Flexibility services and investments in distribution networks

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I declare that this document is an original work of my own authorship and that it fulfils all the requirements of the Code of Conduct and Good Practices of the *Universidade de Lisboa & Universitat Politècnica de Barcelona.*

Abstract

This thesis focuses on the economic question of how to invest in the electricity grid. When a Distribution System Operator (DSO) currently must deal with grid problems, the idea is usually to reinforce the grid, although there is the possibility to opt for so-called utility services to help in these situations and avoid reinforcing the grid. Although this is an option, there are still not the right incentives from the regulatory authorities for DSO to actually opt for the use of such services. This work aims to make an economic study of how much it would cost annually to opt for one of these services, in this case the type of service was a Battery Energy Storage System (BESS), and compare it with how much compensation would be received, in Spain, if it opted for the grid reinforcement. The software "PandaPower" was used to build and simulate the electrical networks on the scenarios. After these simulations, only the scenarios where the utility could actually be used were considered, and in these an economic study was made of how much the utility option would cost annually, creating a cost model. The results of this cost were then compared with the annual remuneration that the DSO would receive from the Spanish regulator if it opted for network reinforcement, after the comparison the results are promising for the study as they show that in many cases the DSO can opt for the utility service. A sensitivity analysis was also done.

Keywords

Electric grids, Distribution Network, Flexibility services, Overloading, Economic Analysis, Battery, Cost Comparison, Annual Cost

Resumo

Esta dissertação foca-se na questão económica de como investir na rede elétrica. Um Operador de Sistemas de Distribuição (OSD), quando atualmente tem de lidar com problemas na rua, tipicamente opta por fazer um reforço da rede, como trocar as linhas ou transformadores, embora exista a possibilidade de optar pelos chamados serviços de flexibilidade que nestas situações conseguem com que se evite reforço da rede. Embora esta sejam uma opção ainda não existem os incentivos adequados por parte das entidades reguladoras para que OSD opte de facto pelo uso de tais serviços. Este trabalho visa fazer um estudo económico de quanto custaria anualmente optar por um destes serviços, neste caso o tipo de serviço foi um *Battery Energy Storage System* (BESS), e compará-lo com quanto receberia de remuneração, em Espanha, se optasse pelo reforço da rede, mais expeditamente troca de cabos elétricos. O software “PandaPower” foi usado para contruir as redes elétricas e simular os cenários. Após estas simulações, consideraram-se apenas os cenários em que se podia utilizar o serviço de utilidade, e nestes foi feito um estudo económico de quanto custaria anualmente a opção do serviço de utilidade. Os resultados deste modelo de custos foram então comparados com a remuneração anual que o OSD iria receber por parte da entidade reguladora Espanhola caso optasse pelo reforço da rede, após a comparação os resultados são promissores para o estudo pois mostram que em muitos casos o OSD pode optar pelo serviço de utilidade. Uma análise de sensibilidade também foi feita.

Palavras-chave

Redes elétricas, Rede de distribuição, Serviços de flexibilidade, Sobrecarga, Análise Económica, Bateria, Comparação de custos, Custo anual

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List of Symbols

BESS	Battery energy storge
BESS_peakpower	Peak power of the BESS, MW
BESS_energy	Energy of the BESS, MWh
DSO	Distribution system operator
TSO	Transportation system operator
EHV	Extra high voltage
HV	High voltage
MV	Medium voltage
LV	Low voltage
DER	Distributed energy resources
RES	Renewable energy sources
LFM	Local flexibility market
CAPEX	Capital expenditures, EUR
OPEX	Operational expenditures, EUR
SG	Smart grids
GRID1	Electrical grid 1
GRID2	Electrical grid 2
PV_GEN	PV generation, MW
Load	Load consumption, MW
NOPV	No PV genration
50PV	50% of PV generation
70PV	70% of PV generation
i_ka	Current that is passing through the line, Amp
max_i_ka	Maximum current that the line can sustain, Amp
loading_percentage	Percentage of loading in the line, %
line_power_h	Power that is passing through the line at a given hour, MW
loading_thersold	Threshold for overloading, %
energy_cost	Energy cost of the BESS, EUR
power_cost	Power cost of the BESS, EUR
use_BESS	How much does the DSO pay for the BESS, %
Li-ion	Lithium-ion battery
NMC/LCO	Nickel manganese cobalt/lithium manganese oxide
NCA	Nickel cobalt aluminium oxide
LFP	Lithium iron phosphate
LTO	Lithium titanate
O&M	Operation and maintenance cost, €
power_capacity	Power capacity of the BESS, MW
energy_capacity	Energy capacity of the BESS, MWh
JAN_SUN	Case for average consumption for a Sunday in June, MW
JAN_THUR	Case for average consumption for a Thursday in June, MW
JUN_SUN	Case for average consumption for a Sunday in January, MW
JUN_THUR	Case for average consumption for a Thursday in January, MW

List of Software

PandaPower	for building and simulating electric grids

Chapter 1

Introduction

This chapter presents the authors' motivation to undertake the thesis topic, and a brief overview of the aims and scope of the work.

1.1 – Motivation & Thesis Objective

With the increase of renewable energy resources (RES) and electrical vehicles (EVs), in distributed generation and increased network use [1], congestion issues occur much more often in distribution networks.

Such issues are often handled by the distribution system operator (DSO), that opts for grid expansion with the objective of giving back to the grid an equilibrium for the long term. Another way to prevent such congestion is the addition of flexibility services. Flexibility services can be defined as the ability of a power system to utilise resources to respond to changes in net load [2], more on that is explained in chapter 2. So comes the role of the DERs (Distributed Energy Resources), which can play a substantial role, because they can offer their flexibility services to the DSO in order to help with the good performance of the grid and prevent grid expansion. The DSO, when faced with a congestion or overloading problem on his grid, should be able to have the option of procuring a flexibility service preventing grid reinforcement. For this to happen, the market as to be structured for such operations to occur, to have the better exploitation of DERs flexibility or even other identities that can offer such service. On [3] the authors focus on this matter, where they state the fact that in a lot of Europeans countries such interactions between the DSO and other identities, such as DERs, that offer flexibility services are not allowed. These authors analyse the European regulation to identify the most important ways to enable such interaction.

If the changes in the markets occur and in the regulation mechanisms, giving the DSO the actual power on having the option to go for a flexibility service it is important to see if in fact such options are profitable for the DSO and that is where the motivation of this work sets place. This work aims to give a view of comparison between the annual cost of investing, in flexibility service, in the case of this study a Battery energy storage system (BESS), and the remuneration given by the regulation of Spain that is built to only support the DSO into grid expansion [4]. Spain was chosen as the present work was developed at Polytechnic University of Catalonia (UPC)

1.2 – Methodology & Thesis Structure

This thesis aims to give an annual cost comparison between a flexibility service and the remuneration scheme set by the Spanish regulation to incentive to grid reinforcement. That being said the methodology is translated on to the thesis structure, where the aim is to:

- Simulate scenarios where grids are under stress, using load consumption behaviours from Spain, more specifically Barcelona, so that the need for grid reinforcement or a flexibility service is needed.
- Select a flexibility service and simulate its application on to the stressed grid to see if the grids go back to a stable scenario.

- Investigate what is the cost of that flexibility service, building a tool cost for such service and compare it with the annual remuneration extracted from the Spanish regulation.

The results and conclusions from this work hoped to serve as future guidance and support for future work done on this matter.

Such methodology is translated into the framework illustrated in Figure (1.1) and is developed along the six chapters of this document.

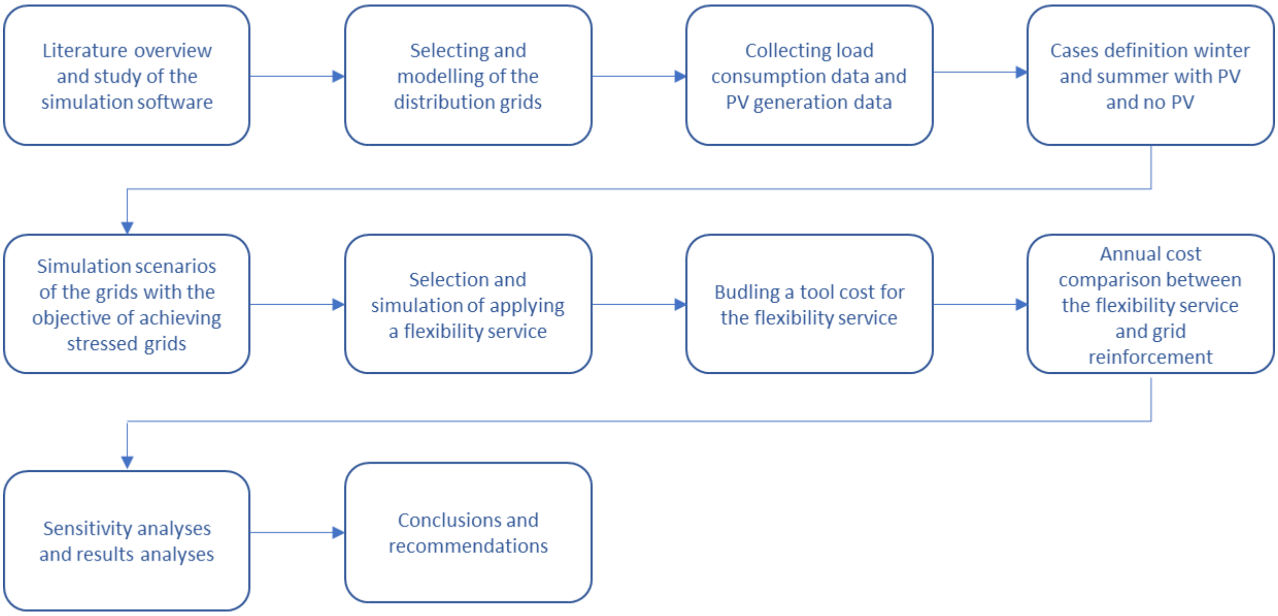


Figure 1. 1 - Methodology outline

The introductory chapter is followed by the 2nd chapter where the literature overview is done on what is a DSO and its obligations, the role that the flexibility services and DERs can have in distribution networks, and the different types of regulatory mechanisms that exist. The 3rd chapter is the first step on building the cases, shows the benchmarking done in selecting the grid to then be study upon, and how they were modelled. Also, the definition of the scenarios are presented in this chapter, after this comes the 4th chapter where the features of each grid are changed with the objective of achieving stressed scenarios, after this the selecting of the flexibility service is done, and thus the application and results of the flexibility service on to the grids is showed. To finalise on the 5th chapter the tool cost of the flexibility service is constructed and an annual cost of investing in this service is calculated and then compared with the annual remuneration from the Spanish regulatory scheme if the DSO would, in fact, go for grid reinforcement, in this case changing the grid line, sensitivity analysis in this chapter is also done to give a more clear view of where does it stop to be profitable to the DSO investing on the chosen flexibility service, after this comes the 6th chapter where the conclusion of the study is done.

Chapter 2

Literature Review

The second chapter presents a review of the literature related to Distributed System Operators (DSO), flexibility services and distributed energy resources. It addresses issues such as high demand, grid efficiency, gird expansion and options to avoid it, types of regulations sectors and gives a short briefing about the problem posted on this thesis.

2.1 – Distribution System Operators

A Distribution System Operator (DSO) is an active manager or owner of one electricity distribution network, and it is responsible for its operation and maintenance, aiming at a good performance. A good performance consists of meeting the demands of all the end-users of the distribution network. These networks include electrical cables, substations and transformers (Figure 2.1) and may operate on low voltage or medium voltage. Before the DSO, the transportation of electricity is carried out by the Transportation System Operator (TSO), which deals with large quantities of voltage (EHV, HV), often from large power plants to large cities or industrial zones. Examples of DSOs around Europe are EDP Distribuição from Portugal, EREDES and E-Distribución from Spain.

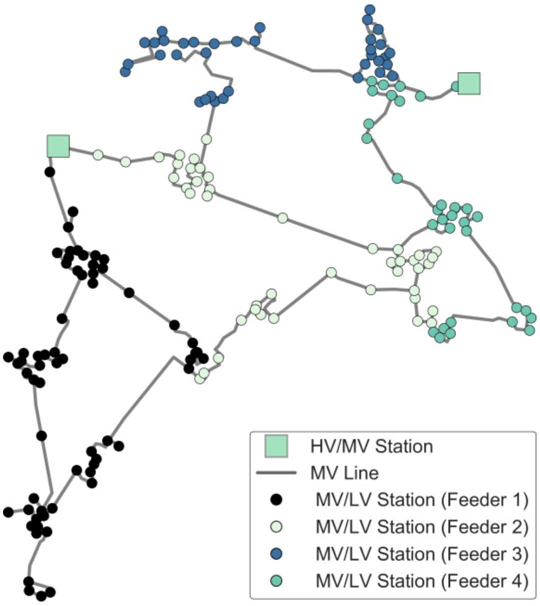


Figure 2. 1 – Electrical Grid (Source:[5]*)*

A country usually has a DSO that operates in a specific area of the country and acts as a monopolist network operator. In the concentration area, the study adopted the approach done by [6], where the country's markets can be divided into three categories: (1) high concentration, where the DSO is serving 99%-100%of the distributed power; (2) medium concentration, includes countries where exists a dominant DSO, covers about 80% of the distribution power market or the three largest DSOs serve more than 60%, with several smaller DSOs serving the rest, a good example is Italy that has 140 DSOs operating and one covers 86% of the demand, and 49 of them have less than one thousand costumers [7]; (3) low concentration, the largest DSOs deliver about 50% of the distributed power, in Finland, Norway and Sweden the biggest companies cover 41%, 33% and 51% of the distributed power respectively [8]. The authors in [8] concluded, by doing the mean values for investments based on the distribution sector concentration, that the investments are greater in low concentration countries and is less in high concentration; the method also provided the information that in the low distribution-sector concentration the satisfaction of the total demand for distribution electricity is statistically and positively correlated to the level of investments.

Due to the high demand for electricity DSO face today the challenge of guaranteeing flexibility. This can be achieved through the usage of flexibility services that can be obtained from different sources as is the case of DER. To explore this in a proper manner the need for appropriate regulation is identified. These aspects are analysed below.

2.2 – Flexibilities Services and DERs in Distribution Networks

With the growth of renewable energy sources (RES), the need for flexibility will always increase. The interaction between DSOs and DERs through the aggregator in electricity markets is assumed by several research papers. But in a lot of European countries, such interaction is not allowed. As it was said before, DERs are raising challenges due to the introduction of reverse flow, congestion problems, and voltage limit violations, but can also help in a lot of technical problems for the DSOs if they are properly aggregated, such aggregation is defended by the local flexibility markets (LFM), allowing markets access to DERs that is studied in [3].

DER flexibility changes differing on the type, might be efficient in one case and inefficient in another. For example, PV systems can only provide during some set of hours during the day, while battery storage can provide for all day if necessary. Another thing is that flexibility services of industrial DERs are more convenient for providing services, bigger sized loads imply a smaller amount of resources is required to reach the minimum size for bidding on the market, and information and communication infrastructures are usually already installed for the purpose of energy management [3].

With regulatory changes in the European Union, the aggregator will be able to offer flexibility from the distribution level up to short-term markets. This will enable DSOs to become their own active manager and so to search for flexibility in their geographical area. In this context, DERs will then become the main flexibility source for DSOs to handle technical problems giving them an alternative to avoid grid reinforcement [9]. “In the context of a liberalised electricity market, the establishment of a market-based procedure to value DER flexibility is one of the possible solutions. DSO performs a grid-oriented use of the flexibility, deciding during the planning process whether to call for a market-bade procurement or to proceed with grid reinforcement” [3].

This type of changes will change the DSO markets, and these markets will be correlated into the local flexibility markets (LFM), but this type of markets is still under research or at the pilot-stage in Europe. The two big stages in this type of market are that it is possible for the parties to trade different services: grid-oriented service and market oriented-services. The DSO market will be used as a grid management measure; some proposal for this are being studied, such as the FLECH market in [10], [11], where the DSO can forecast the load scenarios in order to see when it will need flexibility throughout the planning horizon; as well as the FlexMart [12] where minimisation of the overall cost by the DSO is done considering the cost of flexibility, the cost of grid reinforcement and the cost of energy curtailment. DSO will be the market operator and will evaluate offers of flexibility for grid-oriented use, being made by the aggregators that get these flexibility services from the DERs.

Once again, the flexibility services provided by DERs help the distribution network problems such as overloading of the lines due to the current passing being higher from the maximum current that the lines can sustain, and are alternatives to grid reinforcement, but in some way, the DSOs have to see if, in fact, makes sense to invest in this type of flexibility services. In [13] a method is introduced where for each flexibility service exists a value of the flexibility that is what the DSO is ready to pay for the corresponded flexibility. If the cost of using the flexibility service exceeds its value of flexibility, contracting that service will not be economically viable for the DSO. Several types of flexibility services exist, such as demand response, BESS, reconfiguration (RE) exist.

Demand Response basically consists of the consumers devices operational pattern being changed by an external signal coming from the DSO or an aggregator, demand, response is a flexibility service that can be provided by a wide range of electrical devices [14][13], various studies of cost models for the demand response, based on supply-demand, fixed incentives, average or in dynamic pricing were made in [15–18].

Battery energy storage system (BESS) that can act as a local generator in the DSO perspective, able to provide power during grid congestion in order to decrease the overloading of the grid components [13], usually these types of systems are owned by an independent identity, an aggregator [19], in [20] a cost model taking into account the CAPEX and OPEX of the BESS, other authors did also cost models but only doing a detailed analysis of the BESS CAPEX [21] or the OPEX [22].

Reconfiguration (RE) consists of shifting an electrical load from one position of the network to another to avoid grid congestion so that the consumers are provided with the power they need without affecting the grid. A study of the cost of RE by applying costs to the switches is done in [23]

But these types of investments, in flexibility services, demand an adequate regulation, as will be discussed in the next section.

2.3 – DSO Flexibility and Regulation

The growth of distributed energy resources (DER), like distributed generation, local storage and demand response, posed some challenges for the DSOs and their regulation. In 2014 article [24], the authors focused on the missing aspect of the current regulation, recognising DSOs as regulated monopolies but also key players along the electricity supply chain. DERs appear as a key player and can help the DSOs, with the right market and regulation, and a more efficient and cleaner electricity system could be achieved. In [24] the authors concluded that the main changes that needed to be done are:

- The remuneration schemes for the DSOs needed to be reconsidered.
- The way that the DSOs do their network charges in order to recover their costs should be changed.
- The DSOs should expand their responsibilities and become more active in a number of areas in the newly emerging market environment.
- The cooperation and differentiation between the DSO and the TSO should become more efficient to ensure reliable grids in terms of geography and timing.

With the rapid growth of DERs and electrification mobility, and the challenges they imposed on the DSOs, the necessity for upgrading to a more intelligent and communicative electricity network was inevitable, the so-called Smart Grids (SG). The International Energy Agency (IEA) is expecting electricity network investments in the range of 600 billion € for Europe between 2014 and 2035 [25], and Europe's industry association for electricity estimated a requirement of 600 billion € by 2020, two-thirds of which would be for distribution grids [6].

The deployment of a SG imposes a change in a distribution network that is operated by DSOs. A good correlation between the regulating identities and the DSOs is important since the regulation directly affects DSO budgets and in turn their ability to raise capital for the implementation of innovative SG project [26], [27]. In [28] the author defended in fact that regulation can have an important role in setting up a good framework for grid investment.

The regulatory mechanisms can be divided in the way they induce cost efficiency or productivity by providing relevant incentives to DSOs. In [6] the study identifies three broad categories of models:

(1) incentive-based models, can be described as any model where the regulator delegates certain pricing decisions to the firm and that firm, from cost reduction, can reap profit increases [29]. Most of the European countries use incentive-based regulatory schemes; the first one was the UK and Norway. Since introduced in the UK, price-cap regulation has been one of the most used incentive-based models, to motivate cost minimisation by regulated utilities. In 2008 Spain also adopted a regulatory framework based on revenue caps, for electricity DSOs, with a review period of four years [30];

(2) cost-based models, involves setting prices based on the costs for producing, distributing and selling, in this type of regulatory scheme the process is kept close to realised costs, so that the earnings are close to the target level, the regulation determines a fair rate of return to compensate the company for its efforts and risks, and every price review rates are adjusted so as to ensure the firm earns the authorised return [31]. Many countries adopting the cost-based models usually apply a cap operating expenditures (OPEX), like Greece, Belgium, Switzerland and Malta [6]

(3) hybrid-based models, basically these types of models flown a cost-based approach for capital expenditures and an incentive-based model do operational expenditures. One example of this regulatory scheme model its Italy, where the regulators promoted DSOs to trim down OPEX, while invested capital is remunerated [32]. Another example is Portugal that since 1999 the regulation in

Portugal does efficiency measures on the total cost of the DSOs, in the allowed returns, CAPEX if fully considered, and OPEX depends on the efficiency measures (ERSE, 2011).

In [6] the conclusion is that incentive-based models promote more efficient investments in SG than cost-based and hybrid, supporting [5] , in the fact that cost-based models may not incentive investments in technologies such as SG.

An Innovation-stimulus mechanism is also a way the regulators have used to stimulate innovation within the distribution system; this type of mechanism is designed to support innovative ideas that DSOs are unlikely to undertake without incentives. In [6] the authors support this mechanism, and in their study, a conclusion is made that investments in the SG happen more in countries with an incentive-based mechanism than in countries where there no incentives for innovation investment.

2.4 – The Problem

With base on all the matters that were addressed before, the main goal of this thesis is to when in a situation where a better function of the grid is needed, should the DSO invest in grid reinforcements or should invest in flexibility services by either contracting a type of service or doing it by themselves. Cases of grid stressing will be created, and then budgets will be calculated, one for the grid reinforcement and other for the flexibility service. These will be compared in order to see which one is more plausible for the DSO to invest on.

Chapter 3

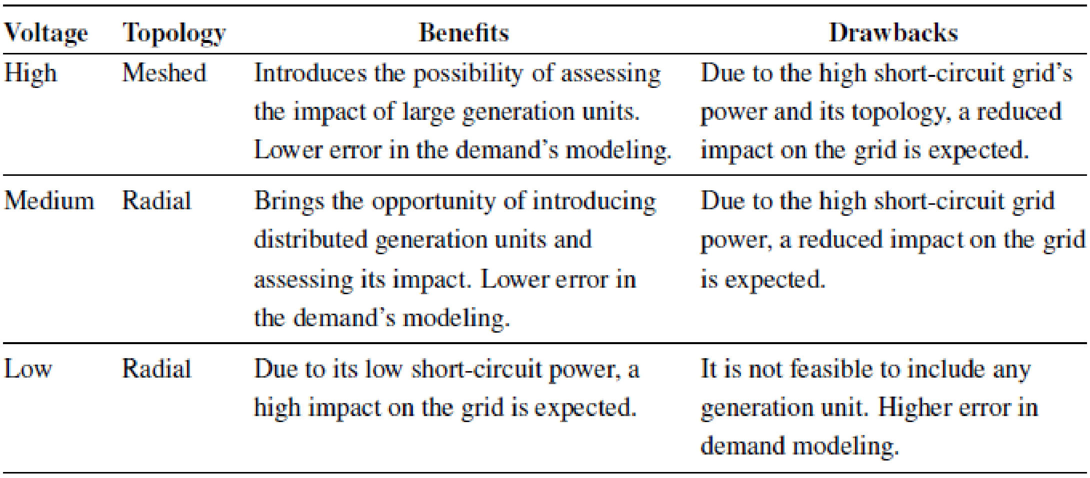
Benchmarking Distribution Networks & Modelling

This chapter explores the benchmarking, the selection and modelling of the grid used in this thesis. The scenarios that were defined to be studied upon are characterised and a short review of the program that was used to build the grids is also given.

3.1 – Building the Benchmark

Due to lack of information in a real Distribution Network, in order to use it for testing and evaluation, a real grid always has the main upside of the practically oriented results that can offer, although it has the disadvantage of obtaining the data. Going for a testing grid gives the advantage of the availability of data and the certainty of working properly. During the study of this thesis, the extra high grid voltage grid has been dismissed because it is a concern of the TSOs, and the study aims the DSOs, so the medium voltage distribution grid allows for a better interpretation of the problem, because it has the benefit of introducing distributed generation units and assessing its impact (Table 3.1). Two testing grids were assembled and modelled, GRID1 and GRID2, the benchmarking and modelling of both grids will be discussed in this chapter.

Table 3. 1 – Benefits and drawbacks of performing the study with different type grids (source: [33]*)*



Voltage	Topology	Benefits	Drawbacks
High	Meshed	Introduces the possibility of assessing the impact of large generation units. Lower error in the demand's modeling.	Due to the high short-circuit grid's power and its topology, a reduced impact on the grid is expected.
Medium	Radial	Brings the opportunity of introducing distributed generation units and assessing its impact. Lower error in the demand's modeling.	Due to the high short-circuit grid power, a reduced impact on the grid is expected.
Low	Radial	Due to its low short-circuit power, a high impact on the grid is expected.	It is not feasible to include any generation unit. Higher error in demand modeling.

3.1.1 – GRID1

This grid was taken out of the article [33], where the authors have chosen replicating the case IEEE 37 bus test system from the article [34], and adapted it to 25 kV and all necessary elements. The gris was also chosen for the same reason that the authors defended in the article, due to the fact it is similar to an underground grid in Barcelona (Figure 3.2). From analysing the grid, all the elements were extracted and organised into support data (Tables 3.2 - 3.4), the grid has 35 nodes and 35 lines, has transformers of 160, 250, 400 and 630 kVA connecting the LV side to the MV side, and each station has a different structure regarding the transformers, some stations have only one transformer, others have 2 or 3. Exists two types of cables, one section area of 240 mm² and an impedance of 0.125+0.116i Ω/km and the other with a section area of 400 mm² and an impedance of 0.00778+0.105i Ω/km.

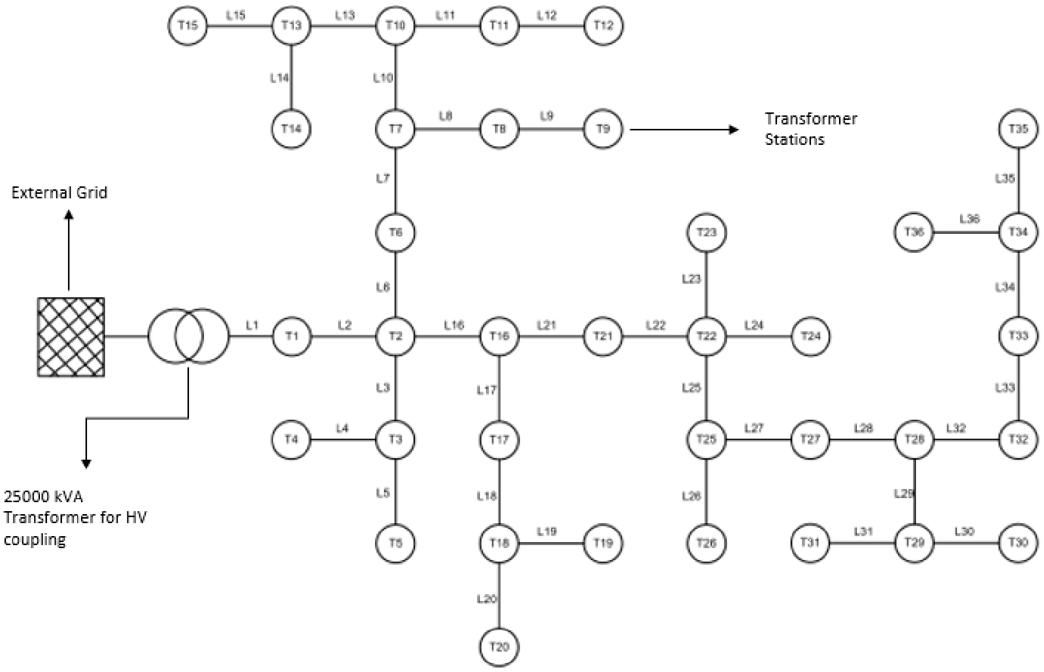


Figure 3. 1 – GRID1 layout (source: [33]*)*

Table 3. 2 – Features of the Transformers

Types of Tranformers	Power[kVA]	Voltage of HV coupling[kV]	Voltage of the LV coupling[V]
A	160	25	420
B	250	25	420
C	400	25	420
D	630	25	420

Table 3. 3 – Features of the Lines/Cables

Types	A[mm^2]	R[Ohm/km]	Xl[Ohm/km]	Imax[A]	Lenghts[km]
LA	240	0.125	0.116	415	0.1-0.7
LB	400	0.0778	0.105	530	0.3-0.4

Table 3. 4 – Features of GRID1 elements

Tranformers Station	Number of Transformers	Types of transformers	Pnom [kVA]	Lines	Lenght [km]	S[mm^2]
T0	1		25000			
T1	1	A	160	L1	0.3	400
T2	3	B+B+C	900	L2	0.2	400
T3	1	B	250	L3	0.4	240
T4	2	A+B	410	L4	0.4	240
T5	1	A	160	L5	0.3	240
T6	1	C	400	L6	0.2	240
T7	1	B	250	L7	0.3	240
T8	2	B+B	500	L8	0.2	240
T9	1	C	400	L9	0.3	240
T10	1	A	160	L10	0.2	240
T11	2	B	250	L11	0.3	240
T12	1	B	250	L12	0.3	240
T13	2	B+B	500	L13	0.3	240
T14	1	A	160	L14	0.3	240
T15	2	B+D	880	L15	0.2	240
T16	2	B+D	880	L16	0.4	240
T17	2	A+C	560	L17	0.4	240
T18	1	B	250	L18	0.2	240
T19	1	A	160	L19	0.5	240
T20	2	A+B	410	L20	0.1	240
T21	1	B	250	L21	0.4	240
T22	2	A+B	410	L22	0.2	240
T23	2	A+B	410	L23	0.3	240
T24	1	D	630	L24	0.2	240
T25	2	B+C	650	L25	0.5	240
T26	2	B+C	650	L26	0.2	240
T27	1	A	160	L27	0.3	240
T28	1	C	400	L28	0.2	240
T29	1	A	160	L29	0.2	240
T30	2	B+B	500	L30	0.3	240
T31	1	B	250	L31	0.2	240
T32	2	A+B	410	L32	0.7	240
T33	1	C	400	L33	0.3	240
T34	2	A+B	410	L34	0.5	240
T35	2	B+C	650	L35	0.3	240
T36	1	C	400	L36	0.4	240

3.1.2 – GRID2

Gird selected from the study [35], the authors aim to investigate the low voltage (LV) and medium voltage (MV) residential grid impact on slow and fast charging electrical vehicles (EV), for different types of strategies. For this study, the interest was only taken into the MV grid topology where the LV grids are connected, with 9 nodes. The rated line to line voltage is 11kV, and the distance between each node is 600m. This type of topology is a realistic urban MV feeder topology [36] (Figure 3.2). The grid is constituted by transformers of 250, 400 and 630 kVA connecting the LV side to the MV side, and the cables are A1 11kV-3 x 95 mm², with an impedance of 0.411+0.105i Ω/km and a current rating of 200 A [37] (Tables 3.5 - 3.7).

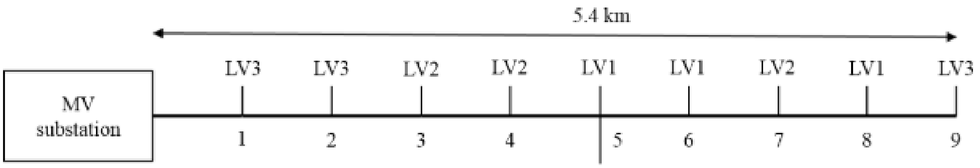


Figure 3. 2 – GRID2 layout (source: [35])

Table 3. 5 – Features of the Transformers

Types of tranformers	Pnom[kVA]	Voltage of HV coupling [kV]	Voltage of the LV coupling[V]
A	250	11	400
B	400	11	400
C	630	11	400

Table 3. 6 – Features on the Lines/Cables

A[mm^2]	R[Ohm/km]	Xl[Ohm/km]	Imax[A]	Lenghts[km]
95	0.411	0.105	200	0.6

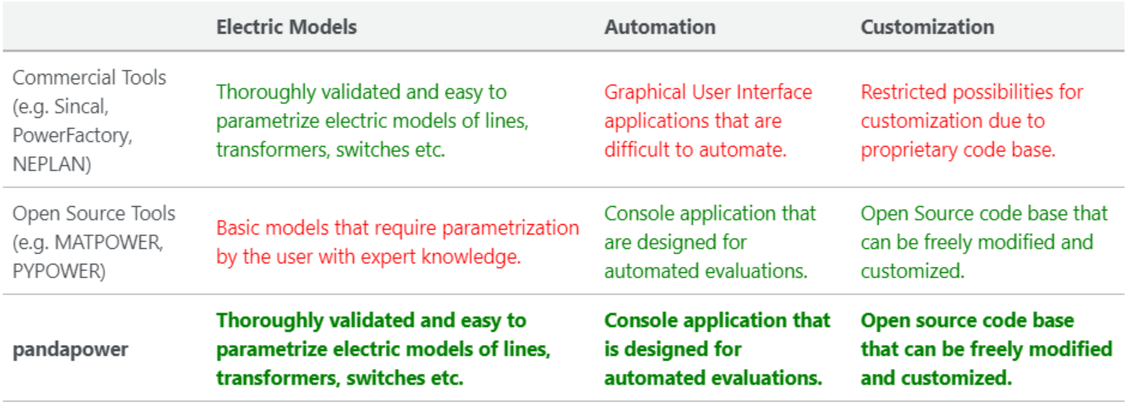
Table 3. 7 – Features of GRID2 elements

Tranformer Station	Types of tranformers	Pnom[kVA]	Lines	Lenght [km]	S [mm²]
T0		25000			
T1	B	630	L1	0.6	48
T2	B	630	L2	0.6	36
T3	C	400	L3	0.6	36
T4	B	400	L4	0.6	36
T5	B	250	L5	0.6	36
T6	C	250	L6	0.6	36
T7	B	400	L7	0.6	36
T8	B	250	L8	0.6	36
T9	C	250	L9	0.6	36

3.1.3 – Tool "PandaPower"

In order to perform a power system analysis of the two grids in this thesis study, "PandaPower" was used. "PandaPower" is a Python based power system analysis tool aimed to the automation of analysis and optimisation of balanced power systems. It provides the possibility of doing power flow and optimal power flow tests, also topology graph searches and short-circuit calculations. The network model is modelled on electric elements such as lines, transformers and switches, and all of these elements exist in variety in the format of libraries and are validated against industry-standard software tools according to article [38]. The main thing of this program is bringing the commercial tools and open-source tools into one (Table 3.6).

Table 3. 8 – "PandaPower" comparison to open-source tools and commercial tools (source: [52])



	Electric Models	**Automation**	**Customization**
Commercial Tools (e.g. Sincal, PowerFactory, NEPLAN)	Thoroughly validated and easy to parametrize electric models of lines, transformers, switches etc.	Graphical User Interface applications that are difficult to automate.	Restricted possibilities for customization due to proprietary code base.
Open Source Tools (e.g. MATPOWER, PYPOWER)	Basic models that require parametrization by the user with expert knowledge.	Console application that are designed for automated evaluations.	Open Source code base that can be freely modified and customized.
pandapower	**Thoroughly validated and easy to parametrize electric models of lines, transformers, switches etc.**	**Console application that is designed for automated evaluations.**	**Open source code base that can be freely modified and customized.**

3.2 – Demand and PV generation Values in Spain

One of the challenges faced during this phase, of gathering values for demand and PV generation, was to find an accurate efficient way to demonstrate a consumption curve as well as a PV generation curve, this due to lack of information given from the utilities, realistic measures of consumption or PV generation never was obtained. This being said, the approach was:

1. Using the Red Eléctrica website, taking out the aggregated consumption curves and measured PV generation curves, hourly, from January and June (this is addressed in the next chapter).
2. Doing an average of consumption and PV generation for each day.
3. A scaling approach was done in order to remove the values of consumption and PV generation from their scale, MWh, and just have curves of behaviour type, either from consumption or PV generation (Figure 3.5).
4. To then pass the unit values again to MW, a power factor was created for consumption and PV generation, and a mathematical calculation was made, for each load, the unit value is multiplied by the power factor and by the value of the transformer that is making the MV/LV connection in that load, that comes in MVA, in order to obtain a value in the dimension to MW (Eq.(1)). Notice that each value is being calculated per hour. For consumption, the power factor is selected to be 0.8; this value was given to the student by the professor upon the experience that he had with the utilities policies and the way they calculate. For PV generation (Eq.(2)) the power factor, ranges from 0.5 to 0.7, representing the percentage of PV that is used (this is addressed in the next chapter).

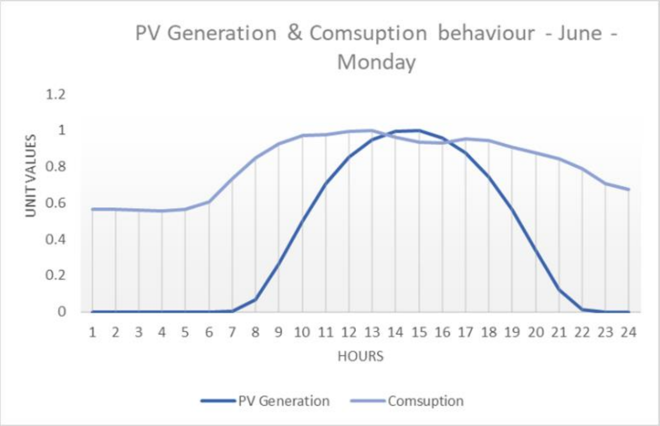


Figure 3. 3 – Average of PV Generation and Consumption for a Monday in June

$$Load(MW) = Unit\ Value \times Power\ Factor \times Power\ of\ the\ Tranformer(MVA) \quad (1)$$

$$PV\_GEN(MW) \ = Unit\ Value \times Generation\ Factor \times Power\ of\ the\ Tranformer(MVA) \quad (2)$$

3.3 – Scenarios Definition

In order to build good cases for testing, the grids were exposed to a scenario during winter, the month of January was chosen, and in the summer, the month of June was chosen because of the PV generation behaviour that differs from one to the other. For example, in January, in the city of Barcelona, according to (https://www.timeanddate.com) the sunrise and sunset were from [8:17-8:04] and [17:32-18:05] respectively, so Barcelona had around 9 hours of sun, and in June it was between [6:17-6:20] and [21:18-21:28] respectively, so the sun was up around 15 hours. So the data collected, that was referred to in the chapter before, was from the month of January in 2019 in Spain and from the month June in 2019 in Spain, after the data was all extracted, was gathered into weekdays and weekends, and an average of the consumption and PV generation for each day was made, with the objective of obtaining a curve that demonstrated an average behaviour of consumption and an average of PV generation for weekdays and weekends, as an example see (Figure 3.3) for a Monday in June, after this Thursday and Sunday were the days selected from weekends and weekdays to build cases on.

Before moving forward is interesting to point out the load consumption behaviour defers from a weekday to a weekend; a good study of this is the article [39] where the authors conclude that in Australia the electricity demand is slightly higher on a Sunday and Saturday than on weekdays (see Figure 3.4).

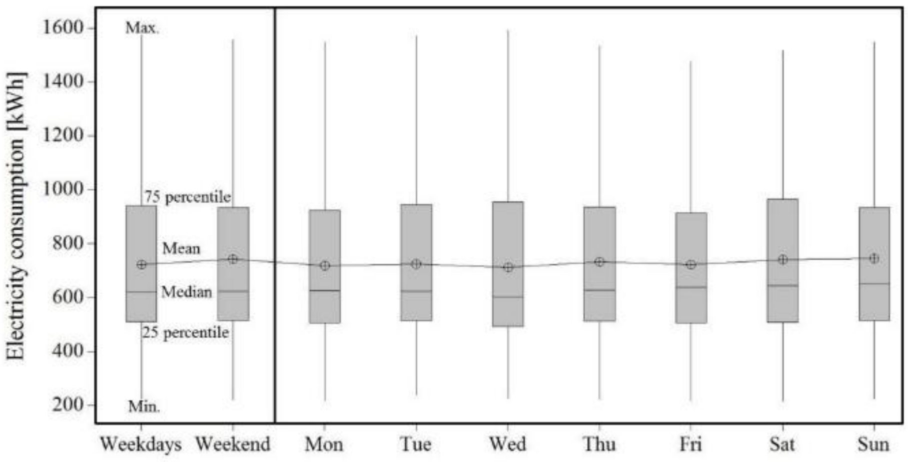


Figure 3. 4 – Comparison of electricity demand between weekdays and weekends (source: [39]*)*

At this point we have the following scenarios, a Thursday and Sunday from January and a Thursday and Sunday from June. To finalise three scenarios of PV generation used were created; for each scenario a different generation factor that is used on Eq.(2), expressed in percentage, was used, so a scenario of non-PV (NOPV) a 50% of PV (50PV), 70% of PV (70PV) and. That 50% and 70% refers to the generation factor in Eq.(2) (Table 3.9).

Table 3. 9 – Scenarios layout

JANUARY						JUNE					
THURSDAY			SUNDAY			THURSDAY			SUNDAY		
NOPV	50PV	70PV	NOPV	50PV	70PV	NOPV	50PV	70PV	NOPV	50PV	70PV

Chapter 4

Stressing the Grid & Flexibility Analysis

In this chapter the process of stressing the grids is presented, and all the steps developed in order to obtain it, such as changing the original element of the grids, then the type of flexibility service is selected and studied upon in order to see if by applying it the grid goes back to a normal status.

4.1 – Running Scenarios

The two chosen grids, GRID1 and GRID2, were then structured in excel files in order that they were accessible to “PandaPower” for the purpose to run a power flow analysis using, as stated before, the demand values from the aggregation consumption curves and the generation values from the measured PV generation curves.

The main objective is now to obtain a stressed grid, meaning that the lines should be overloading. In “PandaPower”, the loading of the line is presented in percentage, so it is calculated multiplying 100 by the division of the current that is passing through the grid, *i_ka*, with the maximum current that the line can sustain*, max_i_ka*, with other two parameters, the derating factor for *max_i_ka*, and the number of parallel lines systems[5], in this study the derating factor was one, and the number of parallel lines was not relevant so in the calculations were not accounted for, (Eq.(3)). The threshold for overloading was considered to be 85%, but this is a value each DSO can define in accordance with the design of its own grid; the focus here is to follow a methodology in order to get a final result, so these values of threshold are not the focus but a step inside the methodology. Running the different scenarios through the two grids in “PandaPower” both grids did not present the stressed situations. From the consumption behaviour of Spain, discussed in the chapter before, it is possible to see that in January the hours of most consumption are [9h-11h] on a Thursday and [10h-12h] on Sunday, and in June are [11h-13h] for a Thursday and a Sunday (Figures 4.1 and 4.2).

$$loading_{\_percentage}(\%) = \frac{i\_ka}{\max\ \_i\_ka} \times 100 \tag{3}$$

Figure 4. 1 – Average consumption behaviour – January (Thursday and Sunday)

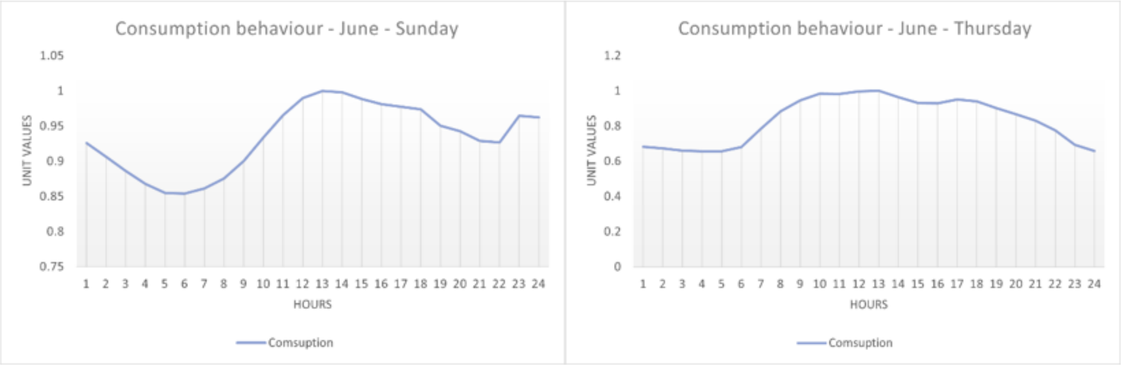


Figure 4. 2 – Average consumption behaviour – June (Thursday and Sunday)

With this information, the loading of the lines for both grids, is the highest in a situation of *NoPV*, in comparison with 50PV and 70PV, because on those cases at the hours presented before there is the generation of PV, so some of the demand is compensated by the power generated, in conclusion, if the lines do not cause overload at those hours in the case where there is no PV generation then they will not overload in the other cases either. Using the command, *ploty*, on Python a very simple design of the grid is created but gives an opportunity of seeing the loading of lines in a specific hour. In Figures (4.3) and (4.4) a design of GRID1 and GRID2 of a Sunday in January between 10h and 12h is presented, as it was declared previously, the lines in GRID1 do not present overloading (the colour blue clearly shows that the lines are not going over 40% of loading), to give a better visualisation of components that are in the figures the transformers are the connection between the yellow dot (HV bus) and the green dot (LV BUS) where the load is connected, in GRID2 (Figure 4.4) the lines do not present overloading, but the first lines is already in the range of 70% to 75% as the colour shows in the figures.

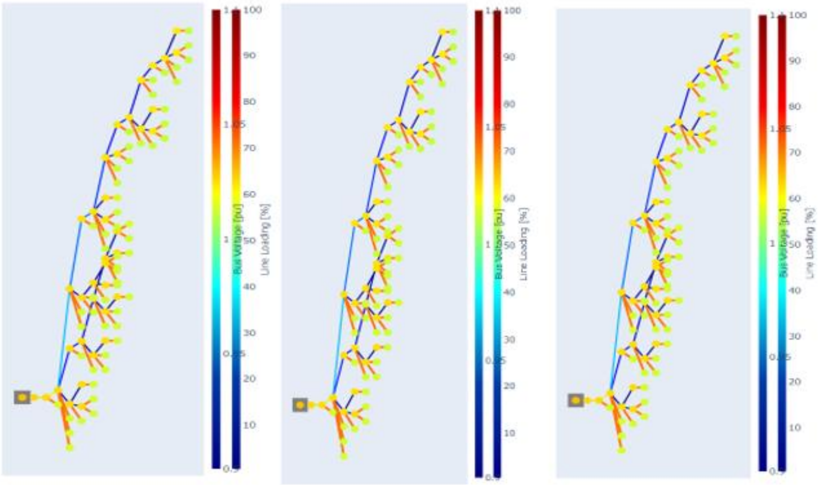


Figure 4. 3 – GRID1 between 10h and 12h on a Sunday of January

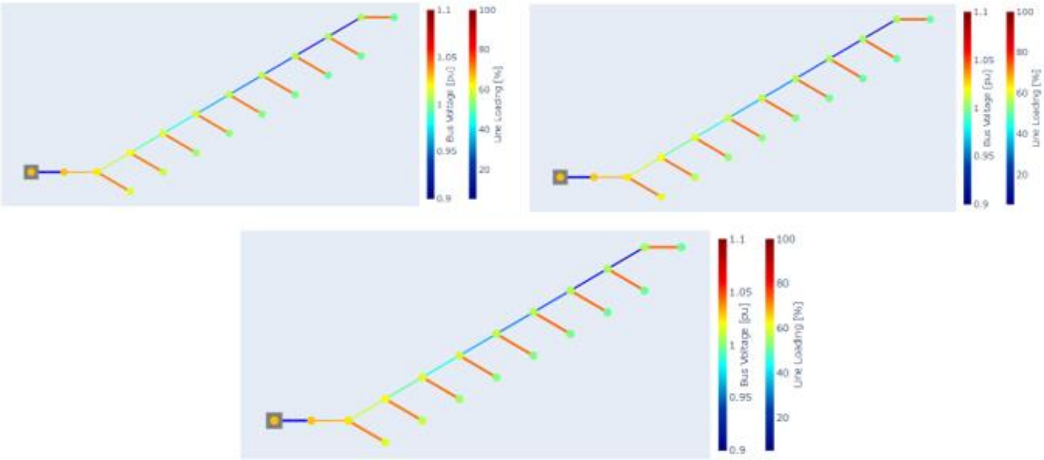


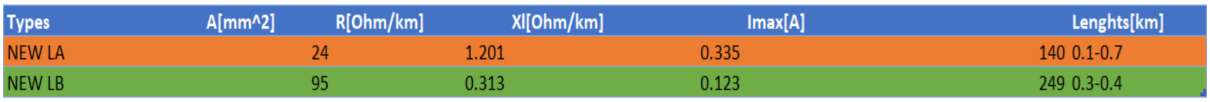
Figure 4. 4 – GRID2 between 10h and 12h on a Sunday of January

The approach implemented was to change lines by weaker ones: for this study, the main parameters when selecting a line were the maximum current that the line can sustain, its reactance and resistance to know the impedance, the cross-section area is not considered in the inputs when creating a line in "PandaPower" [5], therefore was not an important parameter, although thinner lines present weaker behaviour. For the choosing of lines, a library provided by "PandaPower" was used that has various type of lines with the necessary information for the "PandPower" inputs [5]. The length of the lines was maintained as they were found in the studies[33], [35]. The process of changing the lines consisted of a trial and error process where the lines were selected, and then after running the power flow, the outputs of the lines were analysed using the command *res.line* [5], which gives a list of important information, such as the power and current that are passing through the line and the loading of lines that is the main parameter in this path of changing lines. The objective of obtaining a stressed grid was to have three or more lines going over the percentage of voltage that was referred at the beginning of this chapter, 85% for GRID1 and GRID2, and it is also important to point out that the threshold for the loading was 120%, that meaning that although the objective was to stress the grids, some limits were created in order not to have the lines overloading too much.

4.2 – Changes in GRID1 & Results

For GRID1, the original lines, see Table (3.1), were changed, the type of LB that is the one filled in green on Table (3.2) was substituted by a line with a section area of 95 mm², an impedance of 0.313+0.123i and a maximum current of 0.249 kA, and LA by a line with a section area of 24 mm², an impedance of 1.201+0.335i Ω/km and maximum current of 0.140 kA (Table 4.1). In comparison with the original lines, it is notable the decrease in the section area and in the maximum current that the lines can sustain, this was implemented to achieve a worst-case scenario of a stressing grid (more than two lines overloading), the length of lines were untouched.

Table 4. 1 – Features of the new Lines/Cables GRID1



Types	A[mm^2]	R[Ohm/km]	Xl[Ohm/km]	Imax[A]	Lenghts[km]
NEW LA	24	1.201	0.335	140	0.1-0.7
NEW LB	95	0.313	0.123	249	0.3-0.4

The selection was due to the fact, that the results with these types of lines gave a stressed grid, as stated before more than 2 lines were stressed over the day; the stressed lines (going over 85% of line loading), were the L1, L2, L16, L21 and L22, these lines are the ones where more power and current flows through before the grid starts to ramify into other transformer stations, see Figure (3.1). The lines L1 and L2, being the first two lines of the grid, overload, but L16 is the one that overloads the most because it is a line of type LB and being wicker than L1 and L2 and the connection line between transformer station 2 and transformer station 16, see Figure (3.1) has to sustain a lot of power and current. L1, L2 and L16 always present overloading in all the cases referred in the section 3.3 (Table 3.9).

For L21 and L22, without PV generation overload in all the cases and when exists PV generation both lines overload in the January Sunday case, but in January Thursday and June Sunday cases only L21 overloads, and on the June Thursday case neither one overloads (Figures 4.3 and 4.4 present the values for January as an example), the loading of lines also decreases from a weekday to a weekend, this happens due to the fact that the consumption in overall is higher in a weekend in comparison to a weekday (Figures 4.1 and 4.2).

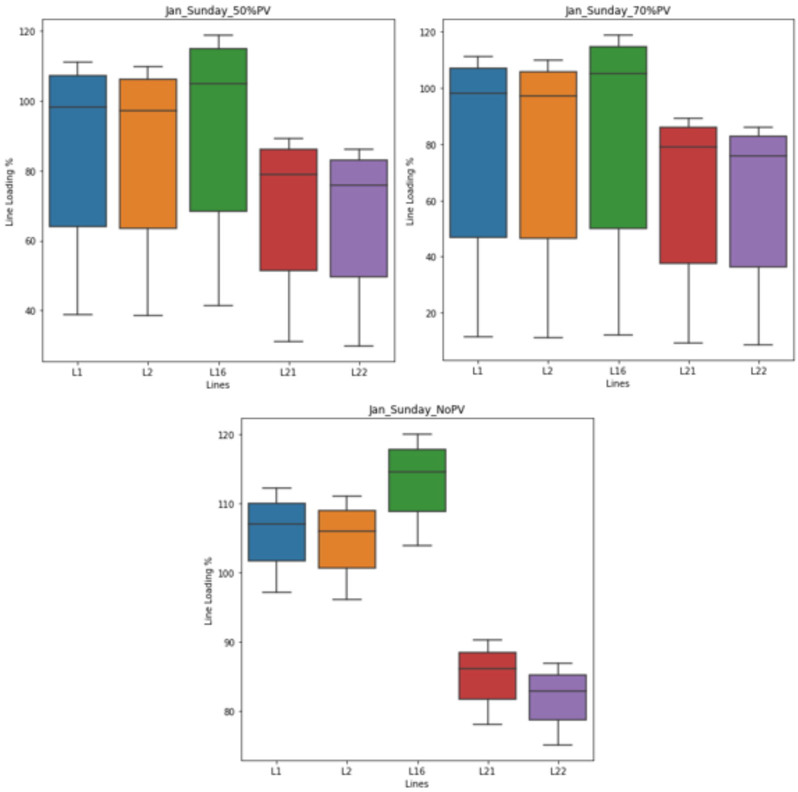


Figure 4. 5 – GRID1 Box Plot of the Line Loading (L1, L2, L16, L21 and L22) in January Sunday

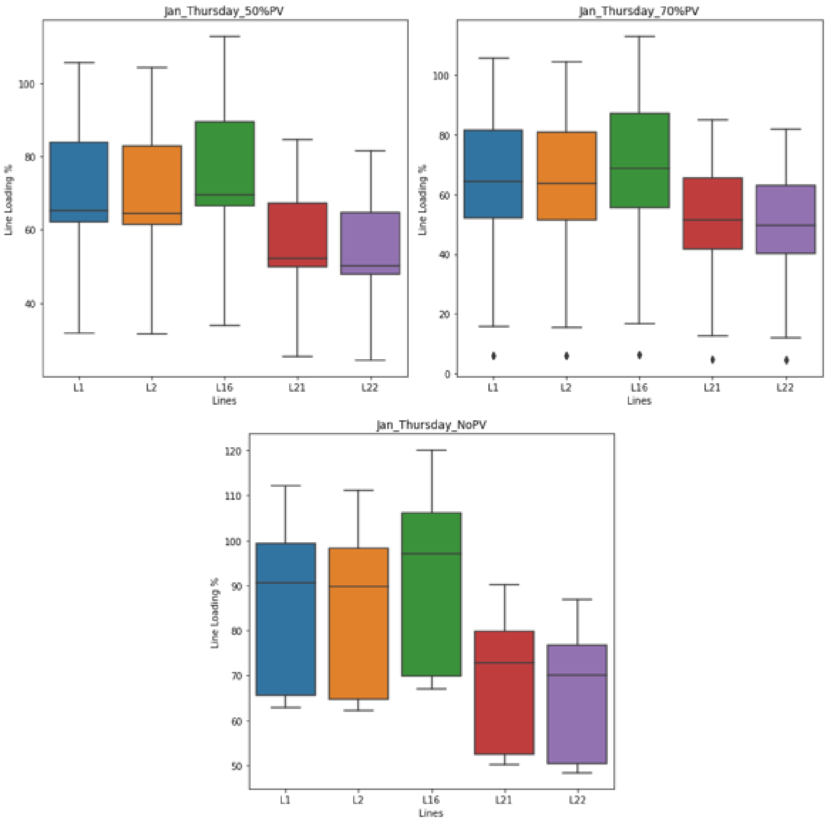


Figure 4. 6 – GRID1 Box Plot of the Line Loading (L1, L2, L16, L21 and L22) in January Thursday

4.3 – Changes in GRID2 & Results

In GRID2, the original lines, see Table (3.5), were changed, and the grid ended up with two different types of lines because the first line had to be stronger to not overload too much, not to go over 120%. The distribution of the transformers was also changed in this grid, once again to achieve the goal of a stressed grid without going over 120%. The first line has now a cross-section of 48 mm², an impedance of 0.5939+0.35i Ω/km and a maximum current of 0.21 kVA. The rest of the grid is now constituted by lines with 36 mm² of section area, impedance of 0.8342+0.36i Ω/km and a maximum current of 0.17 kA (Table 4.2). The transformers of 250 kVA were substituted by transformers of 400 kVA (Table 4.3). The understanding of overloading, for GRID2 is going over 85%, so lines that presented overloading results were L1, L2 and L3. These three were stressed with PV and without PV in a Sunday of January. For a Thursday of January L2 presented overloading with PV and without PV, but L1 and L3 only for the case with no PV generation. In the month of June, L1 did not overload, L2 overloaded with PV and without PV, L3 only on the case with no PV generation (Figures 4.6 and 4.7 present the values for January as an example).

Table 4. 2 – Features on the new Lines/Cables GRID2

Types	A[mm^2]	R[Ohm/km]	Xl[Ohm/km]	Imax[A]	Lenghts[km]
LC	48	0.5939	0.35	210	0.6
LD	36	0.8342	0.36	170	0.6

Table 4. 3 – Features on the new Lines/Cables & Transformers GRID2

Tranformer Station	Types of tranformers	Pnom[kVA]	Lines	Lenght [km]	S [mm²]
T0		25000			
T1	B	400	L1	0.6	48
T2	B	400	L2	0.6	36
T3	C	630	L3	0.6	36
T4	B	400	L4	0.6	36
T5	B	400	L5	0.6	36
T6	C	630	L6	0.6	36
T7	B	400	L7	0.6	36
T8	B	400	L8	0.6	36
T9	C	630	L9	0.6	36

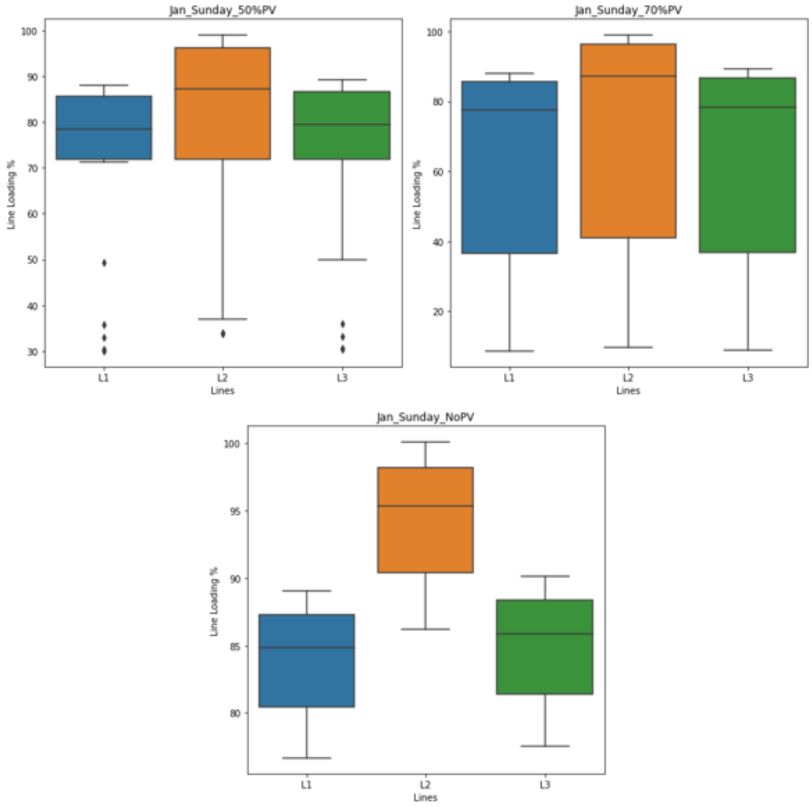


Figure 4. 7 – GRID2 Box Plot of the Line Loading (L1, L2 and L3) in January Sunday

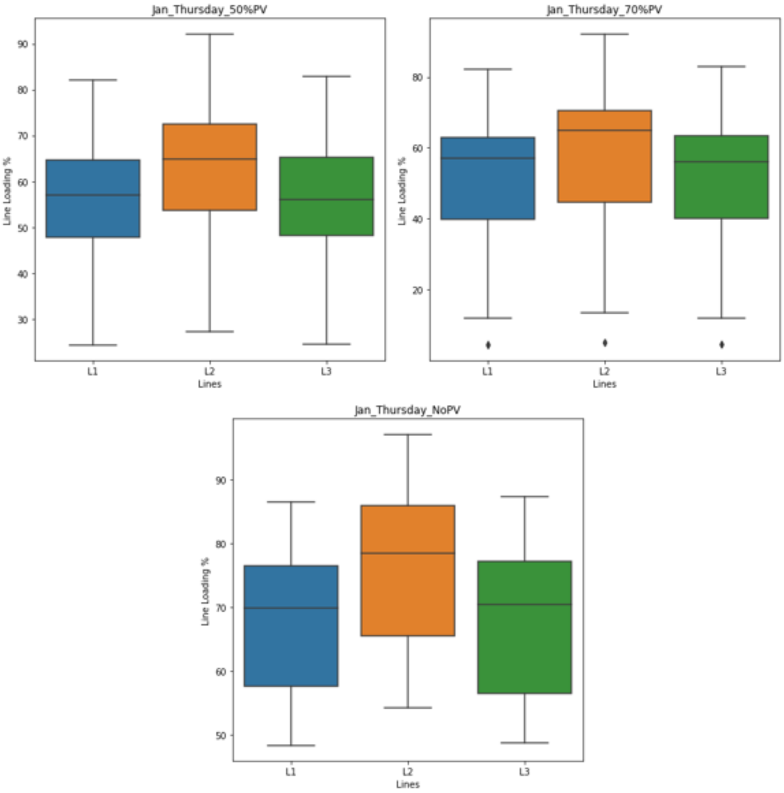


Figure 4. 8 – GRID2 Box Plot of the Line Loading (L1, L2 and L3) in January Thursday

4.4 – Adding Flexibility

GRID1 and GRID 2 are both in a stressed scenario; as it was defended before, in a winter or summer case, more than one line is overloading. The focus now is to add a type of flexibility service that will help the two grids achieve a normal situation where no stress is found. Flexibility services are conventional alternatives to grid reinforcement [13], as it was stated in chapter 2, one of the types of flexibility is BESS (Battery energy storage system) that can play a vital role in avoiding excessive power generation capacity to meet short-term peak electricity need, reduce the investment in power grid conduction, and ensure an efficient and safe operation of the power grid system [40]. In this study, the objective is to add a BESS to help with the overvoltage of lines by implementing a BESS in the end bus of the line that is overloading; by doing such implementation when needed, the BESS would discharge the amount of energy needed so that the line does not have to sustain a big amount of power and current, this would lead to a result where the line is not overloading. Generally, these types of flexibility is expected to meet the demand of peak shaving and load levelling, that refer to the process during which the BESS will charge during low electrical load and discharge under high electrical load [41]. Numerous BESS have been developed to fulfil demands of various fields based on specific applications, such as energy density, response time, specific capacity, discharge performance, cycle life, safety, and cost. However, the application of BESS at a grid level is still a very new thing in studies; according to [42] BESS with rapid response, low cost, long lifetime, high power, and energy efficiency meet the requirements to a grid level application, is also important to point out that batteries are currently regarded as a desirable energy storage system for grid-level applications with high investments benefits and also a high commercial potential and flexible installation [43].

4.4.1 – BESS & Results

When applying a BESS, the first step was to see if it would be possible to apply a battery energy storage system by seeing how many hours each line was overloading during the days in the study for each grid, because a battery has always a charge/discharge cycle, in which takes an number of hours to fully discharge and also the same amount of hours to be fully charged, for the battery energy storage system to be used the required time must be available not only to discharge the battery but more important to charge it.

The second step, if in a scenario is possible to apply a BESS meaning that exists a set of hours, *number_hours*, where the line is overloading and where is possible to charge and discharge a BESS, calculate the amount of power and energy that would be needed for the BESS to discharge, the approach followed was:

1) Identify at which hour in the scenario considered the lines are overloading the most.
2) Identify the amount of power that is flowing through the line, line*_power_h,* and the corresponding loading percentage, *loading_percentage.*
3) Define a threshold of loading percentage that would indicate that the line is not overloading anymore, 85% corresponding with statement made in section 4.1, *loading_thresold*
4) Calculate the difference between the loading of the line and the reference value for the threshold, this difference, in percentage, represents the amount of power that will be needed from the battery at that hour for the line to achieve threshold.
5) Apply this percentage difference to the peak power that is flowing through the line (*line_power_h*) and calculate the power needed for the battery system, *BESS_peakpower,* Eq.(4) and Eq.(5), using *BESS_peakpower* calculate the energy needed, *BESS_energy.* In the calculations, the values for *BESS_peakpower* were rounded to two decimal houses.

$$BESS\_peakpower(MW) = ((loading\_percentage) - (loading\_thresold)) \times line\_power\_h(MW) \tag{4}$$

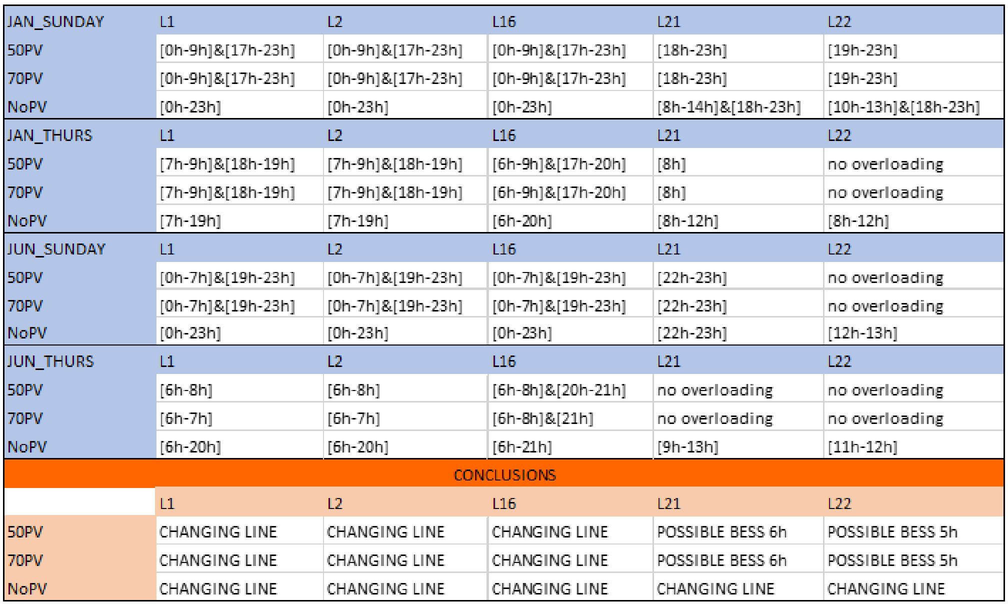
$$BESS\_energy(MWh) = BESS\_peakpower(MW) \ \times number\_hours(h) \tag{5}$$

4.4.1.1 – BESS in GRID1

Following the steps of the chapter before, the first step is to calculate whether if it is possible to apply a BESS in each end bus corresponding to the lines that are overloading. In section 4.2, the results were that L1, L2, L16, L21 and L22 are overloading. L1, L2 and L16 present overload status in all the scenarios and L21 and L22 have some exceptions. By grouping all scenarios, to remember we have JAN_THURS, JAN_SUNDAY, JUN_THURS and JUN_SUNDAY (the days in January to represent winter case and the days in June to represent a summer case), and each day has a different situation of PV generation, the conclusions were that in the situation of L21 and L22 it is possible to apply a BESS (Table 4.4) for the cases with PV generation.

Some cases do not present overloading, this does not mean that there is no need for a battery energy storage system for that specific case of PV generation, because the lines could be on normal loading values during the summer, but be overloading during winter, reinforcing the need of a BESS. Table (4.4) shows, for example, that L1 overloads for 24h straight in JAN_SUNDAY with NoPV, so automatically, the idea of implementing a battery energy storage system in the no PV generation scenario is excluded; another example is in JAN_SUNDAY with no PV generation, L21 overloads from 8h to 14h and from 18h to 23h, if we do the maths there is no time available to fully charge a battery. The conclusions taken were grouped for the situations of PV generation (50PV, 70PV and NoPV), on the Table (4.4), each conclusion taken for each PV generation scenario is that either the DSO has to change the line or if it is possible to apply a BESS and for how many hours its needed to discharge, for example for L22 it is possible to apply a BESS, in cases with PV generation, because there is enough time in a day to charge and discharge a battery during winter (January it is the case for winter), and the time set is of 5h, for 50PV, 70PV, for L21 the time set is 6h.

Table 4. 4 – Conclusions for GRID1 on applying BESS



JAN_SUNDAY	L1	L2	L16	L21	L22
50PV	[0h-9h]&[17h-23h]	[0h-9h]&[17h-23h]	[0h-9h]&[17h-23h]	[18h-23h]	[19h-23h]
70PV	[0h-9h]&[17h-23h]	[0h-9h]&[17h-23h]	[0h-9h]&[17h-23h]	[18h-23h]	[19h-23h]
NoPV	[0h-23h]	[0h-23h]	[0h-23h]	[8h-14h]&[18h-23h]	[10h-13h]&[18h-23h]
JAN_THURS	L1	L2	L16	L21	L22
50PV	[7h-9h]&[18h-19h]	[7h-9h]&[18h-19h]	[6h-9h]&[17h-20h]	[8h]	no overloading
70PV	[7h-9h]&[18h-19h]	[7h-9h]&[18h-19h]	[6h-9h]&[17h-20h]	[8h]	no overloading
NoPV	[7h-19h]	[7h-19h]	[6h-20h]	[8h-12h]	[8h-12h]
JUN_SUNDAY	L1	L2	L16	L21	L22
50PV	[0h-7h]&[19h-23h]	[0h-7h]&[19h-23h]	[0h-7h]&[19h-23h]	[22h-23h]	no overloading
70PV	[0h-7h]&[19h-23h]	[0h-7h]&[19h-23h]	[0h-7h]&[19h-23h]	[22h-23h]	no overloading
NoPV	[0h-23h]	[0h-23h]	[0h-23h]	[22h-23h]	[12h-13h]
JUN_THURS	L1	L2	L16	L21	L22
50PV	[6h-8h]	[6h-8h]	[6h-8h]&[20h-21h]	no overloading	no overloading
70PV	[6h-7h]	[6h-7h]	[6h-8h]&[21h]	no overloading	no overloading
NoPV	[6h-20h]	[6h-20h]	[6h-21h]	[9h-13h]	[11h-12h]
CONCLUSIONS					
	L1	L2	L16	L21	L22
50PV	CHANGING LINE	CHANGING LINE	CHANGING LINE	POSSIBLE BESS 6h	POSSIBLE BESS 5h
70PV	CHANGING LINE	CHANGING LINE	CHANGING LINE	POSSIBLE BESS 6h	POSSIBLE BESS 5h
NoPV	CHANGING LINE	CHANGING LINE	CHANGING LINE	CHANGING LINE	CHANGING LINE

In GRID1 the scenarios were shortened to L21 and L22 on 50PV, 70PV (Table 4.4). The focus now is to calculate the peak power, and the energy needed from the BESS. To simplify the process, the approach was to identify which day had the highest demand, meaning highest load; analysing Figure (4.1), and Figure (4.2), it is possible to conclude that it is Sunday of January (JAN_SUNDAY), and inside the set of hours that the lines were overloading at this day, identify the hour with the bigger load that represents the hour in which the lines are under more stress. The idea behind this process is that the values of peak power and the energy needed for the battery that will lead to a decrease of the loading of the line to an 85% at this hour are the reference values because the demands of energy and power at the other hours are lower and never higher.

For GRID1 the hour was 19h, so the hour 19h of a Sunday in January. And from the output values obtained through the power flow in PandPower calculate each equation defined before Eq.(4) and Eq.(5), thus obtaining the peak power and energy needed from the battery. At 19h, the values from the Powerflows for each scenario, 50%PV, 70%PV and NoPV, are all the same, so no need to separate each case, since the sun in Barcelona was already down at 18h in January 2019 has it was stated in section 3.3. Table (4.5) shows the results for each line, L21 and L22, the hours for L21 are 6h and for L22 are 5h (Table 4.4). So, in conclusion, the BESS to apply in the end bus of L21 needs to supply 1.38MWh and in the end bus of L22 0.25MWh.

Table 4. 5 – Peak Power & Energy Needed from BESS for GRID1

JAN_SUNDAY_19h	Line_power_h (MW)	Loading_percent (%)	Difference beetwen loading_percent and 85%	Peak Power (MW)	Enegy Needed (MWh)
L21	5.5	89.2	4.2	0.23	1.38
L22	5.3	85.9	0.9	0.05	0.25

Results

Using “PandaPower” function *create_storage* [5], which has an input *p_mw*, that represents the active power of the storage (positive for charging and negative for discharging), *bus,* represents the bus id to which the storage is connected, in this particular case the end bus of L21 and the end bus of L22 and *max_e_mwh* that represents the energy stored. It is possible to observe the results in the loading of L21 and L22 after applying the types of BESS calculated before in the Figure (4.9), that shows the scenario of 50% of PV generation. Through the Figure (4.9), it is notable that the loading of the lines in the study, L21 and L22, do not go over 85%. For the case of 70% of PV generation, the lines also present stable loading values; a big reason is that if the application of storage makes the loading of the line decrease in a situation where exists 50% of PV generation, in cases with more PV generation the loading will be lower and never bigger because less power is being demand from the grid, so less power is flowing through the lines.

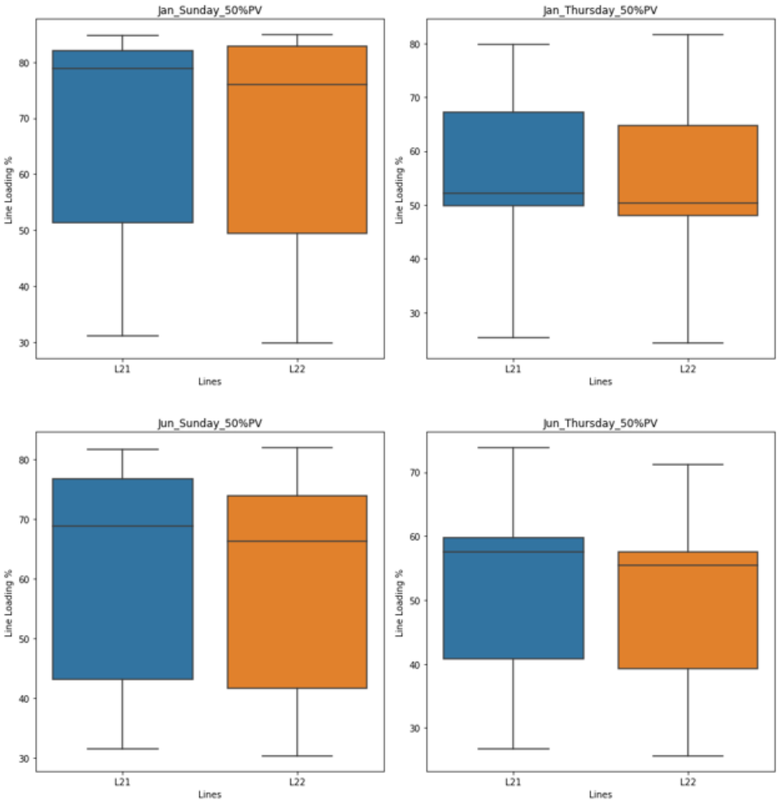
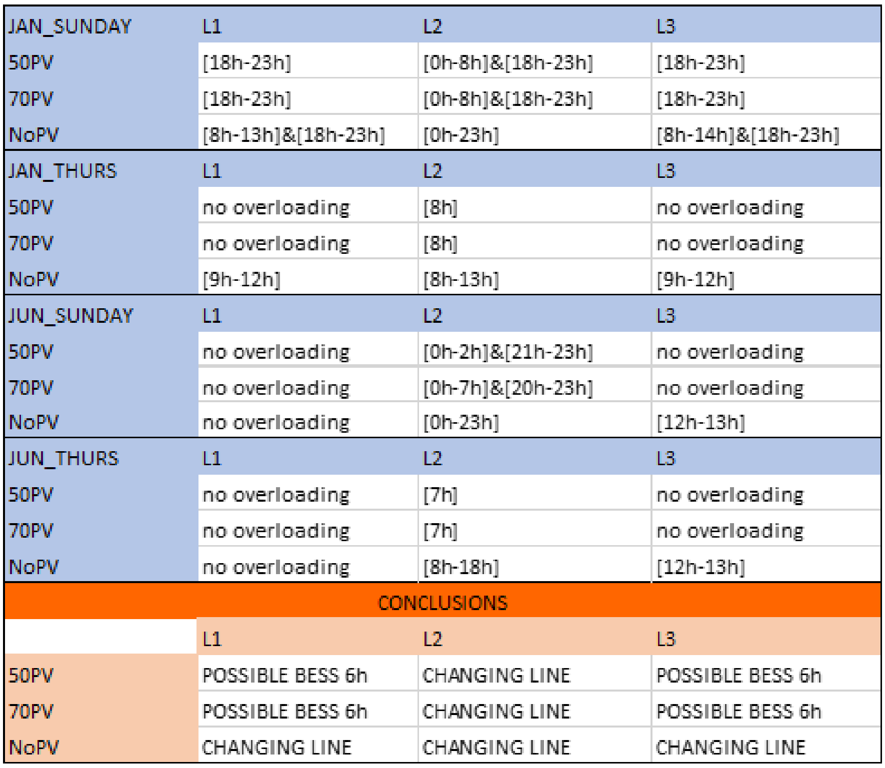


Figure 4. 9 – GRID1 Box Plot of the Line Loading (L21 and L22) with BESS for 50%PV

4.4.1.2 – BESS in GRID2

The process is the same has the one done in the section before referring to GRID1. According to section 4.3 in GRID2 the lines that presented overload were L1, L2 and L3. Once again, by grouping all the days scenarios to see if it is possible or not to use a BESS. According to Table (4.6) the conclusions are that it is possible to apply a BESS in the end bus of L1 and L3 only when exists PV generation, for L2 it is not possible for a battery system to be fully charged before the need to discharge, for example on the day JAN_SUNDAY with 50% of PV, L2 is overloading from 0h to 8h and them from 18h to 23h, it would be possible to charge the battery system between 8h and 18h, but JAN_SUNDAY is an idea of the demand behaviour in a weekend in winter demand behaviour, so it has two days, meaning the line is overloading from 18h of one day to 8h of the next day leaving no space for the battery to be fully charged, automatically L2 on the 50% of PV generation scenario needs to be changed with a new line, the same reason it's applied for the other cases, see Table (4.6). Once again looking at Table (4.6), for L1 the discharge time for a battery system is 6h, because the biggest time set in which the line is overloading is 6h, and for L2 the discharge time is also 6h, following the same approach. To remember, although that some days the lines do not overload, it does not mean that a battery is not necessary because the lines could be stable during summer and stressed during winter.

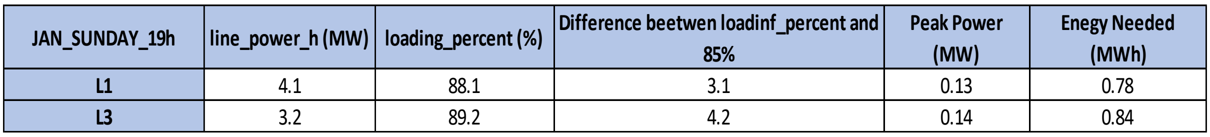
Table 4. 6 – Conclusions for GRID2 on applying BESS



JAN_SUNDAY	L1	L2	L3
50PV	[18h-23h]	[0h-8h]&[18h-23h]	[18h-23h]
70PV	[18h-23h]	[0h-8h]&[18h-23h]	[18h-23h]
NoPV	[8h-13h]&[18h-23h]	[0h-23h]	[8h-14h]&[18h-23h]
JAN_THURS	L1	L2	L3
50PV	no overloading	[8h]	no overloading
70PV	no overloading	[8h]	no overloading
NoPV	[9h-12h]	[8h-13h]	[9h-12h]
JUN_SUNDAY	L1	L2	L3
50PV	no overloading	[0h-2h]&[21h-23h]	no overloading
70PV	no overloading	[0h-7h]&[20h-23h]	no overloading
NoPV	no overloading	[0h-23h]	[12h-13h]
JUN_THURS	L1	L2	L3
50PV	no overloading	[7h]	no overloading
70PV	no overloading	[7h]	no overloading
NoPV	no overloading	[8h-18h]	[12h-13h]
CONCLUSIONS			
	L1	L2	L3
50PV	POSSIBLE BESS 6h	CHANGING LINE	POSSIBLE BESS 6h
70PV	POSSIBLE BESS 6h	CHANGING LINE	POSSIBLE BESS 6h
NoPV	CHANGING LINE	CHANGING LINE	CHANGING LINE

The lines in the study were then shortened to L1 and L3 on the scenarios only with PV generation. The objective is to calculate the power and energy needed from the BESS for each line so that L1 and L2 achieve normal loading values. The threshold is 85%, and the idea was the same as the one done for GRID1, using JAN_SUNDAY as the day to study, and then selecting the hour with the highest demand, 19h. The calculations performed were the for 19h of a Sunday in January (Table 4.7); the results were for L1 the energy needed of a BESS is 0.78MWh and for L3 is 0.84MWh.

Table 4. 7 – Peak Power & Energy Needed from BESS for GRID2



JAN_SUNDAY_19h	line_power_h (MW)	loading_percent (%)	Difference beetwen loadinf_percent and 85%	Peak Power (MW)	Enegy Needed (MWh)
L1	4.1	88.1	3.1	0.13	0.78
L3	3.2	89.2	4.2	0.14	0.84

Results

Once again, using PandaPower function *create_storage,* it was possible to observe the results of applying the respective BESS to the respective end bus of each line, 0.78MWh for L1 and 0.84MWh for L3. Figure (4.10) shows the effect of applying storage in the scenario for 50% PV generation, and it is notable both lines in the study, L1 and L3, do not go over the threshold 85%. To reinforce, for the cases with 70% of PV generation where the loading of the lines will allow being lower and never bigger because with more generation from the PV side, less power is demand from the grid, so less power flows through the lines, L1 and L3 also presented stable loading values.

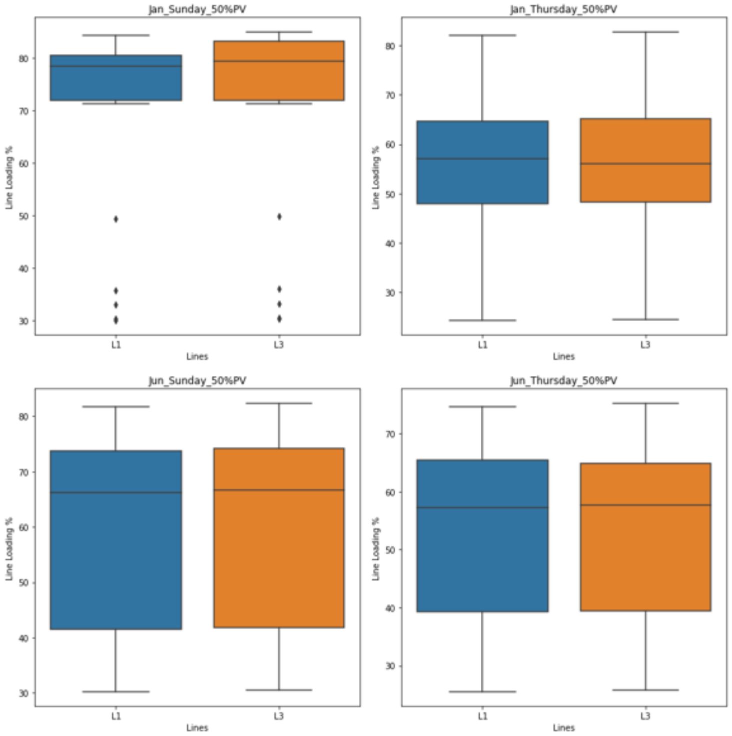


Figure 4. 10 – GRID2 Box Plot of the Line Loading (L1 and L3) with BESS for 50%PV

4.5 – Type of Battery for BESS

The idea in this thesis is for the DSO to contract a flexibility service that would give him an alternative to changing the lines. As stated, before this flexibility service is a BESS, so for the methodology to be concluded, a cost of service must be implemented analysed and compared.

A type of battery as to be selected to have access to costs of service that would serve as an example if the DSO would, in fact go for the contract of a flexibility service. Among the energy storage systems, electric batteries show a big potential for application to grid-level electrical energy storage due to their attractive features, such as flexible installation, modularisation, rapid response, and short construction cycles [5]. Among the various types of electrical batteries technologies, lithium-ion (Li-ion) batteries have attracted significant interest because of their high energy density, high energy efficiency and long cycle life [44][45][46]. In [44] the authors state that 77% of electrical power storage systems in the USA that operate to stabilise the grid rely on lithium-ion batteries. From section 4.4 it was concluded that both grids need BESS with a power of 0.23MW/1.38MWh, 0.05MW/0.25MWh, 0.13MW/0.78MWh and 0.14MW/0.84MWh; these four different amounts of power and energy are achievable using lithium-ion batteries, because for example, in the UK, the largest European lithium-ion energy storage pilot is in process, it as a power of 6MW/10MWh [47][48], and in Japan, it has been deployed a lithium-ion battery energy storage system of 40MW/20MWh.

To access a credible cost of service tool for the batteries, IRENA (International Renewable Energy Agency) report for Cost and Markets to 2030 was used [49], where it’s argued that the total installed cost of Li-ion battery could fall by an additional 54-61% by 2030. Inside the family of Lithium-ion batteries exists, NMC/LMO (nickel manganese cobalt/lithium manganese oxide), NCA (nickel cobalt aluminium oxide), LFP (lithium iron phosphate) and LTO (lithium titanate). In this study, NMC/LMO was the type of Li-ion battery chosen to be used; it carries many advantages, such as: can be fitted for high power or high energy, stable thermal profile, can operate at high voltages, and in terms of energy installation cost has a very low price. The NMC/LCO combined BESS provides a balance between performance and cost[49].

Chapter 5

Cost Comparison

This chapter presents the results of the costs comparisons between adding the BESS and changing the line. For this, a brief overview of the newest royal decree established by the Spain regulation is presented in order to know how much is the remuneration given to the DSO if chosen grid expansion. On the other end, the steps for the building of tool cost for the BESS are explained and presented.

5.1 – Spain Royal Decree IET/2660/2015

To end the process of this study, the goal is to obtain an annual cost relative to the flexibility service BESS compare it and conclude if the investment in this flexibility service is more viable than changing the line. The regulatory identity in Spain, approved a royal decree called IET/2660/2015 [4], in this article is stated that a remuneration methodology for distribution activities will be established by the regulation, considering the costs necessary to build, operate and maintain the facilities and carry out the good performance of the grid and at the lowest cost for the electricity system. This law establishes a clear, stable, and predictable formulation for remunerating distribution assets that contributes to providing regulatory stability and thereby reducing the financial costs of the distribution activity and those of the electrical system. In [4] the National Commission for Markets and Competition defined a series of standard installations, assigning them a series of construction elements; once this operation is carried out, an economic evaluation was made of these items in order to obtain the values of the units of investment and operation and maintenance for each of the standard installations, the last step was then to expand the catalogue of facilities according to voltage. For this study, the main features from this catalogue were the lines, where besides the voltage level the cross-section was also a factor for the cost of lines, the remuneration is also in euros per kilometres, so the length of the lines is also a factor. The values of investment and operation and maintenance was taken out of [4] for the lines are to values that are going to be used as a comparison for the annual costs relative to the BESS.

The approach here is if the DSO is, in fact, going for new lines, the targeted section areas for those lines are the ones that were in the original grids [33] [35] before they were stressed for this study (Table 3.2 and 3.5), and voltages are 25kV for GRID1, see section 3.1.1, and 11kV for GRID2, see section 3.1.2. Since the study focus on distribution networks, to be more precise for low voltage consumption, the lines in focus are of the underground type due to the fact that they are in the middle of a city per se, and do not have to carry high voltages levels. In [4] the catalogue divides the lines into sets of voltages and in sets of section areas. After a brief analysis, the lines were selected from the catalogue, see Table (5.1), and after taking into account, the length of each line in the study, see Table (5.2) (L21 and L22 for GRID1 and L1 and L3 for GRID2), Table (5.3) was created that represents the annual remuneration the DSO would get from the Spain regulation if opted on changing the lines, in [4] the Spain regulation defines the average life for an underground line to be 40 years, so the remuneration will be the total divided by 40, this also applies for the investment done by the DSO for BESS.

Table 5. 1 – Lines from IET/2660/2015

Lines	Voltage(kV)	Section(mm²)	Investment(€/km)	O&M(€/km)
TI-20Y	36kV ≥ U ≥ 24kV	200 < S ≤ 300	151 049.00 €	1 568.00 €
TI-18BX	12kV ≥ U ≥ 1kV	0 < S ≤ 100	94 570.00 €	981.00 €

Table 5. 2 – Lines section area and length

GRID2 LINES	Voltage(kV)	Section(mm²)	Length(km)
L1	12kV ≥ U ≥ 1kV	95	0.6
L3	12kV ≥ U ≥ 1kV	95	0.6
GRID 1 LINES	Voltage(kV)	Section(mm²)	Length(km)
L21	36kV ≥ U ≥ 24kV	240	0.4
L22	36kV ≥ U ≥ 24kV	240	0.2

Table 5. 3 – Annual Remuneration for each line of GRID1 and GRID2

GRID2 LINES	Investement (€)	O&M (€)	Years	Annual Remuneration (€)
L1	60 419.60 €	627.20 €	40	1 526.17 €
L3	30 209.80 €	313.60 €	40	763.09 €
GRID 1 LINES	Cost of Investement (€)	O&M (€)	Years	Annual Remuneration (€)
L21	56 742.00 €	588.60 €	40	1 433.27 €
L22	56 742.00 €	588.60 €	40	1 433.27 €

5.2 – BESS Cost Assessment

The methodology now is to define a cost assessment for the BESS. The idea here is that the DSO contracts a flexibility service, in this case, an identity that owns BESS, that will make to the DSO a cost assessment depending on his requirements for the BESS, to remember that the battery model selected to simulate this cost was the NMC/LMO (nickel manganese cobalt/lithium manganese oxide) from the Li-ion family. The IRENA report [45] was the base structure for this due to the fact that it gives access to more complete and trusted values for NMC/LMO battery. In the IRENA report a tool for cost assessment is available; this tool has combined data from a variety of analytical approaches like installed projects, regulatory databases, installer surveys, individual projects and learning curve studies and made its own assumptions. Values of cost assessment for NMC/LMO for 2020 were extracted, the IRENA report is from 2015, so the values for 2020 are prevision values and are divided into best values, reference values and worst values. In this methodology, the cost assessment is going to have capital expenditure (CAPEX) and operational expenditure (OPEX). The CAPEX is composed by:

1) Energy storage installation cost, the comes in €/kWh, which indicates how much it is going to cost to store the energy needed for each BESS.
2) Power conversion system cost, in €/kW, that represents the cost of the inverter and packing.

The OPEX, in [45] the authors assume that the operation and maintenance (O&M) is 1.5% of the total investment of the represented unit:

1) O&M of the storage system, it is 1.5% of the energy storage installation cost.
2) O&M of the power conversion system, 1.5% of the power conversion system cost.

In section 4.4, the values calculated for power and energy are the needed values per se, so when applying them for the battery NMC/LMO, they have to be divided by the round-trip efficiency (comes in percentage), η, of the battery, that represents the fraction of energy and power put into the storage that can be retrieved. That being said the values of power from section 4.4 have to be divided by the round-trip efficiency in order that the energy losses are accounted for, getting than the power capacity of the BESS, *power_capacity,* and the energy capacity of the BESS, *energy_capacity,* as in Eq.(5) and Eq.(6). The values for the points talked before, that are represented in the Table (5.4) were all extracted from the IRENA report.

$$Power\_Capacity(kW) = \frac{BESS_{peakpower(kW)}}{\eta(\%)} \tag{6}$$

$$Energy\_Capacity(kWh) = Power\_Capacity(kW) \times number\_hours(h) \tag{7}$$

Table 5. 4 – NMC/LMO values for cost assessment

Battery	Power Conversion Installation Cost (€/kW)	Energy Storage Installation Cost (€/kWh)	Round-t rip efficiency	O&M storage system/ power conversion system (%)
Li-ion (NMC/LMO) Best	48.5	125.8	1	1.50%
Li-ion (NMC/LMO) Reference	69.9	264.8	0.95	1.50%
Li-ion (NMC/LMO) Worst	125.8	529.5	0.81	1.50%

This cost assessment is for the total cost of BESS, and usually for a DSO to integrate a BESS only in order to reduce grid reinforcement tend to be nonprofitable [50]. This is particularly true for distribution grids due to the fact that grid equipment has relatively low costs compared to BESS of a large scale, especially for grid equipment in MV or LV levels; in [51] the author gives examples of other orientated applications of large scale batteries at the distribution grid level, one of those examples is for the use in PV systems and residential storage systems. This being said, in this study, a factor defined as usage of BESS if going to be added, this factor represents how much the DSO is actually going to use the BESS in question for grid orientation, in this case, to help with the overloading of the lines, the factor comes in percentage, and it's the percentage of how much of the total cost of the BESS the DSO is going to pay, the first assumption for it was of 10%, but furthermore, a sensitivity analysis is going to be made on this factor, in order to make better conclusions of how much more could the DSO use a BESS for grid application and still be profitable comparing to the grid reinforcement. A big justification for this value is also that the grid, as it is possible to conclude in the chapter 4, it is not always overloading; based on chapter 4 it is possible to say that only during winter the BESS will be needed, because the lines in study do not overload in the cases of June, so the total use of the BESS will not be needed during the year.

5.3 – Annual Cost Comparison

In section 4.4 the values for power and energy needed from the BESS for each grid were extracted. To follow the methodology, the Eq.(6) and Eq.(7) will be applied to these values in order to obtain the values for power capacity and energy capacity of the BESS, where the energy losses for the battery are considered, the units of power and energy were transformed to kilowatts due to the values for cost assessment being in €/kW or €/kWh. The next step now is to calculate how much is going to be the annual cost in investing in a BESS:

1) Calculate the energy storage installation cost in euros, *energy_cost* see Eq.(8), and the power conversion installation cost power in Euros, *power_cost* see Eq.(9).
2) Calculate the total annual CAPEX, consists on the energy storage installation cost, *energy_cost,* and power conversion system cost, *power_cost* divided 40 years as Eq.(10).
3) Calculate the total annual OPEX, that consist on applying the 1.5% of the annual energy installation cost and annual power cost as Eq.(10).
4) Get the total annual cost by summing total annual CAPEX and total annual OPEX, and multiplying the use of BESS factor, *use_BESS*, that come in percentage as Eq.(12).

$$Energy\_Cost(€) = Energy\ \_Storage\_Installation\_Cost(€/kWh) \times Energy\_Capacity(kWh) \tag{8}$$

$$Power\_Cost(€) = Power\_Conversion\ \_Installation\_Cost(€/kW) \times Power\_Capacity(kW) \tag{9}$$

$$Annual\ CAPEX(€) = (Energy\_Cost(€) + Power\_Cost(€))/(40\ years) \tag{10}$$

$$Annual\ OPEX(€) = \left(O\&M\_Energy(\%) \times \left(\frac{Energy\_Cost(€)}{40\ years}\right)\right) + \left(O\&M\_Power(\%) \times \left(\frac{Power\_Cost(€)}{40\ years}\right)\right) \tag{11}$$

$$Annual\ Cost(€) = \big(Annual\ CAPEX(€) + Annual\ OPEX(€)\big) \times use\_BESS(\%) \tag{12}$$

5.3.1 – Annual Cost Comparison for GRID1

In section 4.4 the values for power and energy required from the BESS in GRID1 were:

- 230kW/1380kWh for L21
- 50kW/250kWh for L22

Applying Eq.(6) and Eq.(7) that give the power capacity and energy capacity of the BESS, using NMC/LMO batteries, considering energy losses on the values listed above (a reminder that exists three values of round-trip efficiency, best, reference and worst (Table 5.4)) the results are showed in Table (5.5). Applying the equations (8), (9), (10) and (11) the values of the annual CAPEX for the BESS in L21 and L22 were obtained, see Table (5.6), where also the values for the energy storage installation cost and for power conversion installation cost in Euros for the BESS of both lines are listed. The annual OPEX is listed in Table (5.7), these values are quite low, due to the year of the project (40 years) and also because O&M is only considered to be 1.5% of each cost that is representing, and to finalise the total annual cost of the two BESS are obtained, see Table (5.8), where the use of the BESS factor from the DSO comes in the play, as Eq.(12).

Table 5. 5 – Values for Power and Energy capacity of BESS for each line

Values NMC/LMP	BESS for L21 (kW)	BESS for L22(kW)
Best Values	230kW/1380kWh	50kW/250kWh
Reference Values	242kW/1452kWh	53kW/265kWh
Worst Values	284kW/1704kWh	62kW/310kWh

Table 5. 6 – Annual CAPEX for BESS in L21 and L22

BESS	Valaues NMC/LMP	Energy Storage Installation Cost (€)	Power Conversion Intallation Cost (€)	Years	Annual CAPEX
BESS for L21	**Best Values**	173 554.47 €	11 165.12 €	40	4 617.99 €
	Refrence Values	384 441.02 €	16 909.45 €	40	10 033.76 €
	Worst Values	768 882.05 €	35 719.47 €	40	20 115.04 €
BESS for L22	**Best Values**	31 441.03 €	2 427.20 €	40	846.71 €
	Refrence Values	70 163.13 €	3 703.31 €	40	1 846.66 €
	Worst Values	164 155.26 €	7 797.91 €	40	4 298.83 €

Table 5. 7 – Annual OPEX for BESS in L21 and L22

BESS	Valaues NMC/LMP	O&M Energy	O&M Power	Annual Opex
BESS for L21	Best Values	65.08 €	4.19 €	69.27 €
	Refrence Values	144.17 €	6.34 €	150.51 €
	Worst Values	288.33 €	13.39 €	301.73 €
BESS for L22	Best Values	11.79 €	0.91 €	12.70 €
	Refrence Values	26.31 €	1.39 €	27.70 €
	Worst Values	61.56 €	2.92 €	64.48 €

Table 5. 8 – Total annual Cost of BESS for L21 and L22

BESS	Valaues NMC/LMP	Annual CAPEX	Annual OPEX	BESS use (%)	Total Annual
BESS for L21	Best Values	4 617.99 €	69.27 €	10.00%	468.73 €
	Refrence Values	10 033.76 €	150.51 €	10.00%	1 018.43 €
	Worst Values	20 115.04 €	301.73 €	10.00%	2 041.68 €
BESS for L22	Best Values	846.71 €	12.70 €	10.00%	85.94 €
	Refrence Values	1 846.66 €	27.70 €	10.00%	187.44 €
	Worst Values	4 298.83 €	64.48 €	10.00%	436.33 €

With total annual costs for each BESS, and considering the best, reference and worst values, the comparison with the annual remuneration if the DSO would, in fact, go for grid expansion (changing the lines) is made in Table (5.9), in the column of total annual, when the cost on adding flexibility service BESS its profitable for the DSO the cell is covered in green, and when is not its covered in red. The Table (5.9) shows promising results, due to only not being profitable applying BESS on L21 with worst values, but a big factor in this result is the use of BESS that is only on 10%, meaning that the DSO would only pay for 10% of the total cost.

Table 5. 9 – Comparison between annual costs

BESS	Valaues NMC/LMP	Total Annual	Annual Remunaration	Lines
BESS for L21	Best Values	468.73 €	1 526.17 €	Changing line L21
	Refrence Values	1 018.43 €		
	Worst Values	2 041.68 €		
BESS for L22	Best Values	85.94 €	763.09 €	Changing line L22
	Refrence Values	187.44 €		
	Worst Values	436.33 €		

5.3.1.1 – Sensitivity Analyse GRID1

As it was stated before, the factor of BESS use was considered to be 10%, to remember this factor represents the use of BESS for grid application, represents how much the DSO is going to pay from the total cost of the BESS. So, in this the chapter a sensitivity analysis is going to be done around this factor in the Eq.(12), where the value *use_BESS* is going to be modified to see how much the DSO can use of the BESS and still be profitable. Only the best values and the reference values of the annual CAPEX (Table 5.6) and of the annual OPEX (Table 5.7), are going to be studied upon in the Eq.(12). On this sensitivity analysis, the basis is again the comparison between the annual cost of the BESS and the annual remuneration when changing the line, and to retrieve a breakeven point, basically when thus contracting a flexibility service that uses BESS starts to stop being profitable for the DSO. On the Figures (5.1) and (5.2) the sensitivity analysis for both lines are made, Figure (5.1) for L21, and Figure (5.2) for L22, the orange line represents the annual remuneration on changing the line; the blue one represents the BESS annual cost with the best values and grey one represents the BESS annual cost with reference values.

In Figure (5.1) referring to L21, it is notable the difference in the breakeven point between the best values and reference values, for the reference values, the breakeven point is 14.99%, and for the best values is 32.56%, see Table (5.10), so basically, on one end the DSO could purchase up to 14.99% of the BESS system for grid application and on the other end could go until 32.56% that is reasonably better. In Figure(5.2) referring to L22, the conclusions are basically the same as the ones done for L21, but the breakeven points are higher comparing to the sensitivity analysis done for the BESS of L21, because remembering the Table (5.5), the BESS for L22 requires a notable less amount of energy and power, so automatically the annual costs are going to be lower that leds to the possibility of the DSO using more of the BESS as flexibility service for grid applications, even almost going for the full use of it when the values are at the best levels, 88.79% (Table 5.10).

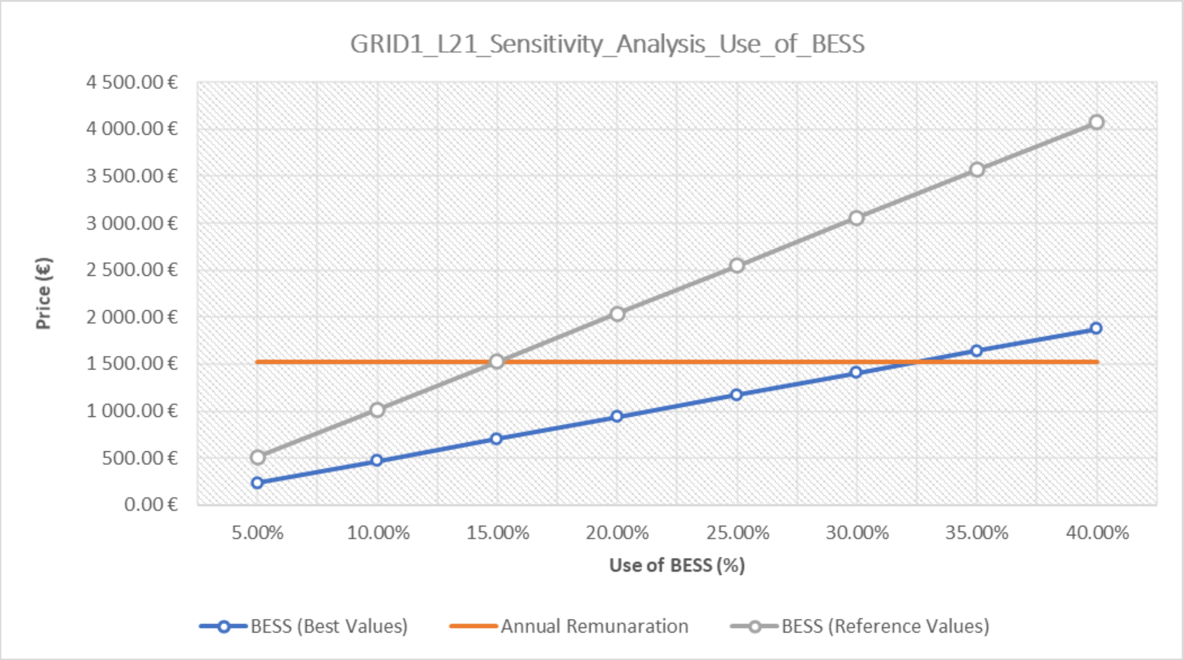


Figure 5. 1 – Sensitivity analysis of the use of BESS for L21

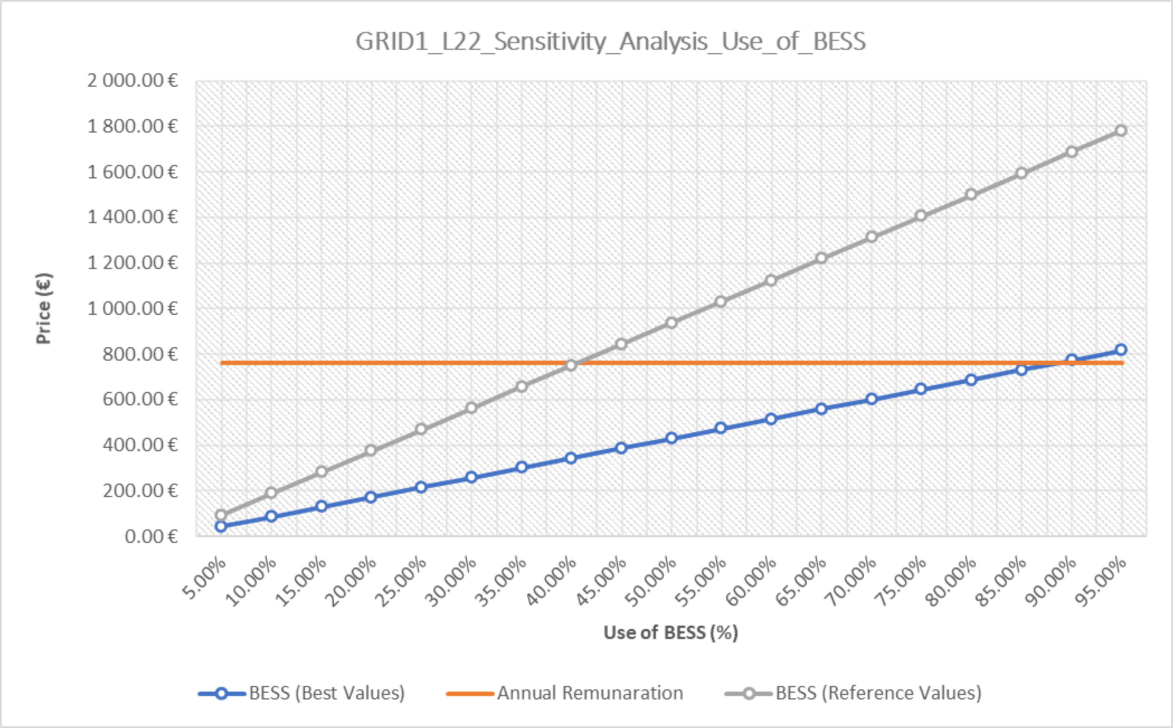


Figure 5. 2 – Sensitivity analysis of the use of BESS for L22

Table 5. 10 – Breakeven points for the use of BESS in L21 and L22

Breakeven Point	Use of BESS L21(%)	Use of BESS L22(&)
Best Values	32.56%	88.79%
Reference Values	14.99%	40.71%

5.3.2 - Annual Cost Comparison for GRID2

In section 4.4 the values for power and energy required from the BESS in GRID2 were:

- 130kW/780kWh for L1
- 140kW/840kWh for L3

The steps are same that were done for GRID1. The Eq.(6) and Eq.(7) are applied to values of power and energy referenced before, obtaining the BESS power capacity and energy capacity, accounting for the energy losses, on the Table (5.11), the results for the power capacity and energy capacity are represented, with the best, reference, and worst round-trip efficiencies. In the Table (5.12) the results for the annual CAPEX in euros of L1 and L3 are represented the culminate from Eq.(8), Eq.(9) and Eq.(10), where the annual cost of energy and power is outputted. Applying Eq.(11), the annual OPEX of both lines is on the Table (5.13), once again, the values are low due to the number of years (40 years) and because they only are considered to be 1.5% of the annual cost of energy and power installation. The annual CAPEX and OPEX are summed and the multiplied bur the use of BESS factor as Eq.(12) to get actual annual costs of DSO on acquiring a service that will provide the BESS, see Table (5.14).

Table 5. 11 – Values for Power and Energy capacity of BESS for each line

Valaues NMC/LMP	BESS for L1 (kW)	BESS for L3 (kW)
Best Values	130kW/780KWh	140kW/840kW
Refrence Values	137kW/822KWh	147kW/882kW
Worst Values	160kW/960KWh	173kW/1038kW

Table 5. 12 – Annual CAPEX for BESS in L1 and L3

BESS	Valaues NMC/LMP	Energy Storage Installation Cost (€)	Power Conversion Intallation Cost (€)	Years	Annual CAPEX
BESS for L1	**Best Values**	98 096.01 €	6 310.72 €	40	2 610.17 €
	Refrence Values	217 638.10 €	9 572.70 €	40	5 680.27 €
	Worst Values	508 351.77 €	20 123.64 €	40	13 211.89 €
BESS for L3	**Best Values**	105 641.85 €	6 796.16 €	40	2 810.95 €
	Refrence Values	233 524.09 €	10 271.44 €	40	6 094.89 €
	Worst Values	549 655.35 €	21 758.69 €	40	14 285.35 €

Table 5. 13 – Annual OPEX for BESS in L1 and L3

BESS	Valaues NMC/LMP	O&M Energy	O&M Power	Annual Opex
BESS for L1	Best Values	36.79 €	2.37 €	39.15 €
	Refrence Values	81.61 €	3.59 €	85.20 €
	Worst Values	190.63 €	7.55 €	198.18 €
BESS for L3	Best Values	39.62 €	2.55 €	42.16 €
	Refrence Values	87.57 €	3.85 €	91.42 €
	Worst Values	206.12 €	8.16 €	214.28 €

Table 5. 14 – Total annual Cost of BESS for L1 and L3

BESS	**Valaues NMC/LMP**	**Annual CAPEX**	**Annual OPEX**	**BESS use (%)**	**Total Annual**
BESS for L1	**Best Values**	2 610.17 €	39.15 €	10.00%	264.93 €
	Refrence Values	5 680.27 €	85.20 €	10.00%	576.55 €
	Worst Values	13 211.89 €	198.18 €	10.00%	1 341.01 €
BESS for L3	**Best Values**	2 810.95 €	42.16 €	10.00%	285.31 €
	Refrence Values	6 094.89 €	91.42 €	10.00%	618.63 €
	Worst Values	14 285.35 €	214.28 €	10.00%	1 449.96 €

The Table (5.15) shows the comparisons between the annual costs of the acquisition of the BESS, considering the best, reference and worst values, and the annual remuneration of the DSO when the decision is changing the line that is overloading, in these case L1 and L2 (the green represents a profitable investment on BESS and the red the contrary). The results are quite like the ones one GRID1, only the worst values of the BESS for L3 do not present a profitable investment. Again, the big factor is the use of BESS being only 10% makes the annual cost of BESS decrease and gives a profitable investment for the DSO.

Table 5. 15 – Comparison between annual costs

BESS	Valaues NMC/LMP	Total Annual	Annual Remunaration	Lines
BESS for L1	Best Values	264.93 €	1 433.27 €	Changing line L21
	Refrence Values	576.55 €		
	Worst Values	1 341.01 €		
BESS for L3	Best Values	285.31 €	1 433.27 €	Changing line L22
	Refrence Values	618.63 €		
	Worst Values	1 449.96 €		

5.3.2.1 – Sensitivity Analyse GRID2

The factor of BESS use, which was considered to be 10% to begin, will go through the study of sensitivity analysis on GRID2, like the one done for GRID1. So once again, in a brief explanation, this factor, the use of BESS, represents how much the DSO is going to pay off the actual cost of the BESS, to then use it for grid applications. Using Eq.(12), and maintaining the annual CAPEX and the annual OPEX, the *use_BESS* is going to be changed in order to see how much percentage of the BESS the DSO use can and still be inside a profitable investment, excluding the worst values of the annual CAPEX and annual OPEX (Table 5.14). The aim is the comparison between the annual remuneration when changing the line that is overloading, in this case, L1 and L3, and the annual cost of the BESS for the DSO, where the breakeven point is retrieved, as it was said in section 5.3.1.1, the breakeven point reflects when contracting a flexibility service stops being profitable over changing the line. The Figures (5.3) and (5.4) show the sensitivity analysis on L1 and L3, respectively.

From the Table (5.11) where the power and energy capacities for each BESS are represented, it is notable that they do not diverge between lines, so basically, the results on the annual costs are similar, and because the lines in the study, L1 and L3 have exactly the same characteristics (Table 5.2), the annual remuneration is the same, which helps on the results of the sensitivity analysis being really similar. That being said, on the Figures (5.3) and (5.4) the results are really similar in terms of, the breakeven points for the reference values on each line are around the 50% and diverge around 25% from the breakeven points for the best values, this can be reinforced on the Table (5.16), where the breakeven points are listed.

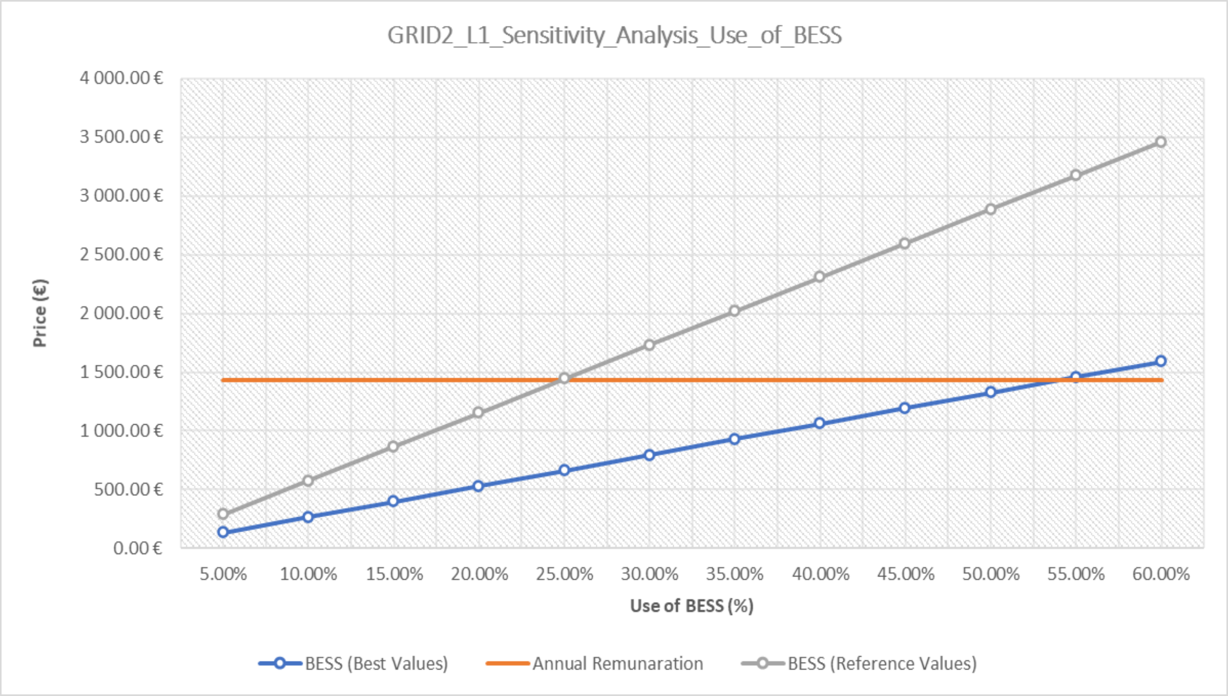


Figure 5. 3 – Sensitivity analysis of the use of BESS for L1

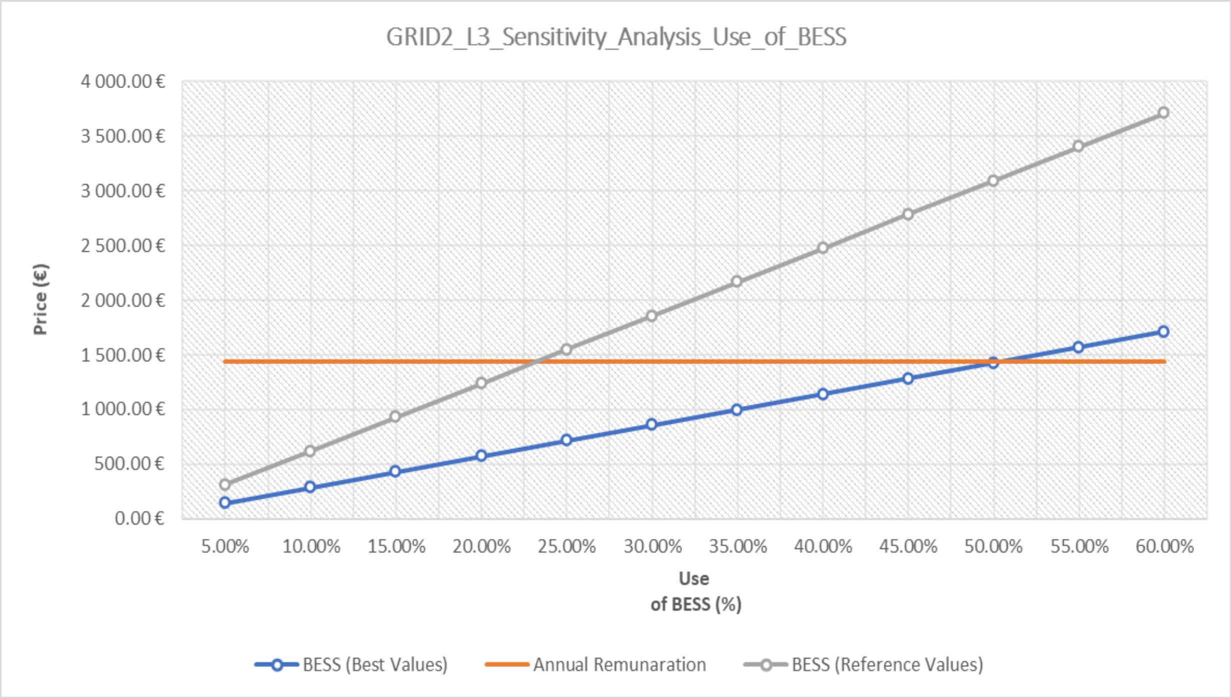


Figure 5. 4 – Sensitivity analysis of the use of BESS for L3

Table 5. 16 – Breakeven points for the use of BESS in L1 and L3

Breakeven Point	Use of BESS L21(%)	Use of BESS L3(&)
Best Values	54.10%	50.24%
Reference Values	24.86%	23.17%

Chapter 6

Conclusion

Conclusion and suggestions for future work are presented in this chapter.

The purpose of this thesis was to get an annual cost of how much would it cost to purchase a flexibility service, more specific a BESS and compare to the annual remuneration that would be given to the DSO if he opted to go for grid expansion; basically, the idea was to build a tool that would give the ability to the DSO of comparing the cost in order to help him with the decision to achieve grid efficiency.

To achieve this goal, the process was structured into:

- A study on the role of a DSO on is proprieties, the obligations and the limitations that a DSO faces on a day-to-day basis, the role of DER (Distributed energy resources) and the flexibility services that they can provide in order to help the distribution networks in problems such as overloading of the lines, also giving a extend reading on different types of flexibility services and the role that each one has in grid flexibility. This type of flexibility services requires adequate regulation, and because of that, a study on the different types of regulatory mechanisms and their schemes was done. All of this is written on chapter 2.
- As chapter 3 states, a benchmarking on distribution networks was done in order to extract the grids that were then modelled and tested to fit the methodology of the thesis. The need for consumption data and PV generation data was a big challenge due to no access to utilities data; that being said, some time was given in order to find an accurate and efficiency way to demonstrate consumption and PV generation curves, to then apply them on the grids selected.
- The main goal was to obtain stressed grids, that would call for the need for either a grid reinforcement or a flexibility service. This part of the study was a real challenge because the approach done was of a test error type, meaning that the features of each gird were changed in order to obtain the closest to an ideal stressed grid where sines of overloading were present but at the same time not for too long and also not achieving huge values of overloading. After obtaining the stressed grid, the application of flexibility service was put in place, selecting BESS as the flexibility service; first, the stressed lines, where it was possible to apply BESS, were selected and then the effect of BESS in those lines was tested to see if normal values of loading could be reached; also a brief study on the types of batteries in the market was done to select one with the objective of getting a cost referred to this batterie to construct a cost tool.
- To finalise the annual cost comparisons were made. Before the comparisons, a cost tool for BESS was constructed in order to give an accurate and effective cost of contracting this type of flexibility service, and the comparison was made with what the regulation of Spain would give the DSO annually if the lines were changed. In this process, a sensitivity analysis was performed on how much of the BESS could the DSO use for grid application proposes and still be a profitable investment.

The results of the costs comparison are the strength of this thesis due to the fact they present promise results where it would be possible for the DSO to acquire a percentage of a BESS and use it for grid applications level and prevent grid expansion for both grids in the study. These results come from some assumptions and decisions made on the curse of this thesis, and that can be viewed as the limitations of this thesis:

1. The unavailability of real data consenting to the consumption curves and PV generation curves due to un access to information from utilities, and also the fact of using model grids and not a real grid scenario.
2. At the beginning of the thesis cases assuming that every type of load consumption in the grid would have PV generation were created, and only in those cases, it was possible to apply a BESS, when no PV generation existed, the need for changing the stressed lines was inevitable. In a real situation not every client of the DSO has a PV system installed, in the future, that could be achieved but by now, it is the reality.
3. The modelling of the battery was not done in this study because it was not the goal; the goal was to in an accurate way show that by applying a BESS the overloading of the lines would stop. It was not the optimisation of the battery but, yes, the results of applying it.
4. The use of BESS factor, presented in chapter 5, is the main feature that gives the DSO the opportunity of buying that type of flexibility service and still have a profitable investment. This factor assumes that other parties are going to join the DSO into the purchase of BESS to then use it for their own necessities, this assumption is reasonable because using a BESS for only one purpose is not always a profitable investment, but nevertheless, it is an assumption that gives the results obtained on chapter 6.
5. The life span of the battery was not considered, because the DSO it is acquiring a service that provides a BESS so the all the concerns on changing the battery were of the identity that provides the BESS.

The main goal of the thesis was achieved, that consisted of giving a methodology to make a cost assessment on flexibility service so that the DSO could them use it to decide whether to go for the purchase of that flexibility service or to opting for grid expansion. The results obtained are promising because they actually give an idea that prevention of grid expansion by using BESS is achievable, although all of the data used in this study is theoretical, and the results are theoretical.

6.1 – Future Work

The developed methodology should, in fact, be more studied open and reinforced by coordinate the project with some DSO utilities to then use real data, give more time to the modelling of the BESS so that the results could be more efficient, do a more accurate study of how could the BESS be distributed by different identities to each one use it for its own purpose and of course built an economic analysis more accurate and efficient that could then be used on the practical field by actual DSO companies. One more important point is the changes in the regulatory mechanisms; in the future, the incentive-based mechanisms and cost-based mechanism should also focus on the fact that the DSO is preventing grid reinforcement by investing in flexibility service and still achieving good performance of the grid, in this example considering the regulation of Spain no remuneration was predicted to this type of cases and only for grid reinforcement. The demand for electricity over the years will only increase, causing a more effective performance of the distribution networks; flexibility services are a very important tool on good grid performance and should be more focused on with the main goal of preventing grid expansion.

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