renewable power generation by 2040 [18]. On top of this, historic generation data from *Fortum*'s solar plants in India and wind farms in Sweden is available.

This work proposes a methodology based on simulation of various services that Li-ion batteries can provide following different techniques and thus study possible business models for the two mentioned case studies.

1.1 Research questions and objectives

The aim of this work is to assesses the profitability of Li-ion batteries, installed in combination with large scale wind in Sweden and solar power generation in India, in the current electricity market frameworks.

In order to be able to find an answer to the research question some objectives have to be fulfilled, which are the following:

- to study and understand the Indian and Swedish power markets structure and operation;
- to identify possible services batteries can provide in these frameworks;
- to develop models to assess the operation of batteries and potential revenue streams for the identified services; and
- to assess the profitability of batteries for the chosen services in the different markets.

1.2 Scope of the study

In order to accomplish the objectives of this study in the allocated time and obtain complete and reliable results, it is necessary to define and narrow the scope of the work.

Li-ion batteries have a broad range of applications in power systems, for which a comprehensive summary is developed in Subsection 2.2.5. At the same time, the possibility to provide specific services and the potential revenue streams which those services could generate are strictly related to market, regulatory and policy framework. Therefore, the profitability appears to be strictly dependent on the location of the storage technology, both with respect to the energy system and in geographical terms, as pointed out by previous research [19]. For these reasons, this work has greatly focused on the electricity markets.

Due to the availability of real production data time series, obtained from *Fortum*'s production plants, and the considerable growth of the technologies in the two countries, it has been chosen to investigate the case of solar PV in India and onshore wind power in Sweden. Moreover, only the application of battery storage on utility-scale is studied, on the generators' side of the electric power system, as represented in Figure 1.

As consequence of the previously mentioned fast technology development, there is no universally accepted definition of "utility" or "large-scale" renewable power generation. In this work these terms are used to refer to plants which have a peak capacity above 5 MW, similarly to previous research [20], and are directly connected to the transmission grid at high voltage level (usually around 400 or 220 kV, depending on the country) through step-up transformers as it can be seen in Figure 1, in which the boundaries of the thesis scope are defined by the dashed green circle.

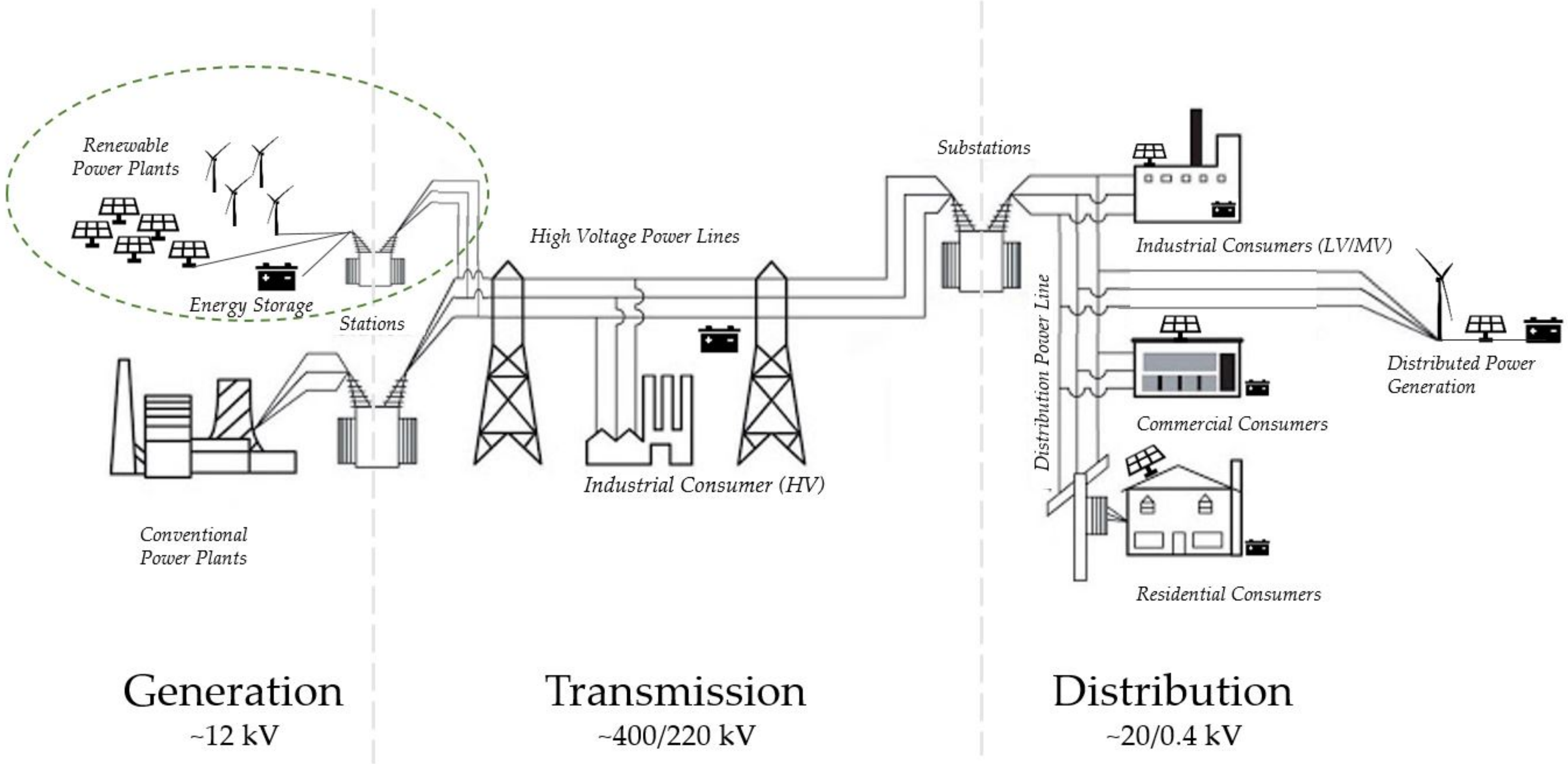


Figure 1: Power system overview with thesis scope boundaries.

Moreover, it seems necessary to explicitly mention some major assumptions regarding the simulation of the energy markets and the electric power system:

- power producers are considered to be price takers[1];
- price forecast, obtained from historical data, is assumed to be perfect;
- no other market players are taken into account; and
- no network constraints are considered.

1.3 Methodology

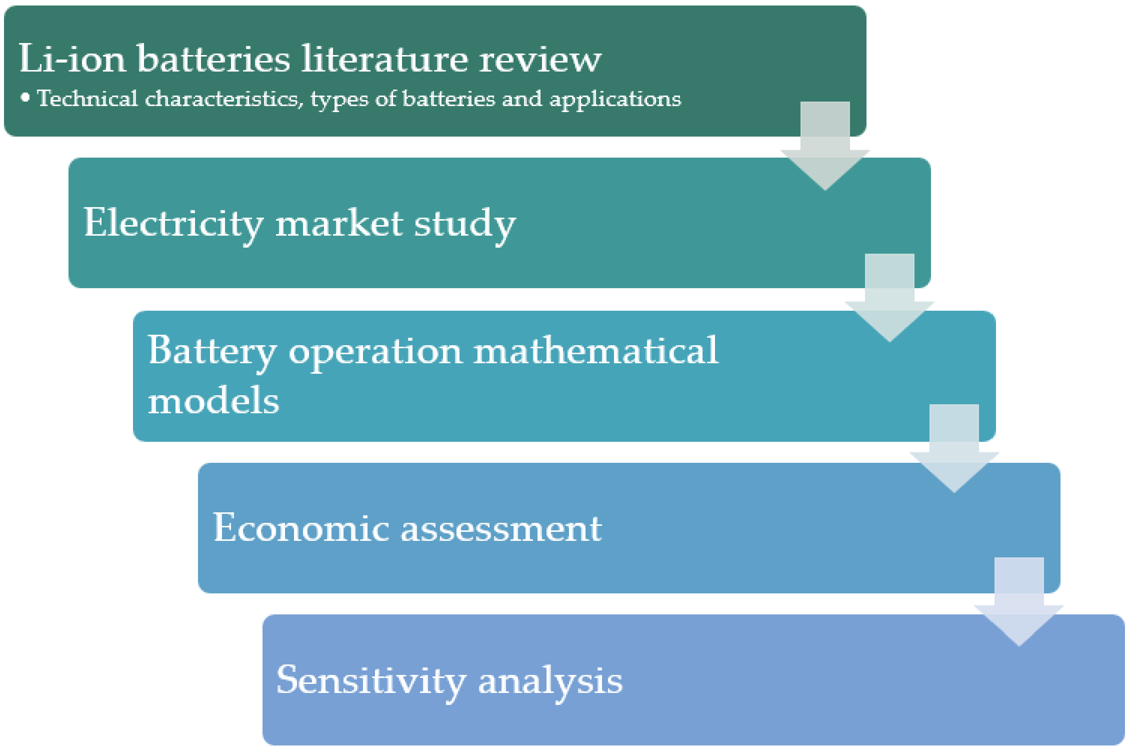


Figure 2: Master Thesis work methodology.

Initially, a thorough literature study on Li-ion batteries' technical characteristics, types based on their chemistry and applications is performed. Based on the fact that potential applications for BESS strongly depend on the energy market structure of each country, it has been decided to structure the work in two case studies. This way all the possibilities in each country of study can be analysed and the best solution or services to be provided can be found.

Afterwards, the market framework in which these batteries would operate, the electricity market of the chosen case studies, is analysed. The focus is put on

[1] No bid is assumed to influence the market, therefore to affect the final clearing price.

identifying the different remunerated services and the requirements to participate in them. After a detailed analysis, the most interesting services suitable for Li-ion batteries operation are selected and thus chosen to be modelled.

In a following step, linear optimisation or control algorithm mathematical models are developed to simulate the operation of the battery and calculate the potential revenues from each service for various battery sizes. These models are built and solved using Microsoft Excel or MATLAB.

After obtaining the operation of the battery for each service, the revenue streams, number of cycles and battery size are calculated. Using these results, together with BESS investment costs and some technical characteristics such as the maximum calendar and cycle lives as inputs, an economic assessment is performed. The potential revenues or costs savings from some services are calculated using *Fortum*'s power generation data, which are covered by a non-disclosure agreement. This is the reason why the economic results for those applications are presented with an uncertainty range. The economic assessment is then followed by a sensitivity analysis, whose aim is to give some insight in the most relevant parameters affecting the profitability of BESS and breakeven costs for services which are not profitable yet.

These steps, shown in Figure 2, are followed in parallel for both case studies, the one studying Li-ion batteries in combination with solar PV in India and the study of BESS with wind power in Sweden. In this work, the Indian case is presented first, being each of the steps of the project described in a separate Section. Afterwards, the Swedish case study is presented.

2 Background study on Li-ion batteries

In this section, the main findings of the literature review regarding Li-ion battery technology, the different types of batteries based on their chemistry, possible applications and simulation and modelling techniques are presented.

A huge variety of energy storage and conversion systems are available. The most developed technologies are usually divided into four groups, according to their principles of operation: mechanical systems, electric systems, electrochemical systems and hydrogen storage [21].

Regarding mechanical systems, the commercially available technologies are Compressed Air Storage Systems (CAES), flywheel energy storage and the oldest storage technology, Pump Hydro Storage (PHS). Among the electric systems technologies, we find supercapacitors and Superconducting Magnetic Energy Storages (SMES) as the most developed ones. Electrochemical systems are represented by flow batteries, lead-acid and lithium-ion batteries. Besides their principles of operation, electrical storage systems differentiate also in some fundamental parameters, which are important especially whether possible applications are considered. Specific power, specific energy, maximum power rating, efficiency, discharge time, lifetime and power and energy cost are some of the most relevant parameters usually taken into consideration [21].

As it can be observed in Figure 3, commercially available Lithium-ion batteries (Li-ion or LIB) cover a significant range of specific power, energy and discharge times and reach the maximum efficiency values for Electrical Energy Storage (EES) [22]. This together with their possibilities of being scaled to theoretically infinite power ratings and energy capacities [23], make them really versatile storage technologies, therefore suitable for a wide range of applications.

Li-ion batteries components include [24, 25]:

- a carbon (usually graphite) negative electrode;
- a metal-oxide positive electrode;
- an organic electrolyte (ether) with dissolved lithium ions; and
- a micro-porous polymer separator.

When the battery is charging, lithium ions flow from the positive metal oxide electrode to the negative graphite electrode, while the reverse flow of ions takes place when the battery is discharging [24].

The technical characteristics of Li-ion batteries are dependent on the electrodes and electrolyte materials, but some generalisations can be made. First, because of their high energy density, most Li-ion cells have a nominal voltage of 3.7 V. This value is much higher than the nominal voltage of many other battery cell chemistries, which means fewer Li-ion cells are needed to produce the same power output. Second, like other battery types, they have response times on the order of 20 milliseconds. Third, Li-ion batteries have relatively high round trip efficiency,

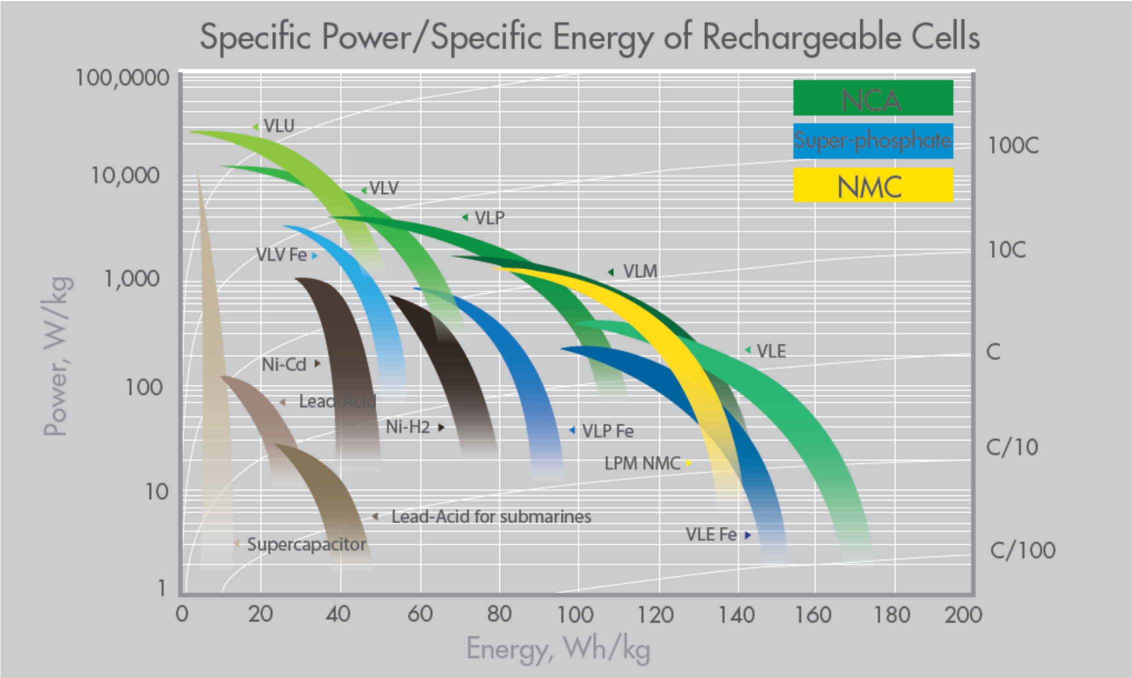


Figure 3: Commercially available storage technologies by Saft [22].

usually ranging between 85 to 95 %. Finally, Li-ion batteries have expected cycle lives of 6 000 to 8 000 cycles [26].

An important parameter used to characterise this technology is the C rating. It represents the continuous current draw the cell would support. As consequence, it is often used to represent the ratio between the maximum power output and the capacity of the cell if represented in coherent measurement units. For example, a 3 MWh cell with a 1 C rating would provide a maximum power output of 3 MW, whereas a maximum power output of 6 MW would be provided with a 2 C rating would provide, and so on.

Cycle life is the number of charge and discharge cycles the battery can do depending on its Depth of Discharge (DoD) and the charging rate. The DoD represents the minimum amount of energy left in the battery when this is discharged, thus the level to which the battery is discharged [27].

A cycle is the equivalent to a full charge and discharge of a battery. The number of cycles in a determined period T, N_T, can therefore be calculated with the following formula:

$$N_T = \frac{\sum_{t=0}^{T} E_{c,t} + E_{d,t}}{2 \cdot E_{b,max}} \quad (1)$$

where:

- $E_{c,t}$ = energy input to the battery (charged) in the time frame t;

- $E_{d,t}$ = energy output from the battery (discharged) in the time frame t; and
- $E_{b,max}$ = battery maximum capacity.

The State of Charge (SOC) is the indicator of how much energy content there is in the battery for each instance, usually given as a percentage of the battery's capacity.

However, Li-ion batteries have disadvantages as well. First, the expected lifetime is related to the cycling DoD. So, it should be avoided to fully discharge Li-ion batteries. Second, the metal oxide electrode can become thermally unstable due to over discharge or charge and be subject to thermal runaway[2] if left unchecked. Finally, Li-ion batteries still face significant cost barriers [24, 29].

2.1 Li-ion battery types according to their chemistry

Apart from the general features of Li-ion batteries, the chemistry of the batteries can affect some of their characteristics, of which specific power and energy, safety, temperature range, cycle life and possibility of fast charge are the most noticeable ones [25]. The performance of some Li-ion electrode materials is shown in Figure 4 [30].

Based on the chemistry, six main types of Li-ion batteries can be identified as relevant in literature [31], which have the following main characteristics.

- Lithium Manganese Oxide, LMO. These batteries are best suited for medium- and large-scale applications, being their poor cycle life the main drawback.
- Lithium Nickel Cobalt Aluminum Oxide, NCA. They have a long lifetime, around 20 years with 6 000 cycles at 60% DoD, and they have high energy capacity.
- Lithium Iron Phosphate, LFP. LFP batteries can have an even longer lifetime than NCA type batteries. They can last around or more than 20 years with over 7 000 cycles at more than 95% DoD. Moreover, they have a very constant charge/discharge voltage and high power, making them very suitable for fast applications. On the other hand, they present a quite high self-discharge rate.
- Lithium Titanate, LTO. This type of batteries have high power rating and low energy capacity, with less than 1h discharge duration. This makes them best suited for power applications.
- Lithium Cobalt Oxide, LCO. LCO batteries are not suitable to be installed in combination with RES plants, as they are not the safest type of technology. In fact, they have been replaced by LFP type Li-ion batteries.

[2]The thermal runaway is a positive feedback phenomenon where an increase of temperature changes the conditions of the battery inducing an even further increase of temperature, potentially leading to severe damages [28].

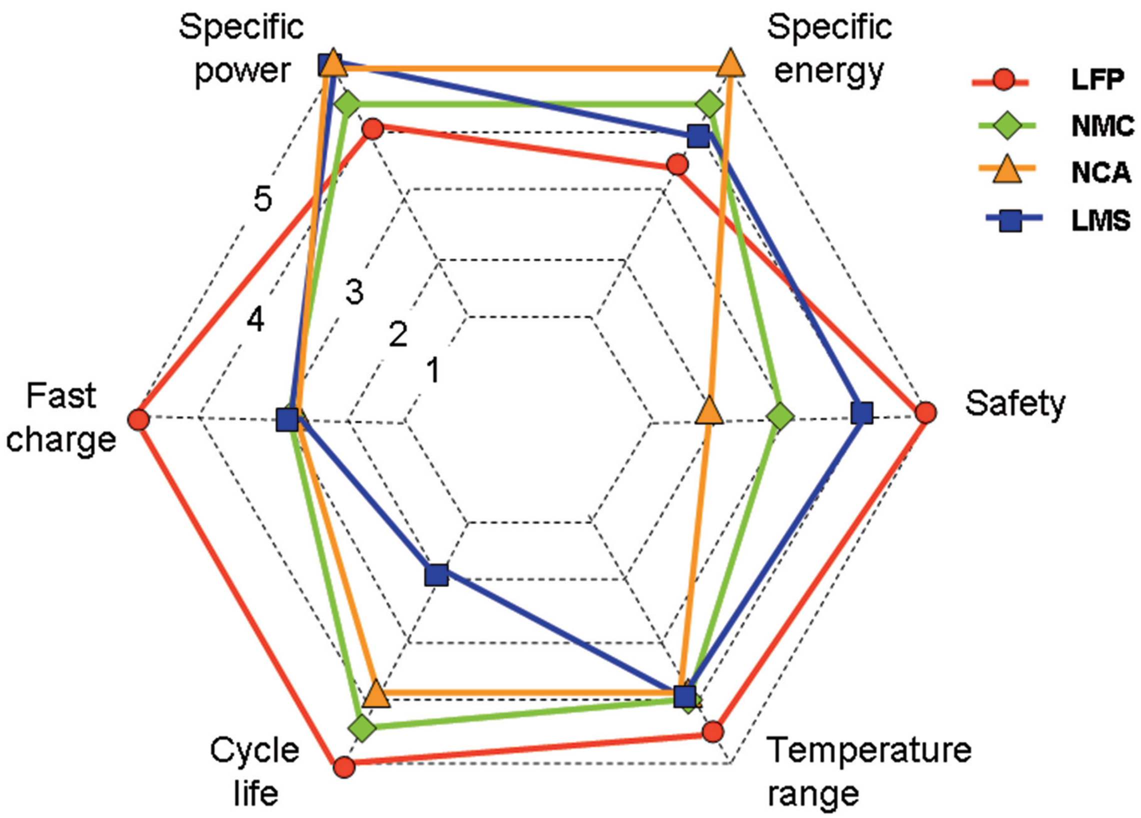


Figure 4: Li-ion batteries performance with respect to several characteristics, ranked from 1 (worst) to 5 (best) [30].

- Lithium nickel manganese cobalt oxide, NMC. They can have quite high energy capacities, with more than 2h duration. Thus, this type of batteries are used for day to night load-shifting applications.

In the following section, the main possible applications of Li-ion batteries in the power system are presented. In this part no distinction is made based on the battery chemistry, since the aim of this work is to assess the profitability of potential applications of commercially available technologies. For the interested reader who wants a deeper insight into Li-ion technology, the work by Pistoia [32] is recommended.

2.2 Battery energy storage systems applications

As mentioned before, the wide range of specific power, specific energy and discharge times together with their scalability, make Li-ion batteries suitable for many different applications in the whole energy system.

Before studying which are the most suitable and interesting services from the perspective of a large-scale power generator, an overall study of the most relevant applications in the energy system has been conducted. The findings presented after are mainly based on reports by Miller et al. [23] and Eyer and Corey [33], which group battery applications in five main categories.

1. Electric supply applications. In this category services such as electricity time-shifting and generation capacity are found.
2. Ancillary services, which are required to maintain grid stability and security and are usually offered by generators and contracted by Transmission System Operators, TSOs.
3. Grid system applications. These are services that can support or benefit the transmission and distribution grid and are usually under the responsibility of the TSOs or Distribution System Operators, DSOs.
4. End-user or utility customer applications. This category groups services like time-of-use energy cost management, demand charge management, electric service reliability and power quality.
5. RES integration applications, which help improve the power generated by these sources in terms of dispatching moment and quality.

In the following part of the section, various applications under each category are going to be presented and briefly explained.

2.2.1 Electric supply applications

The two main electric supply applications batteries can provide are electricity time-shifting and generation capacity.

The first consists on charging the battery when electricity prices are low so that the stored energy can be dispatched later when prices are high. The minimum assumed storage discharge duration for this application is two hours, whereas the maximum or upper boundary is probably the average duration of a daily peak demand period [34].

Besides, generation capacity refers to the possibility of replacing peak demand generation capacity with BESS. This way, batteries could be used to defer and/or to reduce the investment in new capacity [23].

2.2.2 Ancillary services

As defined by the European Network of Transmission System Operators (ENTSO-E) [35], ancillary services refer to a range of functions contracted by TSOs in order to ensure system security and include all the services described next.

Frequency regulation or frequency response is used to guarantee real time generation-load balance within a control area and thus maintain system frequency [23]. Generating units to provide the service must be committed with a certain amount of generating capacity and be able to provide an automatic or very fast response. This way the power supply can be either increased or decreased when grid frequency needs to be adjusted. The battery would be charged during down-regulation moments, while it would be discharged during up-regulation and this way improve the grid frequency by delivering power.

Furthermore, reserve capacity can provide additional energy when needed and comprises spinning reserves, supplemental reserves and backup supply. Spinning reserve is provided by generation capacity that is on-line but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. Like frequency regulation, spinning reserves also hold from power supply within the time period they are committed. Supplemental reserve is used after all spinning reserves are activated and is provided by generation capacity that may be offline, which does not have a synchronous frequency. Finally, backup supply is provided by generation available within an hour and used for backing up reserves or for commercial transactions [23, 34].

Another ancillary service is reactive power supply and voltage control, which refers to the generation or absorption of reactive power from generators to maintain transmission system voltages within required ranges [33]. However, batteries would generally need to be coupled with VAR compensation systems to provide this service.

Finally, black start capability is the ability to restart a grid following a blackout [34].

2.2.3 Grid system applications

Grid system applications are linked to the transmission and distribution network and can provide support to the grid, reduce grid congestion or delay the need for upgrading the grid, among others.

BESS can support the grid and improve the T&D system performance by compensating for electrical anomalies and disturbances such as voltage sag, unstable voltage and sub-synchronous resonance [33, 34].

On the other hand, transmission congestion reduction can be achieved by storing energy when there is no transmission congestion and discharging it during peak demand periods. This reduces the transmission capacity need and avoids congestion-related costs and issues [23].

Another potential effect of the installation of BESS is the T&D upgrade deferral, which refers to the delay and sometimes even avoidance of investment in transmission and/or distribution grid upgrading [34].

Substation on-site power, which can be obtained by installing a battery, provides power to switching components and to the control equipment of the substation when the grid is not energised [23].

2.2.4 End-user applications

From the end-user or utility customer point of view, batteries can have several different applications too. They can help matching generation and consumption, reducing costs and improving power quality, for instance.

One of the most interesting BESS applications for end-users is time-of-use energy cost management, an electricity time-shifting operation which allows customers to reduce their overall cost of electricity [23, 34].

Similarly to the previous one, demand charge management is the reduction of power demand during peak demand periods and consequently reduction of demand charges [23].

Another possible application is electric service reliability. This one refers to the provision of energy to ride through outages of extended duration [34].

Moreover, power quality can be improved by using battery storage to protect on-site load from short-duration events that affect the quality of the power delivered to the load.

Finally, in load following applications the battery operation aims to meet hour-to-hour and daily load variations. The power output would change in order to adjust to the changes in electricity supply and demand within the operation region or area [23].

2.2.5 Integration of renewable energy sources

Batteries can also help in the integration of RES, as they can store energy for later periods and this way decrease the fluctuation and unpredictability of output power from these generation sources.

RES energy time-shift can be done by charging the battery from renewable generation during off-peak or low demand periods and discharging it during peak or high demand periods [23, 33, 34].

The power output of RES can be smoothed by using storage to compensate deviations or rapid fluctuations in renewable energy generation so that the combined power output of battery and the power generation source is somehow smooth [23, 33].

Batteries provide peak shaving possibility too. This service considers the possibility of connecting to a maximum transmission power lower than the peak power of the RES plant. The battery could store the energy exceeding the power to which the plant is subscribed and discharge it during periods when generation is under that connection capacity [23].

From all the different applications for Li-ion batteries, those of interest for a power utility from the large-scale RES power generation and physical trading point of view have been selected, which are:

1. load following;
2. RES energy time-shift, or power arbitrage;
3. frequency regulation;
4. reactive power and voltage control;
5. power output smoothing; and

6. peak shaving.

Table 1: BESS applications summary table.

Electric supply applications
Electricity time-shifting
Peak demand generation capacity replacement
Ancillary services
Frequency regulation
Reserve capacity
Reactive power supply and voltage control
Black start capability
Grid system applications
Grid support
Grid congestion reduction
Grid update deferral
Substation on-site power
End-user applications
Time-of-use energy cost management
Demand charge management
Electric service reliability
Power quality improvement
Load following
RES integration applications
RES time-shifting
Power output smoothing
Peak shaving

Looking into the technological characteristics of Li-ion batteries, the Power-to-Energy ratio of batteries is the key factor determining the most appropriate applications for each system. In general, most of the Li-ion batteries work better in high power and low energy applications, which require a shorter duty cycle. A larger share of IRES (mainly wind and solar power) increases the need for frequency regulation services. Moreover, the amount of thermal- and hydro-plants online and ready to provide frequency regulation may decrease. All these factors highlight the potential of BESS for frequency regulation applications [23].

Furthermore, batteries can be used to decrease grid variability, which can be done by compensating sudden drops in power output due to rapid changes in wind or clouds or by smoothing power output ramp rates, among others. BESS also seem very interesting to cover deviations in the production schedules due to uncertainty and errors in wind power forecast or shift some of the production to peak demand periods [23].

Nevertheless, some types of batteries, like the NCA, are most suitable for energy applications which may require batteries to be able to store energy for some hours. This makes some Li-ion batteries suitable for longer term applications too, such as load following and RES energy time-shift.

The reason for the need of the selected applications listed above and their detailed descriptions are later covered in Sections 3.2 and 4.2, where the most interesting and suitable services to be provided in each case study are studied and modelled.

2.3 Background on simulation and modelling

Different simulation approaches and profitability assessments can be found in literature, regarding both battery storage in stand-alone applications and in combination with renewable sources. A review of relevant studies is hereafter presented.

Braff et al. [15] have compared different storage technologies and set cost improvement targets. As first, the operation of a fixed range of sizes of hybrid wind and solar plants combined with storage in different locations is optimised with a linear solution technique. Then, optimal storage sizes are obtained to maximise the value of the systems for arbitrage purposes. In this second phase, the annual revenue divided by the annualised costs is used as indicator of profitability. Storage technologies are shown to add value to solar and wind energy as of now, but cost decrease is needed to reach profitability.

The operation of different storage technologies considering different markets has been simulated by Berrada et al. [36]. Using a linear programming model, the maximum daily profit generated by offering different energy products has been identified. The simulation of ancillary services has been approached using an average dispatched to contracted energy ratio. Results of the work from Berrada et al. [36] show high potential revenues and profitability for PHS and CAES in different US markets. On the other hand, a strong influence of the previously mentioned contract ratio is proven. The difference between dispatched energy and bidden capacity represents a challenge when offering ancillary services with ESS. First of all, the uncertainty of the availability of the battery during the bidden hours, due to a potential maximum SOC when charge is needed and viceversa, could lead to high penalties for the service not provided. Besides, the remuneration based on the activation could increase the income variability. This process is further explained in Section 4.1 and addressed in Subsection 4.2.3.

Optimal sizing of a lead-acid BESS for primary frequency control in European markets has been performed by Oudalov et al. [14], identifying it as the most valuable service for the owner of the storage system. The simulation has been run on historical data linking the battery operation to the grid frequency, considering a payment linked to the capacity made available according to the market framework. The developed model is a control algorithm which aims to maximise the Net Present Value (NPV) taking into account a series of technical constraints among which dynamic maximum and minimum SOC and grid code requirements are noticeable.

A similar approach has been adopted by Schweer et al. [13], where the operation of the M5BAT hybrid battery storage has been optimised to offer frequency containment reserve[3]. In this simulation, a weekly and a daily spot auction for the service have been considered together, in order to have the possibility to reschedule the production. This way, it would be possible to face the uncertainty of the activation of the service and ensure the operation during a time frame of at least 30 minutes, as required by the regulator in the case of Germany. A piecewise approximation has been used to make the developed model linear.

The importance of balancing the discrepancies between the scheduled and actual wind power production has been analysed by Korpaas et al. [37], performing a three steps simulation: firstly the wind production is forecast. As second, based on this forecast, the bids on the power exchange are scheduled. As last, the operation of the storage in real time to balance the deviation of the wind power generation from the scheduled one is simulated. The model has been solved using a dynamic programming algorithm and the battery efficiency has been identified as a relevant factor. Moreover, it has been demonstrated that the value of the storage is dependent on the difference between spot and regulating power prices. This will be further discussed in this work in Subsection 4.2.2. Applications of battery storage for compensation of forecast errors for wind power have been analysed by Cai et al. [38] and their economic benefit has been demonstrated for the German electricity market.

Regarding energy arbitrage purposes, several simulations are available in literature [19, 39, 36] and the profitability has always been shown to be strongly dependent on the market volatility and the battery storage cost. Energy storage systems with arbitrage purposes have been simulated following two main approaches. A first one is to set price triggers which, when reached, allow the system to charge or discharge. These prices can be static and obtained from historical time series, or dynamically changed during the battery operation using moving averages, as described in [40, 19]. A second option is to assume a price forecast and to optimise the bidding strategy, for example the Day-Ahead bid, maximising the possible revenue with a linear or mixed-integer linear program, as suggested by Sioshansi et al. [41] and Graves et al. [42].

[3]Primary frequency regulation is known as Frequency Containment Reserve (FCR) in some European markets. Among these, the German, French and the Nordic ones. The latter will be explained in detail in Subsection 4.1.

3 Battery energy storage systems and solar photovoltaics in India

In this chapter, the case study of BESS in combination with solar power generation in India is presented. First of all, a review of the Indian power market has been performed, including an analysis of the main tendering processes concerning solar power generation and battery storage and the markets within the Indian Power Exchange. This market review is presented in Section 3.1. Based on this information, possible services to be provided and consequently different system operation strategies for each of those services have been identified and simulated. The mathematical formulation of these models as well as the results of the case studies are presented in Section 3.3. Based on the latter an economic assessment has also been performed.

3.1 Electricity market structure

The Ministry of Power is the central government body in charge of regulating the energy sector in India [43] and the Central Electricity and Regulatory Commission represents the Energy Authority of the country [44].

The Government set two main plans that draw the future of the country's energy market: the National Action Plan on Climate Change (NAPCC) under which there is the National Renewable Energy Act [45]; and, India's electricity-sector transformation program named "Seven Horses of Energy" by the Prime Minister Narenda Modi in reference to Hindu mythology [16], signed in 2014. Under this program, the Indian government has the main goal of adding 175 GW of RES by 2022. In addition, a diversification objective has been set, which aims to improve India's energy security by installing 100 GW of solar PV by 2021-22, under the Jawaharlal Nehru National Solar Mission (JNNSM) described next, and 60 MW of wind power [16].

The NAPCC consists of eight main missions, one of which is the JNNSM. This mission aims to develop solar energy for power generation, with the objective of making it as competitive or more than traditional non-renewable energy options [45]. The National Solar Mission has the target to install 100 GW of solar power by 2022. Of that total capacity, 40 GW would be assigned to Rooftop Solar Projects and 60 GW to utility- or large-scale solar projects. The set targets for large-scale projects are the addition of 7.2 GW during the 2016-17 period, 10 GW each year from 2017 to 2020, 9.5 GW for the 2020-21 period and 8.5 GW during 2021-22. Regarding the total solar power capacity targets set to reach the 100 GW goal, these are shown in Table 2 [46].

At the end of 2016, India had 9 658 MW of installed solar PV capacity [2], representing the 4% of total Indian installed capacity, and slightly below the target set for the end of the 2016-17 period.

Anyway, according to the latest report by the Central Electricity Authority [47], solar power reached 12 288 MW of installed capacity at the end of March 2017,

Table 2: Total solar power capacity targets from 2015 to 2022 [46].

Year	Yearly target (GW)	Cumulative target (GW)
2015-16	2	5
2016-17	12	17
2017-18	15	32
2018-19	16	48
2019-20	17	65
2020-21	17.5	82.5
2021-22	17.5	100

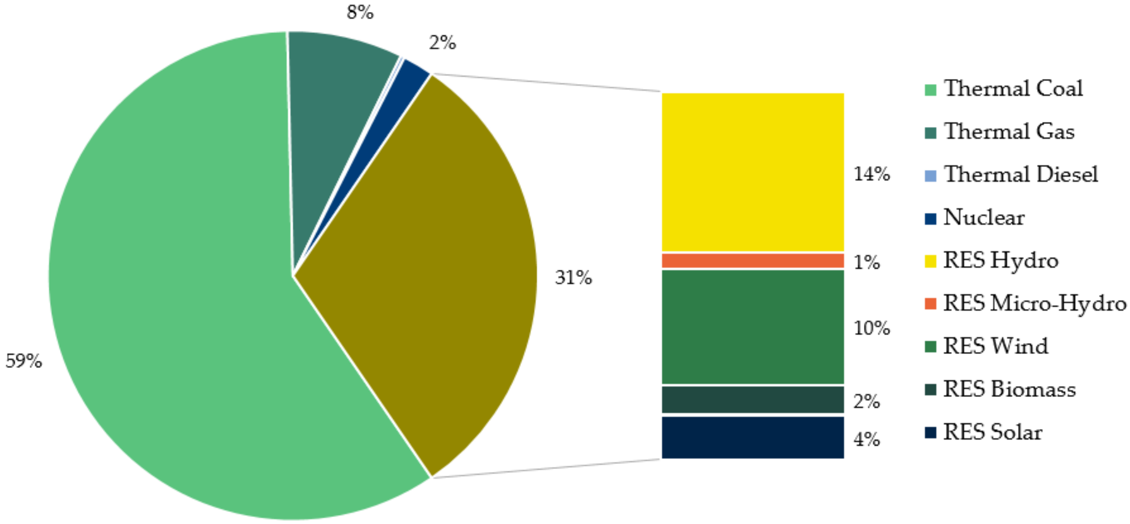


Figure 5: Installed generation capacity [GW] by source in India [47].

representing an increase of almost 30% in three months. Regarding grid-scale batteries, the first 10 MW have been commissioned on January 2017 for peak load management purposes [48].

The overall system power generating capacity in India is 330 GW [47], from which the largest part corresponds to thermal coal plants, which have a 60% share of that total installed capacity, followed by hydropower, as it can be seen in Figure 5. If the JNNSM target is reached and other power sources are installed at a lower rate, solar PV could represent even more than 20% the power capacity of the country. However, if the flexibility need that new solar power generation brings is not addressed gradually, the correct operation of the power system could become a major issue.

Under the Electricity Amendment Bill of 2014 [49], which amended the Electricity Act of 2003, State Electricity Boards (SEBs) were constituted for the development of the electricity industry, which was mainly constituted of vertically integrated monopolies before these were unbundled and competition was introduced. Besides, cross subsidisation in the electricity sector in India was completely removed.

The Solar Energy Corporation of India Ltd. (SECI), under the administrative control of the Ministry of New and Renewable Energy, is responsible to facilitate the fulfillment of the previously mentioned targets. In particular, it has the task to implement the schemes for large-scale grid connected solar projects under the JNNSM [50]. The implementation of the different Phases and Batches of JNNSM is carried out through public tenders which allow the construction of a certain amount of power capacity. Different power producers can bid the capacity they are interested in building together with other technical specifications, which are variable among tenders. At the end of the auction, the permits and the obtained fixed PPA tariff are awarded to the successful participants.

The power supply from large-scale solar projects built in India consists then of bilateral contracts or Power Purchase Agreements (PPAs) with fixed levelised tariffs for a period up to 25 years. Producers commit to sell power to NTPC/NVVN[4] at the quoted tariff over the agreed 25 year period. NTPC/NVVN will then sell the power to state utilities with a margin. NTPC/NVVN will be obliged to buy power only within the Capacity Utilization Factor (CUF) range established in the PPA. Producers have also the option to sell the excess power generated on top of this, whether in normal course or through repowering to NTPC/NVVN or in the market.

The awarded prices for PPAs vary depending on the bids and the tenders specifications, with indicative values in the range between 4 and 5 INR/kWh ($ 0.062-0.078/kWh) [52].

In this context, the current lack of enforcement of the state-based distribution companies' (DISCOMs) Renewable Purchase Obligations (RPO) represents a key bottleneck constraining the Indian electricity sector. The massive losses of DISCOMs lead to limited bankability of PPAs, making payments to electricity producers unreliable [16], which pose a risk for the set targets.

Therefore, the key enablers for the achievement of the Indian government's goal are decreasing the aggregate transmission and distribution loss rates, which are now 26%, and the reform of DISCOMs [16].

Furthermore, ensuring grid robustness and investment/lending appetite at aggressive tariff levels will be two big challenges for India to achieve the 100 GW RES target and a successful electricity sector transformation, together with grid integration and availability of RES, lack of Feed-in-Tariffs (FiTs)[5], poor operating environment, transmission connectivity/grid failure, debt financing and Indian rupee (INR) depreciation risk [16].

Besides these mentioned schemes, the Indian electricity market has two Power Exchanges (PXs): The Indian Energy Exchange (IEX) and Power Exchange India Limited (PXIL), being the first the most relevant one in terms of traded volumes.

[4] NVVN is a subsidary of the energy utility NTPC. It represents the only governmental company in India engaged in the power trading business [51].

[5] A Feed-in-Tariff (FiT) is a policy mechanism which awards, through a long term contract, a fixed price per kWh of energy generated. It aims to accelerate investments on a technology increasing or guaranteeing its profitability.

These exchanges consist of weekly, Day-Ahead and intraday electricity markets and a Renewable Energy Certificates market, lacking any capacity markets. Nowadays, the maximum volume traded on the exchange is on the Day-Ahead Market, representing 97.5% of the total volumes traded through IEX. These are anyway considerably small, as only 11% of total electricity supply in the country is traded through PXs, and most of the generated power is sold through PPAs [49, 53, 54].

The main reason for the small share of PXs in the total electricity market could be their inefficiency. In addition to state utilities, there are other power generating actors in the Indian electricity market, such as participating retail customers, large Independent Power Producers (IPPs) and captive generators. IPPs and Major Power Producers (MPPs) are required to sell a share of their generation to the state utilities, which may vary depending on the states where they are located [55].

In the Day-Ahead market physical trading for single, some or all 15 minutes time blocks for the following 24 hours from midnight to midnight takes place. This market is based on a double sided auction, where bids are double sided and anonymous until the price is cleared. Clearance of accepted prices and volumes is done by the State Load Dispatch Centre (SLDC) based on the transmission network availability and the available power metering [56].

In a double auction, potential power producers submit their bids and potential consumers submit their purchasing prices simultaneously. Then an auctioneer, the power exchange in this case, determines the price that clears the market, p. All the power producers whose bids where equal or lower than p get to sell their power and all buyers whose bids were equal or higher than p buy at price p [57].

In the case of India, aggregated sale and purchase curves define a Market Clearing Price (MCP) and 13 Area Clearing Prices (ACP) are determined after the congestion management.

In the Day-Ahead market bidding process, participants enter bids for sale or purchase of power delivered the following day during the bidding session that lasts from 10:00 to 12:00. Bids for a total of 96 blocks of 15 minutes each can be entered, and these can be single and/or block including linked bids. Bids are stored in the central order book and can be revised or cancelled until the end of the bid call period (i.e. 12:00 of trading day) [56].

Single bids are 15 minute bids for different price and quantity pairs, which can be either totally or partially executed. Block bids represent relational block bids for any 15 minutes block or series of 15 minutes blocks during the same day. In this case, no partial execution is possible, i.e. either the entire order will be selected or rejected [56].

Besides the auction-based Day-Ahead market, continuous markets are also available, namely Intraday, Daily and Day-Ahead Contingency, as presented in Figure 6. This means that in these markets there is not a "call period" but orders are matched continuously with a priority criteria. In particular, the highest buy order and the lowest sell order are prioritised. In case the prices are equal, then the priority is given based on the time the orders have been received [54].

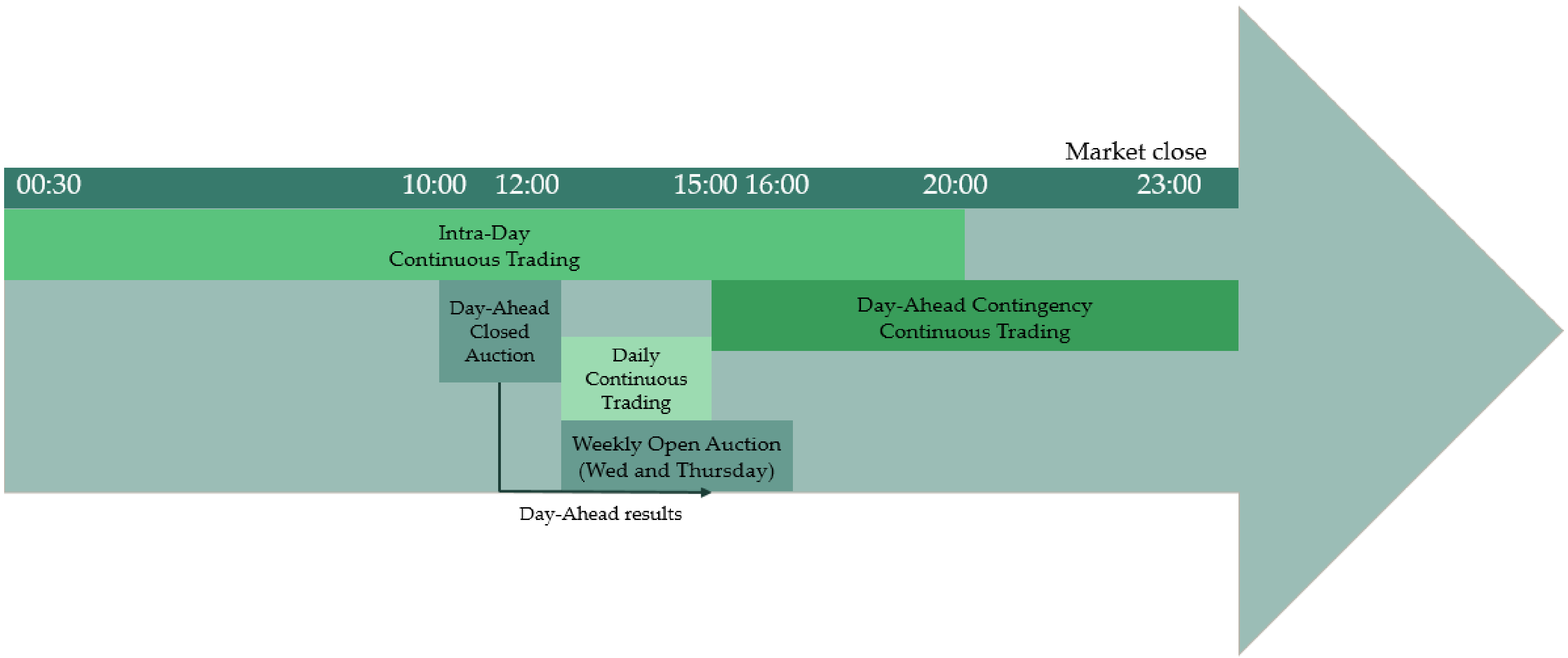


Figure 6: Different electricity markets in IEX [54].

The availability of power determines the Availability Based Tariff (ABT), which is a frequency based tariff system for the DISCOMs, the Indian DSOs, and has the objective of making the system more stable and reliable. The ABT price system is meant to discourage low quality energy production with a system of incentives and disincentives. ABT is the sum of a fixed charge or capacity charge, a variable charge and an Unscheduled Intercharge (UI). The capacity charge measures the power availability, defined as readiness to supply power, and depends on the capacity of the plant. On the other hand, the UI penalises any power supply that deviates from the scheduled one. This way, high frequency deviations and disturbances try to be avoided [58, 56].

The complete bidding process, from accepting bids to collecting funds and issuing request to the National Load Dispatch Centre (Power System Operation Corporation Limited, POSOCO in India) is completed within five hours [56].

However, no mechanism is specified in the regulations for undertaking and monitoring the Day-Ahead scheduling, real time dispatch, preparations of UI account and monthly account. Regarding the ancillary services markets, frequency regulation, voltage control and black start ancillary services still need to be developed [56, 55].

Renewable Energy Certificates (REC) represented 1 MWh of energy generated from RES and were tradable on the PX and valid for 730 days. The idea of these RECs was that renewable power producers could get the equivalent cost to conventional generators and buyers could purchase them, through IEX, in order to fulfill their RPO compliance. The price was guaranteed by a "floor price" and the clearing of the price was based on a closed double auction the last Wednesday of the month. Nevertheless, the REC market was completely inefficient since the offer was much bigger than the demand. Thus, the cleared price was always the lowest possible guaranteed by the floor price [56]. RECs were indeed suspended until further notice in May 2017 [59].

Regarding the transmission system, this is characterised by the existence of high congestion corridors. The system operators, both RLDCs and POSOCO, which operate as TSOs in India, need to approve the transactions on the PXs. These power exchange transactions are based on priority lists of open access to the transmission system for long-, medium- and short-term bilateral contracts [55].

The considerably high losses of the Indian transmission and distribution systems are managed in order to be absorbed by both buyer and sellers of power. More in particular:

- The buyer is expected to draw less power than the contracted one: *Bid Volume - Losses*;
- The seller is expected to inject more power then the contracted one: *Bid Volume + Losses*;

where *Losses* are the average transmission losses of the region where the entity is geographically located [54].

However, several curtailment episodes already took place in July 2016. Problems related to power output curtailment vary considerably from region/state to region [60] and are not only due to the lack of transmission capacity. They are also caused by the financial health of the DISCOMs, which choose to shed the load instead of purchasing power at a higher price.

Power exchanges in India appear to still need further development, which could lead to an increase in the traded volumes, higher liquidity and smaller price volatility over time [55].

Anyway, as previously mentioned, more than at least 89% of power is traded through PPAs in India. The failure of the RECs system suggests that a solar system with energy storage could today operate with a bilateral agreement with industrial costumers, participate in tenders to obtain PPAs with NTPC or bid on the power exchange.

3.2 Battery operation and sizing models

Taking the possible BESS applications which are interesting from a large-scale power producer point of view presented in Subsection 2.2.5 as starting point and the Indian power market as framework, in this section the most interesting possible applications of Li-ion batteries in combination with large-scale solar plants in India are studied. In order to analyse the operation of batteries for each selected service and to determine the required power and battery capacity, some models have been developed using Microsoft Excel and MATLAB.

The models simulate how the battery would operate and the power charged/discharged every instance. Technical constraints are also input to the models, so that the real technology limitations and thus operation are obtained. This way, each model is based either on a control algorithm or linear optimisation (LP) that determines the charge or discharge power of the battery, energy content in the battery and output power delivered to the grid every instance, among others. This way, the required technical characteristics, such as the power and energy capacity of the battery in order to provide the service optimally are calculated. Based on the Indian market characteristics, the simulated models are:

1. Constant power output model, which aims to deliver a constant demand with a hybrid system consisting of a Li-ion battery system with solar PV generation. The operation of such a system and the battery size required are studied in the model.

2. Demand following model, in which instead of being constant, demand varies from instance to instance and the generation tries to match it.

3. Demand following considering solar power curtailment possibility. This model has the same target as the demand following model but allows the possibility of solar generation curtailment so as to decrease the required battery size and thus the investment costs. A smaller battery size requirement can be obtained by oversizing the solar plant capacity.

4. Power output smoothing model, in which the battery tries to cover the rapid power output fluctuations by allowing a maximum deviation from the output power of the previous instance.

5. SECI's required operation for power output smoothing, in which the battery operates in order to stay within a range from the power output target, defined as the average power of the fifteen previous instances.

6. Two days unit commitment in the IEX Day-Ahead spot market, which is a linear optimisation model whose objective is to maximise the additional revenues from selling electricity in the market during the most profitable hours. In this model, the additional revenue potential is directly related to the price volatility in the Day-Ahead spot market.

From the different IEX markets, only the Day-Ahead spot market has been modelled, as this is the only double-sided auction and the one with the largest share of the physical trading. Furthermore, no public information of any market except from the spot market is available [56]. Regarding all the other possible services that batteries can provide, as it has already been mentioned, no payment or remuneration exists.

For all the simulations, solar generation data from *Fortum*'s *Amrit* solar farm has been used, which has a 5 MW_{AC} installed capacity and is located in the state of Rajasthan. Thus, the numerical results are mainly representative for solar plants located within the same region or in areas with similar meteorological conditions, as the seasonal weather variations are an extremely important factor affecting the performance and production fluctuations of the plant, as well as for determining the required battery size.

The justification of the interest of each model, the logic behind them and the results and findings are now going to be explained.

3.2.1 Constant power output, solar firming model

The interest in the constant power output or solar firming model is the possibility to supply power for a constant load based only on solar generation and battery storage, which could be the case for critical loads that have to be running continuously at the same power and do not want to be affected by grid reliability issues which may take place in India.

In this context, the objective of the solar firming model is to obtain the operation and size of the battery required to supply a constant power output throughout each month of the whole year being studied. The model has therefore been formulated according to the following equations.

$$P_{o,t} = P_K \tag{2}$$

$$P_{b,t} = P_{o,t} - P_{s,t} \tag{3}$$

$$P_{c,t} = \begin{cases} 0, & P_{b,t} \geq 0 \\ -\eta_c \cdot P_{b,t}, & P_{b,t} < 0 \end{cases} \tag{4}$$

$$P_{d,t} = \begin{cases} \frac{1}{\eta_d} P_{b,t}, & P_{b,t} \geq 0 \\ 0, & P_{b,t} < 0 \end{cases} \tag{5}$$

$$E_{b,t} = E_{b,t-1} + (P_{c,t} - P_{d,t}) \cdot \Delta t \quad for \quad t = 1, ..., T \tag{6}$$

$$E_{b,t} = E_0 \quad for \quad t = 0 \tag{7}$$

Where:

- $P_{o,t}$ = power output of the whole system during the interval t;
- P_K = constant power output (annual or monthly);
- $P_{s,t}$ = solar PV power production during the interval t;
- $P_{b,t}$ = battery required net input (if negative) or output (if positive) during the interval t;
- $P_{c,t}$ = real power flow of charge of the battery during the interval t, considering the charging efficiency;
- $P_{d,t}$ = real power flow of discharge of the battery during the interval t, considering the discharging efficiency;
- η_c = charging efficiency of the battery;
- η_d = discharging efficiency of the battery;
- $E_{b,t}$ = energy content of the battery at the end of the interval t;
- E_0 = initial energy content of the the battery;
- Δt = interval of time corresponding to 1 minute.

This is the mathematical representation of a control algorithm which calculates the minimum required battery size needed in order to provide a constant power output and has been modelled using Microsoft Excel.

First, a constant power output for the whole year, annual P_K, has been obtained. In the calculation of this value a loss due to the charge/discharge of the battery and energy storage has been considered. In this case, the minimum battery size required would be:

$$Battery\ size = 3.85MW/483MWh$$

The battery would have a 0.008 C rating, which corresponds to 125.5 discharge hours at nominal power.

In order to better represent the solar resource in each month and try to decrease the seasonal storage behaviour, a monthly constant power output, $P_{K,month}$, has been considered. These values have been obtained as the average solar power output for each month.

Looking into the minimum and maximum energy stored in the battery each month, the minimum battery size required has been estimated. This should be the largest value of the monthly needed battery capacity, which in this case corresponds to the month of December, as it can be seen in Table 3.

Table 3: Maximum required storage capacity per month.

	E_b [MWh]
January	44.90
February	50.57
March	43.76
April	40.53
May	39.40
June	61.85
July	60.57
August	49.12
September	32.39
October	45.08
November	33.96
December	100.17

By analysing the maximum battery charge/discharge power and setting the minimum energy content of the battery throughout the year positive, the required battery specifications in order to supply a monthly constant power output with solar power plant rated at $5MW_{AC}$ have been obtained. It is important to mention that even if the biggest amount of energy delivered in a month is 100 MWh, as there is no power curtailment possibility, the battery size that allows to store all the solar generation is larger:

$$Battery\ size = 4.1MW/131MWh$$

The battery would have a 0.03 C rating in this case, which corresponds to 32 discharge hours at nominal power.

The main finding of this model is the extremely large battery capacity required for this type of operation, which would in practice show a seasonal energy storage behaviour, not suitable for BESS. By taking a shorter study period, as it has been done when analysing each month individually, the battery size decreases, but it still remains considerably big. Besides, the main cost component of batteries is the cost related to the energy capacity [61]. In this case, the necessary investment to have such a BESS would be extremely large. Thus, we could say that this is not a service we could think of providing by integrating BESS and solar plants together.

3.2.2 Demand following model

The interest to study a demand following case comes from the possibility to meet the demand with only solar power and batteries, which would represent a 100% renewable generation case based completely on solar PV. Moreover, this operation model is also representative of a business case in which power to individual industrial or commercial customers who want to ensure a reliable power supply is delivered. In this case, a continuous power supply that matches with their demand has to be ensured.

The objective of the model is then to simulate the operation of the battery in order to satisfy the daily demand curve. Thus, the output power of the battery plus solar PV system shall be equal to the demand, D_t, in each 15 minutes time step t, which is assumed to be perfectly forecast. As no demand data from any specific customer were available, a general demand time-series has been considered.

$$P_{o,t} = D_t \tag{8}$$

To determine the demand curve, electricity prices published on the Indian Energy Exchange IEX, of which 15 minutes is the maximum available resolution, have been used. In order to mitigate some daily variations, the average weekly prices for each 15 minute time step have been used as input for the daily price curves. Days of two monsoon season months (July and August) and of two non-monsoon season months (January and February) have been simulated. Then, the daily prices have been normalised using their average value as reference point.

Having the normalised price curve, each time step value has been multiplied by the average power generation of the plant, $\bar{P}_s$, and a demand factor, f, which is applied in order to obtain a demand profile comparable to the production. The following Formula 9 represents the methodology just described.

$$D_t = \frac{p_t}{\frac{1}{T}\sum_{t=1}^{T} p_t} \cdot f \cdot \bar{P}_s \tag{9}$$

Where:

- p_t = normalised price value for the time interval t; and
- $t = 1, 2, ..., T$. $T = \frac{24 \cdot 60}{15} = 96$, when applied to a daily model with 15 minutes time steps.

The mathematical formulation of this model is similar to the one providing a constant output described from Formula 2 onwards, with the only difference that in this case each interval t consists of 15 minutes and the power output during the interval t, $P_{o,t}$, must be equal to certain demand, D_t.

$$P_{o,t} = D_t \tag{10}$$
$$P_{b,t} = P_{o,t} - P_{s,t} \tag{11}$$
$$P_{c,t} = \begin{cases} 0, & P_{b,t} \geq 0 \\ -\eta_c \cdot P_{b,t}, & P_{b,t} < 0 \end{cases} \tag{12}$$
$$P_{d,t} = \begin{cases} \frac{1}{\eta_d} P_{b,t}, & P_{b,t} \geq 0 \\ 0, & P_{b,t} < 0 \end{cases} \tag{13}$$
$$E_{b,t} = E_{b,t-1} + (P_{c,t} - P_{d,t}) \cdot \Delta t \quad for \quad t = 1, ..., T \tag{14}$$
$$E_{b,t} = E_0 \quad for \quad t = 0 \tag{15}$$

The model has been applied to the days 19^{th} January, 1^{st} February, 18^{th} July and 1^{st} August, which have been randomly chosen from the previously mentioned months. In addition, two consecutive days in February have also been simulated to see how a slightly longer time frame affects the obtained results. The normalised results for the two days operation are shown in Figure 7.

Several demand factors f have been tested in order to find the one that allows the battery to be operated without any external energy supply, i.e. $E_{b,T}$, final amount of energy in the battery, as close as possible to E_0, initial amount of energy in the battery. A value of 0.7 has been identified to be adequate for the four days simulated, as well as for the study of the two consecutive days in February.

The specifications of the battery size needed for each of the simulated cases can be seen in Table 4. It is good to mention that the required charging power, which corresponds to the shown values of P_b, is more than double the discharging one. This is reasonable, as the time period in which power is supplied by the battery is longer than the one the battery is getting charged from the solar generation.

Table 4: Required battery size for the simulated cases.

	January	February	July	August	Two days
P_b [MW]	2.54	2.96	2.78	2.73	2.96
E_b [MWh]	10.96	14.82	14.15	10.73	14.82
C rating	0.23	0.20	0.20	0.25	0.20
Discharge time [h]	4.31	5.02	5.08	3.93	5.02

On the other hand, the required battery size increases dramatically when a longer time-frame is considered, such as the one for the monthly or annual models. In this last case, simulated with an annual demand following model, the battery behaves as seasonal storage and thus its size becomes extremely large, 496 MWh. The operation of the battery can be seen in Figure 8. The large size comes as a consequence of the need to supply electricity when there is no generation for time periods of more than 13 hours.

$$Battery\ size = 3.3MW/496MWh$$

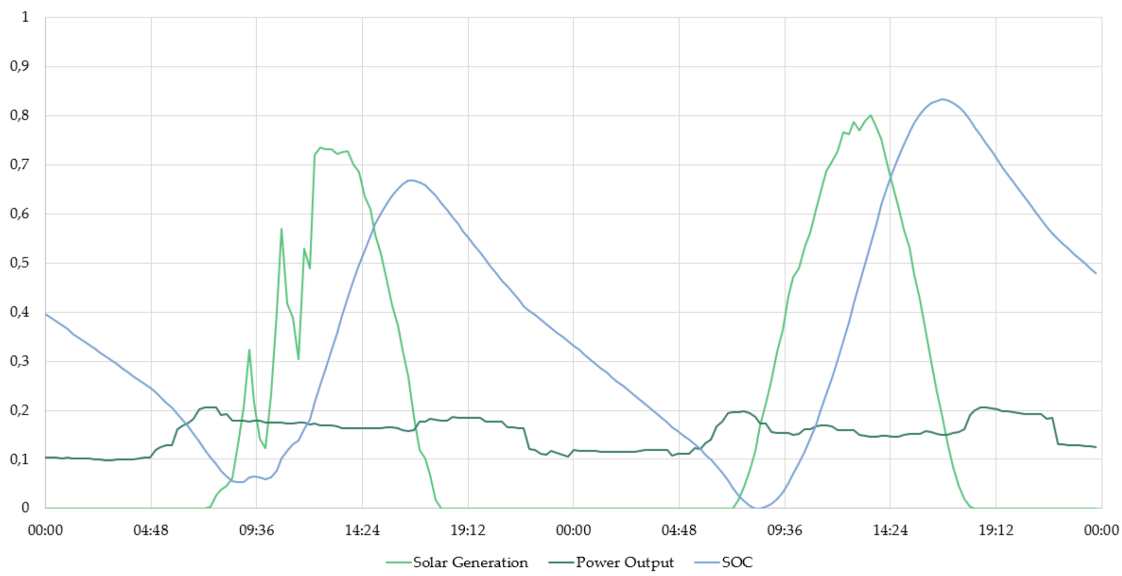


Figure 7: Battery operation in demand following mode for two days.

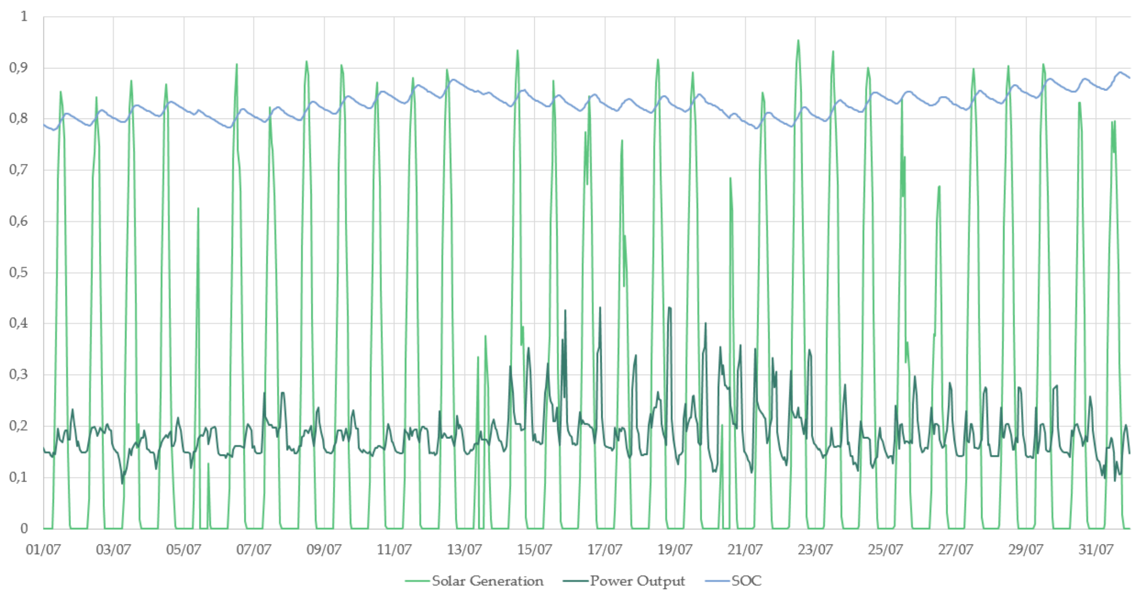


Figure 8: Battery operation in demand following mode for the month of July.

The battery would have a 0.007 C rating in this case, which corresponds to 150 discharge hours at nominal power.

In summary, when trying to cover the demand of a single day, the minimum battery size needed is not very big, so load following looks like a feasible application. But for days when solar generation is very small or has big fluctuations, the battery needs to be much bigger in order to satisfy the demand. This makes the required size much larger when longer time-frames such as the annual case just mentioned above are studied, as more energy needs to be stored to be able to satisfy the demand every day of the year, also when several low solar generation days occur.

As the capital costs, or CAPital EXpenditure (CAPEX), are lower for solar PV than for batteries [62, 63], in the following Subsection 3.2.3, the case of oversizing the solar PV plant allowing the possibility of curtailing the solar production is going to be studied. This way, a smaller minimum required battery size and total investment could be obtained, for a time-frame longer than one or two days.

3.2.3 Demand following model with curtailment possibility

As it can be seen in the demand following model, supplying all the demand with a system consisting of 100% RES, such as a hybrid solar PV and battery system in India, requires an extremely large investment. From the total investment, the battery system costs are considerably higher than the costs of solar technology [62, 63]. Thus, the possibility of oversizing the solar plant and curtailing part of its generation has been considered. This way, the required battery size for the hybrid system in order to be able to satisfy the demand would be notably smaller and so may be the total investment of the project.

To assess the optimal solar plant and battery capacity, the total investment required by different solar capacity to demand and battery size to solar plant capacity ratios has been calculated. With solar plant capacity values smaller than 10 times the average demand to be supplied (e.g. 10 MW_{AC} solar PV for an average demand of 1 MW), the required battery size is too big. On the other hand, if the solar plant has a capacity larger than 20 times the average demand to be supplied, no more energy is supplied and the additional solar power generated is just curtailed, as demand is already satisfied.

Thus, different reasonable solar PV capacity to average demand ratios have been simulated. Then, the battery size needed to be able to cover the demand has been obtained. Having both the solar plant and battery capacity, the total hybrid system capital costs for the different solar PV and battery sizes considered can be obtained, which have been calculated using the technology[6] costs shown in Table 5.

Table 5: CAPEX for battery and solar PV in India.

	Costs	Source
Battery	$ 301/kWh	[63]
Battery BOS	$ 300/kW	[61]
Solar PV	$ 330/kWp	[62]
Solar BOS	$ 200/kW	[64]

The required battery size and the share of the curtailed solar power for each of the different solar plant sizes studied are shown in Table 6. The solar PV plant

[6] Battery Balance of System, BOS, includes all the components of the battery systems other than the battery itself.
Solar BOS includes all the components of the solar systems other than the solar panels.

capacity and the needed battery size to supply demand that require the smallest investment are 18 MW PV plant with a 12.6 MW/37.33 MWh battery, which would supply power to cover an average annual demand of 1 MW, which would result in curtailing 69% of the annual solar generation. From an economic point of view, those are the solar plant and battery sizes considered optimal for this application, as they provide the annual demand to be supplied with minimum investment costs.

Table 6: Battery capacity and curtailed power in function of solar PV capacity.

P_s/D [MW/MW]	Battery capacity [MWh]	% solar power curtailed
20	36.63	72%
19	36.64	71%
18	37.33	69%
17	38.31	67%
16	39.30	65%
15	42.67	63%
14	46.13	60%
13	49.60	57%
12	54.49	53%

$$Optimal\ battery\ size = 12.6MW/37.33MWh$$

The output power and battery charge or discharge power have been simulated as in the previous demand following model. The possibility of curtailing solar generation results in some additional variables and constraints. The solar generation curtailment has been modelled by limiting the maximum energy the battery can store, referred to as $E_{b,max}$. Thus, in each time step the energy content of the battery and power curtailed have been studied as follows:

$$E_{b,t} = \begin{cases} E_{b,max}, & E_{b,t-1} + (P_{c,t} - P_{d,t}) \cdot \Delta t \geq E_{b,max} \\ E_{b,t-1} + (P_{c,t} - P_{d,t}), & E_{b,t-1} + (P_{c,t} - P_{d,t}) \cdot \Delta t < E_{b,max} \end{cases} for\ t = 1, ..., T \tag{16}$$

$$E_{b,t} = E_0 \quad for\ t = 0 \tag{17}$$

$$P_{curt,t} = \begin{cases} P_c - (E_{b,max} - E_{b,t-1}), & E_{b,t-1} + (P_{c,t} - P_{d,t}) \cdot \Delta t \geq E_{b,max} \\ 0, & E_{b,t-1} + (P_{c,t} - P_{d,t}) \cdot \Delta t < E_{b,max} \end{cases} \quad for\ t = 1, ..., T \tag{18}$$

$$P_{curt,t} = 0 \quad for\ t = 0 \tag{19}$$

The battery size needed when allowing solar power generation curtailment decreases dramatically compared to the annual demand following model without

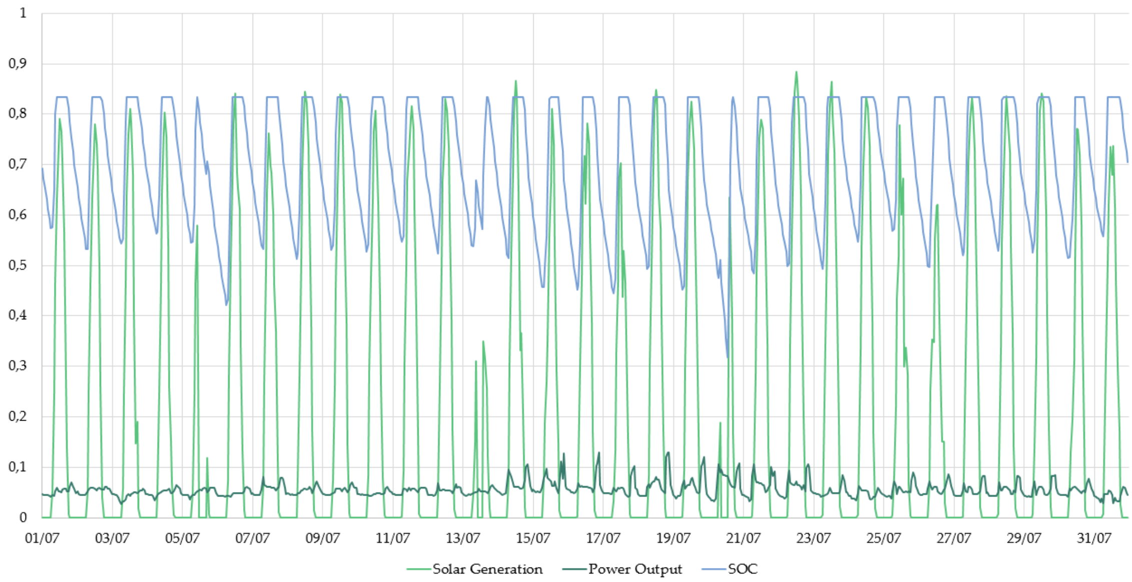


Figure 9: Operation of the battery to satisfy a demand trend allowing solar curtailment in the month of July.

curtailment possibility requirement. The battery capacity goes from 496 to 37 MWh. However, the share of the total solar energy curtailed is too large, as it represents almost the 70% of the total solar generation. Moreover, the nominal power rating of the battery increases significantly, due to the larger PV plant capacity. Thus, this model does not seem feasible for practical applications either.

Performing a monthly assessment of the demand following with curtailment case, the optimal solar PV capacity to demand ratio remains the same. However, the minimum battery size required to cover the monthly demand changes significantly among months, being August and December the ones that require the largest battery size. The additional capacity required for these two months represents around 25% increase in the system investment costs.

The operation of the battery when oversizing the solar plant and allowing to curtail part of the generation for the month of July is shown in Figure 9.

3.2.4 Power output smoothing model

As explained later in Subsection 4.3, power fluctuations can lead to voltage flicker[7] at the buses of the power grid. Another possible consequence of power fluctuations is voltage sag, which is a short duration voltage decrease under 90% the nominal voltage value with a half cycle to 1 minute duration [65].

In order to avoid these issues and improve the quality of the power delivered to the grid, the power output smoothing model tries to smooth the rapid power

[7] Voltage flicker is the instability and luminance fluctuation of a lighting source caused by systematic voltage fluctuations that range from 0.1% to 7% of nominal voltage with frequencies less than 25 Hz [65].

fluctuations that happen in solar generation due to random effects such as clouds. Eliminating these rapid output changes, the quality of the power supplied to the grid improves.

The output power can be smoothed by limiting the range the output power can vary compared to the output power supplied the time step before, $P_{o,t-1}$. This has been done by introducing a parameter which represents the allowed power deviation, in percentage ($\pm\delta$), over the previous output power, as shown in Figure 10. Thus, the maximum and minimum output power values in the time step t depend on both $P_{o,t-1}$ and the allowed fluctuation value. This way, P_{o,min_t} and P_{o,max_t} can be obtained using the following formulae.

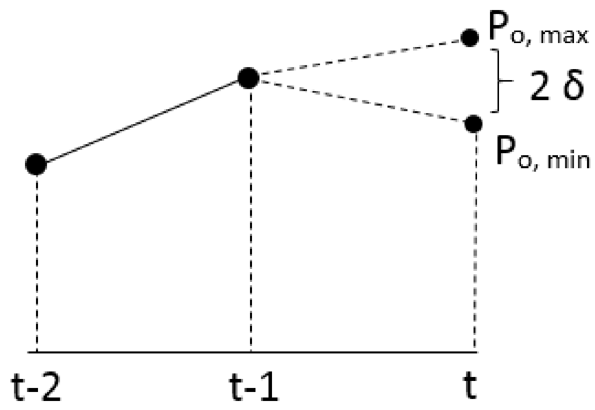


Figure 10: Power output smoothing model logic being the x axis the time and δ the maximum deviation.

$$P_{o,min_t} = P_{o,t-1}(1-\delta) \tag{20}$$
$$P_{o,max_t} = P_{o,t-1}(1+\delta) \tag{21}$$
$$P_{b,t} = 0, \quad Start = 1 \tag{22}$$
$$P_{b,t} = \begin{cases} 0, & P_{o,mint} \leq P_{s,t} \leq P_{o,max_t} \\ P_{o,min_t} - P_{s,t}, & P_{s,t} < P_{o,min_t} \\ P_{o,max_t} - P_{s,t}, & P_{s,t} > P_{o,max_t} \end{cases} \tag{23}$$
$$P_{c,t} = \begin{cases} 0, & P_{b,t} \geq 0 \\ -\eta_c \cdot P_{b,t}, & P_{b,t} < 0 \end{cases} \tag{24}$$
$$P_{d,t} = \begin{cases} \frac{1}{\eta_d} P_{b,t}, & P_{b,t} \geq 0 \\ 0, & P_{b,t} < 0 \end{cases} \tag{25}$$
$$E_{b,t,} = E_{b,t-1} + (P_{c,t} - P_{d,t}) \cdot \Delta t \quad for\ t = 1,2,...,T \tag{26}$$
$$E_{b,t} = E_0 \quad for\ t = 0 \tag{27}$$

Where, $T = 1440$ when applied to a daily model with 1 minute time steps.

Due to the quite rapid start of solar power output after the sun rises, the battery operation algorithm may result too restrictive and not allow a proper output power ramp up. Thus, this situation has been avoided by introducing the following equations:

$$\alpha_t = \begin{cases} 1, & P_{s,t} - P_{o,t-1} \geq 0 \\ 0, & P_{s,t} - P_{o,t-1} < 0 \end{cases} \tag{28}$$

$$for\ t = 1, ..., T \tag{29}$$

$$\alpha_t = 1 \quad for\ t = 0 \tag{30}$$

$$Start = \begin{cases} 1, & \frac{\sum \alpha_t}{t} = 1 \\ 0, & \frac{\sum \alpha_t}{t} = 0 \end{cases} \tag{31}$$

This way, some additional constraints have been included in the model, in order to simulate the solar generation starting conditions during the first sun hours of the day. With the addition of these constraints all the solar power is allowed to be dispatched directly into the grid until a change in the slope of the solar power curve occurs, from increasing to decreasing solar power output for instance. After reaching this point, the normal battery operation algorithm initially described has been applied and the amount of charge or discharge power from the battery in each time step so as to guarantee a smoother power supply has been determined.

This model has been applied to two different days, one in April and another one in August. From those days the first has a quite smooth power generation profile whereas the solar power output of the second presents very big fluctuations. By applying the model to the input data of both days, a smoother power output has been obtained in both cases, with the allowed deviation parameter δ being $\pm 2\%$ and $\pm 5\%$. Microsoft Excel Solver has been used to minimise the battery capacity $E_{b,max}$ with δ and the initial state of charge as variables for the optimisation problem, and subject to the equality constraint $E_{b,0} = E_{b,T}$, which represents the fact that the initial and final state of charge of the battery should be the same. This means that the battery has no net energy consumption.

For the day of April, which has a quite good solar generation curve with few small power fluctuations, a 5% deviation has been allowed and the minimum required battery size is $1.9MW/0.2MWh$. In August instead, the solar power output has big and frequent variations. In this case, the chosen deviation parameter is 2% and the minimum required battery size to be able to smooth the generation and provide a better quality power is $3MW/3.6MWh$. The solar curve and power output curves of both days described can be seen in Figures 11 and 12 below.

As it can be seen, the power output smoothing algorithm decreases the amplitude of the power variations and provides a quite good output power. The battery size needed for this purpose is slightly more than half the solar PV plant capacity, with around 1.2 dispatch hours at the battery's rated nominal power. Thus, having a reasonably small required battery size, power output smoothing seems to be an appropriate service for Li-ion batteries.

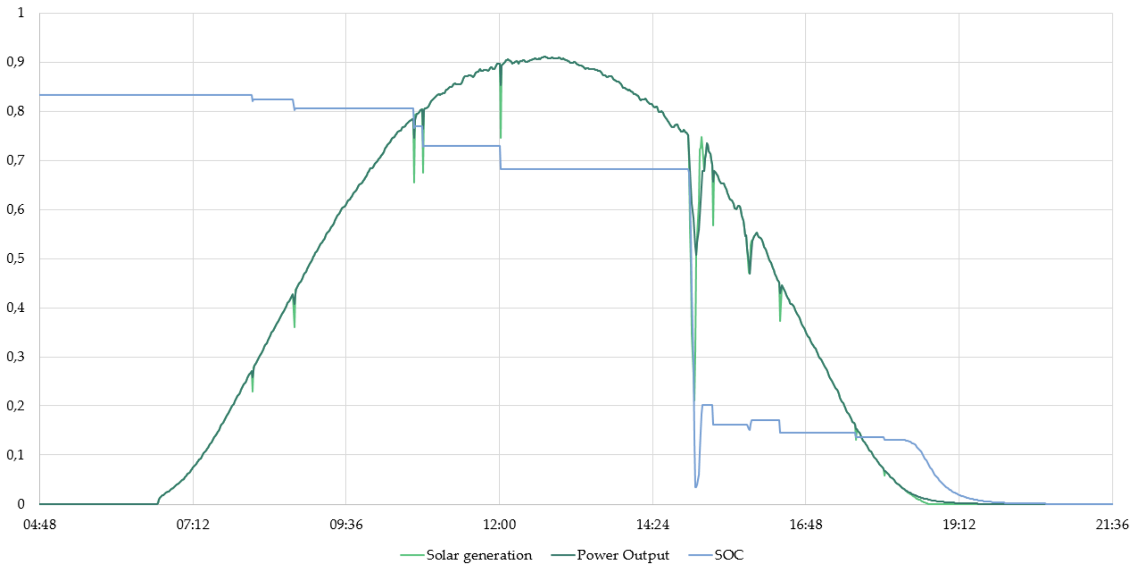


Figure 11: Normalised solar generation and output power example for a day in April.

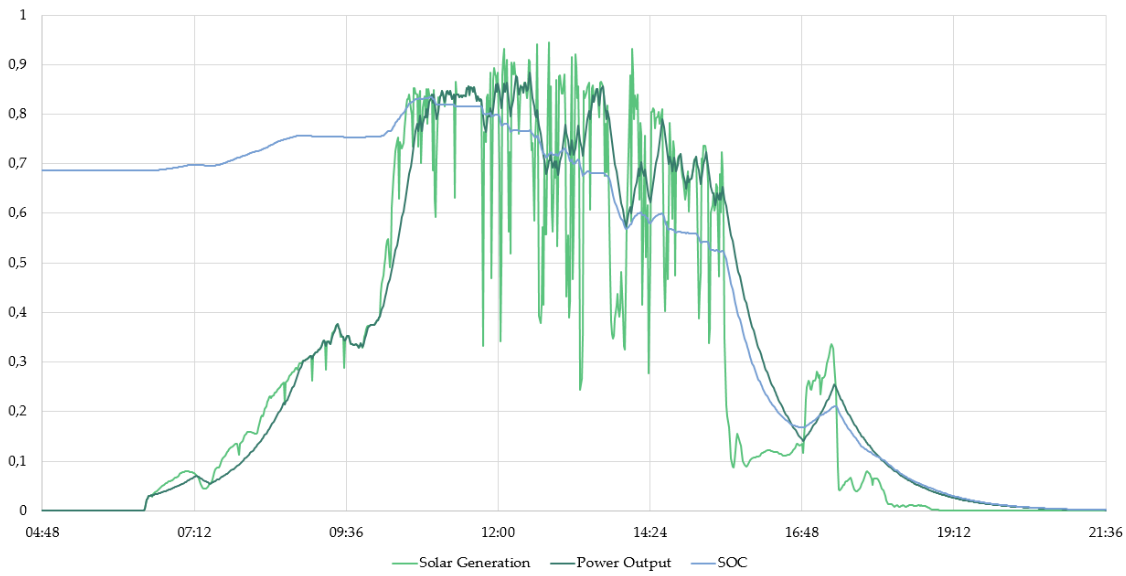


Figure 12: Normalised solar generation and output power example for a day in August.

3.2.5 SECI's power output smoothing model

Being SECI the responsible of the large-scale solar PV plant tenders in India and the one setting the requirements to be able to participate in them and to be eligible for a bilateral agreement if the bidden tariff is accepted, the battery application they consider and the required operation under this application have also been simulated. The fulfillment of these requirements brings the opportunity to participate in hybrid solar PV and BESS project tenders.

SECI's BESS service performance requirements for the Phase II, Batch IV, Tranche V of the JNNSM state that the primary application of BESS for the large-scale solar plants shall be the smoothing of power output due to the fluctuations in solar radiation. Power smoothing has to be successfully performed by the battery for above 75% of the instances within the daily 10 hours assessment period. These instances represent the chosen time step, 1 minute in our case. Besides, 90% of the days of a year have to be successfully operated [66].

Successful operation is determined by the deviation between the combined solar PV and BESS output at the point of common coupling (PCC) and the target previous 15 minute moving average value of the solar PV system output. This deviation must stay within an ±8% limit range to be considered adequate or successful. Nevertheless, those instances in which the battery is charging or discharging at maximum power, regardless of whether this is enough to stay within the required 8% deviation from the target 15 minute average power or not, are counted as successful too.

The required BESS specifications set a minimum BESS power rating of 10% the installed AC capacity of the solar PV plant and the battery should be able to discharge at its rated power for at least 30 consecutive minutes, which corresponds to a 2 C rating. Thus, if we choose a potential solar plant of 100 MW as study case, a battery of 10 MW capacity and 5 MWh energy rating should be installed. Furthermore, the battery shall have a minimum cycle life of 5 000 cycles at 80% DoD and operate for a minimum time-frame of four years.

The optimal battery operation, power delivered to the grid and curtailed power for every instance have been calculated with the following logic:

$$P_{gap,t} = P_{avg,t} - P_{s,t} \tag{32}$$

$$if\ P_{gap,t} \geq P_{b,max},\ P_{breal,t} = \begin{cases} E_{b,t} \cdot \eta \cdot \Delta t, & P_{b,max} \geq E_{b,t} \cdot \eta \cdot \Delta t \\ P_{b,max}, & P_{b,max} < E_{b,t} \cdot \eta \cdot \Delta t \end{cases} \tag{33}$$

$else\ if\ P_{gap,t} \geq 0,$

$$P_{breal,t} = \begin{cases} E_{b,t} \cdot \eta \cdot \Delta t, & P_{gap,t} \geq E_{b,t} \cdot \eta \cdot \Delta t \\ P_{gap,t}(1 - 7.99\%), & P_{gap,t} < E_{b,t} \cdot \eta \cdot \Delta t \end{cases} \tag{34}$$

$else\ if\ P_{gap,t} < -P_{b,max,t},$

$$P_{breal,t} = \begin{cases} -\Delta t(E_{b,max} - E_{b,t}), & P_{b,max} \geq \Delta t(E_{b,max} - E_{b,t}) \\ -P_{b,max}, & P_{b,max} < \Delta t(E_{b,max} - E_{b,t}) \end{cases} \tag{35}$$

$$else,\ P_{breal,t} = \begin{cases} -\Delta t(E_{b,max} - E_{b,t}), & -P_{gap,t} \geq \Delta t(E_{b,max} - E_{b,t}) \\ P_{gap,t}(1 + 7.99\%), & -P_{gap,t} < \Delta t(E_{b,max} - E_{b,t}) \end{cases} \tag{36}$$

$$E_{b,t} = \begin{cases} E_{b,t-1} - \frac{P_{breal,t}}{\eta \cdot \Delta t}, & P_{gap,t} > 0 \\ E_{b,t-1} - \frac{P_{breal,t}}{\Delta t}, & P_{gap,t} \leq 0 \end{cases} \quad for\ t = 1, 2, ..., T \tag{37}$$

$$E_{b,t} = E_0 \quad for\ t = 0 \tag{38}$$

$$P_{PCC,t} = P_{s,t} + P_{breal,t} \tag{39}$$

Where:

- $P_{avg,t}$ = target average solar generation of the previous 15 minutes;
- $P_{s,t}$ = solar output of the instance t;
- $P_{PCC,t}$ = power supplied at the PCC by the system;
- $P_{b,max}$ = maximum battery capacity;
- $P_{gap,t}$ = power required to charge or discharge to supply the target power;
- $P_{breal,t}$ = power the battery charges or discharges in each instance;
- $E_{b,max}$ = maximum energy stored in the battery;
- $E_{b,t}$ = energy content in the battery in each instance;
- E_0 = initial energy content in the battery;
- η = round-trip efficiency of the battery, 90% in our case;
- Δt = time-frame of the instances, 1 minute in our case.

As shown in the equations above, a round-trip efficiency has been used. This is the ratio between the output or discharged energy and the input or charged energy. It has been computed in the discharge side as only the output energy is affected by the losses. Besides, as it has just been described, successful operation is achieved when the deviation between the power delivered at the PCC and the target value is smaller than 8%. Thus, an output power ±7.99% the target power is supplied, being 7.99%<8% and thus operate successfully.

The evaluation of the operation of the battery in each instance has been determined based on these conditions:

$$\begin{aligned} if\ P_{avg,t} = 0, &\quad NR\ (Operation\ Not\ Required) \\ else\ if\ \frac{|P_{avg,t} - P_{PCC,t}|}{P_{avg,t}} < 8\%, &\quad S\ (Successful\ Operation) \\ else\ if\ P_{breal,t} = 8\%, &\quad S\ (Successful\ Operation) \\ else, &\quad U\ (Unsuccessful\ Operation) \end{aligned}$$

Table 7: SECI's power output smoothing model monthly availability.

Monthly availability	
January	97%
February	100%
March	97%
April	100%
May	97%
June	97%
July	90%
August	97%
September	97%
October	97%
November	97%
December	94%
Annual availability	97%

Following this operation strategy an annual availability of 97% has been achieved with the minimum required battery capacity, 10 MW/5 MWh battery for a potential solar plant of 100 MW_{AC} nominal capacity. Monthly availabilities for this case are shown in Table 7, whereas the operation of a day in November is shown in Figure 13.

$$Battery\ size = 10MW/5MWh$$

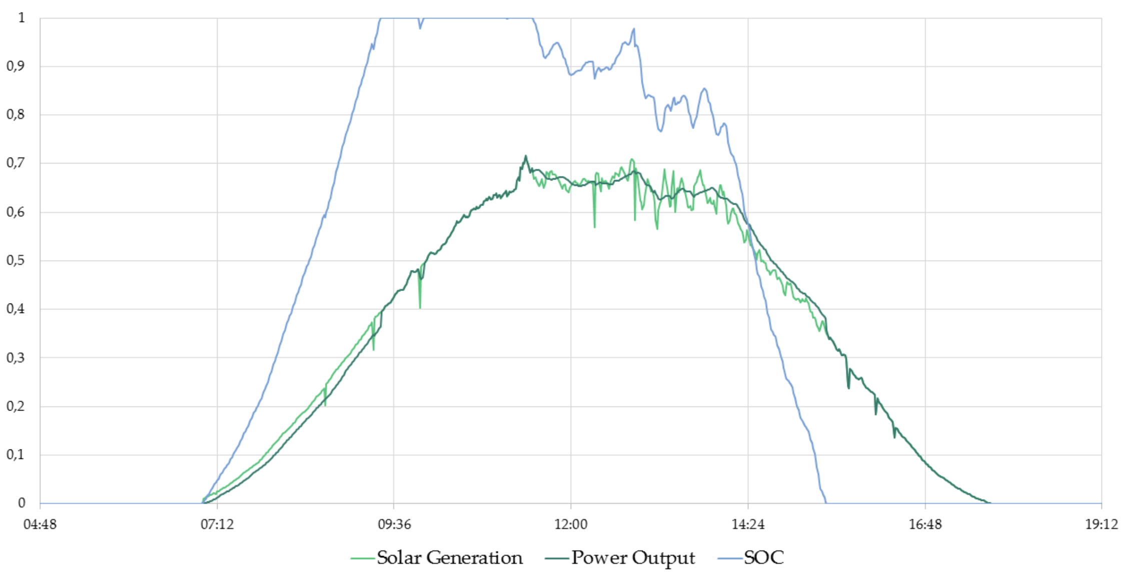


Figure 13: Normalised system operation during one day in November following SECI requirements.

The total annual energy dispatched would be 182.95 GWh, with a total of

898 cycles in a year. For a battery with a cycle life of 5 000 cycles, this gives an estimated lifetime of 5.6 years, which is longer than the minimum four years lifetime required by SECI.

From the total PV generation, 4 727 MWh go to the battery, from which 4 254 MWh are discharged or supplied in another time step. This is the energy used to charge the battery, which represents a 2.6% of the annual energy produced by the PV plant, and by comparing it with the total energy discharged or supplied by the battery, the losses due to the battery operation have been obtained. These losses are 10% of the input energy into the battery, which is consistent with the assumption that the battery has a round-trip efficiency of 90% in the models.

SECI's requested operation model performs the power output smoothing service with a different approach than our own model. The first looks into the instances in which the power output is considered to be good enough and tries to obtain at least a minimum number of days that have a successful operation and thus provide better quality power. However, there is no incentive for generators to try to minimise the power fluctuations during days which would count as not successful.

On the contrary, our model has the objective of minimising the magnitude of the power fluctuations setting a maximum allowed power deviation for each individual day. As result, a smoother power output, with less fluctuation, than when following SECI's operation requirements has been obtained. This case could be interesting if a penalisation to big power fluctuations delivered to the system would be applied in the future.

In the current Indian energy market framework, generators with large-scale PV projects are not incentivised to participate in the liberalised market, as the best for them is to obtain bilateral agreements. Average prices on IEX are low compared to the PPA tariffs, which also provide a sure payment disjointed from the time of delivery. Nevertheless, the interest and case of operating in the Indian electricity exchange are studied in the following section.

3.2.6 IEX spot market optimization model

As previously mentioned, the tariffs guaranteed by the power purchasing agreements are generally considerably higher than the average spot market prices on IEX. However, the considerable market volatility could provide value for electricity supply time-shifting applications. A graph showing the daily price trend in different months of the year is shown in Figure 14. As it can be observed, the price variation is quite high, going from minimum values around 1 000 INR/MWh to peaks which can overcome 6 000 INR/MWh. A strategy which charges the battery instead of dispatching the solar generation in hours where the price is low to then deliver it when the price is higher could therefore make the energy storage investment profitable. This opportunity must then be further studied to reach a conclusion.

The mathematical formulation of the problem is based on Linear Programming (LP) and has been solved using the `linprog` function available in the MATLAB

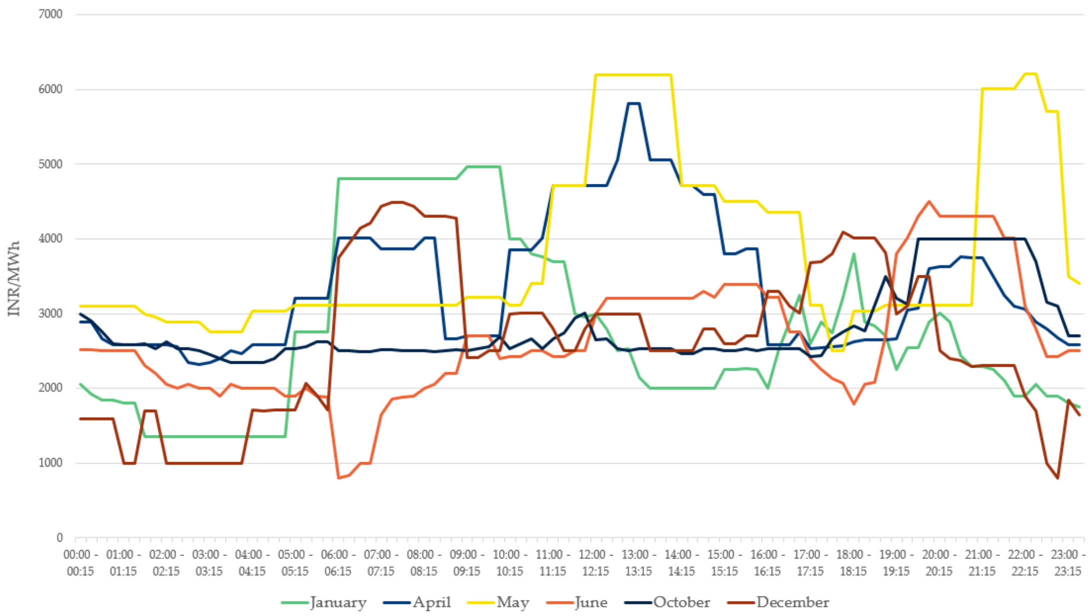


Figure 14: Daily price trend in IEX Day-Ahead market for different months [56].

optimisation toolbox.

The prices for the following two days as well as the solar production have been assumed to be known. The optimisation problem has been formulated on a two-days basis in order to take into account the possibility to take advantage of a better price two days ahead and not discharge completely the battery at the end of every day.

The main inputs for this optimisation problem are the 15 minutes time-series of the solar production from a MW-scale solar plant in Rajasthan and the Day-Ahead IEX price time-series for two days in four different seasons or periods of a year.

The objective function of the problem is formulated as follows:

$$max \sum_{s=1}^{S} \frac{366}{2 \cdot S} \sum_{t=1}^{T} [P_{s,t}(E_{s,grid_{s,t}} + E_{d_{s,t}})] - C_b \cdot E_{BES} - C_{BOS} \cdot P_{b,max} \tag{40}$$

Subject to the following constraints:

$$E_{s,grid_{s,t}} + E_{c_{s,t}} = E_{s_{s,t}} \tag{41}$$

$$0 \leq E_{d_{s,t}} \leq P_{b,max} \Delta t \tag{42}$$

$$0 \leq E_{c_{s,t}} \leq P_{b,max} \Delta t \tag{43}$$

$$SOC_{min} \cdot E_{BES} \leq E_{b_{s,t}} \leq SOC_{max} \cdot E_{BES} \quad for\ t = 1, ..., 192 \quad s = 1, ..., 4 \tag{44}$$

$$\frac{E_{d_{s,t}}}{\eta} - E_{c_{s,t}} + E_{b_{s,t}} = SOC_{initial} \cdot E_{BES} \quad for\ t = 1 \quad s = 1, ..., 4 \tag{45}$$

$$\frac{E_{d_{s,t}}}{\eta} - E_{c_{s,t}} + E_{b_{s,t}} = E_{b_{s,t-1}} \quad for\ t = 2, ..., 192 \quad s = 1, ..., 4 \tag{46}$$

$$E_{s,grid_{s,t}}, E_{c_{s,t}}, E_{c_{s,t}}, E_{b_{s,t}}, P_{b,max}, E_{BES} \geq 0 \tag{47}$$

Where:

- $P_{s,t}$ = IEX Day-Ahead price at time t;
- $E_{s,grid_{s,t}}$ = solar generation directly delivered to the grid, which "bypasses" the battery;
- $E_{d_{s,t}}$ = energy discharged from the battery at time t;
- $E_{c_{s,t}}$ = energy charged to the battery at time t;
- $E_{s_{s,t}}$ = solar energy production at time t;
- $P_{b,max}$ = maximum power of charge/discharge of the battery;
- E_{BES} = battery energy capacity;
- SOC_{min} = minimum SOC of the battery;
- SOC_{max} = maximum SOC of the battery;
- $SOC_{initial}$ = initial SOC of the battery, at $t = 0$;
- $E_{b_{s,t}}$ = energy content of the battery at time t;
- C_b = annuity of the capital expenditure referred to the battery energy capacity;
- C_{BOS} = annuity of the capital expenditure referred to the battery power capacity;
- S = number of seasons simulated.

In order to be solved with the `linprog` function, the problem has to be formulated in canonical form, based on matrices. For this reason, the just presented problem has been reformulated in the following way:

$$\begin{aligned} minimise \quad & -f^T x \\ subject \quad to: \quad & Ax \leq b, \\ & A_{eq}x = b_{eq}, \\ & l_b \leq x \leq u_b. \end{aligned}$$

Where:

- x = vector of optimisation variables;
- f = vector of coefficients of the objective function;
- A = matrix of coefficients of the inequality constraints;
- A_{eq} = matrix of coefficients of the equality constraints;
- b = vector of the right hand side values of the inequality constraints;
- b_{eq} = vector of the right hand side values of the equality constraints;
- l_b and u_b = vectors of lower and upper bounds, respectively, of the variables;

Initially, the same cost estimates used for previous models in the Indian case have been used. Both annuities, C_b and C_{BOS} measured in USD/MWh and USD/MW respectively, have been calculated from the values shown in Table 8 with the following formulae:

$$C_b = CAPEX_b \frac{i}{1-(1+i)^{-n}} \tag{48}$$

$$C_{BOS} = CAPEX_{BOS} \frac{i}{1-(1+i)^{-n}} \tag{49}$$

It has been assumed that the energy-related costs are represented by the capital cost of the battery storage itself and the power-related costs are represented by the BOS costs. i has been assumed to be a 7% nominal interest rate, lower than the previously adopted Weighted Average Cost of Capital, WACC. Anyway, a sensitivity analysis on all these parameters has been performed and is described afterwards in Section 3.3.

Four seasons have been identified to be representative for the simulation, therefore two days from each one have been chosen. Besides the weather conditions already mentioned in the previous sections regarding the other simulations, in this case also the price trends shown in Figure 14, have been taken into account. The chosen days have been taken from February, May, August and November.

With these inputs, the optimization algorithm returns as battery size the minimum lower bound set for the variable, in this case chosen to be $0.5 MWh$. The investment in a BESS with power time-shifting purposes seems therefore not to be profitable under the current conditions, despite having an optimal battery operation that charges during price bottoms and discharges during price peaks. The successful operation is shown in Figure 15, where the x axis of the graph represents the time on a 15 minutes time-frame.

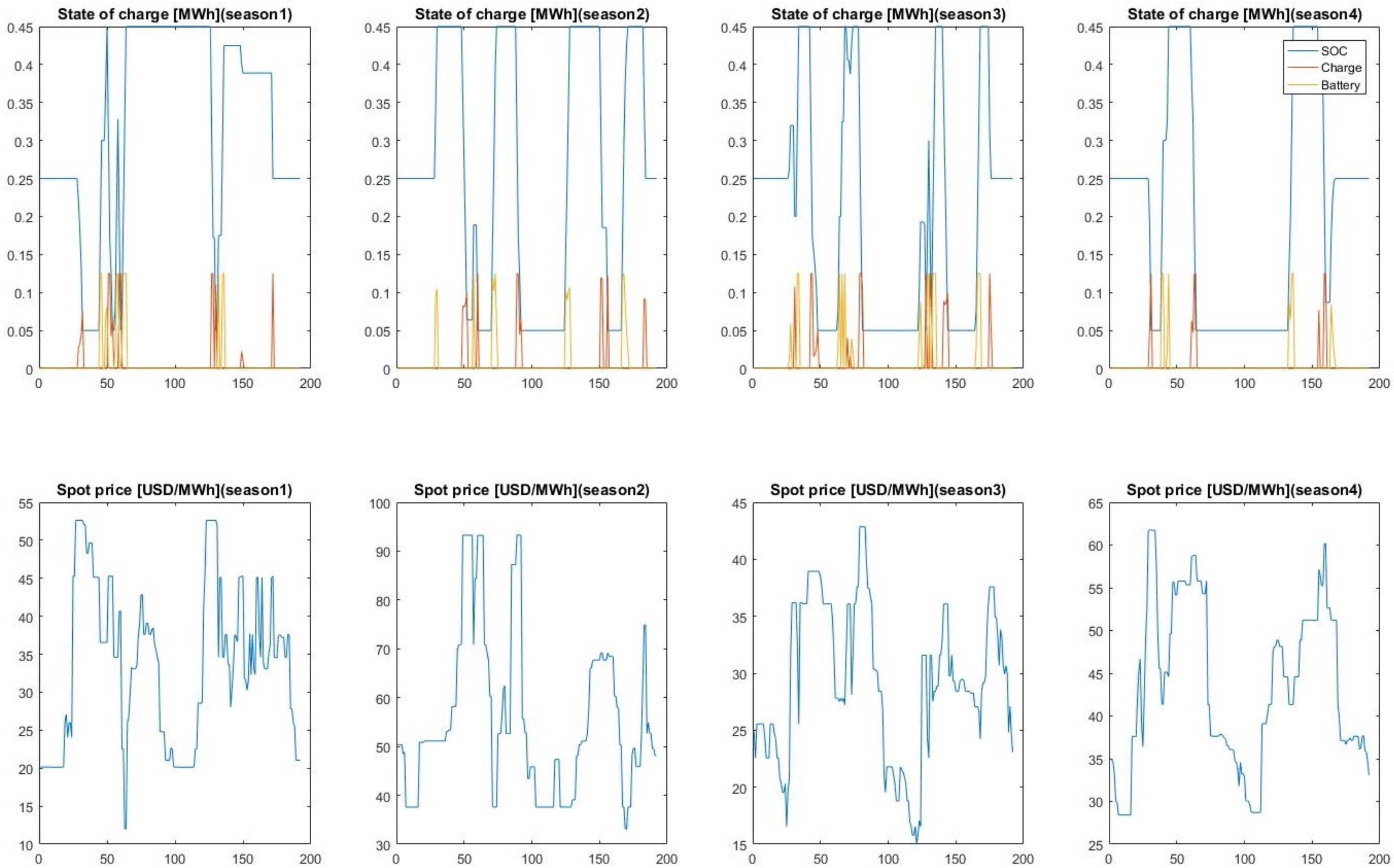


Figure 15: Operation of the battery in the four simulated seasons with respective prices.

3.3 Results and economic assessment

Looking into the battery size requirements for all the different applications modelled and the payments identified during the Indian energy market study, power output smoothing based on SECI's operation model and requirements has been identified to be the most suitable service to provide with a hybrid solar PV plus battery system in India. Power output smoothing and time-shifting are the two services that require reasonably small battery sizes. From those two, the PPA tariff that is possible to obtain with SECI's power output smoothing model is the one with highest potential revenues, as there is no additional payment for higher power quality and IEX Day-Ahead spot market price volatility is not as good as the power price obtained under bilateral agreements. In order to assess the interest of this application, an economic assessment of the model has been performed, using the following costs shown in Table 8.

Table 8: Technology costs in India.

	Costs		Source
Battery	301	$/kWh	[63]
Battery BoS	300	$/kW	[61]
Battery O&M	10.5	$/kWh-yr	[61]
Solar PV	330	$/kWp	[62]
Solar PV BoS	200	$/kW	[64]
Solar PV O&M	15.8	$/kW-yr	[67]
Project costs	159	$/kW	[68]
Battery cost evolution	-7.20	%/yr	[63]
WACC	10	%	[64, 69]

The economic results of the battery operation strongly depend on the solar generation data and PPA tariff. Due to the fact that, as initially mentioned, the first are covered by a non-disclosure agreement and the latter are very project specific, the profitability results for the studied project are presented within a range. The Net Present Value (NPV) and the Internal Rate of Return (IRR) values for the modelled case study plant are presented in Table 9. The NPV and IRR are the two indicators used to assess the profitability and economic value of the different applications studied. The NPV has been calculated by adding all the discounted annual cash flows during the lifetime of the project, whereas the IRR is the interest rate that would make the NPV of the project zero.

$$NPV = \sum_{t=0}^{T} \frac{CF_t}{(1+i)^t} \tag{50}$$

Where i is the WACC of the investment and T the lifetime of the project.

Furthermore, using the costs presented in Table 8, the PPA tariff for a solar PV and battery system which would provide the same profitability as a solar only project has been investigated. For example, taking a 4 INR/kWh PPA tariff as

Table 9: Profitability assessment results.

Efficiency	90%
MW/MWh	2
DoD	100%
CAPEX	$ 77 917 000
Lifetime	25 years
NPV	$ 8 000 000 - 9 000 000
IRR	11 - 12%

baseline for a 100 MW solar PV project, the IRR of the project would be 0.8% higher. For the solar PV plus battery hybrid project, the same rate could be obtained with a 5% higher PPA tariff, thus with a 4.2 INR/kWh tariff.

Finally, a sensitivity analysis has also been performed to assess how different factors affect the annual availability and profitability of the project. The factors studied are:

- battery round-trip efficiency;
- battery capacity ratio, MW/MWh; and
- Depth of Discharge (DoD).

The obtained results are shown in Tables 10, 11 and 12, which can be compared with the base case scenario results in Table 9. The energy production and NPV results are shown as the relative variation with respect to the base scenario figures, whereas the IRR values represent the absolute variation from the initial IRR.

Table 10: Round-trip efficiency sensitivity analysis.

Round-trip efficiency sensitivity analysis				
Efficiency	Energy production	NPV	IRR	Availability
95%	+0.16%	+1.60%	+0.02%	96.72%
85%	-0.11%	-1.65%	-0.02%	96.72%
80%	-0.25%	-3.34%	-0.04%	96.45%

Table 11: Battery capacity ratio sensitivity analysis.

Battery capacity ratio sensitivity analysis				
MW/MWh	Energy production	NPV	IRR	Availability
2.5	+0.05%	+9.70%	+0.15%	94.26%
1	-0.05%	-48.23%	-0.69%	99.18%
0.5	-0.06%	-143.07%	-1.92%	99.45%

As it can be seen, the battery capacity ratio is the parameter which affects most both the availability and profitability of the system from the three studied

Table 12: Depth of discharge sensitivity analysis.

Depth of discharge sensitivity analysis				
DoD	Energy production	NPV	IRR	Availability
90%	0.00%	-5.39%	-0.08%	97.81%
80%	0.00%	-12.11%	-0.18%	98.36%

factors. When increasing the battery capacity ratio, which can be done by either increasing the power rating or decreasing the energy capacity of the battery, the availability decreases whereas the profitability of the project increases. However, this ratio is fixed by the technical characteristics set for SECI's solar PV and battery projects, thus no higher profitability can be obtained by investing in a higher C rating battery.

In addition, it can be seen that a higher efficiency slightly increases the profitability of the battery. However, this result may be overestimated, as the effect of the battery efficiency in the battery's price has been disregarded, which could be the real case in the market.

On the other hand, a battery investment with arbitrage purposes has been demonstrated not to be profitable under the current battery costs and IEX spot market prices, which can be concluded from the profit maximisation result, which gives a no battery case as optimal solution.

For this reason, a study of the battery and battery BOS capital costs has been performed, in order to identify the prices under which the modelled power time-shifting in IEX Day-Ahead spot market operation strategy would become profitable when installing a battery. A wide range of battery CAPEX have been analysed and the results show that a substantial price drop of more than 60% from the current values is necessary for the hybrid system to become profitable.

3.4 Indian case findings and recommendations

Different possible applications or services to be provided with a hybrid solar PV and battery system in India have been studied, with power generation data from *Amrit* solar plant. It has been found that long-term energy storage applications which depict a seasonal storage behaviour, such as constant power output or demand following operation, are not suitable for this type of storage.

Having to provide an output whose value is independent of the solar power generation makes it necessary to store energy from high solar generation season to periods in which the solar resource and thus the electricity generated is considerably lower. In the Indian case, with production data obtained from the region of Rajasthan, electricity is stored from April to July, in order to be delivered during monsoon season, when the solar production is much more fluctuating and unreliable. This results in very large battery size, with a very big investment. Thus, these types of application are not suitable for a battery energy storage system.

In case oversizing of the solar plant and power curtailment possibility are considered, the obtained solar plant capacity to demand ratio so as to have a smaller battery capacity, as well as the amount of curtailed production and thus wasted electricity become extremely large. This makes the greatly oversized system not interesting at all from both investment and efficient resource utilisation perspectives.

A shorter-term service which is more appropriate for the characteristics of a battery system, power output smoothing, has also been studied and modelled. An operation strategy that sets the maximum allowed power deviation between two consequent instances (percentage of the output power of the previous instance under normal operation) provides the best output power with a reasonable battery size, smaller than the solar plant rated capacity and with a near-to-one C rating. On the other hand, an operation that aims at delivering the average solar generation of the 15 previous instances as output (operation strategy to be followed under SECI's bilateral agreement requirements), with a battery power capacity equal to or bigger than 10% of the solar plant capacity and a 2 C rating, results in a slightly less smoothed power output. This contains more fluctuation, with a bit worse power quality delivered to the grid, but obtains the required annual availability and stays within the 8% of the target average power for 75% of the daily instances for more than 90% of days of the year.

Nevertheless, the power output smoothing service is not remunerated in the Indian market, as there is no payment except for the amount of electricity delivered to the grid. As a result, in spite of the fact that setting a more strict maximum power deviation range provides a better output power, there is no economic incentive to do so. Having a smaller battery which smooths the solar generation well enough to achieve the required annual availability value is more interesting from an economic point of view, as it requires a smaller investment and the same revenue is obtained.

Finally, the battery operation under price arbitrage in the IEX Day-Ahead market has been studied. The battery is charged when electricity prices are lowest and discharged when prices are highest. The operation for two-days ahead is optimised, scheduling the charge and discharge hours within those two days. After the day one operation is performed, the day two operation is revisited looking into the price forecast for the following two days. It has been found that the current price volatility in the market is not big enough to justify the investment in a battery for that service only, based on the current battery costs.

In conclusion, with the current battery prices and market conditions in India, the most interesting case for battery systems is to install the minimum required battery capacity together with the solar PV plant and to operate the battery based on SECI's bilateral agreement requirements.

4 Battery energy storage systems and wind power in Sweden

In this chapter, the case study of BESS in combination with wind power generation in Sweden is presented. Similarly to the case of India, first a review of the Swedish power market has been performed and is presented in Section 4.1. Based on this information, possible services to be provided and consequently different system operation strategies for each of those services have been identified and simulated with different strategies. The mathematical formulation of these models as well as the results of the case studies are presented in Section 4.2. Based on the latter an economic assessment has also been performed.

4.1 Electricity market structure

Electricity generation capacity in Sweden is mainly composed of nuclear and hydro power. In the last years a considerable amount of wind power has been installed, which represented 19% of the installed power capacity by May 2017 [17], as it can be seen in Figure 16.

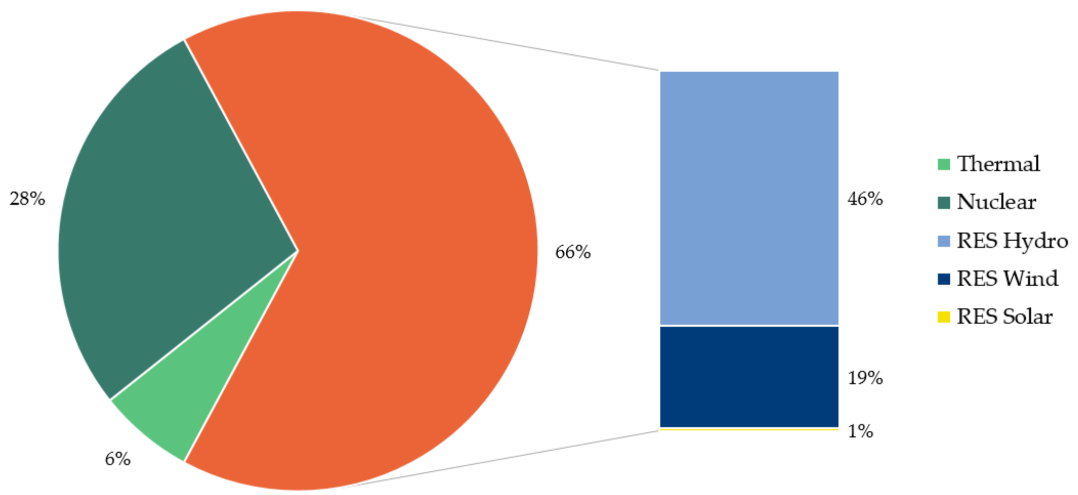


Figure 16: Installed generation capacity [GW] by source in Sweden, May 2017 [17, 70].

The Ministry of the Environment and Energy is the governmental body responsible for energy policy in Sweden and *Energimyndigheten*, the Swedish Energy Agency, represents the energy authority of the country [71, 72].

The Swedish electricity market is completely liberalised since 1996. In the Nordic power markets it is possible to trade power derivatives on Nasdaq OMX Commodities. This financial trading is usually part of risk management and price hedging strategies and does not imply a physical delivery. It is therefore out of the scope of this work.

Physical power trading is performed in Sweden through *Nord Pool*, the largest European energy exchange which operates also in Norway (where it was founded in 2002), Finland, Denmark, Estonia, Latvia, Lithuania, Germany and the UK. Nord Pool provides markets for Day-Ahead and intraday products among others, and is mainly owned by the Nordic TSOs Svenska Kraftnät, Fingrid Oy, Energinet.dk and Statnett SF, with considerably smaller shares of the Baltic TSOs [73].

Svenska Kraftnät, the Swedish TSO, is responsible for the safety and reliability of the electricity grid. It is therefore its task to balance the power production and consumption in each instant and, as consequence, to organise the balancing markets following the *Nordic Balancing Philosophy* [74].

4.1.1 Nord Pool - Elspot

The Day-Ahead market is where most of the power trade takes place in Sweden. Nord Pool's Day-Ahead market, Elspot, is an auction-based exchange for the trading of physically delivered electricity. Players who want to trade on Elspot market must submit their purchase orders the latest at 12:00 the day before the power is physically delivered to the grid. Each order contains information about the volume, expressed in MWh/h, that a participant is willing to buy or sell at a specific price, expressed in EUR/MWh, for each individual hour of the following day. It is also possible to submit bids that are valid for more than one trading period, which are defined as *block bids* and can be either accepted or rejected as a whole [73].

Such a market aims to be efficient and competitive, providing that electricity for each hour of the day is produced at the lowest possible price in order to result economically effective for the society. For this reason, the system price is calculated combining supply and demand curves, and it represents both:

- the cost of producing one kWh from the most expensive source needed in order to supply the power to balance the system; and
- the maximum price that consumers are willing to pay for the last kWh to satisfy their demand.

This type of price formation is referred to as *marginal price setting*. More specifically, the sell bids are combined to form a supply curve, sorted in ascending order, from the lowest to the highest price. In the same way, purchase bids are sorted according to descending willingness to pay. The price cross, i.e. the intersection between the two curves, is what determines the price and the quantity to be traded, as shown in Figure 17. All bids which are on the left hand of the cross are accepted and get the same price, both from demand and supply side. It is important to notice that such a system allows many players to receive more beneficial prices than the ones they were willing to sell or buy for.

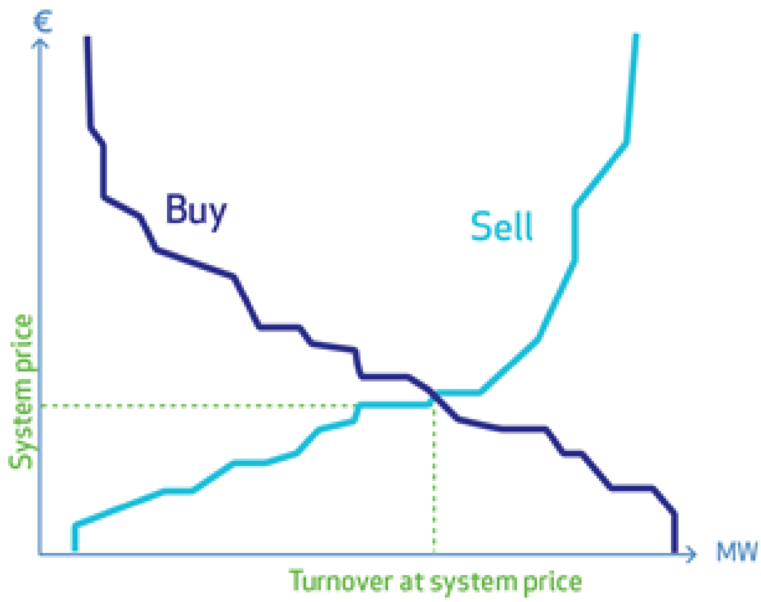


Figure 17: System price clearing in Nord Pool Elspot [73].

A system price is then calculated, based on all the sale and purchase orders but without taking the available transmission capacity between the different areas into account. This system price is mainly used as reference for trading of long and short term financial contracts [75].

Sweden is divided in four price areas, denominated SE1 (Luleå), SE2 (Sundsvall), SE3 (Stockholm) and SE4 (Malmö), and shown in Figure 18. The availability of transmission capacity between these areas may vary and congest the flow of power. This has as consequence the creation of different prices among the areas, which differ from the system price. The Day-Ahead congestion in the Nord Pool exchange area is managed through an *implicit auction*. The idea behind this concept is again to maximise the overall social welfare in the integrated markets. Some areas will have a surplus of power, whereas other areas will have a deficit. The latter ones will be dependent on imports from the former ones. But if there is insufficient transmission capacity, the occurrence of bottlenecks arises differences in price. In particular, the area in deficit will have a higher price than the area with surplus. To calculate the new prices, the export from this latter one will be considered as an additional purchase in the same area and consequently an additional sale in the deficit one. In this system, no market member has privilege on any bottleneck so as to maintain the characteristic of liberalised electricity market [73].

4.1.2 Nord Pool - Elbas

Elbas (Electrical Balancing Adjustment System) is Nord Pool's intraday market with continuous hourly market for transactions in physical power for the present 24 hour period until one hour before delivery, covering the Nordic, Baltic, UK,

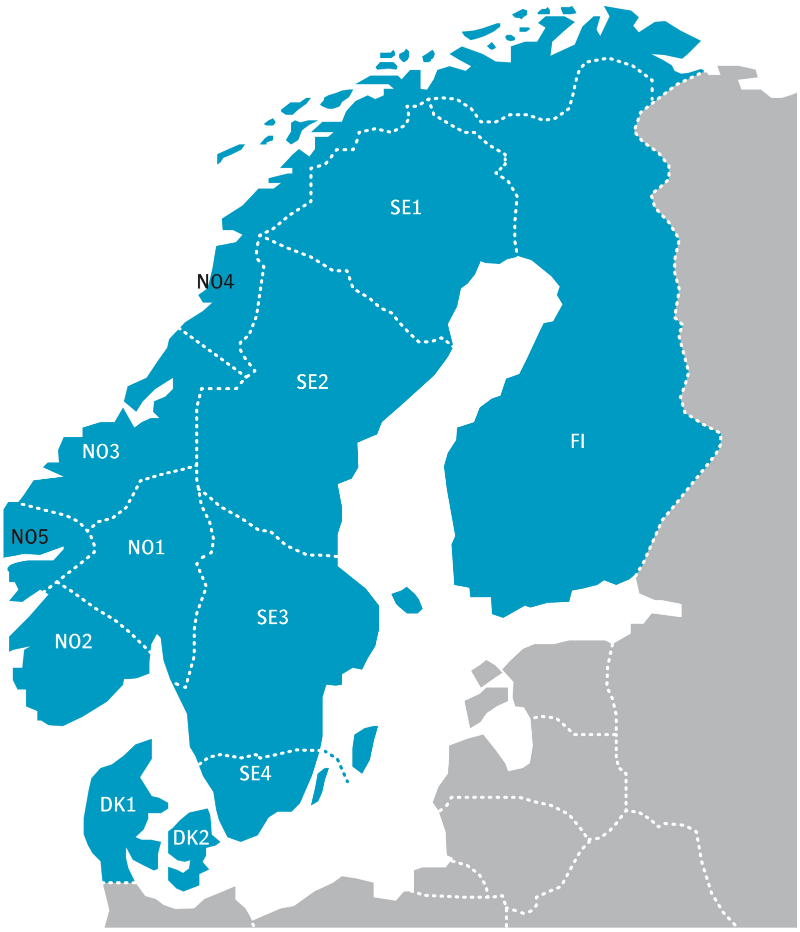


Figure 18: Nord Pool bidding areas [73].

Belgian, Dutch and German markets. Transactions are matched automatically when concurring orders are registered, which means that prices are set on a pay-as-bid basis where best prices come first. The best prices are the highest buy and lowest sell prices. Thus, prices in the intraday market for the same product may vary during the trading period. In other words, in contrast to Elspot, players either get to sell or buy for the price they have offered, or they do not sell or buy at all. Bids can be placed for 15 minutes, 30 minutes or 1 hour, with minimum trade volume of 0.1 MWh [73].

The intraday capacity is determined by the TSO after flow results of the Day-Ahead auction have been obtained. The exact timing of capacity allocation varies and depends both on operational procedures and individual agreements between TSOs on the different borders. Besides, intraday capacities are automatically updated depending on the volume and direction of intraday trades. Gate closure differs among TSOs, being one hour before physical delivery in the Swedish and Finnish markets, i.e. it is possible to trade in Elbas up to one hour prior to power delivery [73].

Elbas provides the possibility to reduce imbalance costs due to supplying more or less energy than the one bidden, the possibility to optimise the own production/consumption schedules, and flexibility in own production/consumption that could be transferred to other market participants.

In terms of intraday trading, flexibility refers to the possibility of increasing or decreasing own energy generation or consumption during the period of delivery (in MWh), whereas bids in the balancing markets offer flexibility in terms of increasing or decreasing own generation or consumption levels in power (in MW), which is explained later in this Section 4.1.

A utility participating in Elbas has the possibility to place different types of bids: limit orders, block orders or iceberg orders. A *limit order* is a buy or sell order with a specified price limit, where buy orders can be executed at the limit price or lower and sell orders can be executed at the limit price or higher. These limit orders may be partially executed. For user-defined *block orders*, only the entire volume may be executed, they cannot be partially accepted. *Iceberg order* (IBO) is a type of limit order, usually of a larger volume, with the purpose of hiding its full size by dividing it into smaller clips. Initially only the first clip is shown to the market and the next clips will be visible when the previous ones have been fully matched [73].

Furthermore, there are two types of execution constraints that participants can execute if desirable, *Fill-or-Kill* (FoK) and *Immediate-or-cancel* (IoC). FoK is a limit order where the entire volume of the order will be either matched immediately upon submission or withdrawn from the market. IoC is a limit order where as much as possible of the order volume is matched immediately upon submission and the remaining volume is withdrawn from the market [73].

Table 13: Possible types of bids in Elbas [73].

Types of orders
Limit orders
Block orders
Iceberg orders (IBO)
Types of execution constraints
Fill-or-Kill (FoK)
Immediate-or-Cancel (IoC)

4.1.3 Balancing markets and ancillary services

The intraday Elbas market is usually not sufficient to achieve the balancing of the demand and supply during each moment. For this reason, additional capacity is needed to be available for the TSO of each country in order to have the possibility to be activated to guarantee the grid security and maintain its reliability. The trading of this capacity is currently ruled and organised by the TSO, thus Svenska Kraftnät (SvK) in Sweden [76]. A Balance Responsible Party (BRP) is a company that has a valid *imbalance settlement agreement* with eSett and a valid *balance agreement* with SvK and manages a balance obligation on its own behalf as producer, consumer or trader of electricity on behalf of other producers, consumers or traders of electricity [77].

The main traded products are the following ones:

- Frequency Containment Reserve (FCR): automatic regulation that happens momentarily to adjust the physical balance in the power system.
- Frequency Restoration Reserve (FRR): automatic and manual reserves used to restore the frequency back to 50 Hz after FCR is activated.

FCR

Regarding FCR, it is in turn divided in two other products: Frequency Containment Reserve in Normal Operation (FCR-N) and Frequency Containment Reserve in Disturbed Operation or Controlled Disturbance Reserve (FCR-D).

FCR-N is active power which should be available in order to be used for frequency control in the range between 49.9 and 50.1 Hz. It must be activated to 63% of its capacity in 60 seconds and to 100% in 3 minutes. FCR-D is active power as well but is used for frequency control within the 49.5 - 49.9 Hz range and must be activated to 50% of full capacity in 5 seconds and to 100% in 30 seconds.

The overall FCR-N volume requirement in Sweden is around 200 MW, with a minimum bid size of 0.1 MW. The product should be automatically controlled and able to regulate up and down. Since a fixed amount of capacity is purchased by SvK, the bids can be either accepted or not and if they are, the compensation is pay-as-bid. Moreover, an energy compensation or payment based on the up- and down-regulating prices for the effectively activated energy is provided as well [76].

Regarding FCR-D, the minimum bid volume is also 0.1 MW and the compensation is pay-as-bid. In this case, the product only needs to regulate upwards, but has to be automatically controlled too.

FCR can be offered to Svenska Kraftnät through bids during the D-2 and/or D-1 trading periods, which means two days and one day before the delivery day, respectively. Bids shall be cost-based and provide some margin for profit and risk premium. Bids are on one hour base, and block bids are possible too. In the D-2 market the maximum block bid duration is 6 hours, whereas in D-1 the maximum duration is 3 hours. Bids for D-2 must be submitted the latest at 15:00 two days before the delivery day. BRP's bids which get sub-ordered are notified by 16:00 of the same day. SvK compiles then the orders, and evaluates the bids. Bids can be repurchased during day D-1 for the marginal price but cannot be retracted. Regarding the D-1 day, similar rules apply, with the difference that bids must be submitted by 18:00 and the sub-ordered ones will be notified by 20:00. In summary, FCR-N is used for balancing ordinary deviations from the expected load and power generation, while FCR-D is used in case of outages of considerable magnitude. In any case, both products represent primary reserves [76].

aFRR

The Automatic Frequency Regulation Reserve (aFRR) represents the secondary control. Similarly to FCR, it is automatically activated, but the control is not local. Instead, the product is remotely controlled by a centralised controller. The aim of aFRR is to bring the frequency back to 50.00 Hz after having been stabilised by FCR. As technical constraint, aFRR shall be fully activated within 120 seconds and controlled by a signal of the TSO.

aFRR bids are not submitted for a period of 24 hours but for the upcoming Saturday – Friday period, no later than 10:00. Bids for each hour can be done in steps of 5 MW in SEK/MW or €/MW and separately for up- and down-regulation. BRPs whose bids have been sub-ordered will be notified by 11:00 the same day as the bidding occurs. Bids sub-ordered cannot be retracted by BRPs. If problems to deliver the sub-ordered volume occur, the BRP shall urgently inform the TSO [76]. SvK usually buys around 100 MW of aFRR capacity [76]. Sub-ordered aFRR capacity is pay-as-bid and the aFRR energy used for up-regulation is priced with the up-regulation price, whereas aFRR used for down-regulation is priced with the down-regulation price [74].

mFRR

As previously mentioned, Manual Frequency Restoration Reserve (mFRR) is used for power balancing and to handle congestions in both normal and disturbance situations. mFRR replaces, when activated, both FCR and aFRR. It can also be activated in opposite direction in case proaction is needed. According to ENTSO-E [74], mFRR is and will continue to be the main balancing resource of the system.

The market players can submit bids to the Nordic Regulation Power Market (RPM). The RPM is used by SvK and other TSOs to perform the balancing. Bids received are ranked according to geographical location, price and activation and regulatory times, and are activated in the most socio-economically efficient way. In general, the activation of bids is based on the following criteria: for upward regulation, the least expensive bid is activated first. For downward regulation, the most expensive is activated first. If activated, up-regulation power is bought by SvK from the BRP, whereas SvK sells power to BRP if down-regulation is activated. Anyway, bids with greater value or settled quickly can have priority. On contrary to aFRR and FCR, tertiary regulation bids can be continuously submitted, amended or removed from 14 days up to 45 minutes prior to the delivery hour. After this moment, all bids become economically binding [74, 77].

The maximum upwards regulation bid price is 5 000 €/MWh. Upwards regulation bids are submitted with a plus sign and downwards regulation bids are submitted with a minus sign. The activation times shall always be mentioned in the bid. The minimum bid volume is 10 MW for SE1, SE2, SE3 and 5 MW for SE4. Replanning is necessary if production exceeds 200 MW between two following hours [76].

In some cases it may be necessary for the TSO to order *special regulation*. In such a case, the normal national ranking order of prices would not be valid anymore. The so called *special regulating circumstances* refer to abnormal frequencies, lower than 49.5 Hz or higher than 50.1 Hz, or extensive disturbances. When calculating the regulating market prices after each hour, the most expensive bids are allocated for special regulation [76].

After each delivery hour during which regulating power has been ordered by SvK, prices for up- and down-regulation are set, which are applicable to all balance settlements during the specific delivery hour they are referred to. These prices are determined as follows:

- The *up-regulation price* is the price for the most expensive upward regulation bid that has been ordered for mFRR during the delivery hour.
- The *down-regulation price* is the price for the least expensive sub-ordered downwards regulation bid that has been ordered for mFRR during the delivery hour.

BRPs whose mFRR bids have been accepted by SvK are paid for the contracted energy in accordance with the up-regulation price if up-regulation is used for balance control. If the regulation price is lower than the bid price, the BRP gets the bid price as this means that the bid has then been used as special regulation. Special regulation is not taken into account in the determination of the price of imbalance power [76].

To sum up, in the Nordic area it is possible to trade the following ancillary service products:

- Primary reserves: FCR-N and FCR-D.
- Secondary reserves: aFRR.
- Tertiary reserves: mFRR.

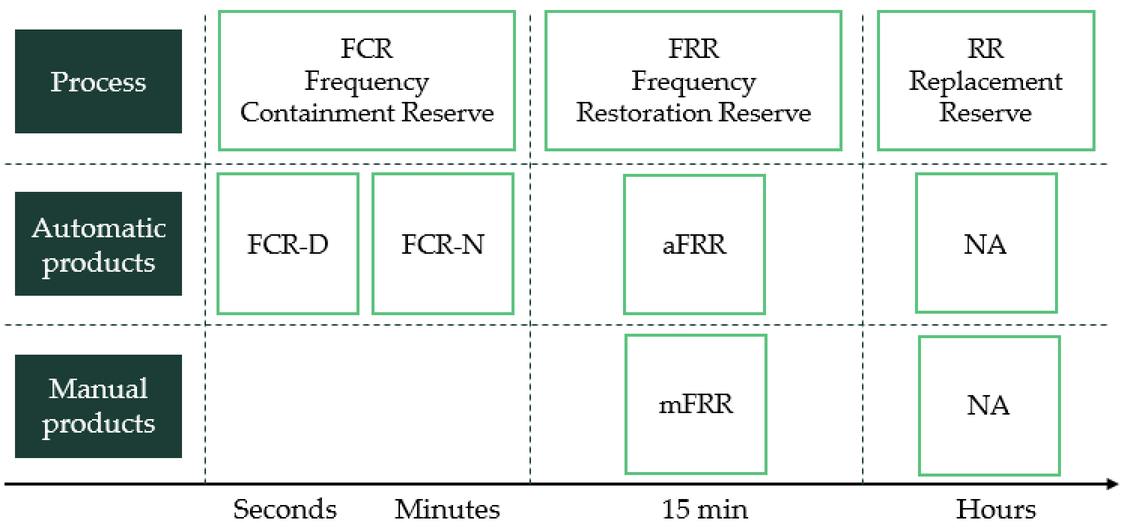


Figure 19: Reserve products in the Nordic power system [74].

Regulating power market

In the Nordic Balancing model, the BRPs are expected to balance their portfolio hourly until the operation hour in each bidding area. This can be done by trading in Elspot, Elbas and through bilateral trading among BRPs. After the closing of the Day-Ahead market, BRPs provide TSOs with information of their preliminary need for balancing power for the following day. But it is not until the closure of the intraday market, Elbas, that the responsibility for balancing passes to the TSOs.

When imbalances occur, the system operator activates additional supply or demand by buying or selling up- and down-regulation power. Up- and down-regulation is traded in the hour-ahead market for mFRR products, as previously explained. If real-time consumption is bigger than production (negative system imbalance), up-regulation (increase of power supply or decrease of demand) is needed. If consumption is smaller than production (positive power imbalance), down-regulation (decrease of power supply or demand increase) is needed. According to the previously explained pricing method, in an up-regulated system, the balancing price is higher than the spot price; and in a down-regulated system, the balancing price is lower than the spot price [78].

Not complying with the dispatched volumes in the spot and balancing markets leads to penalisation of imbalances. Imbalances are settled following the delivery hour (one-price or two-price balancing mechanism is used in the settlement). Under a one-price system, imbalances, either positive or negative, are charged or paid the balancing market price. If a two-price system has been implemented, negative imbalances are charged the balancing market price if the overall system needs up-regulation, and otherwise, the lower spot price (down-regulation). Positive imbalances are paid the balancing market prices if the system is in need of down-regulation, and otherwise, the spot price. This is designed to rule out incentives to deliberately create imbalances, and instead encourage players to help the system [77, 78].

When average balancing prices are higher than average spot prices, smaller down-regulation volumes are traded, whereas up-regulation volumes are significant. When expected price levels in the two markets are almost identical, up- and down-regulation volumes are almost identical and relatively large (value of being able to defer bidding decisions in the balancing market until an hour ahead of operation). If the balancing price is higher than the spot price, it is profitable to offer up-regulation; and if balancing price is lower than the spot price, it is profitable to offer down-regulation. The expected balancing revenues faced by a market participant are effectively lower when adjusted for the risk of not being dispatched. A two-price system penalises market participants for deviations that increase the power system's need for balancing power in real-time, but at the same time, it guarantees that market participants with deviations that mitigated the system's need for balancing in real-time do not profit more than if they would have traded the corresponding energy already on the Day-Ahead market. The imbalance costs and revenues in a two-price system are summed up in Table 14, where P_{up} is the up-regulation price, P_{spot} is the Day-Ahead price, P_{down} is the down-regulation price, $E_{deficit}$ is the amount of own energy deficit and E_{excess} is the amount of own energy excess; always referred to the delivery hour and seen from the perspective of the BRP [76].

Table 14: Imbalance costs calculations in the Nordic Balancing Model [77].

	Up-regulation	No Regulation	Down-regulation
Own deficit	Pay: $P_{up} \cdot E_{deficit}$	Pay: $P_{spot} \cdot E_{deficit}$	Pay: $P_{spot} \cdot E_{deficit}$
Own surplus	Get: $P_{spot} \cdot E_{excess}$	Get: $P_{spot} \cdot E_{excess}$	Get: $P_{down} \cdot E_{excess}$

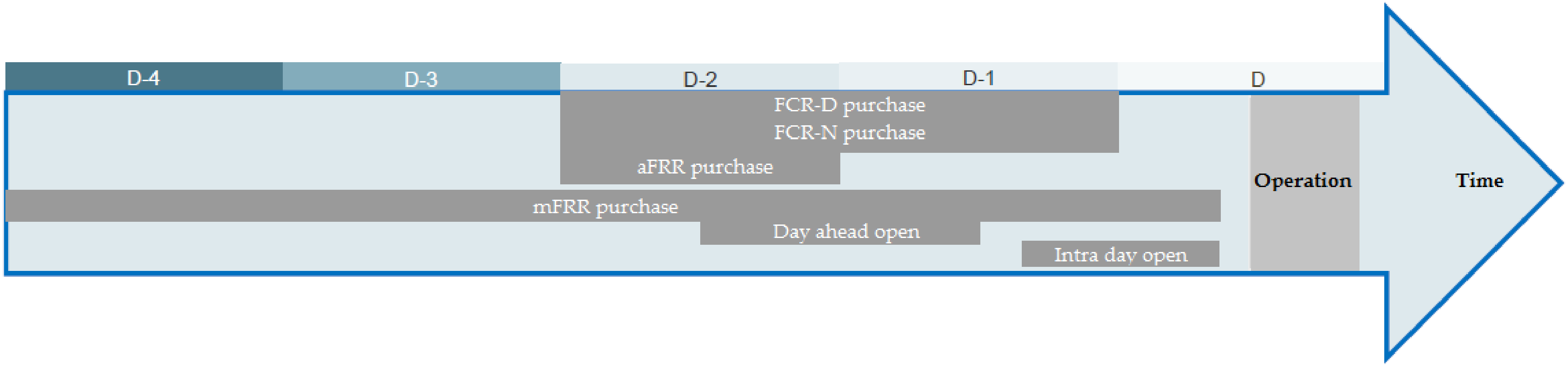


Figure 20: Existing electricity markets and ancillary services in Sweden [79].

The Nordic Imbalance Settlement - eSett

In 2010, Svenska Kraftnät together with the Finnish and Norwegian TSOs, Fingrid and Statnett, agreed to form a joint project in order to harmonise the imbalance settlement model for three of the Nordic Countries. This model is called Nordic Imbalance Settlement (NBS) and took over during spring 2017. The main change is represented by the establishment of a new Imbalance Settlement Responsible (ISR) which is jointly owned by the three TSOs, each of them having an equal share. The new common operational unit, represented by the company eSett Oy, is responsible for performing the imbalance settlement and invoicing the BRPs for balancing services. Anyway, each TSO remains responsible for the national settlement [77].

In other words, each TSO acts as financial counterpart towards the BRPs for all reserve capacity allocation, while eSett is the financial counterpart for all the corresponding activated reserves related to the imbalance settlement.

As previously mentioned, BRPs will therefore need an Imbalance Settlement Agreement with eSett and Balance Agreement with the TSO. BRPs must submit a production plan to the TSO 45 minutes before the delivery hour. This deadline is often referred to as gate closure. The plan must include Elspot, Elbas and bilateral trades as well as Regulation Objects Production Plans referred to the upcoming delivery hour. The TSO will then send this information to eSett. Regarding the reporting between SvK and BRPs, this will be according to the current practice.

In the two balances model shown in Figure 21, generation is handled in one balance, *production imbalance*; and purchases, sales and consumption of electricity in another, *consumption imbalance*. More specifically, the production imbalance is calculated from the metered production per production unit, production plans per regulation object and the sum of activated FCR, FRR and Replacement Reserves (RR). These latter three objects are sometimes referred to as *production imbalance adjustment*.

Regarding the consumption imbalance, it is composed of a BRP's production plan, trades, Metering Grid Area (MGA) imbalance consumption and consumption imbalance adjustment up and down (activated FCR, FRR and RR). MGA imbalance consumption considers retailers' consumption and imports and exports per adjacent areas.

Moreover, the production plan given from the production balance before the gate closure is processed in the consumption balance in the balance settlement procedure. In other words, the production imbalance is the net of metered, planned production and activated ancillary services whereas the consumption imbalance is the net of planned production, trades, area imbalance and metered and profiled consumption [77].

In the NBS, a *two-price system* is applied to the balance deviation in the production balance, and a *one-price system* to the balance deviation in the consumption balance.

In the two-price system (production imbalance), the price of the imbalance power in the production balance sold by the TSO to the BRP is the up-regulating price of the hour. If it is neither an up-regulating nor down-regulating period, the spot price is used as sale price of the imbalance power in production imbalance. The price of the imbalance power in the production balance purchased by eSett from the BRP is the down-regulating price of the hour. If no down-regulation has been carried out or if it is an up-regulating hour, the spot price is used as the purchasing price of the imbalance power in the production balance.

In the one-price system (consumption balance), the purchase and sale prices of imbalance power are the same. During an up-regulating hour, the price of the imbalance power is the up-regulating price, and during a down-regulating hour, the down-regulating price. If no regulations have been carried out, the price of the imbalance is the spot price.

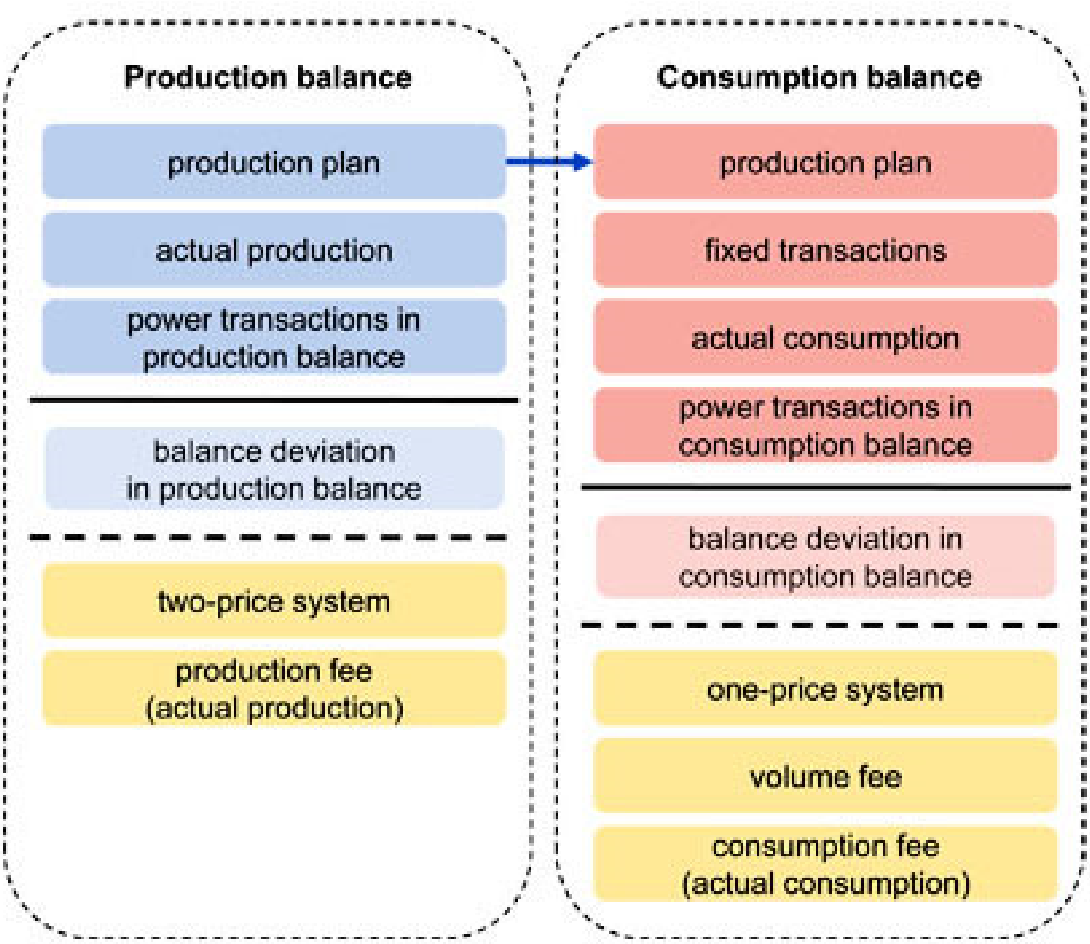


Figure 21: Production and consumption balance composition [78].

4.2 Battery operation and sizing models

The approach to study the integration of BESS with large-scale wind farms in Sweden differs from the one which has been adopted to study the case of large-scale PV plants in India. In particular, as explained in Section 4.1, the Swedish

Electricity market is entirely liberalised, which provides more flexibility for the operation of the battery. The possibility to provide different services brings the opportunity to obtain different revenue streams from different markets.

The aim of this study is therefore, in a first moment, to study the operation of the battery to provide these different services separately and to account the possible revenues generated for each of them. In a second moment the services are stacked together when possible, in order to sum up different revenue streams which a single system can provide. This study is analytically done, by looking into the most suitable time periods to perform each service. As last step, the profitability of such systems is analysed.

For the Swedish case study, wind power generation data from *Fortum*'s Blaiken wind-farm has been used. This plant has a peak capacity of 250 MW and is located in the power area SE2.

The services selected to be studied are the following ones, for which different simulation approaches have been adopted according to their characteristics:

- two days unit commitment in the Nord Pool Elspot market;
- production imbalance compensation; and
- primary frequency regulation, FCR-N.

From the chosen applications, the first two are linked to RES, wind power in this case. Hour-ahead wind forecast and metered production from Blaiken for the whole 2016 have been used for the different simulations.

Besides these three services, the possibilities of performing voltage control by providing reactive power compensation with the battery have been studied. However, as it will be further discussed in Section 4.3, this service is not remunerated. Instead, this is part of the requirements for a wind farm to be able to connect to the grid, and as it is later described, batteries are not the most cost effective technology to provide the service. Thus, reactive power compensation has not been considered for modelling and assessing its profitability.

On the other hand, after interviews and discussions with market experts, it has been decided not to take into account the operation of the battery in the tertiary frequency regulation (mFRR) and intraday (Elbas) markets. The main reason behind the decision is the unpredictability in the price of such products. The profitability in these markets is mainly related to the ability to forecast the prices more than to the opportunities that a new technology such as batteries could provide, and price forecasting is out of the scope of this thesis.

Secondary frequency regulation (aFRR), instead, has not been simulated because of the long-term commitment required when bidding, as explained in Section 4.1. Furthermore, FCR-D prices show to be always significantly lower than the spot prices [80]. For this reason, storing energy produced by the wind farm to then sell it for the FCR-D service shows not to have profitability potential.

4.2.1 Two days unit commitment in the Nord Pool Elspot market

The mathematical formulation of the problem is very similar to the one developed for the unit commitment of the hybrid solar PV and battery storage system described in Subsection 3.2.6. It is then based on Linear Programming (LP) and has been again solved using the `linprog` function available in the MATLAB optimisation toolbox.

The Elspot prices as well as the wind production for the following two days are assumed to be known. Similarly to the Indian case, the battery is charged only with the wind power production and the possibility of purchasing electricity from the power pool has been neglected. It is important to mention that allowing this possibility would not change the concept of operation of the battery: charging a battery using the wind production has an opportunity cost which is equivalent to the possibility of selling that power on the power exchange during the production hour. This cost is therefore equivalent to the one of purchasing the same amount of power from the market. Therefore, using electricity from the grid to charge the battery would be an interesting case only if no power were available from the own production at an instance in which power prices are low. This case would anyway be unlikely, since the considered battery dimensions are significantly small compared to the wind power peak rated capacity.

The main inputs for this optimisation problem are the time series of the hourly wind power generation and the Day-Ahead Elspot prices for two days of four different seasons or periods in a year.

The objective function of the problem, which gives the total revenues of the system from selling the wind production the most optimal way possible, R_{w+BESS}, is formulated as follows:

$$R_{w+BESS} = max \sum_{s=1}^{S} \frac{366}{2 \cdot S} \sum_{t=1}^{T} [P_{s,t}(E_{w,grid_{s,t}} + E_{d_{s,t}})] \tag{51}$$

Subject to the following constraints:

$$E_{w,grid_{s,t}} + E_{c_{s,t}} = E_{w_{s,t}} \tag{52}$$

$$0 \leq E_{d_{s,t}} \leq P_{b,max} \Delta t \tag{53}$$

$$0 \leq E_{c_{s,t}} \leq P_{b,max} \Delta t \tag{54}$$

$$SOC_{min} \cdot E_{BES} \leq E_{b_{s,t}} \leq SOC_{max} \cdot E_{BES} \quad for\ t = 1, ..., 192 \quad s = 1, ..., 4 \tag{55}$$

$$\frac{E_{d_{s,t}}}{\eta} - E_{c_{s,t}} + E_{b_{s,t}} = SOC_{initial} \cdot E_{BES} \quad for\ t = 1 \quad s = 1, ..., 4 \tag{56}$$

$$\frac{E_{d_{s,t}}}{\eta} - E_{c_{s,t}} + E_{b_{s,t}} = E_{b_{s,t-1}} \quad for\ t = 2, ..., 192 \quad s = 1, ..., 4 \tag{57}$$

$$E_{w,grid_{s,t}}, E_{c_{s,t}}, E_{d_{s,t}}, E_{b_{s,t}}, P_{b,max}, E_{BES} \geq 0 \tag{58}$$

Where:

- $P_{s,t}$ = Elspot price at time t, in €/MWh;
- $E_{w,grid_{s,t}}$ = wind generation directly delivered to the grid, which "bypasses" the battery, in MWh;
- $E_{d_{s,t}}$ = energy discharged from the battery at time t, in MWh;
- $E_{c_{s,t}}$ = energy charged to the battery at time t, in MWh;
- $E_{w_{s,t}}$ = wind energy production at time t, in MWh;
- $P_{b,max}$ = maximum charge/discharge power of the battery, in MW;
- E_{BES} = battery energy capacity, in MWh;
- $E_{b_{s,t}}$ = energy content of the battery at time t, in MWh;
- SOC_{min} = minimum SOC of the battery;
- SOC_{max} = maximum SOC of the battery;
- $SOC_{initial}$ = initial SOC of the battery, at $t = 0$.

Four seasons have been chosen as representative for the current simulation. Two representative days of each season's daily price variation and mean value have been chosen. Regarding the wind production, the chosen days represent the average power production and fluctuation within the season. These days were taken from the months of January, May, July and November.

The operation of the battery for this service is shown in Figure 22, where it can be observed that the battery would operate properly, charging during low price periods and discharging during peak hours.

4.2.2 Production imbalance compensation

Two of the main problems that arise with large shares of wind power are the fluctuation of wind generation and its unpredictability or forecast error [81].

Power producers are required to submit their production plans the hour before delivery, which consist of the most accurate wind forecast possible. As previously mentioned, this deadline is referred to as gate closure. There is anyway some uncertainty in this production plan, as real production usually deviates from the latest forecast. The difference between the plan and real production is taken into account in the production imbalance, and is therefore power that will be invoiced at the balancing prices, as described in Subsection 4.1.3.

When modelling the use of the battery for production imbalance compensation, it has been assumed that the production imbalance cannot be forecast. It is indeed extremely complicated to know the balancing prices for the next hour, as well as whether it is going to be an up- or down-regulated hour. As a result, it would not be realistic to choose which imbalances to avoid by optimising the battery operation in order to compensate those imbalances that would result in the highest

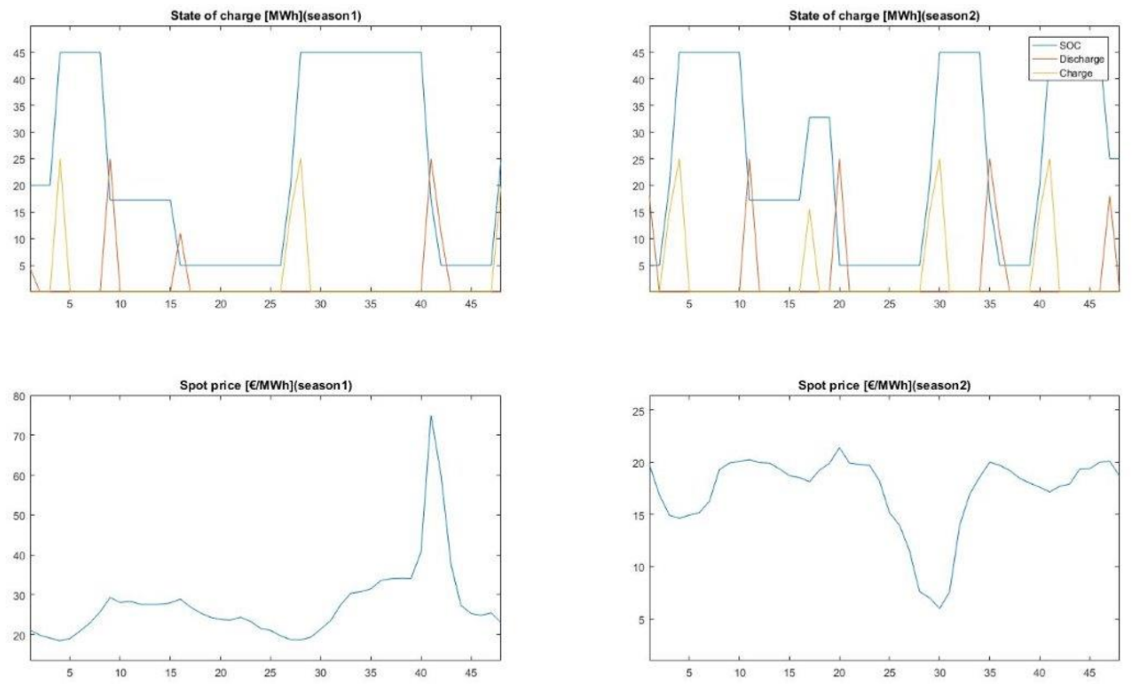


Figure 22: Results of operation of a 25MW/50MWh battery on Elspot market.

cost and give the possibility to store energy for compensation of some selected power deviations later on. This way, the developed operation algorithm never looks into future power imbalance or price estimates.

The aim of the model is thus to compensate the imbalance during each hour when possible. This can be done for all the instances in which there is enough energy stored or capability to charge the battery as well as the necessary power capacity. When the imbalance exceeds the energy or power capacity of the battery, this is partially compensated with the maximum power that can be charged or discharged.

The control strategy that determines the energy charged or discharged into/from the battery each hour is represented in the flow chart shown in Appendix B.

Afterwards, the energy balance of the battery, the number of cycles it runs, the final production imbalance and the total system imbalance costs are calculated using the following equations:

$$E_{b,t} = E_{b,t-1} + E_{c,t} - \frac{E_{d,t}}{\eta} \tag{59}$$

$$E_{imb,t} = E_{real,t} - E_{plan,t} + E_{d,t} - E_{c,t} \tag{60}$$

$$C_t = \begin{cases} (P_{spot,t} - P_{sale,t} + C_{fee,s})E_{imb,t}, & E_{imb,t} > 0 \\ (P_{purch,t} + C_{fee,p})(-E_{imb,t}), & E_{imb,t} \leq 0 \end{cases} \tag{61}$$

$$Cost_{imb,w+BESS} = \sum_{t=0}^{T} C_t \tag{62}$$

Where:

- $E_{c,t}$ = energy charged to the battery, in MWh;
- $E_{d,t}$ = energy discharged from the battery, in MWh;
- $E_{b,t}$ = energy content of the battery at time t, in MWh;
- $E_{imb,t}$ = energy imbalance between the submitted wind production plan and the dispatched energy to the grid, in MWh;
- $E_{real,t}$ = metered, real wind production at time t, in MWh;
- $E_{plan,t}$ = submitted wind production plan one hour ahead of production, in MWh;
- C_t = cost of the imbalance at time t, in €/MWh;
- $P_{spot,t}$ = spot price of electricity for hour t, in €/MWh;
- $P_{sale,t}$ = down-regulation price of electricity if there is down-regulation in the system or the spot price when there is up-regulation, in €/MWh;
- $P_{purch,t}$ = up-regulation price of electricity if there is up-regulation in the system or the spot price when there is down-regulation, in €/MWh;
- $C_{fee,s}$ = fee SvK charges for selling electricity due to an imbalance, in €/MWh;
- $C_{fee,p}$ = fee SvK charges for purchasing electricity due to an imbalance, in €/MWh.

The normalised values of the initial wind power production imbalance and the residual imbalance after the battery operation for one week can be seen in Figure 23. The charge and discharge power to or from the battery are shown in the lower graph of Figure 23 as well. As it can be observed, the battery delivers power to the grid when the wind generation forecast is greater than the actual one, trying to reduce the imbalance. On the other hand, when the forecast power is lower than the real-time production, the battery stores energy through charging.

As it can be observed, the simulated battery capacity (25 MW/50 MWh) is not enough to fully compensate the production imbalance. The battery size is still very small compared to Blaiken's capacity (250 MW), but it helps reducing the imbalance costs, as it is shown in Section 4.4.

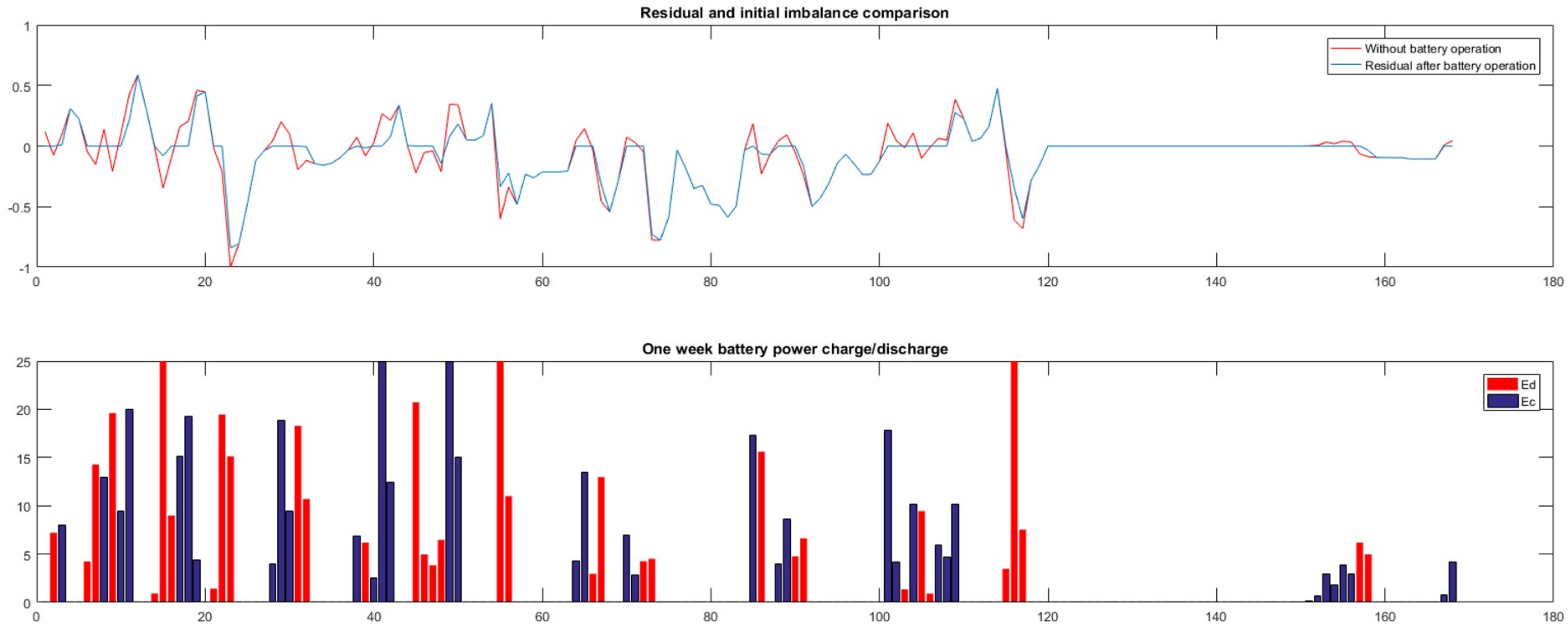


Figure 23: Operation of a 25 MW/50 MWh battery for production imbalance compensation.

4.2.3 Primary frequency regulation, FCR-N

Primary frequency regulation has been identified as service with high value for BESS by several authors [13, 36, 82, 83]. In order to estimate the potential revenues from providing this service a deterministic linear program (LP) has been developed, which as the previous LP problems, has also been solved using the `linprog` function part of MATLAB optimisation toolbox.

Estimates of the hourly average FCR-N prices for Sweden, in €/MW, and the share of activated capacity, represented by the variables $\lambda_{c,t}$ and $\lambda_{d,t}$, for the next two days are inputted into the model. $\lambda_{c,t}$ represents the share of the activated down-regulating capacity from the bidden capacity accepted by SvK. Likewise, $\lambda_{d,t}$ represents the share of the activated up-regulating capacity from the bidden capacity. This last one, the bidden capacity (and accepted) in each hour, is represented by the variable ρ_t.

The model has the objective of maximising the revenues obtained from providing primary frequency regulation, subject to the battery's power and energy constraints. The mathematical formulation of the objective function is the following:

$$\max \sum_{t=0}^{T} P_{FCRN,t} \cdot \rho_t \tag{63}$$

Subject to the following constraints:

$$E_{c,t} = \rho_t \cdot \lambda_{c,t} \cdot \Delta t \tag{64}$$

$$E_{d,t} = \rho_t \cdot \lambda_{d,t} \cdot \Delta t \tag{65}$$

$$E_{b,t} = E_{b,0} + E_{c,t} - \frac{E_{d,t}}{\eta} \quad for\ t = 1 \tag{66}$$

$$E_{b,t} = E_{b,t-1} + E_{c,t} - \frac{E_{d,t}}{\eta} \quad for\ t = 2, ..., T \tag{67}$$

$$SOC_{min} \cdot E_{BES} \leq E_{b,t} \leq SOC_{max} \cdot E_{BES} \tag{68}$$

$$\rho_t \leq P_{b,max} \tag{69}$$

Where:

- $P_{FCRN,t}$ = average FCR-N price in Sweden at time t, in €/MW;
- ρ_t = battery capacity bidden for primary frequency regulation, in MW;
- $E_{c,t}$ = energy charged to the battery, which is the activated down-regulating power during the time-period of study, in MWh;
- $E_{d,t}$ = energy discharged from the battery, which is the activated up-regulating power during the time-period of study, in MWh;
- $E_{b,t}$ = energy content of the battery at time t, in MWh;

- $E_{b,0}$ = initial energy content of the battery, in MWh;
- $\lambda_{c,t}$ = ratio between the activated down-regulating capacity and the bidden capacity, which is zero when it is not a down-regulated moment;
- $\lambda_{d,t}$ = ratio between the activated up-regulating capacity and the bidden capacity, which is zero when it is not an up-regulated moment;
- Δt = time period of study, one hour in our simulation;
- η = round-trip efficiency of the battery;
- SOC_{min} = minimum SOC of the battery;
- SOC_{max} = maximum SOC of the battery;
- E_{BES} = energy capacity of the battery, in MWh;
- $P_{b,max}$ = maximum power capacity, in MW.

Two days which are representative of the average prices during each season have been chosen for the model. The bidden capacity and the hourly activated up- and down-regulation power for these days, given by the energy charged to or discharged from a 2 MW/1 MWh, are shown in Figure 24.

As it can be observed, the bidden capacity is usually considerably higher than the activated one. This seems to be the general case for the historic data of 2016.

Since the activation of primary frequency regulation is automatic and related to the grid frequency, it results extremely hard to predict when and in which quantity the battery will be required to provide or absorb power from the grid. As consequence, it has been decided to consider the uncertainty in this process and address it as a *stochastic* linear optimisation problem.

For this modelling technique, a big number of different hourly battery activation scenarios for a 24 hours time-frame and their probabilities need to be taken into account. This has been done using the scenario generation and selection algorithms described next.

As output from these two algorithms, 25 different hourly battery activation scenarios for FCR-N service and their corresponding probabilities have been obtained, which have been used as input for the stochastic model in order to obtain the optimal FCR-N service bidding strategy for next day (D-1), represented by the time-dependent variable ρ_t in the mathematical formulation.

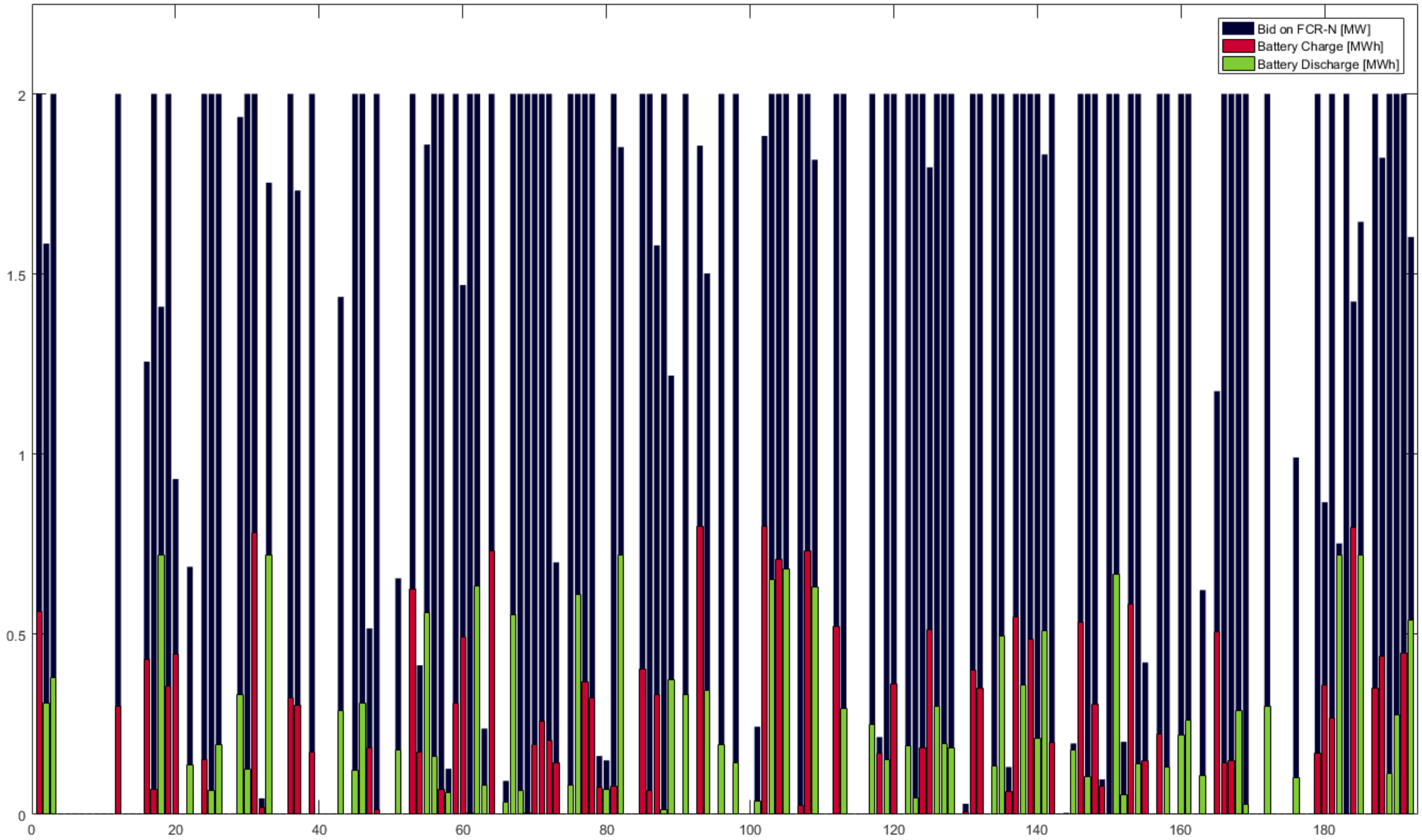


Figure 24: Primary frequency regulation bidden capacity and battery activation for a 2 MW/1 MWh battery in one week.

The model has the objective of maximising the revenues obtained from providing primary frequency regulation, subject to the battery's power and energy constraints, assuming that the energy bidden which is not provided is penalised and considering the payment for the energy charged and discharged as additional cost or revenue, respectively. The mathematical formulation of the objective function and model constraints is the following:

$$\begin{aligned} \max \sum_{t=1}^{24} \rho_t \cdot P_t + \sum_{\omega} \pi_\omega [E_{d_{\omega,t}} \cdot P_{up,t} - E_{c_{\omega,t}} \cdot P_{down,t} \\ - \sum_{t=1}^{24} (C_{c_t} \cdot M_{c_{\omega,t}} \cdot \lambda_{c_{\omega,t}} + C_{d_t} \cdot M_{d_{\omega,t}} \cdot \lambda_{d_{\omega,t}})] \end{aligned} \tag{70}$$

Subject to the following constraints:

$$\rho_t \cdot \lambda_{c_{\omega,t}} \cdot \Delta t - (E_{b,max} - E_{b_{\omega,t-1}}) - M_{c_{\omega,t}} \cdot \lambda_{c_{\omega,t}} \leq 0 \quad for\ t = 1, ..., 24 \tag{71}$$

$$\rho_t \cdot \lambda_{d_{\omega,t}} \cdot \Delta t - (E_{b_{\omega,t-1}} - E_{b,min})\eta - M_{d_{\omega,t}} \cdot \lambda_{d_{\omega,t}} \leq 0 \quad for\ t = 1, ..., 24 \tag{72}$$

$$E_{d_{\omega,t}} = \frac{\rho_t \cdot \lambda_{d_{\omega,t}} \cdot \Delta t}{\eta} - M_{d_{\omega,t}} \cdot \lambda_{d_{\omega,t}} \tag{73}$$

$$E_{c_{\omega,t}} = \rho_t \cdot \lambda_{c_{\omega,t}} \cdot \Delta t - M_{c_{\omega,t}} \cdot \lambda_{c_{\omega,t}} \tag{74}$$

$$E_{b_{\omega,t}} = E_{b_{\omega,t-1}} + E_{c_{\omega,t}} - E_{d_{\omega,t}} \quad for\ t = 1, .., 24 \tag{75}$$

$$E_{b,min} \leq E_{b_{\omega,t}} \leq E_{b,max} \tag{76}$$

$$0 \leq \rho_t \leq P_{b,max} \tag{77}$$

Where:

- ω = the different scenarios being considered;
- t = a given hour;
- ρ_t = capacity bidden for FCR-N service for each hour, in MW;
- P_t = average FCR-N price in Sweden for each hour, in €/MW;
- $P_{up,t}$ = up-regulating price in hour t, in €/MWh;
- $P_{down,t}$ = down-regulating price in hour t, in €/MWh;
- π_ω = probability associated to each scenario;
- C_{c_t} = penalty for not being able to provide down-regulation (charge the battery), in €/MWh;
- C_{d_t} = penalty for not being able to provide up-regulation (discharge the battery), in €/MWh;

- $E_{d_{\omega,t}}$ = energy discharged from the battery, which is the activated up-regulating power during the time-period of study, in MWh;
- $E_{c_{\omega,t}}$ = energy charged to the battery, which is the activated down-regulating power during the time-period of study, in MWh;
- $\lambda_{c_{\omega,t}}$ = ratio of the amount of capacity activated for down-regulation compared to the bidden capacity;
- $\lambda_{d_{\omega,t}}$ = ratio of the amount of capacity activated for up-regulation compared to the bidden capacity;
- $M_{c_{\omega,t}} \cdot \lambda_{c_{\omega,t}}$ = amount of energy not able to charge to the battery and thus not satisfied, in MWh;
- $M_{d_{\omega,t}} \cdot \lambda_{d_{\omega,t}}$ = amount of energy not able to discharge from the battery and thus not satisfied, in MWh;
- $E_{b_{\omega,t}}$ = energy content of the battery at time t, in MWh;
- Δt = time period of study, one hour in our simulation;
- η = round-trip efficiency of the battery;
- $E_{b,min}$ = minimum energy content of the battery;
- $E_{b,max}$ = maximum energy content of the battery;
- $P_{b,max}$ = maximum power capacity, in MW;

Battery activation scenario generation using ARIMA models
Starting from a historical data time-series, a path-based method has been used to generate a large enough number of complete scenarios, as suggested by [84]. In this case, the scenarios have been generated using an Autoregressive Integrated Moving Average (ARIMA) model. Subsequently, a scenario-reduction technique using the Kantorovich distance between probability distributions has been applied in order to select a smaller number of representative scenarios.

ARIMA models are defined by three parameters: p, d, q. These terms represent the number of autoregressive terms, the differencing order and the number of moving average terms [84]. The general mathematical expression for an ARIMA model is the following:

$$(1 - \sum_{j=1}^{p} \phi_j B^j)(1 - B)^d y_t = (1 - \sum_{j=1}^{q} \theta_j B^j)\varepsilon_t \tag{78}$$

The theoretical treatment of the argument is beyond the scope of this work. Therefore, for the interested reader the work by Shumway and Stoffer [85] is recommended.

For stationary time-series, such as the activation of the bidden FCR-N capacity, the ARIMA model can be reduced to an Autoregressive Moving Average model, ARMA [84]. This is mathematically formulated as:

$$y_t = c + \sum_{j=1}^{p} \phi_j \cdot y_{t-j} + \varepsilon_t - \sum_{j=1}^{q} \theta_j \cdot \varepsilon_{t-j} \tag{79}$$

With p autoregressive parameters $\phi_1, \phi_2 ... \phi_p$ and q moving average parameters $\theta_1, \theta_2 ... \theta_q$. The term ε_t represents an uncorrelated normal stochastic process with mean 0 and variance ${\sigma_\varepsilon}^2$. It is referred to as white noise, innovation term or error term. c is the intercept or mean value [84].

In order to obtain the order of the ARMA model, the Autocorrelation Function (ACF) and Partial Autocorrelation Function (PACF) of the historic data of hourly FCR-N activation have been computed using R software. These show the autocorrelation and partial autocorrelation between time-steps, and help determining the number of autoregressive terms and moving average terms required.

Afterwards, the time-series has been fit into an ARMA (2,2) model using the `arima` function in R. This way, the values of the parameters have been obtained and they are shown in Table 15.

Table 15: ARMA (2,2) model parameters.

ϕ_1	ϕ_2	θ_1	θ_2	c	${\sigma_\varepsilon}^2$
0.9704	-0.0268	-0.6310	-0.3422	-0.0019	0.1028

Thus, we obtain and ARMA (2,2) model, which can be expressed as:

$$y_t = c + \phi_1 \cdot y_{t-1} + \phi_2 \cdot y_{t-2} + \varepsilon_t - \theta_1 \cdot \varepsilon_{t-1} - \theta_2 \cdot \varepsilon_{t-2} \tag{80}$$

Once the ARMA model parameters have been obtained, the scenario generation algorithm proposed by [84] has been applied. This procedure is based on a sample of random error terms. The errors are assumed to be normally distributed, with mean zero and standard deviation value obtained from the time-series data. The algorithm has the following seven steps:

- Step 1: Scenario counter initialisation. $\omega = 0$.
- Step 2: Update scenario counter and initialise the time period counter. $\omega = \omega + 1,\ t = 0$.
- Step 3: Update the time period counter. $t = t + 1$.
- Step 4: Random generation of the error term ε_t.
- Step 5: Evaluate the ARMA (2,2) model expression to obtain $y_{t,\omega}$.
- Step 6: If $t < N_T$ go to Step 3, else go to Step 7.
- Step 7: If $\omega < N_\Omega$ go to Step 2, else end of the scenario generation algorithm.

N_T is the time period of study and N_Ω the number of scenarios that want to be obtained. In our case, the first is 24 and the second 200, as we want to generate 200 scenarios of hourly battery activation in a day.

Given that the computational burden and time of a stochastic model rapidly increases with the number of scenarios, a mathematical tool that reduces that number is necessary. In this context, scenario-reduction methodologies aim to downsize the set of scenarios while keeping all or most of the stochastic information in it.

A *fast-forward* scenario-reduction algorithm based on the probability distance has been adopted. The used measure is the Kantorovich distance, which is the most common probability distance considered in stochastic programming, as suggested by Conejo et al. [84].

Instead of eliminating scenarios, a forward-selection algorithm which reduces the set of scenarios by selecting a number of scenarios from the initial set has been applied. For more detail on this scenario-reduction technique, for the interested reader the works by Conejo et al. [84] and Dupacová et al. [86] are recommended.

As output from this fast-forward selection algorithm, 25 different hourly battery activation scenarios for FCR-N service and their corresponding probabilities have been obtained. These are input into the stochastic model in order to obtain the optimal FCR-N service bidding strategy for next day. For the simulation, a penalty

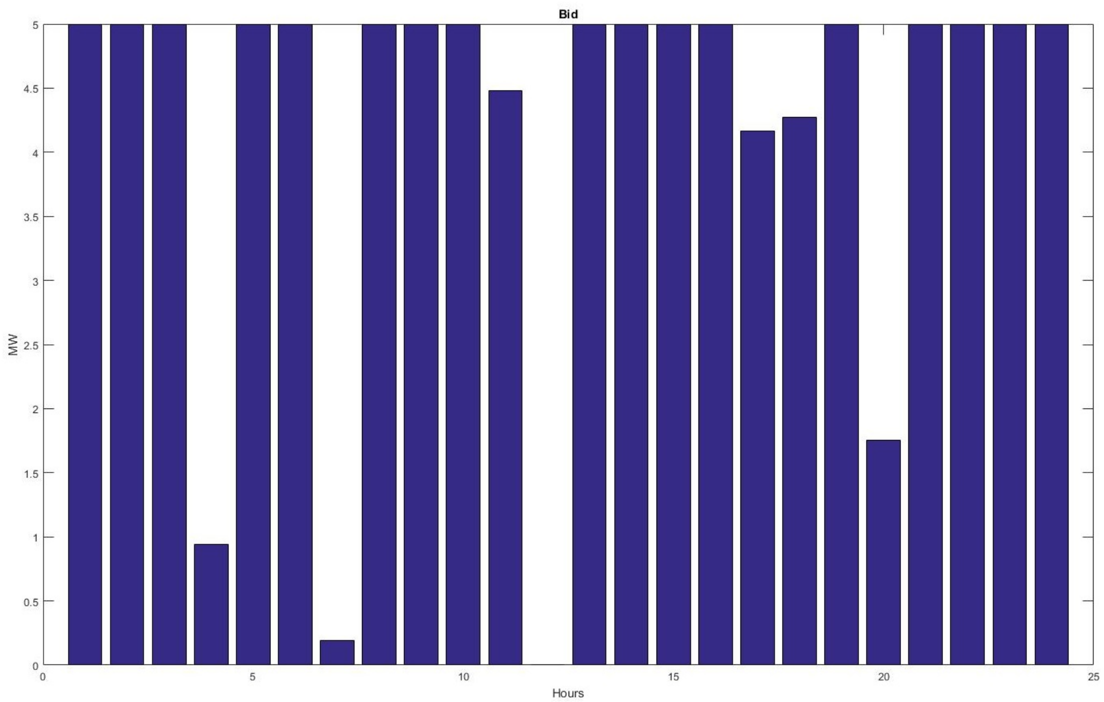


Figure 25: Example of D-1 bidding result of the FCR-N stochastic simulation for a 5 MW/ 2.5 MWh battery.

for failing to provide the bidden capacity of twice the hourly average FCR-N price has been applied. Anyway, this value is an approximation to the real cost, since in Sweden the penalty cost for not providing FCR-N is not proportional to the

FCR-N prices of the hour. Instead, the price to be paid is the one asked by the owner of the replacement source requested to be activated to provide the failed capacity. As this price results extremely hard to predict, and thus model, a penalty function of the hourly price and representative of a higher cost than the obtained FCR-N service payment has been assumed.

From another point of view, this penalty could also represent the opportunity cost of backing-up the provision of the service with another power generation unit. For instance, in case a power generator owned another plant (e.g. a hydropower unit) in the same bidding area which could supply primary frequency regulation instead of the battery, the generator would not receive the penalty. This would nevertheless represent a cost if the other unit was not optimised to provide such service, and therefore operated at a larger marginal cost. This cost could be represented by the just mentioned penalty. The impact of different penalty values is assessed later in Section 4.4.

The hourly bidden capacity for FCR-N service of a given day is shown in Figure 25. Moreover, the operation of a 5 MW/2.5 MWh battery based on the previous FCR-N bid in one of the 25 possible scenarios simulated can be seen in Figure 26.

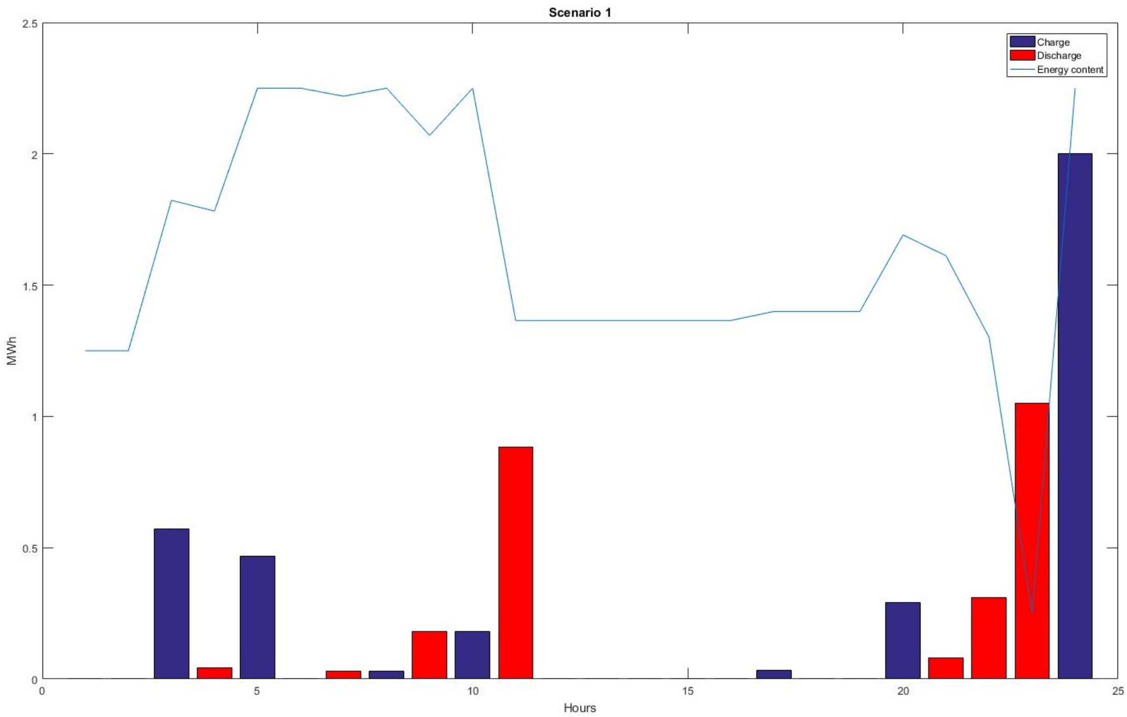


Figure 26: Example of the operation of a 5 MW/2.5 MWh battery in a possible scenario.

4.3 Other possible services for battery energy storage systems with wind power in Sweden

As described in Section 2.2.5, there are some additional applications Li-ion batteries could provide when installed together with utility-scale power generation, which are reactive power and voltage control, power output smoothing and peak shaving. However, these services have not been modelled, due to the fact that there is no market for them. The technical description, requirements regarding those services and their benefits are explained in the following subsections.

Voltage control and reactive power compensation

Voltage stability is a relevant grid performance parameter whose upper and lower boundaries are usually set by grid requirements for power generators and can be controlled through reactive power compensation. Voltage stability is an important aspect to ensure that there is enough power in the system to meet the load demand [87]. Voltage instability is related to the lack of reactive power resources in the system, as consumption of reactive power from high impedance loads or lines causes the voltage to decrease if not additionally provided or compensated. Thus, providing reactive power to the system can keep the voltage level stable [87].

Larger shares of wind power in many countries have made voltage or load stability even more relevant. This is in part related to the reactive power consumption of some types of wind turbines. Besides, grid codes establish requirements for power generators regarding power controllability, power quality and low-voltage ride-through-capability[8], such as voltage sag[9], and require wind farms to be capable of providing both active and reactive power.

The reactive power capability, which refers to the instantaneous reactive power capacity the turbine can absorb or deliver to the grid, is greatly related to the type of wind generator. A detailed explanation of the relation between wind turbine generators and reactive power capability is presented in Appendix A. Moreover, the different technology options and system configurations for providing such service are also described in Appendix A.

Power output smoothing

Similar to the solar resource, as explained in Subsection 3.2.4, wind speed is a highly stochastic component which can have very fast and big deviations. These deviations in wind speed generate output power fluctuations, which are larger in scale due to the fact that wind power is proportional to the cube of wind speed [89].

Wind power fluctuations can have several negative impacts on the grid. One of the main effects is grid frequency fluctuation, which results in grid instability and

[8]Ride-through-capability refers to the ability of generators to stay connected in short periods of lower electric network voltage.

[9]Voltage sags or dips are brief reductions in voltage caused by abrupt increases in loads or source impedance, typically lasting from milliseconds to a second or so [88].

higher ancillary services requirements. Moreover, the deviation in wind speed causes the fluctuation of the active power generation and thus the reactive power, leading to voltage flicker (previously described in Subsection 3.2.4) at the buses of the power grid. These two phenomena lead to poor power quality and can create instability problems in the power system, especially when there are loads sensitive to high voltage and frequency variations [89, 90].

Power output smoothing refers to the partial compensation of these power fluctuations, which smooths the output power delivered to the grid. Batteries could be used for providing this service, by dispatching power when there is a sudden drop in the generation and vice versa, by charging when production ramps up unexpectedly. The battery operation would be similar to the one simulated for the power output smoothing service in the case of India, described in Subsection 3.2.4. However, this service is not remunerated in the Swedish power market and thus has not been studied in this work.

Peak shaving

As described in Subsection 2.2.5, peak shaving refers to the possibility of connecting to a maximum transmission power lower than the peak power of the wind farm. Batteries could be used for this application, as they could store the energy exceeding the power to which the plant is subscribed and dispatch it when the generation is under the connection capacity. Starting from the grid connection fees applied by SvK [91] shown in Table 16, an estimation of the cost savings has been developed. It is necessary to mention that these fees are strictly dependent on the location of the station of connection, in particular the energy fee[10]. Anyway, a sensitivity analysis performed has shown that the variation of these fees among nodes does not significantly affect the result presented.

Table 16: High voltage connection fees applied by Svenska Kraftnät for prower production and consumption at *Blaiken* node [91].

	Feeding	Withdrawal
Connection fee	4.59 €/kW-yr	5.61 €/kW-yr
Exceeding penalty (up to 3h)	0.92 c€/kWh	1.12 c€/kWh
Exceeding penalty (more than 3h)	9.18 c€/kWh	11.22 c€/kWh
Energy fee	-1.12 €/MWh	1.12 €/MWh

A model similar to the one developed for the case of demand following with curtailment possibility presented in Section 3.2.3 has been developed in order to quantify the savings associated to the use of battery for peak shaving and, at the same time, its required size. In addition, the losses associated to an alternative curtailment have been computed for comparison purposes. These latter values have been computed as opportunity cost of not selling the produced power in

[10]For the studied node, the energy fee is a credit when energy is fed into the grid (negative fee) and payment when energy is withdrawn (positive fee). This value differs significantly from node to node, changing also in sign.

each hour at the spot price, taking the previously mentioned negative fee also into account. For the same purpose, the costs of exceeding a contracted lower production have been calculated as well. As it can be seen in Table 16, the penalty is energy-related and has a ten-fold increase whether the contracted capacity is exceeded for a time-frame equal or longer than three hours.

The battery investment has been calculated based on the same costs presented in Table 22, and annualised as previously described in Section 3.2.6 in order to obtain a comparable value as first approximation to the annual savings.

4.4 Results and economic assessment

To assess the economic interest of the services modelled, the potential revenues from each of them are calculated first. This allows to see which services are more interesting from an economic point of view, and whether the profitability of the battery to provide a chosen service could be increased by stacking together another service which provides higher revenues.

The annual revenues added by the BESS for the two days commitment model in Nord Pool Elspot, production imbalance compensation and primary frequency regulation (considering the stochasticity in the battery activation) with different size and rating batteries are shown in Tables 17, 18 and 19.

Whereas the FCR-N model gives the potential revenues that can be obtained with the battery, the other two models have the total hybrid system revenues as output.

Therefore, the annual revenues due to the BESS from the power arbitrage service are the difference between the result obtained from the optimisation function, which gives the annual revenues of a hybrid wind power and battery system as output, and the revenues that would be obtained by selling the wind generation in the instance when it is produced, as represented in Formula 81. This way, the added revenues due to the use of the battery for energy arbitrage are taken into account for the further economic assessment.

Similarly, the production imbalance costs savings with a Li-ion battery are the difference between the production imbalance costs the wind-farm owner would have incurred in without any battery, $Cost_{imb,w}$, and the residual production imbalance costs calculated by the control algorithm, $Cost_{imb,w+BESS}$. This way, the value added of the battery for each of the services of interest can be studied. The production imbalance costs of the wind-farm owner have been calculated by analysing historic power generation data. Thus, the savings potential are specific to the analysed plant and time-period. Therefore, the exact revenue streams and profitability of the service value are not presented due to confidentiality, and are given in a range.

$$R_{arb} = R_{w+BESS} - \sum_{s=1}^{S} \frac{366}{2 \cdot S} \sum_{t=1}^{T} E_{w_{s,t}} P_{s,t} \tag{81}$$

$$R_{imb} = Cost_{imb,w} - Cost_{imb,w+BESS} \tag{82}$$

Table 17: Annual revenue streams potential for 0.5 C rating batteries.

	2.5 MW/5 MWh	10 MW/20 MWh	25 MW/50 MWh
Arbitrage	17 000 €	66 000 €	164 000 €
Imbalance comp.	100k - 150k €	350k - 400k €	650k - 700k €
FCR-N	331 000 €	1 327 000 €	3 298 000 €

Table 18: Annual revenue streams potential for 1 C rating batteries.

	2.5 MW/2.5 MWh	10 MW/10 MWh	25 MW/25 MWh
Arbitrage	9 000 €	36 000 €	89 000 €
Imbalance comp.	50k - 100k €	200k - 250k €	400k - 450k €
FCR-N	277 000 €	1 155 000 €	2 924 000 €

Table 19: Annual revenue streams potential for 2 C rating batteries.

	5 MW/2.5 MWh	20 MW/10 MWh	50 MW/25 MWh
Arbitrage	9 000 €	36 000 €	89 000 €
Imbalance comp.	50k - 100k €	200k - 250k €	400k - 450k €
FCR-N	519 000 €	2 131 000 €	5 236 000 €

As it can be observed, primary frequency regulation is the service which would provide highest potential revenues, for all the different battery ratings considered. Furthermore, increasing the power rating from 1 C to 2 C does not increase the revenue obtained from price arbitrage and imbalance compensation, as both are energy services. For primary frequency regulation, instead, increasing the battery rating from 1 C to 2 C provides higher potential revenues.

It is important to highlight the impact larger penalty values than the one considered, which is twice the average FCR-N price of the hour as mentioned in Subsection 4.2.3, can have in the revenues obtained from FCR-N service. Penalty costs equal and larger than five times the hourly FCR-N price would reduce considerably the bidden capacity for the service and thus smaller revenues would be obtained.

Regarding peak shaving, the results shown in Table 20 clearly show that there is no possibility to have a return on the investment in a battery for such purpose since the annual savings are three orders of magnitude smaller than the battery investment annuity.

On the other hand, the opportunity to curtail the peak power produced by the wind farm in order to subscribe for a lower connection seems to be interesting until a 7 MW reduction. In the same way, the penalty for exceeding by 1 MW the contracted capacity would be lower than the savings on the connection fee. Further analyses on this are anyway out of the scope of this work since they do not involve the use of a battery storage system but on contrary represent alternatives to its installation.

Table 20: Peak shaving model results.

Connection reduction [MW]	Battery size [MWh]	Investment annuity	Annual savings	Cost of curtailment	Costs of exceeding
1	1.21	101 595 €	459 €	147 €	438 €
2	3.95	285 072 €	918 €	455 €	2 859 €
3	6.65	466 307 €	1 378 €	828 €	5 682 €
4	10.51	713 505 €	1 837 €	1 208 €	8 529 €
5	17.83	1 156 130 €	2 296 €	1 658 €	18 060 €
6	25.13	1 597 889 €	2 755 €	2 300 €	24 551 €
7	32.43	2 039 648 €	3 214 €	3 124 €	34 640 €

Moreover, in order to be effective, the battery should be committed to peak shaving as first service in every moment, to prevent the power output to exceed the contracted capacity. This would make very challenging the stacking of peak shaving with others services which include a bid on the electricity market, due to the intermittency of the power generation and thus uncertainty in the need of peak shaving. This combination is therefore disregarded from here on and the peak shaving service has not been considered in the profitability and sensitivity studies presented next.

Being the main focus of our work the study of the benefits the integration of batteries with IRES can provide, the imbalance compensation service cannot be disregarded. As the cost savings obtained may not be high enough to pay the battery investment back, especially with the current technology costs, which are shown in Table 22, the possibility to stack primary frequency regulation (FCR-N) and production imbalance compensation together is studied. This way, the annual revenues obtained with a single battery used for compensating the production imbalance for some hours could be increased, which could help make the battery investment profitable.

In order to study how to stack both services together, an analytic study of their prices/costs within a day is performed. This way, night hours have been identified to be the most remunerative ones for FCR-N, service which has lower prices during the rest of the day hours. Regarding the imbalance compensation savings, these do not show any daily trend and high and low costs are alternate. Hourly FCR-N and up-regulating prices for two days of every season are shown in Figure 27. The up-regulating prices represent the imbalance costs when there is a negative imbalance during an up-regulated hour, and therefore more balancing costs are expected to be generated when up-regulation prices are higher.

The period from 22:00 to 06:00 is the one with highest primary regulation prices for all the seasons. Thus, those are the most profitable hours for the service and have been selected to represent the time period in which the battery would be used for FCR-N. During the rest of the hours the battery would operate to compensate the production imbalance of the wind farm to which it is connected.

The annual revenue streams that could be obtained from providing both services are shown in Table 21, in which the total annual revenue and the remunera-

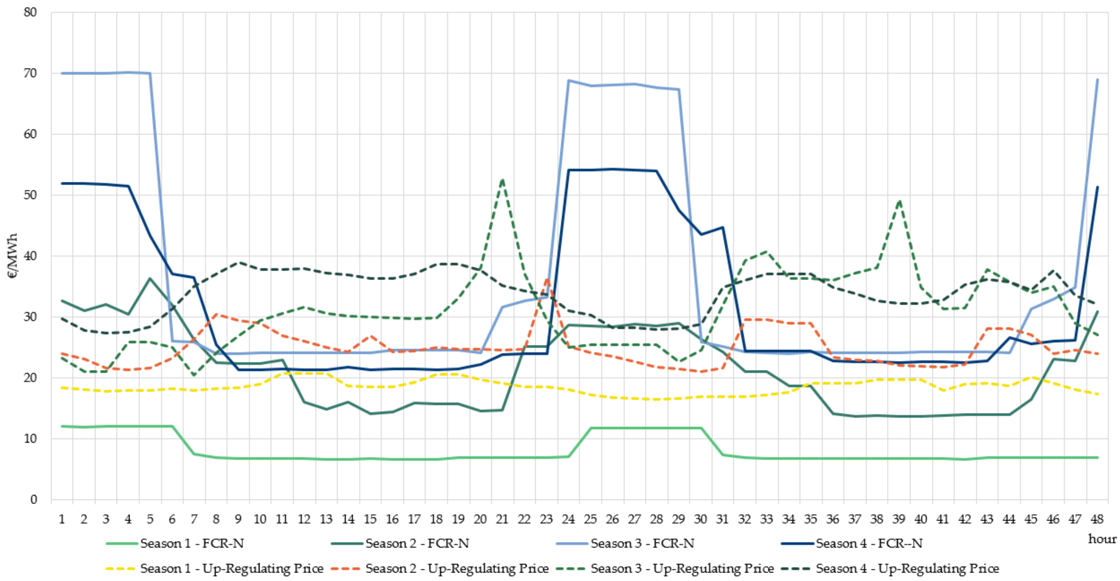


Figure 27: FCR-N hourly prices [80].

tion obtained from each service are shown.

Table 21: Annual revenue streams potential for the stacked services.

	2.5 MW/5 MWh	10 MW/20 MWh	25 MW/50 MWh
0.5 C batteries	250k - 300k €	1 150k - 1 200k €	2 900k - 2 950k €
1 C batteries	250k - 300k €	1 000k - 1 050k €	2 450k - 2 500k €
2 C batteries	400k - 450k €	1 600k - 1 650k €	3 950k - 4 000k €

In Figure 28 the annual revenue streams for all the studied services are represented, where it is possible to appreciate the magnitude of difference between each of them. The precise values on y axis have not been shown due to data confidentiality reasons. The nine different batteries simulated have been included, which have small, medium or large sizes with 0.5 C, 1 C or 2 C ratings. As it can be seen, FCR-N is the service which provides highest revenues. The revenue loss due to the battery activation uncertainty for primary frequency regulation can also be appreciated, as the difference between the FCR-N and FCR-N Stochastic columns. Furthermore, a general increase in the revenues can be observed for larger battery sizes, as well as for higher C rating values.

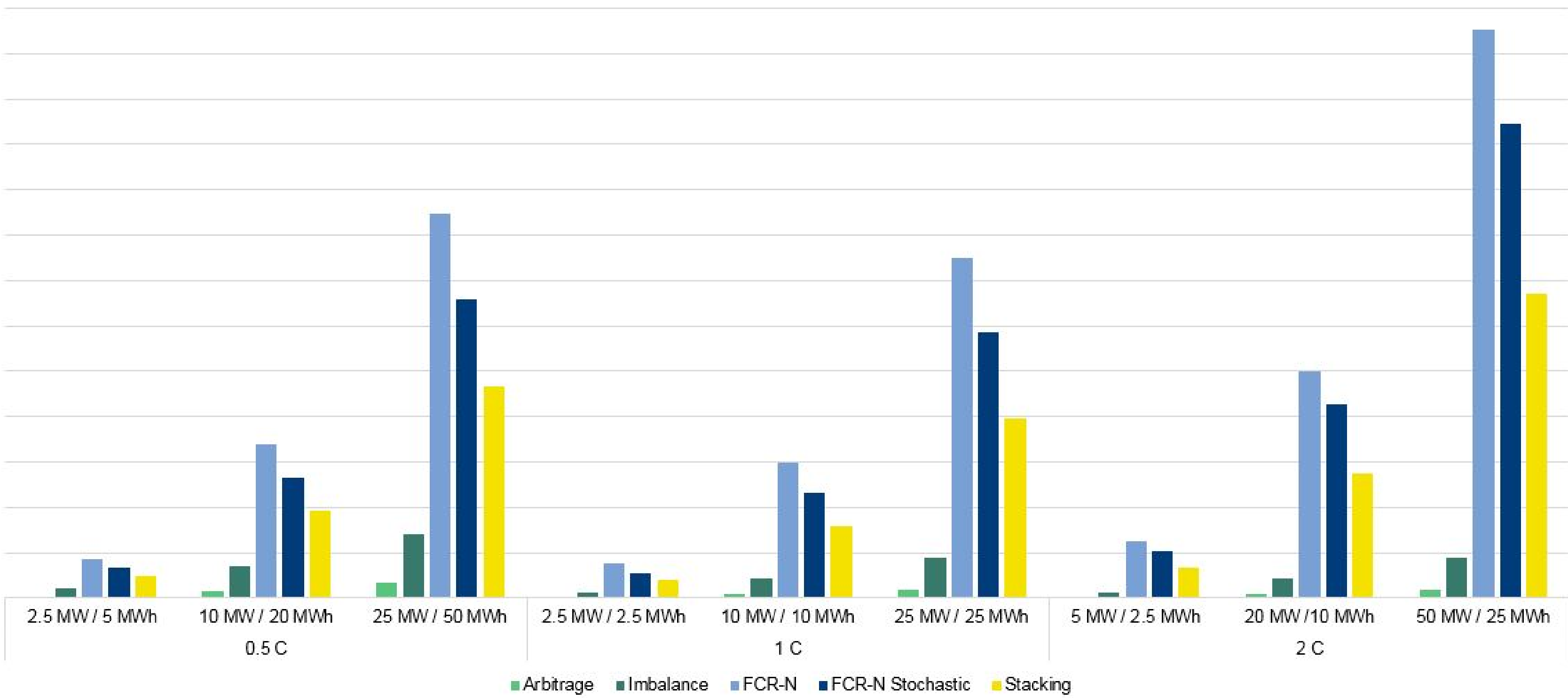


Figure 28: Normalised annual revenue streams potential for the different applications.

To assess the profitability of all the battery sizes for the different services studied, a cycle life of 7 000 cycles (operating within a minimum 10% and maximum 90% SOC) [27] and a 90% battery round-trip efficiency [61] have been considered. Regarding the technology and project investment costs, these are collected in Table 22. Moreover, a 22% corporate tax and 7% WACC have been considered.

Table 22: BESS CAPEX and OPEX in Sweden [61].

CAPEX		
Batteries	600 000	€/MWh
Inverters and power electronics	200 000	€/MW
OPEX		
O&M	10 000	€

The battery lifetime for each of the services has also been calculated. This has been obtained as the ratio between the cycle life and the annual number of cycles the battery runs to provide each service. The latter, the annual number of cycles of the battery for the different services are shown in Table 23.

Table 23: Number of annual cycles of the batteries.

	Arbitrage	Imbalance compensation	FCR-N	Stacked services
0.5 C rating				
2.5 MW/5 MWh	392	813	286	593
10 MW/20 MWh	392	681	295	520
25 MW/50 MWh	390	538	296	437
1 C rating				
2.5 MW/2.5 MWh	435	956	431	737
10 MW/10 MWh	435	815	438	658
25 MW/25 Mwh	435	679	418	570
2 C rating				
5 MW/2.5 MWh	435	956	650	829
20 MW/10 MWh	435	815	661	751
50 MW/25 MWh	435	679	683	681

Having all the revenues and costs, as well as the lifetime of the investment, the profitability of each of the services for different battery sizes has been calculated. This assessment has been done by calculating both the NPV and IRR of the investments. The NPV and IRR of the projects have been calculated using the same procedure as in Section 3.3.

The IRR of the different services and battery sizes are shown in Figure 29. Applications with an IRR higher than 7% are profitable, as this is the WACC used for the economic assessment, and can be identified as those services whose value is over the dashed line. Regarding the NPV values, all the results for FCR-N and stacked services are shown in Figure 30.

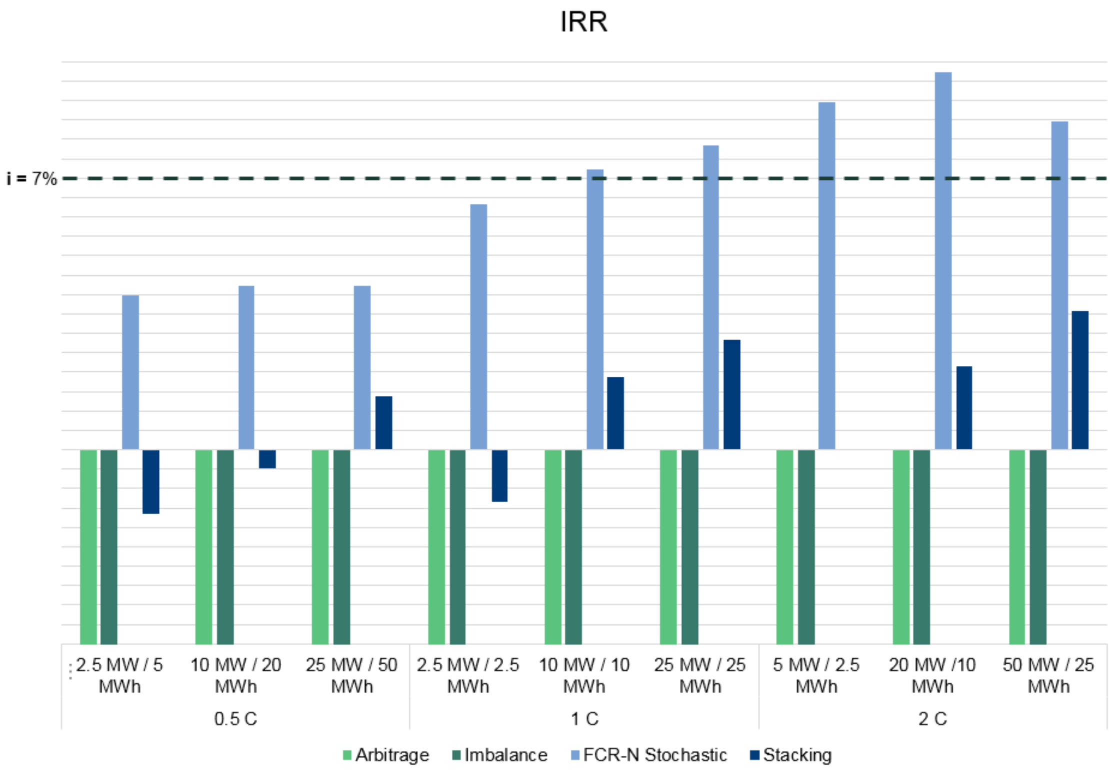


Figure 29: IRR for different battery sizes and applications.

As it can be observed in Figure 29, both arbitrage and wind power production imbalance compensation services are highly unprofitable. Primary frequency regulation is indeed the only service with positive NPV values, mainly due to the considerably larger revenues generated. Despite increasing the imbalance compensation service cash flows when stacked together with FCR-N, these are not large enough to make the combination of services profitable in Sweden yet.

As the main objective of the thesis is to assess the benefit and value of BESS together with IRES, a sensitivity analysis on how different cost components and parameters affect the profitability of the stacked services application has been performed. This assessment has been performed for the 20 MW/10 MWh battery, which has a 2 C characteristic and medium size[11].

The battery CAPEX seems to be the most relevant cost affecting profitability, whereas the BOS CAPEX has a smaller impact in the result, even when analysing the effect on a 2 C characteristic battery, which has double power rating than energy capacity. A 50% cost decrease in the battery investment would make the combined imbalance compensation and FCR-N application profitable. However, a decrease of 75% in the BOS costs would be necessary to achieve the same result. If both the battery and BOS equipment costs are assumed to decrease at the same rate,

[11]Regardless of the higher profitability obtained for the 50 MW/25 MWh battery, this has not been chosen as it represents a very high capacity that could affect the FCR-N market, and thus the profitability of the service itself.

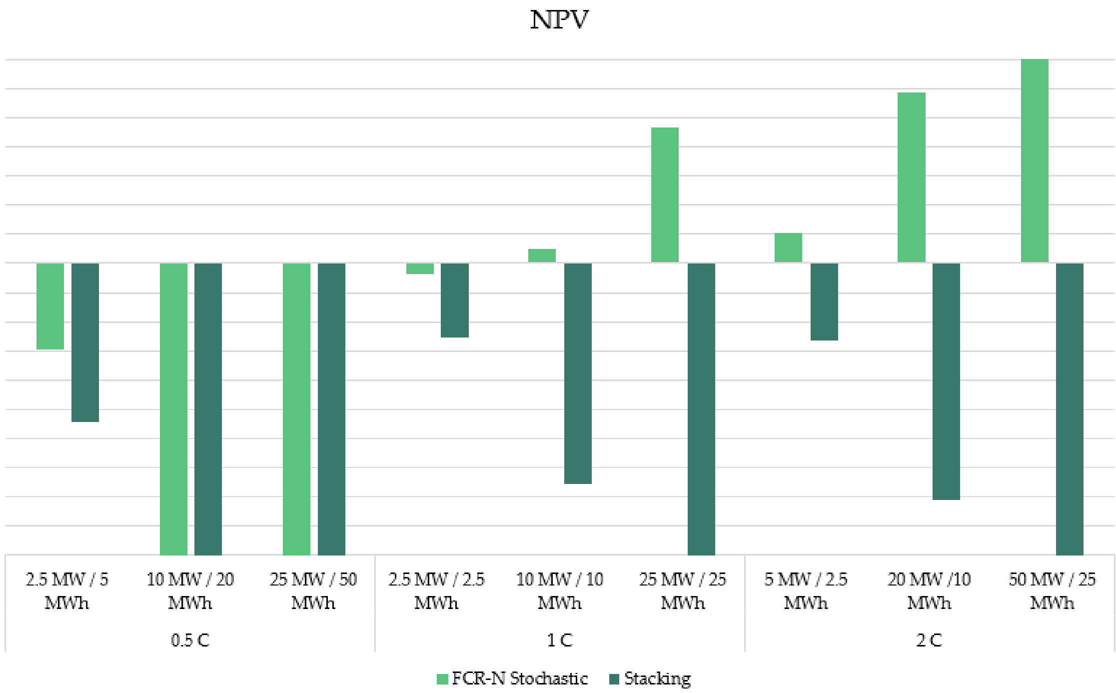


Figure 30: NPV of FCR-N and stacked services for different battery sizes.

a 30% decrease in both components would make the stacked services profitable, being these prices the system breakeven costs.

Table 24: Breakeven costs for stacked services' profitability.

	Battery CAPEX	BOS CAPEX
Current system costs	600 €/kWh	200 €/kW
Individual breakeven costs	300 €/kWh	50 €/kW
System breakeven costs	426 €/kWh	142 €/kW

Based on utility-scale battery costs projections [92], the battery system breakeven costs, which reflect the same price drop in both the battery and BOS equipment, may be expected by 2021 if an aggressive cost reduction (annual 7% cost decrease) is assumed and by 2022 with a conservative cost reduction (5% annual decrease). On the other hand, the individual battery breakeven cost, which as mentioned would be 50% the current cost, can be expected by 2026 in the aggressive price decrease scenario and by 2029 in the conservative scenario. The expected battery CAPEX trend can be seen in Figure 31. In both cases, a higher but more realistic current battery CAPEX than the one assumed by Cole et al. [92] has been considered, as shown also in Table 24, based on Lazard's price estimates [61]. Nevertheless, latest BESS price updates show a larger fall in prices than the expected one [12].

Furthermore, the impact of the battery cycle life and the interest rate have also been studied. The impact battery cycle life increase could have in profitability is

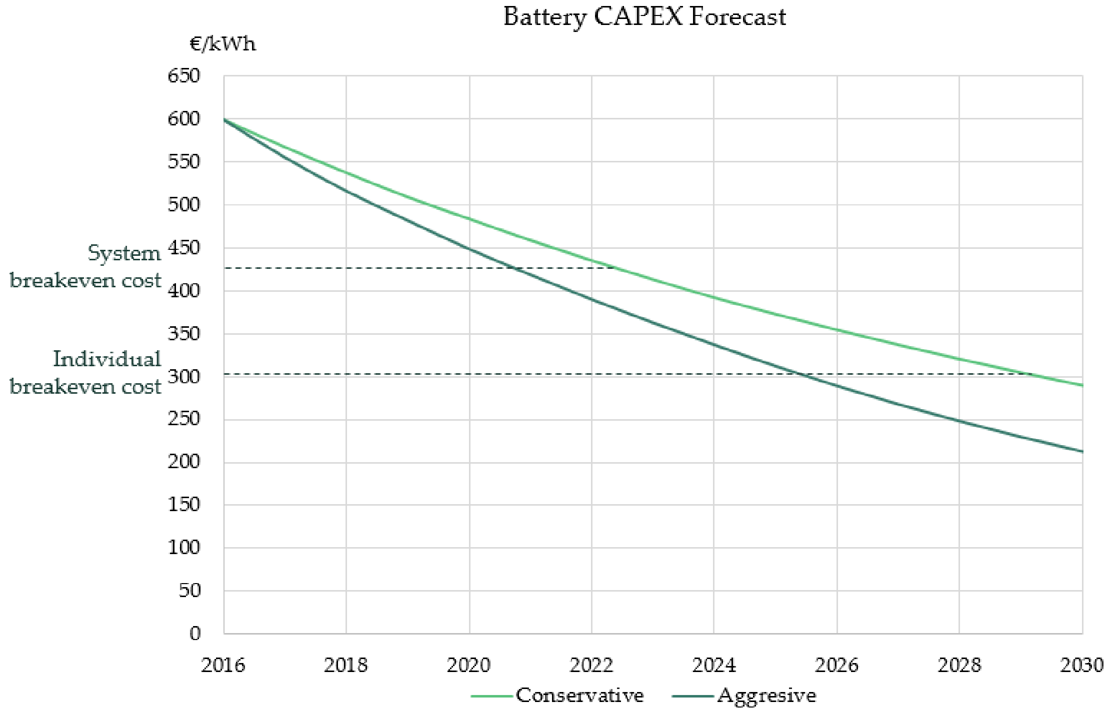


Figure 31: Battery capital costs forecast [92].

similar to the battery cost's one, as a 50% cycle life increase would be necessary to expand the lifetime of the stacked services project and make it profitable. The necessary cycle life is 10 500 cycles compared to the 7 000 cycles assumed in our study. Regarding the interest rate, being the IRR of the studied battery 2.2%, only a WACC equal to that value would make the investment profitable if no changes in technology costs or battery lifetime are considered.

4.5 Swedish case findings and recommendations

Different possible applications or services to be provided with a hybrid wind power and battery system in Sweden have been studied. In this case, only short-term applications have been studied, being two days the longest time-frame under study.

The economic interest of wind power time-shifting, storing wind production during low spot price periods to dispatch it when prices are high, comes from the possibility to take advantage of price volatility in the power exchange. In Elspot, however, the difference between peak and bottom prices is not very big and thus this operation with arbitrage purposes results in quite small revenues. Moreover, this is an energy application, in which a very fast operation and large power charge/discharge are not required, but energy is stored for several hours. The assumption that energy from the wind farm would always be available to charge the battery has been made, since the studied batteries range from 1 to 10% of maximum power with respect to the wind farm rated capacity. Anyway, the model could also be used to study the business case of stand-alone batteries, since the energy charged from the wind farm is always penalised with an opportunity cost equal to the spot price. Anyhow, the power time-shifting service results highly unprofitable and thus does not add value to wind generation.

Using the battery to try to eliminate the effects in output power caused by the high volatility of wind power and the forecast errors has also been analysed. The battery installed before the PCC could help partially compensating and thus reducing the wind farm production imbalance. This operation cannot be scheduled ahead. Instead, the battery charges or discharges in order to be as close as possible from the production plan, which is submitted 45 minutes before the delivery hour and contains the latest and most accurate wind forecast. With a small battery compared to the wind farm of study, often the deviation from the plan cannot be fully compensated and a residual imbalance remains. Nevertheless, interesting cost savings are obtained, which are unfortunately not big enough to make the investment in a utility-scale battery for this application profitable.

On the other hand, the possibility to provide primary frequency regulation, FCR-N in particular, has been analysed. Li-ion batteries' fast response and operation makes them very suitable for this service. The biggest limitation for batteries is in this case the energy capacity, as they risk to be fully charged or discharged if the system is regulated in the same direction for several consecutive hours. As the direction of the regulation and the amount of the bidden capacity that is going to be activated are very uncertain variables, a stochastic optimisation has been performed to assess the operation of the battery for this application. Regardless of the revenue decrease due to the mentioned risk, the service is highly remunerative, especially for power batteries (2 C rating), and pays the investment back. Thus, batteries can be profitable providing FCR-N in the Swedish market.

Anyway, it is necessary to highlight that a battery with a 2 C rating would be able to guarantee the provision of the FCR-N service for a maximum of 15 minutes starting from a 50% SOC. For this reason, in a market with symmetric capacity bids[12] in 1-hour blocks, only batteries with large energy content (i.e. with C rating smaller than 0.25) would be able to guarantee a correct operation coherent with the offered capacity. Since, as previously described, Li-ion batteries are very effective in fast response applications especially with high C rating, the current market structure represents a limiting factor for the penetration of the technology into the system. An update of FCR-N requirements from the TSO appears then necessary, together with a restructuring of the market providing the possibility to offer bids for shorter time blocks. As an example, in Germany batteries have less strict requirements than other technologies when providing primary frequency regulation. This way, the battery SOC can be managed with more freedom, maximising the battery availability for the frequency regulation service.

Furthermore, it has been proven that batteries do not have any value in peak shaving, as the fee cost saving potential is very low compared to the required

[12]Offered capacity could be requested to be activated on both directions, up- and down-regulation.

investment. Moreover, the need to prioritise this service before others and the unpredictability of the power generation makes the stacking of peak shaving with other additional services a very unlikely operation.

Finally, the possibility to combine two services and use the battery to provide FCR-N for some given hours and wind power production imbalance compensation the rest of the day has been studied. This option of stacked services increases the revenue streams the battery can obtain while being beneficial for wind power. Despite obtaining higher revenues than the production imbalance compensation service individually, these are not enough to make this application profitable in Sweden yet. A 30% system cost decrease would be necessary to achieve the breakeven point.

In conclusion, with the current battery prices and market conditions in Sweden, the most interesting case for battery systems is to provide FCR-N, as they can obtain interesting revenues and profitability. However, with lower technology costs, the combination of a service that improves wind power generation, such as the studied production imbalance compensation, and FCR-N can also become profitable in Sweden in the nearby future.

As mentioned in the definition of the scope of the work, it has always been assumed that power generators are price takers in the market. At this point, it seems important to reflect on this assumption.

Despite the fact that in Section 4.4 it has been demonstrated that big batteries have high profitability when committed on primary frequency regulation, it is also true that the bigger the battery is, the weaker the assumption of being price takers becomes. It may be indeed not realistic to assume that when large capacities are bidden on the FCR-N market, even if offered at the average market price, these are always going to be accepted. For example, a 50 MW battery would represent by itself around 25% of the whole committed primary regulation in Sweden if all its capacity is accepted.

At the same time, it should also be mentioned that having a large share of frequency regulation in a single node of the grid may not be optimal for the correct operation of the power system.

Moreover, a considerable increase of batteries in the energy system would risk to saturate the market and significantly decrease the average prices of ancillary services such as FCR-N in Sweden, and therefore have a negative impact on the investments.

5 Conclusions

Li-ion batteries can provide a wide range of applications, grouped in five main categories: electric supply applications, ancillary services, grid system applications, end-user applications and RES integration applications. In general terms, the value of each of the services depends strongly on the energy market in which the Li-ion batteries operate. As consequence, their economic interest is best analysed when individually studied for each specific country and use. In this work, two case studies have been performed: solar PV with batteries in the Indian market framework, and wind power with batteries in the Swedish power market.

In the Indian case, it has been seen that batteries are beneficial for improving solar power generation, by smoothing the fluctuations in the solar resource. Moreover, by fulfilling the Solar Energy Corporation of India's requirements, institution assigned by the Indian Government in order to achieve the National Solar Mission goal, a PPA tariff is awarded and thus, the high remuneration obtained can make the hybrid battery and solar system profitable.

On the other hand, in the case of Sweden, primary frequency regulation (FCR-N) is the only service which is profitable nowadays. However, this service does not directly provide any benefit to wind power. This is the reason why the combination of wind power production imbalance compensation (not profitable on its own) and FCR-N has been studied in this work, as this would improve wind generation while allowing to increase the obtained revenues by providing some hours of FCR-N service. It has been seen that the battery and system costs are still too high to make such a system profitable. So, it can be said that battery and BOS CAPEX costs still need to decrease to be possible to improve wind generation while obtaining profitability in Sweden.

If both the battery and the power conditioning unit are assumed to decrease in price simultaneously and at the same rate, the system breakeven cost for stacked services'[13] profitability would be reached with a 30% price decrease from nowadays values. If individual breakeven costs for batteries and BOS are considered, these would require a 50% price drop from current values.

In an conservative annual 5% cost decrease scenario, the system breakeven cost is expected by 2022, whereas if prices drop by 7% annually, this point would be reached by 2021. Nevertheless, latest BESS price updates show a larger fall in prices than the expected one, trend which would be highly beneficial for the profitability of other services BESS can provide, such as the combination of wind power production imbalance compensation with FCR-N.

The main limitation of this work is the fact of not having considered the price forecast uncertainty in the optimisation programs, as historic data time-series have been used as input for the models. In this sense, upgrading the developed models by adding some price forecasting tools would take into account the uncertainty in the obtained results. Moreover, taking the combination of more markets into account, which have been disregarded in this work, could improve batteries'

[13] In this work, stacked services refer to the combination of wind power production imbalance compensation and FCR-N.

economic results and so their profitability. Furthermore, simulating the battery operation taking the whole system into consideration, by adding transmission constraints, others players, etc., would make the results more accurate and show other potential benefits of batteries.

To sum up, it has been found that Li-ion batteries can already be profitable in India when obtaining a PPA tariff and in Sweden when providing primary frequency regulation. Further technology price falls, which seem likely to have a larger rate than forecast based on latest news and reports, will increase the potential of Li-ion batteries, by making other services and combination of applications profitable as well and thus providing more flexibility to the power system.

References

[1] *World Energy Outlook 2016*. International Energy Agency, IEA. Nov. 2016. URL: http://www.iea.org/newsroom/news/2016/november/world-energy-outlook-2016.html.

[2] *Installed Renewable Energy Capacity - Data & Statistics*. International Renewable Energy Agency, IRENA. 2017. URL: http://resourceirena.irena.org/gateway/dashboard/?topic=4&subTopic=16.

[3] *Renewables 2016. Global Status Report*. Renewable Energy Policy Network for the 21st Century, REN21. 2016. URL: http://www.ren21.net/wp-content/uploads/2016/06/GSR_2016_Full_Report.pdf.

[4] *2016. Snapshot of Global Photovoltaic Markets*. International Energy Agency Photovoltaic Power Systems Programme, IEA PVPS. 2016. URL: http://www.iea-pvps.org/fileadmin/dam/public/report/statistics/IEA-PVPS_-_A_Snapshot_of_Global_PV_-_1992-2016__1_.pdf.

[5] *Global Wind Report. Annual Market Update 2015*. Global Wind Energy Council, GWEC. 2015. URL: http://www.gwec.net/wp-content/uploads/vip/GWEC-Global-Wind-2015-Report_April-2016_22_04.pdf.

[6] *V164 - 8.0 MW Characteristics*. Vestas. 2014. URL: http://www.homepages.ucl.ac.uk/~uceseug/Fluids2/Wind_Turbines/Turbines/V164-8MW.pdf.

[7] *Ningxia built the largest desert photovoltaic integrated area*. Energy Storage Chinese Network, ESCN. 2016. URL: http://www.escn.com.cn/news/show-310093.html.

[8] *The Future Role and Challenges of Energy Storage*. European Commission. 2014. URL: https://ec.europa.eu/energy/sites/ener/files/energy_storage.pdf.

[9] Dr. Georgios Papaefthymiou, Katharina Grave, and Ken Dragoon. *Flexibility options in electricity systems*. Ecofys. 2014.

[10] *PPA Phase-II Batch-I*. International Renewable Energy Agency, IRENA. 2016. URL: http://www.irena.org/DocumentDownloads/Publications/IRENA_REmap_2016_edition_report.pdf.

[11] *Global Trends In Renewable Energy Investment 2016*. United Nations Environment Programme, UNEP and Bloomberg New Energy Finance, BNEF. 2016. URL: http://fs-unep-centre.org/sites/default/files/publications/globaltrendsinrenewableenergyinvestment2016lowres_0.pdf.

[12] David Frankel and Amy Wagner. *Battery storage: The next disruptive technology in the power sector*. McKinsey & Company. June 2017. URL: http://www.mckinsey.com/business-functions/sustainability-and-resource-productivity/our-insights/battery-storage-the-next-disruptive-technology-in-the-power-sector.

[13] D. Schweer, A. Maaz, and A. Moser. "Optimization of frequency containment reserve provision in M5BAT hybrid battery storage". In: *2016 13th International Conference on the European Energy Market (EEM)*. June 2016, pp. 1–5. DOI: 10.1109/EEM.2016.7521335.

[14] A. Oudalov, D. Chartouni, and C. Ohler. "Optimizing a Battery Energy Storage System for Primary Frequency Control". In: *IEEE Transactions on Power Systems* 22.3 (Aug. 2007), pp. 1259–1266. ISSN: 0885-8950. DOI: 10.1109/TPWRS.2007.901459.

[15] William A. Braff, Joshua M. Mueller, and Jessika E. Trancik. "Value of storage technologies for wind and solar energy". In: *Nature Clim. Change* 6.10 (Oct. 2016). Article, pp. 964–969. ISSN: 1758-678X. URL: http://dx.doi.org/10.1038/nclimate3045.

[16] *India's Electricity Sector Transformation*. Institute for Energy Economics and Financial Analysis. 2015. URL: http://ieefa.org/wp-content/uploads/2015/08/IEEFA-Indian-Electricity-Sector-Transformation-11-August-2015.pdf.

[17] *Statistics and Forecasts*. Svensk Vindenergi – Swedish Energy Association, SWEA. May 2017. URL: http://www.vindkraftsbranschen.se/wp-content/blogs.dir/11/files/2017/05/Statistics-and-forecast-Svensk-Vindenergi-20170504.pdf.

[18] *Framework agreement between the Swedish Social Democratic Party, the Moderate Party, the Swedish Green Party, the Centre Party and the Christian Democrats*. Government Offices of Sweden. June 2016. URL: http://www.government.se/49d8c1/contentassets/8239ed8e9517442580aac9bcb00197cc/ek-ok-eng.pdf.

[19] Tobias Goodden and Alexander Esser. *Development of Business Models for Electrical Energy Storage in Europe*. Stockholm, Sweden: KTH - Royal Institute of Technology, 2016.

[20] *Utility-Scale Concentrating Solar Power and Photovoltaics Projects: A Technology and Market Overview*. National Renewable Energy Laboratory, NREL. 2012.

[21] Riccardo Amirante et al. "Overview on recent developments in energy storage: mechanical, electrochemical and hydrogen technologies". In: *Energy Conversion and Management* 132 (2017), pp. 372–387. ISSN: 0196-8904. DOI: http://dx.doi.org/10.1016/j.enconman.2016.11.046. URL: http://www.sciencedirect.com/science/article/pii/S019689041631055X.

[22] *Lithium-ion energy storage systems for large defense applications*. Saft. 2013. URL: www.saftbatteries.com.

[23] N. Miller et al. "Utility scale Battery Energy Storage Systems". In: *IEEE PES General Meeting*. 2010, pp. 1–7. DOI: 10.1109/PES.2010.5589871.

[24] Akira Yoshino. "1 - Development of the Lithium-Ion Battery and Recent Technological Trends". In: *Lithium-Ion Batteries*. Ed. by Gianfranco Pistoia. Amsterdam: Elsevier, 2014, pp. 1–20. ISBN: 978-0-444-59513-3. DOI: http://dx.doi.org/10.1016/B978-0-444-59513-3.00001-7. URL: http://www.sciencedirect.com/science/article/pii/B9780444595133000017.

[25] Peter Kurzweil. "Lithium Battery Energy Storage: State of the Art Including Lithium-Air and Lithium-Sulfur Systems". In: *Electrochemical Energy Storage for Renewable Sources and Grid Balancing*. Elsevier, 2015, pp. 269–307. URL: http://dx.doi.org/10.1016/B978-0-444-62616-5.00016-4.

[26] Rachel Carnegie et al. *Utility Scale Energy Storage Systems*. State Utility Consulting Group. 2013.

[27] *Li-ion battery life technical sheet*. 2017. URL: http://www.saftbatteries.com%5C%2Fforce_download%5C%2Fli_ion_battery_life__TechnicalSheet_en_0514_Protected.pdf&usg=AFQjCNFYc_xZ_rYtc3em9se7VtFBxioe1Q&sig2=_ZKcnPo9cBUATmSWaILacw.

[28] Hsin Wang et al. "Mechanical abuse simulation and thermal runaway risks of large-format Li-ion batteries". In: *Journal of Power Sources* 342 (2017), pp. 913–920. ISSN: 0378-7753. DOI: https://doi.org/10.1016/j.jpowsour.2016.12.111. URL: http://www.sciencedirect.com/science/article/pii/S0378775316318146.

[29] Yoshio Nishi. "2 - Past, Present and Future of Lithium-Ion Batteries: Can New Technologies Open up New Horizons?" In: *Lithium-Ion Batteries*. Ed. by Gianfranco Pistoia. Amsterdam: Elsevier, 2014, pp. 21–39. ISBN: 978-0-444-59513-3. DOI: http://dx.doi.org/10.1016/B978-0-444-59513-3.00002-9. URL: http://www.sciencedirect.com/science/article/pii/B9780444595133000029.

[30] Christian Julien et al. *Lithium Batteries*. Springer International Publishing, 2016. DOI: 10.1007/978-3-319-19108-9. URL: https://doi.org/10.1007%2F978-3-319-19108-9.

[31] Zhengcheng Zhang and Sheng Shui Zhang. *Rechargeable Batteries. Materials, Technologies and New Trends*. Springer International Publishing, 2015. ISBN: 978-3-319-15458-9. DOI: 10.1007/978-3-319-15458-9. URL: https://link-springer-com/book/10.1007/978-3-319-15458-9/page/1.

[32] Gianfranco Pistoia. *Lithium-Ion Batteries: Advances and Applications*. Elsevier, 2013. ISBN: 9780444595164. URL: https://www.amazon.com/Lithium-Ion-Batteries-Applications-Gianfranco-Pistoia-ebook/dp/B00HLLMYKU?SubscriptionId=0JYN1NVW651KCA56C102&tag=techkie-20&linkCode=xm2&camp=2025&creative=165953&creativeASIN=B00HLLMYKU.

[33] Jim Eyer and Garth Corey. *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*. Sandia National Laboratories. 2010.

[34] Niklas Günter and Antonios Marinopoulos. "Energy storage for grid services and applications: Classification, market review, metrics, and methodology for evaluation of deployment cases". In: *Journal of Energy Storage* 8 (2016), pp. 226–234. ISSN: 2352-152X. DOI: http://dx.doi.org/10.1016/j.est.2016.08.011. URL: http://www.sciencedirect.com/science/article/pii/S2352152X16301141.

[35] *Balancing and Ancillary Services Markets*. European Network of Transmission System Operators for Electricity, ENTSO-E. 2015. URL: https://www.entsoe.eu/about-entso-e/market/balancing-and-ancillary-services-markets/Pages/default.aspx.

[36] Asmae Berrada, Khalid Loudiyi, and Izeddine Zorkani. "Valuation of energy storage in energy and regulation markets". In: *Energy* 115 (2016), pp. 1109–1118. ISSN: 0360-5442. DOI: http://dx.doi.org/10.1016/j.energy.2016.09.093. URL: http://www.sciencedirect.com/science/article/pii/S0360544216313639.

[37] Magnus Korpaas, Arne T. Holen, and Ragne Hildrum. "Operation and sizing of energy storage for wind power plants in a market system". In: *International Journal of Electrical Power & Energy Systems* 25.8 (2003). 14th Power Systems Computation Conference, pp. 599–606. ISSN: 0142-0615. DOI: http://dx.doi.org/10.1016/S0142-0615(03)00016-4. URL: http://www.sciencedirect.com/science/article/pii/S0142061503000164.

[38] Zhuang Cai et al. "Application of Battery Storage for Compensation of Forecast Errors of Wind Power Generation in 2050". In: *Energy Procedia* 73 (2015). 9th International Renewable Energy Storage Conference, IRES 2015, pp. 208–217. ISSN: 1876-6102. DOI: http://dx.doi.org/10.1016/j.egypro.2015.07.673. URL: http://www.sciencedirect.com/science/article/pii/S1876610215014411.

[39] G.N. Bathurst and G. Strbac. "Value of combining energy storage and wind in short-term energy and balancing markets". In: *Electric Power Systems Research* 67.1 (2003), pp. 1–8. ISSN: 0378-7796. DOI: http://dx.doi.org/10.1016/S0378-7796(03)00050-6. URL: http://www.sciencedirect.com/science/article/pii/S0378779603000506.

[40] *The Economics of Battery Energy Storage*. Rocky Mountain Institute. Oct. 2015.

[41] Ramteen Sioshansi et al. "Estimating the value of electricity storage in PJM: Arbitrage and some welfare effects". In: *Energy Economics* 31.2 (2009), pp. 269–277. ISSN: 0140-9883. DOI: http://dx.doi.org/10.1016/j.eneco.2008.10.005. URL: http://www.sciencedirect.com/science/article/pii/S0140988308001631.

[42] Frank Graves, Thomas Jenkin, and Dean Murphy. "Opportunities for Electricity Storage in Deregulating Markets". In: *The Electricity Journal* 12.8 (1999), pp. 46–56. ISSN: 1040-6190. DOI: http://dx.doi.org/10.1016/S1040-6190(99)00071-8. URL: http://www.sciencedirect.com/science/article/pii/S1040619099000718.

[43] *Ministry of power's responsibilities*. Ministry of Power - Government of India. 2017. URL: http://powermin.nic.in/en/content/responsibilities.

[44] *Central Electricity and Regulatory Commission - Functions*. Central Electricity and Regulatory Commission - Government of India. 2017. URL: http://www.cercind.gov.in/Function.html.

[45] Harshal T. Pandve. "India's National Action Plan on Climate Change". In: *Indian Journal of Occupational & Environmental Medicine* 13.1 (2009), pp. 17–19. ISSN: 0196-8904. DOI: 10.4103/0019-5278.50718. URL: https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2822162/?report=classic.

[46] *Jawaharlal Nehru National Solar Mission*. Ministry of New and Renewable Energy, Government of India. 2014. URL: http://www.mnre.gov.in/file-manager/UserFiles/mission_document_JNNSM.pdf.

[47] *All India Installed Capacity, Monthly Reports*. Central Electrcity Authority, CEA. May 2017. URL: http://www.cea.nic.in/monthlyinstalledcapacity.html.

[48] Mike Stone. "India's First Grid-Scale Battery Project Signals a Coming Boom for Energy Storage". In: *Green Tech Media* (Jan. 2017). URL: https://www.greentechmedia.com/articles/read/indias-first-grid-scale-battery-project-signals-a-coming-boom-for-storage.

[49] *Electricity Bill Amendment, 2014*. Ministry of Power. 2015. URL: http://164.100.47.193/lsscommittee/Energy/16_Energy_4.pdf.

[50] *Introduction, mission and objectives*. Solar Energy Corporation of India, SECI. May 2017. URL: http://www.seci.gov.in.

[51] *Our business*. NVVN. 2017. URL: http://nvvn.co.in/.

[52] *PPA Phase-II Batch-I*. Solar Energy Corporation of India, SECI. 2013.

[53] *Scheme for Development of Solar Parks*. Solar Energy Corporation of India, SECI. 2014. URL: http://www.seci.gov.in/.

[54] *IEX Electricity Market*. Indian Energy Exchange, IEX. May 2017. URL: www.iexindia.com.

[55] *Indian Power Market*. ÅF Mercados Energy Market India. 2014.

[56] *IEX - Day-Ahead Market*. Indian Energy Exchange. 2017. URL: https://www.iexindia.com/.

[57] *Power exchange spot market trading in Europe: theoretical considerations and empirical evidence*. OSCOGEN. 2002. URL: http://www.oscogen.ethz.ch/reports/oscogen_d5_1b_010702.pdf.

[58] *The Availability Based Tariff (ABT)*. Indian Institute of Science, NPTEL. 2017. URL: http://www.nptel.ac.in/.

[59] *Circular No.: IEX/MO/242/2017, Suspension of REC trading session*. Indian Energy Exchange, IEX. May 2017. URL: https://www.iexindia.com/exchangecirculars.aspx?id=19&mid=1.

[60] Jamie Manley. "India Already Has a Problem With Wasting Renewable Energy on the Grid". In: *Green Tech Media* (2016). URL: https://www.greentechmedia.com/articles/read/how-can-india-avoid-wasting-renewable-energy.

[61] *Lazard's Levelised Cost of Storage - Version 2.0*. Lazard Ltd., 2016.

[62] *PV Module Spot Price*. PV Insights. 2017. URL: http://pvinsights.com/.

[63] *Battery Energy Storage for Renewables: Market Status and Technology Outlook*. International Renewable Energy Agency, IRENA, 2015.

[64] *Petition No. 17/SM/2015 - Determination of Benchmark Capital Cost Norm for Solar PV power projects and Solar Thermal power projects applicable during FY 2016-17*. Central Electricity Regulatory Commission. 2016. URL: http://www.cercind.gov.in/2016/orders/SO17.pdf.

[65] Angelo Baggini. "Handbook of Power Quality". In: Wiley, 2008. ISBN: 978-0-470-06561-7.

[66] *Amendments in the RfS Document of JNNSM Phase-II, Batch-IV, Tranche-V*. Solar Energy Corporation of India, SECI. Oct. 2016.

[67] *Distributed Generation Renewable Energy Estimate of Costs*. National Renewable Energy Laboratory, NREL. 2017. URL: http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html.

[68] V. Viswanathan et al. *National Assessment of Energy Storage for Grid Balancing and Arbitrage. Phase II. Volume 2: Cost and Performance Characterization*. Pacific Northwest National Laboratory, PNNL. 2013.

[69] *India Inflation Rate and Forecasts*. Trading Economics. 2017. URL: http://www.tradingeconomics.com/india/inflation-cpi/forecast.

[70] *Elproduktion*. Energiföretagen. May 2017. URL: https://www.energiforetagen.se/sa-fungerar-det/el/produktion.

[71] *Swedish Energy Agency - Policy and Legislation*. Energimyndigheten. 2015. URL: http://www.energimyndigheten.se/en/about-us/policy-and-legislation/.

[72] *Government policy - Energy*. Government Offices of Sweden. 2015. URL: http://www.government.se/government-policy/energy/.

[73] *About Us*. Nord Pool. 2017. URL: http://www.nordpoolspot.com/.

[74] *Nordic Balancing Philosophy*. Entso-e. 2016. URL: http://www.svk.se/contentassets/bc60c82ceaec44c0b9ffbf3ee2126adf/nordic-balancing-philosophy-160616-final_external.pdf.

[75] *The Nordic Electricity Exchange and The Nordic Model for a Liberalized Electricity Market*. Nord Pool Spot. 2012.

[76] *Balansansvarsavtal 2017*. Svenska Kraftnät. 2017. URL: http://www.svk.se/aktorsportalen/elmarknad/balansansvar/.

[77] *Nordic Imbalance Settlement Handbook*. eSett. 2017. URL: https://www.esett.com/wp-content/uploads/2017/04/NBS-Handbook-v2.21.pdf.

[78] Fingrid. *Fingrid - Two-price and one-price system*. 2017. URL: http://www.fingrid.fi/en/customers/.

[79] *Marknader för förbrukningsflexibilitet*. Svenska Kraftnät. 2017.

[80] *Primärreglering Statistik*. Svenska Kraftnät. 2017. URL: https://mimer.svk.se/PrimaryRegulation/PrimaryRegulationIndex.

[81] *Integrating Variable Renewable Energy: Challenges and Solutions*. National Renewable Energy Laboratory, NREL. 2013. URL: http://www.nrel.gov/docs/fy13osti/60451.pdf.

[82] A. Oudalov, D. Chartouni, and C. Ohler. "Optimizing a Battery Energy Storage System for Primary Frequency Control". In: *IEEE Transactions on Power Systems* 22.3 (Aug. 2007), pp. 1259–1266. ISSN: 0885-8950. DOI: 10.1109/TPWRS.2007.901459.

[83] A. Oudalov et al. "Value Analysis of Battery Energy Storage Applications in Power Systems". In: *2006 IEEE PES Power Systems Conference and Exposition*. Oct. 2006, pp. 2206–2211. DOI: 10.1109/PSCE.2006.296284.

[84] Antonio J. Conejo, Miguel Carrión, and Juan M. Morales. *Decision Making Under Uncertainty in Electricity Markets*. Springer, 2010.

[85] Robert H. Shumway and David S. Stoffer. *Time Series Analysis and Its Applications: With R Examples*. 3rd ed. Springer Texts in Statistics. New York: Springer, 2011. ISBN: 9781441978646. URL: http://www.worldcat.org/isbn/9781441978646.

[86] Jitka Dupacová, Werner Römisch, and N. Gröwe-Kuska. "Scenario reduction in stochastic programming". In: *Mathematical Programming Series* A.95 (Mar. 2003), pp. 493–511. URL: https://www.mathematik.hu-berlin.de/~romisch/papers/DGR03-MP.pdf.

[87] Peter W. Sauer. "Applied Mathematics for Restructured Electric Power Systems". In: 2005. Chap. 2.

[88] Alex McEachern. *Power Standards Lab*. 2017. URL: http://www.powerstandards.com/tutorials/sagsandswells.php.

[89] Abdul Motin Howlader et al. "A review of output power smoothing methods for wind energy conversion systems". In: *Renewable and Sustainable Energy Reviews* 26 (2013), pp. 135–146. ISSN: 1364-0321. DOI: http://dx.doi.org/10.1016/j.rser.2013.05.028. URL: http://www.sciencedirect.com/science/article/pii/S1364032113003316.

[90] A. Aranizadeh, B. Vahidi, and A. Rahiminejad. "Wind turbine power output smoothing in microgrid using ultra-capacitor with continuous wind speed forecasting and online supervisory control". In: *Journal of Renewable and Sustainable Energy* 8.033301 (2016). DOI: 10.1063/1.4950958. URL: http://aip.scitation.org.focus.lib.kth.se/doi/pdf/10.1063/1.4950958.

[91] *Prislista För Stamnätet 2017*. Svenska Kraftnät. Jan. 2017.

[92] W. J. Cole et al. "Utility-scale lithium-ion storage cost projections for use in capacity expansion models". In: *2016 North American Power Symposium (NAPS)*. Sept. 2016, pp. 1–6. DOI: 10.1109/NAPS.2016.7747866.

[93] René Le Doeuff and Mohamed El Hadi Zaïm. "Induction Machines". In: *Rotating Electrical Machines*. John Wiley & Sons, Inc., 2013, pp. 167–236. ISBN: 9781118620649. DOI: 10.1002/9781118620649.ch4. URL: http://dx.doi.org/10.1002/9781118620649.ch4.

[94] Hortensia Amaris, Monica Alonso, and Carlos Alvarez Ortega. *Reactive power management of power networks with wind generation*. Lecture Notes in Energy. Dordrecht: Springer, 2012. URL: http://cds.cern.ch/record/1616273.

[95] Siemens. *Back-to-back HVDC*. 2016. URL: http://www.energy.siemens.com/co/en/power-transmission/hvdc/applications-benefits/configurations/back-to-back-hvdc.htm.

[96] U.A. Bakshi and V.U. Bakshi. "Electrical Machines I". In: Technical Publications, 2009. ISBN: 9788184315356.

[97] Austin Hughes. "Electric Motors and Drives: Fundamentals, Types and Applications". In: Elsevier Ltd., 2009. ISBN: 9780750647182.

[98] G. Kömürgöz and T. Gündogdu. "Comparison of salient pole and Permanent Magnet Synchronous Machines designed for wind turbines". In: *2012 IEEE Power Electronics and Machines in Wind Applications*. 2012, pp. 1–5. DOI: 10.1109/PEMWA.2012.6316381.

[99] N. R. Ullah, K. Bhattacharya, and T. Thiringer. "Wind Farms as Reactive Power Ancillary Service Providers. Technical and Economic Issues". In: *IEEE Transactions on Energy Conversion* 24.3 (2009), pp. 661–672. ISSN: 0885-8969. DOI: 10.1109/TEC.2008.2008957.

[100] *Commission Regulation (EU) No. 2016/631 of 14 April 2016 on establishing a network code on requirements for grid connection of generators*. Eurelectric.

[101] *Affärsverket svenska kraftnäts författningssamling*. Svenska Kraftnät. 2005. URL: http://www.svk.se/siteassets/om-oss/foreskrifter/svkfs2005_2.pdf.

[102] Tobias Keller. *Fault-ride-through capability - network stability as a key challenge in power plants*. 2014. URL: http://www.abb.com/cawp/seitp202/20bd91df80a8ff08c1257cb00031bedc.aspx.

[103] *Internal Electricity Market Glossary - Power Park Module (PPM)*. EUETS. 2017. URL: http://www.emissions-euets.com/internal-electricity-market-glossary/830-power-park-module-ppm.

[104] Hortensia Amaris and Monica Alonso. "Coordinated reactive power management in power networks with wind turbines and {FACTS} devices". In: *Energy Conversion and Management* 52.7 (2011), pp. 2575–2586. ISSN: 0196-8904. DOI: http://dx.doi.org/10.1016/j.enconman.2011.02.012. URL: http://www.sciencedirect.com/science/article/pii/S0196890411000847.

[105] J. J. Shea. "Understanding FACTS-concepts and technology of flexible AC transmission systems [Book Review]". In: *IEEE Electrical Insulation Magazine* 18.1 (2002), pp. 46–46. ISSN: 0883-7554. DOI: 10.1109/MEI.2002.981326.

[106] A. Chakraborty et al. *Integrating STATCOM and Battery Energy Storage System for Power System Transient Stability: A Review and Application*. 2012. DOI: 10.1155/2012/676010.

[107] M. C. Kisacikoglu, B. Ozpineci, and L. M. Tolbert. "Reactive power operation analysis of a single-phase EV/PHEV bidirectional battery charger". In: *8th International Conference on Power Electronics - ECCE Asia*. 2011, pp. 585–592. DOI: 10.1109/ICPE.2011.5944614.

[108] N. W. Miller et al. "Design and commissioning of a 5 MVA, 2.5 MWh battery energy storage system". In: *Proceedings of 1996 Transmission and Distribution Conference and Exposition*. 1996, pp. 339–345. DOI: 10.1109/TDC.1996.545957.

[109] J. Zeng et al. "Use of Battery Energy Storage System to Improve the Power Quality and Stability of Wind Farms". In: *2006 International Conference on Power System Technology*. 2006, pp. 1–6. DOI: 10.1109/ICPST.2006.321662.

[110] B. Lalitha P. Sindhuja. "Reactive Power Compensation for Grid Connected Distribution System using D-STATCOM for Different Loads". In: (2016). DOI: 10.14445/22315381/IJETT-V40P242.

A Voltage control and reactive power compensation

The reactive power capability, which refers to the instantaneous reactive power capacity the turbine can absorb or deliver to the grid, is greatly related to the type of wind generator. These are generally classified as fixed-speed or variable-speed generators.

Fixed-speed wind turbines consist of squirrel induction generators[14] directly coupled to the grid. This type of wind turbines consume a large amount of reactive power during the magnetisation of the stator of the generator. Reactive power consumption comes from the need to produce rotating magnetic field, which has a high inductance. Moreover, under voltage sag events, the stator of the asynchronous machine remains demagnetised and the consumption of reactive power increases significantly, decreasing the voltage. The configuration of fixed-speed wind turbines is shown in Figure A1.

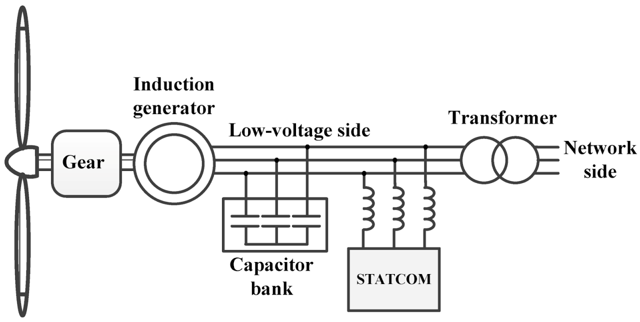


Figure A1: Fixed-speed wind turbine [94].

Regarding **variable-speed wind turbines**, they can have two types of generators: *Doubly Fed Induction Generators (DFIG)* or *Direct Drive Generators*.

DFIG have the possibility to supply power at high efficiency as well as constant voltage and frequency over a wide range of wind speeds. In these machines, the stator is directly connected to the grid, whereas the rotor is an induction generator connected to the grid through a back-to-back power converter[15]. This type of configuration is shown in Figure A2.

In this type of generators, both stator and rotor deliver reactive power to the grid. The reactive power delivered by the rotor is usually set to zero. Therefore, the only reactive power which can be controlled is the one delivered by the stator, being it possible to control the Grid Side Converter (GSC) of the wind turbine for such purpose [94].

[14] In squirrel induction generators, the alternating current in the stator produces a rotating magnetic field. Moreover, the rotor winding has current induced in it by the stator field, and produces its own magnetic field. It is the interaction of the two sources of magnetic field what produce torque on the rotor [93].

[15] A back-to-back configuration refers to two independent neighbouring systems with different and incompatible electrical parameters, in this case frequency, which are connected through a DC link [95].

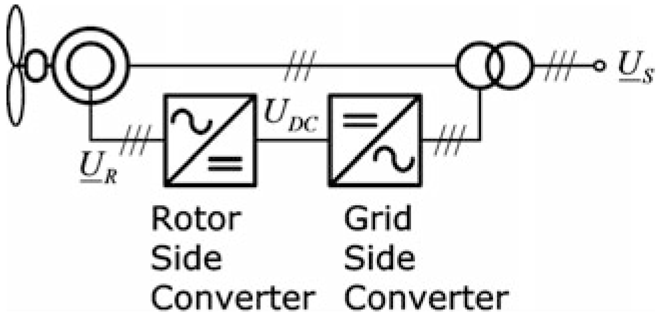


Figure A2: DFIG variable-speed wind turbine [94].

Direct Drive Wind Generators involve the use of an electric power converter. This way, it is possible to have a total control of the machine, regarding both reactive power and mechanical torque. Moreover, the power converter does not require any additional reactive power compensation devices, making this type of turbines some of the ones with least reactive power compensation required [94].

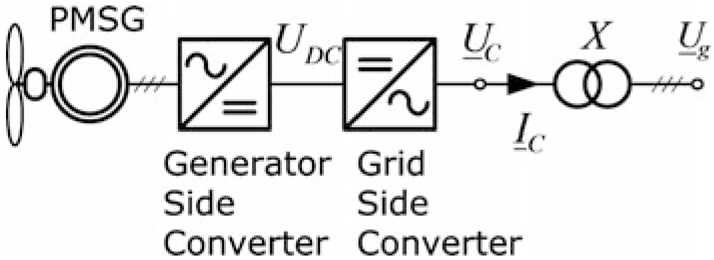


Figure A3: Direct-drive wind turbine [94].

Direct Drive Generators can be classified into three different types: induction generators, Wound Rotor Synchronous Generators (WRSG) and Permanent Synchronous Magnet Generators (PSMG).

Induction generators are induction machines with a squirrel cage rotor without brushes[16], type of generator used also by fixed-speed wind turbines, connected to the grid with an electric power converter in this case. They require large diameter turbines and the converters must be designed to be able to control both output and magnetisation power.

WRSG are electric machines with a wound rotor synchronous generator[17] with an auto-excitation circuit[18] which controls its magnetisation and as consequence

[16]Brushes are used to deliver current to the motor windings through commutator contacts. In brushless motors instead, the field is switched via an amplifier triggered by a commutating device, such as an optical encoder [93].

[17]Wound rotors are a type of induction motor where the rotor windings are connected through slip rings to external resistances. The speed and torque can be controlled by adjusting these resistances [93].

[18]Auto-excitation circuits use some of the rotor power output to power the field coils, which retain some magnetism. The auto-excited circuit is started with no load connected - the initial weak field creates a weak voltage in the stator coils, which in turn increases the field current, until it arrives to full voltage [96].

all the generation torque[19]. These generators provide the possibility to disjunct the control of reactive power from active power, depending on grid requirements [98].

On the other hand, *PSMG*, the type of direct drive generator shown in Figure A3, can produce magnetic field in an air-gap without the need of excitation winding, therefore with no dissipation of power. Permanent magnets are mounted on the surface of the rotor, and the energy input is needed only to charge the magnetic field but not to maintain it [99].

In summary, as it has just been described, different types of generators create different reactive power compensation needs, as they consume more or less reactive power.

In order to ensure voltage stability and power quality, power generators shall comply with the network code requirements based on the voltage level of the grid they are connected to and their maximum plant capacity. In the Nordic countries, generators either connected to the 110 kV or above or with a maximum capacity larger than 30 MW are considered to be *Type D* generators. As this work aims to study the integration of batteries with large-scale wind power, we can consider that the cases of interest would generally be classified as Type D generators. Thus, the requirements from both ENTSO-E [100] and SvK [101] for this group of power generators are going to be presented next.

First of all, regarding **fault-ride-through capability**[20] of power-generating units, SvK specifies the voltage-against-time profile which describes the conditions in which power generators should stay connected to the network and continue to operate stably after the power system has been disturbed by secured faults on the transmission system. The fault-ride-through profile required by SvK is shown in Figure A4.

Requirements regarding **voltage stability** determine an unlimited operation time between 0.90 pu[21] and 1.05 pu, and not more than 60 minutes operation period between 1.05 pu and 1.10 pu, being the reference 1 pu value.

As it has been explained more in detail before, in order to ensure voltage stability in the grid, power generators shall provide supplementary reactive power to compensate the reactive power demand of the wind power park and of the voltage-line between the step-up transformer and the connection point.

In order to maintain voltage stability in the grid, reactive power at maximum capacity should be provided within the $U - Q/P_{max}$-profile boundaries presented in Figure A5 and defined by the area referred to as inner envelope. This reactive power provision capability requirement applies at the connection point. The $U - Q/P_{max}$-profile shall not exceed the $U - Q/P_{max}$-profile limits, which are set at -0.35 Q/P_{max} (leading, reactive power consumption) and 0.4 Q/P_{max} (lagging, reactive power production). In voltage terms, the limits that should not be

[19] Electric torque is proportional to the product of magnetic flux and the armature current [97].

[20] Fault-ride-through capability is the ability of generators to maintain synchronous operation when a severe disturbance occurs in electrical proximity of the generator [102].

[21] Per unit, pu, refers to the normalised voltage value based on the maximum voltage level at a given point in the grid. For instance, for the 400 kV transmission grid voltage level, 1 pu = 400 kV and 0.90 pu = 360 kV.

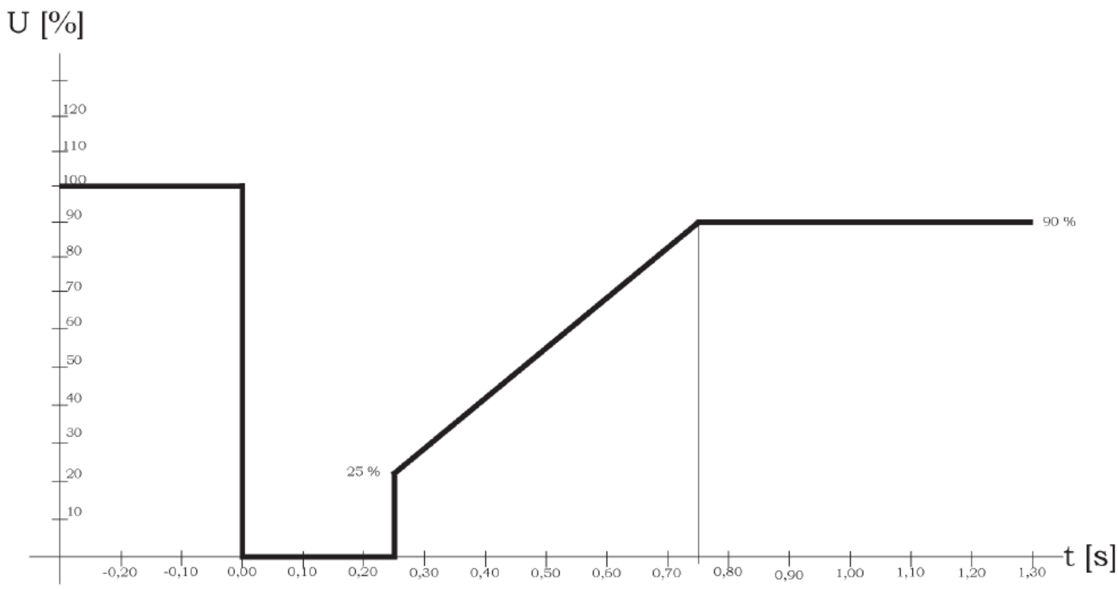


Figure A4: Fault-ride-through profile of a power generator required by SvK [101].

exceeded are 0.9 V/pu and 1.075 V/pu.

The power park module[22] shall be capable of providing reactive power automatically by one of the following control modes:

- voltage control mode;
- reactive power control mode; or
- power factor control mode.

In the voltage control mode, the power park module shall be capable of contributing to voltage control at the connection point by provision of reactive power exchange with the network with a set-point voltage between 0.95 and 1.05 pu, which corresponds to a dead-band from zero to ±5% of reference 1 pu network voltage. The voltage value should vary in steps no greater than 0.01 pu. Once the grid voltage value at the connection point equals the voltage set-point, the reactive power output shall be zero. The power park module shall be capable of achieving 90% of the change in reactive power output within 1 to 5 seconds, and must settle at the target value within 5 to 60 seconds.

In the reactive power control mode, the reactive power at the connection point shall be controlled to a value within plus or minus 5 MVAr or plus or minus 5%, whichever range is smaller, of the full reactive power.

[22] A Power Park Module (PPM) refers to a unit or ensemble of units generating electricity, which is either non-synchronously connected to the network or connected through power electronics, and that also has a single connection point to a transmission system, distribution system including closed distribution system or HVDC system, according to [103]. In our case, the hybrid wind and BESS system are part of the power park module.

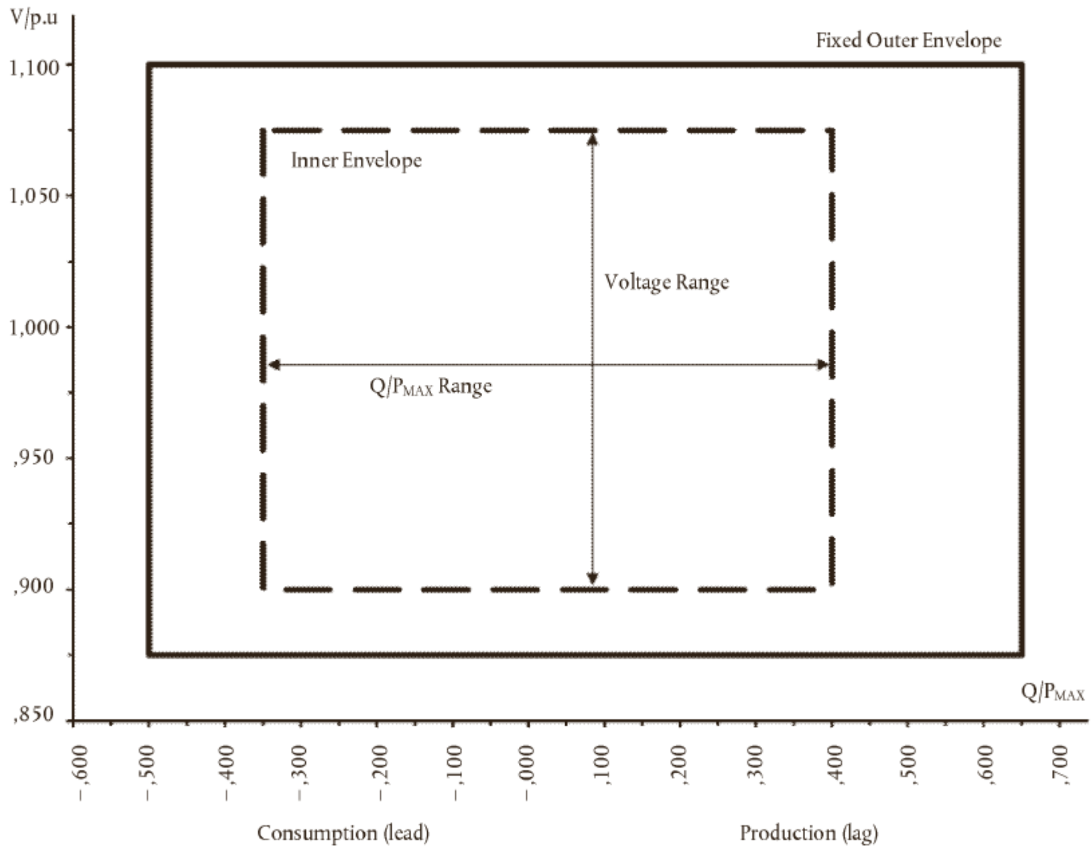


Figure A5: $U - Q/P_{max}$-profile of a power park module [100].

In the power factor control mode, the system operator shall specify the target power factor value, its tolerance and the period of time to achieve the target power factor following a sudden change of active power output. The tolerance of the target power factor shall be expressed through the tolerance of its corresponding reactive power.

Different solutions exist to provide reactive power compensation. Currently, reactive power correction in order to provide voltage stability is mainly performed with Flexible Alternative Current Transmission Systems (FACTS) installed where the wind farms are connected to the transmission grid [104]. This point of connection is usually referred to as Point of Common Coupling (PCC).

Static Var Compensators (SVC), which are the oldest and most simple type of FACTS, are shunt-connected (connected in parallel) static var generators or absorbers whose output is adjusted in order to exchange capacitive or inductive current to maintain and control the voltage level at the PCC [105].

Another type of FACTS are Static Synchronous Compensators (STATCOMs), which are static synchronous generators operated as shunt-connected static var compensators whose capacitive or inductive output current can be controlled independently from the AC system voltage. It is composed of a Voltage Source Converter (VSC) which converts a DC voltage input into an AC voltage with a given magnitude and a controllable phase. The output AC current can be dynamically controlled to supply the required reactive power to the grid. Generally, STATCOMs are controlled based on one of the following techniques [104]:

- Voltage control at the PCC, so that the voltage is maintained to a reference value.
- Reactive Power control at the PCC, injecting reactive power into the grid in coordination with wind farms production and according to TSO specifications.

The major disadvantage of a traditional STATCOMs with no energy storage is that they only have two possible steady-state operating modes, namely, inductive or lagging and capacitive or leading. Even though both the STATCOM output voltage magnitude and phase angle can be controlled, they cannot be independently adjusted in steady state due to the lack of significant active power capability of STATCOMs. Typically, the converter voltage is maintained in phase with the PCC voltage, allowing only reactive power to flow from the STATCOM to the system [106].

The combination of STATCOM and BES can significantly improve the performance of the wind power system [106]. By the method of integration of BES into FACTS devices, an independent real and reactive power absorption or injection into and from the grid is possible, having a symmetric lead-lag capability, as shown in Figure A6, and being theoretically possible to go from full lag to full lead in fraction of cycles [107].

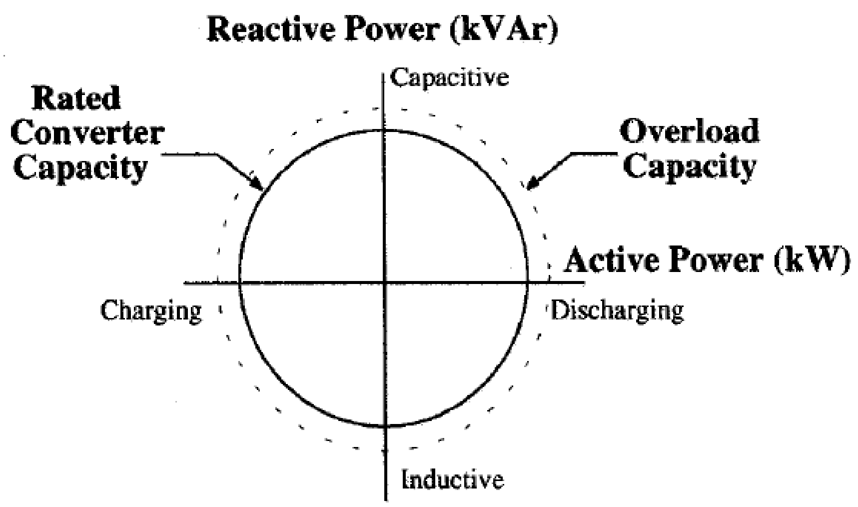


Figure A6: Active and reactive power capability of a system including BESS and PCS to STATCOMs [108].

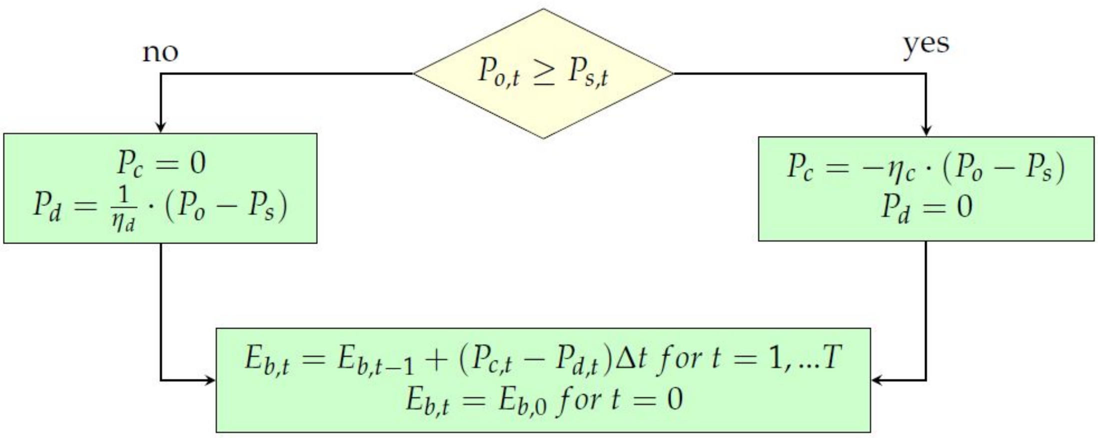
The real and reactive power flow from and to a battery can be controlled by adjusting the phase angle between the converter voltage and the AC system voltage and the magnitude of the converter output voltage, enabling control over the wind farm's power factor and stabilising the voltage of the PCC [109].

Increasing the power factor the phase angle decreases, and so does the reactive power Q (P/S ratio increases). On the other hand, when decreasing the power factor P/S ratio decreases and thus, the phase angle and Q increase. In case of a grid fault or power outage, the BESS can absorb imbalance power generated by the induction generators, slowing down the rotor speed of the electric machines and therefore improving the transient stability of the wind farm [110].

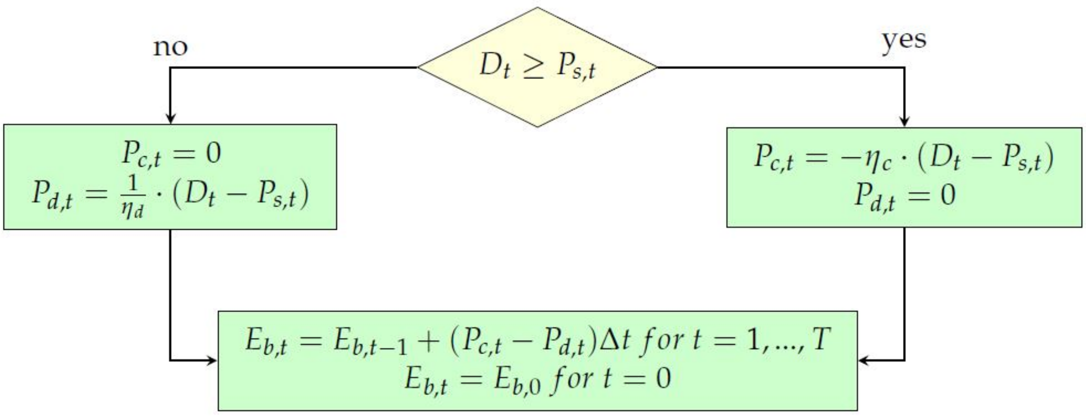
Hybrid systems which combine BESS and STATCOMs can, with proper control strategies, significantly improve the power quality at the PCC. However, simulation results from literature [109, 106] show better performances of these hybrid systems with respect to the minimum requirements from the European grid codes [100], which can be satisfied using only FACTS. A deeper study of these systems goes therefore beyond the scope of this work.

B Flow diagrams of the control algorithms

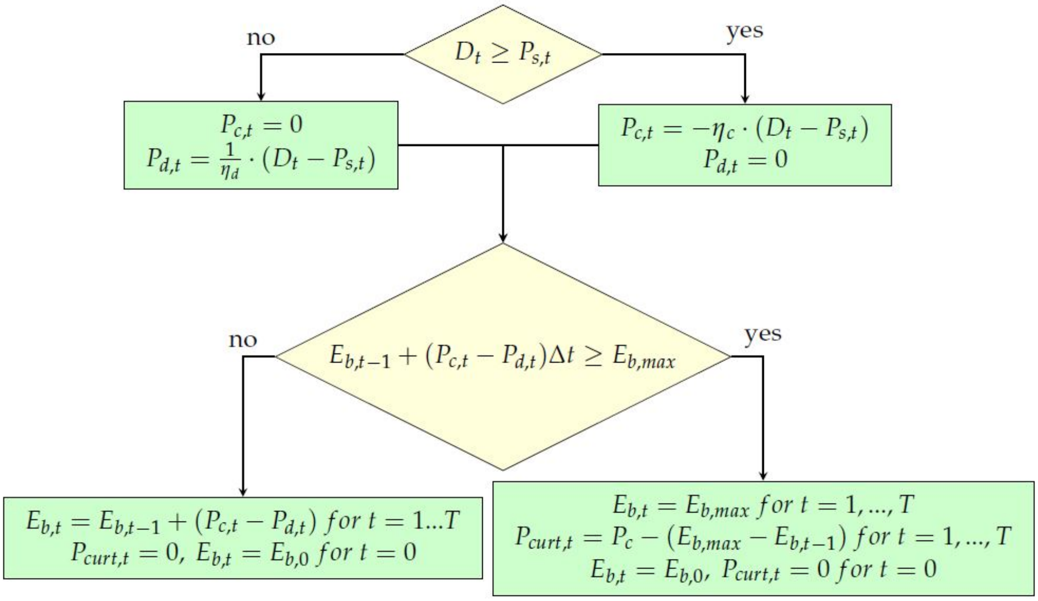
B.1 Constant power output flow diagram



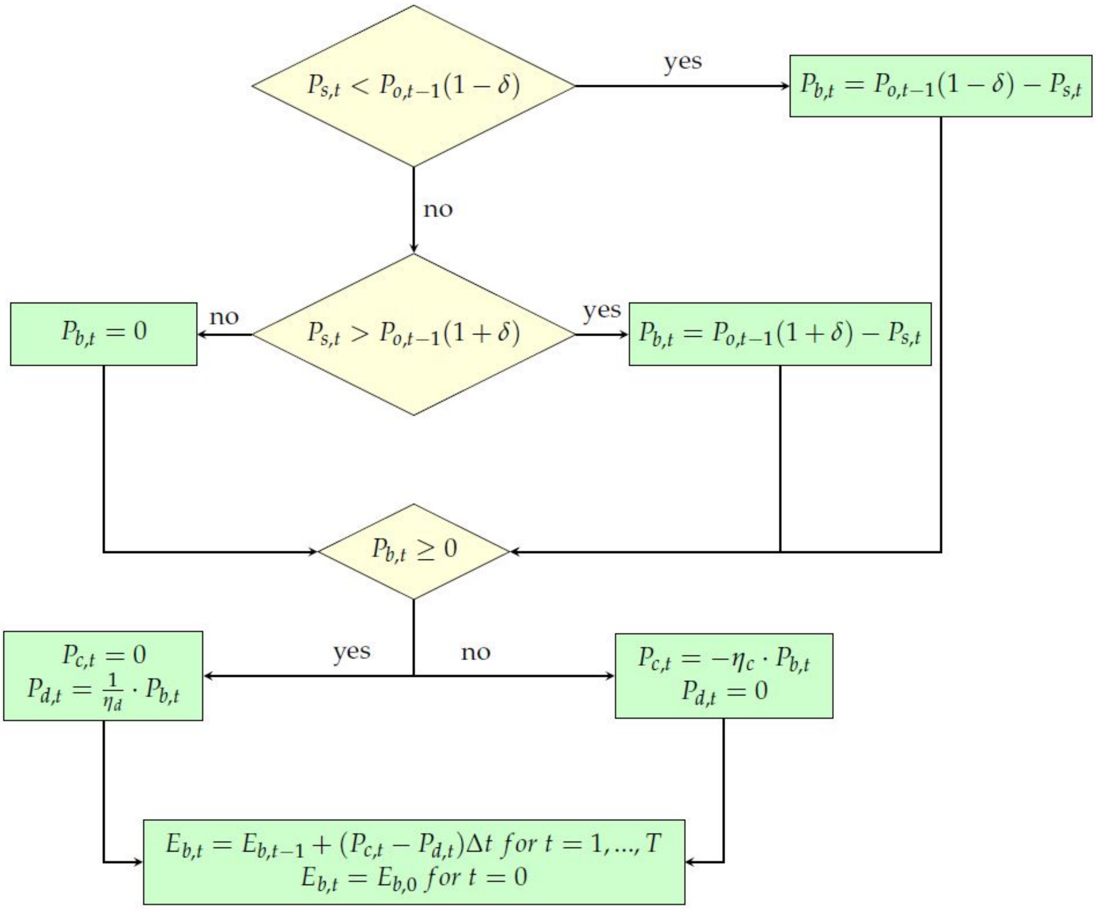
B.2 Demand following model flow diagram



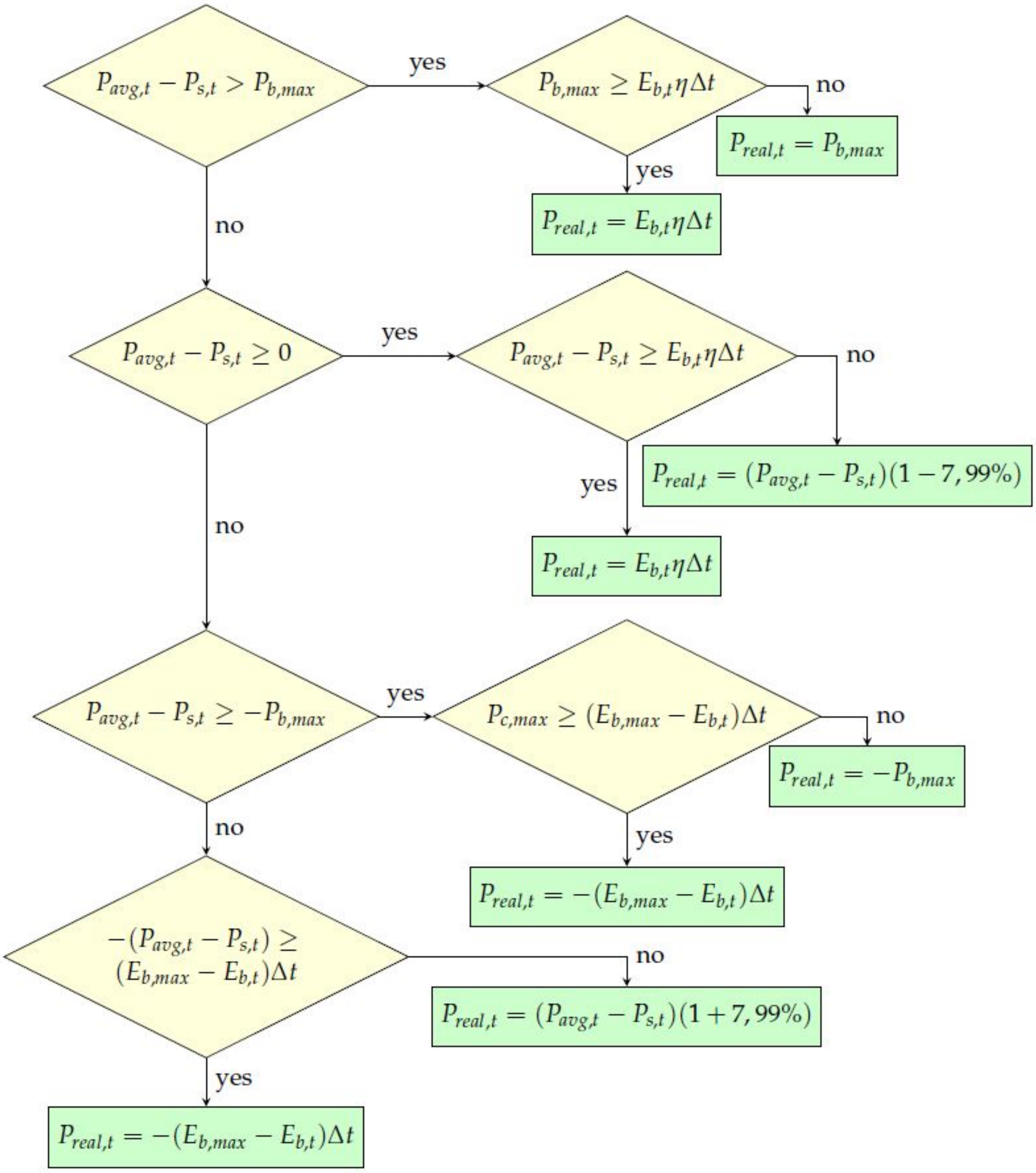
B.3 Demand following model with curtailment possibility flow diagram

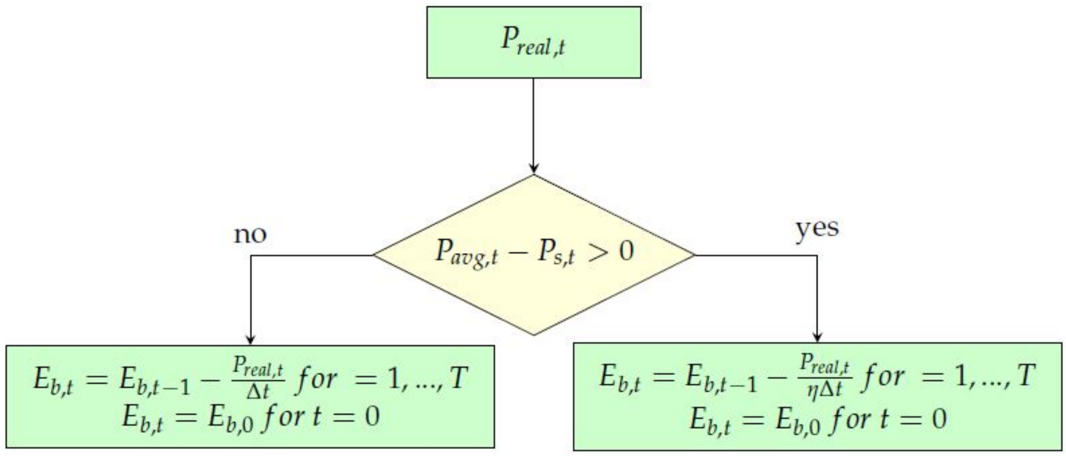


C Power output smoothing model flow diagram

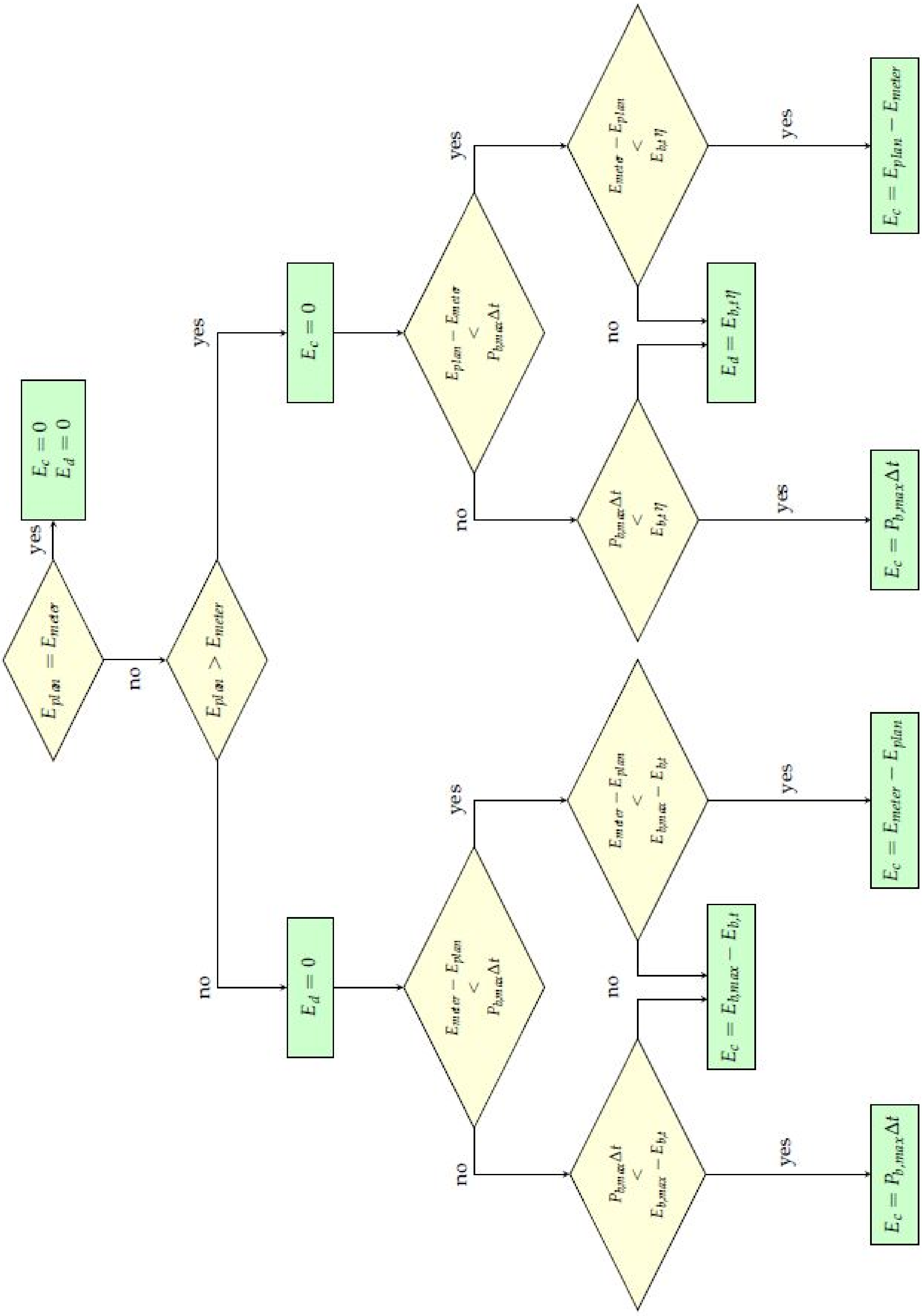


C.1 SECI's power output smoothing model flow diagram




$P_{real,t}$
no
$P_{avg,t} - P_{s,t} > 0$
yes
$E_{b,t} = E_{b,t-1} - \frac{P_{real,t}}{\Delta t}\ for\ = 1, ..., T$
$E_{b,t} = E_{b,0}\ for\ t = 0$
$E_{b,t} = E_{b,t-1} - \frac{P_{real,t}}{\eta \Delta t}\ for\ = 1, ..., T$
$E_{b,t} = E_{b,0}\ for\ t = 0$

C.2 Production imbalance compensation model flow diagram



D Codes

In this appendix, the core MATLAB codes of the models developed in the work are presented. Appendix D.1 reports the code used to optimise the operation of the BESS and solar PV system on the Indian IEX market. It has been slightly modified to be applied to the Nord Pool Elspot market with wind power generation, therefore this latter case is not here reported. Appendix D.2 represents the code used to simulate the battery system providing the production plan imbalance compensation. Appendix D.3 reports the code used to solve the stochastic problem of the battery providing frequency regulation, including the scenario reduction algorithm.

D.1 Time-shifting in Day-Ahead spot market

```
clear
clc

seas = 4; % Number of studied seasons.
d_coeff = 2 * seas; % Number of days the optimized.
deltat = 1/4; %Timestep of the optmization model: 15 min.

exch = 1/66.5; % [USD/INR]
price = priceinp(seas,exch); % [USD/MWh]
Esol = solardata(seas) * deltat; % Production time series.
    [MWh]

M = 4 * length(price) + 2; % Number of variables.
Neq = 2 * 192 + 1; % Number of eq constraints, 2 balances +
    final condition.
Nin = 4 * 192; % Number of inequality constraints. Min and
    max P and E.
eff = 0.9; % Round trip efficiency of the battery.
SOC_ini = 0.5; % Initial state of charge of the battery.
SOC_min = 0.1; % Minimum SOC of the battery.
SOC_max = 0.9; % Maximum SOC of the battery.
CAPEX_b = 42713; % Annuity of the capital expanditure
    referred to energy.
CAPEX_p = 42713; % Annuity of the capital expanditure
    referred to power.

j = 1;
for i = 1:length(price) % Define vector of obj function
    coefficients.
    f(j) = price(i) * 366/d_coeff;
    j = j + 1;
```

```
    f(j) = price(i) * 366/d_coeff;
    j = j + 1;
    f(j) = 0;
    j = j + 1;
    f(j) = 0;
    j = j + 1;
end

% Create equality and inequality matrices
Aeq = zeros(Neq * seas,M);
beq = zeros(Neq * seas,1);
Ain = zeros(Nin * seas,M);
bin = zeros(Nin * seas,1);

% Define lower and upper boundaries for the variables
lb = zeros(M,1);
lb(M) = 0.5;
lb(M-1) = 0.5;
ub = inf(M,1);
ub(M) = inf();
ub(M-1) = inf();

% Constraint 1: Energy balance of solar production.

j = 1;
for i = 1:192*seas
  Aeq(i,j) = 1;
  Aeq(i,j+2) = 1;
  j = j + 4;

  beq(i) = Esol(i);
end

% Constraint 2: Battery energy balance.
j = 1;
Aeq((seas * 192) + 1,j+1) = 1/eff;
Aeq((seas * 192) + 1,j+2) = -1;
Aeq((seas * 192) + 1,j+3) = 1;
Aeq((seas * 192) + 1,M-1) = -SOC_ini;
j = j + 4;

for i = ((seas * 192) + 2):(2 * seas * 192)
    Aeq(i,j-1) = -1;
    Aeq(i,j+1) = 1/eff;
    Aeq(i,j+2) = -1;
```

```
        Aeq(i,j+3) = 1;
        j = j + 4;
end

for e=1:seas
        Aeq(((2 * seas * 192) + e),(e * 4 * 192)) = 1;
        Aeq(((2 * seas * 192) + e),M-1) = -SOC_ini;
end

%Inequality constraint 1: Min SOC.
j = 1;
for i = 1:192 * seas
    Ain(i,j+3) = -1;
    Ain(i,M-1) = SOC_min;
    j = j + 4;
end

%Inequality constraint 2: Max SOC.
j = 1;
for i = (192 * seas + 1):(2 * 192 * seas)
    Ain(i,j+3) = 1;
    Ain(i,M-1) = -SOC_max;
    j = j + 4;
end

%Inequality constraint 3: Max battery discharge capacity.
j = 1;
for i = (2 * 192 * seas + 1):(3 * 192 * seas)
    Ain(i,j+1) = 1;
    Ain(i,M) = -deltat;
    j = j + 4;
end

%Inequality constraint 4: Max battery charge capacity.
j = 1;
for i = (3 * 192 * seas + 1):(4 * 192 * seas)
    Ain(i,j+2) = 1;
    Ain(i,M) = -deltat;
    j = j + 4;
end

f(M-1) = -CAPEX_b;
f(M) = -CAPEX_p;

% Optimization tool function
```

```
x = linprog(-f,Ain,bin,Aeq,beq,lb,ub);

Esda = zeros(192*seas,1);
Ebd = zeros(192*seas,1);
Ebc = zeros(192*seas,1);
Eb = zeros(192*seas,1);
Egrid = zeros(192*seas,1);
revenue = zeros(192*seas,1);

j = 1;
for i = 1:192*seas
    Esda(i) = x(j);
    j = j + 1;
    Ebd(i) = x(j);
    j = j + 1;
    Ebc(i) = x(j);
    j = j + 1;
    Eb(i) = x(j);
    j = j + 1;
    Egrid(i) = Esda(i) + Ebd(i);
    revenue(i) = (Egrid(i) * price(i))*366/d_coeff;
end

Battsize = x(M-1)
Pbmax = x(M)

Totrev = sum(revenue);
Profit = Totrev - CAPEX_b * Battsize - CAPEX_p * Pbmax;
```

D.2 Wind power production imbalance compensation

```
clear
clc

inputspot; % Import Elspot price [EUR/MWh]
inputplan; % Import production plan [MWh]
inputreal; % Import metered production [MWh]
inputregulation; % Import purchase and sale balancing
    prices.
fee_sale = 0.217; % Fee applied by the TSO on the sale of
    balancing power.
fee_purch = 2 * fee_sale; % Fee applied by the TSO on the
    purchase of balancing power.

```

```
%Input data
eff = 0.90; % Battery round-trip efficiency
deltat = 1; % Time-step of study [h]
Pb_max = 25; % Maximum charge/discharge capacity [MW]
Eb_max = 50; % Energy capacity of the battery [MWh]
Eb_start  = 0.9 * Eb_max; % Initial SOC of battery
SOC_min = 0.1;
SOC_max = 0.9;

% Starting conditions
i = 1;
if E_plan(i) == E_metered(i)
    Ec(i) = 0;
    Ed(i) = 0;

elseif E_plan(i) > E_metered(i)
    Ec(i) = 0;

    if (E_plan(i) - E_metered(i)) < Pb_max * deltat

        if (E_plan(i) - E_metered(i)) < (Eb_start - SOC_min * Eb_max) * eff
            Ed(i) = E_plan(i) - E_metered(i);
        else
            Ed(i) = (Eb_start - SOC_min * Eb_max) * eff;
        end
    else
        if Pb_max * deltat < (Eb_start - SOC_min * Eb_max) * eff
            Ed(i) = Pb_max * deltat;
        else
            Ed(i) = (Eb_start - SOC_min * Eb_max) * eff;
        end
    end

else
    Ed(i) = 0;

    if (E_metered(i) - E_plan(i)) < Pb_max * deltat
        if (E_metered(i) - E_plan(i)) < (Eb_max * SOC_max - Eb_start)
            Ec(i) = E_metered(i) - E_plan(i);
        else
            Ec(i) = Eb_max * SOC_max - Eb_start;
        end
```

```
    else
        if Pb_max * deltat < (Eb_max * SOC_max - Eb_start)
            Ec(i) = Pb_max * deltat;
        else
            Ec(i) = Eb_max * SOC_max - Eb_start;
        end
    end
end
Eb(i) = Eb_start + Ec(i) - Ed(i);


% Main operation
for i = 2:length(E_metered)

if E_plan(i) == E_metered(i)
    Ec(i) = 0;
    Ed(i) = 0;

elseif E_plan(i) > E_metered(i)
    Ec(i) = 0;

    if (E_plan(i) - E_metered(i)) < Pb_max * deltat

        if (E_plan(i) - E_metered(i)) < (Eb(i-1) - SOC_min
          * Eb_max) * eff
            Ed(i) = E_plan(i) - E_metered(i);
        else
            Ed(i) = (Eb(i-1) - SOC_min * Eb_max) * eff;
        end
    else
        if Pb_max * deltat < (Eb(i-1) - SOC_min * Eb_max) *
            eff
            Ed(i) = Pb_max * deltat;
        else
            Ed(i) = (Eb(i-1) - SOC_min * Eb_max) * eff;
        end
    end

else
    Ed(i) = 0;

    if (E_metered(i) - E_plan(i)) < Pb_max * deltat
        if (E_metered(i) - E_plan(i)) < (Eb_max * SOC_max -
            Eb(i-1))
            Ec(i) = E_metered(i) - E_plan(i);
```

```
            else
                Ec(i) = (Eb_max * SOC_max - Eb(i-1));
            end
        else
            if Pb_max * deltat < (Eb_max * SOC_max - Eb(i-1))
                Ec(i) = Pb_max * deltat;
            else
                Ec(i) = (Eb_max * SOC_max - Eb(i-1));
            end
        end
end
Eb(i) = Eb(i-1) + Ec(i) - Ed(i)/eff;
E_imb(i) = E_metered(i) - E_plan(i) + Ed(i) - Ec(i);

% Calculation of the production imbalance cost
if E_imb(i) > 0
    cost(i) = (p_spot(i) - p_sale(i) + fee_sale) * E_imb(i); %Opportunity cost of selling power at a lower price than day-ahead price
else
    cost(i) = (p_purch(i) + fee_purch) * (-E_imb(i)); %Price at which electricity has to be purchased
end
% Calculation of base imbalance costs (no battery)
if E_metered(i) - E_plan(i) > 0
    base_cost(i) = (p_spot(i) - p_sale(i) + fee_sale) * (E_metered(i) - E_plan(i)); %Opportunity cost of selling power at a lower price than day-ahead price
else
    base_cost(i) = (p_purch(i) + fee_purch) * (-(E_metered(i) - E_plan(i))); %Price at which electricity has to be purchased
end
end

% Cycles
cycles = sum(Ec + Ed)/2/(Eb_max);

% Annual production imbalance cost
imb_cost = sum(cost);
base_imb_cost = sum(base_cost);

% Total cost
savings = base_imb_cost - imb_cost
```

D.3 Primary frequency regulation, FCR-N

```
clear
clc

hour = [1033 1057 3361 3385 6505 6529 7225 7249];
pen_fac = 2;

for DAY = 1:4

clearvars -except START DAY cycles Revenue hour pen_fac
START = hour(DAY);% First hour of forecast (out of 8760)
day_range = (24*DAY-23):24*DAY;
Nw = 25; % Number of scenarios = Nw
% ARIMA scenario generation and reduction techniques
% Reduces the number of scenarios (rows) for a t (columns) time-frame

% START First hour of forecast
% Nw = Final number of scenarios (after reduction), defined in FCR_stoc

% Step 0: Kantorovich distance for each pair of scenarios
[y,act] = ARMA(200,START);

[row,column] = size(y);
v = zeros(row,row);

for i = 1:row
    for j = i:row

        v(i,j) = sum(abs(y(i,:) - y(j,:)));
        v(j,i) = v(i,j);

    end
end

v_ini = v;

% Step 1: Select min Kantorovich distance

scenarios = zeros(Nw,1); %Selected scenarios
omega_s = zeros(Nw,24); %Values of the selected set of scenarios to simulate
```

```
pi = 1/row * ones(row,1);
d = v * pi;

[value,index] = min(d);

% Scenario to be selected, which minimizes the Kantorovich distance = index


scenarios(1) = index;
scen_ind = zeros(row,1);
scen_ind(index) = 1;
omega_s(1,:) = y(index,:);

% Step 2: Update the cost matrix
for N = 2:Nw
    for i = 1:row
        for j = 1:row
            if (sum(j ~= scenarios) == 0) && (sum(i ~= scenarios) == 0)
            v(i,j) = min(v(i,j),v(i,scenarios(1:N-1)));
            end

        d(i) = v(i,:) * (pi .* (1 - scen_ind));

        if scen_ind(i) ~=1
            d_new(i) = d(i);
        else
            d_new(i) = inf;
        end

        end
    end

    [value,index] = min(d_new);

    scen_ind(index) = 1;
    scenarios(N) = index;
    omega_s(N,:) = y(index,:);
end
selected = sort(scenarios);

% Step 3: Probability calculation
% x = zeros(row-Nw,row);
```

```
z = 1;
for i = 1:row
    if scen_ind(i) == 0
        x(z,:) = v_ini(i,:);
        z = z + 1;
    end

end

for j = 1:(row-Nw)
   for i = 1:row
      if scen_ind(i) == 1
          dist(j,i) = x(j,i);
      else
          dist(j,i) = inf;
      end
   end
   [value(j),index(j)] = min(dist(j,:));
end

pi = pi .* scen_ind;
for i= 1:(row-Nw)

    pi(index(i)) = pi(index(i)) + 1/row;

end
 % sum(pi) Cumulative probability (must be = 1)

prob = pi(scenarios).';
clearvars x v_ini
Pbmax = 5; % MW
Battery = 2.5; % MWh

% Split activation values in two positive variables
lambda_d = zeros(Nw,24);
lambda_c = zeros(Nw,24);
pi = prob;% Probabilities associated to each scenario

for w = 1:Nw
    for t = 1:24
        if omega_s(w,t) < 0
            lambda_d(w,t) = -omega_s(w,t);
        else
            lambda_c(w,t) = omega_s(w,t);
        end
```

```
    end
end

input_price;

deltat = 1;
eff = 0.9;
Ebmax = 0.9 * Battery;
Ebmin = 0.1 * Battery;
Eb0 = 0.5 * Battery;

p = FCR_price(day_range);
up = up_price(day_range);
down = down_price(day_range);


% Coefficient of the bidden capacity, hourly prices
f = zeros(5 * 24 * Nw + 24,1);
Ain = zeros(24 * Nw * 2, 5 * 24 * Nw + 24);
bin = zeros(24 * Nw * 2,1);
Aeq = zeros(24 * Nw * 3, 5 * 24 * Nw + 24);
beq = zeros(24 * Nw * 3,1);
lb = zeros(5 * 24 * Nw + 24,1);
ub = inf(5 * 24 * Nw + 24,1);

f(1:24) = p; % Define first 24 coeff as prices
c_d(1:24) = pen_fac * p; % Penalty not to discharge ( /MWh)
c_c(1:24) =  pen_fac * p; % Penalty not to charge ( /MWh)

% Coefficients of the rest of the variables (M, Eb, Ed, Ec)
    for every hour
% and scenario
t = 1;
w = 1;
i = 25;
for w = 1:Nw
    for t = 1:24
        f(i) = - pi(w) * c_d(t) * lambda_d(w,t);  % Penalty
        f(i+1) = - pi(w) * c_c(t) * lambda_c(w,t); % Penalty
        f(i+3) = pi(w) * up(t); % Energy Payment
        f(i+4) = - pi(w) * down(t); % Energy Purchase
        i = i + 5;
    end
end

```

```
% Equality and inequality constraints for the hourly bidden
    capacities (ro1:ro24)
row = 1;

for i = 1:Nw
    column = 1;
    for j = 1:24
        Ain(row,column) = lambda_c(i,j) * deltat;
        Ain(row + 24 * Nw,column) = lambda_d(i,j) * deltat;
        Aeq(row,column) = lambda_d(i,j) * deltat / eff;
        Aeq(row + 24 * Nw,column) = lambda_c(i,j) * deltat;

        row = row + 1;
        column = column + 1;
    end
end

% Equality and inequality constraints for M, Eb, Ed, Ec
row = 1;
for i = 1:Nw
    for j = 1:24
        if row == 1 + (i - 1) * 24 %Initial condition
            Ain(row,column+1) = -1;
            Ain(row + 24 * Nw,column) = -1;

            Aeq(row,column) = -1 * lambda_d(i,j);
            Aeq(row,column + 3) = -1;
            Aeq(row + 24 * Nw,column + 1) = -1 * lambda_c(i
                ,j);
            Aeq(row + 24 * Nw,column + 4) = -1;

            bin(row) = Ebmax - Eb0;
            bin(row + 24 * Nw) = eff * (Eb0 - Ebmin);

            column = column + 5;
            row = row + 1;
        else
            Ain(row,column + 1) = -1;
            Ain(row,column - 3) = 1;
            Ain(row + 24 * Nw,column) = -1;
            Ain(row + 24 * Nw, column - 3) = -eff;

            Aeq(row,column) = -1 * lambda_d(i,j);
            Aeq(row,column + 3) = -1;
            Aeq(row + 24 * Nw,column + 1) = -1 * lambda_c(i
```

```
                  ,j);
            Aeq(row + 24 * Nw,column + 4) = -1;

            bin(row) = Ebmax;
            bin(row + 24 * Nw) = -(eff * Ebmin);

            column = column + 5;
            row = row + 1;
        end
    end
end

row = (2 * Nw * 24) + 1;
column = 25;
for i = 1:Nw
    for j = 1:24
    if row == (2 * Nw * 24) + 1 + (i - 1) * 24 %Initial
       condition
        Aeq(row,column + 2) = 1;
        Aeq(row,column + 3) = 1;
        Aeq(row,column + 4) = -1;
        beq(row) = Eb0;

        column = column + 5;
        row = row + 1;
    else
        Aeq(row,column + 2) = 1;
        Aeq(row,column + 3) = 1;
        Aeq(row,column + 4) = -1;
        Aeq(row,column - 3) = -1;

        column = column + 5;
        row = row + 1;
    end
    end
end

ub(1:24) = Pbmax;

lb(27:5:5 * 24 * Nw + 24) = Ebmin;
ub(27:5:5 * 24 * Nw + 24) = Ebmax;

x = linprog(-f,Ain,bin,Aeq,beq,lb,ub);

Bid(1:24) = x(1:24);
```

```

Revenue(DAY) = f.' * x

s = 25;
for w = 1:Nw
    M_d(w,:) = x(s:5:s+5*23);
    M_c(w,:) = x(s+1:5:s+1+5*23);
    Eb(w,:) = x(s+2:5:s+2+5*23);
    Ed(w,:) = x(s+3:5:s+3+5*23);
    Ec(w,:) = x(s+4:5:s+4+5*23);
    s = s + 5*24;
end

cycles(DAY) = sum(pi * (Ec + Ed))/2/Battery;
Unsatisfied_d = M_d .* lambda_d(1:Nw,:); % Hourly energy not discharged, MWh
Unsatisfied_c = M_c .* lambda_c(1:Nw,:); % Hourly energy not charged, MWh

end
Result = sum(Revenue)*366/DAY;
```