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MASTER'S THESIS

Assessing the value of energy storage systems in future power grids: a techno-economical study

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Madrid,

July 2021

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EVALUACIÓN DEL VALOR DE LOS SISTEMAS DE ALMACENAMIENTO EN LAS REDES ELÉCTRICAS DEL FUTURO: UN ANÁLISIS TECNO-ECONÓMICO

Autor: Niño Serrano, Marta
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RESUMEN DEL PROYECTO

Palabras clave: Almacenamiento, Baterías, optimización, modelo

1. Introducción

Uno de los principales desafíos en la transición energética es la integración de un escenario de generación totalmente renovable: ya sea con producción eólica o solar. La generación renovable a menudo incurre en vertidos si la energía producida no se consume o se almacena y, por esta razón, tienden a combinarse con baterías en sus estudios de negocio. Además, este almacenamiento distribuido puede proporcionar múltiples servicios: brindan servicios auxiliares, son capaces de mitigar las rampas en el sistema (podrían potencialmente sustituir a las CCGT como unidades flexibles), y también podrían dedicarse a proporcionar capacidad firme, aportando seguridad de suministro.

A pesar de proporcionar estos servicios de forma simultánea, las baterías se encuentran compitiendo con unidades de generación (o demanda flexible), dedicadas únicamente a uno solo de estos servicios. Esto hace que las baterías tengan un futuro cuestionable en términos de rentabilidad, ya que los ingresos provienen del mercado spot, de provisión de reservas y mediante pagos de capacidad firme, pagos menores que los percibidos por otros recursos dedicados.

2. Definición del Proyecto

El objetivo del proyecto es analizar en profundidad las ventajas, fuentes de financiación de los ingresos del almacenamiento en los sistemas de energía eléctrica, y estudiar su integración y potencial conflicto con otros planes convencionales de expansión de generación y transporte, así como con el uso incipiente de la participación de la demanda.

Finalmente, se incluye un breve estudio de rentabilidad y también se realiza un análisis de sensibilidad para examinar el impacto de agrupar todo un año en un solo conjunto de 7 días representativos, que reducen el tiempo y la complejidad computacional, pero subestiman los costes totales del sistema, la inversión en baterías y el suministro de la energía almacenada.

3. Descripción del modelo/sistema/herramienta

Este estudio se ha realizado mediante la ejecución y modificación de diferentes casos de estudio haciendo uso de un modelo de optimización en GAMS y aplicándolo sobre un mix de generación y red específica. El enfoque del modelo es determinista y de minimización de costes, en el que diferentes tecnologías compiten para suministrar energía al coste marginal más barato. En el modelado se consideran tanto las decisiones de inversión como de operación, y en lo que se refiere a tecnologías: los planes de expansión de transmisión y generación pueden ser (o no) efectivos, al igual que se incluyen el uso del almacenamiento y el desplazamiento de la demanda a través de la participación de la demanda.

4. Resultados

La reducción de costes lograda con el de almacenamiento, nuevas líneas de transporte entre nudos del sistema y con la ayuda de la flexibilidad de la demanda es del 15,00%. La alternativa preferida en esta red y caso de estudio específicos es la capacidad de transmisión, con un 13,03% de reducción de costes, si bien el solo uso de almacenamiento reduce el coste total un 8,33%, seguido de la contribución de un 4,60% de DSM. A esto cabe añadir que a medida que se eligen las líneas de transporte, el potencial de las baterías se reduce, ya que los precios nodales convergen a un precio homogéneo, reduciendo así el esquema de 'trading' diario que utilizan las baterías para financiar sus inversiones.

Además, si se hace una distinción entre el caso actual (año 2020) y el futuro mix totalmente renovable (2050), la necesidad de almacenamiento será cada vez más relevante y se realizarán sobreinversiones en almacenamiento, bajo los escenarios sin TEP (Figura 1). En cuanto a la operación de almacenamiento, las baterías alcanzan mayores niveles profundidad de descarga, bajo un sistema sin TEP (Figura 2).

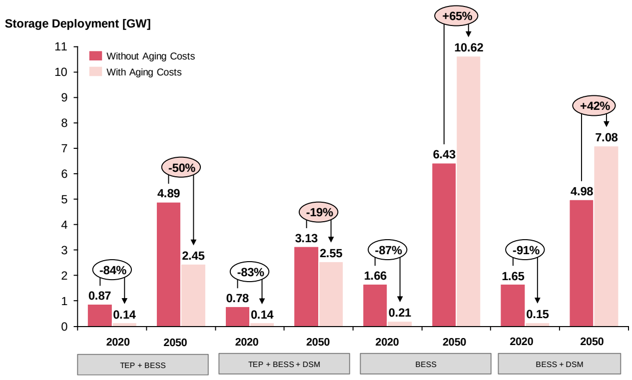

Figura 1. Inversión en almacenamiento, considerando costes de degradación

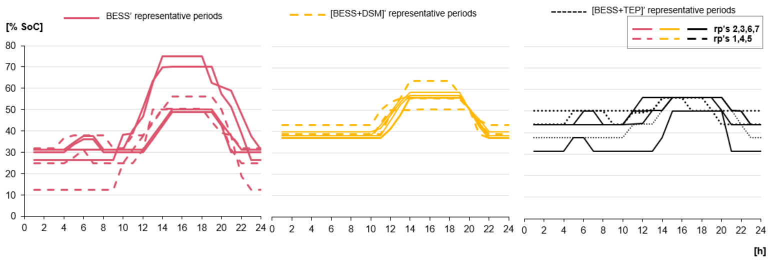

Figura 2. Estado de carga de las baterías considerando costes de degradación

En cuanto a la integración de BESS con TEP tiene dos ventajas: el almacenamiento puede usarse como una solución temporal que difiere los planes de inversión, mientras que los conflictos vienen de la mano del TEP, que hace converger los precios nodales del sistema, reduciendo el potencial de BESS para el trading.

En cuanto a su relación con DSM provoca algunas incompatibilidades, ya que el uso de respuesta a la demanda reduce las inversiones en almacenamiento y limita el estado de carga.

En cuanto a las fuentes de ingresos de las baterías (mercado diario, mercado de reservas y otros pagos de capacidad firme), todos los casos financian el almacenamiento con un 70% de las ganancias provenientes del mercado spot, dejando la provisión de reserva para financiar un 2-4% de su negocio. En este caso, si los pagos por capacidad firme están más sujetos a la cantidad de producción verde: varían de 30 a 0%, siendo este último caso un escenario totalmente renovable.

Finalmente, la rentabilidad de BESS está sujeta al estudio de si el sistema de almacenamiento se sitúa en una competencia perfecta o no. En caso de que los beneficios sean superiores a los de los MC, el margen resultante (ratio entre las dos cifras anteriores) es superior a 1, por lo que el proyecto BESS sería rentable. De lo contrario, el caso de negocio BESS incurriría en pérdidas, al ser el margen inferior a 1.

El impacto de obtener la solución del modelo en un horizonte de tiempo horario implica un ligero aumento en la función objetivo (coste total del sistema), así como un aumento de las inversiones en capacidad convencional y la operación y la disminución de la producción de energía limpia. Por otro lado, esto aumenta la capacidad en unidades de almacenamiento, al igual que el despliegue y operación solar. El uso de BESS también es mayor en el caso horario, así como su porcentaje de degradación y reducción de vida útil.

ASSESSING THE VALUE OF ENERGY STORAGE SYSTEMS IN FUTURE POWER GRIDS: A TECHNO-ECONOMICAL STUDY

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ABSTRACT

Key Words: Storage, Batteries, BESS, optimization model

1. Introduction

One of the main challenges in the energy transition is integrating a fully renewable generation scenario: either with wind or solar production. A renewable generation often suffers from curtailment if the produced energy is not consumed or stored. For this reason, renewable units tend to be combined with distributed storage - like batteries. Besides, distributed storage serves for many other purposes: they provide ancillary services since are able to mitigate renewable ramps (and could potentially substitute CCGTs as flexible units in the power system), and could also be dedicated to provide firm capacity, acting as a security of supply generation resource.
Despite serving for diverse purposes simultaneously, batteries find themselves competing against dedicated generation units (or flexible demand), that are just providing a single service at a time. This causes batteries to have a questionable future in profitability terms, since revenues come from the spot market, reserve provision and firm capacity payments, but in a lower extent than those dedicated resources.

2. Project Definition

The project aim is to deeply analyze the advantages, sources of profits and financial distribution of revenues of storage in electric power systems, and to study the complementarities and potential conflicts of storage with other conventional generation and transmission expansion plans, and with the incipient use of demand response to curtail demand peaks. Finally, a brief profitability study is included, and a final sensitivity analysis is also undertaken in order to examine the impact of clustering a whole year down to a single set of 7 representative days, that reduce computational time and complexity, but underestimate all total system costs, batteries investment and the provision of stored energy.

3. Model Description

This study is conveyed by running and modifying different case studies by making use of an optimization model in GAMS and applying it over a specific generation mix and grid. The optimization approach is a deterministic cost-minimization one, in which different technologies compete to supply energy at the cheapest marginal cost. In the modelling, both investment and operation decisions are considered, and in which refers to technologies: a transmission and generation expansion plans may be effective, but also storage use and demand shifting via demand response are included.

4. Results

The cost reduction achieved from the inclusion of storage, new transmission lines between nodes in the system and with the aid of demand flexibility (response) is a 15,00%. The

preferred alternative in this specific grid and case study is transmission capacity, with a 13,03% of cost reduction, whether only using storage lowers the cost an 8,33%, followed by the contribution of a 4,60% of demand response. Besides, as transmission lines are chosen, BESS potential is reduced, since nodal prices converge to a homogeneous system price, reducing therefore the daily trading scheme batteries use in order to finance their investments.

Additionally, if a distinction between the current case (year 2020) and the future fully renewable mix (2050) is made, the need for storage will be increasingly relevant, and storage overinvestments will be undertaken, under the considered scenarios not combined with TEP (Figure 3). Regarding the storage operation, BESS reach higher levels of charge and discharge cycles and depth, under a system without TEP (Figure 4).

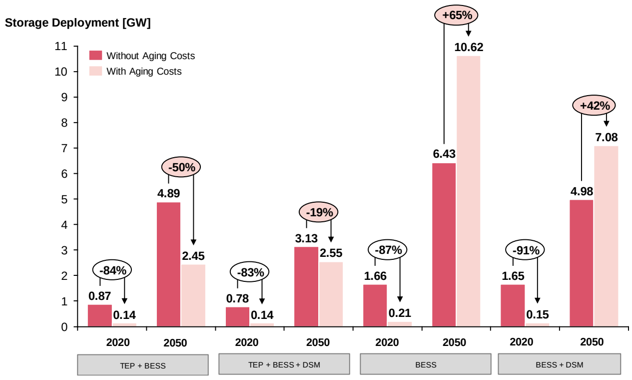

Figure 3. *Storage deployment for all scenarios considering BESS with storage degradation costs*

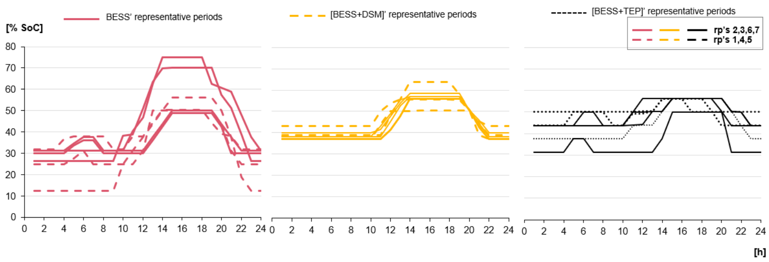

Figure 4. Battery's charge evolution Differential– Aging Costs

Regarding the **integration of BESS** with TEP has both **complementarities**: because storage may be used as a temporal solution that defers investment plans and **conflicts** since TEP makes MC at nodes to converge, reducing BESS potential for trading.

Regarding its relationship with DSM causes some disputes, since demand response use shaves storage investments and limits the state of charge.

Regarding **the sources of revenues** for batteries (day ahead market, reserves market and other regulated capacity payments), all cases finance storage with a 70% of profits coming from the spot market, leaving reserve provision to finance a 2-4% of their business case, whether firm capacity payments are more subject to the amount of clean produced considered: they vary from 30 to 0%, being this last case a fully renewable scenario.

Finally, **BESS profitability** is subject to the study of whether the storage system is placed in a perfect competitive market or not. In case that profits are greater than those of MCs, the resulting mark-up (ratio between the two previous figures) is greater than 1, so BESS project would be profitable. If not, the BESS business case would incur in losses, by being the mark-up lower than 1.

The impact of solving the model in an hourly time horizon solution comes with a slight increase in the objective function (total system cost), with increasing thermal investments and operation and decreasing the clean energy production. On the other hand, capacity in storage units increases, as does the solar deployment and operation. BESS use is also higher in the hourly case, as well as the loss of its useful life.

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CHAPTER 1. INTRODUCTION

1.1 MOTIVATION

Many of the challenges of the energy transition of the 21st century involve the massive deployment of renewable energy sources, with wind and solar photovoltaic as main actors. This increasing penetration is due to a bimodal factor: on one hand, the existence of incentives issued by the European Union [1] whose aim is to increase the renewable presence; and on the other hand, a considerable reduced investment in comparison with conventional generation. The main reason supporting decisions investing in renewable energy sources (also noted as RES in this document onwards), is the environmental one, since these technologies can provide clean energy, that is in other words, without incurring in CO2 emissions derived from coal and natural gas used as fuels in conventional generation. But not only the impact is environmental, also RES has a very contained production cost, which are indeed their variable and operational costs.

Since these resources come with an interesting advantage that is the lack of ‘fuel’, those costs related to provisioning and managing are close to zero. On the contrary, they present a disadvantage, as they are intermittent energy sources, since not all hours can be exploited from wind and solar incidence due to the natural variation in climatologic conditions. This intermittent -but cheap- generation makes their renewable producers to exploit generation plants as much as possible, bidding in a competitive level at a low variable cost, in fact, their marginal one. The competitive level is truly quantified by their participation in wholesale markets: day ahead participation, with reserves provision in the reserve market, and other potential participations providing, among others, firm capacity in the future. This last part may be contradictory from the technical point of view, due to the intermittent nature of renewable deployment capacity, but not so much, since wind and solar photovoltaic are often complemented with local and small-scale (compared to pumped hydro large storage facilities) storage deployment, by means of battery energy storage systems (also referred to as BESS).

From the economic perspective, their low bids -at costs that are below those of thermal conventional generation- provokes an accumulated effect that in fact is an attractive economic signal difficult to ignore, as renewable generation increases in the mix. These signals coming from RES translate into:

i. The existence of large daily periods with near-zero or even negative prices due to low demand levels at central hours in the day, combined with an elevated solar generation precisely at those moments.
ii. The existence of daily price volatility, especially because of an accumulated participation in the Day Ahead Market (often referred as DA in this document onwards).

Both effects can be easily seen in the famous 'duck curve', depicted in Figure 5. Here, the expected 2030 generation mix will have a relevant share of solar capacity deployed, causing some technical issues: both risk of renewable overproduction with its potential spillages and risk of not meeting the demand. Both are especially noticeable either when the sun is increasingly providing energy (from 9 in the morning up until 6 in the afternoon), or, on the contrary, when this production decreasingly being available (from 7 pm onwards).

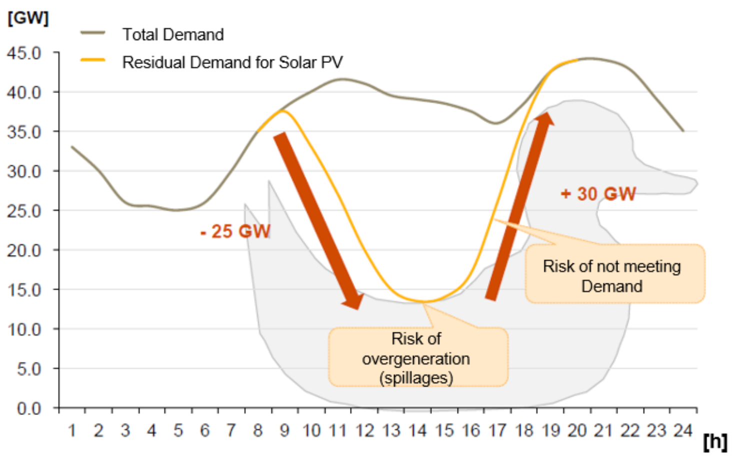

Figure 5. Duck curve estimated up to a 2030 scenario

Ultimately, from an economic perspective, this price differential may be the root cause to BESS rise, acting as auxiliary generation and economic exploitation via price arbitrage and other mechanisms able to increase the batteries' profitability and utilization as ancillary small- scale generation.

Therefore, from an engineering point of view, this production differential may cause several stability problems if not supported by other complementary generation able to provide (1) firm capacity and availability, ensuring at every moment the existence of enough generation capacity to cover the peak demand of the system and (2) enough flexibility to stand those ramp-ups and downs in order to provide to the system the required flexibility to produce quickly enough to adjust the renewable intermittency. For these reasons, power systems need to grant other services, such as ancillary services, of a higher weight and economic benefits, in order to allow new technologies -like the storage- balance the system with an adequate price signal.

Currently, there are 3 main technologies able to provide firmness and flexibility to the system. On one hand, thermal conventional generation (such as CCGTs) is the one covering for this flexibility. On the other hand, demand response/demand side management (also referred as DSM in this document) which empowers big industrial consumers and domestic ones to modify at will their consumption: either by shedding their consumption (this is, by not being supplied in exchange of an economic signal) or shifting it a certain amount of time for demand not to be concentrated at the very same moment in time. And finally, Energy Storage Systems are also capable of accumulating enough energy with the aim of discharging it at the required moment, improving renewable production and becoming one of the most promising alternatives in the long term.

Thus, BESS can solve many of the energy transition issues, with the advantage of being connected at a transmission and distribution level in the grid. In fact, distributed storage systems could present as a great opportunity for the system operator due to their positioning as a backup system, also capable of flattening both the demand curve and daily prices. In this way, storage systems could support via the procurement of several grid services:

1. Frequency Regulation and Stability (Frequency Containment Reserves -FCR and Frequency Restoration Reserves- FRR)

2. Black-Start Capability
3. Support and/or conventional generation (to cover ramps)
4. Reduction of one of the limitations of renewable energy: via not incurring in spillages
5. Intraday (and potentially seasonal if large storage facilities were developed) price arbitrage

On this path towards electric power systems with high renewable generation (almost 100% coming from these sources in 2050) penetration and carbon-neutral, that is, without pollutant emissions, those past and current synchronous generators are increasingly being displaced by variable RES, unable to provide system inertia nor reactive power support. In fact, this is creating serious problems of system stability in those countries with high renewable penetrations existing nowadays (i.e.: Ireland) and it represents the picture to be looking at in the upcoming years to those countries willing to readjust its generation mix to a cleaner/greener one.

For these (1) environmental, (2) technical and (3) economic reasons, energy storage systems -specially batteries- seem to be called to play an important role in the energy transition towards a free emissions environment.

It should be noted that, of all storage systems, the scope of this work is to carry out a cost & benefit analysis of battery energy systems (measuring the social and economic impact in a centralized context) due to their upcoming technological development, cost reduction expectations and the supply of a wide range of services, among other reasons. However, it seems that, under the current regulatory framework, batteries' performance, deployment and financial viability is not completely ensured despite providing essential services in the power system of the future. The objective of this thesis is to broadly study if this statement is true and under which conditions storage can be profitable, but also proposing the needed regulatory mechanisms to ensure their viability.

1.2 LITERATURE REVIEW

The focus of the literature review carried out in this thesis lies on realistic Generation Expansion Planning (GEP) and Unit Commitment (UC) models, including network topology, and an explicit representation of renewable technologies, battery energy storage systems (BESS) with degradation and Demand Response, all together. Palmintier and Webster [14] have previously pointed out the importance of considering UC constraints in GEP, considering a high penetration of renewables in the system. Although

Since there is no single work that covers all of these topics at once, we will try to discuss this research topic, by reviewing the available literature on each one of the isolated topics (the GEP+UC with high renewable and storage quota, the DC-Optimal Power flow and the shifting DSM).

Firstly, DC-OPF constraints allow us to linearize the equation of active power flow, disregarding the reactive component, that is, assuming all voltages are equal to 1 p.u. permanently. This is a commonly used practice for Generation and/or Transmission Expansion planning models that consider UC constraints, due to the computational burden UC models convey. This has a voltage limitation, and the main drawback is that assuming that voltages are not relevant in the optimization may lead to a higher systems costs, since a high-cost generation unit is forced to run and give voltage support in a specific node, by means of local reactive power provision. In the DC-OPC this cannot be captured, since the reactive component is ignored, as are voltage deviations. Since this thesis is not focused on assessing the impact of voltage deviations and reactive power flow through lines in the system cost, but more likely to study the complementarities that a particular storage typology may have with both expansion plans and other flexibility resources, this has no bigger importance.

On the other hand, the introduction of Demand Response, often referred to as Demand side Management, in this type of optimization models fills a research gap that we will try to study. Previous work in Demand Response is carried out in [2], but for regionalized German demand, not the adaptable and flexible electric system that is used in this work.

1.3 OBJECTIVES

The main objective of this thesis is to quantify the economic impact of battery energy storage systems (BESS) in a 9-node grid considering both the yearly system operation and investment decisions in generation energy sources (thermal conventional units and renewable plants) and transmission lines, so to reinforce the system interconnection. Although a yearly operation is comprised, it must be said that a single representative week has been chosen in order to reduce the computational time dedicated to obtaining the results (this is explained in the model formulation chapter). Additionally, it exists the possibility of investing in storage facilities: a single hydro unit and the many battery energy storage systems, already mentioned and whose economic analysis and profitability are carried out in this thesis. The optimization model, developed in GAMS, also considers demand flexibility through two types of demand response: Demand Side Management (DSM) Shedding and Shifting. These terms represent that both industrial and residential consumers may be price responsive: the DSM shedding typology models industrial customers, willing to accept an economical compensation for not supplying them electricity; and DSM shifting represents ‘smart’ residential consumers, able to shift their consumption from 1 to 6 hours, depending on the electronic appliances that could participate in this demand postponement (electric vehicles, air conditioning systems, domotic appliances, etc).

Therefore, all generation and transmission expansion (deployment), along with battery energy storage systems and demand response are eligible for participating in the system yearly operation. This enables us to carry out a **cost analysis in a variety of scenarios** (8, including the base case scenario), **where BESS is present** with other technologies in the generation mix (the remaining Generation Expansion and Transmission Planning and DSM). Additionally, it will also be studied under which specific conditions (or scenarios) these tools would be of most use: for instance, if nodal prices take place in the system, transmission capacity will be the most reasonable alternative, rather than having distributed storage in several nodes of the system. This will finally allow us to determine the optimal mix and combination of flexible resources mentioned.

This is one of the main objectives of this document, which is broadly examined in Chapter 3.1 and 3.2, and naturally leads to the analysis of a BESS' **competitiveness and complementarities** study (Chapter 3.3).

With competitiveness and complementarities we understand that, if both batteries and other technologies in the generation mix (or even in the demand side, if it is willing not to consume) provide a flexible service in different markets and in a short-term basis (days), BESS deployment and operation may be narrowed, from a cost minimization perspective. Therefore, flexibility inclusion though generation, transmission capacity and demand resources may hamper BESS operation, and therefore, profitability (if the investment decision is made, it will make much more sense to exploit BESS' potential). On the other hand, the lack of some specific resources may be suitably provided by distributed storage.

Therefore, storage short-term operation may both affect other short-term resources (demand side management in exchange of a remuneration), and long-term decisions, like generation and transmission expansion planning scenarios.

The evaluation of the 8-scenarios transversal comparison enables to **quantify the value to the system provided by BESS, TEP and DSM flexibilities**, in terms of their contributions through economic savings, both in a 2020 and 2050 perspective. Although 2020 and 2050 scenarios differences will be further explained, the idea behind both scenarios is a having a current generation mix perspective- which allows GEP in many thermal and renewable units- and a final 2050 renewable exclusive generation mix, respectively.

Although the previous value quantification is very simplistic, it will represent a first approach of the BESS value provision. This will also be deeply and broadly analyzed in the future, since BESS are key for the **simultaneous energy provision in the day ahead market** (whose product is hourly energy), the **reserves market** (whose normal product are secondary reserves) and potential participation in **capacity remuneration mechanisms** (whose product will be power, representing firm capacity to the system). Therefore, batteries are simultaneously providing day ahead services, ancillary reserve services, reactive power support and security of supply, which is of special importance, since not many generation units can state that. Then, since batteries receive some kind of remuneration from many (at least 3) sources or markets, in Chapter 4.1 and 4.2 we will **assess the share of each financing source**, so to understand whose sources of funding batteries use to recover their initial investments. Additionally, and since batteries are often (but not always) deployed in electric systems with intermittent renewable generation, Chapter 4.3 will study if their incomes' share depends on how the energy source is installed. In other words, since we may have an initial intuition of BESS' being more competitive and used in a hybrid environment (combined with renewable units), the same volumetric and percentual income study will be included with respect to the BESS sole deployment in a system node.

All the previous outlined objectives are subject to many sensitivity analyses to be performed, if considered of special interest in this thesis, and included as the thesis works gets done.

If schedule goes according to plan, other additional objectives will be included: for instance, comprising a **profitability analysis for batteries** will end up determining whether batteries are profitable in the short term (less than a year), and if they are able to recover their investments by means of their yearly operation.

To sum up, carrying out an hourly study, considering the whole year in a chronological and hourly approach, will provide much more valuable information for batteries. This is because batteries potential lies on the amount of scenarios variability and extreme cases (considering all hours in a year, that is, considering outlier hours, if seen from the perspective of the 7 representative days clusterization technique used to reduce data and time computation).

1.4 THESIS OUTLINE

This document is organized as follows: Section 2.1 includes a detailed description of the methodology employed in this project, which includes the mathematical formulation of the optimization model, and a full grid description taken as an example in this thesis. Further sections convey a general and specific storage analysis.

Firstly, an analysis of scenarios is synthetized in Sections 3.1 and 3.2, taking a deeper approach for storage deployment and operation in those selected scenarios, with or without other flexible options for operating the grid in the yearly scope. This is carried out in the current (2020) benchmark and a future 2050, fully renewable, system. These resources sum demand participation through demand response, as well as the investment in other generating units- dispatchable and renewables, and transmission lines' deployment. This naturally draws attention towards the complementarities of conflicts of energy storage in different electric grids, which can be complemented either with one or other resources, as said before. This last part is summarized in section 3.3.

Then, Section 4 takes a more detailed analysis on the funding opportunities and total costs that storage have. A sensibility analysis is conveyed for the inclusion or avoidance of storage degradation costs, since results significantly vary if they are (Section 4.1), or not (Section 4.2), considered. A final Section 4.3 is included, under which the storage configuration is studied, taking both a Solar PV+ Storage hybridation or just a storage Stand-Alone approach.

Regarding the profitability (Section 5), a brief analysis on what causes storage business cases to be negative, is undertaken analysing the mark-up in each scenario with BESS use and installation. After this, a concise Section 6 examines the impact of the used hourly clustering technique used in contrast to the hourly model.

To end up with the structure of the document, a final conclusions section is included with the main bullet points of the whole assessment of distributed storage systems.

CHAPTER 2. METHODOLOGY

The methodology to be applied in the completion of the economic analysis to be studied in this thesis is based on the use of modelling techniques using GAMS, resulting in a MIQCP (Mixed Integer Quadratically Constrained Programming) model, that is, with integer variables and quadratic constraints). Also, it would be programmed using a relaxed approach, to relax integer investment decisions and calculate nonzero dual variables related to capacity payments or renewable support payment mechanisms. This also allows to execute the model in a much more agile way and validate results even quicker. A MIP approach is followed in the profitability analysis, since integer storage investments are necessary in order to study if profits may be higher than costs, considering operational and those related to investments.

For this optimization approach, a brief description of the electric system will be now outlined in Section 2.1, along with the data in standard generation units, transmission capacity and others, but also for the novel DSM flexibility.

2.1. ELECTRIC SYSTEM – CASE DATA

This thesis covers a single static year in the future as for the time horizon, that has been approximated by 7 representative days. The main features of the network contemplate 9 buses, 13 existing transmission lines with an 800MVA capacity limit on each line, and a potential additional transmission line between nodes 4 and 5. Network, generation units and transmission lines (existing and candidate) are depicted in Figure 6.

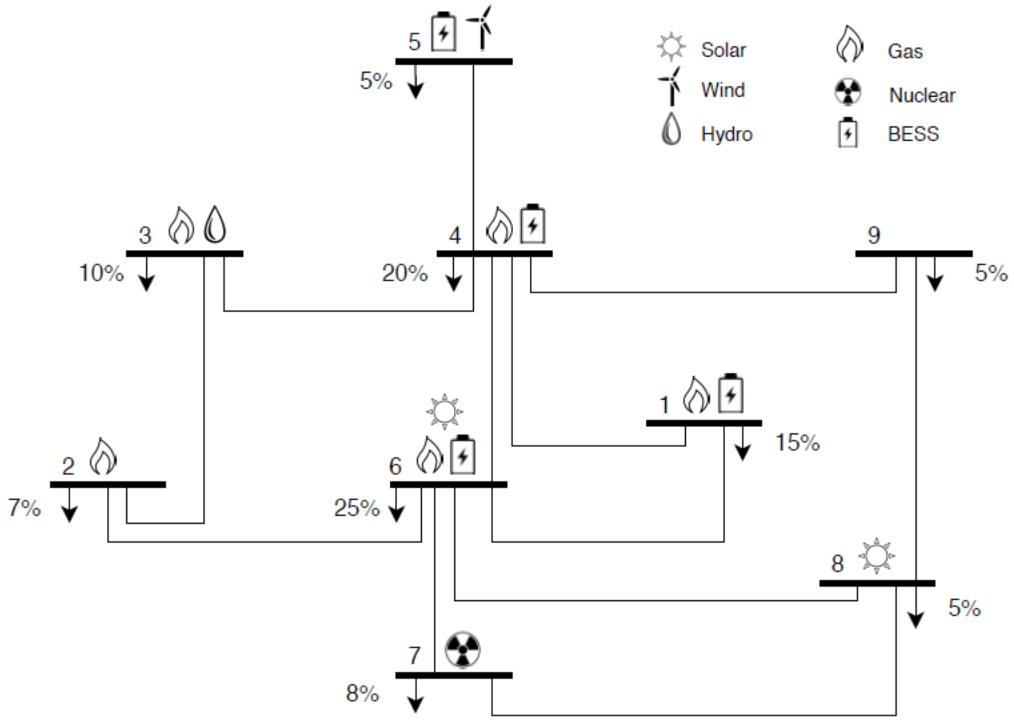

Figure 6. 9-bus network, including existing and candidate generation units; and nodal demand in [%]

Moreover, data for thermal generators, renewable technologies, battery energy storage systems and demand response profiles are included in Annex I. This data coincides with the one used in the StarNet Lite demo version for long-term planning developed by Prof. Andres Ramos at IIT-Comillas (available online), extending the original data set to include storage [3] and renewable generation profiles from [4] and [5]. Data for Demand Side Management is available online in [2], via hourly volumetric demand shifting in Germany, and transformed into a profile [p.u. units], taking German demand data from smard.de/en. Therefore, we have considered the Spanish demand response potential to equal the German one, open to 4 segments of demand responsive users/systems, capable of shifting their consumption in an aggregated manner: cooling ventilation systems, emobility applications, and residential washing and freezing units. Each of these segments has a unique delay time, as well as upwards & downwards demand variation.

2.1. MODEL FORMULATION

This section contains the mathematical formulation of the model which had already been designed in a modular approach, so to maximize model flexibility both in time representation and in how are technologies or blocks can be combined among each other. Therefore, the model formulation is not a novel contribution of this thesis, although the existence of the new flexible resource that DSM represents is.

The model has a cost-minimization perspective and a concrete representation of the time horizon with all the standard UC constraints typical of operation models, DC-OPF constraints representing power flows in between lines ignoring the reactive (Q) component by means of linearization and both renewable and storage constraints. In further Sections 2.1.1 and 2.1.2 it will be explained the use of a single representative week in the yearly scope and the constraints explanation.

2.1.1. TIME REPRESENTATION

According to the time representation, several approaches are followed in the literature for generation expansion planning models for representing time in generation expansion planning models: firstly, the complete hourly representation of the considered period, often computationally intractable for MIP models; secondly some chosen representative periods that often are days or weeks and finally hourly time slices (or time blocks).

In this thesis, a flexible model formulation is presented, which allows us to pick one or another method (full year vs a linked representative week). Therefore, three different temporal indices: p; k; rp, are introduced and used in the model formulation. Index p represents the real chronological periods, hourly in the model, rp are the representative periods used, and k corresponds to all the chronological periods within the previous representative period rp. To be able to weight each representative period in the full time scope, a the parameter W_{rp}^{rp} is introduced, as well as W_k^k, parameter indicating the weight of the period k within each rp. The relationship in between p; rp; k is represented by a mapping $\Gamma(p, rp, k)$, that relates each period p to its representative period rp and chronological k. In this way, we can move from a 'Full Year' model to a '7-Days Linked Representative Periods' Representative Periods' in Table 1.

Time Models	Full Year	Chronological week	7LRP
rp	1	1	7
k [h]	8736	168	24
t [h]	8736	8736	8736
W_{rp}^{rp}	1	1	$7^{result\ of\ clusterization}$
W_k^k	1	1	1
Representative hours [h]	8736 (1 year)	168 (1 week)	168 (1 week)

Table 1. Flexible Time Representation: Models

Taking a didactical approach and considering that January 1st may be represented by rp4, and January 2nd by rp5, then, on one hand, Γ (p1; rp4; k1) = 1, […] up until Γ (p24; rp5; k24) and on the other, Γ (p25; rp4; k1)=1, and so on. This means that the 25th hour (parameter p) of the complete year corresponds to the 1st hour (parameter k) of a different representative day (in this case rp5). Additionally, sometimes a double minus/plus appears in the formulation, with the aim of creating a cyclic association between the first and last k of a single representative period. For example, if k=2, a k--1 refers to k=1, whether if k=1, k--1 goes to k=24. This will be of special use in the storage constraints.

2.1.2. STANDARD CONSTRAINTS

Although he full notation of all model indices, parameters and variables can be found in the appendix, the operation and investment constraints are hereunder briefly explained. For the sake of simplicity, index g represents all generating units (both existing and candidate units), Firstly, the objective function (1a) represents total system cost as the sum of thermal production cost (start-up cost C_t^{st}, activated if the binary start-up variable $y_{rp,k,t}$=1; the commitment cost C_t^{int} in which we incur in case the commitment variable $u_{rp,k,t} = 1$ and the variable cost C_t^{var}, associated to production $p_{rp,k,t}$; in this case thermal); operational cost for renewable and storage productions $p_{rp,k,r}$ and $p_{rp,k,s}$: in the latter, it has also been included a cost of degradation associated to deep batteries' discharges; potential cost

C^{ENS} for non-supplied energy $pns_{rp,k,i}$ and spillages of storage units ($sp_{rp,k,s}$, weighted by half of the non-supplied energy cost); cost incurred in each one of the two DSM typologies represented by $dsm_{rp,k,i,seg}^{shed}$ and $dsm_{rp,k,i,sec}^{Dw}$ variables; cost of providing upward and downward secondary reserves by thermal and storage units; and investment costs related to both the investment in new generation units via x_g variable and the building of new transmission candidate lines. Constraints (1b) and (1c) represent the upper and lower bounds of non-supplied energy; and the definition of investment variables as non-negative integers, while establishing an upper bound introduced by parameter X_g^+.

Constraints in (2) account for the functioning of the shift-type of DSM, defined for various sectors-sec set- in the demand (mainly small active consumers, able to bring forward or delay demand for a certain amount of time, sector-dependent). In constraint (2a) the amount of 'Up' demand is compensated with a 'Down' one, for each sector and node in every representative period. Bounds are defined in (2c), (2d) and (2e). The logic behind the periods in which DSM can be used is defined in constraint (2f). The shed DSM typology is not modelled with a sole and exclusive constraint, as it can be understood as a cheaper NSE (Non-Served Energy) cost.

Constraints in (3) define the need for reserves: upward reserve (3a) and downward requirements, (3b) including reserves provided by storage units that summed to thermal reserves must surpass the minimum defined by a pre-existing factor of the total demand in the system for each time period.

The included constraints in the (4^{th}) group, apply to thermal generators:; total power output ($p_{rp,k,t}$) and its relation to the one above the technical minimum, $\hat{p}_{rp,k,t}$, being the minimum P_t^-, in case the unit is committed. It is also necessary to define the limit of upward reserve in case of start-ups (4d) or shut-downs, and the limit of downward reserve; in (4e) the logic between commitment, start-up and shut-down is defined; in (4f) the commitment variable is bounded to 1, considering both the existing units of each thermal generator and the potential investments in new units. Then, both the ramp-up and down bound constraints are included as the maximum variation of power in between two consecutive (chronological) periods, in (4g) and (4h), respectively. Finally, the bounds for power above the minimum, total power output and reserves are included in (4i) and (4j) as well as it is the definition of binary variables (4k).

The constraints in (5) model the functioning of the two types of storage technologies, whose time dynamics differ in a noticeable way. Since the time representation in the model allows us to use representative periods, in that case, we can differentiate between intra-period constraints (within the rp) and inter-period ones (between consecutive representative periods). The latter are imposed on a moving window MOW throughout the time horizon, to model hydro storage long-term effects. If, on the other hand, we want to run the hourly model (either it can be understood as if no rps will be necessary or if as rp=1 being that 1 the whole year), the storage constraints will only comprise the intra-period ones. Since this formulation is not novel, we refer the interested reader to [6] where such a formulation is described in detail. With this, we have that constraint (5a) represents the inter-period evolution of charge state; then, both the upper and lower bounds of inter storage state of charge are defined in (5b); a cyclic storage constraint is defined in (5c); intra-period evolution of charge state for storage (5d); bound of upward and downward reserve in (5e); as well as upper and lower bounds of intra storage state of charge (5f); constraint (5g) to avoid simultaneous charging and discharging; and final definition of binary variable to avoid simultaneous charging and discharging (5h). The lower and upper bounds on production, consumption and reserve variables are defined in (5i); lower and upper bounds of intra storage state of charge in (5j); and lower and upper bounds on spillages in (5k). Moreover, as storage's degradation is modelled with a cycle depth stress function, equations (5l) to (5p) define storage production (5l), consumption (5m) and intra-storage level (5n) as the sum of all 'a' segments in the cycle aging cost function in the charge, discharge and state of charge variables, respectively. Storage state of charge in between periods is limited in equation (5o) to initial reserve, charges and discharges along the time scope; and finally (5p) caps the maximum energy for Cycle depth stress function.

Constraints in (6) apply to renewable units, establishing both upper and lower bounds on their production in (6a), considering investment decisions, and the k renewable production share in (6b) in the whole-time scope.

Finally, constraints in 7 account for the balance equation of power flows in each node (7a), and the establishment of a **firm capacity lower bound constraint** in (7b), with a minimum firm capacity (FC^{-}) share, with respect to the peak system demand. Since this model is run under a 9-node electric system, a definition of power flow variable (using line parameters and angle differences between nodes) and bounds for this power flow (8c) are included for existing lines (8a), and for candidate lines (not yet built, if running the model with a Transmission Expansion approach) in (8b).

$$
\begin{aligned}
& min \sum_{rp,k} W_{rp}^{rp} \cdot W_k^k \qquad\qquad (1a) \\
& \cdot \left(\sum_{i} (C^{ENS} \cdot \; pns_{rp,k,i} + \frac{C^{ENS}}{2} \cdot \; sp_{rp,k,s}) \right. \\
& + \sum_{seg,i} (C_{seg}^{DSM_{shed}} \cdot \; dsm_{rp,k,i,seg}^{shed}) \\
& + \sum_{sec,i} (C_{rp,k,i}^{DSM_{shift}} \cdot \; dsm_{rp,k,i,sec}^{Dw}) \\
& + \sum_{t} (C_t^{st} \cdot y_{rp,k,t} + C_t^{int} \cdot u_{rp,k,t} + \; C_t^{var} \cdot p_{rp,k,t}) \\
& + \sum_{s} \; C_s^{OM} \cdot p_{rp,k,s} + \sum_{r} \; C_r^{OM} \cdot p_{rp,k,r} \\
& \left. + \sum_{s} C_s^{DEG} \cdot cdsf_{rp,k,s,a}^{DIS} \right) \\
& + \sum_{rp,k} \; W_{rp}^{rp} \cdot W_k^k \\
& \cdot \left(\sum_{t} (C_t^{VAR} \cdot C^{RES+} \cdot res_{rp,k,t}^{+} + C_t^{VAR} \cdot C^{RES-} \cdot res_{rp,k,t}^{-}) \right. \\
& \left. + \sum_{s} \; C_s^{OM} \cdot C^{RES+} \cdot res_{rp,k,t}^{+} + \sum_{r} \; C_r^{OM} \cdot C^{RES-} \cdot res_{rp,k,t}^{-} \right) \\
& + \sum_{g} \; C_g^{INV} \cdot x_g + \sum_{\text{lc\_ijc(i,j,c)}} \; C_g^{INV} \cdot x_{ijc}
\end{aligned}
$$

$$x_g \leq \hat{X}_g \qquad \forall\, g \qquad (1b)$$

$$0 \leq pns_{rp,k,i} \leq D^P_{rp,k,i} \qquad \forall\, g \qquad (1c)$$

$$\sum_{rp} dsm^{UP}_{rp,k,i,sec} = \sum_{rp} dsm^{DW}_{rp,k,i,sec} \qquad \forall\, rp, i, sec \qquad (2a)$$

$$dsm^{UP}_{rp,k,i,sec} \leq \sum_{kk} dsm^{DW}_{rp,kk,i,sec} \qquad \forall\, rp, k, i, sec \qquad (2b)$$

$$dsm^{UP}_{rp,k,i,sec} + dsm^{DW}_{rp,k,i,sec} \leq \widehat{DSM}_{rp,k,i,sec} \qquad \forall\, rp, k, i, sec \qquad (2c)$$

$$dsm^{UP}_{rp,k,i,sec} \leq \widehat{DSM}^{UP}{}_{rp,k,i,sec} \qquad \forall\, rp, k, i, sec \qquad (2d)$$

$$dsm^{DW}_{rp,k,i,sec} \leq \widehat{DSM}^{DW}{}_{rp,k,i,sec} \qquad \forall\, rp, k, i, sec \qquad (2e)$$

$$\sum_{t} res^{+}_{rp,k,t} - \sum_{s} res^{+}_{rp,k,s} \geq RES^{+} \cdot \sum_{i} D^P_{rp,k,i} \qquad \forall\, rp, k, i \qquad (3a)$$

$$\sum_{t} res^{-}_{rp,k,t} - \sum_{s} res^{-}_{rp,k,s} \geq RES^{-} \cdot \sum_{i} D^P_{rp,k,i} \qquad \forall\, rp, k, i \qquad (3b)$$

$$p_{rp,k,t} = u_{rp,k,t} \cdot P^{-}_{t} + \hat{p}_{rp,k,t} \qquad \forall\, rp, k, t \qquad (4a)$$

$$\hat{p}_{rp,k,t} + res^{+}_{rp,k,t} \leq (P^{+}_{t} - P^{-}_{t}) \cdot (u_{rp,k,t} - y_{rp,k,t}) \qquad \forall\, rp, k, t \qquad (4b)$$

$$\hat{p}_{rp,k,t} + res^{+}_{rp,k,t} \leq (P^{+}_{t} - P^{-}_{t}) \cdot (u_{rp,k,t} - z_{rp,k,t}) \qquad \forall\, rp, k, t \qquad (4c)$$

$$\hat{p}_{rp,k,t} \geq res^{-}_{rp,k,t} \qquad \forall\, rp, k, t \qquad (4d)$$

$$u_{rp,k,t} - u_{rp,k--1,t} = y_{rp,k,t} - z_{rp,k,t} \qquad \forall\, rp, k, t \qquad (4e)$$

$$u_{rp,k,t} \leq x_t + EU_t \qquad \forall\, rp, k, t \qquad (4f)$$

$$\hat{p}_{rp,k,t} - \hat{p}_{rp,k--1,t} + res^{+}_{rp,k,t} \leq u_{rp,k,t} \cdot RU_t \qquad \forall\, rp, k, t \qquad (4g)$$

$$\hat{p}_{rp,k,t} - \hat{p}_{rp,k--1,t} - res^{-}_{rp,k,t} \leq -u_{rp,k--1,t} \cdot RD_t \qquad \forall\, rp,k,t \qquad (4h)$$

$$0 \leq p_{rp,k,t} \leq P^{+}_{t} \cdot (x_t + EU_t) \qquad \forall\, rp,k,t \qquad (4i)$$

$$0 \leq \hat{p}_{rp,k,t}, res^{-}_{rp,k,t}, res^{+}_{rp,k,t} \leq (P^{+}_{g} - P^{-}_{g}) \cdot (x_t + EU_t) \qquad \forall\, rp,k,t \qquad (4j)$$

$$u_{rp,k,t}, y_{rp,k,t}, z_{rp,k,t} \in \{0,1\} \qquad \forall\, rp,k,t \qquad (4k)$$

$$\begin{aligned} inter_{p,s} = {} & inter_{p-MOW,s} + InRes_{s,p=MOW} \\ & + \sum_{p-MOW \leq pp \leq p, rp, k} (-sp_{rp,k,s} + IF_{rp,k,s} \cdot W^{k}_{k} \\ & - \frac{p_{rp,k,s} \cdot W^{k}_{k}}{\eta^{CH}_{s}} + cs_{rp,k,s} \cdot W^{k}_{k} \cdot \eta^{DIS}_{s}) \end{aligned} \qquad \forall\, p,s \qquad (5a)$$

$$R^{-}_{s} \cdot P^{+}_{s} \cdot ETP_s(x_s + EU_s) \leq inter_{p,s} \leq P^{+}_{s} \cdot ETP_s(x_s + EU_s) \qquad \forall\, p,s\!: mod(p, MOW) = 0$$

$$inter_{p,s} \geq InRes_{s,p} \qquad \forall\, s,p = CARD(p) \qquad (5c)$$

$$\begin{aligned} intra_{rp,k,s} = {} & intra_{rp,k--1,s} - sp_{rp,k,t} + IF_{rp,k,s} \cdot W^{k}_{k} \\ & - \frac{p_{rp,k,s} \cdot W^{k}_{k}}{\eta^{CH}_{s}} + cs_{rp,k,s} \cdot W^{k}_{k} \cdot \eta^{DIS}_{s} \end{aligned} \qquad \forall\, rp,k,s \qquad (5d)$$

$$\begin{aligned} -P^{+}_{s} \cdot (x_s + EU_s) \leq {} & \hat{p}_{rp,k,s} - cs_{rp,k,s} + res^{+}_{rp,k,s} \\ & \leq P^{+}_{s} \cdot (x_s + EU_s) \end{aligned} \qquad \forall\, rp,k,s \qquad (5e)$$

$$\begin{aligned} R^{-}_{s} \cdot P^{+}_{s} \cdot ETP_s \cdot (x_s + EU_s) + {} & (res^{+}_{rp,k,s} + res^{+}_{rp,k--1,s}) \\ & \cdot W^{k}_{k} \leq intra_{rp,k,s} \\ & \leq P^{+}_{s} \cdot ETP_s \cdot (x_s + EU_s) - (res^{-}_{rp,k,s} \\ & + res^{-}_{rp,k--1,s}) \cdot W^{k}_{k} \end{aligned} \qquad \forall\, rp,k,s \qquad (5f)$$

$$p_{rp,k,s} \leq b^{\frac{ch}{d}}_{rp,k,d} \cdot M^{\frac{ch}{d}}, cs_{rp,k,s} \leq (1 - b^{ch/d}_{rp,k,s}) \cdot M^{\frac{ch}{d}} \qquad \forall\, rp,k,s \qquad (5g)$$

$$b_{rp,k,d}^{\frac{ch}{d}} \in \{0,1\} \qquad \forall\, rp,k,s \tag{5h}$$

$$0 \leq p_{rp,k,s}, cs_{rp,k,s} res_{rp,k,s}^{-}, res_{rp,k,s}^{+} \leq P_s^{+} \cdot (bx_s + EU_s) \qquad \forall\, rp,k,s \tag{5i}$$

$$R_s^{-} \cdot P_s^{+} ETP_s \cdot (x_s + EU_s) \leq intra_{rp,k,s} \leq (1 - R_s^{-}) \cdot P_s^{+} \cdot ETP_s \cdot (x_s + EU_s) \qquad \forall\, rp,k,s \tag{5j}$$

$$0 \leq sp_{rp,k,s} \leq (1 - R_s^{-}) \cdot P_s^{+} \cdot ETP_s \cdot (x_s + EU_s) \qquad \forall\, rp,k,s = hydro \tag{5k}$$

$$p_{rp,k,s} = \sum_a cdsf_{rp,k,s,a}^{CH} \qquad \forall\, rp,k,s \tag{5l}$$

$$cs_{rp,k,s} = \sum_a cdsf_{rp,k,s,a}^{DIS} \qquad \forall\, rp,k,s \tag{5m}$$

$$intra_{rp,k,s} = \sum_a cdsf_{rp,k,s,a}^{SoC} \qquad \forall\, rp,k,s \tag{5n}$$

$$cdsf_{rp,k,s,a}^{SoC} - cdsf_{rp,k--1,s,a}^{SoC} = InRes_{s,k=1} + \frac{cdsf_{rp,k,s,a}^{CH} \cdot W_k^k}{\eta_s^{CH}} - cdsf_{rp,k,s,a}^{DIS} \cdot W_k^k \cdot \eta_s^{DIS} \qquad \forall\, rp,k,s,a \tag{5o}$$

$$cdsf_{rp,k,s,a}^{SoC} \leq P_s^{+} \cdot \frac{ETP_s}{A} \cdot (x_s + EU_s) \qquad \forall\, rp,k,s,a \tag{5p}$$

$$0 \leq p_{rp,k,r} \leq P_r^{+} \cdot PF_r \cdot (x_r + EU_r) \qquad \forall\, rp,k,r \tag{6a}$$

$$\sum_{rp,k,t} W_{rp}^{rp} \cdot W_k^k \cdot p_{rp,k,r} \geq \mu \cdot \sum_{rp,k,i} W_{rp}^{rp} \cdot W_k^k \cdot D_{rp,k,i}^{P} \tag{6b}$$

$$\sum_{gi(t,i)} p_{rp,k,t} + \sum_{gi(r,i)} p_{rp,k,t} + \sum_{gi(s,i)} (p_{rp,k,s} - cs_{rp,k,s}) + \sum_{ijc(j,i,c)} f^{P}_{rp,k,j,i,c} - \sum_{ijc(j,i,c)} f^{P}_{rp,k,i,j,c} + \sum_{sec} dsm^{Dw}_{rp,k,i,sec} + \sum_{seg} dsm^{shed}_{rp,k,i,seg} + pns_{rp,k,i} = D^{P}_{rp,k,i} + \sum_{sec} dsm^{up}_{rp,k,i,sec} \quad \forall\, rp,k,i \tag{7a}$$

$$\sum_{g} FC_g \cdot P^{+}_{g} \cdot (x_g + EU_g) \geq FC^{-} \cdot D^{P^{+}}_{rp,k,i} \tag{7b}$$

$$f^{P}_{rp,k,le(i,j,c)} = \Delta \cdot \frac{S_{base}}{Xline_{i,j,c}} \quad \forall\, rp,k,le(i,j, \tag{8a}$$

$$\Delta \cdot \frac{S_{base}}{Xline_{i,j,c} \cdot M \cdot T^{+}_{i,j,c}} - 1 + x_{ijc} \leq f^{P}_{rp,k,i,j,c} \cdot \frac{T^{+}_{i,j,c}}{M} \leq \Delta \cdot \frac{S_{base}}{Xline_{i,j,c} \cdot M \cdot T^{+}_{i,j,c}} - 1 - x_{ijc} \quad \forall\, rp,k,lc(i,j, \tag{8b}$$

$$-T^{+}_{i,j,c} \cdot x_{ijc} \leq f^{P}_{rp,k,i,j,c} \leq T^{+}_{i,j,c} \cdot x_{ijc} \quad \forall\, rp,k,lc(i,j, \tag{8c}$$

CHAPTER 3. GENERAL FACTS AND ANALYSIS OF SCENARIOS

In this chapter, we will assess all the considered scenarios and how their study is detailed hereon. The criterion followed to distinguish between one scenario and the remaining ones is what types and how many sources of flexibility the model comprises. As it has been previously explained in Section Parte I1.1, flexibility and firmness can come through generation and demand flexibility.

On one hand, generation flexibility is also referred to as the traditional/conventional approach because it commonly aggregates investment in flexible generation (generation expansion planning, often in CCGTs, able to cope with large ramps, and already developed in many countries), but also investment in new transmission lines. These resources are Generation Expansion Planning (GEP) and Transmission Expansion Planning (TEP) models, but now it is mandatory to include the study of distributed storage. At a utility level, storage comes in form of battery energy storage systems (BESS), able to consume and provide stored energy. On the opposite side, demand flexibility is modelled as Demand Side Management (DSM), either shifting consumption or shedding certain amount of demand.

Therefore, in this chapter the considered scenarios are the resulting ones from all the possible combinations between GEP, TEP, BESS and DSM. As base case it has been considered the only one including the most conventional resource, in other words, only GEP. The following scenarios develop from this point onwards, considering all generation expansion planning, as it is the most realistic approach. On the opposite side, the scenario that sums generation, transmission, storage deployment and demand participation results to be the most economical alternative for the yearly demand consumption. The cost difference between them is of 14%, as seen in Figure 7.

As a cost-minimization approach is being followed in the model formulation, one of the numerous results obtained and urged to be closely studied is the value and composition of the total system cost. In Figure 7, there have been depicted all the incurred costs for the same yearly demand levels and renewable generation profiles.

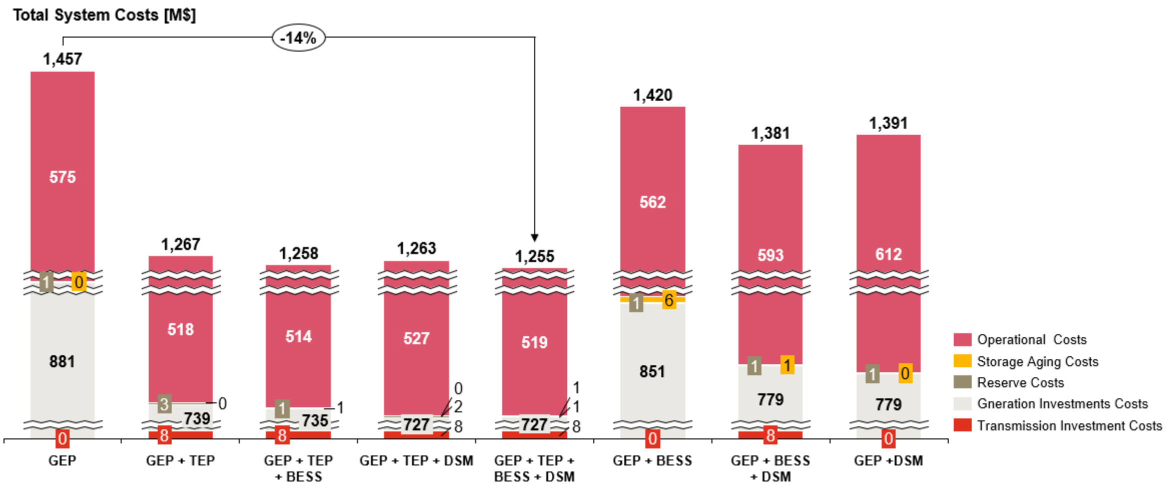

Figure 7. Total System Cost Composition for all the scenarios

As a general fact, operational and generation investment costs amount to 80-95% of total system costs for all cases, whether transmission investment costs, storage aging and reserve provision cost amount for a very limited percentage.

As it was expected, those cases where transmission investments are allowed (2, 3, 4 and 5 scenarios, if counting from the left-hand side of Figure 7) significantly reduce the need for new generation overcapacity and drastically reduce costs. This is due to the specific combination of grid, nodal demand distribution and renewable generation profiles. In other words, considering that nodes 5 and 4 are poorly interconnected, but also that that node 5 may be able to provide much more wind production to 4, whose demand consumption is the highest of the grid, results in several infeasibilities. Network congestion of the capacity between these two nodes leads to nodal prices in the system and increasing their transmission capacity would decrease short-run marginal costs at nodes. To illustrate this effect, several boxplots are depicted in Figure 8. They show three effects: price variability at each node through the range and quartiles; the average and variability of SRMC in node 5 with respect to others, and the evolution of nodal prices in each scenario.

This last effect proves that the base case has both the highest price variability and median statistics. We consider the median instead of the average because it is not subject to extreme values and represents a different complement to the range variation visual study of Figure 8. In the first place, the base case establishes that all nodes (except from 5 with lower MC due to cheap wind generation) have the same variability and quartiles, indicating that no congestions take place, but also that price differential has a greater potential for price arbitrage, for instance. This price arbitrage could be exploited by transmission assets' investors, since they could take advantage of congestion rents between node 5 and 4 (buying generation at 5 and selling at 4, obtaining the net difference), but also by BESS in an hourly trading working scheme; and finally by DSM, that, if able to respond to price signals and in possession of storage facilities, could also have the same position as distributed BESS.

Moreover, moving from the base case (left-hand boxplot in Figure 8) to 'TEP' solutions (taking as an example the right-hand side of Figure 8, where 'TEP'-only case is depicted), the price variability is capped, as are the possibilities of trading and benefiting from price differentials. Also, the median is reduced in up to 2 $/MWh in nodes excluding the fifth.

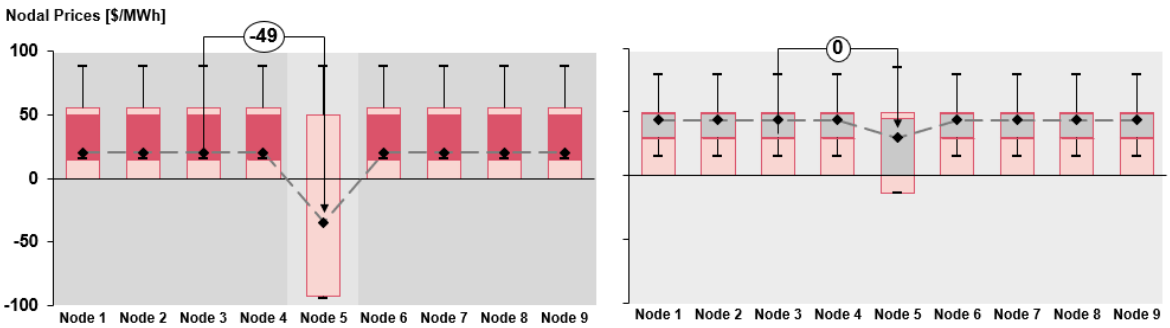

Figure 8. MC at all nodes and at the base case (left) and TEP-only scenario (right)

Furthermore, opting for 'BESS' solutions, does make sense if added over TEP, because all alone does increase price variations in the central statistical range, although combined with others decreases these variations and stabilizes marginal costs at a level of 45 $/MWh.

To end up with this, the fact that in no single case Node 5 equals its peers implies an inadequate interconnection capacity, even with the transmission investment in the new candidate line.

This is the reason behind a common fact: the model always chooses to invest in the candidate line between nodes 4 and 5, which makes us think that TEP provides the most value to the system in terms of cost reduction. It clearly seems that line 4-5 is very necessary for the model to allow electric flows due to wind generation at node 5 and high demand share for node 4.

In order to see the explicit system price variability between scenarios, Figure 9 illustrates a box & whiskers plot for all single and combined cases, forcing a 50% of green production. This share of clean energy provokes negative marginal prices, especially at node 5, where a vast wind production is considered. As reasonable, TEP solutions reduce marginal price ranges and volatility, but incur in higher average prices. On the other hand, BESS cases have the higher variability in between nodes and hours, and, at the same time, they reduce average prices.

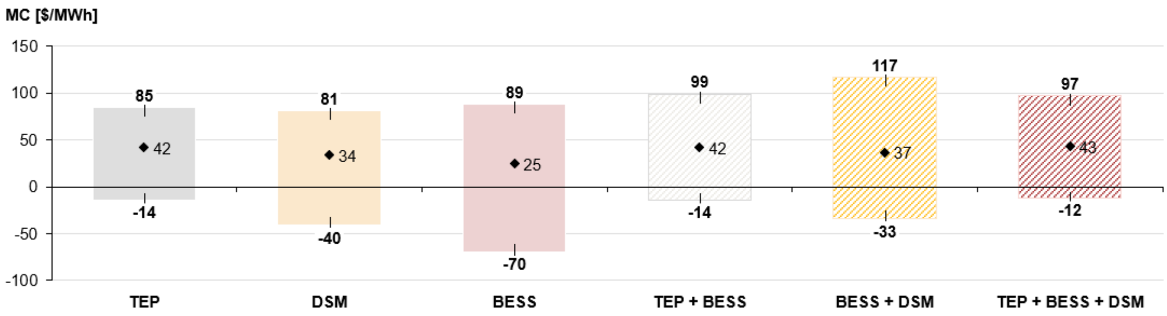

Figure 9. System MC variation between scenarios

From a practical point of view, the most general and complete scenario (TEP+BESS+DSM) can be compared to other electric power systems around the globe (Figure 10). In this sense, our case study is like Australia, a system characterized by long distances, without much transport lines that act as interconnection between nodes and with high penetration of solar across the continent. This makes both our case study and Australia to have the higher price variation of all systems. But what could be interpreted as an incipient power system, causes batteries to be way more profitable, mainly because they accumulate spot profits from the MC differentials.

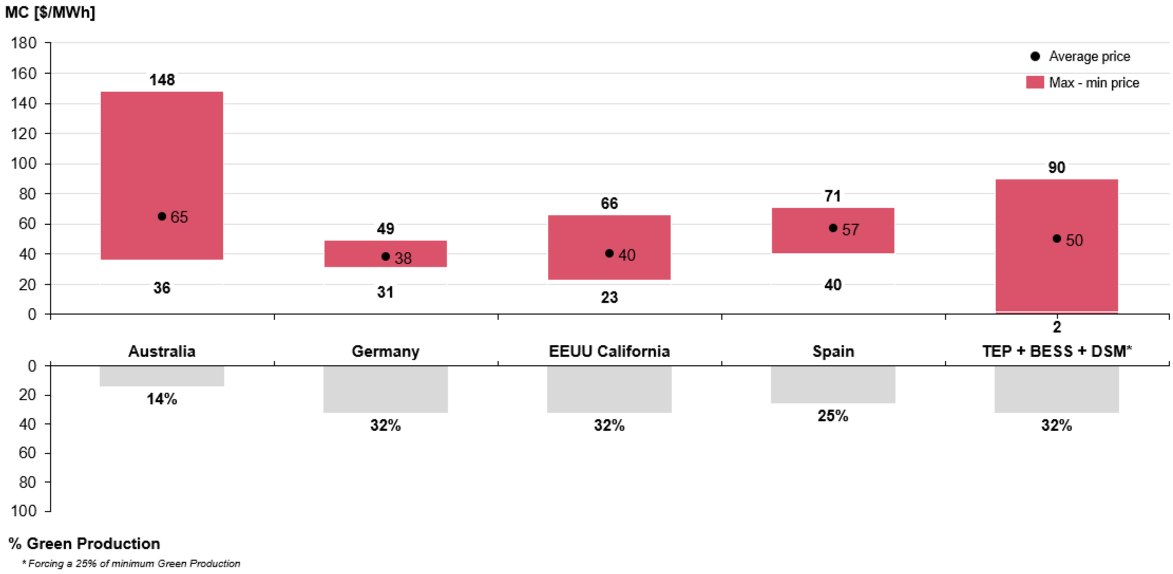

Figure 10. MC differential & % of clean energy production in diverse electric power systems. Source: Lazard's

If an increasing approach is followed when assessing how, independently or jointly, all resources provide value to the system, Figure 11 is able to quantify the value in terms of percentual cost reductions of the combinations (in white) and of each single 'added' resource (colors in legend).

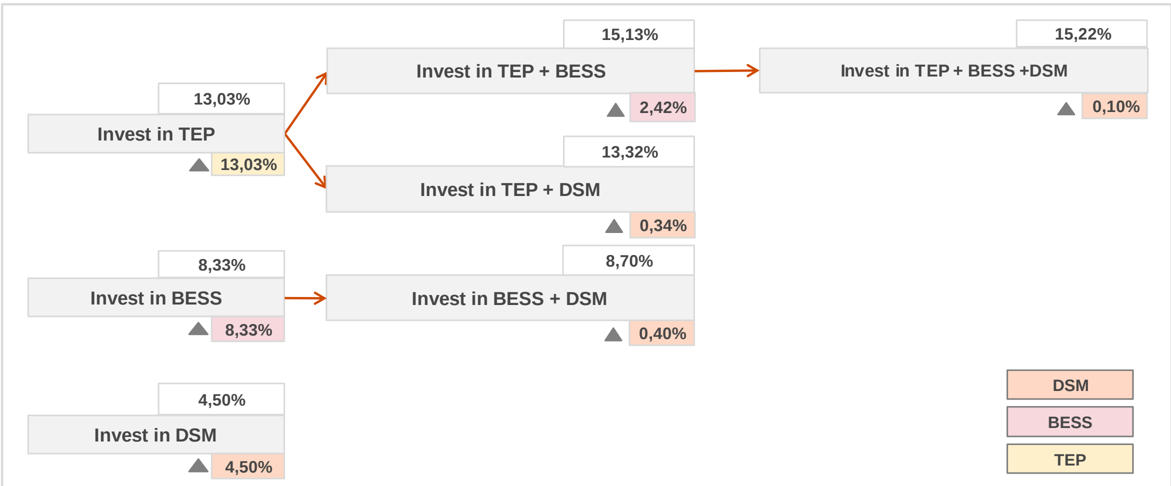

Figure 11. Added value to the system of all possible combinations

After TEP, BESS is the one providing higher cost reductions (8.33% alone or 2,42% if complementing TEP). Then, demand response adds in top of all scenarios providing cost reductions of 4.5% independent and around 0.10-0.40% if combined with others. Obviously, the 'first step' in this incremental decision tree can reduce costs significantly due to the system's need for variety in flexibility terms.

The preferable case can freely choose all types of variability, with a net reduction of nearly 15% in system costs. Then, their cost composition is unfolded in Figure 12, with three slices of investment, operation and system flexibility guarantee.

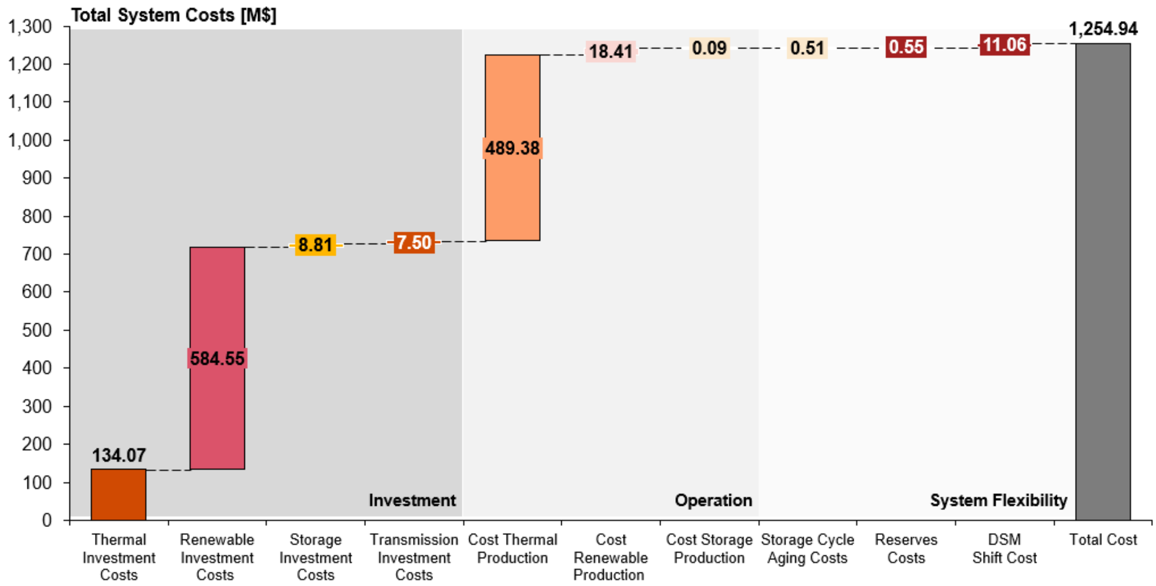

Figure 12. Total System Cost considering all technologies– 2020

In 2020, the system cost is decomposed mainly in renewable investment costs and thermal operation, with other minor parties as thermal investments and DSM costs of paying responsive consumers. It is expected, since thermal generation new investments are not that incentivized for environmental reasons (equation on clean energy production), but their operational costs amount for fuel and start-ups incurred in. Regarding renewables, it is also reasonable having most costs concentrated in investments rather than their cheap operation. Investments in storage and transmission lines have a similar order of magnitudes, considering that TEP capacity is insufficient. To end up, DSM costs are even higher than BESS and TEP investments, so their economic viability may even be questioned in the future.

Another distinction has been studied for all the GEP scenarios, in other words, all of them; and is the one accounting for the lack of incentives for developing new thermal generation plants, towards only renewable generation. These new scenarios mean that GEP generation expansion can only be effective if using renewable power (solar and wind units). Therefore, and in order to make a clear separation of the 8 previous scenarios and the set of 8 new scenarios, these last ones will be considered as the ones in a long-term system in 2050, whether the first ones are a 2020 current set of scenarios. In Figure 13 it has been included the same decomposition as in Figure 12, but with a 2050 vision.

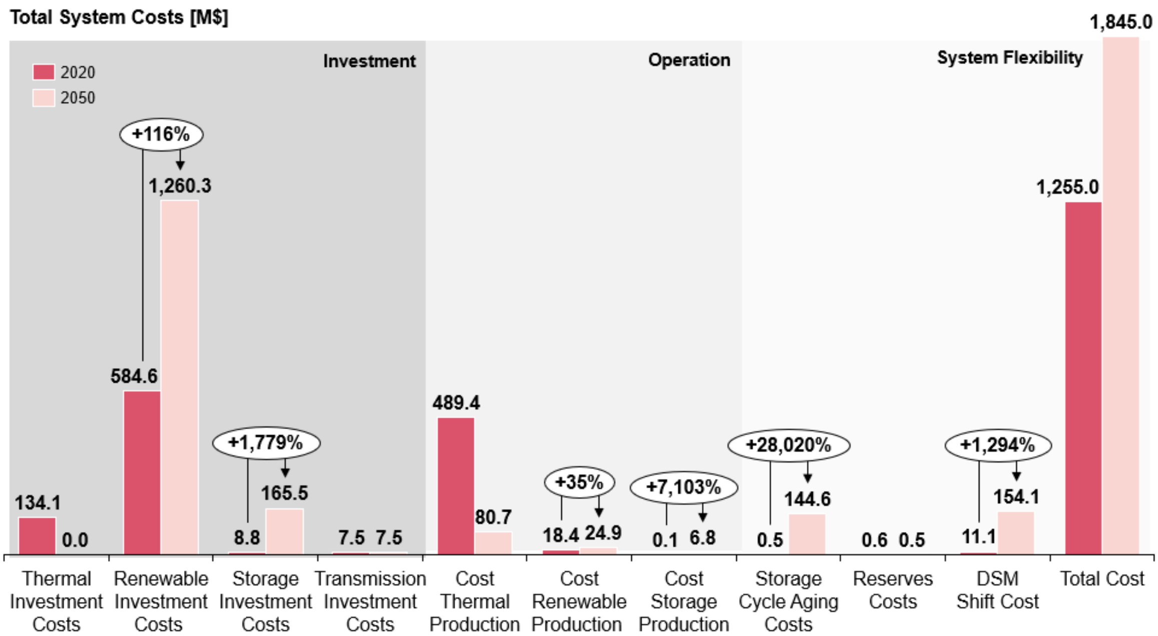

Figure 13. Total System Cost considering all technologies– 2020 & 2050

In 2050, the system is more expensive since overinvestments in renewable capacity are taking place (renewable investments increase a 116% and operation in a 35%) to substitute dispatchable thermal units. In this sense, thermal investment in reduced to null investments cost, although this thermal operation is reduced to the operation of the, already existing, nuclear unit. On the other hand, the most interesting aspect is the impact on short-term responses: storage operation and aging costs along with DSM. The magnitude of storage aging costs is due to their exponential behaviour, but the operation of demand response and BESS incurs in a much higher amount of costs when buying energy mainly at the spot market and then, the demand response price signals payment to those responsive consumers.

3.1. IMPACT OF FLEXIBLE RESOURCES & TRADITIONAL APPROACH IN STORAGE DEPLOYMENT

What is clear is that distributed storage is increasingly becoming needed in current and future power systems, with the growth of renewable generation. But quantifying how much storage is needed is a key piece in the design of an optimal generation mix and share between technologies, to guarantee continuity and quality of supply in restrictive conditions. Several countries at the European level have already begun their corresponding development plans for the next decade, keeping an eye on 2050 targets on (1) emission reduction, (2) renewable generation production and (3) cross-sectorial energy efficiency. The aim of this point is evaluating the need for storage capacity under the scenarios previously defined, in a concrete network and generation mix- defined in the methodology and Annex.

The different model results are graphically represented in Figure 14, that shows the battery energy storage deployment capacity needed in 2020 and 2050 for all the studied scenarios where batteries (BESS) are included. It also additionally displays the storage increment in absolute terms between 2020 and 2050. Finally, it also includes a final distinction on how accounting for storage cycle aging costs affects, not only the total system cost, but also the express need of storage.

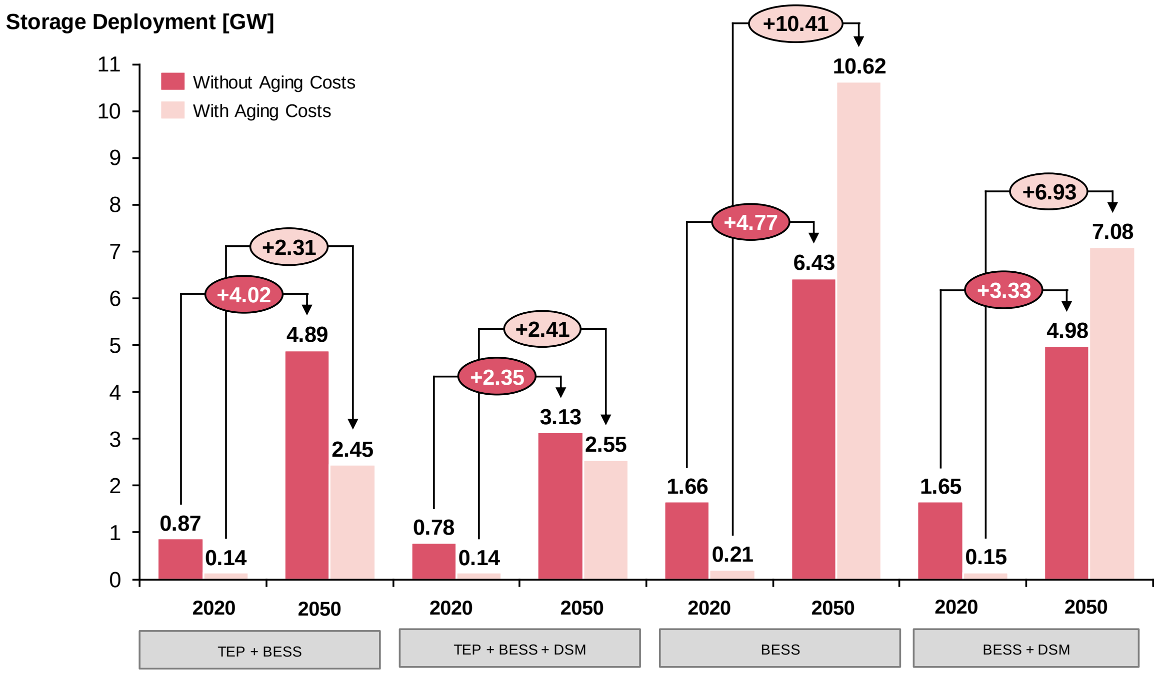

Figure 14. Storage deployment for all scenarios considering BESS – Complementarities and Potential Conflicts/ Better alternatives for Storage

In general terms, and considering as base case the deployment of storage not complimented by other sources of flexibility (either demand with DSM or generation with traditional generation or transmission expansion planning models), the deployed capacity in this sole case (referred to as ‘BESS’ in Figure 14) is the highest of all the scenarios considered. From this case, with a capacity of 0.21÷1.66 GW in 2020 (and 6.43÷10.62 GW), ‘onwards’, a fewer amount of batteries are installed, since other scenarios bring flexibility to the system by means of a better connected network or via demand flexibility, response and shifting procedures. Followed by the case of ‘BESS + DSM,’ the battery energy storage deployment is brought to 0.15÷1.65 GW in 2020 (and 4.98÷7.08 GW), and this is only due to the existence of demand response mechanisms that allow the demand curves to shift its consumption up to 5÷6 hours for emobility applications and residential washing loads, respectively. In a cost-minimization modelling, where DSM only incurs in a volumetric charge of 30÷55 €/MWh with no investment costs, in opposition to BESS that does incur in both operational and investment costs, obliges the system to choose demand response over storage deployment, which finally translates into a lower deployed storage capacity. Numerically, Battery energy storage systems in the electric grid incur in a TOTEX: both (1) an investment yearly cost [€/MW year] or [€/MWh year], depending on if BESS is referred to as capacity or energy (e.g.: a battery can be 50 MW/200MWh and their relation indicates the maximum time where it is able to supply its nominal capacity, which, in other words is the same as taking in energy terms via MWh); and (2) operation & maintenance cost [€/MWh], which, in opposition to DSM, has values around 4÷10 €/MWh and, therefore, is much lower in an OPEX 'window'. Nevertheless, as the model does consider a medium-term operation and grid expansion planning, the short-term economic signal considers the effect of CAPEX (capital expenditure), which in the end is a long-term economic signal. Here, it can be stated that BESS and DSM can feel as being competing to provide the same service in different ways: storage charges and discharges their levels to supply instantaneous energy at peak demand and charge their energy levels at valley hours; whether demand response either sheds demand at peak loads or shifts the instantaneous consumption by flattening the daily consumption curves, allocating peak demand at less critical consumption hours.

The following scenario of storage capacity ordered in a decreasing order is the case of enhancing batteries potential with traditional transmission expansion via new lines' deployment. This case is also known as 'TEP + BESS' in Figure 14, has a storage capacity of 0.14÷0.87 GW in 2020 (2.45÷4.89 GW in 2050) and matches with the model meaning and modelling, since new transmission interconnections reduce the need for local battery deployment, that is, distributed storage in the considered grid. The flexibility here comes with transmission expansion possibilities, which numerically positions as the most advantageous complement to storage (is cost-reduced if computing transmission vs generation unitary costs and makes storage not as vital as when taken by its own). Lastly, the most balanced case in which all possibilities are participating in the system is TEP+BESS+DSM, and allows BESS deployment to be the lowest, with capacities of 0.14÷0.78 GW (2.55÷3.13 GW in 2050). Therefore, a good balance between resources is key to ensure economic viability and economic containment along with avoiding infra/overcapacities in the system that would make the model's solution feasible, although not realistic, due to the partially useless deployed capacity. This last idea is represented when carefully studying the 'BESS' only case, in which the system invests in a higher capacity that afterwards is not going to be fully exploited. This is due to the need of a large amount of instantaneous energy at peak demand moments, which contrasts with medium-to-low demand periods (that occupy 50-60% of daily time) with BESS underuse and operation. These last periods with low consumption do not necessarily imply an instantaneous energy discharge and therefore, the installed capacity is less used in relative terms to its nominal deployed capacity. Moreover, if the distinction of considering -or not- storage cycle aging costs is made, this overcapacity/underuse effect is more noticeable.

Now, it will be interesting to study the effect of aging costs for storage in the global storage installed capacity, because it exists more than a noticeable distinction in their capacities throughout the system. In general terms, all scenarios share an 80-90% installed capacity reduction in 2020, if cycle aging costs are considered. Aging costs represent an economic internalization [in M€] of 2 combined effects:

1. The existence of an annual life loss from cycling the batteries. If used in excess, the storage degradation will become clearer and it will potentially exist a second-life battery period since an exponential degradation is considered. This also has a double effect/meaning and is that the system will tend to install a higher storage capacity to use it at a higher level for the firsts charges & discharges (and not in the consecutive cycles, where the exponential life loss is expected to occur), rather than deploying a lower nominal capacity and bringing itself to full use by means of continuous charges & discharges.
2. And a higher (lower) batteries' life expectancies if not they are not excessively used and cycled (if they are underused or cycled over daily periods)

The differences of storage reduction through scenarios are less perceptible if BESS is considered along new transmission lines than is considered alone due to both (1) and (2) mentioned effects. Since 'BESS' and 'BESS+DSM' cases install a higher capacity, considering cycle aging costs enhances the effect of storage underuse, compared to larger installations.

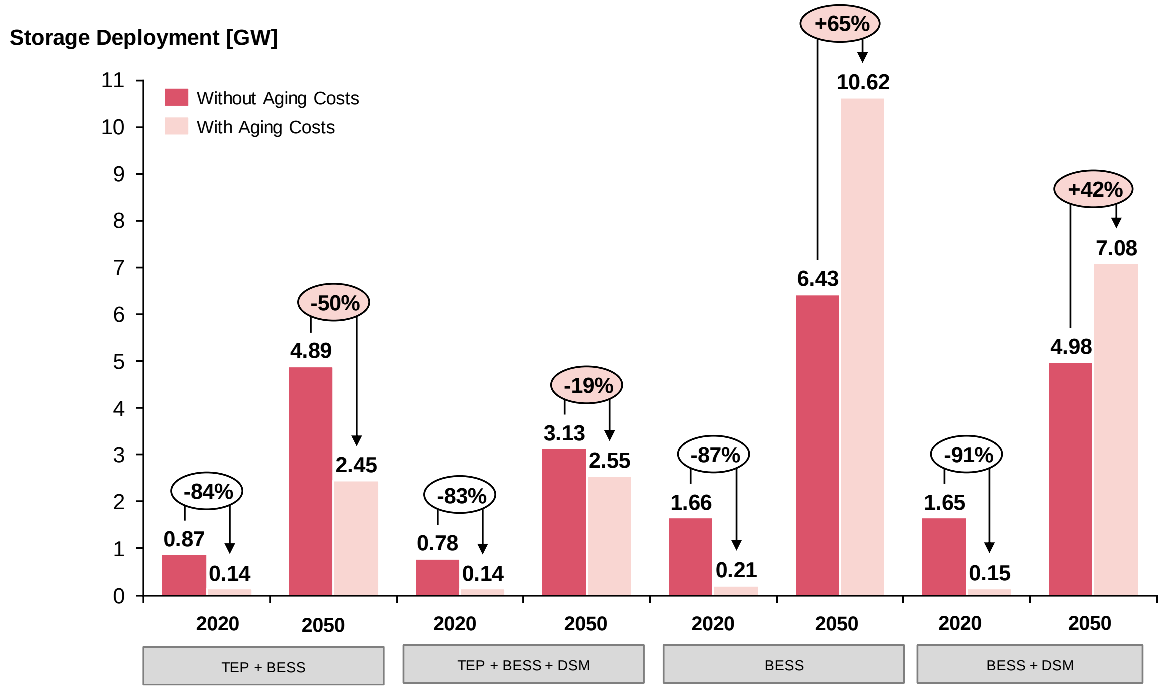

Figure 15. Storage deployment for all scenarios considering BESS – Aging Costs Effect

Finally, a new study discrimination has been considered, and this is the effect of deploying a 2020 scenario (real and current generation mix deployment possibilities) versus a long-term 2050 perspective where only renewable generation is operated and installed. Figure 14 oversees numerically assessing the net storage increase between 2020 and 2050 for cases considering -or not- degradation over the years' storage use. As a general conclusion, it can be stated that, the higher renewable penetration becomes, as they also do all the new generation deployment plans around Europe, the higher the need for storage capacity is obtained. Most specifically, Figure 14, states the absolute increment of storage capacity in GW with the conclusion that these increments become increasingly noticeable on 'BESS' only case and 'BESS +DSM' scenario, due to its similarities on functioning and short-term dynamic response, which contrasts with the traditional approach TEP provides.

3.2. IMPACT OF FLEXIBLE RESOURCES & TRADITIONAL APPROACH ON STORAGE OPERATION

Once it has been decided how much storage is needed and will be deployed depending on energy needs, future renewable generation targets and many other variables, it is also required to study how that capacity operates in the short and medium term.

For this reason, it has been taken as a representative node 'Node 6' of the system, which has high demand needs and incorporates solar generation and distributed storage to the system. In this node, it has been depicted (Figure 16) the evolution of BESS charge and discharge levels in a daily window for a whole representative week (7 representative periods) in a current situation (2020). Aging costs are considered, for being the most realistic approach to reality and in order to obtain a real result. Not accounting for aging costs would disturb BESS operation since it will randomly charge and discharge energy nearly without interruptions and restrictions on how that impacts the system's costs. This Figure is, at the same time, generated for the scenarios where BESS is alone and combined either with other flexible short-term responses, or with new traditional transmission interconnections.

Although obvious, all three scenarios have similar profiles in their charge and discharge evolutions, because high solar PV generation is obtained in central hours of the day, with the corresponding battery charge. On the other hand, neutral or peak demand periods serve the batteries for remaining stable over time or discharging their energy when needed (i.e. in the evening), respectively.

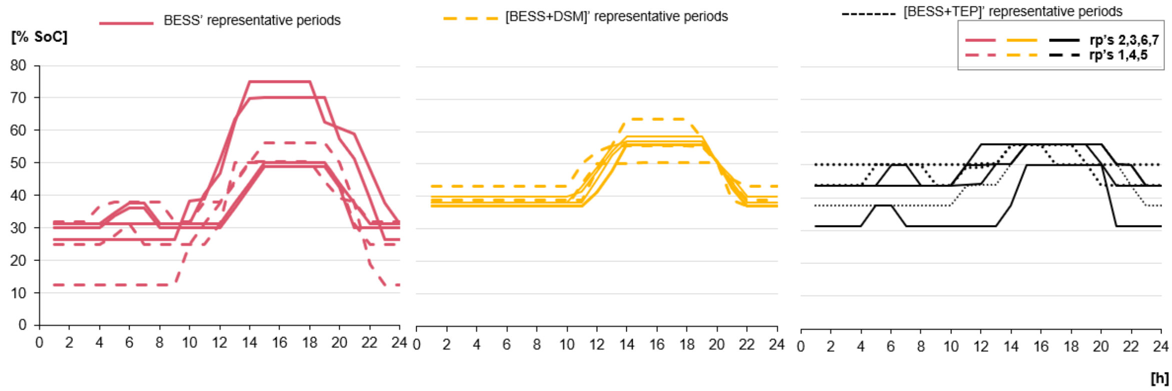

Figure 16. Battery's charge evolution Differential– Aging Costs

Figure 16 confirms that traditional new lines' deployment along with batteries incur in the lowest BESS operation (and deployment, as previously said). This makes all sense since it exists a different alternative to BESS utilization nearly without incurring in variable/operation costs. If we consider that, if the investment cost on building a new line is undertook (so to say, it can be seen as a sunk cost), the most meaningful solution will be to exploit the capacity of the new line, rather than using distributed batteries for meeting load increases. This alternative comprehends the remote production of cheaper generation in another node of the system (different from the depicted Node 6) and the transport through the new installed line of the power generated.

At the opposite end, 'BESS' scenario has deeper discharges and higher-level charges, due to the combined existence of solar production and storage to manage demand deviations. This effect would be even more distinguishable for the 2050 scenario, characterised by large renewable production shares.

And finally, in a 'compromise' solution, the combination of storage with other flexible demand resources does incur in lower charge cycles, since demand side shifting represents kind of a cheap storage. Moreover, since DSM shifting depends on the considered sectors, defined by their shifting profiles and maximum delay times, only those able to respond in a quick way, that is, less than 4 hours to be competitive with batteries, would have potential conflicts with the considered storage. Therefore, the only 2 sectors able to respond in less than 4 hours will be cooling ventilation loads (able to shift their consumption in 1 hour) and cooling freezer loads at a residential level (with a period of 2 hours). If more 'quick' sectors are included as input data for demand shifting, the system would benefit more from their existence and complement, rather than marginally excluding storage potential.

3.3. BESS INTEGRATION: COMPLEMENTARITIES AND DISPUTES

With what has been discussed up to this point, it seems that the combined effect of this specific grid and modelling approach tends to have:

- Complementarities if treating both distributed storage and generation/transmission expansion planning. Therefore, a traditional approach combined with storage deployment, can result in perfect complementarities between these sources of flexibility.
- Potential conflicts between demand response mechanisms and distributed battery energy storage operation. Therefore, non-conventional or short-term types of response, flexibility and operation, fight against who of them benefits the system the most, in a minimization approach.

For these reasons, sections 3.3.1 and 3.3.2 are included in this study.

3.3.1. COMPLEMENTARITIES

Battery energy storage systems can be easily integrated in the grid so to reduce system cost, increase the economic viability of other renewable sources of generation and boost the operation of the system. Referring to the latter, distributed batteries could easily help the system both in the short and long term. In the first one, they could alleviate the electric grid through the reduction of network congestions (e.g., avoiding curtailment), and in the long-term, through the deferral of future lines' investments or even with the avoidance of new lines' implementation.

From a dynamic point of view and in short time periods, network congestions represent system infeasibilities and often lead to increase in network costs due to redispatches coming from the system operator, or the use of local thermal units' generation that imply costly start-ups. But, as expected, storage would be required to supply and/or store energy of the amount of the local congestion and of a magnitude order of hours.

In a practical way, if new deployment plans are being designed for the next decades, it would be a noteworthy opportunity to plan investments on new lines' installations along with distributed storage at certain nodes of the grid. By doing this, potential overinvestments would not take place and, as complement, smaller storage facilities would gain weight. Even in the medium-term of 1-2 years, as new lines cannot be built, storage would serve as a great temporary alternative to an inefficient network operation or even the appearance of periods with non-served energy. It is for these reasons that storage is seen more as a complement to transmission expansion and generation expansion planning rather than a substitute to them.

In this specific study, this conflict between storage potentially substituting new transmission lines does not take place due to a high imbalance between the generation and consumption between nodes 4 and 5. One of those nodes has a great amount of wind production, whether the other one has a great amount of demand. The result of this is the appearance of network congestions in the existing line between those nodes, but also the construction of the available candidate line of 400 MW of nominal capacity, that results in being always chosen due to this generation-demand differential. Independently, even in the most balanced case, in which there are two lines (existing and candidate, that has been built), nodal prices take place. Therefore, the overall interconnection transmission capacity between both nodes cannot cope with the amount of generation of node 5 and it is not possible to equal their nodal prices. In order to do so, either more lines will be needed or higher capacity ones to be deployed and chosen to be built. Obviously, this could be adjusted a bit more in the model to find the optimal balance between number of lines and transmission capacity and could be an interesting sensibility analysis to carry out.

3.3.2. POTENTIAL DISPUTES

As seen in sections 3.1 and 3.2 both storage investments in new capacity and operation are kind of capped by the existence of demand side management. This is obviously not completely erasing the need for storage in the combined cases of BESS + DSM since the latter has a great operational cost, compared to storage, but does significantly decrease the use made of batteries. In Section 3.2 we analysed that battery cycling was deeper in the case where BESS was all alone because DSM acts the same as BESS but without incurring in cycle aging costs, which clearly limits batteries operation potential. Furthermore, in Section 3.1 a reduction of storage capacity of 1.4-3.5 GW takes place. Therefore, we can say that DSM clearly reduces BESS possibilities and we could talk of certain disputes or the existence of competition between them. Even with this, it is relevant to notice that the optimal scenario considers both resources each of them with their proportional presence.

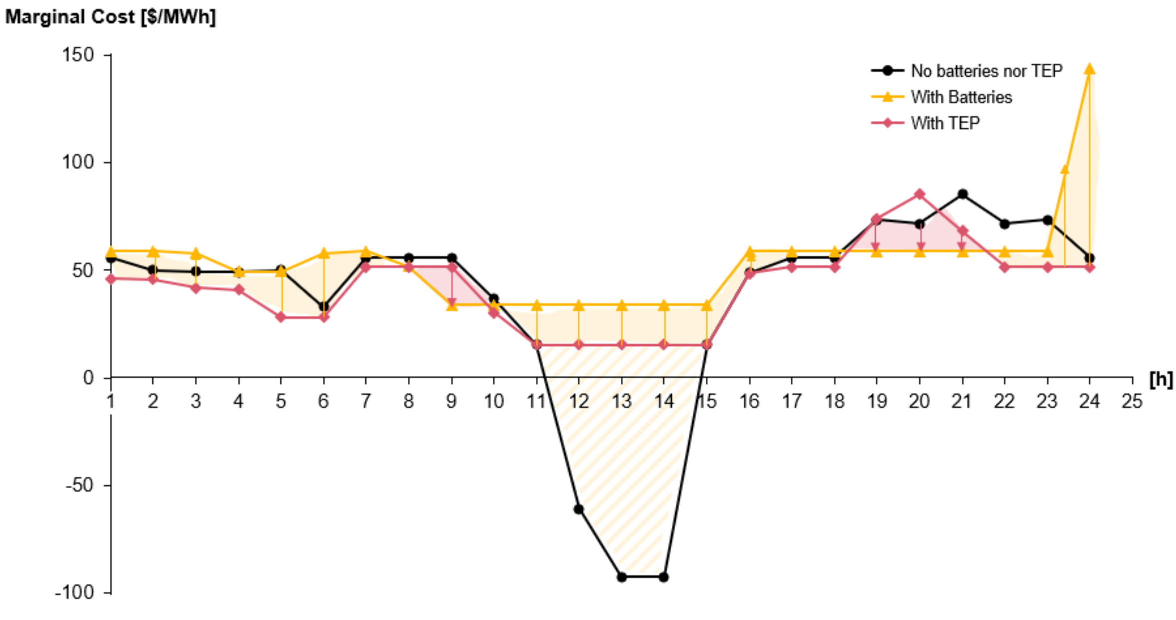

Figure 17. Marginal Cost (Nodal Price) Differential for Node 6 & rp 4 – TEP vs BESS – No aging costs

On the contrary, transmission interconnections may reduce price arbitrage possibilities for batteries, especially when considering aging costs (Figure 18). In Figure 17 we can see the marginal nodal cost when in the base case, along with BESS and TEP+BESS cases. Here, adding transmission interconnections reduces daily price spikes, reducing the hatched area and then, the incentives for trading that storage initially have. Independently, not considering degradation costs for storage makes BESS assets to capture a great amount of price volatility, that is minimized when adopting the realistic approach of aging costs.

In fact, Figure 18 displays that the cost for cycling storage may position transmission capacity as a better alternative to flatten the daily price curve (orange area of price difference between base case and the one considering new lines).

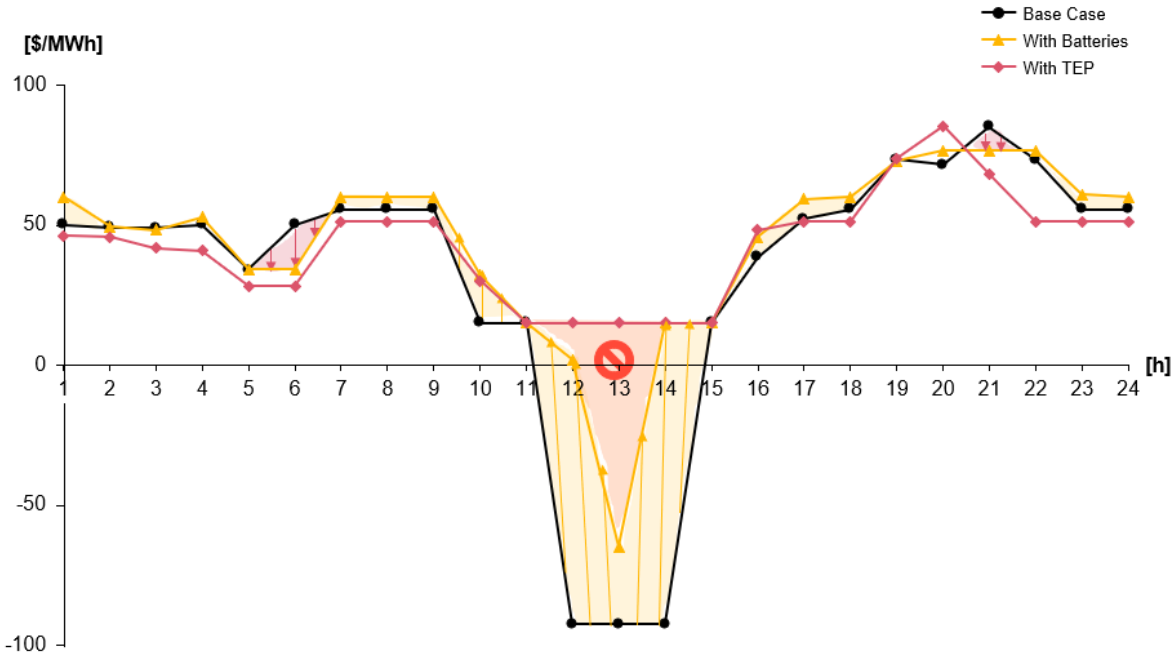

Figure 18. Marginal Cost (Nodal Price) Differential for Node 6 & Representative Period 4 – With Aging Costs

In Figure 19, a single representative week (168 hours) depicts the use of DSM and BESS flexibilities, via DSM shifting profiles and batteries' SoC, respectively. This is implemented under two different scenarios: the first one where neither DSM nor BESS are supported by the deployment of new transmission capacity, and the second one in the right, where the three play all together in the considered electric system. Some conclusions can be drawn by the portrayal of these cases:

- It is reasonable to firstly assume that running the model only with the flexibility that demand response mechanism provides, would result in a higher use of this resource. After doing so, the initial assumption is confirmed, since the shifted demand volume is the highest of all scenarios that have been run. These maximum/minimum limits are represented through dotted lines in Figure 19, and can be considered as DSM caps for demand shifting.

- It can also be seen that the difference between the right/left cases lays on the deployment of transmission capacity (introducing TEP flexibility in the boxplot positioned in the right). This TEP deployment hampers the use of both DSM and a higher BESS' use, seen via the evolution of their States of Charge.
- Although both short-term dynamics (demand response and BESS use) are responsive to transmission capacity, it is DSM the most sensitive resource, because its use is highly reduced, if compared to than batteries' state of charge through the whole week.

For all these reasons, this can be understood again as a dispute between TEP and BESS or DSM.

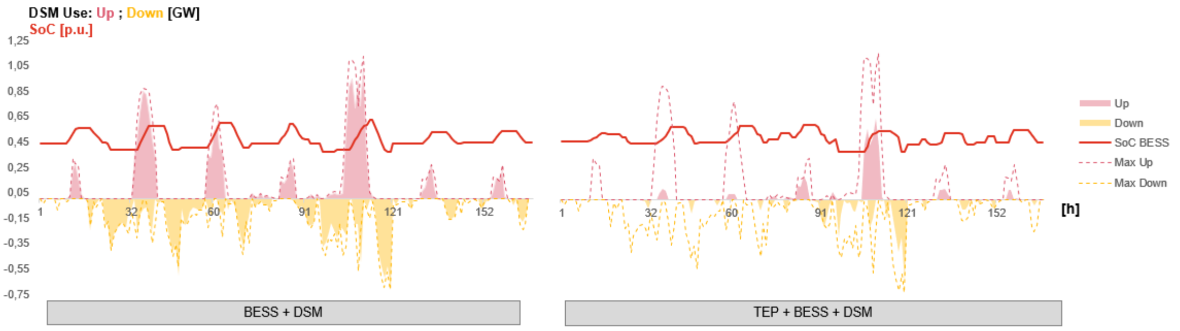

Figure 19. DSM use and BESS' SoC competing with TEP

CHAPTER 4. STORAGE COST ANALYSIS

Nowadays and in what respects to their economic model, batteries obtain benefits from 3 main sources:

1. Participation in the daily spot market (also called day ahead market) buying generation at off-peak hours in which prices are low and selling that already-charged energy at peak demand levels. This could also be referred as price arbitrage and is specially correlated to the introduction of new photovoltaic capacity in the system, principal cause of large prices differentials in between hour in the day. This difference is due to a high solar production in hours with sun versus those hours in which this natural resource is not available. Batteries are indeed capable of taking advantage of this price margin, contributing, at the same time, to a dual factor:
    a. The flattering of the price curve.
    b. The increase in profitability of solar generation, in case of being complemented by storage deployment. Since the configuration in which storage is installed may result in diverse profitabilities, Section 4.3 is created.

Both a. and b. can be graphically seen in Figure 20, that follows.

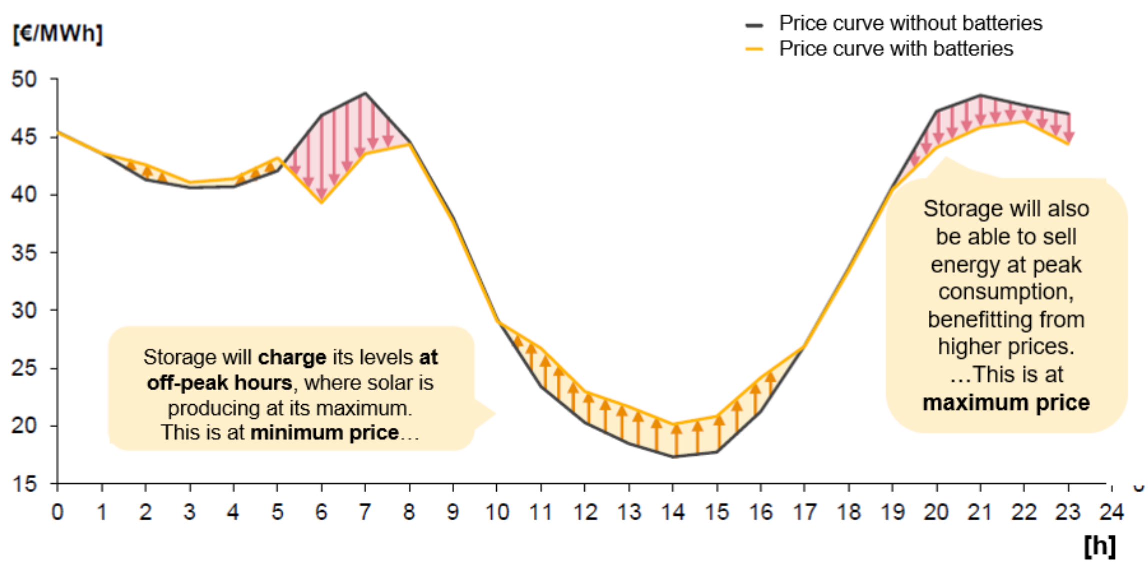

Figure 20. Artificially generated marginal cost (Nodal Price) differential with batteries integration

Therefore, since the configuration in which the battery is deployed seems to have an advantageous effect on other technologies' profitability, this configuration can have a great impact in these day-ahead revenues, both to batteries and renewable capacity. By configuration we refer as the (1) combination of renewable and storage in the same system node (also referred as PV or wind support, respecting the type of renewable hybridization) or (2) a stand-alone configuration, in which the BESS is left alone in a node, without providing support to RES or other thermal conventional generation. Further sections of this chapter will deepen in the study of BESS' configuration.

From the modelling approach point of view, batteries receive revenues and incur in cost for their participation in the spot market, being the only type of technologies able to buy energy in this market, of all the available ones in the generation mix. This fact is modelled through the dual variable of the load and generation balance constraint at each node and pair of representative period and period: (rp, k).

2. Participation in the reserves market, helping to meet the instantaneous equilibrium between generation and demand. The provision of reserves is only retributed in the Spanish case for secondary reserve, whether primary reserve supply is mandatory, though not paid. Talking of primary, secondary, and tertiary reserves is the same as referring to Frequency containment, frequency restoration or reserve restoration reserves, respectively. This nomenclature often varies depending on the country and system operators and may create some confusion in the transversal comparison.

   From the modelling perspective, the net revenues and costs related to the participation in the reserves markets, are correlated to the product of the dual variable of the secondary reserves equation [$/GW], both upwards and downwards; and the secondary reserve production allocation [GW]. The costs are weighted with the O&M variable costs of each kind of BESS.

3. Regulated payments coming from various sources, and needed to ensure firm capacity provision, acting as a backup for the System, etc. Of course, parties referring to capacity mechanisms are large, since the insurance of enough available capacity will be an issue in a future renewable-dominated intermittent electric System. By needed available capacity it is often understood a certain % of the peak demand,

similarly to when considering the loss of a generator and an ENS (Energy Not Served) evaluation is carried out. Then, this capacity is known as firm capacity and in the model, it is defined as the maximum value of the sums of demand over the all the nodes in the grid, in the yearly scope.

From the modelling perspective, the payments for firm capacity depend on how many units (already existing or new investments) are providing the service of being available to produce a Firm Capacity coefficient amount of power (i.e.: 2% of their maximum output), and how the product of this power and the corresponding dual variable of the Firm Capacity equation, result.

4. If considered with a renewable facility (hybrid configuration with a solar or wind installation), payments for their renewable nature are also considered, via renewable quotas, often expressed in volumetric terms [$/GWh]. From an environmental point of view, clean energy production is incentivized through certain targets and restrictions, which often oblige to invest in renewable generation rather than in thermal units. The LEGO model does consider renewable payments, via the product of the dual variable of the clean energy production constraint and the actual generated power, which result in net [$] payments.

But, of course, batteries often incur in several costs:

1. Market participation: either they incur in spot market or reserves market costs.
2. Investment costs (CAPEX), if the decision of deploying new storage capacity is taken.
3. And finally, operational O&M or OPEX costs, that sum both the product of their variable cost and real production, but also the cost of degradation, considering cycle aging costs. As it has been commented on previous sections, the degradation cost is of special importance in BESS installation and operation, due to its exponential behaviour, and therefore, have a large will of avoiding it. An important distinction of scenarios accounting for degradation costs and without them is done in Sections 4.1 and 4.2.

It is reasonable that, if the difference between revenues and costs is positive, and sufficiently large to meet economic viability and good returns, BESS would awake investment desires, and that is why a further profitability study is required.

4.1. WITHOUT CONSIDERING STORAGE AGING COSTS

Degradation costs are ignored in this section, in order to serve as a reference for the next section, that does include aging costs for storage. In both, the net amount of benefits batteries receives from the services they provide is quantified, along with the weight each of those services represents globally. Moreover, the secondary reserve they can provide is also studied in comparison to the one able to be supplied by hydro resources and other thermal conventional units. All these studies are carried out in the scenarios where BESS is present.

4.1.1. PROFITS PER SERVICE PROVIDED

As it has been previously discussed, batteries are able to provide energy in the day ahead market, as they do with the reserves market, but also receiving payments for firm capacity. The aim of this section is to assess how their revenues are distributed among these services and determine if this cost analysis has some relationship with BESS' profitability.

In Figure 21, we see that in 2020 net benefits do not have large variations with the presence of TEP or DSM complementing storage. In fact, the case that implies the highest revenue is the one including all of them, and only has a 1.83 M$ of difference with respect to the case that only deploys batteries. On the opposite side, in 2050, this difference becomes larger, causing the DSM+BESS case to capture 135 M$ less than the case where storage serves as a complement to TEP. Moreover, and a quite interesting result is that the short-term dynamics of BESS and DSM in the 2050 scenario are significantly less beneficial -they capture up to 49% less revenues-than the cases of distributed storage with the installation of transmission lines, where this difference amounts only to 1.55%.

With respect to service provision revenues' distribution, and as a general expected result, in 2050 firm capacity payments are null, except the case where only wind generation can be installed. This is reasonable, since having dedicated batteries to supply a % of peak demand is of no value, even especially when having a high intermittency of renewable production.

Also, as a general fact, in 2020 spot market revenues account for ~60-78% of the global revenues BESS receive, whether this share increases with the 2050 case. Firm capacity payments also have a relevant share, with up to 30-40% of batteries' incomes, for all cases. The remaining 1-3% of their positive incomes come from reserve market participation, that gains weight in the future, as complement to the day ahead market revenues.

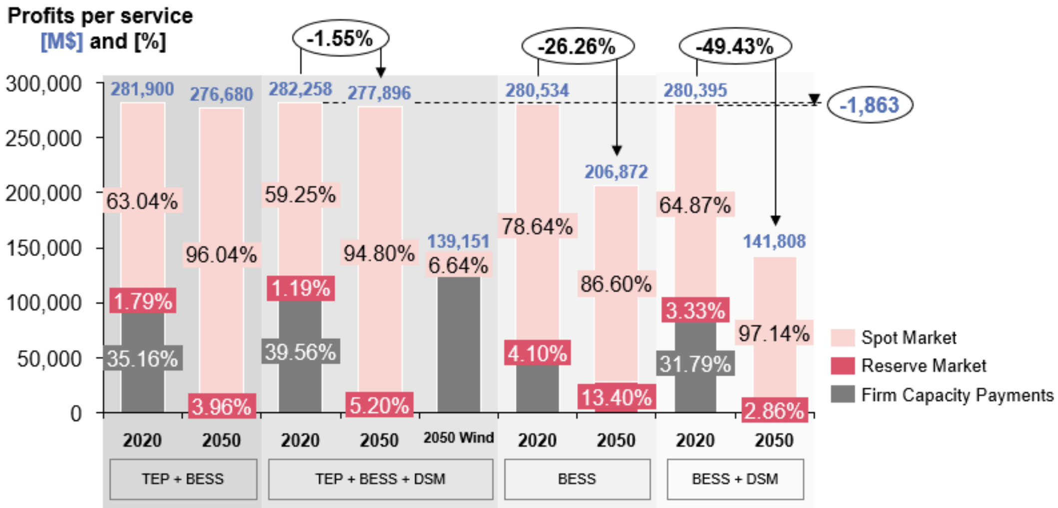

Figure 21. Profits of batteries in [M$] and [%] by service provided – No degradation Costs

Both types of storage, particularly in 2050, and due to their similar functioning, possess similar order of magnitude of traded volumes in the spot and reserve market (Table 2 and Table 3), unlike other generation sources. And this is one of the particularities of batteries versus thermal dispatchable units: the ability to participate in several markets at the same time, with a substantial participation in the 'secondary' market, so to say, that will be the reserves market. This specific feature of storage should be remunerated somehow, and put into value, as this study is stating.

Spot Market Traded Volumes [GWh]	2020				2050			
	TEP + BESS	TEP + BESS + DSM	BESS	BESS + DSM	TEP + BESS	TEP + BESS + DSM	BESS	BESS + DSM
Nuclear	6405,65	5154,03	6434,12	5890,51	6159,61	4640,54	6346,46	4975,66
CCGT	7930,31	0,00	7885,27	0,00	8292,05	0,00	8094,18	0,00
OCGT	36,83	0,00	42,57	0,00	41,80	0,00	50,33	0,00
Hydro	1545,15	1545,15	1545,15	1545,15	1545,15	1545,15	1545,15	1545,15
BESS	**1115,79**	**5839,55**	**1015,57**	**4086,09**	**2232,73**	**8406,57**	**2209,74**	**6731,55**
Wind	9129,76	10669,03	9150,68	10575,56	5246,50	5064,56	5332,20	5509,19
Solar	6667,63	14857,45	6646,72	14025,00	10550,90	21252,73	10465,20	20285,25

Table 2. Spot Market Traded Volumes [GWh]

4.1.2. RESERVE PROVISION

Since the reserve market provides non negligible revenues to battery energy storage systems, this section includes what types of generation (apart from BESS) can provide secondary reserve margins, both in the short and long-term. Figure 22 states that hydro resources are the most valuable source to manage secondary reserve requirements, due to the facility in their operation and dispatchability. BESS do work in the exact same way than hydro units, and, although having very limited capacities, they provide up to a 10-12% of global reserves.

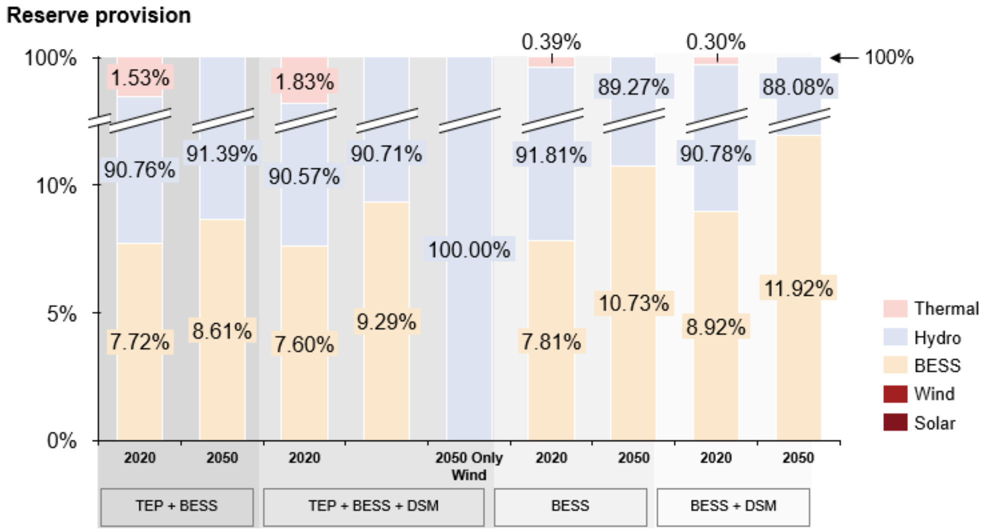

Figure 22. Secondary Reserve provision by type of technology [%] - No degradation Costs

As renewable penetration becomes mandatory (2050), BESS' reserve volumetric participation and remuneration slightly increase, being able to respond to system requirements in a quick and dynamic way.

Reserves Market Traded Volumes [GWh]								
	2020				2050			
Nuclear	0,00	0,00	0,00	0	0,00	0,00	0,00	0
CCGT	88,13	105,90	22,21	17,24	0,00	0,00	0,00	0
OCGT	0,00	0,00	0	0	0,00	0,00	0,00	0
Hydro	5241,60	5241,6	5241,6	5241,6	5421,60	5241,6	5241,6	5241,6
BESS	**1115,79**	**439,68**	**445,64**	**515,24**	**493,99**	**536,93**	**629,99**	**709,34**
Wind	445,62	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Solar	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
	TEP + BESS	TEP + BESS + DSM	BESS	BESS + DSM	TEP + BESS	TEP + BESS + DSM	BESS	BESS + DSM

Table 3. Reserves Market Traded Volumes [GWh]

4.2. CONSIDERING STORAGE AGING COSTS

Now, storage cycle aging costs are considered, and the variations with respect to the previous section are put in place, following the same approach. As we previously studied, considering these degradation costs had a direct effect on installing less capacity if there is another cheaper alternative, as TEP, but increases if left alone or with a costly operational alternative as DSM is. Therefore, we would expect a noticeable change in the revenues obtained from the a higher/lower investment and storage operation.

4.2.1. PROFITS PER SERVICE

Many interesting conclusions can be drawn from Figure 23 but the main one is the drastic reduction in the share revenues obtained from the spot market represent, in a case where the global net incomes are maintained in a ~280 M$ level. If spot revenues decrease and globally the remuneration does not meaningfully vary, it is because firm capacity and reserves participation have a higher weight. This last point is a key piece in the guarantee of BESS' economic profitability, since the most profitable utility-scale storages around the globe (the ones with higher IRRs) depend not as much of on price arbitrage but on reserves and capacity payments. Then, the need of well-designed capacity remuneration schemes is vital in the long-term.

With what respects to total revenues, aging costs make the BESS-only scenario to collect the higher volumes, compared to the least efficient that is its combination with DSM (242 M$ more). Visibly, DSM presents as an alternative to batteries and caps their revenues in the short term, day ahead market (for that reason the share batteries in the spot market where DSM also participates drops down to 28%).

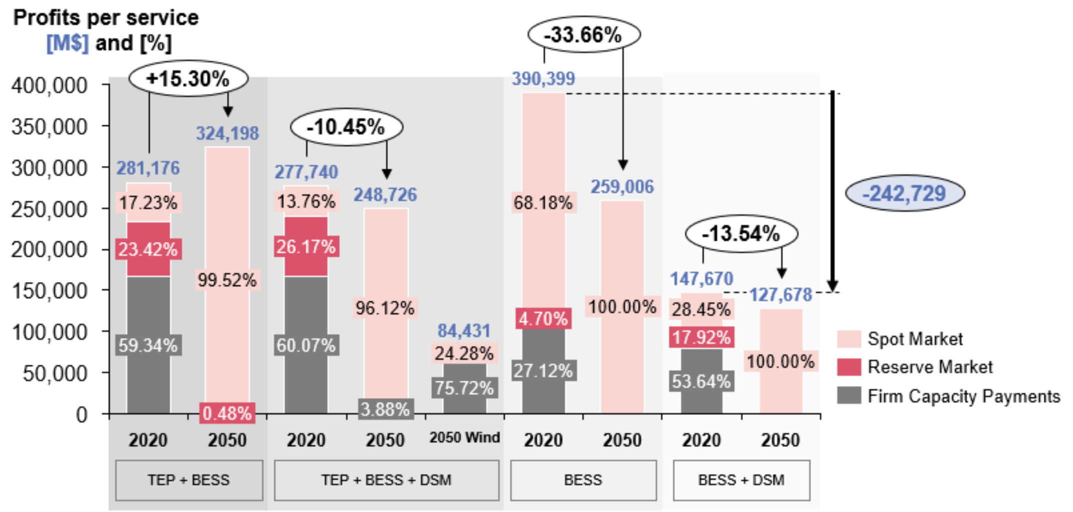

Figure 23. Profits of batteries in [M$] and [%] by service provided – No degradation Costs

If not considering aging costs, made price arbitrage the mechanism responsible for 80 or 90% of batteries' incomes, adopting now a realistic approach with degradation and reduction in their life expectancy makes them rely on the other 2 sources in that exact 80 or 90%; in other words, the previous conclusions taken upside down.

4.2.2. RESERVE PROVISION

Although there are crucial changes in the way benefits are distributed, there is no major modification of the reserves that they can provide. Again, BESS amount only for 12-13% of the essential secondary reserve (Figure 24). This can be due to the combination of having a very limited capacity and the exact same need for reserves moment happening at the time of having available stored energy. If our case study would be run without the treatment of time via a representative week, many other extreme cases would be alleviated thanks to BESS installations, in which we include the reserves traded volumes expected to increase.

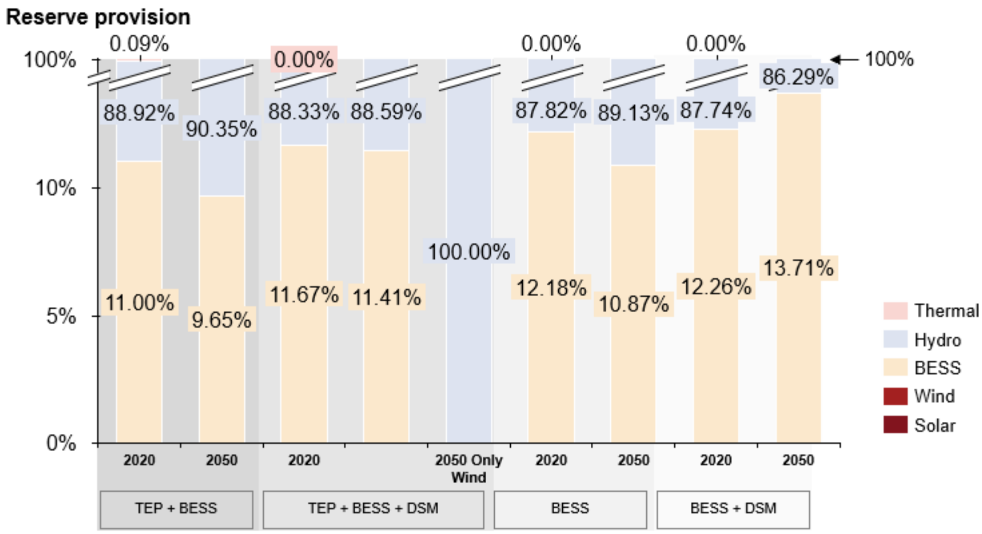

Figure 24. Secondary Reserve provision by type of technology [%] - Degradation Costs

4.3. BESS CONFIGURATION

In this section we will analyse if batteries' configuration (stand alone, isolated in a node or supporting other generation units) has an impact on the ability to capture revenues, and how income and costs are distributed (i.e.: if hybrid models considering renewable power and BESS do have a better picture and are able to capture better revenues in the daily market), among others.

We will begin by depicting again the (marginal) nodal prices of different nodes: one in Node 1 in which batteries are isolated and the other, in node 6, where they support a solar PV unit. For the sake of simplicity, a single representative period (rp=4, because has a higher BESS charge & discharge variability) is exposed, rather than all 7 representative days studied. In Figure 25 we can see that no major difference is appreciated in the MC evolution with either one or other configuration. In fact, the stand-alone configuration seems to flatten the curve in a more efficient way in the last hours of the day, as opposed with what was initially thought.

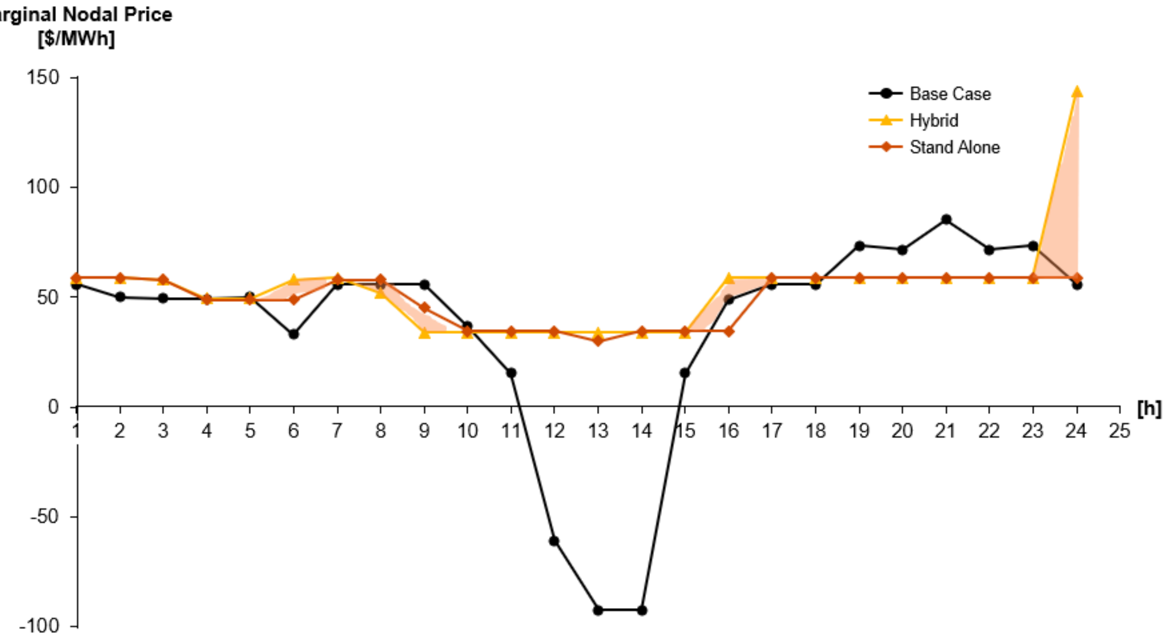

Figure 25. Marginal Cost (Nodal Price) Differential for Node 6 & rp 4 – Impact on BESS Configuration

Now, and with the aim of analysing if solar (renewable in general) profitability increases as batteries are increasingly integrated with them, a study on the solar revenues' distribution is comprised- among a case where batteries are combined in the same node and the base case, where there is no battery deployment. Figure 26

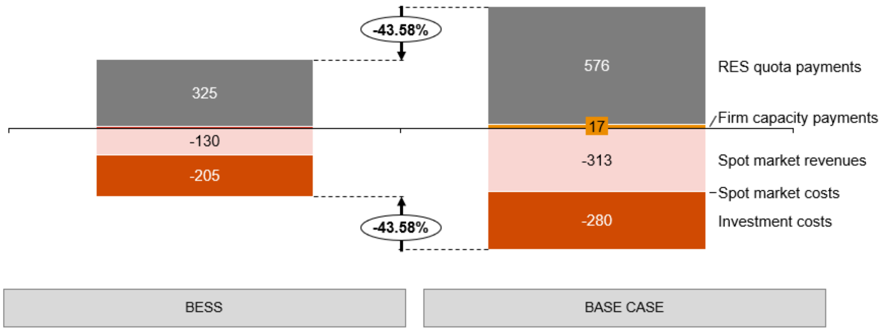

Figure 26. Solar PV Revenues & Costs Distribution in BESS case compared to Base one

Spot market revenues are always negative, that is, they only incur in costs, not generating any profits. Besides, the difference between the BESS only case and the base benchmark modifies the picture using the same proportion, by reducing costs and profits in a 43,58%. This means that solar revenues do not significantly vary if they are added to storage facilities.

4.3.1. LONG-TERM FLEXIBILITY

Aiming for a better approach to reality, degradation costs are being considered in this section and the following one. Figure 27 depicts the distribution of the profits for the case where batteries are supported by TEP flexibility. As it was previously discussed, profits coming from the spot market are reduced to 20% of the global revenues, fact that begins as soon as new transmission lines are deployed. This fact hampers the BESS potential to act as a trader in the system, able to capture high revenues at peak prices, and maintaining a constant state of charge (or charging) at low prices. These results are coherent to the ones included in Chapter 3, and no significant difference in between the way BESS are deployed is seen in the profits distribution quota.

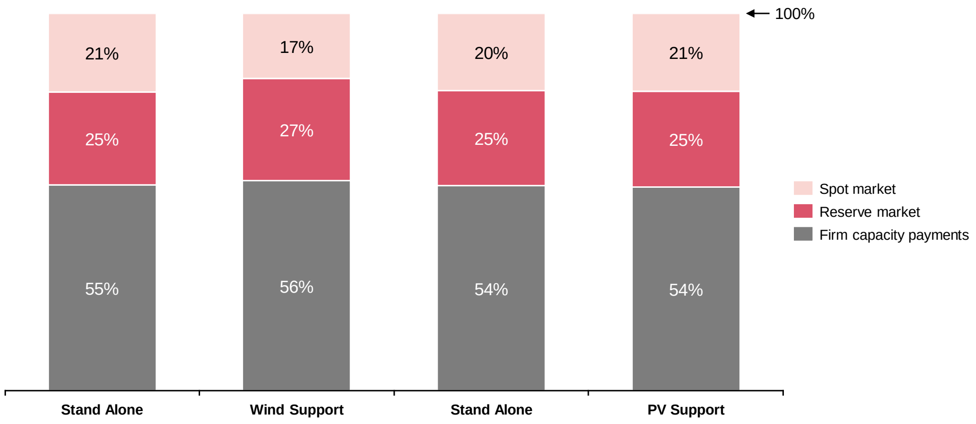

Figure 27. Profits of batteries in [%] by service provided – Impact Configuration in TEP cases

4.3.2. SHORT-TERM FLEXIBILITY

Again, aging costs are considered in this section. Figure 28 depicts the profits distribution for the case where batteries are supported by demand response flexibility. As it was previously discussed, profits coming from the spot market are the primary income source, representing between 63% to 70% of the global revenues. The reason behind the 63 to 70% differential may be due to a complex combination of factors, in which one of the considered could easily be the BESS location; in other words, in its configuration. It is in node 4, where BESS helps a wind park, that profits coming from reserve market participation increase, as spot ones decrease.

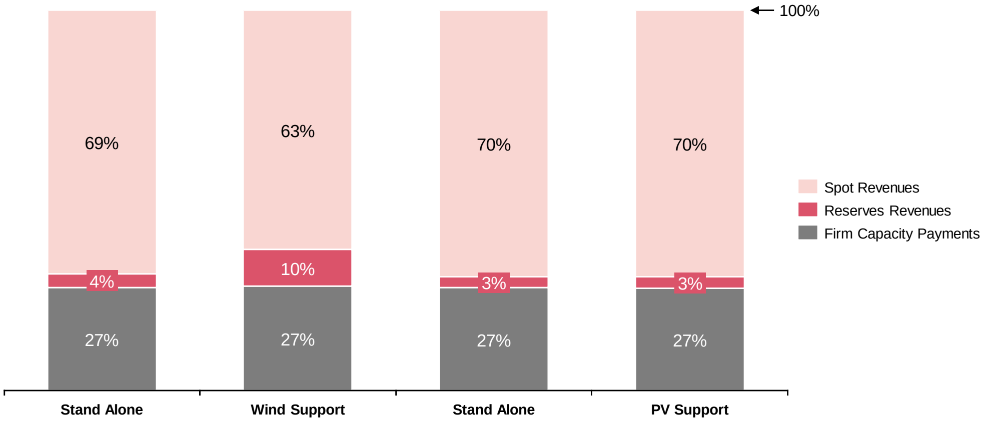

Figure 28. Profits of batteries in [%] by service provided – Impact Configuration in DSM cases

Therefore, we can conclude that in this specific case and studied grid, the battery configuration has no impact on how they obtain their revenues from a particular specific source or another, as seen in Figure 27 and Figure 28

CHAPTER 5. PROFITABILITY

This section studies the batteries' profitability under the scenarios where they are considered. To do this, four different BESS have been identified (BESS 1, 3, 5 and 7), with their corresponding profits breakdown.

All cases have been solved under a MIP approach, which makes us point out that fixed costs, associated to investments and discrete variables, are not fully reflected in the system prices- this is the already known existing difference between short-run marginal costs and long-run marginal ones. Hence, this leads to a missing money problem for BESS, caused by the difference in between prices and greater overall costs, covering for investment and operation decisions.

Taking a different approach, a reason for BESS not recovering costs would be the difference between considering a brownfield approach, taken in this Section, in opposition to a greenfield one. Under a brownfield scenario, where already installed capacity is placed in the system, BESS would not be able to cover for the sunk costs of investment decisions, but only for the operation of the storage itself. On the other hand, under a greenfield approach, only the new installed storage capacity will fully recover costs.

When reaching the bottom line of their profits, this is, summing revenues coming from the spot market, reserves, and other kind of firm capacity payments, and removing investment and operation costs, if positive, the BESS business case results in a profitable scenario. If negative, we identified the reason for this is: the existing difference between ex-ante marginal costs and ex-post spot profits that are calculated by dividing the total amount of revenues coming from this source into the total spot energy provision. This truly means that there is no such thing as perfect competition in our case, as happens in many real power systems. Therefore, the difference between the perceived profits for BESS in each scenario differs from the marginal cost at each node, resulting from the market, which concludes with a different mark-up for each case.

Hereunder, we will briefly illustrate three different scenarios where BESS is present, one of them with a positive mark-up, in fact, the only scenario with a positive mark-up (this is, greater than 1, since perceived profits are more significant than the average annual marginal cost at the node in which the corresponding battery is connected), and the remaining two cases with a <1 mark-up, that means that the BESS project is not profitable.

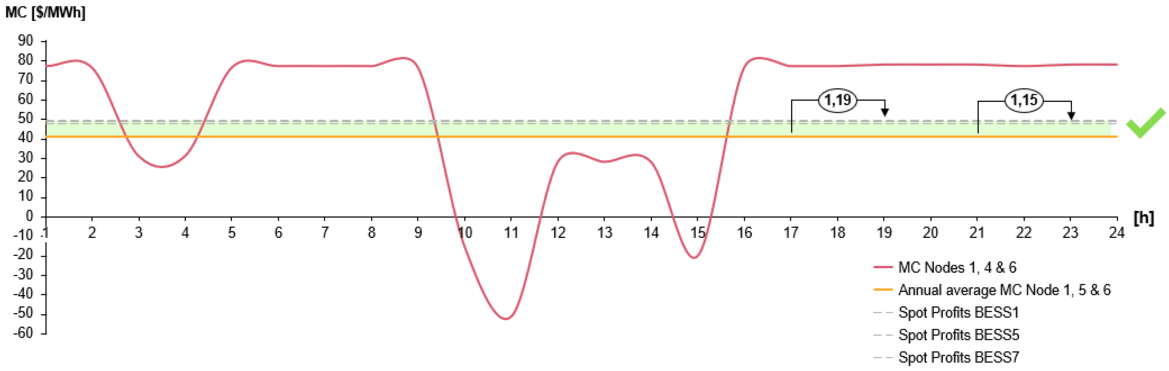

Figure 29. BESS only case: positive annual mark-up & guaranteed profitability

Figure 29 presents the case where BESS is not competing against TEP or DSM to provide flexibility and serve as an hourly storage system, which is the only profitable scenario. It can be seen that the mark-up fluctuates between 1,15 and 1,2 for batteries 1 (and 5) or 7.

The only profitable case is the one only including BESS as a flexibility resource, although its profitability is restrained to 0.19 M$/year, which may be questioned if not complemented by other additional payments. The following alternative in decreasing profitability would be the TEP + BESS + DSM case, but, since TEP reduces spot profits in the way that marginal prices at nodes converge, BESS are not able to capture high nodal price variations and therefore, spot profits are reduced in a high proportion.

This reduction in the spot market, and the increase in investment costs due to a slightly higher BESS deployment (moving from 0,3 GW to 0,35 GW), make both cases considering the construction of new transmission candidate lines not profitable. Then, the following 2 cases present a non-profitable business case, since mark-ups situate below 1, which will necessarily mean that the generated profits from the sale of electricity in the spot market does not cover for the average marginal cost of the node in which the storage system is connected, this is, it is incurring in a financial and volumetric loss. This obviously happened in cases where a new transmission capacity is deployed. Additionally, to this, it has been included in both Figure 30. Figure 31 an artificial spot curve, generated weighting the MC evolution with the mark-up, this is, considering that the pool price would be lower than the actual one. If the evolution of MCs would have been the green dotted lines, the average pool price would have also been lower, which could have equalled the perceived volumetric profits in the day-ahead market.

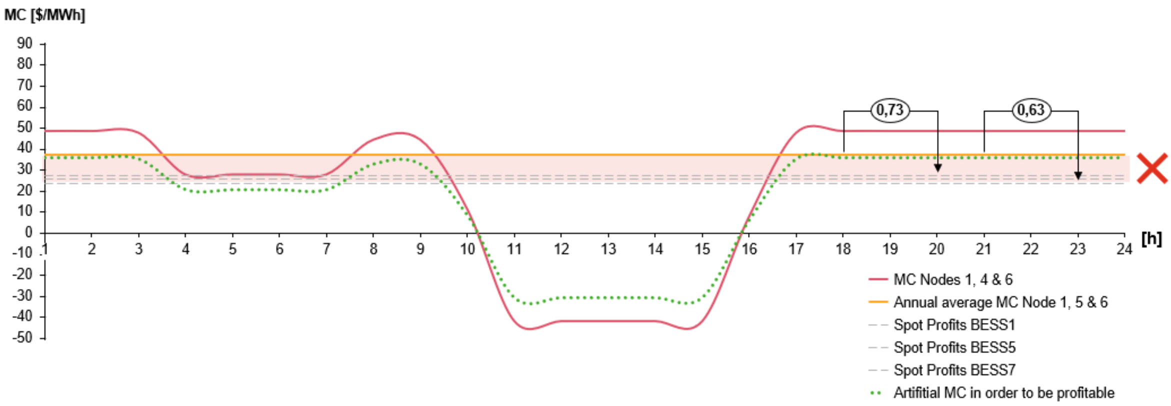

Figure 30. BESS + TEP scenario: 'negative' annual mark-up & non-profitable case

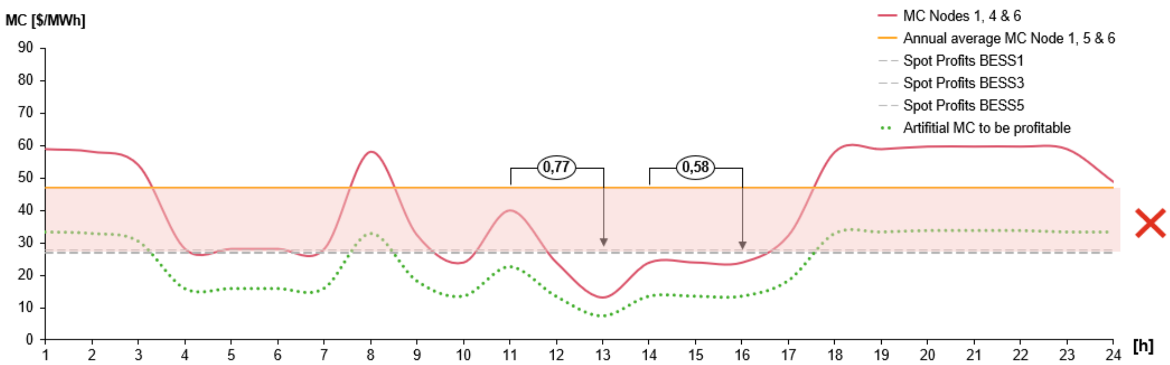

Figure 31. BESS + TEP + DSM case: 'negative' annual mark-up & non-profitable scenario

CHAPTER 6. TIME-DEPENDANT SENSITIVITY ANALYSIS (HOURLY)

A final additional analysis has been executed in order to examine the main existing differences in the obtained results when choosing an hourly approach to the optimization model or either opting for a single representative week to reduce the time horizon. Some of the general differences are summarized in Table 4. The examined model has been the one comprising BESS and TEP, that is, considering a better-interconnected network, without the influence of DSM in the operation of BESS storage. The hourly model, therefore, studies a single representative period that sums 8736 annual periods, whether the 7LRP refers to the annual approach narrowed down to a single set of 7 periods (days), each one of them with their corresponding weight, since each hour in the year is assigned to a representative day, repeated with a different frequency. As it may seem obvious, the hourly model is solved in, approximately, 30 minutes, whether the 7LRP is narrowed down to just 2,3 s. If results are immediately desired, the 7LRP approach would be advisable.

	Hourly	7LRP	Variation Hourly vs 7LRP
Objective Function [M$]	1540,69	1.492,66	**3,22%**
CPU Time Model Generation [s]	63,55	1,67	
CPU Time Model Solution [s]	1.799,56	2,31	
Renewable Investment [GW]	5,32	4,17	**49,29%**
Storage Investment [GW]	0,219	0,209	**4,95%**
Thermal Investment [GW]	2,98	3,47	**115%**
Renewable Production [GWh]	6.627,62	7.520,05	**-13,47%**
Storage Production [GWh]	1.822,28	1.783,76	**2,11%**
Thermal Production [GWh]	23.451,96	22.555,38	**3,82%**

Table 4. Model summary in the time dependant sensitivity analysis

The hourly model incurs in slightly higher costs, which is due to several factors: renewable investments are 49% higher with respect to the 7LRP model, but operation is a 13,47% lower, so overinvestments are not that used. Since these renewable investments are always cheaper than investments in thermal technologies, if new conventional sources are needed to supply demand, the system will incur in higher investments, resulting in a higher system cost. Not only the thermal investments are higher, also storage investments are too, which means that the hourly model can find more hours to efficiently allocate renewables. With respect to BESS operation, it is confirmed that the hourly approach takes advantage of storage in non-representative hours, since production is higher than in the 7LRP.

In order to see the detail of these aspects, Figure 32 is depicted.

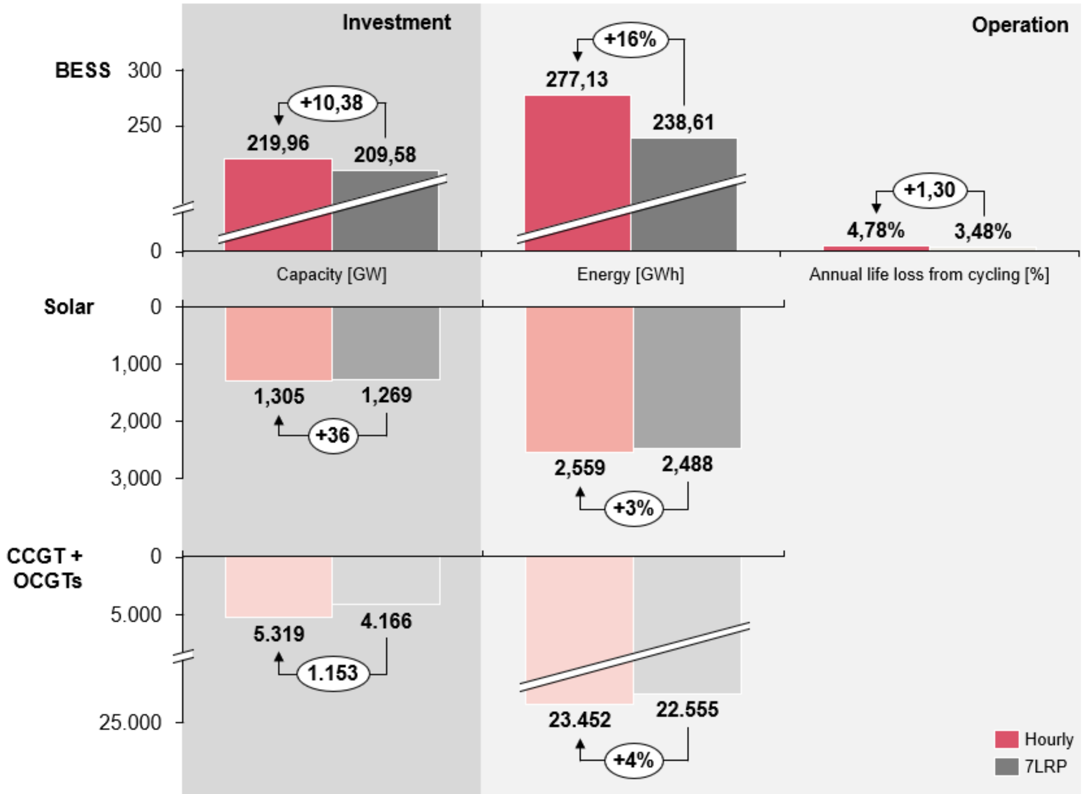

Figure 32. Investment & operation decisions in the hourly solution with respect to the 7LRP model

In Figure 32 it can be seen that investments in storage, solar units and combined cycles follow the same rationale: in the hourly detailed model investments in batteries, solar units and CCGTs are higher than in the simplified clustered model approach. This is because batteries act as a perfect complement to solar units, and combined cycles supply the system the required flexibility, especially in ‘extreme’ scenarios where storage may be operated more often, at the expense of incurring in higher investments. After making the investment decisions, operation takes place for the 3 mentioned technologies. In the hourly solution, batteries are operated in a 16% higher than in the simplified case, while solar (and CCGTs) is only deployed for a 3% (4%) higher capacity. As it was expected, and since BESS operation is higher in the hourly approach, BESS life loss is projected to be greater in this higher operated regime, which is confirmed through an increase of 1,30% in the annual BESS life loss. This results in a lower life expectancy if individual extreme hours are accounted for.

The main objective of this section was to study if extreme-outlier hours make an impact on the both the use and investment of batteries in the system. This can be easily seen through the variability of nodal prices at nodes, and overall marginal system cost, in the hourly approach with respect to the simplified 7LRP followed up to this point in the document. This is precisely done because price differential among (1) hours in the day and (2) nodes in the system is one of the main drivers for batteries deployment, use and profitability.

Figure 33 is precisely depicting this system price variability, in which the previous 7LRP TEP + BESS + DSM model is solved with a 25% minimum green production (resulting in a 32% of clean energy provision) and then, compared to the hourly and 7LRP model with TEP and BESS possibilities. As it was previously mentioned, hourly model incurs in higher costs, at the expense of having a lower green production and investment (27% w.r.t. the 29% of the 7LRP method). Therefore, it would be reasonable for price variability in the hourly model to be greater than the original 7LRP. This is confirmed, since both average and maximum system prices are 5,30 and 6,75 $/MWh higher than in the original case.

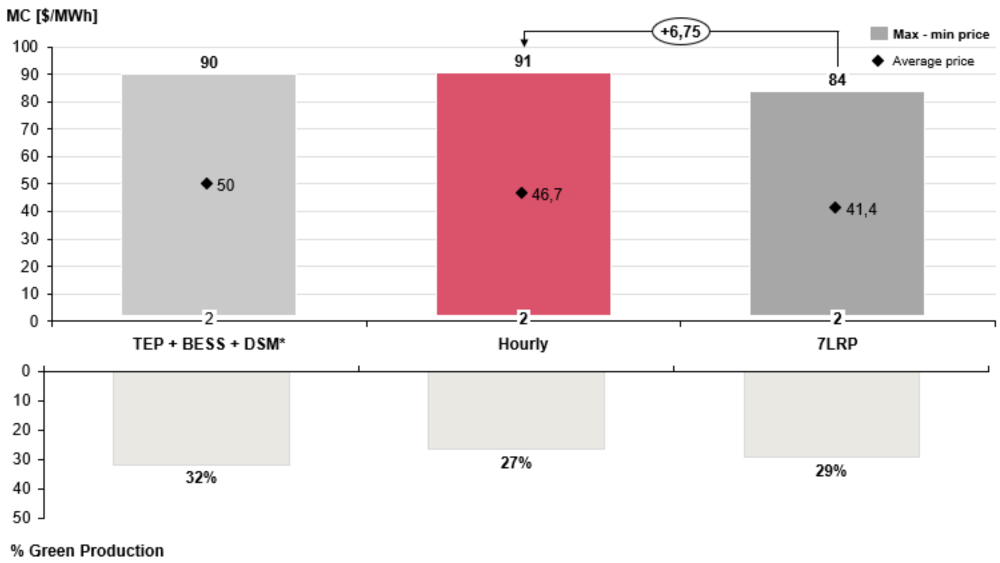

Figure 33. System MC differential for hourly and 7LRP solutions; w.r.t. 7LRP TEP + BESS + DSM case

The next reasonable step would be to study what trend would BESS profits have in the hourly model approach in comparison to the 7 representative periods one. Since results are similar to the ones obtained in Section 3.1, a twist in the study is conveyed in this section. Two groups in BESS units have been identified: the first one is storage connected in the poorly interconnected nodes (BESS3, acting as wind support) and the second one, other batteries in the system. The first type is obviously making a significant amount of profits with respect to profits of other BESS in the system, since price differential encourages batteries to be both deployed and used. But, in the hourly approach, BESS3 investment is higher, as are the profits associated with it since all hours are representative, encouraging batteries to sell energy at higher prices in hours not yet depicted and buying it at a null price (or at a 2$/MWh price).

In the second type (other batteries), the hourly model invests in less capacity, making profits noticeably lower in opposition to the 7LRP results.

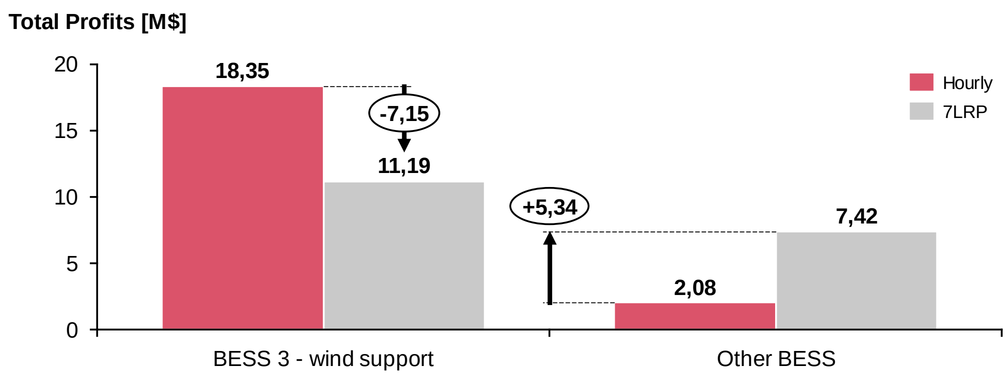

Figure 34. BESS identified types: profits in hourly and 7LRP model typologies

To sum up, profits go up or down depending on the BESS location and service they are providing. However, in total, the sum of BESS profits is 2M$ higher in the hourly case than in the 7LRP.

CHAPTER 7. CONCLUSIONS

This last section summarizes the main conclusions drawn from this work. They can be categorized into:

1. **General conclusions** on the inclusion of batteries, transmission capacity and flexibility coming from demand response in electric systems and how this fact impacts on total costs and use of generation and transmission facilities.

   1.1. Independently of how many 'players', talking in terms of resources, that are actually being used to fulfil demand requirements, **operational costs and generation investments costs amount for 80-95% of total** system **costs** for all scenarios, whether the remaining transmission investment costs, storage cycle aging and reserve provision cost amount for a very limited percentage (Figure 12).

   1.2. The **cost reduction** achieved from the inclusion of storage, new transmission lines between nodes 4 and 5 in the system and with the aid of demand flexibility (response) is a **14%**.

   1.3. In this specific grid and case study, **the resource that can contribute in a higher way** to reducing costs is **transmission expansion plans**, **followed by batteries and then, demand flexibility**. If an incremental approach if followed, this will be the optimal sequence in which value may be added to the system. TEP does help the system in a way that nodal prices and grid congestions are reduced, since cheaper generation may supply-demand at a different node in which it is connected and since now new lines have been deployed and are being used for transporting electricity in between nodes. Although TEP is the first optimal decision for reducing price differentials, by reducing nodal prices, a stable and equal price for all nodes in the system is not achieved. This can be seen in Figure 8, in which node five does not meet equal prices as other nodes do. This means that the optimal transmission capacity is not installed, and it will be necessary to allow the model to invest in more transmission capacity and new lines. It clearly seems that line 4-5 is very necessary in order to transport electricity coming from wind generation at node 5 to the highest demand share located at node 4.

Besides, as transmission lines are chosen, BESS potential is reduced, since nodal prices converge to a homogeneous system price, reducing therefore the daily trading scheme batteries use in order to finance their investments.

1.4. If a distinction between the current case (year 2020) and future fully renewable scenarios (2050, as European Green Deal wants to achieve) is made, also the total amount of costs in which a system incurs and the relationship in between operational, investment costs and those related to flexibility (imperative in renewable dominated scenarios) will change. In 2020 thermal investment and operating costs will exist and, in fact, will account for the main party, in opposition with the 2050 case, dominated by (also) renewable investment costs (in which overinvestments will be undertaken, renewable investment costs increase a 116%) , complemented by investment costs in storage assets and in their operational cycle use and flexibility via DSM.

2. **Specific conclusions.** These conclusions take a more profound focus BESS assets' deployment and use and how it integrates with other flexible resources.

2.1. Regarding storage **deployment**, the lower the system flexibility is, the higher BESS capacity is chosen to be installed. Flexibility is measured by how much energy can be supplied using dispatchable generation units or controlled demand and storage resources. Therefore, a system considering only BESS flexibility will deploy a higher amount of batteries in opposition to an effectively interconnected system, that also counts with responsive users.

In a fully renewable scenario, 2050, the need for batteries will increase up to needing 10.62 GW of capacity in case storage is not added to DSM and conventional transmission expansion plans.

Besides, **considering storage aging costs**, reduces the installed capacity in an 80% for the 2020 scenario, in opposition to overestimating BESS capacity in the 2050 renewable case, if the system is poorly interconnected (no TEP plans have been followed). This is due to the exponential costs in which batteries incur when operating in long periods of time.

2.2. Regarding storage **operation**, the batteries' state of charge evolution was analyzed, and several conclusions were drawn: the most frequent charge & discharge dynamics were found in the BESS only case, followed by BESS+DSM and finally BESS+TEP. Transmission plans noticeable shave the use of storage and demand response is found to reduce the SoC of batteries slightly. This means that DSM and TEP can potentially generate some conflicts when using them along with batteries.

3. **Specific conclusions** on the **integration of BESS along with other resources**.

3.1. First, some **complementarities and conflicts** can be extracted when using storage **with TEP** plans**.**

3.1.1. Complementarities. This is because storage may serve in the short term as a temporal solution to the deployment of a new transmission line, and because it defers the need for these investments to take place. At the same time, storage facilities may reduce system infeasibilities represented by network congestions. In a practical way, if new transmission deployment plans were simultaneously studied with BESS plans, System Operators could take advantage of a remarkable opportunity, by not overestimating storage capacity.

3.1.2. Conflicts. On the other hand, some disputes may rise from the integration of storage with transmission lines' investment. This is because the existing spread between hourly marginal costs at nodes is limited, which caps the potential of batteries for trading energy in the daily window. Again, considering degradation costs for storage enhances the competitiveness between BESS and TEP.

3.2. Secondly, the integration of **storage and demand flexibility** causes some conflicts: firstly, DSM reduces BESS capacity installation between 1.4 and 3.5 GW, and limits storage operation in a 10 to 20% of shallower States of Charge.

3.3. Finally, studying **both storage and demand response against Transmission expansion plans** suggest several conflicts, in uneven ways: DSM is more affected by the development of new lines, than the State of Charge that the one BESS suffers (Figure 19).

4. **Conclusions drawn from the total amount of storage costs and revenues and their distribution** among the spot and reserves market with capacity payments are summarized as follows:
   4.1. If ignoring storage degradation costs:
      4.1.1. Spot market revenues account for ~60-78% of the global revenues BESS receive, whether this share increases with the 2050 case, with a ~90% of benefits coming from the pool, since in 2050 capacity payments to storage will be null due to their inability to provide firmness in a big scale. Regarding the amount of energy traded via storage (4000 to 8000 GWh/year), if compared to other generation technologies, the spot volume increases as renewable generation does, and surpasses conventional thermal base generation.
      4.1.2. Reserves costs and revenues sum up to a limited 2-4%, and are higher in cases with poor interconnection capacity, where BESS could dynamically operate in providing ancillary services. Regarding the amount of reserves' energy traded 400 to 550 GWh/year), BESS supplies between 7 and 12% of the global reserves. The remaining energy is supplied with hydro resources.

   Besides, in the long-term (2050), storage profits are reduced in a ~26-49%, especially if not added to TEP plans.
   4.2. If considering storage aging costs:
      4.2.1. Spot market revenues are drastically reduced to ~20-30% of the global revenues BESS receive, since now degradation costs depend on the frequency of cycles. Regarding the amount of energy traded via storage (4000 to 8000 GWh/year), if compared to other generation technologies, the spot volume increases as renewable generation does, and surpasses conventional thermal base generation.

4.2.2. With the decrease of spot revenues, reserves costs and capacity payments are expected to increase their share, and so they do. Now, ~50-60% of revenues depend on capacity mechanisms in 2020, although reduced in 2050 for security of supply reasons.

Besides, in the long-term (2050), storage profits are reduced in a lower proportion, around 13 and 33%, especially if not added to TEP plans.

5. **BESS configuration** has proved to have **no substantial impact on the profitability of storage** itself nor to other renewable projects such as solar facilities.
6. **BESS profitability is subject to the study of whether the storage system is placed in a perfect competitive market or not.** In this case study, storage systems (and other units) either perceive strictly more or fewer profits than those corresponding to the marginal ones in the market. In case that profits are greater than those of MCs, the resulting mark-up (ratio between the two previous figures) is greater than 1, so BESS project would be profitable. If not, the BESS business case would incur in losses, by being the mark-up lower than 1.
7. **The impact of solving the model in an hourly time horizon** solution comes with a slight increase in the objective function (total system cost), since we have only analyzed 7 days of the year in the 7LRP, with increasing thermal investments and operation and decreasing the clean energy production. On the other hand, capacity in storage units increases, as does the solar deployment and operation. BESS use is also higher in the hourly case, as well as its life loss. The takeaway considering BESS profits would be having, approximately 2M$ more in the hourly model than in the representative case.

CHAPTER 7. ALIGNMENT WITH THE SDGS

From a different perspective, this Project is aligned with many of the Sustainable Development Goals set by the United Nations General Assembly in 2015 and meant to be a blueprint for the 2030 agenda. The main global goals touched by this study are:

- Goal nº 12: Responsible Consumption and Production: the study of whose technologies are of most use in the electric grid from a purely economic perspective allows us to be efficient with both our electric consumption and production. Most specifically, batteries are meant to play an important role as facilitators for a clean and cheap way to store energy whose value will be higher in the future, now of consumption. In fact, the instalment of renewable plants with storage facilities to them associated makes electric consumption to be produced, stored and consumed locally at low prices. Therefore, the analysis and final choice of the most adequate mechanisms (in terms of generation and storage installations, new transmission lines or demand participation), is of special importance to make first local but global consumption to be increasingly efficient.
- Goal nº 13: Climate Action. Taking an environmental point of view, rather than an economical one, the electric system is currently facing a process of decarbonisation called Energy Transition. This clean transition is fostering the rise and implementation of new non-pollutant (renewable) generation technologies, distributed storage or the need for better interconnections between electrical borders or frontiers. Not only that, customers are also noticing that they can be smart and responsible for their energy consumption, so that they can choose to store energy in order not to incur in extra costs (for them and many millions of euros for the system, overall) as well as extra pollutant emissions, both linked to thermal generation being dispatched and operating. Therefore, a correct share between clean generation, well developed interconnections, distributed generation, storage, energy communities, demand response and other sources of flexibility, is key from a cost and emission minimization perspective.

- Goal nº 11: Sustainable cities and communities: some of the key aspects that promote the existence of efficient energy communities are (1) the existence of a price discriminatory billing scheme, which enhances demand participation in the day ahead market by modifying their consumption by either shifting or shedding it; and (2) also, distributed generation and storage, connected to the distribution grid, in close contact with the end-customers. After the COVID-19 pandemic and knowing that most of the population is based on the cities, investing in infrastructures that boost self-consumption and energy efficiency is a milestone that this nº11 goal could achieve in 2030. Although the pandemic should, by itself, represent a change in the urban-placed lifestyle, the creation of COVID-19 Response Plan aspires to the support of transversal solutions in community. In this Plan, battery energy storage systems could mean a new way in the objectives' achievement.
- Goal nº 8: Decent work and y economic growth. From a practical point of view, batteries are yet to experiment cost reductions in the future, with investments in emerging solutions and innovations. Therefore, the value added to the support of storage is related to the national job creation in the industrial sector and the purely economic perspective, as seen from other indirect activities. Attached to storage manufacturing, investments in generation units and transmission lines are already known, and demand response mechanisms urge digital solutions that enable remote demand shifting, are related to skilled job creation in digitalisation and modernisation.

APPENDIX I - NOTATION OF MODEL

Indexes and sets

$p \in \mathcal{T}$	Hourly periods
rp	Representative periods
k	Periods inside a representative period
$h_{t,rp,k}$	Relation among periods and rp
$g \in \mathcal{J}$	Generation technology
$t(g) \subseteq \mathcal{J}$	Thermal generator unit
$s(g) \subseteq \mathcal{J}$	Storage unit
$r(g) \subseteq \mathcal{J}$	Renewable unit
i	Node i
g_i	Generator g connected to node i
$la(i,j,c) \subseteq \mathcal{L}$	All transmission lines between nodes i and j
$lc(i,j,c) \subseteq \mathcal{L}$	Candidate transmission lines between nodes i and j
$le(i,j,c) \subseteq \mathcal{L}$	Existing transmission lines between nodes i and j
a	Segments in the cycle aging cost function

Parameters

A	Number of segments of cycle depth storage function [#]
$C_{seg}^{DSM_{shed}}$	Demand shedding cost [M€/GWh]
$C_{rp,k,i}^{DSM_{shift}}$	Demand shifting cost [M€/GWh]
C^{ENS}	Energy non-served cost [M€/GWh]
C_g^{INV}	Investment cost for generator g [M$/GW/year]
C_g^{var}	Slope variable cost [M€/GWh]
C_g^{int}	Intercept variable cost [M€/h]
C_g^{st}	Start-up cost [M€]
C_g^{OM}	Operation and maintenance cost [M€]
C_s^{DEG}	Degradation / aging cost for storage units [M€]
C^{RES+}	Cost factor for secondary upwards reserve [p.u.]
C^{RES-}	Cost factor for secondary downwards reserve [p.u.]

$D_{rp,k,i}^{P}$	Hourly active demand per node [GW]
$D_{rp,k,i}^{P+}$	Active peak demand [GW]
$\widehat{DSM}_{rp,k,i,sec}$	Bound on DSM [GW]
$\widehat{DSM}^{UP}{}_{rp,k,i,sec}$	Bound on upwards DSM [GW]
$\widehat{DSM}^{DW}{}_{rp,k,i,sec}$	Bound on downwards DSM [GW]
ε_g	EFOR: interruptibility of generation unit
EU_g	Existing generation unit

ETP_s	Energy-to-Power ratio [-]
FC_g	Firm Capacity coefficient of generator g [p.u.]
FC^-	Minimum firm capacity requirement [p.u.]
$IF_{rp,k,s}$	Inflows for hydro storage [GWh]
$InRes_{s,p}$	Initial reserve [MWh]
μ	Minimum clean production [p.u.]
P_j^+	Maximum output production [GW]
P_j^-	Minimum output production [GW]
PF_r	Renewable profile [p.u.]
R_s^+	Maximum Reserve [MWh]
R_s^-	Minimum Reserve [MWh]
RU_g	Ramp up limit [GW]
RD_g	Ramp down limit [GW]
W_{rp}^{rp}	Representative periods weight [h]
W_{rp}^{k}	Hourly weight for each rp [h]
MOW	Moving window for inter-period [h]
$\hat{X}_g$	Upper bound on generation investments [#]
η_s^{CH}	Charge efficiency for storage unit s [p.u.]
η_s^{DIS}	Discharge efficiency for storage unit s [p.u.]
S_{base}	Base Power [MVA]
Δ	Angle difference between nodes i and j of system [rad]
$Xline_{i,j,c}$	Reactance X of line [p.u.]
$T_{i,j,c}^+$	Maximum active flow between lines i and j [MW]

Variables

$b^{\frac{ch}{d}}_{rp,k,d}$	Binary variable to avoid simultaneous charging and discharging for storage
$M^{\frac{ch}{d}}$	Upper bound on charge and discharge [GW]
$u_{rp,k,g}$	Binary commitment decision
$y_{rp,k,g}$	Binary start-up decision
$z_{rp,k,g}$	Binary shutdown decision
x_g	Binary investment decision on generator g
x_{ijc}	Binary investment decision on transmission line between nodes i and j
$cdsf_{rp,k,s,a}^{CH}$	Charge for Cycle Depth Stress Function [GW]
$cdsf_{rp,k,s,a}^{DIS}$	Discharge for Cycle Depth Stress Function [GW]
$cdsf_{rp,k,s,a}^{SoC}$	State of charge for Cycle Depth Stress Function [GW]
$dsm_{rp,k,i,seg}^{shed}$	Price-responsive shed demand-side management [GW]
$dsm_{rp,k,i,sec}^{Dw}$	Shifting demand-side management (down) [GW]

$dsm^{Up}_{rp,k,i,sec}$	Shifting demand-side management (Up) [GW]
$inter_{p,s}$	Reserve at the end of inter-period for storage unit s [GWh]
$intra_{p,s}$	Reserve at the end of intra-period for storage unit s [GWh]

$p_{rp,k,j}$	Production of the unit [GW]
$cs_{rp,k,s}$	Consumption of the unit [GW]
$\hat{p}_{rp,k,g}$	Production above minimum production [GW]
$pns_{rp,k,i}$	Power non-served [GW]
$pf_{rp,k,l}$	Power flow
$sp_{rp,k,s}$	Spillage [GWh]
$R^{inter}_{rp,k,j}$	Reserve at the end inter period [GWh]
$R^{intra}_{rp,k,j}$	Reserve at the end intra period [GWh]
$R0_s$	Initial reserve
$res^{+}_{rp,k,g}$	Needs for secondary upwards reserve [%]
$res^{-}_{rp,k,g}$	Needs for secondary downwards reserve [%]
$f^{P}_{rp,k,i,j,c}$	Active power flow in between lines i and j [MW]

APPENDIX II. DATA

Firstly, we can find the details of the fossil fuels generation plants in the system. The main technologies in the case study are: Nuclear, thermal, combined cycles, fuel oil, and gas turbine units. Furthermore, the specification of the hydro reservoir, renewable wind and solar units and batteries is defined. Finally, the considered demand response profiles are included for the single representative week chosen in the yearly scope. Where no investment cost is included, is because no investment in that type pf technology is eligible.

GENERATION MIX

NUCLEAR

Initial amount of plants: 1

Nuclear:		1
P_j^+	Maximum output production [MW]	771.6
P_j^-	Minimum output production [MW]	771.6
RU_j	Ramp up limit [MW]	0
RD_j	Ramp down limit [MW]	0
C^{ENS}	Energy non-served cost [M€/GWh]	10000
C_j^{var}	Slope variable cost [M€/GWh]	0.015
C_j^{int}	Intercept variable cost [M€/h]	0
C_j^{st}	Start-up cost [M€]	0
ε_g	EFOR: interruptibility of generation unit	0
FC_t	Firm Capacity Coefficient [p.u.]	0.97

COAL

Initial amount of plants: 0

(Domestic Coal Anthracite, Brown Lignite, Imported and Coal Subbituminous and Imported Coal Bituminous)

Coal:		1	2	3	4
P_j^+	Maximum output production [MW]	588.0	203.1	150.4	194.4
P_j^-	Minimum output production [MW]	235.2	81.2	60.2	77.8
RU_j	Ramp up limit [MW]	88.2	30.5	22.6	29.2
RD_j	Ramp down limit [MW]	88.2	30.5	22.6	29.2

C^{ENS}	Energy non-served cost [M€/GWh]	10000	10000	10000	10000
C_j^{var}	Slope variable cost [M€/GWh]	0.054	0.052	0.052	0.05
C_j^{int}	Intercept variable cost [M€/h]	0.001	0.001	0.001	0.001
C_j^{st}	Start-up cost [M€]	0.04	0.04	0.04	0.04
ε_g	EFOR: interruptibility of generation unit	0	0	0	0
C_t^{INV}	Investment Cost of coal units [$/GW/y]	145.591 for all [1-4] units			
FC_t	Firm Capacity Coefficient [p.u.]	0.95	0.96	0.96	0.96

CCGT

Initial amount of plants: 0

CCGT		1	2	3	4
P_j^+	Maximum output production [MW]	500.0	500.0	500.0	667.5
P_j^-	Minimum output production [MW]	100.0	100.0	100.0	133.5
RU_j	Ramp up limit [MW]	200.0	200.0	200.0	267.0
RD_j	Ramp down limit [MW]	200.0	200.0	200.0	267.0
C^{ENS}	Energy non-served cost [M€/GWh]	10000	10000	10000	10000
C_j^{var}	Slope variable cost [M€/GWh]	0.03	0.031	0.034	0.028
C_j^{int}	Intercept variable cost [M€/h]	0.009	0.009	0.009	0.009
C_j^{st}	Start-up cost [M€]	0.03	0.03	0.03	0.03
ε_g	EFOR: interruptibility of generation unit	0	0	0	0
C_t^{INV}	Investment Cost of CCGTs units [$/GW/y]	41.818 for all [1-4] units			
FC_t	Firm Capacity Coefficient [p.u.]	0.96 for all [1-3] units			

OCGT

Initial amount of plants: 0

OCGT:		1	2	3
P_j^+	Maximum output production [MW]	400.0	400.0	400.0
P_j^-	Minimum output production [MW]	0	0	0
RU_j	Ramp up limit [MW]	400.0	400.0	400.0
RD_j	Ramp down limit [MW]	400.0	400.0	400.0
C^{ENS}	Energy non-served cost [M€/GWh]	10000	10000	10000
C_j^{var}	Slope variable cost [M€/GWh]	0.064	0.067	0.07
C_j^{int}	Intercept variable cost [M€/h]	0.003	0.003	0.003
C_j^{st}	Start-up cost [M€]	0	0	0
ε_g	EFOR: interruptibility of generation unit	0	0	0
C_t^{INV}	Investment Cost of OCGTs units [$/GW/y]	24.781for all [1-3] units		

FC_t	Firm Capacity Coefficient [p.u.]	0.96 for all [1-3] units

FUELOILGAS

Initial amount of plants: 0

P_j^+	Maximum output production [MW]	441.8
P_j^-	Minimum output production [MW]	0
RU_j	Ramp up limit [MW]	441.8
RD_j	Ramp down limit [MW]	441.8
C^{ENS}	Energy non-served cost [M€/GWh]	10000
C_j^{var}	Slope variable cost [M€/GWh]	0.123
C_j^{int}	Intercept variable cost [M€/h]	0.018
C_j^{st}	Start-up cost [M€]	0.06
ε_g	EFOR: interruptibility of generation unit	0
C_t^{INV}	Investment Cost of Fuel units [$/GW/y]	43.367
FC_t	Firm Capacity Coefficient [p.u.]	0.95

STORAGE: HYDRO

Initial amount of plants: 1

P_s^+	Maximum output production [MW]	600.0
P_s^-	Minimum output production [MW]	0
$R0_s$	Initial reserve [MWh]	750000
R_s^+	Maximum Reserve [MWh]	960000
R_s^-	Minimum Reserve [MWh]	300000
FC_s	Firm Capacity Coefficient [p.u.]	0.25

STORAGE: BATTERIES

Initial amount of plants: 0

BESS:		1	2	3	4	5	6	7	8
P_s^+	Maximum output production [MW]	50	50	50	50	50	50	50	50
P_s^-	Minimum output production [MW]	0	0	0	0	0	0	0	0
E_s	Pumping Efficiency [p.u.]	0.95	0.95	0.95	0.95	0.95	0.95	0.95	
R_s^+	Maximum Reserve [MWh]	200	200	200	200	200	200	200	200
Q_s^+	Maximum Consumption [MW]	50	50	50	50	50	50	50	50
N_s	Maximum number of units [#]	50	50	50	50	50	50	200	150
C_s^{INV}	Investment Cost of BESS [$/GW/y]	3,82	4	3,82	4	3,82	4	3,82	4
C_s^{INV}	Investment Cost of BESS [$/GWh/y]	15.28	16	15.28	16	15.28	16	15.28	16
FC_s	Firm Capacity Coefficient [p.u.]	0.96 for all [1-8] units							

RES: WIND

Initial amount of plants: 0

Wind:		1	2
P_r^+	Maximum output production [MW]	2900.0	2900.0
P_s^-	Minimum output production [MW]	0	0
C_s^{INV}	Investment Cost of BESS [$/GW/y]	72.64	80
C_s^{OM}	Operation & maintenance Cost [$/MWh]	2	5
FC_s	Firm Capacity Coefficient [p.u.]	0.07	0.07

RES: SOLAR

Solar:		1	2
P_r^+	Maximum output production [MW]	2000.0	2000.0
P_s^-	Minimum output production [MW]	0	0
C_s^{INV}	Investment Cost of BESS [$/GW/y]	84.47	84.47
C_s^{OM}	Operation & maintenance Cost [$/MWh]	0	0
FC_s	Firm Capacity Coefficient [p.u.]	0.14	0.14

DEMAND RESPONSE PROFILES

Now, data for a representative week is displayed for upwards and downwards variation for all 4-demand shifting responsive systems (CTs, CF, Wd; Emobility has a stable profile of 0-0.01 p.u of variation, therefore, its data is not included). Cost is included hereunder, with hourly price differentiation:

rp	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Cost	35	30	30	30	30	30	35	45	45	45	55	55	55	45	45	45	45	45	55	60	60	55	45	35

On the other hand, cost and profile for demand shedding is 400 $/MWh and 0,0025 p.u., respectively.

CTS ($t_{CTS}^{delay} = 1$):

Up [p.u.]	rp1	rp2	rp3	rp4	rp5	rp6	rp7
1	0,22	0,21	0,22	0,21	0,23	0,21	0,21
2	0,16	0,25	0,21	0,19	0,25	0,17	0,18
3	0,19	0,24	0,20	0,18	0,23	0,18	0,18
4	0,22	0,24	0,24	0,23	0,26	0,23	0,23

5	0,16	0,25	0,20	0,16	0,25	0,15	0,16
6	0,20	0,21	0,21	0,20	0,22	0,19	0,20
7	0,15	0,15	0,17	0,16	0,15	0,16	0,16
8	0,17	0,14	0,13	0,14	0,13	0,17	0,16
9	0,12	0,12	0,11	0,10	0,11	0,11	0,11
10	0,06	0,07	0,07	0,06	0,07	0,06	0,07
11	0,08	0,07	0,06	0,06	0,06	0,07	0,07
12	0,07	0,08	0,07	0,06	0,08	0,06	0,07
13	0,07	0,06	0,06	0,05	0,06	0,06	0,07
14	0,09	0,07	0,05	0,06	0,05	0,08	0,07
15	0,12	0,10	0,10	0,10	0,10	0,11	0,11
16	0,12	0,09	0,09	0,10	0,09	0,12	0,12
17	0,09	0,10	0,09	0,09	0,09	0,09	0,10
18	0,10	0,10	0,09	0,08	0,10	0,09	0,10
19	0,06	0,10	0,07	0,06	0,10	0,06	0,07
20	0,09	0,09	0,07	0,07	0,09	0,08	0,08
21	0,13	0,12	0,12	0,12	0,12	0,13	0,13
22	0,16	0,16	0,16	0,15	0,16	0,16	0,16
23	0,18	0,18	0,18	0,17	0,18	0,17	0,17
24	0,21	0,19	0,16	0,18	0,17	0,20	0,19

Down [p.u.]	rp1	rp2	rp3	rp4	rp5	rp6	rp7
1	0,22	0,28	0,25	0,25	0,29	0,23	0,23
2	0,26	0,24	0,26	0,26	0,23	0,25	0,25
3	0,19	0,30	0,22	0,18	0,30	0,18	0,19
4	0,22	0,29	0,25	0,24	0,28	0,23	0,23
5	0,25	0,27	0,24	0,24	0,26	0,24	0,24
6	0,27	0,23	0,24	0,25	0,23	0,27	0,26
7	0,27	0,24	0,21	0,24	0,22	0,26	0,25
8	0,18	0,25	0,19	0,16	0,24	0,17	0,18
9	0,24	0,24	0,22	0,24	0,23	0,25	0,24
10	0,30	0,26	0,22	0,26	0,23	0,30	0,28
11	0,28	0,29	0,28	0,28	0,28	0,28	0,27
12	0,30	0,28	0,28	0,29	0,28	0,30	0,29
13	0,30	0,28	0,29	0,29	0,28	0,30	0,29
14	0,29	0,30	0,29	0,29	0,29	0,29	0,29
15	0,27	0,20	0,24	0,26	0,21	0,27	0,27
16	0,24	0,28	0,27	0,26	0,29	0,24	0,24
17	0,27	0,25	0,22	0,26	0,24	0,26	0,26
18	0,23	0,29	0,26	0,25	0,28	0,22	0,23
19	0,28	0,30	0,29	0,29	0,30	0,28	0,28
20	0,19	0,30	0,23	0,20	0,29	0,19	0,19
21	0,25	0,20	0,21	0,23	0,18	0,24	0,24
22	0,25	0,27	0,23	0,23	0,26	0,24	0,24
23	0,20	0,29	0,23	0,19	0,28	0,19	0,19
24	0,21	0,27	0,25	0,23	0,28	0,22	0,22

CF ($t_{CF}^{delay} = 2$):

Up [p.u.]	rp1	rp2	rp3	rp4	rp5	rp6	rp7
1	0,24	0,33	0,28	0,06	0,33	0,27	0,27
2	0,28	0,35	0,28	0,05	0,32	0,35	0,34
3	0,35	0,41	0,40	0,06	0,42	0,38	0,38
4	0,39	0,39	0,38	0,05	0,41	0,34	0,34
5	0,36	0,39	0,36	0,05	0,39	0,34	0,34
6	0,35	0,33	0,34	0,05	0,34	0,36	0,36
7	0,37	0,26	0,28	0,08	0,25	0,31	0,30
8	0,32	0,16	0,19	0,11	0,14	0,26	0,25
9	0,27	0,20	0,19	0,11	0,19	0,22	0,22
10	0,23	0,18	0,17	0,13	0,17	0,19	0,19
11	0,19	0,18	0,19	0,10	0,18	0,20	0,19
12	0,20	0,18	0,17	0,13	0,18	0,15	0,15
13	0,14	0,16	0,13	0,12	0,17	0,11	0,11
14	0,11	0,18	0,19	0,14	0,19	0,19	0,19
15	0,19	0,21	0,21	0,12	0,21	0,20	0,20
16	0,20	0,23	0,23	0,11	0,23	0,22	0,22
17	0,23	0,22	0,21	0,11	0,21	0,22	0,22
18	0,22	0,16	0,21	0,10	0,17	0,19	0,20
19	0,19	0,20	0,17	0,14	0,20	0,13	0,14
20	0,13	0,18	0,12	0,14	0,17	0,09	0,10
21	0,10	0,19	0,17	0,16	0,19	0,16	0,16
22	0,16	0,18	0,20	0,15	0,17	0,21	0,20
23	0,22	0,23	0,23	0,11	0,24	0,21	0,21
24	0,20	0,29	0,29	0,11	0,29	0,29	0,28

Down [p.u.]	rp1	rp2	rp3	rp4	rp5	rp6	rp7
1	0,10	0,09	0,06	0,07	0,07	0,08	0,07
2	0,08	0,07	0,05	0,03	0,07	0,03	0,04
3	0,04	0,07	0,06	0,05	0,07	0,05	0,05
4	0,05	0,06	0,05	0,05	0,06	0,05	0,05
5	0,05	0,06	0,05	0,05	0,05	0,05	0,05
6	0,05	0,06	0,05	0,05	0,06	0,05	0,05
7	0,05	0,08	0,08	0,08	0,08	0,08	0,08
8	0,08	0,11	0,11	0,11	0,11	0,11	0,10
9	0,10	0,08	0,11	0,11	0,08	0,11	0,10
10	0,10	0,14	0,13	0,12	0,14	0,12	0,13
11	0,13	0,14	0,10	0,07	0,13	0,07	0,08
12	0,08	0,15	0,13	0,12	0,14	0,13	0,13
13	0,14	0,15	0,12	0,12	0,14	0,14	0,14
14	0,15	0,16	0,14	0,13	0,15	0,14	0,14
15	0,14	0,14	0,12	0,11	0,13	0,12	0,12

16	0,12	0,11	0,11	0,11	0,12	0,11	0,11
17	0,11	0,12	0,11	0,11	0,11	0,11	0,11
18	0,11	0,12	0,10	0,08	0,12	0,08	0,09
19	0,09	0,14	0,14	0,15	0,14	0,16	0,15
20	0,16	0,17	0,14	0,12	0,17	0,11	0,12
21	0,11	0,13	0,16	0,16	0,13	0,16	0,16
22	0,17	0,17	0,15	0,14	0,17	0,14	0,14
23	0,14	0,17	0,11	0,10	0,15	0,10	0,10
24	0,11	0,14	0,11	0,10	0,14	0,10	0,10

WD ($t_{wd}^{delay} = 6$):

Up [p.u.]	rp1	rp2	rp3	rp4	rp5	rp6	rp7
1	0,14	0,15	0,15	0,14	0,15	0,14	0,14
2	0,16	0,11	0,16	0,15	0,12	0,16	0,15
3	0,14	0,17	0,15	0,13	0,17	0,13	0,14
4	0,17	0,11	0,17	0,16	0,13	0,16	0,16
5	0,17	0,16	0,16	0,16	0,16	0,16	0,16
6	0,11	0,15	0,11	0,09	0,14	0,10	0,10
7	0,13	0,11	0,10	0,11	0,11	0,12	0,12
8	0,11	0,08	0,08	0,08	0,07	0,10	0,10
9	0,07	0,08	0,06	0,05	0,08	0,06	0,06
10	0,08	0,07	0,07	0,07	0,07	0,08	0,08
11	0,06	0,07	0,06	0,06	0,07	0,06	0,06
12	0,07	0,06	0,07	0,07	0,07	0,07	0,07
13	0,06	0,06	0,06	0,06	0,06	0,06	0,06
14	0,07	0,06	0,07	0,07	0,06	0,07	0,07
15	0,08	0,07	0,08	0,08	0,07	0,08	0,08
16	0,09	0,09	0,09	0,09	0,09	0,09	0,09
17	0,09	0,09	0,09	0,09	0,09	0,08	0,09
18	0,07	0,09	0,08	0,07	0,09	0,07	0,07
19	0,05	0,07	0,06	0,05	0,07	0,05	0,05
20	0,04	0,06	0,04	0,04	0,06	0,04	0,04
21	0,06	0,06	0,06	0,06	0,06	0,06	0,06
22	0,08	0,06	0,08	0,08	0,06	0,08	0,08
23	0,10	0,08	0,08	0,09	0,08	0,09	0,09
24	0,08	0,11	0,09	0,07	0,12	0,07	0,08

Down [p.u.]	rp1	rp2	rp3	rp4	rp5	rp6	rp7
1	0,02	0,03	0,02	0,02	0,03	0,02	0,02
2	0,01	0,02	0,01	0,01	0,02	0,01	0,01
3	0,01	0,02	0,01	0,01	0,01	0,01	0,01
4	0,01	0,01	0,01	0,01	0,01	0,01	0,01
5	0,01	0,01	0,01	0,01	0,01	0,01	0,01
6	0,01	0,01	0,01	0,01	0,01	0,01	0,01

7	0,02	0,03	0,03	0,03	0,03	0,03	0,02
8	0,04	0,04	0,04	0,04	0,04	0,04	0,04
9	0,05	0,05	0,05	0,05	0,05	0,05	0,05
10	0,05	0,05	0,05	0,05	0,05	0,05	0,05
11	0,05	0,05	0,05	0,05	0,05	0,05	0,05
12	0,04	0,06	0,05	0,05	0,06	0,04	0,05
13	0,05	0,07	0,05	0,04	0,07	0,04	0,05
14	0,05	0,07	0,06	0,05	0,07	0,05	0,05
15	0,05	0,06	0,05	0,05	0,05	0,05	0,05
16	0,02	0,04	0,03	0,03	0,04	0,02	0,03
17	0,03	0,04	0,04	0,03	0,04	0,03	0,03
18	0,05	0,05	0,05	0,05	0,05	0,05	0,05
19	0,07	0,06	0,05	0,06	0,05	0,07	0,07
20	0,08	0,08	0,07	0,07	0,08	0,07	0,07
21	0,07	0,08	0,07	0,07	0,08	0,07	0,07
22	0,06	0,07	0,06	0,06	0,07	0,06	0,06
23	0,05	0,07	0,06	0,05	0,07	0,05	0,05
24	0,04	0,05	0,04	0,04	0,05	0,04	0,04

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