THE IMPACT OF DEMAND-SIDE FLEXIBILITY ON GENERATION INVESTMENT PLANNING AND OPERATION OF THE FUTURE ELECTRIC SYSTEM

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DECLARATION

I declare that this dissertation was composed by myself, that the work contained herein is my own except where explicitly stated otherwise in the text, and that this work has not been submitted for any other degree or professional qualification except as specified.

Teresa Freire
Madrid, April 2024

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ABSTRACT

Technological advancements, environmental concerns, and political commitments are steering the electricity sector toward a transition to a renewable era. The original electricity mix is evolving to an emission-free mix; therefore, to integrate solar and wind energy efficiently, more non-pollutant solutions are needed to maintain a robust, firm, and cost-effective system.

In this context, demand-side flexibility (DSF) can play a significant role by influencing system expansion needs due to its impact on firm capacity requirements. The operation of the system would also be affected by DSF participating in balancing services and its potential contribution to managing grid constraints. The review of the state of the art of DSF, identifies a few gaps in the literature, mainly the study of DSF impact in the generation expansion planning, therefore this dissertation focuses on filling this gap considering residential and commercial DSF. Other gaps such as market design, capacity mechanism design or specific industrial DSF modeling is out of the scope of this work.

Demand assets are able to participate in the wholesale energy market, but their role is going to be unleashed when they can participate in intraday and balancing services. The role and opportunities of residential and commercial DSF in the system are analyzed in depth, to foster the development of regulatory measures that encourage DSF's full potential. Besides, social and technological barriers that should also be faced.

To address social acceptance and engagement and provide the right signals to design the best regulatory measures, this dissertation strategically emphasizes the value of DSF. It begins by highlighting the opportunities presented by flexible demand in addressing firm capacity needs. Subsequently, it delves into an analysis of DSF actively participating in balancing markets. Lastly, a cost analysis is conducted to identify the thresholds at which residential and commercial DSF becomes more, less, or not profitable.

Firstly, a comparison of operational and investment decisions is performed to analyze the impact DSF consideration can have in the firm capacity provisioning. The analysis is performed considering varying quantities of DSF availability in the Spanish system and highlighting the significance of DSF development. The security of the energy supply would be jeopardized during periods of low sun and wind availability with the renewable production quota objectives. Hence, substantial storage capacity is necessary. This analysis reveals a non-negligible impact on the firm capacity required in the system, as well as the optimal shares of wind and solar PV renewable generation when there is DSF in the system. This underscores the interconnected nature of energy infrastructure, where the introduction or absence of a specific technology can influence decisions across the energy system.

Secondly, this dissertation models the effect of demand participating in balancing services. The balancing markets are becoming more relevant due to the higher mismatch between generation and demand with high shares of renewables, as generation is harder to predict and gas turbines will gradually be removed from the system. DSF is one of the possible solutions offering these services which require fast response. Once again, the example of Spain has been used, this dissertation brings light to the priorities of the disaggregated demand categories to optimize their use and how residential and commercial demand could provide even 50% of the European Automatic Frequency Restoration Reserve (aFRR) needed in a real scenario.

Thirdly, the deployment and use of this flexible demand entail an unknown cost. Providing information on the range of investment and operational and maintenance costs associated with DSF is crucial to foster their deployment. The impact of DSF will only be a reality if the costs of its deployment are economically justified compared to those of its competitors, and the level of its deployment will depend on that cost. The dissertation incorporates the modeling to obtain a range of costs for optimizing investment and operation of the system for the different flexible demand assets.

Thus, this dissertation demonstrates that the exploitation of DSF provides multiple advantages and that diversifying options enhances the mix of electricity generation technologies analyzing their impact for the Spanish system. Firstly, in order to guarantee the security of supply of the electricity system, considering the inclusion of DSF in the system optimization, changes optimal investment in generation technology, not only in firm capacity sources but in solar and wind generation installation. Secondly, by allowing DSF participation in aFRR, the whole electric system operation can be performed at a lower cost than if there was no DSF available in the system. This is mainly due to the significant decrease in renewables curtailment by making better use of them and preventing other more expensive technologies from producing this energy. Finally, the cost range within which the residential and commercial DSF should fall to be profitable is determined. Contributing to incentivize investment as long as the costs remain within that range. Moreover, considering DSF costs has shown that, under some circumstances, can even change some regulatory recommendations, such as the additional remunerations to firm capacity sources , as these costs could leverage the firm capacity needs with the electricity market price; therefore, it is important to take them into consideration in order to advise with energy policy measures.

RESUMEN

Los avances tecnológicos, la creciente preocupación por el medioambiente y los compromisos políticos están dirigiendo al sector eléctrico hacia una era renovable. El mix de generación de electricidad está evolucionando para contar con más producción libre de emisiones; por lo tanto, para integrar eficientemente la energía solar y eólica, se necesitan más recursos no contaminantes para mantener un sistema eléctrico robusto, firme y rentable.

En este contexto, la flexibilidad de la demanda puede desempeñar un papel importante al influir en las necesidades de expansión del sistema debido a su impacto en los requisitos de capacidad firme. La operación del sistema también se vería afectada por la participación de la demanda flexible en los servicios de balance y su posible contribución a la gestión de las restricciones de la red. En el análisis del estado del arte actual de la flexibilidad de la demanda, se identifican múltiples carencias, la principal está relacionada con el estudio del impacto de contar con flexibilidad de la demanda en la planificación de la expansión del sistema eléctrico, por tanto, el enfoque principal de esta tesis se centra en abordar esta carencia, considerando la flexibilidad de la demanda residencial y comercial en la planificación de la expansión del sistema. Sin embargo, otras áreas pendientes de estudio como el diseño del mercado, el diseño del mecanismo de capacidad o el modelado específico de la flexibilidad de la demanda industrial están fuera del alcance de esta investigación.

Para abordar la aceptación y el compromiso social y proporcionar las señales correctas para diseñar las mejores medidas regulatorias, esta tesis pone en valor las oportunidades de contar con flexibilidad de la demanda en el sistema. Comienza destacando las oportunidades que ofrece la flexibilidad de la demanda para abordar las necesidades de capacidad firme. Posteriormente, profundiza en un análisis del potencial que tiene la flexibilidad de la demanda participando en mercados de balance. Por último, se realiza un análisis de costes para identificar el umbral en el que la inversión en flexibilidad de la demanda del sector residencial y comercial es rentable.

En primer lugar, se realiza una comparación de las decisiones de operación e inversión para analizar el impacto que tiene en la seguridad de suministro del sistema disponer de flexibilidad de la demanda. Para realizar este análisis se consideran diferentes cantidades de demanda flexible disponible en el sistema español y resaltando la importancia del desarrollo de la demanda flexible y sus ventajas frente a sus competidores. La seguridad del suministro de energía se vería comprometida durante períodos de baja disponibilidad de sol y viento con los objetivos de producción renovable, por lo que, se necesita una capacidad de almacenamiento sustancial. Este análisis revela un impacto relevante en la capacidad firme requerida en el sistema, así como el balance óptimo de generación renovable proveniente de energía eólica y solar cuando hay flexibilidad de la demanda en el sistema. Todo esto resalta, que el sistema eléctrico está estrechamente interconectado, por lo contar o no con una tecnología específica puede influir en las decisiones en todo el sistema energético.

En segundo lugar, esta tesis modela el efecto de la demanda participando en servicios de balance. Los mercados de balance están cobrando cada vez más relevancia debido a que los desajustes entre generación y demanda cada vez son más frecuentes por la alta penetración de energías renovables, ya que la generación es más difícil de predecir y poco a poco las turbinas de gas se irán eliminando del sistema. La flexibilidad de la demanda es una de las posibles soluciones que ofrecen estos servicios que requieren una respuesta rápida. Una vez más, utilizando el caso de España como ejemplo, con la demanda residencial y comercial desagregada en distintas categorías de consumo, esta tesis pone en valor, cómo la demanda podría proporcionar incluso el 50% de la reserva de Restauración Automática de Frecuencia (Regulación secundaria) necesaria en un escenario real.

En tercer lugar, la implementación y el uso de la demanda flexible conllevan un coste desconocido. Proporcionar información sobre el rango de costes de inversión, operación y mantenimiento asociados a la flexibilidad de la demanda es crucial para fomentar su implementación. El impacto de la flexibilidad de la demanda sólo será una realidad si los costes de su implementación están económicamente justificados en comparación con los de sus competidores, y su implementación dependerá de esos costes. Esta tesis incorpora el modelado para obtener un rango de costes para optimizar la inversión y operación del sistema para los diferentes activos de demanda flexible.

Por lo tanto, esta tesis demuestra que la explotación de la flexibilidad de la demanda proporciona múltiples ventajas y que diversificar las opciones mejora la combinación de tecnologías de generación de electricidad analizando su impacto para el sistema español. En primer lugar, para garantizar la seguridad del suministro del sistema eléctrico, considerar la inclusión de demanda flexible en la optimización del sistema, cambia la inversión óptima en tecnologías de generación, no solo respecto a las fuentes de capacidad firme sino en la proporción de instalación solar y eólica. En segundo lugar, al permitir la participación de la flexibilidad de la demanda en servicios de balance, toda la operación del sistema eléctrico puede realizarse a un coste menor que si no hubiera flexibilidad de la demanda disponible en el sistema. Esto se debe principalmente a la disminución significativa de los vertidos renovables al hacer un mejor uso de ellos y evitar que otras tecnologías más caras produzcan esta energía. Finalmente, se determina el rango de costes dentro del cual la puesta en marcha de la flexibilidad de la demanda residencial y comercial debería estar para ser rentable. Con este rango de costes, se contribuye a incentivar la inversión siempre que los costes se mantengan dentro de ese rango. Además, considerar los costes de la flexibilidad de la demanda se ha demostrado que, en algunas circunstancias, incluso puede cambiar algunas recomendaciones regulatorias, como los pagos adicionales a las fuentes de capacidad firme, ya que estos costes podrían aumentar el precio de mercado de la electricidad y así la participación de la demanda recuperar costes únicamente mediante su participación en el mercado; por lo tanto, es importante tenerlos en cuenta para asesorar con las medidas de política energética más adecuadas para cada caso.

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ABBREVIATIONS AND ACRONYMS

aFRR	Automatic Frequency Restoration Reserve
CCGT	Combined Cycle Gas Turbines
DHW	Domestic hot water
DR	Demand Response
DSF	Demand-side Flexibility
DSO	Distribution System Operator
EDF	Explicit Demand Flexibility
EV	Electric Vehicle
EVC	Equivalent variable cost
FCR	Frequency containment reserve
FRR	Frequency Restoration Reserve
H&C	Heating and cooling
IDF	Implicit Demand Flexibility
LCOE	Levelized cost of electricity
mFRR	Manual Frequency Restoration Reserve
MW	Megawatt
O&M	Operation and management
OCGT	Open Cycle Gas Turbines
RR	Replacement Reserve
ToU	Time of Use
TSO	Transmission System Operator

1

1. INTRODUCTION

This chapter explains the motivation and objectives tackled in this dissertation. The objective of this dissertation is to analyze the impact that residential and commercial demand-side flexibility can have on the electric system. For this reason, analyzing its contribution to the systems firm capacity needs, considering its participation in different markets and quantifying its costs is essential to fully understand flexible demand impact.

Technological advancements, environmental concerns, and political commitments are heading the electricity sector toward a renewable generation era. The new picture of the electric system in European countries, counts with a significant amount of solar and wind installed capacity [1,2], which implies more volatility and fewer options for adjusting generation to demand at every moment. Therefore, new ways to adjust generation and demand must be developed and implemented at the same time as the renewable generation installed capacity increases and conventional pollutant power plants are disposed of.

The adaptability of energy systems to accommodate shifts in generation and demand curves has primarily relied on flexibility sources from the generation side, such as thermal generation, cross-border interconnection, and large energy storage. However, there is a growing recognition that Demand-side Flexibility (DSF) measures can also play a significant role in meeting these system needs. First, it can influence the generation expansion planning due to its impact in the firm capacity needs. Secondly, the system operation can also benefit from DSF sources with its participation in balancing services and potential participation in solving network congestion problems. Demand Response (DR) or DSF, *means the change of electricity load by final customers from their normal or current consumption patterns in response to market signals, including in response to time-variable electricity prices or incentive payments, or in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organized market, whether alone or through aggregation*[3,4]. Therefore, in this dissertation, the terms DR and DSF will be used interchangeably to denote the same concept.

The electricity system has traditionally adapted the generation to the demand curve. However, there is now an opportunity to additionally take advantage of the existing flexible demand within the system, leveraging its potential to adapt to generation needs. This dissertation aims to delve into the interplay between DSF costs and contributions to system reliability and efficiency. Through an in-depth analysis, it seeks to provide insights into the challenges, opportunities, and potential pathways to leverage residential and commercial DSF as a cornerstone of a resilient and sustainable energy future, both in evolving energy systems transitioning to more renewable sources and in conventional energy systems.

1.1 OBJECTIVES AND METHODOLOGY

DSF is a very broad topic with many uncertainties. **The objective of this dissertation is to analyze the impact that residential and commercial DSF can have on the electricity generation mix.** This broad objective has been tackled by specifically answering these questions:

A. What are the benefits of DSF from a system perspective?
B. Does the inclusion of DSF have an impact on firm capacity requirements?
C. How does DSF behaves when balancing services are considered?
D. What are the costs associated with the DSF investment and operation?

This dissertation has conducted a comprehensive literature review to identify key weaknesses in the optimization models that need to be addressed to assess DSF impact as realistically as possible [5]. Much work has been conducted in the detailed operation of flexible demand but none from an expansion planning perspective. Moreover, most of this work assumes that shifting demand is unconstrained and entirely cost-free, overlooking potential limitations and associated expenses that may hinder its effectiveness. This dissertation focuses on residential and commercial DSF, being the methodology and approach used also valid for extending the analysis to industrial demand.

DSF must first compete effectively with all electricity market suppliers. Hence, it's essential to include a detailed representation of generation and storage technologies that are working in the system to analyze the real competence that DSF has in the market; this dissertation incorporates Hydro-Pumping storage with different capacities and associated installation costs, centralized four hours Ion-Li Batteries and different generation profiles for solar and wind technologies to represent different geographical areas. Additionally, to exploit DSF's full potential, this dissertation analyzes the different residential and commercial DSF source's participation in the European product, Automatic Frequency Restoration Reserve (aFRR), which was not previously considered when planning technology investment. Finally, DSF exploitation has associated costs; these costs need to be clarified to ascertain the investment payback period and profitability accurately; the model prepared to develop this dissertation optimizes the residential and commercial DSF investment from a system perspective, obtaining a levelized cost of electricity (LCOE) range in which DSF is profitable for each consumption category.

1.1.1 Model description

The model, hereinafter SPLODER, has been the tool used to develop this dissertation with convenient upgrades. The initial version of SPLODER was fully described in [6]. Some previous upgrades are presented in [7,8] to include policy constraints. SPLODER is a generation expansion planning tool for both centralized and distributed generation and storage resources of the electricity system.
Through input data and an optimization approach, the model obtains the optimal mix of generation and storage technologies in economic terms to meet the demand, both in terms of energy consumed and security of supply. Therefore, the objective function of the model

minimizes the cost of investments in new centralized and distributed resources and the operating cost of both these new investments and existing resources.

To be computationally efficient, a generation and storage expansion model such as SPLODER needs to simplify the simulation of the system operation. Hence, the model simplifies the system operation by considering four representative weeks of the year with hourly granularity. Each representative week has a different weight according to the number of weeks in the year it represents:

- Week 1: December, January, February.
- Week 2: March, April, October, and November.
- Week 3: May, June, July, and September.
- Week 4: August.

To adequately model the charging and discharging cycles of the storage facilities and the hydraulic production management, technologies that allow energy storage, the model follows the rule that the state of charge has to be the same at the first and at the last hour of each representative week. This is not true in the case of pumping hydro, which allows water to be stored from one week to another; otherwise, its potential would be underestimated.

To evaluate the contribution to the system firmness of the different technologies, SPLODER model incorporates an additional restriction to guarantee the system adequacy. Consequently, a set of firm coefficients are defined dependently on each technology, which strongly impacts each technology's competitiveness when deciding new investments (together with their other characteristic parameters including CAPEX, OPEX, performance rate, storage capacity, etc...).

The model classifies electricity generation by technology and electricity demand by sector (residential, commercial, and industrial). The residential and commercial sectors are also disaggregated into different consumption categories: Heating and cooling (H&C), Domestic hot water (DHW), electric vehicles (EV), lighting, and others. H&C, DHW, and EV are considered as potential flexible demand sources, and the model is prepared to assess different flexible demand penetration quantities. This dissertation develops three significant upgrades to the decribed model that enable it to answer the questions raised:

1. **Integration of storage technologies**:

New hydro-pumping storage types, with different capacities and associated costs, and large-scale centralized batteries, have enabled continuous operation and enhanced competition with flexible demand resources.

2. **Incorporation of the aFRR service with demand assets participation:**

This balancing service allows demand-side assets participation, ensuring a more comprehensive and dynamic approach to energy management benefits. The amount of energy used for each market is also revealed for the three flexible demand assets.

3. **Consideration of DR as an investment option:**

DR is now evaluated as a potential investment option, offering the model the ability to determine the optimal allocation of resources and investment considering its costs. Consequently, the thermal consumption model has been improved, as the comfort temperature range is fixed, and with the new input data, what changes is the moment when the energy is consumed to maintain the comfort temperature within the building.

The differences between the earlier version of the optimization model and the present version, incorporating all the implemented upgrades, are showcased and highlighted in Figure 1.

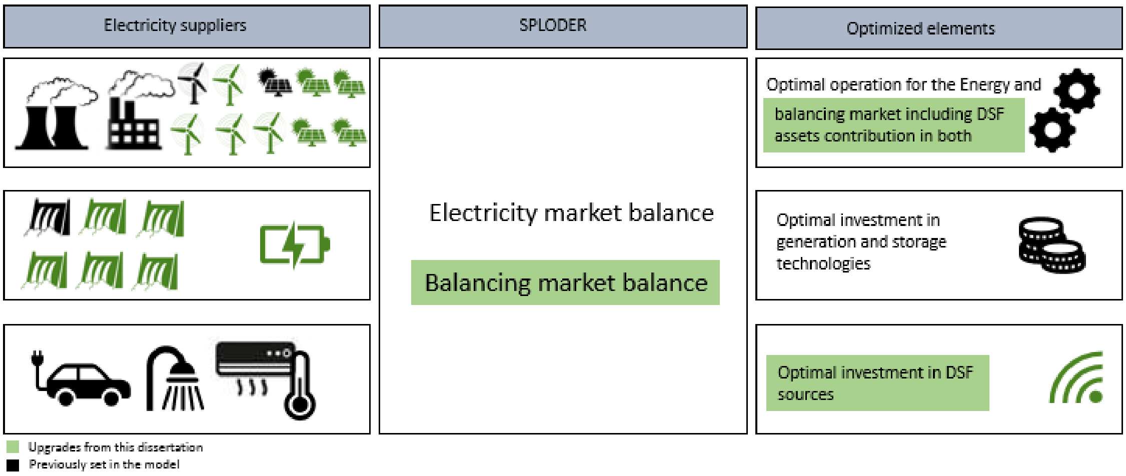

FIGURE 1 OPTIMIZATION MODEL UPGRADES WITH THIS DISSERTATION CONTRIBUTIONS

Figure 2 schematically provides an overview of the primary input data and output results of SPLODER model, distinguishing in bold type the new elements that are a result of this dissertation work and pre-existing components.

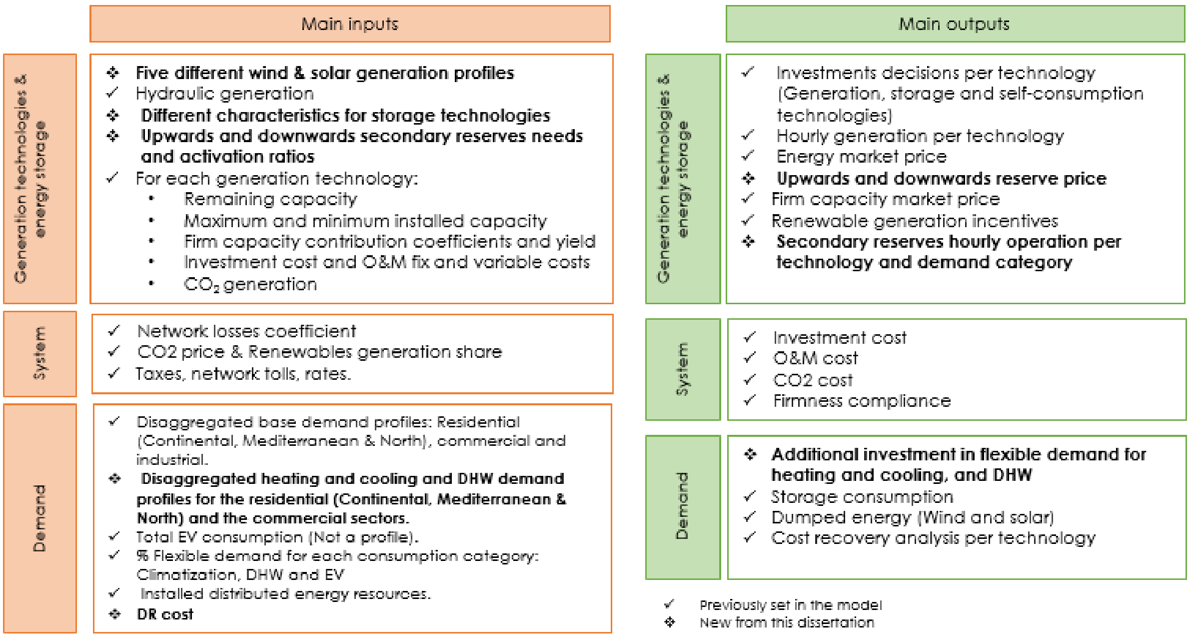

FIGURE 2 SPLODER MAIN INPUTS AND OUTPUTS

1.1.2 Model validation

Despite SPLODER's simplified time scale, the resulting generation expansion and operation of the system has been thoroughly tested against a more sophisticated model, named OpenTepes [9] with hourly granularity of the entire year.

OpenTepes, has a detailed representation of the electricity system operation, with different types of hydraulicity, different meteorological conditions, and it gathers one whole year with hourly granularity (8760 hours), which makes it reliable for studying operation issues. The objective of using the OpenTepes model has been to validate that the technological mix obtained by SPLODER is adequate and sufficient to cover the hourly needs of electricity demand, without, for example, episodes of unsupplied energy. This model sequence was used to develop projects for the industry, such as FLEXENER [10] and MODESC [11], where the results of SPLODER were validated by the detailed operation model OpenTepes, without needing specific constraints or changes.

Furthermore, industry projects, model input data, and generation expansion results have also been verified and presented in journal papers. The work presented in [12] validates certain technology firm coefficients established in SPLODER through the OpenTepes operation model, demonstrating their contribution to system firmness. However, it also suggests adjustments for other overestimated coefficients in the case of Spain. The newly corrected firm coefficients are used in paper [13], which is part of this dissertation presented as a compendium of papers.

1.2 SCIENTIFIC CONTRIBUTIONS

The scientific main contributions that this dissertation will explain throughout the document are as follows:

C1- Offering a state-of-the-art review, emphasizing diverse uses of DSF and identifying untapped opportunities.

C2- Providing a technology investment planning model able to consider demand response from 3 different consumption categories. This disaggregated demand is prepared to participate in both wholesale and reserve markets. Lastly, the model is able to optimize the amount of flexible demand for each consumption category in the system by introducing its associated investment and operation costs. The mathematical formulation is provided, and the required inputs for the methodology are described.

C3- Analyzing the impact of DSF in the firm capacity requirements in an illustrative real-world electricity system.

C4- Analyzing the impact in the generation expansion planning, when incorporating the balancing market with flexible demand participation into an illustrative real-world electricity system. The participation of DSF in the balancing market can also have an effect on how other technologies operate in the system. Besides, the model is prepared to provide information about which demand category participates the most and the effect of DR deployment in emissions.

C5- Proposing a range of DSF costs within the investment and operation of flexible demand is profitable for each aggregated demand category.

C6- Analyzing the impact of including DSF costs in the system planning and how this can affect to energy policy measures recommendations.

1.3 DISSERTATION STRUCTURE

This dissertation is presented as a collection of articles that tackle each of the tasks described in section 1.1. Each chapter builds upon the previous one to assess the impact or costs associated with integrating DSF into the system. The subsequent steps are outlined below.

The first step in this dissertation was to investigate the current state of development of DSF. Chapter 2. presents a literature review of the DSF situation and its development state in different European countries. It thoroughly explains the DSF concept and justifies its potential. This chapter also identifies the questions to be addressed in this dissertation, setting the stage for an in-depth exploration of this critical topic.

In order to address a robust analysis of DSF, its impact on the firm capacity needs should be modeled. DSF and storage technologies are competitors that directly affect the system's security of supply. Chapter **Error! Reference source not found.** focuses on analyzing the effect that c onsidering DSF has over the different storage technology options available in the system, and its impact on the capacity mix required to guarantee the security of supply of the Spanish electricity system. It aims to provide a roadmap for prudent investment decisions that are critical to ensuring a secure supply of electricity in the evolving energy landscape.

To perform a comprehensive analysis of DSF potential, it is necessary to allow different demand types to participate in balancing services. Chapter 4. includes aFRR service in the generation and expansion planning model, to explore the role that DSF can play when participating in this market and its impact in the operation and investment decisions when planning the future Spanish electricity system.

Lastly, in Chapter 5. , it is possible to determine the cost range at which DR technology becomes profitable. This estimation is complex, and the effects on the Spanish electricity system will depend strongly on it. Besides, the optimal amount of DR within the system, considering its associated costs, has also been presented within the context of the future electricity mix.

Chapters 3. 4. 5. use Spain as a reference country. Spain is considered representative due to its unique location and limited interconnection options. The Iberian Peninsula has adopted specific regulatory measures to mitigate the gas price crisis. Additionally, Spain’s favorable geography, with abundant sunlight and mountainous terrain, presents significant opportunities for renewable energy development. Therefore, some of the conclusions drawn may be influenced by the specifics of the Spanish electricity mix and the lack of interconnections.

This dissertation is structured as a compendium of papers, each of which contributes to the exploration of these specific questions.

In Table 1, the relation between the questions addressed in this dissertation, the scientific contribution, the related journal publication, and the dissertation chapter is presented.

TABLE 1 DISSERTATION CONTRIBUTIONS PUBLICATION AND DISSERTATION CHAPTER

QUESTION TACKLED	CONTRIBUTION	PUBLICATION	DISSERTATION
A	C1	Paper 1	Chapters 2 & 4
B	C2 & C3	Paper 2	Chapter 3
C	C2 & C4	Paper 3	Chapter 4
D	C2 & C5 & C6	Paper 4	Chapter 5

- Paper 1: A literature review of Explicit Demand Flexibility providing energy services. Published in Electric Power Systems Research [5]
- Paper 2: Storage and demand response contribution to firm capacity: analysis of the Spanish electricity system. Published in Energy Reports [13]
- Paper 3: System planning with demand assets in balancing markets. Published in the International Journal of Electrical Power & Energy Systems [14]
- Paper 4: Demand response cost analysis and its effect on system planning. Sent to International Journal of Electrical Power & Energy Systems[15]

Other publications that are not part of the compendium:

- Paper: Exploring the roles of storage technologies in the Spanish electricity system with high share of renewable energy. Published in Energy Reports [12]
- Technical report: Solar and wind production profiles and 2030 disaggregated electricity demand profiles to feed the SPLODER generation expansion planning model [16].
- Technical report: Análisis de la competitividad del bombeo como sistema de almacenamiento y contribución a la garantía de suministro en España en el horizonte 2030.[17]

2

2. LITERATURE REVIEW ON DEMAND-SIDE FLEXIBILITY

In this chapter, the differences between implicit and explicit DSF are detailed. It provides a DSF context and how DSF entails an opportunity for the electricity system to optimize the available resources.

Ever since the electricity system started working, generation technologies have adapted their generation to the demand curve. The increased volatility of electric systems with the expected high renewable quotas [1] is responsible for the required development of new ways to adjust generation and demand. Besides the need to increase the energy storage capability in the electric system to keep adapting generation to the consumption needs, the DSF existing in the system represents another essential source to enhance the system's capabilities.

There are two different ways of exploiting DSF potential [18] whose main difference is how the change in consumption is incentivized:

1) **Implicit Demand Flexibility (IDF)** [19] consumption decisions [19,20]. The main tools to take advantage of the implicit flexibility are the electricity tariffs [21]: ToU tariffs [22], Power-based tariffs, or Real-Time pricing [23]. All of them have a common thing: end-users see different power or energy prices during the day and are willing to consume more or less in specific periods. IDF works using price signals [24–26]. However, there is no guarantee that demand would follow those premises. Therefore, this type is used to flat the demand curve to avoid network reinforcement in the long term, but it does not provide real-time flexibility to the system as there is no commitment from the consumer point of view since end users can freely decide whether to react to these price signals or not.

2) **Explicit Demand Flexibility (EDF)** can also be referred to as incentive-based DR [12] and direct, dynamic, or active demand participation. This flexibility concept comprises committed prosumers that contemplate increasing or decreasing load or distributed generation in response to system needs, obtaining a reward or penalty for their compliance or non-compliance with their flexibility offer. In this case, the incentive can be understood as an additional payment for developing a flexibility action.

Figure 3 is a scheme to present and clarify the electric system flexibility provision. How the generation and the demand-side sources can supply the system with its flexibility needs. The scheme also gathers the different terms used when demand-side is supplying this flexibility, and the final parties involved to count with DSF in the system.

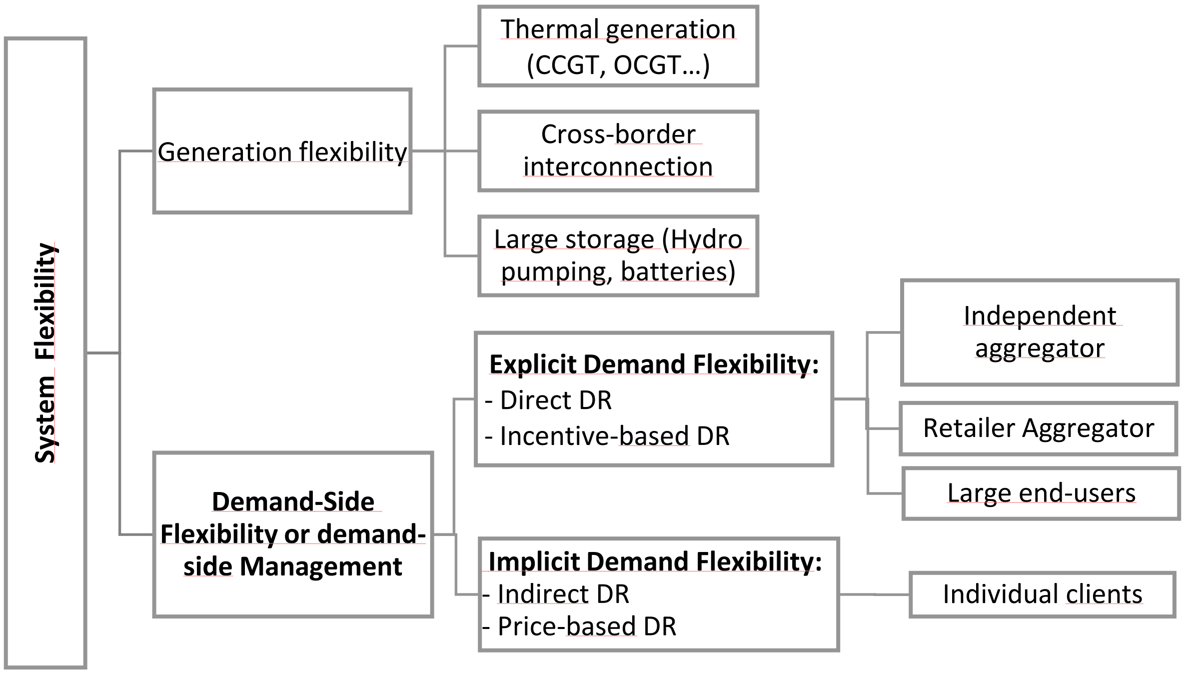

FIGURE 3 SYSTEM FLEXIBILITY SCHEME

As a result, IDF could flatten the curve and reduce expected network congestions if end users decide to follow the signal, whereas the EDF is the only one that can offer flexibility/adaptability to the system in real-time since it is the one that can participate in the markets in the same conditions than traditional generators to solve specific system needs. Therefore, chapter 4. of this dissertation is focused on the EDF type.

2.1 EDF POTENTIAL

EDF participation in balancing services has a vast potential presented in [27], which is still untapped in most European countries. Only a few countries have a high deployment of demand-side regulatory measures for participating in balancing services, such as Germany and Switzerland [28][29].

Congestion management services can also be provided by EDF, *which is committed, and refers to dispatchable flexibility that can be traded (similar to generation flexibility) on the different energy markets (wholesale, balancing, system support and reserves markets). This is usually facilitated and managed by an aggregator that can be an independent service provider or a supplier* [30]. Multiple models are being developed so that the distribution system operator (DSO) can take advantage of DSF to solve its own congestion problems. Some countries that are doing this are the Netherlands, Belgium, Germany, Denmark, Ireland, Norway, France, and recently Spain [31].

To fully exploit EDF potential, technological advances, and social approval are required before facing regulatory barriers [4]. Hence, in order to increase the potential of EDF, the following actions should be taken first:

- Remote control of the demand should be developed with equipment that allows measuring asset consumption. Facing sub-metering challenges [32]and very fast granularities for data control, it needs to be implemented together with the deployment of smart equipment and submetering options.
- Larger quantities of demand (electrification) are needed to make it manageable and worthy of preparing regulatory measures.
- Social acceptance and normalization of contributing to this matter by investing in electrical devices and making flexible consumption available to an aggregator.
- Prepare the network to allow bidirectional power flows in order to take advantage of the increase in DER installation.

Subsequently, renovating regulatory measures is required in almost all countries to enable and foster EDF participation in balancing and congestion services, considering the guidelines that can be found in [33]. The main regulatory barriers that prevent its inclusion could be handled by modifying the following three regulation blocks [20]:

- **The standardization of the different products allowing EDF participation**: This means that prequalification, measurement, and verification protocols must be clearly defined for each service. Also, payment and penalty criteria should be based on open and fair competition. Besides, a baseline consumption calculation method should be stated, which estimates what an end-user would have consumed if EDF had not been used [34]. This methodology needs to be developed so that consumers can be paid for what they provide. Lastly, clarifying service prioritization rules and where demand flexibility will be more valued will facilitate investment decisions [35].
- **Aggregators allowance**: Member States must define roles and responsibilities around aggregation providers. Relationships between retailers, BRPs, and IAs should be clarified and, again, search for fair competition. Well-defined standard procedures by the regulator and Transmission System Operator (TSO) are important to protect the financial interests of all parties [20]. Hence, to manage the access to data from the different entities fairly, a process reform is required [35]. To guarantee security in this data exchange, cyber-security protocols should also be developed [35].
- **Adjust technical requirements in line with participants' capabilities**: It is important to play in a competitive framework and hold auctions in a transparent manner. Hence, strong and traditional requirements for market parties need to evolve. For instance, the bidding size requirement should be small enough to allow new entrants such as EDF and IA [36]. The duration of the call should be as short as the technical requirements of markets allow. Availability of the offer may change according to specific necessities [37], always trying to keep it as small as possible. Moreover, the frequency of activations/short recovery periods should be reasonable as some participants need time to rest between activations. Lastly, asymmetrical bids should be allowed to foster some new technology integration in the market [20].

To incentivize the different countries to move towards solving these barriers, this dissertation presents in detail some benefits and the impact of developing EDF.

A more detailed literature review of EDF and the identification of this gap in the literature is presented and justified in the publication part of this dissertation compendium:

- Paper 1: A literature review of Explicit Demand Flexibility providing energy services. Published in Electric Power Systems Research [5]

It can be cited as:

T. Freire-Barceló, F. Martín-Martínez, Á. Sánchez-Miralles, A literature review of Explicit Demand Flexibility providing energy services, Electric Power Systems Research. 209 (2022). https://doi.org/10.1016/j.epsr.2022.107953.

3

3. DEMAND-SIDE FLEXIBILITY CONTRIBUTION TO SYSTEM'S FIRM CAPACITY

Investment in pumping-hydro storage and ion-Li batteries are the alternative and they are the main competitors of DSF in the system. DSF contribution to firm capacity, refers to its ability to shift energy usage across different time periods where the system has generation limitations. This chapter includes these competitors in the model and justifies the benefits of counting with DSF in the system.

The rise in installed renewable generation capacity increases the variability and instability issues within the electrical system. Additionally, the disposal of conventional generation sources that have traditionally supplied energy during wind and sun scarcity periods requires new sources of firm capacity to guarantee the security of supply of the power system and also to integrate renewables efficiently without overcrowding the landscape with unnecessary wind turbines or covering rooftops with excessive solar PV panels. This is where EDF adds value to the electricity system by reducing peak demand and, consequently, the firm capacity needs.

The industrial sector's available flexibility has been thoroughly studied [38][22] and it is already providing energy services [39][40]. However, consumption in the residential and commercial sectors is where DSF is most underutilized and where its exploitation presents the most opportunities[41][42][43]. This dissertation assesses the impact of aggregating demand in the residential and commercial sectors, which has not traditionally been economically viable [41]. However, European grants for electrification in these sectors [44], come with an increase in customers flexibility potential and hence, profitability. In particular, Spain has developed measures to incentivize electrification for heating and cooling services [45] and for overland transportation[44][46]. Furthermore, technological advances facilitate the remote controllability of end-use energy demand to be able to participate in electricity system services [47].

DSF can involve different sources and technologies, such as distributed solar PV generation and battery storage. The deployment effect of these two technologies has been thoroughly studied as flexible sources, with the aim of justifying the need for investment in distributed solar PV [48][49] and distributed batteries [50], although batteries are still not competitive. In this dissertation, distributed solar PV generation capacity has been pre-installed, and distributed batteries have been modeled, although neither are considered when referring to flexible demand sources, as done in [38]. The focus of these analyses is on the potential flexible demand available from consumption in the residential and commercial sectors. This includes the categorization of H&C, DHW, and EV chargers, each with its respective constraints related to external temperature and plugged-in times for EVs. Modeling them all at the same time, considering their appropriate usage constraints is an aspect that has been studied less in the existing literature. There are models that focus on one or two of these demand sources [51–53] or consider them all as aggregated loads [54,55]. These studies [16–18] achieve a cost reduction of between 15% and 21%. When analyzing Europe as a whole, total system costs can be reduced by 17%[56]. Furthermore, 30% savings are estimated for the Spanish system when modeling flexibility as 8% of the total demand without considering special constraints for the use of this flexibility [57].

This chapter of the dissertation demonstrates that EDF has a non-negligible impact on the system firm capacity requirements and, therefore, in its generation investment decisions. Paper 2, part of this dissertation compendium [13] analyzes the competitiveness and role of battery storage, six types of pumped-hydro storage, OCGT, and demand-side response technology in providing the firm capacity required to ensure the security of supply of a real-size system such as the Spanish system in a 2030 horizon.

Furthermore, the mathematical formulation presented in [6] and [7] considers disaggregated demand suitable for limiting the amount that can be shifted and obtaining a better estimation of DR capabilities. This formulation has been accordingly upgraded to enable the SPLODER model to analyze the contribution of DR, the different storage alternatives, and other technologies to firm capacity requirements for the electricity system.

3.1 KEY FINDINGS

The results highlight the importance of considering demand response when evaluating long-term firm capacity requirements, showing a non-negligible impact on investment decisions regarding the amount of firm capacity required in the system and the optimal shares of wind and solar PV renewable generation. The compliance with firm capacity requirements has been verified using another model with hourly representation of the operation, as presented in [12]. However, this assessment is out of the scope of this dissertation. Results also show the dominance of cost-competitiveness of pumped hydro and OCGTs over batteries. Additionally, capacity payments are required to support firm capacity providers' investments.

The main findings driven by a Spanish-like system are:

1. DR decreases firm capacity requirements in the system, replacing short-duration pumped hydro storage and OCGT investment. Neglecting DR in long-term analyses could lead to biased investment decisions or recommended policy measures. Besides, DR fosters solar generation over wind generation, due to its capacity to move consumption to solar generation hours.
2. Large pumped hydro with storage capacity is a very competitive choice to provide system firm capacity. They are more competitive than OCGTs and batteries based on the data used, even for extremely high reductions in battery installation costs (85%).
3. Ion-Li batteries are far from being competitive enough to provide firm capacity to the system as their storage time is not enough to face longer episodes of renewable production scarcity in the system. Pumped-hydro storage, OCGTS, and DR are far more competitive than batteries for the Spanish case study.
4. The competitiveness among different technological options to provide firm capacity to the system depends mainly on the ratio (investment cost/Firmness Coefficient). The value of the firm coefficient assigned to each technology depends on the specific power

system analyzed. The most promising firm capacity providers at this stage for the Spanish system are pumped-hydro storages. Nevertheless, OCGTs would produce very little electricity, with their primary role being to provide firm capacity. The firm capacity providers' preferences for a similar electricity generation mix to the Spanish one, are presented in Figure 4.

5. The technologies selected to provide firm capacity also have an impact on the renewable generation mix. DR and storage-based technologies favor solar PV over wind since solar PV is cheaper but produces only in mid-day hours. On the contrary, OCGT favors wind over solar PV.
6. CO_2 emission rights and natural gas prices have a combined impact when planning generation investments. This combined effect is related to the equivalent variable cost (EVC) of the technologies that require CO_2 emission rights or gas for their operation (OCGT and CCGT). EVC integrates into a single production cost per technology the actual impact of both the gas and CO_2 emission allowance prices.
   - The higher the EVC, the better it is to invest in renewables, leading to a reduction of CO_2 emissions, although the higher the electricity price becomes. Therefore, there is a heavy dependence between electricity prices and CO_2 and natural gas prices.
   - There is a turning point in which the increase in EVC would lead to a rise in electricity prices not comparable to the renewable ratio growth.
7. Results show the relevance of capacity payments to ensure the investments meet the system firm capacity requirements, that is, to ensure maintaining reasonable levels of security of supply. Incomes from the energy market do not allow for full recovery costs with the data used for this analysis.

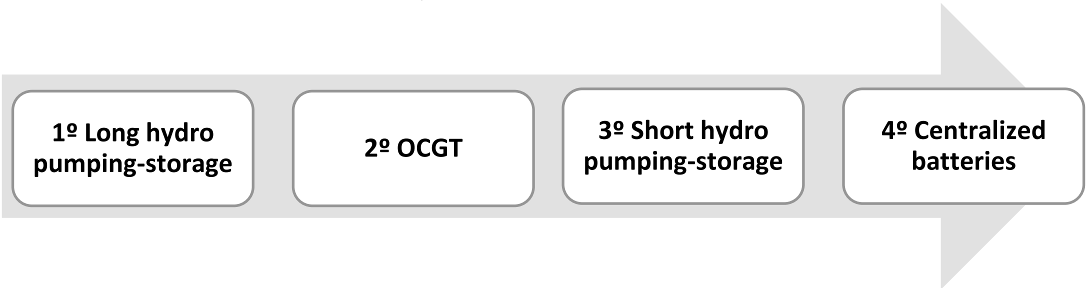

FIGURE 4 FIRM CAPACITY PROVIDERS RANKING.

The paper where this discussion is tackled is part of this dissertation compendium.

- Paper 2: Storage and demand response contribution to firm capacity: analysis of the Spanish electricity system. Published in Energy Reports [13]

It can be cited as:

T. Freire-Barceló, F. Martín-Martínez, Á. Sánchez-Miralles, M. Rivier, T.G.S. Román, S. Huclin, J.P.C. Ávila, A. Ramos, Storage and demand response contribution to firm capacity: analysis of the Spanish electricity system, Energy Reports. 8 (2022) 10546–10560. https://doi.org/10.1016/j.egyr.2022.08.014.

4

4. DEMAND-SIDE FLEXIBILITY WITH BALANCING SERVICES

The participation of demand in markets like intraday or balancing services is an opportunity. The impact that demand assets participation in balancing services have on investment planning and operation of the electric system, have been studied in this chapter.

The participation of flexible demand in the wholesale market has already been studied and deployed [58][59][28], somehow affecting the spot price[60][61]. Recent work [62][63] has proven a high potential of demand participating in balancing services using their EDF capability. Thus, a full deployment of DR, also in the industrial sector, could lead to significant balancing savings for Europe, between 43% and 66% of balancing costs, depending on the country and the balancing capacity needs [64]. Therefore, this dissertation incorporates DSF participation in balancing services since its current implementation in European countries is still very small [39] [65] [66] [67].

Diverse services can be part of balancing services, attending to the characteristics of activation and response time. However, although they are referred differently around Europe, the four main balancing services are common in many countries. These four balancing services are explained in detail, and how demand participation could add value to the services:

- Frequency containment reserve (FCR): Primary reserves respond rapidly (within milliseconds), usually in an automated way, against frequency deviations in the grid. This fact is why only thermal power plants have traditionally supplied FCR. However, there are several types of loads (Electric heaters, heat pumps, EV…) that are prepared to supply this service, although the fast ramp rate and the frequency of activation and shortages still make it difficult for EDF to participate [23]. Remuneration can be capacity-based, activation-based, or a combination of both of them or not remunerated when it is a mandatory service for generators [68].

- Frequency Restoration Reserve (FRR): it is the second step in the case that frequency has not returned within the agreed threshold 30 seconds after the disturbance. The aim of FRR service is to replace FCR to release the capacity needed by the primary control and to restore the primary control reserves. Remuneration can be capacity-based, energy-based, or a combination of both, and can be pay-as-bid (remunerated at the offered Price) or pay-as-cleared (price determined for each hour by the intersection of the demand and supply curves) [68]. Activation time is required to respond between 30 seconds to 15 minutes after the disturbance [69].

- Automatic Frequency Restoration Reserve (aFRR): Automatic service activated between 30 seconds and 15 minutes after the disturbance by the load frequency controller of the TSO.

- Manual Frequency Restoration Reserve (mFRR): After the aFRR service, since it has a slower ramp rate, it can last longer. This service is activated manually and operates in a continuous manner to recover aFRR reserves after the frequency has been restored [18].

EDF has a high potential to participate in these services, but product requirements still need to evolve, allowing aggregation, smaller minimum bids, and asymmetrical bids [29].

- Replacement Reserve (RR): the service replaces the previously activated reserves (aFRR or mFRR) to return to full operation with the availability of reserves and be prepared to respond to another failure in the grid. RR has a longer duration and slower ramp rate than the previous frequency restoration services. Activation needs to last from 15 minutes up to two hours, and it must be manually or semi-automatically activated [69]. RR long-lasting activation periods are a barrier to EDF participation as long as aggregation is not permitted. Remuneration can be according to terms of energy provided or a mix of the energy supplied and available capacity [18].

There is a desire to increase harmonization in European countries, balancing services regulation and products. The more regulatory measures are unified, the easier it becomes to extend the markets internationally, reaching a more efficient system.

The progress in adapting some national balancing services to integrate demand resources has been limited. Differences in existing legislation and regulatory frameworks make it difficult for some countries to cooperate on a common electricity market [69]. However, there are some countries with extensive adoption of demand inclusion regulatory measures where demand is actively participating, such as Germany and Switzerland. Table 2 provides a summary of EDF's participation in EU countries across each balancing service. This information has been updated based on the developments made by each country since the data presented in paper [5] with most recent data from [70].

TABLE 2 EU COUNTRIES BALANCING SERVICES OPENNESS TO DEMAND PARTICIPATION

Demand participation	FCR	aFRR	mFRR	RR
Austria	YES	YES	YES	N/A
Belgium	YES. Load upwards	YES	YES	N/A
Germany	YES	YES	YES	N/A
Denmark	YES	YES	YES	N/A
Finland	YES	YES	YES	N/A
France	YES	NO. PICASSO project.	YES	YES
Ireland	YES	YES. Only industrial customers	YES. Only industrial customers	NO
Netherlands	YES	YES	YES	N/A
Sweden	YES	YES	YES	YES
UK	YES	Doesn't exist	YES	N/A

Poland	NO	NO	NO	NO
Spain	NO	YES	YES	YES
Italy	NO	YES	YES	YES
Switzerland	YES	YES	YES	YES

In the Spanish electricity system, balancing services include secondary and tertiary regulation services. On the one hand, secondary regulation refers to a voluntary service designed to maintain the generation-demand balance, automatically correcting deviations concerning the planned exchange program and deviations in system frequency. Its time horizon ranges from 20 seconds to 15 minutes. This service is remunerated through market mechanisms for two concepts: availability and net utilization. Secondary regulation energy corresponds to the standard European product of aFRR [71]. On the other hand, for tertiary reserves, it is mandatory to increase and decrease the available capacity, taking into account the availability of the primary energy source. This service is managed and remunerated through market mechanisms. Its main purpose is to resolve deviations between generation and consumption and restore the secondary regulation reserve after 15 minutes. The tertiary regulation reserve corresponds to the European standard product mFRR [71]. Each model must specify what they are referring to when modeling these services and indicate if the up and down distinction is considered. For this dissertation, balancing services will refer only to aFRR service with up and down considered separately.

The modeling of DSF participation in the aFRR service, considering a system-wide view of behind-the-meter assets in the residential and commercial sectors, has not been thoroughly explored. Therefore, this dissertation contributes to a generation and storage expansion planning model, conveniently upgraded to allow flexible demand participation in both wholesale and balancing services, constraining the different demand assets to better represent their consumption nature.

A review of the current state of the art has been conducted, analyzing whether prior studies have introduced an optimization model that comprehensively considers, from a system perspective, the integration of balancing services with DSF participation. This includes the incorporation of various demand sources, each with its own limitations, to avoid overestimation of DR potential. The assessment also determines DR costs and compensations to evaluate its competitiveness against other options. Table 4 highlights that this holistic analysis has not been previously undertaken. All the models presented in Table 3 include DSF integration in balancing services, though [54] and [72] include both EDF and IDF. Although, flexibility is primarily used for upward reserve in [73] and other authors prove that the main use of DR is in the wholesale market rather than for balancing energy in [65].

TABLE 3 OPTIMIZATION MODELS WITH DSF PARTICIPATION IN BALANCING SERVICES

Source	Energy market	Balancing services are specified			Storage is modeled	EDF sources are disaggregated			EDF limited	Payment/ remuneration for flexibility	System perspective	
		FCR	FRR	RR		H&C	DHW	EV			OPER	INV
[51]	Yes	No	Yes	No	No	No	No	Yes	No	Yes	No	
[52]	Yes	~			No	No	No	Yes	No	Yes	No	
[54]	Yes	~			No	~			No	No	Yes	No
[72]	Yes	Yes	Yes	No	No	~			No	No	Yes	No
[74]	Yes	No	Yes	Yes	Yes	Yes	Yes	No	Yes	No	Yes	No
[75]	No	~			No	No	Yes	No	No	No	Yes	No
[73]	Yes	No	Yes	No	No	~			No	Yes	No	
[76]	Yes	No	Yes	No	No	~			Yes	Yes	Yes	No
[77]	Yes	~			No	Yes	Yes	No	Yes	No	No	
[78]	Yes	Yes	Yes	No	No	~			No	No	Yes	No
[79]	Yes	Yes	Yes	Yes	No	~			No	No	No	
[80]	No	~			No	~			No	Yes	Yes	No
[81]	Yes	No	Yes	No	No	Yes	No	Yes	Yes	Yes	No	
[82]	Yes	No	No	Yes	No	Yes	Yes	Yes	Yes	No	No	
[83]	Yes	~			Yes	~			No	No	No	
[84]	Yes	~			Yes	~			No	Yes	No	
[85]	Yes	~			No	~			Yes	Yes	No	
[86]	No	~			Yes	~			Yes	No	No	
[87]	No	Yes	No	No	No	Yes	Yes	No	Yes	Yes	No	
[88]	No	~			No	No	Yes	No	Yes	No	No	
This Dissertation	**Yes**	**No**	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

~ Not specified

4.1 MODEL

This dissertation added to the SPLODER model the balancing service provision, allowing different flexible demand assets with their limitations to provide this balancing service. The mathematical formulation of the balancing service could be stochastic or deterministic. The necessary input data for both formulations are the same; consequently, the only thing that changes is the equations determined. In the stochastic approach [74,81,82,89,90], variables and parameters would have been reused for the new model, adding only an additional set solve each equation for wholesale and upward and downward balancing service.

In this dissertation, the deterministic approach has been modeled by including additional variables and parameters to consider the increase and decrease in generation or demand due to the aFRR service. The wholesale and balancing markets are not modeled sequentially, and the energy required for both markets is known in advance and optimized accordingly. Hence, system operation results can be over-optimized, showing better performance than what would be achievable in real-world conditions. However, the wholesale market balance equation does not consider the contribution of different technologies to the balancing services. Therefore, its dual variable represents the wholesale price, independent of the technologies' contributions to balancing. This means that the activation balance equations for balancing services have a different dual price from the wholesale price because the balancing provider can differ from the marginal technology used in the wholesale market. With this procedure, the previous wholesale market is only affected by the new balancing service provision solution with the status of the storage technologies [12,55,83].

SPLODER model is now prepared to assess different flexible demand penetration quantities. The model outputs facilitate a comparison of the flexible demand operation of H&C, DHW, and EVs to understand how their flexibility interacts with the electric power system. Although more flexible demand categories could have been considered, such as refrigeration and compressed air, they were not introduced to enhance the understanding of the model.

All model developments are optional, given that many of them rely on specific input data that may not always be accessible. Consequently, the model is designed to run a simplified version when the required data is unavailable. As a consequence of modeling this, the thermal model has been improved.

4.2 KEY FINDINGS

This study analyzes the impact of incorporating balancing services into operational and investment decisions when planning the future electricity system, using the Spanish electricity system as a reference. Additionally, the role of DR and its effects when participating in the energy and aFRR service, have been assessed, leading to certain conclusions.

This work proves that there is a difference between whether or not the aFRR service is considered for system operation CCGT and hydroelectric technologies, reduce their generation in the energy market in order to have more available energy to provide upward reserves. In contrast, pumping storage increases its generation and reduces its consumption for the energy market in order to provide more downward reserve. Regarding CO_2 emissions, their decrease is not directly related to a decrease in curtailment needs or an increase in DR available in the system. The reduction of CO_2 emissions implies an increase in total system costs. Therefore, in the case where lowering CO_2 emissions was the target, an additional constraint should be taken into consideration to optimize investment and operation from that perspective instead of from the cost minimization point of view. Conversely, investment decisions about generation technologies do not change due to considering or not considering balancing services in the system, as this service represents only 1% of total energy supply needs.

Furthermore, this work also demonstrates that demand participation in balancing services has a relevant role. Although the percentage of DSF used for aFRR service provision is low compared to wholesale use, more than 50% of total energy needs for this service could be met with demand assets. Results show that H&C is the category that provides the majority of energy in reserves due to its larger energy presence in the system. However, results also reflect that the two other categories, DHW and EV, offer more relative flexibility. This is because their demand has fewer shifting constraints, whereas H&C is limited by outdoor temperatures and indoor comfort maintenance, which constrains the possibilities of shifting demand.

Finally, DR participating in the energy and aFRR service would be responsible for savings of 5% in the total electricity system costs when generation technologies investment is not considered. If DR availability was considered before technology investments were decided, up to 12% of total system costs could be saved with a high penetration of DR (60% of its total potential), although CO_2 emissions increase by 95%. The investment cost avoidance is so significant that it makes comparing the cost of emissions negligible. However, when considered on a unitary basis, the two curves converge between 20-40% of DR. Therefore, the decision between desired savings and emissions could establishes a trade-off point within this 20-40% DR range. Due to the use limitations established for the different flexibility sources, the estimated total system savings are below what the literature forecasts (between 15-30%).

Different scenarios have been defined to assess the role of these demand assets providing aFRR service and their impact on generation and storage investment planning and on electricity system costs and emissions using the Spanish system as a reference. All the analysis and the resulting numbers presented are justified and extensively explained in the research paper entitled Assessing Demand Response Participation in Wholesale and Balancing Markets, which corresponds with paper 3 of this dissertation compendium.

- Paper 3: System planning with demand assets in balancing markets. Published in the International Journal of Electrical Power & Energy Systems [14]

It can be cited as:

T. Freire-Barceló, F. Martín-Martínez, Á. Sánchez-Miralles, System planning with demand assets in balancing markets, International Journal of Electrical Power & Energy Systems 156 (2024) 109747. https://doi.org/10.1016/j.ijepes.2023.109747.

5

5. EFFECTS OF CONSIDERING DEMAND-SIDE FLEXIBILITY COSTS

Analyzing the costs associated to DSF investment and operation is challenging due to its complex and unique nature, its operation involves various new remunerated parties such as final consumers and aggregators, therefore costs allocation is not straightforward.. This chapter will try to determine the range of DSF associated costs and the consequences of considering them.

Existing studies have emphasized the importance of DSF in enhancing grid resilience and reducing system costs [64][67][91][14]. However, while the sustainable nature and the theoretical prospects of demand flexibility are compelling, a critical gap exists in understanding the costs related to its implementation.

Some studies obtain the savings that DSF can achieve with an specific application. However, those savings neglect DSF costs and, therefore, are overestimated. Moreover, these studies establish a fixed amount of DSF available in the system [86][87] [57]. This study [92] estimates the system savings with DR by 2050 for the UK, obtaining that these savings come from network development (60%), from fuel needs (24%), and from peaking plant investment (16%). This study [67] compares the different uses of DR separately within the German context, concluding that using DR for load shifting is where the most significant economic opportunities are obtained, achieving 2,83% of operational savings. However, it does not mention which are the associated DR costs. The Belgium electricity system has also been analyzed [74] to quantify the operation savings on the day ahead market with DR available from residential heating. With this limitation, only 6-7% of operation savings are achieved. The approach presented in [91] focuses on estimating the benefits of DR for the UK, emphasizing the quantification of economic welfare. It also reviews related literature on DR costs and benefits. However, most existing studies primarily highlight the economic benefits, with limited references that mention costs, and when costs are considered usually only a qualitative allocation of them is given [93]. The analysis presented in [94] explores diverse interaction methods among energy producers, aggregators, and users when there is DR in the system, determining the most advantageous approach that maximizes benefits for all parties involved. Although the study estimates the operational benefits of using DR, the associated costs are not mentioned as they are difficult to obtain.

Another branch of studies estimates the willingness of consumers to invest in new electric equipment in order to participate in DSF services. This could be the cost associated with DR equipment and services that a user is willing to pay/receive. According to [95] heating and electric appliances have a higher consumers' willingness to enroll than EVs. Besides, consumers preferred financial incentives to environmental incentives. However, existing incentives are still not enough to foster the electrification [96] [97]. These studies are performed with final consumers surveys, and the results only involve the end-user's perspective, providing qualitative recommendations without considering the effect on the system.

Other studies compare the system costs with and without DSF in the system. However, they do not specify who the DR providers are and what their costs are. Results in [98] reflect that system investment costs increase while operating costs decrease when there is DSF because the full cost of the equipment, such as the heat pumps, is considered, which is the opposite of what most studies argue [91]. However, assigning all the costs of the appliance for DR purposes is not representative since the installation of appliances does not mean their availability for DR. On the contrary, reference [14] concludes that DSF decreases system investment costs, mainly from storage technologies avoided investment, instead DSF increases system operating costs, since the system makes better use of the old available power plants.

The potential benefits of a full deployment of DSF for the whole EU by 2030 are quantified in [64]. The study intends to inform policymakers on the most cost-efficient pathway for both the energy system and consumers. Large-scale numbers for the entire EU are presented without offering specific details for individual countries. For instance, a total investment cost of 120 €/MW per year for DSF is provided.

This dissertation works with two separated costs for DSF; one is considered fixed, the investment cost and the other is a variable cost as it depends on the amount of flexibility used, which is the operation and management (O&M) cost. The expenses that these costs should recover, and therefore, each involved party should define its financial strategy to be sustainable include, from the system perspective:

1) The smart meter investment and maintenance (it does not include the individual devices such as the heat pump or EV) [99]
2) Customer service, information, control center, communication system and cloud costs [93]. This is related to the operation of the devices.
3) Minimum end-user and Aggregator remuneration. The user will change their normal behavior due to an economic incentive. This end user remuneration should be greater than the value of the loss of comfort due to the external control of their devices and, it will have a minimum value that will mean the willingness to participate in these DSF programs.

5.1 MODEL

Up to now, the system's quantity of DR for each demand category was an input to the model as a percentage of the total consumption. However, this dissertation contributes to optimizing this quantity through appropriate upgrades and necessary input data. The model now treats the DR as another available technology in the system to optimize its investment for H&C, DHW, and EV categories, providing the result again as a percentage of the total consumption for each demand category. To enable the model to do this, H&C and DHW consumption input profiles are needed and have been gathered from [16]. The changes and enhancements developed results in a double-step model to avoid non-linearities in the heating consumption. H&C consumption category consumes more efficiently when its consumption is flexible, thus changing the total energy consumed for H&C. The thermal model considers the comfort temperature inside a representative building to decide whether to consume or not, then, this consumption is scaled to the system level considering the number of buildings and the percentage of DR. When the percentage is a variable and not an input, two variables are multiplied, the representative consumption and the percentage, therefore, the problem becomes non-linear. On the contrary, DHW and smart EVs' energy consumption is the same no matter how flexible it is; this is because the rebound effect is considered in the problem (the energy shifts from one period to other) . This means that the total energy is equal between flexible or fixed profiles and everything keep linear if DR percentage are included as variable.

Therefore, the sequence of a two-step model is only required for the H&C consumption category to avoid nonlinearities in the formulation. The first step (Problem A) uses the consumption input profiles to build an 'ideal' consumption profile, assuming all H&C demand was completely flexible. Subsequently, in the second step (Problem B), considering the DR investment cost, this 'ideal' profile is employed to determine the feasibility of investing in DR. The investment in flexible DHW and smart EVs are both decided in the second step, which is where the model has the global picture of the available resources and their individual constraints to optimize their investment. These two steps of the formulation are summarized in Figure 5. This approach prevents an overestimation of DR potential and its role within the system.

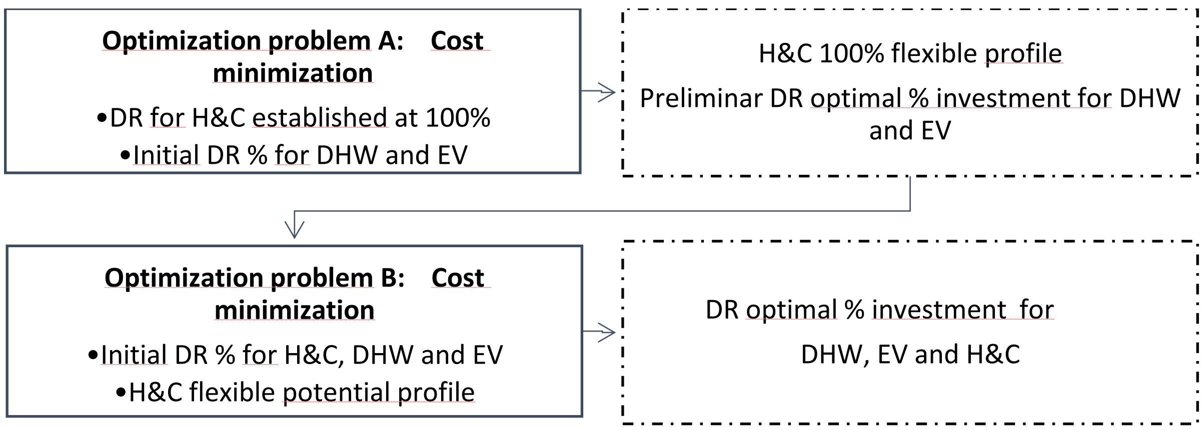

FIGURE 5 DOUBLE-STEP MODEL SEQUENCE

5.2 KEY FINDINGS

The latest version of the presented model is able to optimize the quantity of DR for various consumption categories with flexibility potential (H&C, DHW, and EV). Traditionally, the literature has treated DR as an input without delving into its potential optimization across different consumption categories.

With the different scenarios conducted, the range of investment and O&M costs for DSF from the different consumption categories at which DR has a positive business case are obtained. The ranges for the three flexible demand sources available are presented in Table 4. The model used performs its own cost distribution between investment and O&M costs. Hence, using the equivalent operating hours of each flexible demand category, obtained as the energy consumed divided by the installed capacity, the Levelized Cost of Electricity (LCOE) has been calculated to compare cases. This cost measures the average net present cost of electricity provision for a electricity provider over its lifetime, taking into account all the costs involved, including capital, operation and maintenance, as the cost distribution depends only on the particular business strategy. The LCOE is also presented in Table 4 for the three consumption categories. From comparing the LCOE for the different DSF sources with the used data, it can be concluded that H&C is the most restrictive technology, as it requires lower costs to achieve a positive business case, followed by DHW and finally the EV flexibility is the one that has wider cost range while still profitable.

TABLE 4 BOUNDARY INVESTMENT AND OPERATION COSTS FOR DISAGGREGATED DEMAND CATEGORIES

	INVESTMENT COST RANGE [€/MW/Year]		*O&M COST RANGE [€/MWh]*		*LCOE [€/MWh]*
H&C	0	43,540	0	80	100
DHW	0	35,720	0	100	120
EV	0	24,320	0	100	140

These results have been validated through comparison with existing literature presented in Table 5, proving that previous work remains within the estimated range. The huge variability in the different references derive from lack of real data and accumulative different assumptions, however, the units and concept presented in Table 5 are unified. With this range, possible investors and interested entities can work on their own business cases and decide where to allocate the different costs and how much it is worth to invest in DR deployment.

TABLE 5 DR COST RANGE CONTRASTS WITH THE LITERATURE

Reference	Investment cost [€/MW/Year]	O&M costs [€/MWh]
[64]	120-45,500	-
[87]	-	23.5
[100]	37,200	-
[101]	-	10
[102]	-	20
[103]	-	1.3
This dissertation	**43,540**	**100**

The impact of considering DR costs has been assessed by comparing two cases with and without DR costs. When DR is free, additional payments of 51.5 €/kW are required to guarantee the firm capacity required. This means that technologies that provide firm capacity, such as storage, do not recover their investment with their operation due to the decrease in the average electricity market price, when DR investment and operation associated costs are neglected in the system. On the other hand, the increased storage investment due to the consideration of DR costs and the higher average market price is enough to satisfy firm capacity needs. Thus, considering DR costs is key to making policy recommendations about additional payment needs since previous studies as the results of chapter 3. have raised the need for capacity payments that seem to be unnecessary if DR is present in the system.

The average market price in these cases is 40,9 €/MWh, which is lower than the average annual spot market prices over the last years in Spain, which is 48,2 €/MWh if years 2014 to 2019 are considered [104], and it boosts to 68,9€/MWh if years from 2020 to 2023 are also considered due to the multiple extraordinary events experienced in Europe (Pandemic and Ukraine-Russia conflict). This suggests that, in a market with prices similar to those in Spain, the DSF investment is justified, as DSF market participation would help to recover the expenses sooner.

The optimal amount of DR depends on the specific priorities of the particular case under consideration. The focus can be on minimizing system expenses, emissions, hours of renewables curtailment, or price deviations and the correlation between these factors and the availability of DR is not linear. Additionally, technology mix and total demand substantially affect both, the profitability and the optimal amount of DR.

The sweep of scenarios performed to analyze the impact of considering DR costs and obtain a cost range in which DR has a positive business case are justified and extensively explained in the research paper entitled: Demand response costs for system planning. This corresponds with paper 4 of this dissertation compendium, and it is yet unpublished.

- Paper 4: Demand response cost analysis and its effect on system planning. Sent to International Journal of Electrical Power & Energy Systems [15]

6

6. CONCLUSIONS, CONTRIBUTIONS, AND FUTURE WORK

Final conclusions, original contributions, and recommendations for future research lines are presented in this chapter.

6.1 CONCLUSIONS

The paradigm of energy systems is evolving rapidly, driven by the imperatives of sustainability, reliability, and economic efficiency. Among the myriad solutions emerging, EDF stands out as a pivotal mechanism capable of harmonizing supply-demand imbalances in the grid. EDF empowers consumers to actively adapt their usage patterns in response to supply fluctuations, price variations, and system requirements. It can be used to optimize the grid operation and foster the sustainable integration of renewable energy by reducing renewables curtailment hours.

Moreover, the energy transition towards wind and solar technologies, while pivotal for decarbonization efforts, faces challenges concerning the availability and geopolitical dependencies of critical raw materials. Wind turbines, solar panels, and Li-Ion batteries, which are reliant on rare earth metals and specific materials for their production, raise concerns about supply chain vulnerabilities and material constraints. Conversely, among the different sustainable energy solutions, EDF is another sustainable resource that can provide energy services and decrease technology investment requirements, avoiding these raw material challenges. Therefore, EDF is an attractive solution within the energy transition, offering resilience against potential raw material shortages and supply chain disruptions. It has been demonstrated to have a large potential as it can avoid renewables curtailment needs in the system, hence integrating renewables sustainably. Finally, EDF also enhances the grid system operation by solving network congestion and reducing peak demand.

Each chapter highlights the main conclusions obtained by the different case studies developed with the available data. The following points can be highlighted as final dissertation conclusions:

- This dissertation provides new insights about additional firm capacity payments. The analysis of chapter 3. allows ordering the technologies evaluating the marginal prices set by the marginal technology that provides firm capacity. It also has shown that in a Spanish-like case study DR decreases firm capacity requirements in the system roughly at a rate of 30 MW per 1% of the total potentially controllable demand participating in DR programs. DR competes with pumped hydro storage and OCGT and fosters solar generation investment over wind generation. In addition, the impact of considering DSF costs in chapter 5. has been assessed by comparing two cases with and without costs, showing that policy recommendations could drastically change whether these costs are considered or not.
- This dissertation, also evaluates the impact of considering balancing services in the operation and investment decisions when planning the future electricity system with DR participation in Chapter 4. For a Spanish-like case study, CCGT and hydroelectric reduce their generation in the energy market in order to have more available energy to provide upward reserves. In contrast, pumping storage increases its generation and reduces its energy market consumption to provide more downward reserve. Investment decisions about generation technologies do not change due to considering or not considering reserves, as this market represents only 1% of total energy supply needs.
- This dissertation results show that the role of DR and its effect when participating in the energy and balancing services is quite relevant. Although the percentage of flexible demand used for balancing is low compared to wholesale use, more than 50% of energy needs could be met with demand assets with the available data. Results in chapter 4. show that H&C is the category that provides the majority of energy in aFRR service due to its more significant energy presence in the Spanish system. However, results also reflect that the two other categories, DHW and EV, offer more relative flexibility. This is because their demand has fewer shifting constraints, whereas H&C is limited by outdoor temperatures and indoor comfort maintenance, which constrains the possibilities of shifting demand. Chapter 5. also highlights the preference for EV flexibility and its higher profitability than for H&C and DHW flexibility.
- The impact of DSF on CO_2 emissions is analyzed for the Spanish case. Chapter 4. shows a decrease in emissions that is not directly related to a decrease in renewables curtailment hours or an increase in DR available in the system. This dissertation concludes that the reduction of CO_2 emissions implies an increase in total system costs for a technology mix similar to the Spanish one. This analysis demonstrates that, without DSF costs, DR participating in the energy and balancing services would be responsible for savings of 5% in total system costs, without considering DSF when planning generation investment. If DR availability was considered before technology investments were decided, up to 12% of total system costs could be saved with a high penetration of DR (60% of its total potential), although CO_2 emissions increase by 95%. Even considering a maximum level of 60% and neglecting the DSF costs the total estimated savings (5%-12%) are below what the literature forecasts (between 15-30%).
- The decision between desired investment savings and increased emissions establishes a trade-off point within the 20-40% DR participation range for DHW and H&C demands. This is concluded in Chapter 4. 2.
- Chapter 5 has conducted an investment and O&M cost case sweeping, optimizing DR investment, and obtaining a range of costs within the DR is profitable for implementing and operating EDF assets in the residential and commercial sectors. The threshold LCOE required to ensure the profitability of EDF is below 100€/MWh. It is found that the most

profitable source of DR is the EVs demand, followed by DHW, and lastly H&C DR, due to its temperature constraints which limit its potential.
- Determining the optimal amount of DR is not straightforward, as seen in chapters 3. 4. and 5. It depends on the specific priorities of the country or policymakers, which differ depending on whether the perspective is focused on minimizing system costs, minimizing emissions, reducing renewables curtailment, or decreasing price deviation. The relationship between these variables and DR availability is not directly proportional. Factors such as technology mix and total demand also significantly influence the profitability and optimal quantity of DR.

6.2 ORIGINAL CONTRIBUTIONS

This dissertation was conceived with the objective of pushing forward research on demand participation and its effect at system level. The research shown in this dissertation aims to contribute to the understanding of the potential of DSF assets. The benefits that planning the system can have and the associated impact on the electricity mix operation when DSF is considered.

The model proposed provides relevant information to deal with policymakers, investors, and utility companies' challenges in designing DSF regulation and clarifying the role DSF can play in the system and how much it is worth investing in it.

A summary of the original contributions of this dissertation are the following:

- First, this dissertation contributes to clearly defining the term and possibilities of DSF in future electric systems (Chapter 2.). One way to take advantage of its possibilities is by participating in the balancing and congestion management services as another market party. Then, the main barriers to EDF integration as another market participant were identified and classified into two different levels. In addition, mathematical models where EDF participates have been studied and classified, identifying the main weaknesses these models have and where they should be worked on.
- The firm capacity analysis that study the competitiveness among different firm capacity technology providers (Chapter 3.).
- The modeling of demand participation in balancing services from a system overview has not been extensively studied. This dissertation provides a comprehensive generation and storage expansion planning model that allows demand participation in both wholesale and balancing services which is also a contribution (Chapter 4.).
- The analysis and modelling of a tool to analyze the optimal amount of DR and its implementation costs, including fixed and variable costs and how their consideration can affect policy recommendations (Chapter 5.).
- Lastly, the methodology applied resorts to an optimization tool, the SPLODER model. This dissertation has upgraded the model functionalities, including different storage technologies competing with DR, modeling both the energy and balancing market, besides enabling the optimization of the amount of DR for the different consumption categories with flexibility potential (H&C, DHW, and EV). Table 6 summarizes the characteristics of the model and identifies those that have changed from the original version, indicating where this changes detail explanation can be found. The original version can be found in [6,7]. From Table 6, it can be concluded that almost the entire model has been changed

and improved from this dissertation work. The table columns disaggregate between the three papers that are part of this dissertation work, indicating where the last version of each model equation and feature has been changed from the original full description of the model. Storage column refers to Paper 2, Reserves Market to Paper 3, and DR optimized to Paper 4.

TABLE 6 CONSTRAINTS THAT SHAPE THE FINAL VERSION OF THE MODEL

MODELING PART	ORIGINAL [6,7]	STORAGE [13]	RESERVES MARKET [14]	DR OPTIMIZED [15]
DEMAND ASSETS	✓		✓	✓
TRADITIONAL GENERATION TECHNOLOGIES	✓		✓	✓
RENEWABLE GENERATION CONSTRAINT	✓			
FIRM CAPACITY GENERATION CONSTRAINT	✓			
CENTRALIZED STORAGE		✓	✓	✓
RENEWABLE GENERATION PROFILES VARIABILITY		✓		
FIX/FLEXIBLE DEMAND PROFILES FOR EACH MARKET			✓	
SYSTEM BALANCE: ENERGY AND RESERVES MARKET			✓	✓
OPTIMAL INVESTMENT OF DR				✓
OBJECTIVE FUNCTION	✓		✓	✓

6.3 FUTURE WORK

All these findings raise some proposals for future developments, which follow the idea that deepening the EDF research will foster its implementation, and the whole electricity system would benefit from its functionalities. These future research lines are:

1. Additional technologies should be considered as firm capacity providers' options, such as power-to-gas technologies (hydrogen, among others), to analyze their competitiveness, role, and impact on the rest of the technologies in the mix.
2. Include other sources of flexible demand, such as industrial processes or refrigeration, that could increase total system savings and overall DSF possibilities to better approach its real potential.
3. The DSF LCOE has been assessed. However, analyzing different allocations for these DSF costs, which part goes to the TSO, the aggregator, or the individuals would help to design a better business strategy. Besides creating a remuneration mechanism for active consumers quantifying the value for service provision and quantifying the loss of

comfort. Defining also imbalance responsibility allocation, which would also push the independent aggregator figure definition in Spain.

4. Although there is no need to apply a tariff exemption for DSF providers [105], it is necessary to define the most efficient remuneration mechanism for DSF participation in the different markets to make it an interesting option for consumers in the same way other mechanism as additional renewable energy or firm capacity mechanisms exist.
5. The independent aggregator effect in the system can be studied by analyzing how the reserves market participation changes the energy market demand, thus estimating the rebound effect consequences, penalizations…
6. How can the gas prices variability affect the cost and benefits analysis of DSF?
7. Developing a cost recovery analysis for DSF would involve clarifying the costs associated with DR and examining DR's primary sources of income, including the energy market, reserves market, or other subsidies and additional payments. On the other hand, simultaneously estimating the optimal amount of DR for each demand category in Spain would be another area of focus. This would involve identifying a trade-off between minimizing costs and avoiding compromise to system emissions.

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ANNEX

PAPER 1

- System flexibility and demand flexibility concepts clarification. This review explains why the known as Explicit Demand Flexibility is the one that offers flexibility to the system.
- Congestion management and balancing services in which Explicit Demand Flexibility can bring value, identifying also the barriers found for including it as another market party regarding European products.
- Main weaknesses of mathematical models for balancing and congestion management services that include Explicit Demand Flexibility participation.
- Analysis of how integrated is Explicit Demand Flexibility in European countries markets and work being performed to develop it.

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A literature review of Explicit Demand Flexibility providing energy services

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ABSTRACT

Current power systems are characterized by the increase of renewable generation and distributed energy resources introducing more variability on the generation and enhancing the importance of the management in the consumption side. In this paper, a thorough review about the explicit demand flexibility (EDF) concept is addressed. This review, firstly, brings clarification over the different terms that have been used in the literature and the agents that are involved in the demand flexibility framework. Secondly, analyzes the different balancing services where EDF could participate, identifying the main barriers found for each market. In addition, it contributes to classify how mathematical models include EDF participation in ancillary services and congestion management, finding the main weaknesses and working lines for EDF integration in such models. Finally, a European overview is assessed to see where flexible resources have actual participation and how it is performed.

1. Introduction

Climate change has been an international concern since 1997 when some countries started to be aware of the high Green-house gas (GHG) emissions. Some of the most developed countries were interested in acting in consequence and carried out the Kyoto protocol, with the main aim of reducing GHG emissions [1].

In November 2016, several countries worldwide started moving in the same direction with the Paris Agreement. The main objective of this agreement was to limit global warming to 1.5 to 2 °Celsius above pre-industrial levels over the next century [2]. At the end of 2018, around 78% of total emissions in most European countries came from the energy sector, including energy used to power transportation sectors [3]. Therefore, an 'Energy transition' towards a more electrified and renewable system is being developed more seriously in recent years. European countries involved in the Paris agreement signed an update in 2018 with the 'Clean Energy package' (CEP) [4] that covers the following aspects:

- Develop a new electricity market design. This design includes the regulation framework about how demand and energy storage can participate in the markets and be connected to the main grid.
- Encourage and integrate Renewable Energy Sources (RES). The committed share of renewable energy in the EU's gross final energy consumption is set at a minimum of 32% by 2030. This percentage is translated to 74% share in the electricity sector.
- Increase energy efficiency. Member States must reduce their annual final energy consumption by 0.8% every year.
- Create a national roadmap for the following 10-year period (from 2020 to 2030). Each country had to develop a National Energy and Climate Plan (NECP). The NECP document should include each countries' objectives and targets regarding the five dimensions of the energy union: Energy security of supply, reinforced of internal energy market, improvements in energy efficiency, strategy for decarbonizing the economy and investments in research, innovation and competitiveness [5]. Moreover, policies and measures should be implemented to reduce GHG emissions, deal with renewables deployment, and increase interconnection between bidding zones.

Therefore, thermal generation is expected to be replaced with more RES installation, thereby considerably increasing uncertainty and volatility in the electricity system that results in a need of complicated management of the balance between electricity generation and demand. This balance has been guaranteed with thermal (e.g., CCGT, OCGT, Coal), pumped hydroelectric storage and cross-border interconnections so far. Hence, the integration of new technologies that provide security to the system without carbon emissions is required to face this challenge (e.g., demand management and energy storage) as assessed in [6]. For this reason, the CEP fosters the integration of energy storage and manageable demand in the markets.

In fact, electric networks are evolving with this energy transition due to the deployment of Distributed Energy Resources (DERs), including distributed generation (DG), manageable loads such as electric vehicles

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Abbreviations

Acronym	Meaning
aFRR	Automatic Frequency Restoration Reserve
AGR	Aggregator
AIM	Aggregator Implementation Models
AS	Ancillary Services
ATC	Available Transfer Capacity
BM	Balancing Markets
BRP	Balance Responsible Parties
BSP	Balance Service Providers
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbines
CEP	Clean Energy Package
DA	Day-ahead
DC	Direct current
DER	Distributed Energy Resources
DG	Distributed generation
DR	Demand Response
DSM	Demand-side Management
DSO	Distribution System Operator
EB GL	Electricity Balancing Guideline
EDF	Explicit Demand Flexibility
EG3	Expert Group 3
ESS	Energy Storage System
EV	Electric Vehicle
FCR	Frequency containment reserve
GHG	Green House Gas
IA	Independent Aggregator
IDF	Implicit Demand Flexibility
IGCC	International Grid Control Cooperation
mFRR	Manual Frequency Restoration Reserve
MV	Medium Voltage
NECP	National Energy and Climate Plan
OCGT	Open Cycle Gas Turbines
OPEX	Operational Expenditure
PV	Photovoltaic
REE	Red Eléctrica de España
RES	Renewable Energy Sources
RR	Replacement Reserve
RT	Real-time
RTE	Réseau de Transport d'Électricité
SUP	Supplier
TCL	Thermostatically controlled load
TOTEX	Total Expenditure
ToU	Time of Use
TSO	Transmission System Operator
V2G	Vehicle to grid
VPP	Virtual Power Plant
WIP	Work in Progress

(EV), and different types of energy storage systems (ESS) both on a grid operating system scale and behind the meter. Consumers with DERs are now called prosumers. They can provide a wide variety of benefits to the grid operator such as voltage and reactive power control and solve localized distribution system congestions using their energy management capabilities [7]. Despite the fact that aggregated DER participation in the wholesale market it is already allowed in The United States [8] and a few countries in Europe [9], the options this paper will analyze for prosumers participation in the market are from the'demand-side participation' due to their small generation capacity.

There is previous work explaining different ways for the demand-side to participate in the markets. To make this operational, energy management systems are necessary, which are devices prepared to centrally monitor, analyze, and control DERs performance [10]. Besides, to take advantage of the flexibility potential of DERs of small end-users and to promote their access to the retail electricity market, an aggregator [11] is required to collect relevant amounts of DG, manageable load and ESS to trade their flexibility and benefit from rewards or lower energy bills [12].

Classifications to distinguish the ways to take advantage of prosumers flexibility have traditionally considered two kinds of participation. These two types have been referred with different terms; as price-based or incentive-based programs [13]; indirect and direct demand participation [13, 14]; as static and dynamic demand participation [15]; as passive or active demand response [16]; and as implicit or explicit demand participation [7] correspondingly. The ones considered in this study are the most recent ones which correspond with implicit and explicit demand flexibility. The main feature that differentiates the two of them is the way flexible demand is used. On the one side, **implicit demand flexibility** (IDF) only takes advantage of flexible demand by incentivizing prosumers with different electricity tariffs to consume or generate at certain hours. Models presented in [17] and [18] use this kind of flexible demand, and the benefits that can be obtained are assessed qualitatively in [13] and in a quantitative way in [19] for the case of Spain. On the other side, **explicit demand flexibility** (EDF), refers to committed prosumers in acting to increase or decrease load or distributed generation in response to system needs, as presented in the model used in [20]. In particular, this review is focused on the different ways of exploiting EDF potential, as it has not been detailed addressed in the literature. The IDF can still play a crucial role in the electric systems to induce consumption behavior changes, but the EDF is the one prepared to provide sudden congestion management services to solve local and national constraints in distribution and transmission networks or to participate in balancing markets to solve stability issues for the transmission network.

Furthermore, a model classification has been performed in order to provide an overview of what has been and what can be done with respect to modeling the congestion and balancing markets including demand-side management participation. Classifying electricity market models has previously been addressed considering balancing services [21, 22], even considering flexible demand participation [23, 24]. However, no model assessment focused on European balancing products and congestion services where EDF participates as another market party, which is the perspective this approach tackles. References [14, 25, 26] analyze potential flexibility products and services. Demand-response-control schemes referred in [14] are related to the different services demand could provide, but it is focused on the IDF potential and the technologies prepared to do so. In [25] a comparison between UK and USA flexible demand participation is addressed, conversely, this paper provides a holistic approach on how developed EDF integration is in all European countries. Resource [26] presents flexibility products and services from both transmission and distribution levels. However, it does not delve into the different available congestion and balancing services nor how specifically demand could be included as a market participant.

The aim of this paper is to bring clarification over demand response concept and all that surrounds it, exposing its high potential providing energy services. On this purpose, the paper contributes to organize demand response terms and involved agents for its exploitation; explains why EDF is the one that offers flexibility to the electricity system; classifies congestion management and balancing services in which EDF can bring value regarding also the main barriers found for including it as another market party in European products; identifies main weaknesses of mathematical models that include EDF participation in balancing and congestion management services; finally it analyses how integrated is EDF in European countries markets and classifies projects and initiatives being performed to develop it.

This paper is organized as follows. Section II presents the historical evolution of the terms meaning and involved agents roles in the demand flexibility framework and why it is needed. The balancing and congestion management services where EDF could participate are assessed, providing the main barriers found to include EDF as another market party. The way this participation has been modeled so far is presented in section III. How EDF participation is implemented in some European countries is analyzed in IV. Section V summarizes the paper's contributions and points out some relevant gaps of the literature on the EDF matter. Finally, conclusions are gathered in section VI.

2. Evolution of terms in the literature

This section brings clarification over the mix found in the literature when referring to demand-side flexibility terms, when they are used and how did they evolve along the years. Besides, describes the different agents required to exploit the available flexible demand in the system.

2.1. Electric system flexibility

The *system flexibility* is defined as the need of the electric system to adjust generation (*Generation flexibility*) or consumption (*Demand-side flexibility*) in order to maintain a secure system operation considering grid stability constraints and interruptible renewable energy sources [27]. In [25] and [26] potential flexibility products and services are analyzed mixing both generation and demand-side flexibility.

On the one hand, the conventional main sources that have been providing generation flexibility to the system are:

1) *Thermal generation*: fossil-fuels power plants can provide flexibility to the system thanks to their faster regulating advantages. The more energy is needed, the more fuel is burned and the other way round. However, the huge environmental impact together with the more restrictive policies in emissions and renewable shares, make necessary alternatives to substitute this source of system flexibility.
2) *Cross-border interconnection*: Exchanges facilitate adjusting wholesale, balancing, system support and reserve markets [27]. The Electricity Balancing Guideline (EB GL) enables Transmission System Operators (TSOs) to reserve cross-border capacity to facilitate the exchange of balancing energy. This process will be co-optimized with capacity reserved for market timeframes [28, 29].
3) *Energy storage*: can adapt its electricity production and consumption to system requirements. Hydro plants have been the traditional way to do it, but the places where these plants can be built are limited. Another way to store energy is batteries, but it also presents environmental impacts, as indicated in [30].

On the other hand, demand participation started to be available through "interruptible-load tariffs" for commercial and industrial customers in the 50 s [31]. In the 70 s, experts began to see the potential of changing demand patterns, mentioning the future cost-effectiveness of reducing electricity demand rather than increasing supply [14]. Demand-side flexibility or demand-side management (DSM) term started in 1973 [14], when electric utilities slowly started to include DSM programs in their strategic plans. In the beginning, DSM was exploited with time-based electricity tariffs such as Time of Use (ToU) tariffs [32], thus giving rise to the first demand response (DR) programs, which will not receive this name until the late 80 s [33]. Later on, DSM started to provide energy or power when wholesale prices rose, when there was a shortfall of generation or transmission capacity issues or during emergency grid operating situations (load shedding) [34]. Nowadays, DSM could be used to reduce the energy bills of the prosumers responding to price signals or help the system with frequency restoration, congestion management, and voltage control support [34]. The whole DSM concept includes all DER possibilities that range from load management (which is referred to as DR) to distributed solar photovoltaic (PV) panels and storage onsite. Therefore, it is becoming possible to participate in balancing and congestion management services where regulation measures are prepared. Fig. 1 summarized all the abovementioned terms evolution and some relevant events for demand-side flexibility development.

The most recent way DSM is exploited leads to two types of flexibility [7] whose main difference is how the change in consumption is incentivized:

1) Load management concept evolved to DR, being defined in the literature [19, 35, 10] as any form of communicating to the end-user their energy consumption in order to encourage them to modify it, responding to changes in prices to reduce their bill. This is now named as **IDF** [36] which is the same concept as price-based DR [35] and indirect, static or passive demand participation, since demand is fostered to change according to price signals that sways customers consumption decisions [36, 37]. The main tools to take advantage of the implicit flexibility are the Electricity **tariffs** [15]: ToU tariffs [38], Power based tariffs or Real Time pricing [39]. All of them have a common thing, end-users see different power or energy prices during the day to be willing to consume more or less in specific periods. However, there is no guarantee that demand would follow those premises. Therefore, this type is used to flat the demand curve to avoid network reinforcement in long term, but it does not provide real-time flexibility to the system as there is no commitment from the consumer point of view since end users can freely decide whether to react to these price signals or not.
2) In the early 2000s, DR could also refer to situations where a prosumer is committed to provide a flexibility service and therefore considers a reward or a penalty for complying or not with it, it is known as **EDF**. This flexibility can also be referred to as incentive-based DR [35] and direct, dynamic or active demand participation. In this case, the incentive can be understood as an additional payment for developing a flexibility action.

EDF usually involves all DER options, from the capacity of manageable loads to move their consumption (DR) to the generation produced by DG and storage onsite, which are also understood as part of the demand-side resources. This approach consists on re-scheduling consumption or onsite generation with a specific strategy that can be for instance, to bring stability to the network, to avoid peak electricity prices or to deal with grid congestion problems [40] competing directly with power plants (As a Virtual Power Plant (VPP)) [41, 42] in the wholesale market, balancing markets, system support and reserves markets. If it is a large prosumer, then individual participation can be considered. In any other case, **aggregation** is required. The energy is committed with the system operator [36, 37] to obtain a reward for the given service. The benefits of using explicit demand flexibility to efficiently manage a high RES scenario is assessed in [43].

Therefore, IDF could flat the curve and reduce expected network congestions if end users decide to follow the signal, whereas the EDF is the only one that can offer flexibility/adaptability (balancing services and sudden congestion problems) to the system in real-time since it is the one that can participate in the markets in the same conditions than traditional generators to solve specific system need. In reality, both will be present in the usual operation. As a reference of the benefits that could be achieved with combined explicit and implicit demand flexibility, [44] concludes that savings in the electricity system in the UK could be around £4.55bn/year. These savings are allocated throughout the system, 60% from avoided investment in network capacity, 16% from avoided investment in generation peaking capacity, and 22% from the reduced curtailment of renewable energy [44]. Besides, significant network investments will be reduced by 50% of the expected cost by

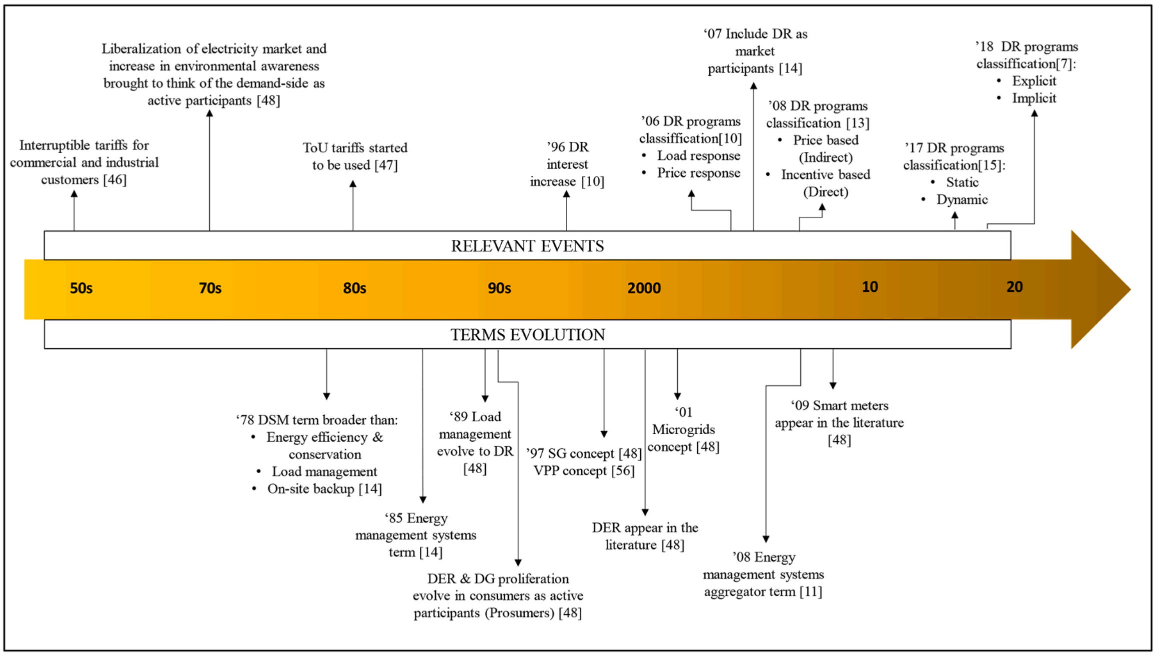

Fig. 1. Evolution of demand-side flexibility related terms.

2050. A flexible electricity system will be crucial for ensuring that the build-out of network expansion until 2050 will be feasible [44]. Henceforth, paper is focused on the EDF type.

2.2. Involved agents

Although technically possible, EDF still has a long way to go. The development of an EDF framework will provide relevant advantages such as the increase of system flexibility sources to cope with the high RES scenario, savings associated to the avoided investment costs in networks and the ones associated with the avoided payments for curtailing RES to solve congestions [45]. One of the main challenges is that manageable electricity demand coming from residential buildings and small and medium size enterprises [46] need the figure of the Aggregator.

The *Aggregator* figure has appeared in the system in order to obtain enough volume to participate in ancillary services markets, joining different amounts of distributed generation and small amounts of flexible consumption (from residential or commercial customers) [47, 48]. The Regulation on aggregation is still being developed. For example, the Spanish NECP is committed to promoting the aggregator role and detecting ways to encourage it: economic incentives, more efficient technologies and techniques, and influencing consumer habits [49]. The final regulation about the Aggregator should clarify the utilities and customers in terms of roles and responsibilities, guarantying a fair exchange and access to data and ensuring fair competition while protecting relevant information [49]. It should also establish the relationship between entities that provide aggregation services and other market participants, coordinating also liability for deviations [49].

Other agents are also relevant to face this new context, such as the Balance Service Providers (BSPs) and Balance Responsible Parties (BRPs). The first ones, BSPs, are market participants that can offer balancing services to TSOs in terms of capacity or energy and can provide energy bids for the market on a voluntary basis. They include generators, aggregators, and energy storage operators. The latter ones, BRPs, represent a group of BSPs being financially responsible for their portfolio's imbalances (consumption/generation deviations) [50].

If the aggregator and the utility that supplies energy to a prosumer are different entities, the Aggregator is named as *independent aggregator* (IA). In this situation, the aggregator must have the option of exploiting the prosumer EDF without signing a contract with the supplier or BRP serving the same prosumer [47]. An imbalance charge is imposed to the BRP if the scheduled sum of generation and consumption does not match the actual one in real-time [51]. In this special case, regulation should care about how to deal with imbalances and with the financial risks assumed by the associated BRP and Supplier, with the IA actions [52].

2019/944 Directive [53] clearly states how compensation should not result in a barrier to the development of the aggregator's activity. However, the IA models present some barriers in European countries' regulation related to supplier and aggregator financial compensation methodology and the imbalance volume correction methods. The main difficulties found are stated in Articles 17.3 and 17.4 of the EU proposals and are related to the 'imbalance' issue and the 'bulk energy' issue, respectively [54], that retailer would suffer from the IA actions:

1. **Bulk energy issue** is referred to the problem caused to the retailer due to the difference between actual consumption compared to the day before procured energy as supplier neglects when EDF can be activated. Hence, the retailer perimeter is modified, and as a result, the retailer will not invoice the full electricity procured cost [54].
2. **Imbalance issue** refers to how retailers would deal with electricity deviations caused by the IA when activating the reduction or increase in demand and not due to an estimation mistake. Volume correction or energy transfer is necessary for imbalance settlement [54]. Nonetheless, beyond the time of activation of the service, consumers who, due to the energy requirements in their processes, must offset the activated demand by additional / less consumption afterward, would create an imbalance problem again. This situation is called the 'rebound effect'. However, according to the Electricity Directive [53], if the aggregator has no active role in the rebound period and the energy transfer has already been arranged between supplier and aggregator in the initial period of activation, the imbalance issue would be only supplier's responsibility during the rebound period [54], as only costs incurred during the activation of the service can be recovered through compensation.

In Europe, only France and Switzerland have defined legislation for IA [55] facing these issues. There are countries where IA can only access markets in agreement with the customers BRP, such as Finland, Germany, and Denmark. There are also cases where the aggregator is responsible of adjustments and their costs to correct imbalances caused by demand. In this case, payments to the BRP are negotiated and agreed between aggregator and the BRP as they do in France. While in other countries, TSO assumes responsibility for imbalances adjustments and costs such as Switzerland, Ireland, and Finland [48].

How aggregator operates and interacts with other system parties is known as Aggregator Implementation Model (AIM) [47]. The flow diagram shown in Fig. 2 presents the options that will define the different possibilities of AIMs. In Fig. 2, supplier is referred to as SUP and aggregator as AGR:

If besides the BRP_{SUP} there is also a BRP_{AGR}, the transfer of energy methods work as follows [47]:

I With bilateral energy contracts, the aggregator will receive the energy ex-post from BRP_{SUP} through a hub deal. The amount of energy transferred would be equal to the difference between measurement and baseline.
II When the energy is transferred via the prosumer, the aggregator is responsible for financially compensating the prosumer for the overcharged or undercharged energy, depending on contract conditions.
III The centralized method uses rules to enable the responsible allocation party to transfer the energy between the BRP from the supplier and the one from the aggregator.
IV The socialized method implies that there is no energy transfer from/toward the aggregator BRP. However, the impacted supplier is compensated through a regulated price formula by all other BRPs for the sourced but not delivered energy.

The combination of the electricity imbalance correction (Transfer of energy methods presented in Fig. 2) and the financial responsibility when there is no contract between supplier and aggregator [47] result in different IA models [56, 57]. According to 2019/944 directive [53], the main combination options can be summarized in three models:

- **Uncorrected model**: There is no imbalance volume correction or compensation, hence the BRP compensation is settled through the socialized energy transfer method.
- **Corrected model with no compensation**: Where there is imbalance volume correction but no compensation. Usually, the prosumer corrects the BRP's imbalance volumes based on the amount of activated flexibility. For TSO markets, the correction responsibility lies in the same TSO. However, the BRP does not receive compensation from any market participant in any case.
- **Corrected model with compensation**: Where there is imbalance volume correction and compensation with a bilateral contract. TSO corrects the BRP's imbalance volumes based on the amount of flexibility that was activated. In addition, a reference price should be agreed with the purpose that the aggregator compensates the BRP [57].

Together these features provide a common starting point for the aggregator figure that will speed up cross-border trading of EDF products, contributing at the same time to the development of a single European market for demand-side participation. Each member state has complete freedom to choose the most suitable AIM to comply with the 2019/944 directive [53].

Fig. 3 is a scheme to present and clarify previous explanations, terms used, and interactions, together with the means to facilitate demand-side flexibility incorporation in the markets.

3. EDF in balancing services and congestion management

This section contributes to highlight the possibilities of EDF participating in balancing and congestion management services working in European countries. Furthermore, the main barriers found for integrating EDF as another market party are addressed and classified. Lastly, this section contributes to gather and classify the mathematical models available in the literature, designed to include EDF in balancing and congestion management services.

The markets or services where prosumers electricity flexibility is participating differentiate between wholesale markets, adequacy management services, congestion management services, and balancing markets [7].

- Wholesale markets: flexible demand participation has been previously regarded and analyzed in detail a while ago with also recent findings and new models testing [58–60]and possibilities assessment. Besides, the impact of demand flexibility participating in the wholesale markets has also been analyzed from retailers' side [61] and electricity system side [62]. There are many European countries where flexible demand is already participating, such as: Denmark,

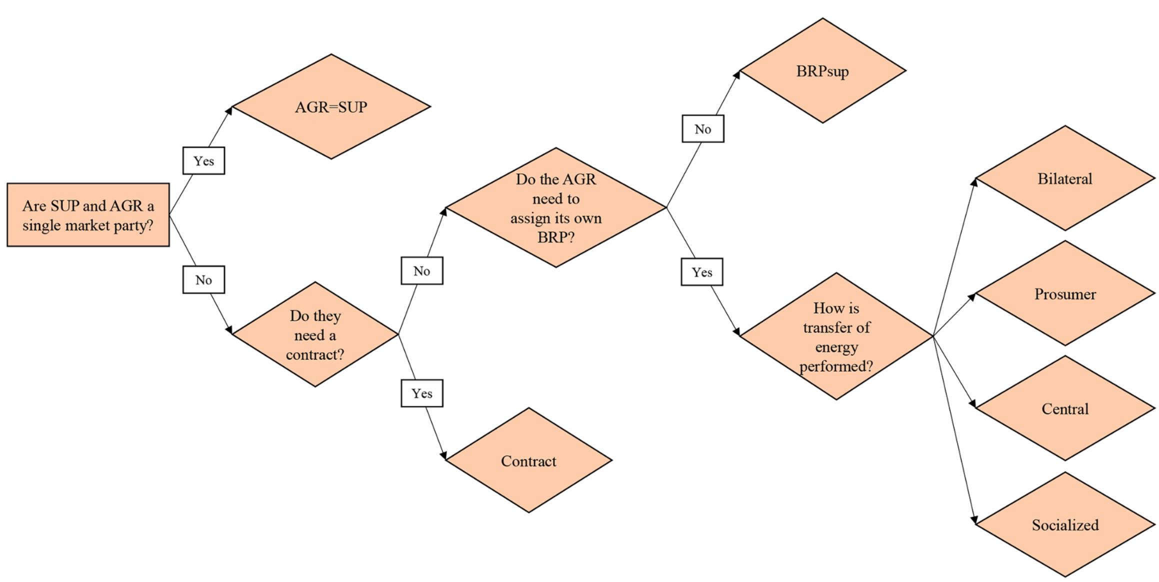

Fig. 2. Aggregator Implementation Models characteristics.

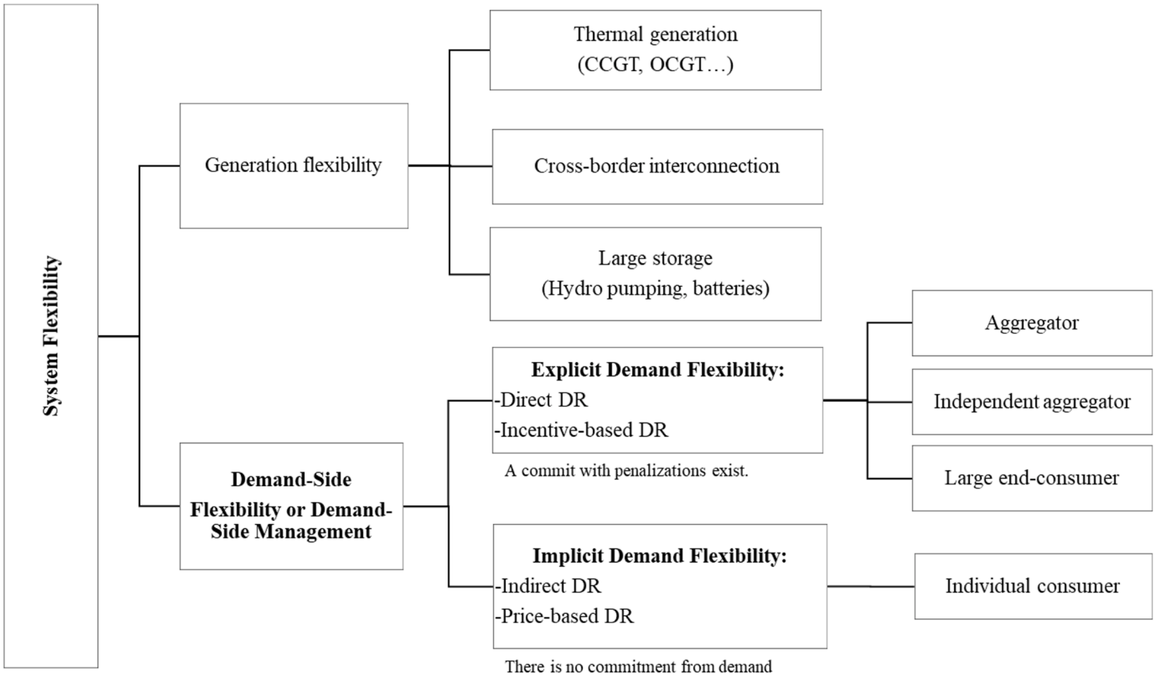

Fig. 3. System flexibility clarification.

Finland, France, Germany, The Netherlands, Norway, Poland, Sweeden, and Switzerland [63]. The introduction of demand flexibility in the wholesale market involves a decrease in the spot market price along the usual day peak hours [64, 65]. However, these markets are out of the scope of this review.

- Adequacy management services (capacity mechanisms or strategic reserves): European Countries are cautiously allowing demand participation in this market. Directorate-General of Competition of the European Commission has recently approved four capacity mechanisms in Poland, Italy, France, and Greece, and two strategic reserve schemes in Belgium and Germany [66]. However, that does not mean demand-side is allowed to participate. For instance, demand-side is allowed to participate in Germany, but the lack of transparency and the eligibility criteria for providers makes uncertain the actual participation [67]. France has real EDF participation [68], and Italy is working on it [63]. The demand-side flexibility potential to provide adequacy services has already been analyzed for some northern European countries: Sweden, Denmark, Finland, Norway, Estonia, Latvia, and Lithuania are assessed in [69] achieving that the peak of the system could be decreased by a 15–30% with the use of demand-side flexibility. Nevertheless, these markets are out of the scope of this review.
- Congestion management services can also be provided by EDF. Multiple models are being developed where the DSO can take advantage of demand-side flexibility to solve its own congestion problems. Some countries that are doing this are: Netherlands, Belgium, Germany, Denmark, Ireland, Norway, France and recently Spain [70]. These markets will be assessed in this review.
- EDF participation in balancing services has a vast potential presented in [71], which is still untapped in most European countries. Only a few countries have a high deployment of demand-side regulatory measures for participating in balancing services, such as Germany and Switzerland [63, 72]. These are the markets that will also be assessed in this review.

Thus, this section provides a general overview of the balancing services working in European countries according to their regulation requirements and congestion management available services as they are the main EDF focus markets. These services are described and analyzed to see the EDF potential when participating as another market party. Furthermore, the main barriers found for integrating EDF are addressed. Lastly, in this section, mathematical models designed to include EDF in balancing and congestion services are classified and explained in detail.

3.1. Balancing services

Balancing services aim to restore system frequency to its nominal value of 50 Hz (in Europe) and maintain active power exchanges within the scheduled threshold maintaining power quality at the lowest cost. The TSO is the responsible party for dimensioning and procuring this service guaranteeing sufficient capacity and energy [28].

The different balancing services are explained in detail and how demand participation could add value to the services:

Frequency containment reserve (FCR): Primary reserves respond rapidly (within milliseconds), usually in an automated way, against frequency deviations in the grid. This fact is why only thermal power plants have traditionally supplied FCR. However, there are several types of loads (Electric heaters, heat pumps, EV…) that are prepared to supply this service although the fast ramp rate and the frequency of activation and shortages still makes it difficult for EDF to participate [39]. Remuneration can be capacity-based, activation-based, a combination of both of them, or not remunerated when it is a mandatory service for generators [73].

Frequency Restoration Reserve (FRR): it is the second step in the case that frequency has not returned within the agreed threshold, 30 s after the disturbance. The aim of FRR service is to replace FCR to release the capacity needed by the primary control and to restore the primary control reserves. Remuneration can be capacity based, energy based, a combination of both, and can be pay-as-bid (remunerated at the offered Price) or pay-as-cleared (price determined, for each hour, by the intersection of the demand and supply curves) [73]. Activation time is required to respond between 30 s up to 15 min after the disturbance [51].

- *Automatic Frequency Restoration Reserve (aFRR)*: Automatic service activated between 30 s and 15 min after the disturbance by the load frequency controller of the TSO.
- *Manual Frequency Restoration Reserve (mFRR)*: After the aFRR service since it has a slower ramp rate and can last longer. This service is activated manually and operates in a continuous manner to recover aFRR reserves after the frequency has been restored [7].

EDF has a high potential to participate in these services, but product requirements still need to evolve, allowing aggregation, smaller minimum bids, and asymmetrical bids [72].

Replacement Reserve (RR): the service replaces the previously activated reserves (aFRR or mFRR) to return to full operation with availability of reserves and be prepared to respond to another failure in the grid. RR has a longer duration and slower ramp rate than the previous frequency restoration services. Activation needs to last from 15 min up to two hours and it is manually or semi-automatically activated [51]. RR long-lasting activation periods are a barrier for EDF participation as long as aggregation is not permitted. Remuneration can be according to terms of energy provided or a mix of the energy supplied and available capacity [7].

In general, balancing services in Europe are organized in time as Table 1 summarizes [72, 74]:

The slowest balancing service takes 30 min at the most to activate it. For this reason, an efficient EDF participation design able to respond to system needs in a fast way is essential to foster its development.

3.2. Congestion management

Congestion management aims to avoid the thermal overload of system components [7]. There are two different congestion management categories: preventive and corrective methods [75]. Both congestion management categories are procured with market-based programs rewarding service providers (Consumer, aggregator…) with money. The reward is based on a good performance, penalizing participants who do not successfully respond to their commitment decrease in consumption. These penalties are different depending on the program terms and conditions.

On the one hand, preventive methods are based on using transmission rights and available transfer capability (ATC) considering congestion issue in a medium- or long-term basis. On the other hand, corrective methods are performed in real-time electricity markets (short-term basis) when congestion problem has already occurred. Therefore, the DSO requires a quick response complying with regulatory and networks operator rules. Corrective methods utilize the activation of flexible DSO /TSO grid assets. One traditional source is the interruptible load that some large consumers provide. Another flexible asset that can be used is EDF. To procure with it, participating prosumers are informed of the ATC in order to optimally modify their consumption pattern to alleviate the congestion taking place while, at the same time, increasing their own benefits [75]. EDF for corrective congestion management services, results a cost-effective solution [70, 39].

3.3. Main barriers for EDF participation in balancing and congestion services

A two-level classification of existing barriers is presented to separate the first actions that must be overcome before facing the second level barriers

Table 1
Balancing Services timing.

Product	Response time	Lasting time
FCR	0–30s	15min
aFRR	30s-15mins	15min
mFRR	$\leq$15mins	15min
RR	$\geq$15min	2h

i First level barriers: These ones are related to technological advances and social approval to increase the EDF potential.
  - Remote control of the demand should be developed with equipment that allows measuring asset consumption. Facing submetering challenges and very fast granularities for data control needs to be implemented together with the deployment of smart equipment and submetering options.
  - Larger quantities of demand (electrification) are needed to make it manageable and worthy to prepare regulatory measures.
  - Social acceptance and normalization of contributing to this matter investing in electrical devices and making the flexible consumption available to an aggregator.
  - Prepare the network to allow bidirectional power flows in order to take advantage of the increase in DER installation.

ii Second level barriers: Subsequently, renovating regulatory measures is required in almost all the countries to enable and foster EDF participation in balancing and congestion services considering the guideline that can be found in [28]. The main regulatory barriers that prevent its inclusion could be handle by modifying the following three regulation blocks [37]:
  - The standardization of the different products allowing EDF participation: Which means that prequalification, measurement and verification protocols must be clearly defined for each service. Also, payment and penalties criteria should be based on open and fair competition. Besides, a baseline consumption calculation method should be stated, which estimates what an end-user would have consumed if EDF had not been used [76]. This methodology needs to be developed for consumers to be paid for what they provide. Lastly, clarifying service prioritization rules and forecasting where demand flexibility will be more valued will facilitate investment decisions [77].
  - Aggregator's allowance: Member States must define roles and responsibilities around aggregation providers. Relationships between retailers, BRPs and IAs should be clarified and again search for fair competition. Well-defined standard procedures by the regulator and TSO are important to protect the financial interests of all parties [37]. Hence, to manage in a fair way the access to data from the different entities, a process reform is required [77]. To guarantee security in this data exchange, cyber-security protocols should also be developed [77].
  - Adjust technical requirements in line with participants' capabilities: It is important to play in a competitive framework holding auctions in a transparent manner. Hence, strong and traditional requirements for market parties need to evolve. For instance, the bidding size requirement should be small enough to allow new entrants such as EDF and IA [53]. The duration of the call should be as short as the technical requirements of markets allow. Availability of the offer may change according to specific necessities [78], always trying to keep it as small as possible. Moreover, the frequency of activations/short recovery periods should be reasonable as some participants need time to rest between activations. Lastly, asymmetrical bids should be allowed to foster some new technologies integration in the market [37]. Table 2 summarizes the main technical barriers that the different ancillary services find to include EDF as another market party. Moreover, the potential of EDF in that particular service is assessed considering three levels: high (H), medium (M), low (L), which evaluate the economic efficiency of using EDF instead of other technologies considering the difficulty of inclusion versus benefits achieved such as avoidance of generation investment.

Table 2
Main technical market barriers for EDF participation.

	Services	EDF potential	Main barriers
Balancing services	FCR	L	Too fast ramping rates. Symmetrical and high min bids. Very frequent activations/ Shortages
	aFRR mFRR	M-H M-H	High min bids. Very frequent activations/Shortages. Aggregator allowance
	RR	L	Availability of the activation offer can be too long for EDF. High min bid.
Congestion management	DSO /TSO	H	Aggregator allowance

3.4. Mathematical models that include EDF in balancing or congestion services

Two exploitation manners of demand flexibility were clearly identified in section II, are modeled in the literature. First, implicit demand flexibility has been largely addressed using price signals [79–81] which foster customers to change their consumption patterns. However, the real challenge is to include EDF as a market participant in the models as the bunch of services that EDF can provide is much wider than the implicit one. Hence, models presented in Table 3 focus on EDF integration, though [82] and [83] include both.

Depending on the markets where EDF is involved, there is more or less work done beforehand. Much work has already been done in order to find the best way to model EDF participation in the wholesale markets, affecting somehow to the spot price [84, 85]. However, recent work [86, 87] has proven a high potential of demand participating in the ancillary services markets using their EDF capability. In this regard, it is still not fully mature the best practices to model EDF participation in ancillary markets. In this section, previous work related to models that include EDF participation in balancing services is classified in Table 3 to address the main weaknesses of EDF participation in balancing services.

Other models' classifications have been previously done. However, the focus of the classifications is very different. In [88], the classification is based on the changes required in power system planning models to include a high variable renewable energy integration and discuss various scenarios on a national or regional level. In addition, this classification does not necessarily include demand-side response as a source of system flexibility and the markets where EDF can participate are not analyzed. In the classification presented in [89], all kinds of approaches performed to implement demand response programs in the smart grid environment are presented. However, these approaches are not only mathematical models (Pilot projects and other type of approaches are

Table 3
Mathematical models for balancing services.

Source/ Model	Markets involved	Timing (DA, intra-day or RT)	Sources of EDF	Payment/ remuneration for flexibility	Considers the Network (Yes,No) Type.	Opt.Sto, Opt.Det or Equilibrium	CAPEX, OPEX or TOTEX
[82]	Energy and balancing services	DA, intra-day and RT	Aggregated load	No	No	Det	TOTEX
[83]	Energy and balancing services (FCR, aFRR, mFRR)	DA	Aggregated ESS	No	No	Sto	OPEX
[90]	Energy and balancing services (aFRR, mFRR, RR)	DA	Aggregated residential electric heating systems	No	No	Det. with stochasticity for RES generation and flexibility availability	OPEX
[91]	Balancing services	RT	Aggregated residential thermal energy storage	No	No	Det	OPEX
[92]	Energy and mFRR	DA and hour ahead	Aggregated load from EV	Yes	No	Det.	OPEX
[93]	Energy and balancing services	DA and RT	Aggregated load from EV	Yes	No	Sto.	OPEX
[94]	Energy and only upwards mFRR	DA	Aggregated load	Yes	No	Det.	TOTEX
[95]	Energy and balancing services	DA	Aggregated load	No	Yes. National. DC	Sto.	OPEX
[96]	Energy and balancing services (FCR, aFRR, mFRR)	DA	Aggregated load	No	No	Det.	OPEX
[97]	Energy,FCR, aFRR, mFRR and RR	DA	Demand blocks	No	No	Eq.	OPEX
[98]	Balancing services	DA and RT	Aggregated DG, ESS and load	Yes	No	Sto.	TOTEX
[99]	Energy and aFRR	DA and RT	Aggregated DG and load (V2G or TCL)	Yes	No	Sto.	OPEX
[100]	Energy and RR	DA and RT	Aggregated DG and load (SL, V2G or TCL)	No	No	Sto.	OPEX
[101]	Energy and balancing services	DA	Aggregated DG and load	No	Yes. Microgrid	Det.	OPEX
[102]	Energy and balancing services	DA and RT	Aggregated DG, ESS and load	Yes	Yes. Maximum power flow of lines	Sto.	TOTEX
[103]	Energy and balancing services	DA and RT	Aggregated DG and load	Yes	Yes. Maximum transmission capacity of lines	Sto.	TOTEX
[104]	Balancing services	DA and RT	Aggregated DG and load	No	Yes. Microgrid	Sto	OPEX
[105]	FCR	DA	Aggregated thermostat and heating units	Yes	No	Det	TOTEX
[106]	Balancing services	DA and RT	Aggregated ESS provided by: water heaters, pools and agriculture loads	No	No	Det	TOTEX

included) and approaches are not oriented to market participation. Hence, the gap in the literature addressed in this section is a mathematical models' classification that include EDF participation in balancing and congestion management services.

The features assessed to classify the balancing models are:

✓ **Electricity markets modeled**: defining which balancing services are considered (FCR, aFRR, mFRR and RR) and if previous energy dispatch is considered. When referred as 'balancing services', all balancing services are included. However, the modeling treats all of them as a whole for computational simplification.

✓ **Time framework:** depending on the target of the model, different time frameworks for market-solving are considered. Long-term consideration usually corresponds with 'Generation expansion planning models' and can be daily or hourly scheduled (with a lot of simplifications, such as representative weeks or months for each season). For short-term planning there are three main markets: day-ahead (DA) [90], intra-day [82] and real-time (RT) [91]. For DA, hourly schedule is used, and for RT, sub-hourly timing is considered. As our interest is focused on reserve markets, energy capacity to provide these services are traded the DA and power is activated in RT. This is why all models work in a short-term schedule and classification over this feature considers DA, intra-day or RT markets.

✓ **Sources of flexibility:** All these models consider EDF participation. For this reason, to characterize them, it is relevant to specify which sources of flexibility are considered. Options are: DG, Energy Storage Systems (ESS) and manageable loads, such as EV, thermostatically controlled load (TCL) or shiftable load (SL) in general. The particular case of the electric vehicle to grid (V2G) acts as an ESS. Flexibility modeled can come from a specific type of loads such as EVs [92, 93], electric heating systems [90] or all types of aggregated load [94–96]. The way these loads are modeled can be as a linear segment that can be plugged or unplugged [97], referred to as demand blocks, or in the case where the aggregator is involved, full control is assumed over each particular load [92–94]. Furthermore, when aggregator gathers DG or ESS besides load, the same criteria applies [98–104] being the aggregator the full responsible to decide whether to bid in one market or another and which flexibility resources should provide it.

✓ **Flexibility remuneration mechanism:** In addition, to encourage EDF providers to participate in the markets, cost avoidance analysis presented in [82, 90, 101] are not enough, remuneration mechanisms for flexibility products are necessary. However, they are still not well developed nor clear the best way to do so. Nevertheless, some models presented in Table 3 consider somehow demand flexibility payments. Some remuneration mechanisms can distinguish two different paid categories, band availability and utilization (in both directions) [99]. A more used remuneration mechanism only remunerates for utilization [98, 92, 93, 105], considered as the resources that changed their dispatch. In [92] a penalization for the deviations is also considered. Another way of remuneration in an indirect way for the flexibility used is by reducing billing costs [102]. Capacity payments are considered in [94] and as an up-front payment for only availability is also considered in [103].

✓ **Network consideration:** the network constraints are considered or not depending on the target of the model and the accuracy of results required. Table 3 gathers models with and without network consideration. There are also different ways of considering the network. For instance, as a microgrid, which assesses local results for specific studies as presented in [101] and [104]. In case the model applies to a whole country or a bigger system, a 'national grid' is considered where the way the grid is modeled is with power limitations based on ATC [95, 102, 103]. Moreover, in these models, the grid is simplified as active power limits (Direct Current (DC)). On the other side, in other studies as [92] and [93] unidirectional interaction with the grid is assumed, hence network is not modeled, as congestion and allocation of loads and generators are neglected.

✓ **Mathematical formulation**: This classification differentiates between deterministic optimization (Det.), stochastic optimization (Sto.), or equilibrium (Eq.) model based on [22]. Optimization models are formulated as a single objective function to be optimized, subject to a set of technical and economic constraints. When an optimization model considered perfect competition dispatch, the objective function is usually focused on (as explained in [21]) maximization social welfare [82,102], maximization profit or minimization of operational costs, where most models are formulated with this last objective function [90, 92–100, 101, 103, 104]. Furthermore, according to its parameters, certainty can be deterministic or stochastic. It is deterministic when parameters are known (i.e. mean value) and is stochastic if parameters are modeled as random variables with known distributions (Probabilities). In contrast, equilibrium models consider the simultaneous profit maximization of each participant competing in the market, usually using game theory approaches [22]. Models based on game-theory are adequate to assess medium and long-term strategies, as they evaluate and calculate the strategic behavior for every generation company. However, these models are generally simplified by using demand representations that do not follow a chronological sequence. Hence, when looking at reserves, these models are not appropriate as temporal constraints are not considered [21].

✓ **Market clearing-price calculation:** When calculating the market clearing-price it can be considered the initial investment payback which refers to the capital expenditure (CAPEX) which is not very common, the operating costs (OPEX) or consider both costs (TOTEX) to calculate the price.

Table 3 shows the abovementioned characteristics of the models with EDF participation in balancing services from the literature.

For congestion management models with EDF participation classification presented in Table 4, the characteristics that have been considered are similar to the ones above with some nuances:

✓ **Electricity markets modeled**: When the focus is placed on the markets that apply to constraint management the options are: voltage control, network loss and congestion management. When all of them are modeled, it is referred as 'All DSO services'; when there is no specification over the market modeled, it is referred as 'DSO services'. Besides, these services can apply to the TSO [81], to the DSO, or both. In [107], congestion and balancing services are modeled at the same time as an exception.

✓ **Time framework:** It is a relevant feature for these models whether they are designed to prevent a future congestion problem or correct an already existing one. Therefore, the timing where the congestion is solved is classified between preventive or corrective [75].

✓ **Sources of flexibility**: For this research, only EDF sources are considered. Therefore [81] has been neglected as only implicit demand flexibility is modeled for solving congestion problems. This classification is the same as for balancing services detailed explained above.

✓ **Flexibility remuneration mechanism:** As mentioned, it is still not well developed nor clears the best way to remunerate flexibility services. For solving congestion problems, some examples for remunerating this service are regarded in the models presented in Table 4. In [108], remuneration is defined by end-users according to changes in baseline consumption. In [109] a price incentive iteration method is applied to EV aggregators. In the model presented in [110], the objective is to maximize the payoff for the electricity provider which is obtained by subtracting the cost of energy purchase at the wholesale market from the sales to end-users.

✓ **Network consideration:** congestion can occur in the distribution or in the transmission grid, as EDF is connected to the distribution grid, all the models analyzed take the grid into account only at distribution level.

Table 4
Mathematical models for congestion management services.

Source/ Model	Markets involved	Timing (Preventive or corrective)	Sources of EDF	Payment/remuneration for flexibility	Considers the Network (Yes, No)	Opt.Sto, Opt.Det or Equilibrium (Eq)	Purpose
[75]	All DSO services	Preventive	DG and ESS	No	Distribution grid	Det	DSO
[107]	Balancing and CM for DSO	Corrective	Aggregated loads	No	Distribution grid	Det	DSO
[108]	DSO and BRP services	Preventive	Aggregated Residential loads	Yes	Distribution grid	Det	Aggregator
[109]	All DSO services	Corrective	Aggregated EVs	Yes	Distribution grid	Det	DSO
[110]	CM service for DSO	Preventive	Aggregated EVs and HP loads	Yes.	Distribution grid	Sto	Aggregator
[111]	CM service for DSO	Preventive	Aggregated industrial and residential loads	No	Distribution grid	Det	DSO

✓ **Mathematical formulation:** Focus on the same classification explained above, differentiating between deterministic optimization (Det.), stochastic optimization (Sto.) or equilibrium (Eq.) model based on [22].
✓ **Purpose:** The purpose of all these models is minimizing the costs (or maximizing the profit) of procuring with flexible sources capable of solving congestion at distribution level and minimizing also congestion problems. The optimization problem can be regarded from different entities: DSO or Aggregator.

Table 4 shows the abovementioned characteristics of models that include EDF participation in congestion management services from the literature.

4. EDF in Europe

In this section, first, a general overview of the European countries' achievements and developments over EDF integration as another market participant in balancing services is given. Secondly, demand participation in congestion management products available in Europe is presented. The third point, contributes to organize and classify the projects and initiatives that encourage EDF integration in European countries.

4.1. Balancing services in Europe

There is a desire to increase harmonization in European countries, balancing services regulation and products. The more regulatory measures are unified, the easier it becomes to extend the markets internationally, reaching a more efficient system. There are three ongoing projects to redesign harmoniously European balancing platforms. Each one corresponds with a different product available to manage operation reserves [112–114]:

- TERRE project aims to develop a common platform for RR products, which corresponds with balancing energy with an activation time up to 30mins [112].
- MARI project aims to implement a platform for European countries to exchange balancing energy from mFRR with an activation time of less than 15 min. [113]
- PICASSO project aims to establish the European platform for the exchange of balancing energy from aFRR with an activation time between 30 s and 15 min. [114]

These platforms together will facilitate the participation of all kinds of resources in the balancing services.

The progress in adapting some national BMs to integrate demand resources has been limited. Differences in existing legislation and regulatory frameworks make it difficult for some countries to cooperate on a common electricity market [51]. However, there are also countries with a high deployment of demand inclusion regulatory measures such as: Germany and Switzerland that are participating. A brief summary on EDF participation for EU countries in each market is gathered from sources [72, 63] in Table 5 :

Germany, Switzerland, and Sweden stand out as they have progressed quite fast regarding EDF access to the balancing markets [72, 63]. All balancing services are open to all market parties and all technologies, as long as they meet the technical requirements of each service. In Germany, the definition of an aggregator framework encouraged independent entities to participate as the participation process and the contracts needed have been simplified, thus considerably fostering EDF participation. However, in Germany IA is not yet allowed as there is no regulation over this figure [55]. The main weakness in Germany is transparency. The amount of energy traded in the balancing markets that comes from the demand side is not easy to estimate, since only the prequalified capacity per technology is publicly available; therefore, Table 6 does not specify quantities for the German case.

Conversely, in France the majority of ancillary services are open to demand participation, as technical prerequisites are reasonable and easier to comply by independent parties to be able to bid into the market through pooling [72], although in RR there is no real participation as there are still some barriers. In addition, direct access to aFRR is limited as only large generators are obliged to provide it. Hence, generators procure with their required reserve through a secondary market enabling other BSPs to trade their flexibility for the system. Nevertheless, activation selection is made on a pro-rata basis and the activations period would be too long and frequent. Hence, in practice there is no EDF participating in this product. The PICCASO project tackles this barrier as it will implement merit order list activation for this secondary market [72]. Another barrier is that aggregation of flexible demand and generation in the same pool is not allowed, only a pilot project has been

Table 5
EU countries balancing market openness to demand participation.

Demand participation	FCR	aFRR	mFRR	RR
Austria	NO	YES	YES	Doesn't exist
Belgium	YES. Load upwards	NO	YES	NO
Germany	YES	YES	YES	Doesn't exist
Denmark	YES	YES	YES. Limited to electric boilers	YES
Finland	YES	NO	YES	Doesn't exist
France	YES	NO. PICASSO project.	YES	YES
Ireland	YES	YES. Only industrial customers	YES. Only industrial customers	Only De-synchronised
Netherlands	NO	YES	YES	NO
Sweden	YES	YES	YES	YES
UK	YES	NO	NO	YES
Poland	NO	NO	NO	NO
Spain	NO	YES	YES	YES
Italy	NO	NO	NO	NO
Switzerland	YES	YES	YES	YES

Table 6
Germany and France EDF participation in AS [53].

	Service	Country product name	Total capacity contracted [MW]	EDF access and participation	Aggregation accepted
GERMANY	FCR	Primary control reserve	830	✔	✔
	aFRR	Secondary control reserve	1.976	✔	✔
			1.907	✔	✔
	mFRR	Minute reserve	1.850	✔	✔
			1.654	✔	✔
FRANCE	FCR	Primary Control	600-700	70MW	✔
	aFRR	Secondary Control	600-1.000	Access through a secondary market	!
	mFRR	Fast Reserve	1.000	500MW	✔
	RR	Complementary Reserve	Max. 500	Access but no participation	✔
	DSR-RR	Demand Response Call for Tender	750-1.400	730MW	✔

✔ YES ! HALTINGLY ✖ NO

launched for FCR, mixing on-site generation with flexible demand. The French TSO (RTE) is also considering allowing asymmetrical product participation to enable this kind of aggregated pool. In addition, the IA framework is quite developed in France, allowing aggregators and consumers to use their flexibility without having to sign a contract with the supplier BRP. This key regulatory progress has led the French market to develop a mechanism called NEBEF, created to allow virtual pools of load to be traded in the wholesale market [115]. In November 2018, the "energy mix planification" program [72] started working, establishing the amount of EDF necessary to be bided in the markets. To achieve this required amount and to develop EDF participation in the existing products, additional exclusive tenders for EDF began to be organized. The French government is in charge of deciding beforehand the quantities of EDF that will be tendered. For 2018, 2.200 MW were originally tendered, however was not reached due to the penalties established which disincentivize participation and the falling trend in payments in this product [72]. Table 6 shows the 2017 total contracted capacity, EDF participation and aggregation allowance. Table 7describes Germany and France balancing services characteristics:

There are also some countries like Spain that has not yet developed adequate national regulations neither for the prosumer figure nor demand aggregation. In Spain, there is only one real scheme that provides flexibility to the system, which is the interruptibility system for the electro-intensive industry. The big consumer responds to the need of the system of disconnecting from the network, enabling this way other users to be fed in scarcity circumstances. This scheme is managed by the Spanish TSO, Red Eléctrica de España (REE) [117]. However, further developments have been recently applied in regulatory measures to include demand participation in balancing services, this changes are presented in the Operation procedures (OP) [104].

4.2. *Congestion management in Europe*

European countries agree that demand flexibility should be available for solving congestions at DSOs and TSOs level, on an open flexibility market. Several initiatives and regulatory framework amendments are evolving in European countries but only at distribution level. The Expert Group 3 (EG3) pushes many of these modifications in its first version of the report 'Regulatory Recommendations for the Deployment of Flexibility' [118]. However, did not work on a market model. Therefore, multiple models are appearing where the DSO can take advantage of demand flexibility to solve its own congestion problems. Some countries that are doing this are: Netherlands, Belgium, Germany, Denmark, Ireland, Norway, France and recently Spain [70].

Germany and Spain models with the aim of including the use of EDF to solve congestion problems harness the 'Smart Grid Traffic Light Concept' [119], to incorporate demand flexibility into distribution grids. Localized network congestion is managed using the available distributed demand flexibility, and to trigger it there is a communication process between grid operators and market partners that procures with the different traffic light phases [70].

Table 7
Germany and France AS features. Based on sources [72,20,116].

	Service	Minimum size [MW]	Symmetrical bid required?	Notification time	Activation	Utilization settlement rule	Max. Duration of activation
GERMANY	FCR	1	Yes	<30s	Automatic	Pay as bid	1 week
	aFRR	5 (1 MW if no other offer)	No	<5mins	Automatic	Pay as bid	4 h
	mFRR	5 (1 MW if no other offer)	No	<15mins	Automatic	Pay as bid	4 h
FRANCE	FCR	1	No	<30s	Automatic	Regulated price	30mins
	aFRR	1	No	<15mins	Automatic	Mandatory	30mins
	mFRR	10	No	<15mins	Manual	Pay as bid	30mins
	RR	10	No	30mins	Manual	Pay as bid	30mins
	DSR-RR	1	No	2h	Manual	Regulated price	30mins

- Green light means no congestion predicted. Hence, demand flexibility is offered by aggregators for market and system-oriented portfolio optimization and for balancing.
- Yellow means grid congestion predicted. Hence, demand flexibility is requested by DSO (grid oriented) on a contractual basis to avoid economic inefficient network expansion.
- Red means congestion in real time. Hence, demand flexibility nodes are controlled by DSO without contractual basis to preserve a secure network operation [120].

In the German initiative 'The Proactive Distribution Grid' the DSOs request to the aggregator a list with their total flexibility requirements, including necessary types and boundary conditions in order to provide congestion management services. There are different variables such as: grid location, topology and predicted power flow of a specific area that would influence the usefulness of possible flexibilities. Therefore, the aggregator individually values the elements of their portfolio to optimize selected assets according to the congestion-specific sensitivity for each flexibility type [121]. This selection of demand flexibility options and its final activation procedure are managed through a platform which has the information at the same time of the congestion forecasts. Subsequently, aggregators are in charge of deciding the best assets to use to comply with the flexibility request while upholding existing contractual agreements with their customers. Another research project in Germany is 'Advanced Decentral Grid Control' [70] which also works in developing a process to integrate the market participants and the DSO to facilitate power flow predictions in Medium/Low Voltage grids. The main difference with the other initiative is that a contract with the prosumer is necessary [122].

There is also an ongoing project in Spain called IREMEL and is working on developing an efficient model to take advantage of DERs [123].It is necessary to allow DER participation in the existing European electricity markets for the periods where no restriction exists to achieve an efficient market model. Moreover, participation allowance in the local flexibility markets is also a must. To know when European markets have restrictions or not for DER participation, grid traffic light code is used in the same way as in Germany [124]. IREMEL involves large and small DSOs, individual DERs, aggregation companies, proactive consumers, battery producers, tech companies, Energy Associations etc. All these entities will participate in the different pilots in order to assure a correct performance of the system in case congestion is detected at DSO level. 5 pilots will be carried out to test the proposed model in different Spanish areas. The project also includes the definition of an efficient information sharing procedure between DERs, Aggregators, Market Operator, DSOs and TSOs [123].

Conversely, in France, the main barrier comes from the established method of connecting resources to the distribution grid. In the traditional connection method, the prosumer pays most of the connection costs. Hence the DSOs not have the right to refuse connection of any medium voltage (MV) power plant to the network. To address this barrier, the Innovative Connection Offer (InnoCon) project was developed with the aim to provide an alternative to the reference connection offer to renewables power plants, facilitating the connection rapidly and less costly. The way it works is offering a connection contract providing the opportunity for the producer to produce more than the contracted quantity when technical conditions are favorable. In return, the DSO has the right to curtail their power generation at certain times of the year when network constraints are likely to occur. Thus, as the electricity generation depends on the state of the network, this would lead to an increase in the network's overall connected power, limiting at the same time the amount of energy curtailed. As a result, investment in capacity necessary with current connection rules can be avoided [70].

4.3. Projects and initiatives

There are many other projects, pilots, and initiatives on track involving flexible demand integration in the grid and EDF participation in markets and data management.

These projects goals are sometimes similar. Briefly, some of the objectives the projects are working on are organized as follows:

1. Proving the feasibility of a proposed solution to network congestion
2. Providing imbalances services efficiently
3. Including demand flexibility participation in a market product/service.
4. Fostering a specific technology (Solar distributed, ESS or smart grids deployment)
5. Improving aggregated demand participation framework. This means standardizing processes over involved parties' relationship and data sharing, facing barriers to aggregator's participation in different markets and providing technological solutions, and everything in accordance with European regulation.

In addition, the different categories that are going to be considered according to their main aim and developments to classify all these initiatives are based on [125] and are presented in Table 8:

The types of loads that the initiatives involve are specified, distinguishing over: Residential, Commercial, Industrial, Electric vehicle (EV), Distributed Generation (DG), Energy Storage (ES), All (Which include all distributed generation and loads at TSO and DSO level) or Aggregated (Which refers to all DERs gathered by the aggregator).

Table 9, summarizes these characteristics for each project:

5. Critical analysis on EDF

From a technical point of view the deployment of EDF as another market party for balancing services or congestion management is possible as the needed technology and devices exist. However, there is much work to be done to make this really happen. In order to face the main social and regulatory barriers for EDF development and integration in the different electricity markets, a significant economical investment is required and a strong commitment is necessary from the different countries' governments to develop policies that foster EDF deployment and exploitation in the short term. In addition, to design and analyze the EDF participation in markets, mathematical models are required. For this reason, an analysis is performed over the already existing models capable of counting on the participation of EDF in the markets.

Table 8
Initiatives categories classification.

Categories	Main aim of the initiatives
Market platform	Place where buyers and sellers of flexibility meet to trade flexibility.
TSO/DSO operational platform	Platform to operate balancing services or to manage the grid with flexible resources participation either at TSO or DSO level.
TSO/DSO coordination platform	Platform where TSOs and DSOs cooperate to carry out the tendering, trading, activation and/or settlement of EDF for their own purposes (i.e. ancillary services).
Market facilitation platform	To support the energy market well-functioning and wholesale settlement, by distributing the available data previously validated and enriched.
Technology platform/VPP	Platform to monitor and control particular features of the flexible assets in a specific portfolio or location.
Energy management progress	Work to improve control devices performance and foster the use of new appliances prepared to be controlled remotely within the home, building or factory.
Policies pusher by providing technical solutions	by analyzing a particular barrier in the market (Relationship between parties, data sharing…) aims to influence and prove a Regulatory policy that address the problem.

Table 9
EU Projects and initiatives.

Project	Type/Category	Goal	Countries involved	Target loads	Active or work in progress (WIP)	Source
Invade	DSO operational platform	1	BG, DE, ES, NO, and NL	EV and ES	Finalice by 2019 ACTIVE	[126, 127]
FUSION-TRANSITION	DSO operational platform	3	UK	All	2018–2023 WIP	[128, 129]
InterFlex - Enexis	DSO operational platform	5	NL	ES and EV. Commercial aggregators	2017–2019 ACTIVE	[128]
MADE	Energy management progress	5	UK	Residential	2019–2020 WIP	[130, 131]
Future Flex	Energy management progress	1	GB	Residential	2019–2021 WIP	[132]
EnergieKoplopers	Energy management progress	3	NL	Residential	2016 ACTIVE	[128, 133]
Cordis	Energy management progress	5	EU	Residential	2020–2023 WIP	[134]
Cordinet	Energy policies pusher	5	ES, SE and GR	All	2019–2022 WIP	[135]
Smart Solar Charging	Market and DSO operation platform	4	NL	Residential and commercial	Jan 2020 ACTIVE	[128]
DRIvE	Market facilitation and DSO operational platform	5	EU	Residential and commercial	2017–2020 WIP	[128]
Flex4Grid	Market facilitation platform	5	EU	All	2015–2018 ACTIVE	[136]
Fskar	Market facilitation platform	5	EU	All	2019-WIP	[137]
CATALYST	Market facilitator platform	5	EU	All	2017–2020 WIP	[128]
DRES2MARKET	Market facilitation platform	2	ES, FR, NL, GR, AT and NO	DG	2020–2023 WIP	[138]
OneNet	Market facilitation platform	3	EU	All	2020–2022 WIP	[139]
IDCONS	Market platform	1	NL	All	2019 ACTIVE but still WIP	[125, 140,141]
Piclo Flex	Market platform	5	UK	All	1st phase active since 2018. 2nd phase WIP	[123, 142]
DYNAMO	Market platform	1	NL	Aggregated	2016–2019 ACTIVE	[128, 143,144]
FlexLab	Market platform	1	NO	All	2020-WIP	[145]
IREMEL	Policies pusher by providing technical solucitions	5	ES	DG	2019-WIP	[123, 124]
Smart Grids Task Force – EG3	Policies pusher by providing technical solutions	4	EU	All	2018 ACTIVE	[128, 146,40]
ebIX distributed flexibility project	Policies pusher by providing technical solutions	3	EU	All	2020 ACTIVE	[128, 147,148]
ENGENE	Technology platform	4	NO	All	2018 ACTIVE	[125] [145]
NorFlex	Technology platform	3	NO	Residential, commercial and industrial	2019–2021 WIP	[149]
DOLFIN	Technology platform	5	EU	Industrial	2013–2020 WIP	[150] [151]
Hoog Dalem	Technology platform	4	NL	Residential	2017 ACTIVE	[128]
Smart Energy Isles	Technology platform	5	UK	Residential	2019 ACTIVE	[128]
REDREAM	Technology platform	5	ES, BE, IT, HR, UK, GR, FR, DE	Residential, commercial and industrial	2020–2023 WIP	[152]
MOMEBIA	Technology platform	1	ES	Aggregated	2020–2022 WIP	[153]
ENERA	TSO operational and coodination platform and also market facilitation platform.	5	GR,FR,UK, NL, BE,AT,LX, SW	Aggregated	2018–2020 WIP	[125, 154]
International Grid Control Cooperation (IGCC)	TSO/DSO operational platform	2	AT, BE, CH, CZ, DE, DK, EL, FR, HR, IT, NL, PL, PT, RO, RS, SI and ES	All	2019 ACTIVE	[155]
Danish Market Models	TSO/DSO coordination & market platform	2	DK	All	2018–2020 WIP	[128]
GOPACS	TSO/DSO coordination platform	1	NL	All	Jan 2019 ACTIVE	[123, 156]
Intra Flex	TSO/DSO operational platform	2	UK	All	2019–2021 WIP	[157, 158]
Interreg CvvP	VPP	5	EU	DG	2017–2020 WIP	[128, 159]

From the assessed models able to include EDF as a participant in the balancing services, some weaknesses identified include:

- Models do not separate between the different balancing services, only [97] distinguishes among the ancillary markets, but a demand block simplification is applied. Requirements for the different services are neither the same nor remunerations. Therefore, treating them as a whole can limit EDF participation, as a supplier cannot be prepared to provide all of them. Thus, neglecting some technologies possibilities.
- There is a lack of models that consider how EDF participating in balancing services can influence in long-term planification of generation expansion. A key factor to face the energy transition it is to include EDF as another market participant, being necessary to develop long-term analysis models that take it into account to take consistent investment decisions.

- Type of loads considered is still limited. General modeling of aggregated DG, ESS and load is only presented in [98,102] and the rest of the models do not consider the three categories at the same time.
- From the models above, it is not yet clear which is the best flexibility remuneration mechanism to incentivize flexibility sources participation in balancing markets.
- Very few models consider the whole system network [95, 102, 103] being an essential part when DER is considered to assess bidirectional flows.

Conversely, the most relevant weak points found in the congestion management models analyzed in the literature that include EDF participation are:

- Lack of mixture of preventive and corrective models, as usually both are complementary one with the other.
- No clarification on which remuneration mechanisms are more efficient and fairer.
- Sources of EDF are still limited. Most aggregators only include loads. There is no congestion solving models aggregating DG, ESS and loads at the same time.
- Including stochasticity in preventive models may improve these models' results.

Furthermore, each country is planning their deployment of regulatory measures and policies. In this regard Netherlands and Great Britain are the most advanced European countries in active initiatives. Additionally, there are plenty of projects from a European perspective that are relevant to unify the market as much as possible. According to the Network Codes [160] all three European platforms (TERRE, MARI & PICCASO) that allow for EDF participation in the balancing markets should be deployed by the end of 2022.

All these findings raise some questions for future research:

1. Estimation of EDF integration costs: for the TSO, the aggregator, or the individuals.
2. How to manage all distributed energy resources (DG, ESS and manageable load) at the same time for operation optimization.
3. Define the most appropriate and fairest remuneration mechanism for EDF participation in the different markets.
4. How EDF participation in all other markets besides balancing and congestion services could be addressed. Always taking into account a non-discriminatory market, in which participation is allowed regardless of the DER technology (storage, generation or demand) and the size of the consumer.

6. Conclusions

This paper contributes to clearly define the term of EDF in future electric systems. To the authors' best knowledge, it is the first time an exhaustive EDF review has been performed in different parts: clarifying the difference between system flexibility and demand flexibility terms, the potential of the markets where EDF can participate, what are the current barriers, what is being studied and what is done in Europe. The outcomes of the analysis and review performed at each part is suitably summarized and classified in Tables and Figures enabling a comprehensive outlook of the main options and relevant issues involved in each part.

Thus, the article starts understanding the different types of demand flexibility. It can be assured that EDF is the only type of demand flexibility that really provides system flexibility, aggregated or not. One way to take advantage of its possibilities is participating in the balancing and congestion management services as another market party. Then, the main barriers for EDF integration as another market participant have been identified and classified in two different levels. In addition, mathematical models where EDF participates have been studied and classified; identifying the main weaknesses these models have and where should be work on.

Then, some European countries have been gathered and analyzed regarding their current status of the EDF integration in the balancing markets explaining Germany and France in more detail. Besides, a summary of the most relevant projects and initiatives that are working to improve the EDF participation framework and how they are doing it is provided.

Finally, the next research lines, questions to be solved and current gaps have been outlined taking into account the review done in each of the previous parts.

Declaration of Competing Interest

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

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PAPER 2

- Detailed Spanish demand growth analysis for 2030 horizon.
- Competition between different firm capacity technologies.
- Demand response relevance when planning the future of the Spanish electric system.
- Firm capacity payments are needed to assure firm providers cost effectiveness.

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Research paper

Storage and demand response contribution to firm capacity: Analysis of the Spanish electricity system

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Pumped-hydro storage

ABSTRACT

Provision of firm capacity will become a challenge in power systems dominated by renewable generation. This paper analyzes the competitiveness and role of battery storage, six types of pumped-hydro storage, open cycle gas turbine (OCGT), and demand response (DR) technologies in providing the firm capacity required to guarantee the security of supply in a real-size power system such as the Spanish one in horizon 2030. The paper contributes with detailed and realistic modeling of the DR capabilities. Demand is disaggregated by sector and activities and projected towards 2030, applying a growth rate by activity. The load flexibility constraints are considered to ensure the validity of the results. A generation operation planning and expansion model, SPLODER, is conveniently upgraded to properly represent the different storage alternatives addressed in the paper. The results highlight the importance of considering demand response for evaluating long-term firm capacity requirements, showing a non-negligible impact on the investment decisions on the amount of firm capacity required in the system and the optimal shares of wind and solar PV renewable generation. Results also show the dominance of cost-competitiveness of pumped hydro and OCGTs over batteries. Additionally, capacity payments are required to support firm capacity providers' investments.

1. Introduction

Ensuring the security of supply in the Spanish electricity system is a task that faces multiple challenges in the near future. The Spanish national energy strategy commits to achieving at least 74% of renewable electricity generation by 2030 (PNIEC, 2020). Spurred by their increasingly competitive investment costs, there is no doubt the system will mainly rely on wind farms and solar photovoltaic (PV) power plants to meet this target. The production of such renewable generation is fully weather dependent, severely jeopardizing the security of supply, that is, the system's availability to count on enough available generation to meet the demand at any time. These renewable sources are substituting thermal generation, which has traditionally provided the system security of supply and flexibility. Therefore, it will be necessary to resort to additional resources to fill the gap left by phased-out thermal generators as firm capacity[1] providers. Moreover, to be aligned with European goals (Meeus and Nouicer, 2020), these new resources should also have low emissions.

Storage facilities are one of the most suitable technologies to provide firm capacity. A large-scale battery is one of the options. (Mallapragada et al., 2020) assess its potential as the primary resource of firm capacity, concluding that further cost reduction is necessary for batteries to become a cost-effective alternative. Although available in scarce locations, pumped-hydro storage is another option to be considered due to their maturity, large storage capacity, relatively low capital costs, mainly when they take

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[1] Firm capacity technologies refer to energy sources whose capacity is available at the most critical periods of generation as it is controllable and able to supply energy as needed independently of weather or external conditions (Zachary et al., 2019) safeguarding system adequacy.

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advantage of some already installed hydro reservoirs, and fast response capability when needed (Amirante et al., 2017). Many other innovative storage kinds of resources have also been assessed in Korkmaz (2019), such as compressed air energy storage, hydrogen storage, and other developing technologies such as flow batteries and liquid air energy storage. However, none of these more innovative resources is yet close to being cost-competitive.

Other options to provide security of supply beyond storage technologies have also been considered in some publications addressing the future of electricity systems. For instance, the use of power plants with carbon capture and storage combined with high interconnectors capacity (Brouwer et al., 2014), or the geographical diversification of wind farms in Germany, show the reduction of firm capacity needed (Bucksteeg, 2019).

There are other papers similar to this one, where the high penetration of renewables is the issue that result in the pursuit of generation alternatives to guarantee the security of supply of the electricity system. Gaete-Morales et al. (2019) provides the analysis of the Chilean system in horizon 2050. Ruhnau and Qvist (2022) compare different storage types (hydrogen storage, pumped-hydro storage & batteries) to guarantee the security of supply in the German electricity system. Arion (2020) analyze Moldova's pumped-hydro storage needs and Lu et al. (2021) assess China's options to achieve a carbon-neutral electricity system where DR is mentioned qualitatively. However, it is not assessed its impact on the electricity system.

As presented, in the literature, firm capacity requirements are primarily addressed, in addition to generation units, with pumped-hydro storage and lithium-ion batteries. The main contribution of this paper is the analysis of an additional competitor in the provision of firmness, neglected in those studies, which is the impact of demand-side management in a high renewables penetration electricity system. Besides, the paper contributes with the upgrades performed in the model to enable it to be used for the first time for this purpose. DR is expected to rapidly increase to comply with European Commission directives (European Parliament, 2019), although regulatory, technological, and social barriers (Freire-Barceló et al., 2022) need to be addressed. New automation technologies and increasing customer engagement (Gómez-Barredo et al., 2021) may have a non-negligible impact in many aspects, also regarding the firmness requisites and generation investment planning.

Moreover, the information available in the literature about the origin of electricity demand and the corresponding flexibility, was completely outdated (Red Eléctrica de España, 1998; Instituto para la Diversificación y Ahorro de la Energía, 2016a). Therefore, a disaggregated representation of the demand differentiates demand growth rates towards 2030 by demand use and to accurately and realistically represent the demand response capabilities of each consumption category. Thus, this valuable and useful information can be used for developing different types of studies.

Overall, the work presented in this paper is a natural follow-up of the one presented in Huclin et al. (2022), where firm coefficients are determined for the different storage technologies. Using those coefficients and the ones that can be found in the literature, the paper analyzes and discusses the need for new firm resources to maintain the security of supply of the Spanish electricity system in horizon 2030 and to consider the generation volatility in a scenario 2030 with a high share of renewables. The SPLODER model, a generation expansion planning model, is the tool used for the analysis. The first version of the model has been presented in Martínez et al. (2017) where the core equations were introduced with the novelty of a disaggregated representation of the demand by usage types such as heating and cooling, domestic hot water or electric vehicles. This fact limits the capability to shift demand freely since each consumption type have specific constraints. The model has already been applied in previous studies such as Martín-Martínez et al. (2017), in which the analysis and scenario definition was focused on comparing centralized vs. distributed generation alternatives considering flexible loads. The model formulation has also been upgraded and used in Gerres et al. (2019), including new remuneration mechanisms required to achieve the renewable penetration targets together with enough firm capacity provision. In addition, the model is already prepared to manage flexible demand and to develop this study, it has been upgraded to properly represent in detail different firm capacity providers, namely different kinds of pumped-hydro storages, large-scale batteries, and OCGT, as well as the consideration of the demand-side response. Thus, the model is used for the first time to analyze the resources required to provide firm capacity and the competitiveness among them, and how the full potential of DR may impact these results as well as the optimal investments in renewable generation. The Spanish electricity system is weakly interconnected, and it can be considered as an energy island (THE LOCAL, 2022; Wilson and Muñoz, 2022). Therefore, neglecting interconnections allows obtaining insights into the possible evolution of power systems with high penetration of variable renewable energy resources.

The main contributions of this paper are threefold. Firstly, the paper contributes by providing a detailed Spanish demand growth disaggregated analysis, obtaining two extreme cases. This allows the consideration of a detailed and realistic representation of DR, previously modeled, in a real-sized electricity system and assessing its role and relevance when planning the future firm capacity provision, as it considerably diminishes the required investments. Secondly, the paper contributes to analyzing the competitiveness among different firm capacity technology providers under different scenarios. Thirdly, the methodology applied resorts to an optimization tool, the SPLODER model. SPLODER mathematical formulation presented in Martínez et al. (2017) and Gerres et al. (2019) has been upgraded with the inclusion of storage technologies to enable the analysis of the contribution of DR and other technologies to firm capacity requirements. These changes are thoroughly explained in Section 3, thus contributing with a more complete model in the literature.

The rest of the paper presents the following structure. Section 2 presents a demand growth analysis necessary for characterizing the Spanish electricity system until 2030 and identifies demand management capabilities as another firm capacity resource. Section 3 describes the new formulation added to SPLODER, differentiating multiple different types of centralized storage resources, and the description of the associated required input data. Section 4 presents the scenarios assessed in the paper based on the national policy targets and extended to cover different sensitivities aligned with this study's main aim. Results are discussed in Section 5. Finally, Section 6 assesses the findings and identifies additional future research needs.

2. Demand growth analysis

In the next future, electricity systems will experience a deep change in the demand side towards more efficient energy consumption. Besides, decarbonization targets will boost higher levels of electrification so that significant growth of demand flexibility is expected to be available. The more electric loads, the easier it becomes to profit from their adaptability to consume at different times without compromising the electricity end usage and the consumers' comfort. To take advantage of controllable loads, it is necessary to compute the load flexibility potential and the limits that consumption can be managed. To this end, four categories of electricity consumption within the residential

Table 1
2015 electricity demand in Spain.

Electricity demand	2015	
Sector	TWh	%
Residential	72.73	29%
Services	76.24	31%
Transport	6.40	3%
Industry	91.86	37%
Total	247.22	100%

Table 2
2015 electricity demand of the residential sector in Spain.

Electricity demand	2015	
Residential sector	TWh	%
Heating	4.42	6%
Cooling	3.40	5%
DHW	4.48	6%
Lighting and others	60.43	83%
Total residential	72.73	100%

and services sectors have been considered to be controllable in different ways: heating & cooling (climatization), domestic hot water (DHW), refrigeration (cold chain, freezers, and fridges) and electric vehicles (EV). It is relevant to come up with an estimation of the amount of demand associated with each of these categories and which proportion of each one will be ready to be controllable.

To estimate the amount of demand in the Spanish sector, classified according to the above-mentioned categories, the following methodology has been applied:

– First, load hourly data of the Spanish electricity system for the year 2015 are considered for each sector (residential, services, transport, industry) as the base profiles. This year has been selected because the information available is very detailed by different usage types. In addition, the pandemic does not influence consumption and clearly serves as a reference year for estimating growth rates (Instituto para la Diversificación y Ahorro de la Energía, 2011).
– Second, residential and commercial sectors' data are further disaggregated using a set of complementarity reports to reach the granularity required to identify the potential controllable, that is, climatization, DHW, refrigeration, and estimation of EVs loads. This disaggregation was deeply studied during the years 2014–2018.
– Third, a literature review has been performed to set a range of annual demand growth for each category.
– Fourth, the two extreme values found in the literature for the 2030 demand growth will define the range in which it is located and the potentially controllable load that the model will consider. Furthermore, to validate the estimated growth, it has been checked that there are no inconsistencies with the information available up to 2022.

Table 1 shows the 2015 electricity demand breakdown in the four main consumption sectors, obtained as the average value from reports (PNIEC, 2020; International Energy Agency, 2015; Linares and Declercq, 2018; Deloitte, 2018b; Government of Spain, 2018).

As shown in Tables 2 & 3, the "Residential" and "Services" consumption sectors have then been further broken down into different categories based on Instituto para la Diversificación y Ahorro de la Energía (2016a), Persson and Werner (2015) and Consultores (2005), using the "Lighting and others" category to gather the rest of demand, considered as inflexible.

The transport sector electricity consumption for 2015 has been calculated as the sum of EV and electric trains consumption. The following calculation has been applied to estimate the part of it corresponding to EV. The EV fleet published in European Commission (2015) and presented in Table 4 has been used as the starting point. Then, an average EV consumption of 0.2 kWh/km has been assumed based on the average electric car consumption in Oak Ridge (2022), and considering the inefficiency due to the charging and discharging cycle as assessed in Iclodean et al. (2017). Finally, Spain's average daily car uses is assumed to be 40 km/day, as shown in European Environment Agency (2019). These assumptions led to an estimation of 17 GWh for the total EV electricity demand in 2015, as presented in Table 5. The remaining transport sector electricity consumption in Table 1 has been associated with the railway sector.

Table 3
2015 electricity demand of the services sector in Spain.

Electricity demand	2015	
Services sector	TWh	%
Heating	13.89	18%
Cooling	11.11	15%
DHW	0.80	1%
Lighting and others	47.91	63%
Refrigeration	2.52	3%
Total services	76.24	100%

Table 4
2015 EV fleet in Spain.

EV	2015
EV fleet [N° of vehicles]	5848

Table 5
2015 total transport sector electricity consumption in Spain.

Transport	2015
EV consumption [TWh]	0.017
Trains [TWh]	6.39
Total [TWh]	6.40

Table 6
2030 min. and max. demand for the residential sector [TWh].

Residential demand	2030 min	2030 max
Heating	36.87	48.29
Cooling	5.65	13.48
DHW	14.79	22.77
Lighting and others	39.68	45.46
Total residential	97	130

Once the 2015 demand breakdown has been set, minimum and maximum demand growth values for 2030 have been estimated for the different sectors and consumption categories.

For residential and service sectors, forecasts published in Linares and Declercq (2018), Instituto para la Diversificación y Ahorro de la Energía (2011), Jakubcionis and Carlsson (2018) and Instituto para la Diversificación y Ahorro de la Energía (2016b) have been contrasted to determine the demand growth rate for the different consumption categories. The most optimistic and pessimistic predictions published across the reviewed publications have been selected to define a range with the minimum and the maximum demand growth for 2030. The residential and services sector's minimum and maximum consumption are presented in Tables 6 and 7, respectively.

Transport sector demand growth assumed in the study and presented in Table 8 is based on the most extreme values concerning the expected EV fleet growth stated by PNIEC (2020) and International Energy Agency (2015) .

Table 7
2030 min. and max. demand for the services sector [TWh].

Services demand	2030 min	2030 max
Heating	14.71	22.47
Cooling	12.03	17.08
DHW	0.89	1.78
Lighting and others	56.92	43.49
Refrigeration	2.80	2.81
Trains	6.60	8.77
Total including trains	93.94	96.39

Table 8
2030 min. and max. demand for the transport sector.

Transport demand	2030 min	2030 max
EV fleet [N° of vehicles]	300,000	5,000,000
EV consumption [TWh]	0.876	14.6

Table 9
2030 min. and max. demand for the industrial sector [TWh].

Industrial demand	2030 min	2030 max
Industry	103.6	124.9

Table 10
2030 total min. max. and average demand [TWh].

Total demand	2030 min	2030 max	Average
Residential	97	130	114
Services	94	96	95
Industry	104	125	114
Transport	1	15	8
Total	295	366	331

Industrial demand growth for 2030 is expected to be in the range described in Linares and Declercq (2018) and presented in Table 9.

In the scenarios presented below, intermediate growths in-between the range presented (2030Min and 2030Max) are considered individually for each sector and consumption category. Table 10 presents the minimum, the maximum and the average of the total electricity demand by sector.

As a final step in the demand characterization, different degrees of penetration of demand response are considered in the study. It is assumed that only a fraction of all the potentially controllable loads will be ready to participate in demand response programs by 2030.

Finally, it is important to properly model the actual capabilities of demand response of such manageable loads. Demand management corresponds to a demand shift among hours. But demand cannot be shifted in any way. Each of these loads obeys to a process that limits its response capabilities. For instance, the heating and cooling demand cannot be freely shifted over time as it should ensure that the temperature of the building does not go out of a preset comfort band.

The SPLODER model enables a very detailed representation of the demand. The way different consumption categories that can provide DR are modeled is detailed in Martín-Martínez et al. (2017), but overall is as follows:

- EVs: a given portion of the EV demand if considered fully flexible and manageable during the 24 h. The rest of EV demand is considered a non-flexible one and follows a pre-determined charging profile, split up between base and peak hours, as presented in Gerres et al. (2019).
- Heating and cooling: a reference and comfort band temperature is set according to predefined temperature bands. The building thermal inertia is considered to simulate the temperature evolution. Buildings are clustered according to their geographical area with different external temperatures according to the month and their level of thermal isolation.
- DHW: the portion assumed to be flexible can be managed freely during a whole day as it is associated with the stored hot water inertia.
- Refrigeration: is flexible if the average temperature follows a reference temperature. The temperature could be two degrees upper or lower this reference, whereas the average is respected at the end of the day. The energy to keep the temperature in reference during a day can be considered constant in an adiabatic system, and it can be freely allocated throughout the day.

3. Characterizing storage resources in SPLODER

The SPLODER model performs an optimal generation expansion plan minimizing investment, production, and O&M costs for a given time horizon. Years are represented by a set of clustered representative weeks with hourly time granularity. These four weeks represent the seasons' winter, spring/fall, summer, and vacations, each of them with different weights along the year. The four-week demand and renewables generation profiles are obtained by applying the k-means clustering algorithm (Hartigan and Wong, 1979).

Several renewable production profiles are considered in the optimization framework (three renewable scenarios are used in this study); although there is stochasticity, another model with the 8760 h of the year could validate SPLODERs operation decisions; however, this proof is out of the scope of the paper. The main inputs and outputs of the model are summarized in Fig. 1. As further explained in Gerres et al. (2019), the resulting optimal generation and storage mix should comply with two main constraints. First, generation and demand should meet hourly. Hourly energy prices (€/MWh) are obtained as the dual variable of such generation–demand balance constraint. Second, the model guarantees that enough firm capacity is provided to the system (a 10% reserve margin over the peak demand is used in this study). Each generation technology contributes differently to the system firm capacity. A specific firm capacity coefficient is assigned to each generation technology. An annual based capacity price (€/MW) is obtained as the dual variable of firm capacity requirement constraint and thus used to model a new capacity market for the Spanish electricity system. Hence, generation units are remunerated both for providing energy and firm capacity to the system, and both incomes are considered to ensure the full cost recovery of all newly installed units. Balancing services provision is out of the scope of this paper. The full description of the SPLODER optimization model, including a detailed explanation and formulation of the objective function and constraints, can be found in Martínez et al. (2017) and Gerres et al. (2019).

For this paper, SPLODER has been upgraded to improve the modeling of firm capacity resources, enabling the characterization of different pumped-hydro storage types and adding centralized battery storage as candidate technologies to be considered in the future generation and storage mix. This section focuses specifically on describing the storage technologies considered in this study and the detailed formulation of equations added to the existing SPLODER model to represent their behavior properly.

According to the Spanish context, six different categories of pumped-hydro storage have been modeled as candidates for expanding the system. They have different storage capacity sizes and investment costs representing basically two options: build an artificial upper reservoir associated with an existing storage hydro power plant or build a new penstock with a reversible turbine in an already existing pumped-hydro storage power plant (CEEPR, 2020). Table 11 summarizes the set of new pumped hydro storage

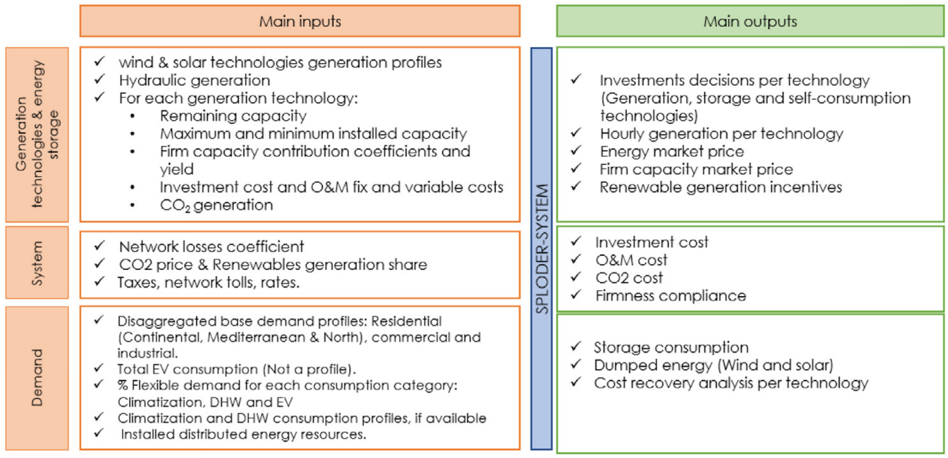

Fig. 1. Main inputs and outputs of SPLODER (Gerres et al., 2019).

Table 11
Storage data.

Agent	Max. install. [MW]	Min. install. [MW]	Annualized install. cost [€/MW]	Fix annual O&M [€/MW]	Var annual O&M [€/MWh]	Firm Coeff.	Round-trip eff.	Charge hours	Discharge hours
Batt_cent	0	0	133,799	5550	0.00025	0.69	0.9	4	4
Sto_8h_1	1000	400	39,255	9000	3	0.96	0.75	8	8
Sto_20h_1	2000	400	52,340	12,000	3	0.96	0.75	20	20
Sto_20h_2	5800	400	65,424	15,000	3	0.96	0.75	20	20
Sto_40h_1	800	400	35,983	8250	3	0.96	0.75	40	40
Sto_40h_2	600	400	62,153	14,250	3	0.96	0.75	40	40
Sto_60h_1	1500	400	55,611	12,750	3	0.96	0.75	60	60

types included in SPLODER. Table 11 also shows the centralized large-scale Li-Ion batteries that have been modeled and considered in the study. The economy of scale of centralized storage makes distributed batteries unprofitable, thus discouraging their deployment from a centralized point of view. The same thing happens with distributed solar generation, although in this case, a fixed amount has been set as input in the model (Red Eléctrica de España, 2019), considering their natural deployment due to individual motivations or local tariffs incentives. However, profits from solving local distributed system congestion problems are not considered.

Installation, fix, and variable O&M costs for batteries are based on Mongird et al. (2019). Pumped-storage hydro data, including maximum available installation capacities for the different options and the associated firm capacity coefficients, are estimated based on CEEPR (2020) and PNIEC (2020). Additionally, the annualized installation costs for the different storage options have been estimated with public pumped-storage hydro projects with different storage capacities (Repsol, 2021; European Commission, 2019; Roca, 2019, 2020). These storage facilities are modeled within an upgraded version of SPLODER. The detailed formulation of equations is provided, preceded by the used nomenclature (Table 12):

All new storage types, both pumping hydro and batteries, have been modeled similarly. Constraints (1), (2), (3), (4) & (5), control the state of charge (SOC) of all storage types, forcing it not to exceed the maximum storage capacity according to investment decisions.

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,w,m,h} \tag{1}$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,w,m,h-1} + charge_{i,p,w,m,h} \times YIELD_{ist} \forall\ ist, p, w, m, h > 1 \tag{2}$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,w,m-1,24} + charge_{i,p,w,m,h} \times YIELD_{ist} \forall\ ist, p, w, m, h = 1 \tag{3}$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,w-1,7,24} + charge_{i,p,w,m,h} \times YIELD_{ist} \forall\ ist, p, w, m = 1, h1 \tag{4}$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,4,7,24} + charge_{i,p,w,m,h} \times YIELD_{ist} \forall\ ist, p, w = 1, m = 1, h1 \tag{5}$$

Constraints (6), (7), (8) & (9), are the boundary conditions for the maximum energy that can be discharged at each time of the year. The $YIELD_{ist}$ considered in the model gathers the round-trip efficiency. Hence, it is not necessary to multiply the $discharge_{i,p,w,m,h}$ variable again.

$$soc_{ist,p,w,m,h-1} \geq discharge_{i,p,w,m,h} \forall\ ist, p, w, m, h > 1 \tag{6}$$

$$soc_{ist,p,w,m-1,24} \geq discharge_{i,p,w,m,h} \forall\ ist, p, w, m, h = 1 \tag{7}$$

$$soc_{ist,p,w-1,7,24} \geq discharge_{i,p,w,m,h} \forall\ ist, p, w-1, m = 1, h = 1 \tag{8}$$

$$soc_{ist,p,4,7,24} \geq discharge_{i,p,w,m,h} \forall\ ist, p, w = 1, m = 1, h = 1 \tag{9}$$

Constraints (10), (11), (12) & (13) calculate the SOC at every hour for each storage type. The SOC at each hour equals to the SOC at the previous hour, plus the charged energy, minus the discharged energy. The four equations differ only in reference to the previous hour SOC, in which, due to the temporal granularity of the model, the sets to be referred to slightly change with time (depending on the week, the day and the hour).

$$soc_{ist,p,w,m,h} = soc_{ist,p,w,m,h-1} + \left(charge_{i,p,w,m,h} \times YIELD_{ist}\right) - discharge_{i,p,w,m,h} \forall\ ist, p, w, m, \mathrm{h} > 1 \tag{10}$$

Table 12
Sets, parameters, and variables added.

Sets	
i	Technology type {1–27}
ist ϵ i	New storage types {1–7}
p	Renewable scenario {1–3}
w	Week {1–4}
m	Day of the week {1–7}
h	Hour {1–24}
Parameters	
$INSTALLED_i$	Existing power previously installed for each technology i [MW]
$CHARHOURS_i$	Charging hours for each type of storage [h]
$DISCHARHOURS_i$	Discharging hours for each type of storage [h]
$YIELD_i$	Storage round-trip efficiency by technology i [%]
$MAXINSTALL_i$	Maximum capacity to be installed of each technology i [MW]
Variables	
$finalinstalled_i$	Total capacity in place for each technology i [MW]
$newInstall_i$	New installed capacity for each technology i [MW]
$soc_{i,p,w,m,h}$	State of charge of hydro plant at each hour [MWh]
$charge_{i,p,w,m,h}$	Pumped hydro storage charge at each hour [MW]
$discharge_{i,p,w,m,h}$	Pumped hydro storage discharge at each hour [MW]
$energySell_{i,p,w,m,h}$	Hourly energy sold by each technology i [MWh]
$energyBought_{i,p,w,m,h}$	Hourly energy bought by each technology i [MWh]

$$soc_{ist,p,w,m,h} = soc_{ist,p,w,m-1,24} + \left(charge_{i,p,w,m,h} \times YIELD_{ist}\right) - discharge_{i,p,w,m,h} \forall\ ist, p, w, m > 1, \mathrm{h} = 1 \quad (11)$$

$$soc_{ist,p,w,m,h} = soc_{ist,p,w-1,7,24} + \left(charge_{i,p,w,m,h} \times YIELD_{ist}\right) - discharge_{i,p,w,m,h} \forall\ ist, p, w > 1, m = 1, \mathrm{h} = 1 \quad (12)$$

$$soc_{ist,p,w,m,h} = soc_{ist,p,4,7,24} + \left(charge_{i,p,w,m,h} \times YIELD_{ist}\right) - discharge_{i,p,w,m,h} \forall\ ist, p, w = 1, m = 1, \mathrm{h} = 1 \quad (13)$$

Constraint (14) sets the SOC to be the same at the beginning and end of the year (first hour of the first representative week and last hour of the last representative week) for all storage types in order to better represent the storage potential throughout the year.

$$soc_{ist,p,1,1,0} = soc_{ist,p,4,7,24} \quad (14)$$

Constraints (15) & (16) set the charging and discharging speed rate depending on the storage hours' capacity.

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist}/CHARHOURS_{ist} \geq charge_{ist,p,w,m,h} \quad (15)$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist}/CHARHOURS_{ist} \geq discharge_{ist,p,w,m,h} \quad (16)$$

For each pumping storage type, the new installed capacity cannot exceed the total available capacity to be built, as stated in (17).

$$MAXINSTALL_{ist} \geq newInstall_{ist} \quad (17)$$

In (18), the three different renewable scenarios considered in the study are forced to start at the same state of charge for each storage type, which is set to be 60% of their total installed capacity.

$$soc_{ist,p,1,1,0} = 0.6 \times (INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \forall p \quad (18)$$

Additionally, (19) guarantees that each technology considers its given yield when buying electricity.

$$energySell_{i,p,w,m,h} = energyBought_{i,p,w,m,h} \times YIELD_{ist} \forall\ ist, p, w, m, \mathrm{h} \quad (19)$$

4. Case study and scenario definition

This section describes the scenarios considered in the study. Since the study focuses on the cost competitiveness of the different firm capacity providers and how DR may impact the overall firm capacity needs and that competitiveness, four sets of scenarios have been built. These four blocks are characterized by the parameter which sensitivity is analyzed. These sets of scenarios and sensitivities addressed are presented in Table 13:

A base case scenario is used as a reference for each scenario set. All base cases evolve from the baseline scenario. The baseline scenario assumes there are no DR capabilities in the system and looks for an optimal, minimum cost, mix of generation and storage technologies for the 2030 Spanish electricity system, assuming the following set of technical and cost parameters. As explained in Section 2, demand growth from 2015 data is set using an intermediate value between the minimum and maximum growth rates for each disaggregated category of demand.

Table 14 summarizes the firm capacity coefficients assumed for each technology. These values are obtained from Red Eléctrica (2020), except for batteries with four hours of discharging rate (NationalgridESO, 2020) and pumped hydro storage (National Grid, 2017). The values corresponding to the candidate pumped storage hydro facilities are presented in Table 11.

Table 15 summarizes the 2019 existing generation capacity expected to be still available by 2030. Values are extracted from PNIEC (2020).

Table 16 presents the values assumed for the investment costs and the fix and variable O&M costs for both conventional and renewable technologies, updated from previous studies (Gerres et al., 2019) and based on additional Refs. International Renewable Energy Agency (2017), European Commision (2018), Allen (2017), Larsen and Rønnov (2018), The National Renewable Energy Laboratory (NREL) (2018) and PNIEC (2020). The values corresponding to storage facilities (including hydropower) are presented in Table 11.

Table 17 summarizes the assumptions adopted for fuel prices, CO_2 emission costs, and taxes for pollutant technologies. Prices for CO_2 and gas are based on International Energy Agency (2019):

4.1. Baseline_NewFC scenario: Firm coefficient sensitivities

The SPLODER model results may be pretty sensitive to the firm capacity coefficient (FC) parameter adopted for each technology.

Table 13
Scenarios sets definition.

Set	Main feature analyzed	Base case	Sensitivities built upon base case scenario	
A	Firm coefficient	Baseline	Baseline_NewFC	
B	Percentage of DR deployment	Baseline_NewFC(0%DR)	25%DR	50%DR
C	Reduction of battery price	25%DR	PriceBatt_L	PriceBatt_LL
D	CO_2 and gas prices	Baseline	EVC_XHigh EVC_High	EVC_Low

Table 14
Firmness coefficients.

Technology	Firm capacity coefficient
Nuclear	0.97
OCGT	0.96
CCGT	0.96
Cogeneration	0.55
Biomass/Biogas	0.55
Solar thermal	0.14
Hydro (reservoir)	0.44
Hydro (run-of-river)	0.25
Existing pumped hydro storage	0.77
Solar photovoltaics	0
Wind power	0.07
Li-Ion batteries	0.69

Table 15
2019 existing generation capacity expected to be still available by 2030.

Technology	Installed capacity (MW)
Nuclear power plants	3050
OCGT	0
CCGT	24,560
Cogeneration	3745
Biomass/Biogas	2146
Solar thermal	2299
Hydro (reservoir)	15,614
Hydro (run-of-river)	636
Existing pumped hydro storage	3329
Solar photovoltaics	8372
Wind Power	25,553
Li-Ion batteries	0

Table 16
2030 generation technologies' costs.

	Investment costs (€/kW)	Annual fixed O&M cost (€/kW-year)	Variable O&M cost (€/MWh)
Nuclear	–	108.3	–
OCGT	544.1	18.4	11.0
CCGT	845.1	19.3	2.0
Hydropower (All)	–	68.8	3.0
Solar PV (utility)	500	10	–
Solar thermal	4396.6	49.6	0.46
Wind	950	29	–

Table 17
2030 fuel costs, CO2 emissions costs and individual taxes.

	Fuel cost (€/MWh)	CO_2 cost (84 €/tonCO_2)	Taxes (€/MWh)
Nuclear	8.72	–	15.02
OCGT	48.88	42.42	4.68
CCGT	32.58	28	4.68
Cogeneration	–	48.78	–

In a system dominated by renewable generation, it is quite often that scarcity periods last longer than 4 h (which is the charging and discharging cycle of batteries) and sometimes last even longer than 8 h (which is the charging and discharging cycle of 8 h pumped hydro storage) (Huclin et al., 2022). To be conservative, the security of supply of an electricity system should not fall upon storage with less than 10 h of storage capacity. For this reason, authors evaluated in Huclin et al. (2022) the firm coefficient of the different storages, coming up with lower FCs for batteries and 8 h cycle pumped hydro storage, and with these new FCs has been built another scenario, referred to as Baseline_newFC, being these values more accurate for future scenarios. Considering (Huclin et al., 2022; NationalGrid, 2018), the new values adopted for these two technologies are shown in Table 18 and are used for all the rest of the scenarios.

Table 18
Firmness coefficients sensitivities.

Scenario	Batt_cent	Sto_8h_1
Baseline	0.69	0.96
Baseline_newFC	0.294	0.567

Table 19
Scenarios with distributed PV panels under different DR percentages.

Scenario	DR Climate	DR DHW	DR EV	DR REF
0DR	0	0	0	0
25DR	25%	25%	25%	25%
50DR	50%	50%	50%	50%

4.2. DR scenarios: Percentage of DR sensitivities

Three additional scenarios built upon the Baseline_NewFC scenario are considered to analyze the impact of DR on the firm capacity requirements of the system. The three scenarios include a fixed amount of solar distributed generation as explained below. Baseline_NewFC scenario neglected any DR capability in the system as the 0DR scenario does. Two additional scenarios (25DR and 50DR scenarios) are built for which, respectively, 25% and 50% of the total load identified as controllable (see Section 2) is considered ready to actively participate in demand response programs. These segments of load correspond to heating and cooling (climate), domestic hot water (DHW), electric vehicles (EV) and refrigeration (REF) as shown in Table 19.

An amount of distributed small-size self-consumption solar PV generation is assumed to be already installed by 2030 for these three scenarios (0DR, 25DR and 50DR). A conservative fixed preset amount, shown in Table 20, has been considered. This amount has been estimated assuming that there will be a 25% of new installation capacity between the two extreme values found in the literature, a minimum growth by 2030 of 0.6 GW (Deloitte Advisory, 2017) and a maximum one of 6.5 GW (Deloitte, 2018a), upon the currently 1 GW installed capacity (Red Eléctrica de España, 2019). This amount is geographically allocated by climate zones around Spain according to Red Eléctrica de España (2019) and associated with the three demand sectors (residential, services and industry) according to NationalgridESO (2020). Nevertheless, these distributed solar PV panels have a very marginal impact on the results of this study. They substitute utility-scale solar PV installation needs (actually at a slightly larger ratio than 1:1 as some network losses are avoided) but do not contribute to firm capacity.

4.3. Battery low price scenarios: Battery price sensitivities

As results will show later, batteries are far from being competitive, provided the installation costs assumed in scenarios so

Table 20
Assumed installed PV distributed capacity in 2030.

Technology	Installed capacity (MW)
Solar distributed	2467

Table 21
Batteries installation costs.

Scenario	Batt_cent install cost [€/kW]
25DR	133.8
PriceBatt_L	30
PriceBatt_LL	20

Table 22
CO_2 and gas prices scenarios.

Scenario	CO_2 [€/tonCO_2]	Natural gas [€/MMBTU]
EVC_XHigh	83	27
EVC_High	62	18
Baseline	84	6
EVC_Low	90	4

far. Two additional scenarios (PriceBatt_L and PriceBat_LL) have been considered lowering the installation cost of batteries, as presented in Table 21. Both are built upon the 25DR scenario. The main purpose of the first scenario, PriceBatt_L, is to identify the battery installation cost threshold below which batteries begin to be competitive enough to be competitive. For that purpose, batteries installation costs have been reduced in steps of 1€/kW until results show some battery installation, substituting OCGT. This happens for an installation cost decrease of 77%, as shown in Table 21. The second scenario, PriceBatt_LL, allows a larger penetration of batteries to understand the impact of the technological mix of renewables and the competitiveness of other firm capacity providers. This is achieved with a further reduction in batteries installation costs (85% of reduction), as shown in Table 21.

4.4. Equivalent variable cost scenarios: CO_2 and gas prices sensitivities

CO_2 and gas prices have a substantial impact on electricity wholesale market prices. Therefore, a set of scenarios has been built to specifically assess their incidence on generation investment priorities. The Baseline of this set of scenarios assumes the same prices for gas and CO_2 in 2030 than all previously described sets of scenarios. They follow the values stated in the WEO2019 (International Energy Agency, 2019) for 2030. Then, three sensitivities to these prices are performed. The EVC_XHigh scenario is built upon the first semester of 2022 average CO_2 (SENDECO, 2022) and natural gas (MIBGAS, 2022) prices, which have historically influenced the market in the Iberian Peninsula. EVC_High scenario assumes extremely high prices for gas and moderately high prices for CO_2, similar to those the world faced in the summer, autumn, and winter of 2021, taken respectively from MIBGAS (2021) and SENDECO (2021). It assumes those prices will remain similar in 2030. Finally, the EVC_Low scenario considers the more recent forecasts up to a day for CO_2 (Simon, 2021) and natural gas (Sönnichsen, 2022) price evolution. These three scenarios provide a sensitive sensibility analysis of the gas and CO_2 emission prices. These values are presented in Table 22. Unit conversion types considered in these cases are: 1$ →0.84€ and 1 MWh→3.41MMBTU

The price tendency of each of the three scenarios has been clarified by calculating the equivalent variable cost (EVC) in €/MWh for the two-generation technologies affected by CO_2 and gas prices: OCGT and CCGT. EVC integrates into a single production cost per technology the actual impact of both the gas and

Table 23
Equivalent variable cost for OCGT and CCGT.

Scenario	OCGT [€/MWh]	CCGT [€/MWh]
EVC_XHigh	258	167
EVC_High	180	115
Baseline	102	63
EVC_Low	90	54

CO_2 emission allowance prices. Table 23 summarizes the resulting EVC for both technologies. It provides sensible information on the assumption made in each scenario. The production cost of both technologies respectively increases and decreases in the EVC_High and EVC_Low sensitivity scenarios compared to the Baseline one.

5. Results

This section presents and discusses the results provided by the SPLODER model. Results are organized following the sequence of the blocks of scenarios described previously.

5.1. Firm coefficients analysis

Figs. 2 and 3 show the generation and storage optimal investment decisions for the period 2019–2030 as provided by SPLODER for these scenarios. Namely, Fig. 2 displays the investments in renewable technologies (wind and solar PV) for both scenarios, while Fig. 3 shows the investments in the rest of the technologies, mainly oriented to provide firm capacity to the system (storage and thermal backup capacity).

Fig. 2 shows that the new installed renewable capacity is very large (almost 73 GW) compared to the peak demand value for 2030, which is assumed to be 51.39 GW and given the initially existent installed capacity (see Table 15). This is because storage technologies are helping to decrease renewables' spillage. Although installation costs are significantly lower for solar PV than for wind, investments in both technologies are balanced. This is partly because solar PV production is concentrated in fewer hours than wind production. Therefore, solar contribution to the system firm capacity is much lower (indeed, it is zero in this study, as the more stressful periods for the system happen during hours without sun). Besides, the concentration of the solar PV in the hours of sunshine ends up cannibalizing the energy income of solar PV. This effect is more significant than for wind since the latter has more variability at different hours.

On the other hand, as shown in Fig. 3, batteries are fully discarded, not being competitive compared to other options. On the contrary, 5 out of 7 available pumped-hydro storage options are selected. The mix is completed with thermal OCGT backup generation to meet the system firm capacity requirements.[2]

By comparing in Figs. 2 and 3, the impact of considering stricter (lower) firm capacity coefficients for shorter-term storage technologies, that is, batteries and 8 h pumping storage, no very relevant changes are shown (Baseline_NewFC results compared to Baseline ones). Renewable investments almost do not change, although wind generation comes out slightly favored at the expense of solar PV. This is because 8 h pumping storage loses some competitiveness due to its reduced firm capacity coefficient,

[2] If investments in gas generation technologies are to be avoided to meet decarbonization commitments, the OCGTs investment would be replaced by the rest of available hydro pumping options and batteries if also needed. Nevertheless, OCGTs would almost not produce, being their role mainly to provide firm capacity.

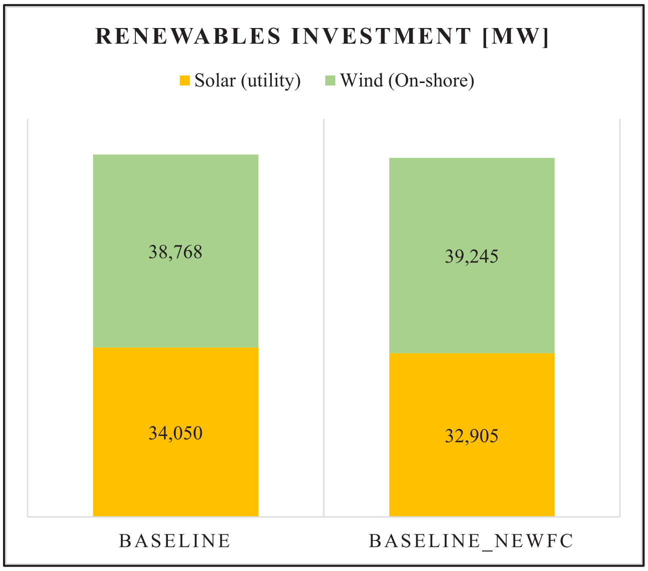

Fig. 2. New renewable investments (2019–2030) in baseline scenarios.

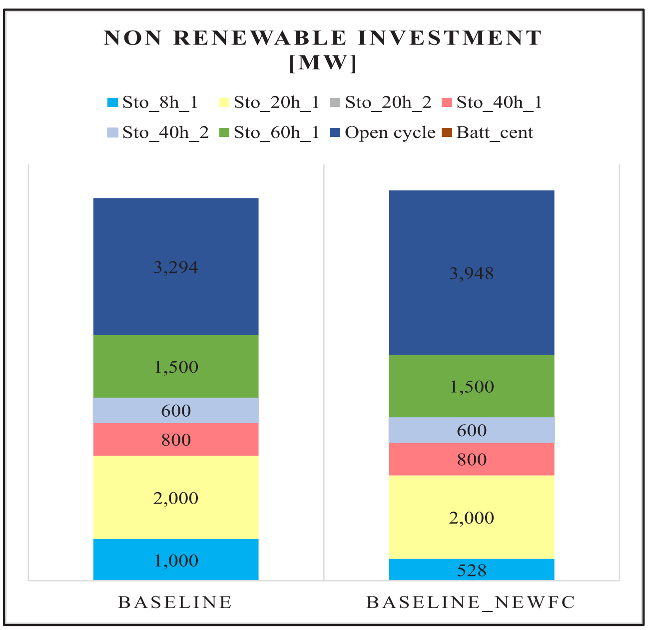

Fig. 3. New firm capacity investments (2019–2030) in baseline scenarios.

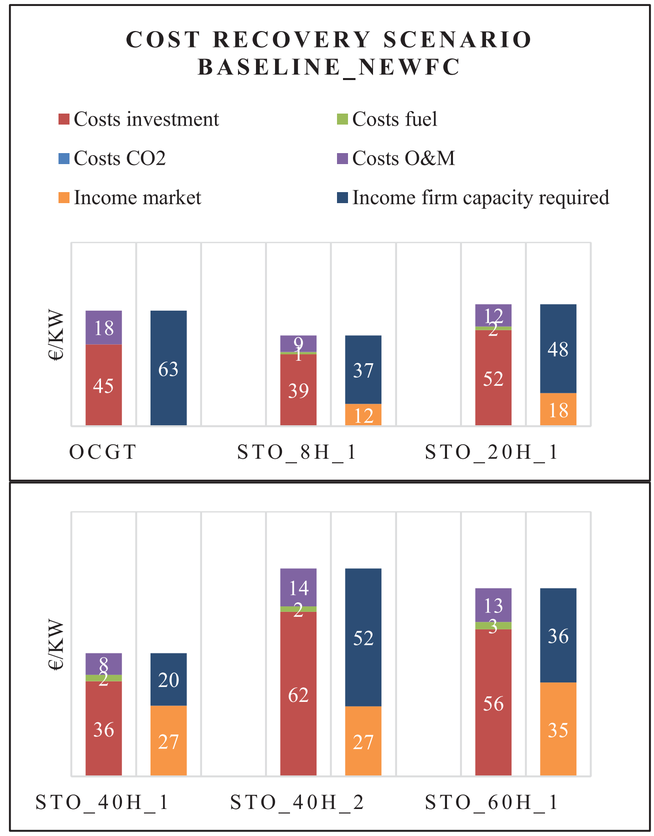

Fig. 4. Cost recovery for new firm capacity investments (2019–2030) in Baseline_NewFC scenario.

being thus replaced by OCGT. This reduces the system's total storage capacity, which disfavors solar PV more than wind. Also, the lower the storage capacity, the higher the total firm capacity required in the system since storage supply peak demand. In this case, around 200 MW of additional firm capacity is needed. Wind power provides some firm capacity while PV solar does not.

To complete the analysis of the competitiveness of firm capacity providers, a cost recovery analysis for new investments for the baseline_newFC is presented in Fig. 4. This figure shows, on the left-hand bar, the total annualized costs faced by the technology, disaggregated into investment, fuel, O&M and CO2 emissions costs, and on the right-hand bar the total incomes received by the technology, disaggregated into the incomes from the hourly energy production valued at the hourly energy price and the required income from the firm capacity provision to balance costs and incomes.

It could be observed first that all selected technologies do recover their total costs considering an income due to firm capacity provision equal to the missing money for each technology. Indeed, the capacity payment mechanism would follow a marginal price approach for the provision of firm capacity. The incomes from capacity payments would equal or exceed these values for the selected technologies, as OCGTs and the 8 h pumped-hydro storage are the marginal technologies providing firm capacity.

OCGT incomes fully come from the provision of firm capacity showing that its role in producing energy will be very marginal.[3] On the contrary, although they are also providing firm capacity, pumped-hydro storage technologies do have some income by operating in the energy market.[4] The energy market-related incomes may recover up to 60% of their total costs for some of these technologies (for instance, the Sto_40h_1), but only 22% for others. The more hours the pumped-hydro storage can store, the more it would operate and more income from the energy market.

The results show the relevance of capacity payments to ensure investments cover the system firm capacity requirements.

5.2. DR analysis

Fig. 5 shows the investment decisions in renewable technologies, and Fig. 6 those in firm capacity providers' technologies

[3] The production of such peaking units is however somehow underestimated in models such as SPLODER since a fully stochastic approach will reveal more situations where these back-up technologies will produce some energy.

[4] These figures are slightly underestimated due to the same reason as for OCGTs. See previous footnote.

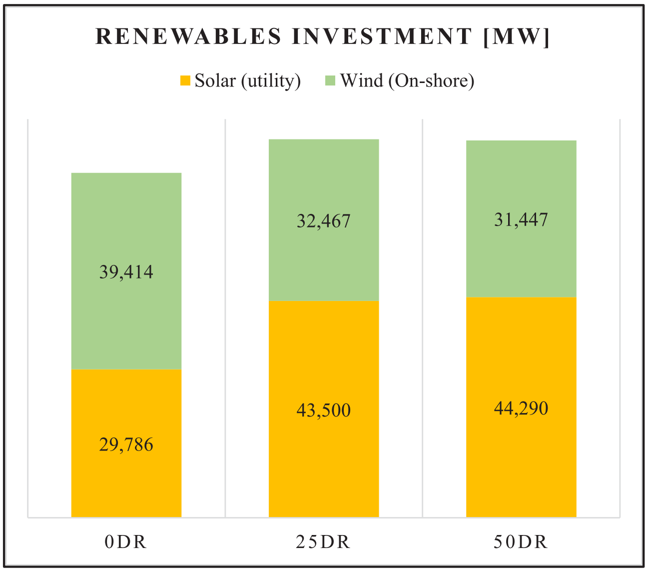

Fig. 5. New renewable investments (2019–2030) in DR scenarios.[5]

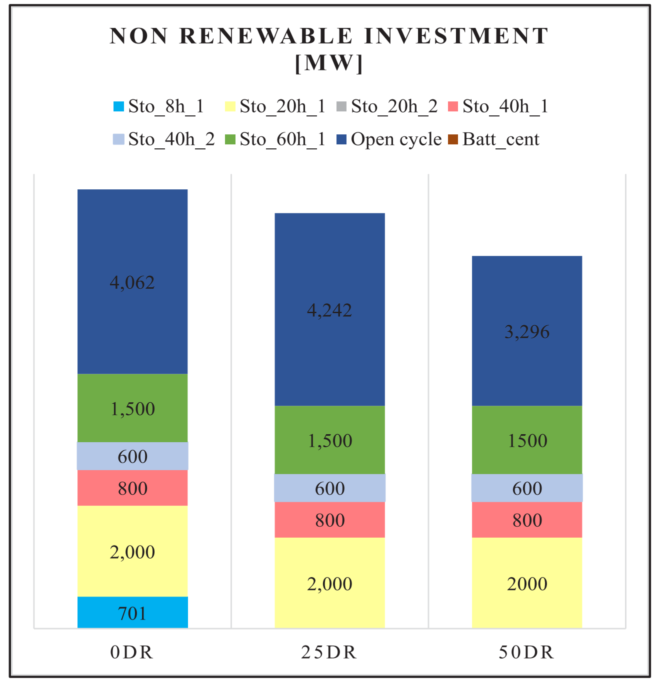

Fig. 6. New firm capacity investments (2019–2030) in DR scenarios.

for the three DR capability scenarios for the period 2019–2030. Firstly, it is noticeable how DR increases the overall optimal renewable investments by more than 7%. This impact seems to saturate once 25% of DR is reached. Secondly, there is a clear switch between the two renewable generation technologies. Comparing 0% DR and 25% DR scenarios, results in a 46% increase in solar generation investment and an 18% decrease in wind generation. This is because DR maximizes the value of solar generation since part of the load can be switched to hours with solar PV production. This effect also seems to saturate above a 25% rate of DR. Results point out the relevance of considering DR in long-term system requirements.

Fig. 6 shows that firm capacity requirements in the system significantly reduce when considering DR capabilities. Indeed, peak demand in the system could be reduced, hence, reducing firm capacity investments. As could be expected, the marginal firm capacity technologies reduce their investments or even disappear, as is the case for the 8 h pumped-hydro storage. The rest of the hydro pumping options remain competitive and are needed to meet the firm capacity requirements while also providing energy to satisfy demand.

To better illustrate the impact of DR on firm capacity requirements, Fig. 7 represents the evolution of the equivalent firm capacity (EFC) with respect to the level of DR penetration. EFC measures the total firm capacity required to be met by newly installed technologies, that is, once discounted for the firm capacity already provided by the initially existing technologies.

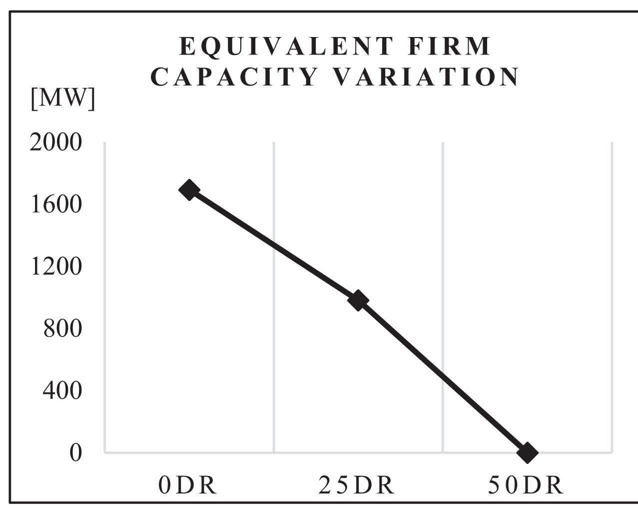

Fig. 7. Equivalent firm capacity variation for DR scenarios.

Roughly, it could be concluded that each point of a percentage of DR reduces around 30 MW of firm capacity requirement in the system. This percentage corresponds to the load considered to be controllable, not to the whole demand. Moreover, it is important to highlight also that the management of this demand is not free but subject to specific behavioral constraints. These considerations enhance the relevance of these results.

5.3. Battery low price assessment

As presented in Table 21, battery installation costs are lowered in these scenarios to identify their threshold installation costs to become competitive (PriceBatt_L scenario) and, in that case, to understand how they may impact other firm capacity technology options (PriceBatt_LL scenario).

A 77% reduction of the batteries' installation costs upon the initially assumed values is necessary for the batteries to become competitive. Costs must go down from 133.8 €/kW to 30 €/kW. Batteries are still far from being competitive.

Figs. 8 and 9 show the optimized investment decision in renewables and firm capacity providers' technologies for the three scenarios related to the battery installation costs for the period 2019–2030. Fig. 8 clearly shows that batteries enhance the role of solar PV generation as compared to wind generation. Indeed, higher levels of storage favor solar generation deployment, substituting wind farms installation. It is equivalent to that observed for DR deployment but larger as batteries do not have the DR

5 In order to properly analyze these results it should be remembered that around 2.5 GW have already been expanded as small-size distributed PV solar.

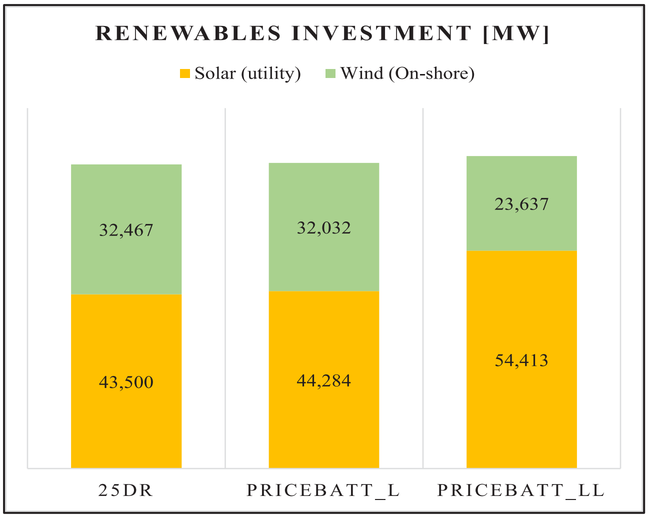

Fig. 8. New renewable investments (2019–2030) in the Battery low-cost scenarios (see footnote 5).

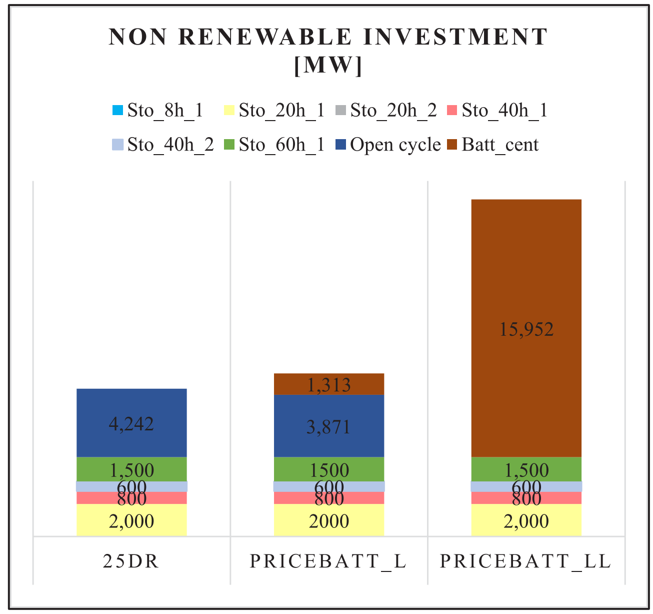

Fig. 9. New firm capacity investments (2019–2030) in Battery low-cost scenarios.

limitations associated with complying with temperature comfort constraints or EC availability.

Fig. 9 shows several interesting features. First, batteries compete with OCGTs, not with pumped-hydro storage, once 8 h pumped hydro storage has been already expelled by DR, as shown in the 25DR scenario. Even with a further reduction of its installation costs, batteries do not replace pumped-hydro storage with storage capabilities larger than 8 h. This is certainly because 4 h batteries contribution to firm capacity is quite low (its FC stands for 0.294). Four hours of storage is not enough to face longer episodes of renewable production scarcity in the system. Very large amounts of battery investments would be needed to substitute the firm capacity provided by pumped hydro storage with storage capabilities larger than 8 h.

Second, 4 h batteries need a substantial installation cost reduction to replace OCGT as a firm capacity provider. This is again a consequence of its low contribution to firm capacity. Roughly three times more capacity of 4 h batteries are needed to replace OCGT capacity. This is clearly shown in the PriceBat_LL scenario results. Batteries have entirely replaced OCGTs, but the investments required to meet firm capacity requirements skyrocket.

These three scenarios present the same EFC. The main difference between them is which technology is providing firm capacity. In the PriceBatt_LL scenario, solar generation installation increases and substitutes wind installation reducing their overall contribution to EFC, which is replaced by batteries' contribution to EFC. Anyhow, the huge investments in batteries in that scenario obey the replacement of OCGT as firm capacity provider, as explained previously.

5.4. CO_2 and gas prices sensitivity analysis

Optimal renewables investment capacity is presented in Fig. 10 for the four CO_2 and Natural Gas price sensitivity scenarios presented in Table 22. Besides, Fig. 11 presents the optimal investment in the rest of the technologies that provide firm capacity. Table 24 summarizes some of the main outcomes (market prices, CO_2 emissions and renewable quota energy production) for these scenarios.

Results show that for high OCGT and CCGT's EVCs (EVC_XHigh and EVC_High scenarios), hydro storage technologies, even the costlier ones (Sto_20h_2), replace OCGTs as providers of firm capacity to the system, together with a significant increase of both wind and solar generation capacity. So high gas and CO_2 emission prices expel generation gas-based technologies' investments. Only the current CCGTs, still in place in 2030, remain in the system. Market prices increase somewhat, allowing the cost recovery of the additional wind and solar investments. A relevant increase in renewable production quota is achieved together with a significant reduction of CO_2 emissions. The increase of EVC cost between EVC_High scenario and EVC_XHigh produce a lower change in renewable ratio than the variation obtained from the Baseline to the EVC_High scenario (Table 24). Results reveal a turning point at which increasing the EVC cost does not lead to a relevant increase in renewable production. As expected, high prices of gas and/or CO_2 (high prices of EVC for OCGTs and CCGTs), lead to a faster decarbonization process of the electricity system, resorting to more pumped-hydro storage capacity to provide firm capacity to the system. Also, it is noticeable that, as already identified in previous results, an increase in storage facilities favors solar over wind generation capacity since solar is a cheaper generation technology than wind. Indeed, in this scenario, both increase their installed capacity, but proportionally in larger amounts for solar.

The system behaves the other way around for lower OCGT and CCGT's EVCs (EVC_Low scenario). Being cheaper, OCGTs investments increase their share, disincentivizing renewable generation investments altogether, although solar significantly replaces wind technology. Higher amounts of firm capacity (driven by cheaper OCGTs), as it happens in this case, also favor solar over wind. Consequently, this scenario leads to larger expected CO_2 emissions and lower renewable production quotas. Market prices, instead, are slightly reduced.

6. Conclusions & future work

The provision of firm capacity becomes a challenge in power systems dominated by renewable generation. This paper demonstrates that DR has a non-negligible impact on the system firm capacity requirements and, therefore, in its generation investment decisions. This study analyzes the competitiveness of battery

Table 24
CO_2 and gas prices sensitivity scenarios results.

	EVC_XHigh	EVC_High	Baseline	EVC_Low
Average marginal market price (€/MWh)	48	42	39	38
Market price standard deviation (€/MWh)	70	52	34	30
CO2 emissions (Mton)	9	11	16	21
Renewable generation quota (%)	86%	85%	81%	77%

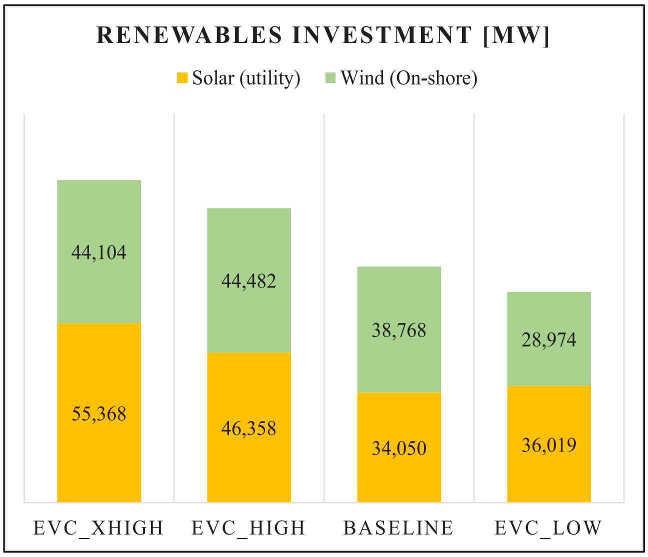

Fig. 10. New renewable investments (2019–2030) in CO_2 and gas prices scenarios.

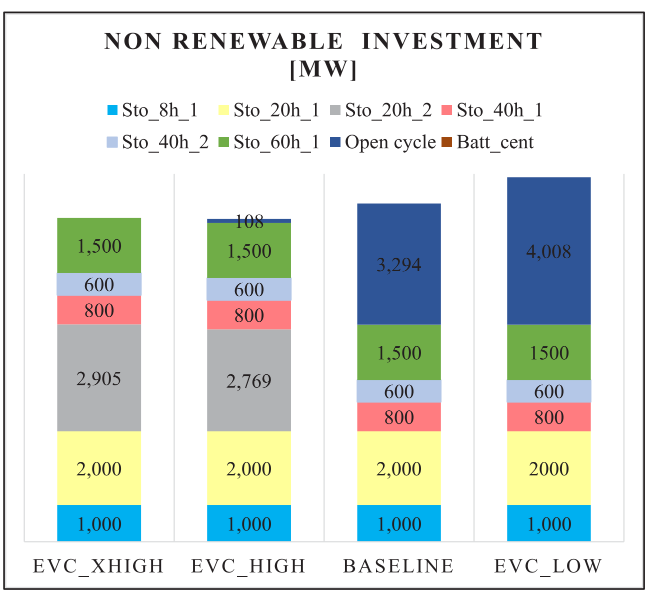

Fig. 11. New firm capacity investments (2019–2030) in CO_2 and gas prices scenarios.

storage, six types of pumped-hydro storage, OCGT, and demand-side response technology in providing the firm capacity required to ensure the security of supply of a real-size system such as the Spanish system in a 2030 horizon.

Furthermore, the mathematical formulation presented in Martínez et al. (2017) and Gerres et al. (2019) considers disaggregated demand suitable for limiting the amount that can be shifted and obtain a better estimation of DR capabilities. This formulation has been accordingly upgraded to enable SPLODER model to analyze the contribution of DR, storage and other technologies, to firm capacity requirements for the electricity system.

The third contribution of this paper is to provide a detailed study of the 2030 Spanish demand. The electricity demand is disaggregated by sector and consumption activities and projected towards 2030, applying the estimated growth rates by energy usage. This demand disaggregation identifies the controllable portion of the electricity consumption. Moreover, the controllability constraints of such flexible loads are considered to ensure the validity of the results.

The main findings driven by a Spanish-like system are:

- DR does have a non-negligible impact on the system firm capacity requirements. Neglecting DR in long-term analyzes could lead to biased decisions.
  - DR decreases firm capacity requirements in the system, roughly at a rate of 30 MW per 1% of the total potentially controllable demand participating in demand-response programs.
  - DR replaces (and therefore somehow competes with) eight-hours pumped hydro storage and OCGT. More than eight hours pumped hydro storage is not replaced by DR. However, DR implementation costs (new equipment, smart meters…) are not considered in this study. Hence, DR competitiveness results can be somehow overestimated.
  - DR fosters solar generation over wind generation.
- Pumped hydro with storage capacity larger than eight hours (except for one of the study's options) is very competitive choices to provide system firm capacity.
  - They are more competitive than OCGTs
  - They are more competitive than batteries even for extremely high reductions of batteries installation costs (85%).
  - DR does not replace them even with a high share (50%) of the potentially controllable load being participating in demand-response programs.
- Four-hour large-scale batteries are far from being competitive enough to provide firm capacity to the system
  - Pumped-hydro storage, OCGTS, and DR are far more competitive than batteries.
  - In the presence of DR, batteries installation costs should decrease up to at least 77% to become competitive against OCGT. A cost reduction of up to 85% leads to replace OCGT fully but is not enough to replace more significant than eight-hours pumped hydro storage alternatives.
  - Batteries are penalized because of their high installation costs and their low firm capacity contribution (its FC is 0.294). Four-hour storage is not enough to face longer episodes of renewable production scarcity in the system. But this effect may be very much system-dependent.

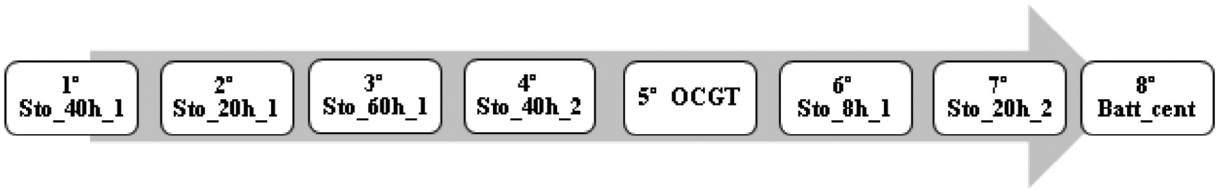

Fig. 12. Investment in firm capacity technologies priority order for baseline_newFC scenario.

- The competitiveness among different technological options to provide firm capacity to the system does depend mainly on the ratio (investment cost/FC). Fig. 12 below shows the resulting competitiveness rank for the firm capacity providers' technologies considered in the study in the Baseline_newFC scenario.
  - Pumped-hydro storages and OCGTs are the most promising firm capacity providers at this stage for the Spanish system, provided there are no restrictions on the installation of emitting capacity. If this were the case, OCGTs would be replaced by the rest of the available hydro pumping options and, if needed, also batteries if also needed. Nevertheless, OCGTs would almost not produce, being their role mainly to provide firm capacity.
  - The value of FC assigned to each technology depends on the specific power system analyzed. For thermal backup, FC is high (0.96 in this case) and non-system dependent.[6] The larger the storage capacity, the greater the FC since critical periods for supply may last several hours in a system dominated by renewable generation. Indeed, they could provide firm capacity in scarcity periods lasting less than their storage capacity (for instance storing PV production excesses in sunny hours and delivering that energy in non-sunny hours) but will not be able to do so for events with larger durations for instance a whole week with low wind. Nevertheless, the resulting values could be very much system-dependent.
- The technologies selected to provide firm capacity do also have an impact on the renewable generation mix. DR and storage-based technologies favor solar PV over wind since solar PV is cheaper but produces only in mid-day hours. On the contrary, OCGT favors wind over solar PV.
- CO_2 emission rights and natural gas prices have a combined impact when planning generation investment. This combined effect is related to the EVC of the technologies that require CO_2 emission rights or gas for their operation.
  - The higher the EVC, the better it is to invest in renewables, leading to a reduction of CO_2 emissions, although the higher the electricity price becomes. Therefore, there is a heavy dependence between electricity prices and CO_2 and natural gas prices.
  - There is a turning point in which the increase in EVC would lead to a rise in electricity prices not comparable to the renewable ratio growth.
- Results show the relevance of capacity payments to ensure the investments meet the system firm capacity requirements, that is, to ensure maintaining reasonable levels of security of supply
  - Incomes from the energy market, although underestimated in this study, do not allow for full recovery costs. OCGTs almost do not obtain payment from the energy market. On the contrary, one of the pumped hydro storage options recovers up to 60% in an extreme case.

Four main lines of future work would enhance the analysis performed in this paper. First, results have shown to be quite sensitive to the FC adopted for each technology. Although reports support values, FCs do depend on the final generation and storage mix adopted in each specific system. Further methodological and modeling work to better estimate them will enhance the accuracy of the results. Second, the deployment of DR does have a cost. Correctly estimating it for each kind of sector and activity and including it as an additional technological alternative for SPLODER, may provide interesting insights into the optimal level of deployment of DR in the system. Third, additional technologies should be considered in the basket of firm capacity providers' options, for instance, power-to-gas technologies (hydrogen, among others), to analyze their competitiveness, role, and impact on the rest of the technologies in the mix. Fourthly, the situation Europe is facing in 2022 with the gas crisis (Elliott, 2022), opens another research question, which is the effect of geopolitical issues on the electricity security of supply, that should not be underestimated, and how countries could protect themselves from a power outage.

Declaration of competing interest

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

Data availability

The data that has been used is confidential.

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PAPER 3

- DR prioritizes reducing peak demand and spillages over participating in the reserves market
- DR can reduce up to 12% of total system costs, mainly from peaking plant investment needs.
- Although DHW and EV are more flexible, H&C are more relevant for reserves.
- DR is prepared to provide more than 50% of total reserve needs.
- A 33% of DR participation minimizes system emissions and costs.

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System planning with demand assets in balancing markets

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A B S T R A C T

Balancing markets will become more and more relevant with the increased volatility in the electricity system due to the increase in the renewable quota. New policies are paving the way for customers flexibility participation as demand response in reserve products. This paper contributes with an assessment of the impact of demand response participation in the reserve market when planning the electricity system's operation and investment in new technologies. The model used has been conveniently upgraded and a set of scenarios have been raised to conduct the analysis. The residential and services sectors' consumption for heating, cooling, hot water, and electric vehicles are considered as sources of flexibility. Each one has their own modeling to represent their nature. Main findings show that demand response receives and offers more benefits for the system on the wholesale market than in balancing services, although their participation in them is quite relevant. This is due to the decrease in firm capacity investment needs thanks to reducing systems' peak technologies and the decrease of spillages from renewables. Additionally, increasing demand response percentages in the systems lead to cost reduction. However, there is a limitation associated with an increase of CO_2 emissions due to the usage of existing polluting technologies to avoid investments in storages. Finally, flexibility providers are compared to determine their flexible capabilities.

1. Introduction

The evolution of power systems and electricity markets is experiencing an increase in renewable resources, creating the need for flexible resources such as batteries and demand assets or the reinforcement of interconnections. European directives (Directive 2019/944) [1] and policies such as the Clean Energy Package [2], are paving the way to extend energy customers flexibility, capability of shifting consumption, by taking part in a demand response (DR) program. Consequently, this paper explores the role that DR can fulfill within the entire electricity system. It addresses technology investment planning and operation by considering DR full potential, enabling its participation in wholesale and balancing markets. Besides, to be able to limit DR potential and avoid overestimating it, this work counts with a detailed representation of the different demand sectors, which are the residential, services and industrial sectors, and disaggregated consumption categories, between heating and cooling (H&C), domestic hot water (DHW), electric vehicle (EV) and others. The purpose of this analysis is to compare the sources of DR and assess their influence on investment and operational decisions, determining when DR can be effectively employed in each commodity, whether in wholesale or balancing markets.

Full deployment of DR, could lead to significant balancing savings for Europe, between 43 % and 66 % of balancing costs, depending on the country and the balancing capacity needs [3]. These studies[4,5], demonstrate cost reductions ranging from 15 % to 21 %, primarily through operational cost reductions, achieving a more pronounced cost reduction when DR participates in reserve markets. By managing the full availability of DR specific sources [6], economic savings can rise to 14 % of annual costs solely by providing downward reserve. When analyzing Europe as a whole, total system costs can be reduced by 17 %[7]. Furthermore, 30 % savings are estimated for the Spanish system when modeling flexibility as 8 % of the total demand, without considering special constraints for the use of this flexibility [8]. DR current implementation in European countries is still very small [9–11] and there are still some regulatory and social barriers that should be faced [12,13]. Therefore, to foster all DR possibilities development in the different countries, this paper studies the effect of considering DR participation in balancing services. This paper assesses different flexible demand penetration quantities, with a more conservative range estimated for system cost savings due to limitations in DR movements. This study also compares the operation of H&C, DHW and EVs to understand how their flexibility interacts with the electric power system. Although more

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flexible demand categories could have been considered, such as refrigeration and compressed air, they were not introduced to facilitate understanding the model.

In [14], district heating systems are assessed as a source of flexibility, providing all balancing services at a European level. The study determines that flexibility sources have a higher potential in providing Automatic Frequency Restoration Reserve (aFRR) service due to constraints on their ramping periods, almost double the Manually Frequency Restoration Reserve (mFRR) potential and four times the Frequency Containment Reserve (FCR), potential. The challenge of relying on DR participation in FRR services has been handled throughout literature from different points of view. In [15], DR participation in balancing markets is analyzed from an aggregator perspective. Moreover, [16,17] value DR contribution to balancing services from a building perspective. Finally, demand participation in reserves has also been analyzed from the DSO and TSO controller perspective, solving frequency and voltage regulation network issues [18,19]. For this case study, balancing services will refer only to aFRR service with up and down considered separately, and it will be analyzed from a system perspective, with investment planning and operation optimization.

Consumption in the residential and services sectors is where customers flexibility is most underutilized and where its exploitation presents the most opportunities[20,21]. This paper focuses on assessing the impact of DR provision from the residential and services sectors', which has not traditionally been economically viable [20]. However, European grants for electrification in these sectors [22], come with an increase in customers flexibility potential and hence, profitability. In particular, Spain has developed measures to incentivize electrification for heating and cooling services [23] and for overland transportation [22,24]. Furthermore, technological advances facilitate the remote controllability of end-use energy demand to be able to participate in electricity system services [25]. Table 1 compiles prior models that have assessed the participation of DR in balancing services. The columns within the table highlight key characteristics of these models, revealing the novelty of the model presented and employed in this paper. First, the markets in which DR can participate are indicated, distinguishing between the wholesale market and various balancing services, including FCR, FRR [26], and Replacement Reserve (RR). Subsequently, the sectors within which DR has been studied are specified, distinguishing among residential (RES), commercial (COM) and industrial (IND). Additionally, the modeled disaggregated consumption categories capable of providing DR are identified, considering only H&C, DHW and EV classification. Furthermore, it is indicated whether any specific constraints have been applied to restrict DR potential. Finally, the last column refers to the type of model under consideration, indicating if the model applies to the whole system and in case it does whether both operational (OPER) and investment (INV) optimization are considered.

From the literature review it can be concluded that the modelling of DR participation in the reserves market from a system overview of behind-the-meter assets from the residential and services sectors has not been extensively studied. Therefore, this paper contributes with a comprehensive generation and storage expansion planning model, conveniently upgraded to allow DR participation in both wholesale and reserves markets constraining the demand assets to better represent their consumption nature. Through the analysis conducted, this paper also contributes to identifying which DR assets supply more energy and in which market (wholesale or reserves) they are best suited to participate. Finally, the analysis also reveals that increasing demand response percentages in the systems lead to cost reduction. However, there is a limitation associated with an increase of CO2 emissions due to the usage of existing polluting technologies to avoid investments in storages. This finding has policy implications since it shows that although demand response leverages existing infrastructure, it should be combined with new storage investments (against the minimum cost alternative) to deal with the increase of emissions.

Different scenarios have been defined to assess the role of these demand assets providing reserves and their impact on generation and storage investment planning and on electricity system costs and emissions using the Spanish system as a reference. The rest of the paper is organized as follows. Section II, describes the upgrades in the formulation of the model to include the reserves market and demand participation in providing balancing services. Section III gathers the input data required to run the model and perform this analysis for the Spanish system in 2030. An analysis and description of results are presented in Section IV. Section V summarizes the relevant conclusions and proposes some future research lines to enrich this study.

2. Model formulation

The tool used to develop this study has been an operation and expansion planning model, named SPLODER, with the convenient upgrades. The initial version of the model was fully described in [44]. Some other upgrades are presented in [45–47] to include policy constraints and new storage technologies that can compete with flexible

Table 1
Optimization models with DR participation in balancing services.

Source	Energy market	Balancing services			Sector with DR			DR sources are disaggregated			DR limited	System perspective	
		FCR	FRR	RR	RES	COM	IND	H&C	DHW	EV		OPER	INV
[4]	Yes	No	Yes	No	Yes	No	No	No	No	Yes	No	No	
[5]	Yes		~		Yes	No	No	No	No	Yes	No	No	
[27]	Yes		~			~			~		No	Yes	No
[28]	Yes	Yes	Yes	No	No	No	Yes		~		No	Yes	No
[29]	Yes	No	Yes	Yes	Yes	No	No	Yes	Yes	No	Yes	Yes	No
[30]	No		~		Yes	No	No	No	Yes	No	No	Yes	No
[31]	Yes	No	Yes	No	No	Yes	No		~		No	No	
[32]	Yes		~		Yes	Yes	Yes	Yes	Yes	No	Yes	No	
[33]	Yes	Yes	Yes	No		~			~		No	Yes	No
[34]	Yes	Yes	Yes	Yes		~			~		No	No	
[35]	No		~			~			~		No	Yes	No
[36]	Yes	No	Yes	No	Yes	No	No	Yes	No	Yes	Yes	No	
[37]	Yes	No	No	Yes	Yes	No	No	Yes	Yes	Yes	Yes	No	
[38]	Yes		~			~			~		No	No	
[39]	Yes		~			~			~		No	No	
[40]	Yes		~		Yes	Yes	Yes		~		Yes	No	
[41]	No		~			~			~		Yes	No	
[42]	No	Yes	No	No	Yes	No	No	Yes	Yes	No	Yes	No	
[43]	No		~		Yes	No	No	No	Yes	No	Yes	No	
This Paper	**Yes**	**No**	**Yes**	**No**	**Yes**	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

~ Not specified.

demand resources. The model considers a time scale of hours for only four representative weeks of a year. Additionally, electricity generation is classified by technology and electricity demand by sector (residential, services and industrial). The residential and services sectors are also disaggregated in different consumption categories (H&C, DHW, EV, lighting and others), where H&C, DHW and EV are considered as potential flexible resources.

The contribution of this paper is to include the different demand assets in the reserves market formulation and their limitations. The mathematical formulation of the reserves could be stochastic or deterministic. The necessary input data for both formulations are the same; consequently, the only thing that changes is the equations determined. In the stochastic approach [29,32,36,37,48], variables and parameters would have been reused for the new model adding only an additional set to iterate and solve each equation for wholesale and upward and downward reserve markets. For this case, the deterministic approach has been modelled by including additional variables and parameters to consider the increase and decrease in generation or demand due to the secondary regulation market. With this procedure, the previous wholesale market is affected by the reserves market solution with the status of the storage technologies [38,49,50].

Fig. 1 briefly depicts the new formulation needed to model the reserves market, it distinguishes between modified constraints for energy suppliers and additional constraints. Fig. 2 summarizes the required input data, identifying also the additional data needs from this paper work, and the resulting outputs obtained from running the model.

2.1. Sets, parameters, and variables

The inclusion of the reserves market in the model affects the entire model formulation. Moreover, the particular equations affected are detailed below using the same format of symbols as in previous publications to facilitate comparison. Table 2 presents the sets, parameters, and variables used to model the reserves market. Note that all parameters are written in capital letters while variables are defined in lower case letters.

2.2. Objective function

The objective function was updated to take into account the additional energy produced by the generators that participate in the reserves market. The objective function of the model is to minimize total system costs and is presented in equation (1). Equations (2) to (4) calculate the corresponding installation, maintenance, and operating costs that comprise the objective function. The operation costs now include those that correspond to reserves market costs, as well as wholesale market costs. This might alter reality, like in real life, since the energy used to supply reserves needs is not known in advance and hence, optimized.

$$costs = installcosts + fixcosts + operationcosts \tag{1}$$

$$\begin{aligned} installcosts = \sum_i (& COSTDER_{PV} * powerpv_i + COSTDER_{ES} * batcapacity_i \\ & + COSTDER_{HP} * powerhp_i + COSTDER_{ERD} * powererd_i \\ & + newinstall_i * COSTINSTALL_i) \end{aligned} \tag{2}$$

$$\begin{aligned} fixcosts = \sum_i & (COSTOMFIX_i * (INSTALLED_i + newinstall_i) \\ & + (PVCAP_i + powerpv_i) * COSTOM_{PV} + (HPCAP_i + powerhp_i) * COSTOM_{HP} + (ESCAP_i + batcapacity_i) * COSTOM_{ES}) \end{aligned} \tag{3}$$

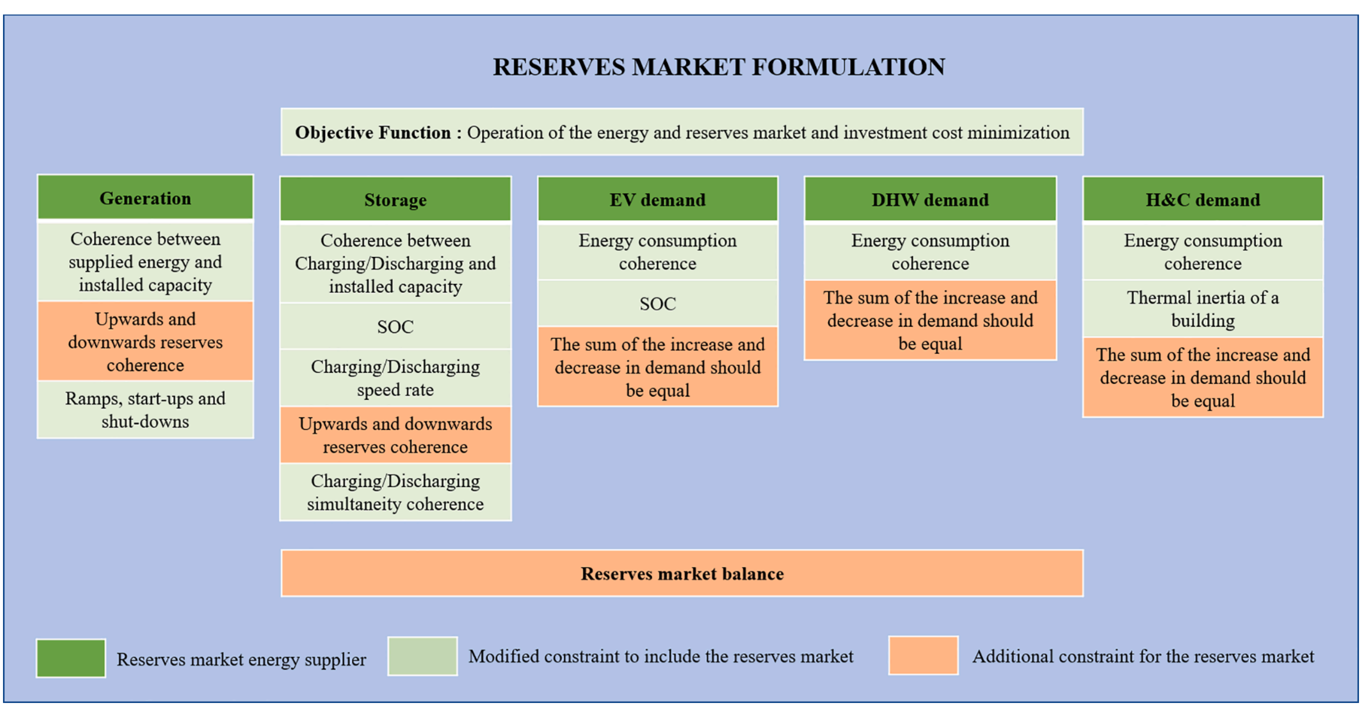

Fig. 1. Reserves market formulation organization.

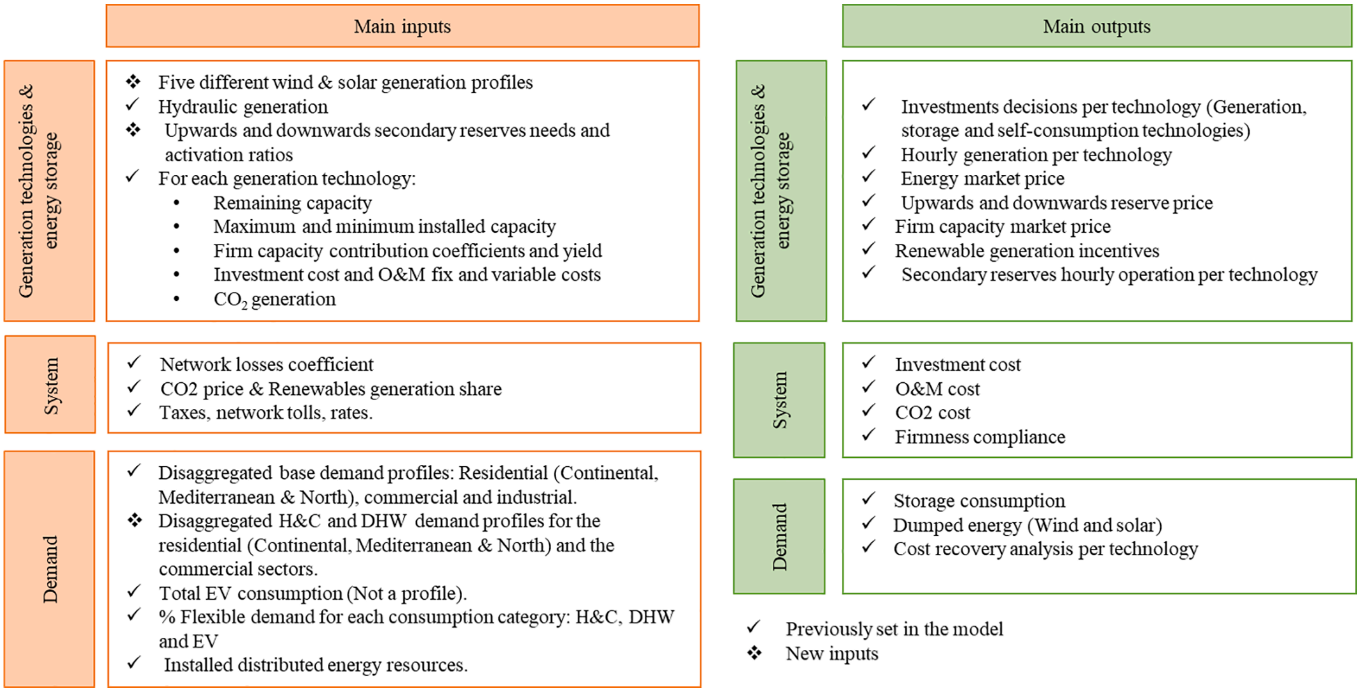

Fig. 2. Model inputs and outputs schematically.

$$operationcosts = \sum_{w,d} MONTHDAYS_{w,d} \sum_{h} (COSTOMVAR_i + INDTAX_i) \\ *(energysell_{i,w,d,h} + dumped_{i,w,d,h} + energysellupR_{i,w,d,h} \\ - energyselldownR_{i,w,d,h}) + (energyproduced_{i,w,d,h} \\ + energyproducedupR_{i,w,d,h} \\ - energyproduceddownR_{i,w,d,h})*CO2EMI_i*EMICOST \\ + (startup_{i,w,d,h} + startupR_{i,w,d,h} + stop_{i,w,d,h} \\ + stopR_{i,w,d,h})*STARTUP_i \tag{4}$$

2.3. Generation technologies able to provide reserves

The total energy produced for the wholesale and reserves markets from nonrenewable technologies, *inr*, is limited in equation (5). The total production at each hour should not exceed the total installed capacity. Besides, the coherence of the energy provided for the downward reserve is controlled with equation (6). The amount of power that nonrenewable technologies able to provide reserves and which include OCGT, CCGT, and hydroelectric technologies can produce for downward reserve capacity should be lower than their energy production for the wholesale market plus the upward reserves market at that same hour.

$$(INSTALLED_{inr} + newinstall_{inr}) \geq energyproduced_{inr,w,d,h} \\ + energyproducedupR_{inr,w,d,h} \\ - energyproduceddownR_{inr,w,d,h} \forall inr, w, d, h \tag{5}$$

$$energyproduced_{inr,w,d,h} + energyproducedupR_{inr,w,d,h} \\ \geq energyproduceddownR_{inr,w,d,h} \forall w, d, h \tag{6}$$

Total hydroelectric energy production for the wholesale and reserves market cannot surpass the available water for this technology in one week due to equation (7). The sum of the wholesale and reserves market production from a CCGT source is limited in equation (8). It should be less than the available capacity for this technology at every hour.

$$\sum_{d} ((INSTALLED_{hydro} + newinstall_{hydro})*HYDROAVAILABLE_{w,d}) \\ \geq \sum_{d,h} energyproduced_{hydro,w,d,h} + energyproducedupR_{hydro,w,d,h} \forall w \tag{7}$$

$$(INSTALLED_{CCGT} + newinstall_{CCGT})*CAPDISP_{CCGT} \geq energyproduced_{CCGT,w,d,h} \\ + energyproducedupR_{CCGT,w,d,h} - energyproducedDownR_{CCGT,w,d,h} \forall w, d, h \tag{8}$$

2.4. Ramps, start-ups and shutdowns

The thermal technologies that compose the *ither* set, have their energy production limited with the number of active power plants and their maximum size (9). Minimum production must also comply with the technical minimum of the plants. This compliance is restricted by constraint (10).

$$nplants_{ither,w,d,h}*PRODMAX_{ither} \geq energyproduced_{ither,w,d,h} \\ + energyproducedupR_{ither,w,d,h} \forall ither, w, d, h \tag{9}$$

$$energyproduced_{ither,w,d,h} - energyproducedDownR_{ither,w,d,h} \\ \geq nplants_{ither,w,d,h}*PRODMIN_{ither} \forall ither, w, d, h \tag{10}$$

Moreover, the number of new active power plants for thermal technologies at each hour is estimated by equations (11) and (12) with the start-ups and shutdowns performed.

$$nplants_{ither,w,d,h} - nplants_{ither,w,d,h-1} = startup_{ither,w,d,h} - stop_{ither,w,d,h} \\ + startupR_{ither,w,d,h} - stopR_{ither,w,d,h} \forall ither, w, d, h \geq 2 \tag{11}$$

$$nplants_{ither,w,d,h} - nplants_{ither,w,d-1,24} = startup_{ither,w,d,h} - stop_{ither,w,d,h} \\ + startupR_{ither,w,d,h} - stopR_{ither,w,d,h} \forall ither, w, d \geq 2, h = 1 \tag{12}$$

Equations (13) and (14) guarantee that thermal technologies' up and down ramping limits are not surpassed.

Table 2
Sets, parameters and variables defined for SPLODER.

Sets	
i	Technology type {Nuclear, CCGT,OCGT, Coal, Cogeneration, Pumping Storage, Batteries, Solar, Wind, Solar Thermal, Hydroelectric, Flowing, Biopower, Thermal renewable, Demand}
$ires \in i$	Technologies able to provide reserves {CCGT, Hydroelectric, Storage}
$ist \in i$	Storage technologies {Pumping Storage and Batteries}
$ict \in i$	Consumption categories without industry
$icres \in i$	{Continental, Mediterranean, North and Commercial}
$iccom \in i$	Residential consumption categories {Continental, Mediterranean and North}
	Commercial consumption category {Commercial}
$ither \in i$	Thermal technologies {Nuclear, CCGT,OCGT and Coal}
$inr \in i$	Nonrenewable technologies {Nuclear, CCGT,OCGT, Coal, Cogeneration, Hydroelectric, Flowing, Biopower}
w	Week {1–4}
d	Day of the week {1–7}
h	Hour {1–24}
Parameters	
$ACTRD_{w,d,h}$	Activated downwards reserves ratio over capacity requirement [%]
$ACTRU_{w,d,h}$	Activated upwards reserves ratio over capacity requirement [%]
$ASIGDR_{w,d,h}$	Downwards reserve requirement ratio over total demand [%]
$ASIGUR_{w,d,h}$	Upwards reserve requirement ratio over total demand [%]
$BOILEREFF$	Boiler efficiency ratio is 0.8 [%]
$CAPDISP_i$	Availability ration for nuclear, CCGT, Coal & OCGT technologies [%]
$CHARHOURS_i$	Charging hours for each type of storage [h]
$CHARMAXEV$	Maximum SOC capacity for each EV [MWh]
C_i	Thermal building wall equivalent capacitor [kWh/°C]
$CO2EMI_i$	Tons of CO_2 emitted for each MWh generated with each technology [tonCO_2/MWh]
$COPAC_i$	Coefficient of Performance [-]
$COSTDER_i$	Distributed energy sources installation cost [€/kW]
$COSTINSTALL_i$	Installation cost [€/MW]
$COSTOMFIX_i$	Operation and maintenance fix costs [€/MW]
$COSTOM_i$	Maintenance DER Cost [€/kW/year]
$COSTOMVAR_i$	Operation and maintenance variable costs [€/MWh]
$DEMANDTHER_{i,w,d,h}$	DHW demand profiles [MWh]
$DISCHARHOURS_i$	Discharging hours for each type of storage [h]
$DNI_{i,w,d,h}$	Solar Direct Normal Irradiance for the different zones [W/m^2]
$DRDHW_{i,w,d,h}$	Percentage of DR stablished for DHW demand [%]
$EFFCHAREV$	EV charging efficiency [%]
$EMICOST$	Cost per ton of CO2 [€/MtonCO_2]
$ERDCAP_i$	ERD Power already installed for each agent [MW]
$ESCAP_i$	ES Power already installed for each agent [MW]
$EVAVAIDEM$	Hourly indicator (0 or 1) to gather when flexible EV are available to change their demand [-]
$EVBASEDEM_{i,w,d,h}$	Hourly demand from fix EV [MW]
$EVCAP24_i$	EV capacity available from the 24 h smart vehicles [MW]
$EVCAP_i$	EV available capacity from the day or night smart vehicles [MW]
$EVTRAVEL_i$	Discharged power of an EV when is not recharging (full capacity is discharged in 10 h for residential vehicles and in 14 h for commercial) [MWh/h]
$HPCAP_i$	HP Power already installed for each agent [MW]
$HYDROAVAILABLE_{w,d}$	Available water for each day of the week for hydroelectric technology [h]
$INDTAX_i$	Specific taxes for each technology [€/MWh]
$INSTALLED_i$	Existing power previously installed for each technology i [MW]
$LOSSESHP$	Losses produced in the HP functioning [p.u.]
$LOSSESPV$	Losses produced in electronics and those due to the slope of the solar panel [p.u.]
M	Very large number: 100,000
$MONTHDAYS_{w,d}$	Number of days along the year that each representative day represent [days]

Table 2 (*continued*)

Sets	
$NUM_{i,w}$	People [n°]
$OUTTEMP_{i,w,d,h}$	Outdoor temperature profiles for each climate zone [°C]
$PRODMAX_i$	Typical size of a power plant for CCGT, OCGT and nuclear power [MW]
$PRODMIN_i$	Minimum size of a power plant for CCGT, OCGT and nuclear power [MW]
$PVCAP_i$	PV Power already installed for each agent [MW]
$RAMPDOWN_i$	Maximum downwards ramp for CCGT, OCGT and nuclear power [MW]
$RAMPUP_i$	Maximum upwards ramp for CCGT, OCGT and nuclear power [MW]
RUA_i	Resistance of the overall heat transfer coefficient [°C/kWh]
$STARTUP_i$	Cost of starting up a power plant [€/power plant]
TAU_i	Thermal inertia = RUA*C [-]
$WIND_{i,w,d,h}$	Wind Power profile for the different zones[p.u.]
$YIELD_{ist}$	Storage technologies yield [%]
Binary Variables (0 or 1)	
$binstoem_{i,w,d,h}$	Indicates whether the storage technology is discharging or not for the wholesale market
$binstorr_{i,w,d,h}$	Indicate whether the storage technology is discharging or not for the reserves market
Positive Variables (>=0)	
$acinput_{i,w,d,h}$	Hourly consumption of one heat pump that is cooling [MWh]
$batcapacity_i$	New installed distributed batteries [MW]
$charge_{i,w,m,h}$	Storage charge at each hour [MW]
$costs$	Total system costs [€]
$discharge_{i,w,m,h}$	Storage discharge at each hour [MW]
$dumped_{i,w,d,h}$	Energy dumped [MWh]
$energybought_{i,w,d,h}$	Hourly energy bought by each technology i [MWh]
$energyproduceddownR_{i,w,d,h}$	Hourly energy produced by each technology i for downward reserves [MWh]
$energyproduced_{i,w,d,h}$	Hourly energy produced by each technology i [MWh]
$energyproducedupR_{i,w,d,h}$	Hourly energy produced by each technology i for upwards reserves [MWh]
$energyselldownR_{i,w,d,h}$	Hourly energy sold by each technology i for downward reserves [MWh]
$energysell_{i,w,d,h}$	Hourly energy sold by each technology i [MWh]
$energysellupR_{i,w,d,h}$	Hourly energy sold by each technology i for upward reserves [MWh]
$erd_{i,w,d,h}$	Electric radiator consumption for each device [kWh]
$evcharge24_{i,w,d,h}$	EV Charging for vehicles considered smart all along the day (24 h) [MWh]
$evcharge_{i,w,d,h}$	EV Charging for smart vehicles during the day or at night [MWh]
$evsoc_{i,w,d,h}$	State of charge of the EV [MWh]
$fixcosts$	Maintenance costs [€]
$hptemp_{i,w,d,h}$	Hourly consumption of one heat pump that is heating [MWh]
$incac_{i,w,d,h}$ $decac_{i,w,d,h}$	Hourly increase and decrease in cooling consumption to supply reserves [MWh]
$incerd_{i,w,d,h}$ $decerd_{i,w,d,h}$	Hourly increase and decrease in DHW consumption to supply reserves [MWh]
$incev_{i,w,d,h}$ $decev_{i,w,d,h}$	Hourly increase and decrease in charging electric vehicles to supply reserves [MWh]
$inchpt_{i,w,d,h}$ $dechpt_{i,w,d,h}$	Hourly increase and decrease in heating consumption to supply reserves [MWh]
$installcosts$	Costs related with installation [€]
$neg_{i,w,d,h}$	Negative production change [MW]
$newinstall_i$	New installed capacity for each technology i [MW]
$nplants_{i,w,d,h}$	Number of activated plants for thermal technologies [n°]
$operationcosts$	Operation costs of generators including start-up and CO_2 emissions costs [€]
$pos_{i,w,d,h}$	Positive production change [MW]
$powererd_i$	New installed Electric Radiators [MW]
$powerhp_i$	New installed Heat Pumps [MW]
$powerpv_i$	New installed PV distributed panels [MW]
$schar_{i,w,d,h}$	Stop charging for storage (Batteries and pumping) [MWh]
$sdischar_{i,w,d,h}$	Stop discharging for storage (Batteries and pumping) [MWh]
$start\text{-}up_{,i,w,d,h}$ $startupR_{,i,w,d,h}$	Start-up of a power plant in response to wholesale or reserve needs [n° power plants]

(*continued on next page*)

Table 2 (*continued*)

Sets	
$stop_{i,\ w,\ d,\ h}$ $stopR_{i,\ w,\ d,\ h}$	Stop a power plant in response to wholesale or reserve needs [n° power plants]
$tempin_{i,w,d,h}$	Indoor temperature profiles for a building [°C]
$xchar_{i,\ w,\ d,\ h}$	Extra charge for storage (Batteries and pumping) [MWh]
$xdischar_{i,\ w,\ d,\ h}$	Extra discharge for storage (Batteries and pumping) [MWh]

$$nplants_{ither,w,d,h}{}^{*}RAMPUP_{ither} \geq pos_{ither,w,d,h} - PRODMAX_{ither}{}^{*}(startup_{ither,w,d,h} + startupR_{ither,w,d,h})\forall ither, w, d \geq 2, h \geq 2 \tag{13}$$

$$nplants_{ither,w,d,h}{}^{*}RAMPDOWN_{ither} \geq neg_{ither,w,d,h} - PRODMIN_{ither}{}^{*}(stop_{ither,w,d,h} + stopR_{ither,w,d,h})\forall ither, w, d \geq 2, h \geq 2 \tag{14}$$

The positive, *pos*, or negative, *neg*, power change is defined at each hour for nonrenewable technologies by equations (15) and (16), including reserves market participation for hydroelectric and CCGT technologies.

$$pos_{inr,w,d,h} - neg_{inr,w,d,h} = energyproduced_{inr,w,d,h} - energyproduced_{inr,w,d,h-1} + energyproducedupR_{inr,w,d,h} - energyproducedupR_{inr,w,d,h-1} - energyproduceddownR_{inr,w,d,h} + energyproduceddownR_{inr,w,d,h-1} \forall inr, w, d, h \geq 2 \tag{15}$$

$$pos_{inr,w,d,h} - neg_{inr,w,d,h} = energyproduced_{inr,w,d,h} - energyproduced_{inr,w,d-1,24} + energyproducedupR_{inr,w,d,h} - energyproducedupR_{inr,w,d-1,24} - energyproducedDownR_{inr,w,d,h} + energyproduceddownR_{inr,w,d-1,24} \forall inr, w, d \geq 2, h = 1 \tag{16}$$

2.5. Storage technologies able to provide reserves

Four new variables were introduced to represent the contribution of storage in reserves. When batteries are charging, it can increase their consumption, *xchar*, or reduce it, *schar*. Conversely, when batteries are discharging, they can produce more, *xdischar*, or produce less, *sdischar*. Constraints (17) to (21) control that the total storage capacity according to the installed capacity is not exceeded, even with the additional charging and stop charging performed for the reserves market.

$$(INSTALLED_{ist} + newinstall_{ist}){}^{*}DISCHARHOURS_{ist} \geq soc_{ist,p,w,d,h} \tag{17}$$

$$(INSTALLED_{ist} + newinstall_{ist}){}^{*}DISCHARHOURS_{ist} \geq soc_{ist,p,w,d,h-1} + (charge_{ist,w,d,h} + xchar_{ist,w,d,h} - schar_{ist,w,d,h}){}^{*}YIELD_{ist}\forall \mathrm{ist, w, d, h} > 1 \tag{18}$$

$$(INSTALLED_{ist} + newinstall_{ist}){}^{*}DISCHARHOURS_{ist} \geq soc_{ist,p,w,d-1,24} + (charge_{ist,w,d,h} + xchar_{ist,w,d,h} - schar_{ist,w,d,h}){}^{*}YIELD_{ist}\forall \mathrm{ist, w, d} >, \mathrm{h} = 1 \tag{19}$$

$$(INSTALLED_{ist} + newinstall_{ist}){}^{*}DISCHARHOURS_{ist} \geq soc_{ist,p,w-1,7,24} + (charge_{ist,w,d,h} + xchar_{ist,w,d,h} - schar_{ist,w,d,h}){}^{*}YIELD_{ist}\forall \mathrm{ist, w} > 1, \mathrm{d} = 1, \mathrm{h} = 1 \tag{20}$$

$$(INSTALLED_{ist} + newinstall_{ist}){}^{*}DISCHARHOURS_{ist} \geq soc_{ist,p,4,7,24} + (charge_{ist,w,d,h} + xchar_{ist,w,d,h} - schar_{ist,w,d,h}){}^{*}YIELD_{ist}\forall \mathrm{ist, w} = 1, \mathrm{d} = 1, \mathrm{h} = 1 \tag{21}$$

Constraints (22) to (25)calculate each storage type's state of charge (SOC) at every hour. The SOC at each hour equals the SOC at the previous hour, plus the charged energy for the reserves market minus the discharged energy for the wholesale and reserves market. The four equations only differ regarding the previous hour's SOC in which, due to the temporal granularity of the model, the sets to be referred to slightly change over time (depending on the week, the day, and the hour).

$$soc_{ist,w,d,h} = soc_{ist,w,d,h-1} + \left((charge_{ist,w,d,h} + xchar_{ist,w,d,h} - schar_{ist,w,d,h}){}^{*}YIELD_{ist}\right) - discharge_{i,w,d,h} - xdischar_{ist,w,d,h} + sdischar_{ist,w,d,h}\forall ist, w, d, \mathrm{h} > 1 \tag{22}$$

$$soc_{ist,w,d,h} = soc_{ist,w,d-1,24} + \left((charge_{ist,w,d,h} + xchar_{ist,w,d,h} - schar_{ist,w,d,h}){}^{*}YIELD_{ist}\right) - discharge_{i,w,d,h} - xdischar_{ist,w,d,h} + sdischar_{ist,w,d,h}\forall ist, w, d > 1, \mathrm{h} = 1 \tag{23}$$

$$soc_{ist,w,d,h} = soc_{ist,w-1,7,24} + \left((charge_{ist,w,d,h} + xchar_{ist,w,d,h} - schar_{ist,w,d,h}){}^{*}YIELD_{ist}\right) - discharge_{i,w,d,h} - xdischar_{ist,w,d,h} + sdischar_{ist,w,d,h}\forall ist, w > 1, d = 1, \mathrm{h} = 1 \tag{24}$$

$$soc_{ist,w,d,h} = soc_{ist,4,7,24} + \left((charge_{ist,w,d,h} + xchar_{ist,w,d,h} - schar_{ist,w,d,h}){}^{*}YIELD_{ist}\right) - discharge_{i,w,d,h} - xdischar_{ist,w,d,h} + sdischar_{ist,w,d,h} \forall ist, w = 1, d = 1, \mathrm{h} = 1 \tag{25}$$

Constraints (26) to (29) are the boundary conditions for the maximum energy that can be discharged at each time of the year, considering the reserves market. The $YIELD_{ist}$ considered in the model contains the round-trip efficiency. Hence, it is not necessary to multiply the $discharge_{i,p,w,m,h}$ variable again.

$$soc_{ist,w,d,h-1} \geq discharge_{i,w,d,h} + xdischar_{ist,w,d,h} - sdischar_{ist,w,d,h}\forall ist, w, d, \mathrm{h} > 1 \tag{26}$$

$$soc_{ist,p,w,d-1,24} \geq discharge_{i,w,d,h} + xdischar_{ist,w,d,h} - sdischar_{ist,w,d,h}\forall ist, w, d > 1, \mathrm{h} = 1 \tag{27}$$

$$soc_{ist,w-1,7,24} \geq discharge_{i,w,d,h} + xdischar_{ist,w,d,h} - sdischar_{ist,w,d,h}\forall ist, w > 1, d = 1, \mathrm{h} = 1 \tag{28}$$

$$soc_{ist,4,7,24} \geq discharge_{i,w,d,h} + xdischar_{ist,w,d,h} - sdischar_{ist,w,d,h}\forall ist, w = 1, d = 1, \mathrm{h} = 1 \tag{29}$$

Constraints (30) and (31)set the charging and discharging speed rate depending on the capacity of the storage hours. Constraint (32) guarantees that the discharged water from the pumping vessel has been refilled throughout the week, considering both, the wholesale and the reserves markets.

$$(INSTALLED_{ist} + newinstall_{ist})*\frac{DISCHARHOURS_{ist}}{CHARHOURS_{ist}} \geq charge_{ist,w,m,h} + xchar_{ist,w,m,h} \forall ist, w, m, h \tag{30}$$

$$(INSTALLED_{ist} + newinstall_{ist})*\frac{DISCHARHOURS_{ist}}{CHARHOURS_{ist}} \geq discharge_{ist,w,m,h} + xdischar_{ist,w,m,h} \forall ist, w, m, h \tag{31}$$

$$\sum_{w,d} MONTHDAYS_{w,d}*\sum_{h}(energysell_{i,w,d,h} + xdischar_{i,w,d,h} - sdischar_{i,w,d,h}) = YIELD_{ist}*\sum_{w,d} MONTHDAYS_{w,d}*\sum_{h}(energybought_{i,w,d,h} + xchar_{i,w,d,h} - schar_{i,w,d,h}) \tag{32}$$

The total amount of energy provided for upward and downward reserves from storage technologies is defined with the extra charge and discharge variables (*xchar, xdischar*) and the stop charging or discharging variables (*schar, sdischar*). This sum of the energy supplied by storage technologies is presented in equations (33) and (34). Besides, the amount of energy that stops charging or discharging should be less than the corresponding energy that was being charged or discharged at that time. This is limited in constraints (35) and (36).

$$energysellupR_{ist,w,d,h} = xdischar_{ist,w,d,h} + schar_{ist,w,d,h} \forall ist, w, d, h \tag{33}$$

$$energysellDownR_{ist,w,d,h} = xchar_{ist,w,d,h} + sdischar_{ist,w,d,h} \forall ist, w, d, h \tag{34}$$

$$charge_{ist,w,d,h} \geq schar_{ist,w,d,h} \forall ist, w, d, h \tag{35}$$

$$discharge_{ist,w,d,h} \geq sdischar_{ist,w,d,h} \forall ist, w, d, h \tag{36}$$

One restriction of the model is that when a storage type is charging, it cannot be discharged at the same time, neither for the wholesale market (constraints (37)(38)) nor the reserves market (constraints (39)-(42)).

$$binstoem_{ist,w,d,h}*M \geq discharge_{ist,w,m,h} \tag{37}$$

$$(1 - binstoem_{ist,w,d,h})*M \geq charge_{ist,w,m,h} \tag{38}$$

$$binstorr_{ist,w,d,h}*M \geq xdischar_{ist,w,d,h} \forall ist, w, d, h \tag{39}$$

$$(1 - binstorr_{ist,w,d,h})*M \geq xchar_{ist,w,d,h} \forall ist, w, d, h \tag{40}$$

$$binstorr_{ist,w,d,h}*M \geq energysellupR_{ist,w,d,h} \forall ist, w, d, h \tag{41}$$

$$(1 - binstorr_{ist,w,d,h})*M \geq energyselldownR_{ist,w,d,h} \forall ist, w, d, h \tag{42}$$

2.6. EV demand

EV demand is assumed to be partially flexible. SPLODER EV types differentiate between EVs with fixed demand that follow a base consumption profile that is the same all day (BASE EVs), and smart charging vehicles, for which the model distinguishes three different categories:

- SMART DAY: smart vehicles that are charged during the day (from 9 a.m. to 7p.m.) and are assigned to commercial sector consumption. They are discharged uniformly during the 14 h of the day when they are disconnected
- SMART NIGHT: EVs that can be charged at any time during the night period (from 7p.m. to 9 a.m.) and are assigned to residential sector consumption. They are discharged uniformly during the 10 h disconnected.
- SMART 24 h: smart EVs that can be charged at any time during the 24 h of a day. They are assumed to be discharged for 10 consecutive hours in a day.

Intelligent EVs, SMART DAY and SMART NIGHT types do not have unlimited available capacity for charging. Therefore, constraints (43) and (44) limit their capacity, also considering the upwards reserve provided. Two new variables have been added per flexible demand type. The variable *incX* represents an increase in consumption, whereas the variable *decX* means a decrease in consumption. The *decev* variable represents the energy supplied from EVs for upwards reserve, which means stopping the charging that was initially scheduled. Constraint (45) guarantees that the total initially charged power is higher than the amount of upwards reserve provided.

$$EVCAP_{ict} \geq evsoc_{ict,w,d,h-1} + (evcharge_{ict,w,d,h} + incev_{ict,w,d,h})*EFFCHAREV \forall ict, w, d, \mathrm{h} > 1 \tag{43}$$

$$EVCAP_{ict} \geq evsoc_{ict,w,d-1,24} + (evcharge_{ict,w,d,h} + incev_{ict,w,d,h})*EFFCHAREV \forall ict, w, d, \mathrm{h} = 1 \tag{44}$$

$$evcharge_{ict,w,d,h} + incev_{ict,w,d,h} \geq decev_{ict,w,d,h} \forall ict, w, d, h \tag{45}$$

Constraints (46), (47) and (48) define the state of charge of the EVs, considering increase and decrease in consumption due to demand participation in wholesale and reserves markets.

$$evsoc_{ict,w,d,h} = evsoc_{ict,w,d,h-1} + (evcharge_{ict,w,d,h} + incev_{ict,w,d,h} - decev_{ict,w,d,h})*EFFCHAREV - EVTRAVEL_{icres}*EVCAP_{ict}*(1 - EVAVAIDEM_{icres,w,d,h}) - EVTRAVEL_{iccom}*EVCAP_{ict}*(1 - EVAVAIDEM_{iccom,w,d,h}) \forall ict, w, d, h \geq 2 \tag{46}$$

$$evsoc_{ict,w,d,h} = evsoc_{ict,w,d-1,24} + (evcharge_{ict,w,d,h} + incev_{ict,w,d,h} - decev_{ict,w,d,h})*EFFCHAREV - EVTRAVEL_{icres}*EVCAP_{ict}*(1 - EVAVAIDEM_{icres,w,d,h}) - EVTRAVEL_{iccom}*EVCAP_{ict}*(1 - EVAVAIDEM_{iccom,w,d,h}) \forall ict, w, d \geq 2, h = 1 \tag{47}$$

$$evsoc_{ict,w,d,h} = evsoc_{ict,w,1,0} + (evcharge_{ict,w,d,h} + incev_{ict,w,d,h} - decev_{ict,w,d,h})*EFFCHAREV - EVTRAVEL_{icres}*EVCAP_{ict}*(1 - EVAVAIDEM_{icres,w,d,h}) - EVTRAVEL_{iccom}*EVCAP_{ict}*(1 - EVAVAIDEM_{iccom,w,d,h}) \forall ict, w, d = 1, h = 1 \tag{48}$$

Intelligent EVs, have their maximum charging capacity limited by constraint (49) for the SMART DAY and NIGHT vehicles and by constraint (50) for the SMART 24 h vehicles. Moreover, constraint (51) forces the SMART 24 h vehicles to charge the discharged power throughout the 14 h of the day they are considered to be connected to a recharging point.

$$EVCAP_{ict}*CHARMAXEV*EVAVAIDEM_{ict,w,d,h} \geq evcharge_{ict,w,d,h} + incev_{ict,w,d,h} \forall ict, w, d, \mathrm{h} \tag{49}$$

$$EVCAP24_{ict}*CHARMAXEV \geq evcharge24_{ict,w,d,h} + incev_{ict,w,d,h} \forall ict, w, d, \mathrm{h} \tag{50}$$

$$\sum_{h}(evcharge24_{ict,w,d,h} + incev_{ict,w,d,h} - decev_{ict,w,d,h})*EFFCHAREV = EVTRAVEL_{icres}*EVCAP24_{ict} \forall ict, w, d \tag{51}$$

2.7. Domestic hot water Demand

To provide DHW, electric radiators (ERD) are the installed devices used to represent immersion heaters. Constraint (52) limits ERD consumption to total installed capacity. The coherence of the energy provided for the upwards reserve is controlled by constraint (53). Providing upward reserve from the demand side means stopping consumption. Therefore, this amount should be lower than the total expected consumption of that consumption category from the wholesale market, plus the increase in consumption planned to provide downward reserve. On the one hand, the total DHW consumption profile should be consumed, although the hour when it is consumed can change for the flexible part. Constraint (54), guarantees that the entire consumption profile is consumed at some point. On the other hand, the fixed DHW demand cannot be shifted. This condition is met by equation (55).

Table 3
Geographical distribution of solar and wind generation profiles.

ZONE	Solar Spain provinces	Wind Spain provinces
A1	Galicia & Asturias	Galicia, Asturias, Cantabria & Castilla Leon
A2	Valencia & Murcia	Pais vasco, Navarra, Aragón & La Rioja
A3	Aragón, Cataluña, Extremadura, Madrid, Castilla La Mancha, & Andalucia	Cataluña, Valencia & Murcia
A4	Castilla Leon	Andalucia
A5	Cantabria,Pais vasco, Navarra & La Rioja	Extremadura, Madrid & Castilla La Mancha

$$powerhp_{ict} + HPCAP_{ict} \geq NUM_{ict,w} * \left(hptemp_{ict,w,d,h} + inchpt_{ict,w,d,h}\right) + NUM_{ict,w} * \left(acinput_{ict,w,d,h} + incac_{ict,w,d,h}\right) \forall ict, w, d, h \tag{56}$$

$$tempin_{ict,w,d,h} = tempin_{ict,w,d,h-1} + \left(tempin_{ict,w,d,h-1} - OUTTEMP_{ict,w,d,h-1}\right) * \frac{2}{TAU_{ict}} + (hptemp_{ict,w,d,h} + inchpt_{ict,w,d,h} - dechpt_{ict,w,d,h}) * COPAC_{ict} * (1 - LOSSESHP) + GAStemp_{ict,w,d,h} * BOILEREFF - (acinput_{ict,w,d,h} + incac_{ict,w,d,h} - decac_{ict,w,d,h}) * COPAC_{ict} * (\frac{RUA_{ict}}{2} - \frac{2}{C_{ict}}) - ((hptemp_{ict,w,d,h-1} + inchpt_{ict,w,d,h-1} - dechpt_{ict,w,d,h-1}) * COP_{ict} * (1 - LOSSESHP - (acinput_{ict,w,d,h-1} + incac_{ict,w,d,h-1} - decac_{ict,w,d,h-1}) * COPAC_{ict} * (\frac{RUA_{ict}}{2} - \frac{2}{C_{ict}})) \forall ict, w, d, \mathrm{h} > 1 \tag{57}$$

$$tempin_{ict,w,d,h} = tempin_{ict,w,d-1,24} + \left(tempin_{ict,w,d-1,24} - OUTTEMP_{ict,w,d-1,24}\right) * \frac{2}{TAU_{ict}} + (hptemp_{ict,w,d,h} + inchpt_{ict,w,d,h} - dechpt_{ict,w,d,h}) * COPAC_{ict} * (1 - LOSSESHP) + GAStemp_{ict,w,d,h} * BOILEREFF - (acinput_{ict,w,d,h} + incac_{ict,w,d,h} - decac_{ict,w,d,h}) * COPAC_{ict} * (\frac{RUA_{ict}}{2} - \frac{2}{C_{ict}}) - ((hptemp_{ict,w,d-1,24} + inchpt_{ict,w,d-1,24} - dechpt_{ict,w,d-1,24}) * COPAC_{ict} * (1 - LOSSESHP) - (acinput_{ict,w,d-1,24} + incac_{ict,w,d-1,24} - decac_{ict,w,d-1,24}) * COPAC_{ict} * (\frac{RUA_{ict}}{2} - \frac{2}{C_{ict}})) \forall ict, w, d > 1, \mathrm{h} = 1 \tag{58}$$

$$powererd_{ict} + ERDCAP_{ict} \geq erd_{ict,w,d,h} + incerd_{ict,w,d,h} \forall ict, w, d, h \tag{52}$$

$$erd_{ict,w,d,h} + incerd_{ict,w,d,h} \geq decerd_{ict,w,d,h} \forall ict, w, d, h \tag{53}$$

$$\sum_h erd_{ict,w,d,h} + incerd_{ict,w,d,h} - decerd_{ict,w,d,h} = \sum_h DEMANDTHER_{ict,w,d,h} \forall ict, w, d \tag{54}$$

$$erd_{ict,w,d,h} - decerd_{ict,w,d,h} \geq DEMANDTHER_{ict,w,d,h} * (1 - DRDHW_{ict}) \forall ict, w, d, h \tag{55}$$

2.8. Heating and cooling Demand

For heating and cooling purposes, heat pumps (HP) are the available electric devices. The total amount of electric heating and cooling installed capacity should always be higher than the total consumption. This is limited in equation (56). The model's internal formulation of the heating and cooling needs considers outdoor temperatures and a comfort range for indoor temperatures considering the thermal inertia of a building. Equations (57) and (58) guarantee that the indoor temperature is within the established comfort range, even when there is an increase or decrease in flexible demand due to its reserve market participation.

A decrease in heating and cooling demand when providing reserves means to stop consuming. Therefore, this decrease should be lower the expected consumption at that particular time. This is limited by equations (59) and (60).

$$hptemp_{ict,w,d,h} + inchpt_{ict,w,d,h} \geq dechpt_{ict,w,d,h} \forall ict, w, d, h \tag{59}$$

$$ac + incac_{ict,w,d,h} \geq decac_{ict,w,d,h} \forall ict, w, d, h \tag{60}$$

2.9. Reserve market balance

The wholesale market balance equation is not affected by the reserves market needs to guarantee the balance of production and demand in this market. Therefore, equations (61) and (62) are added separately to collect the new balance equations for the upward and downward reserves market. The reserve needs have been estimated depending on the total *energySell* decided for each hour, considering the ratio of requirements needed and the activation ratio of this requirement as in [50].

$$\sum_i (energysellupR_{i,w,d,h} + decerd_{i,w,d,h} + NUM_{ict,w} * (dechpt_{i,w,d,h} + decac_{i,w,d,h}) + decev_{i,w,d,h}) = \sum_i energysell_{i,w,d,h} * ASIGUR_{w,d,h} * ACTRU_{w,d,h} \forall w, d, h \tag{61}$$

$$\sum_i (energyselldownR_{i,w,d,h} + incerd_{i,w,d,h} + NUM_{ict,w} * (inchpt_{i,w,d,h} + incac_{i,w,d,h}) + incev_{i,w,d,h}) = \sum_i energysell_{i,w,d,h} * ASIGDR_{w,d,h} * ACTRD_{w,d,h} \forall w,d,h \quad (62)$$

Two different variables that represent the energy produced by each generation technology to provide upward and downward reserves are required to be able to model the reserves market for storage technologies and their peculiarities. Equations (63) and (64) balance the two different variables. For all generation technologies from set “I” that are not included in the set “ires”, both variables would acquire a null value.

$$energysellupR_{i,w,d,h} = energyproducedupR_{i,w,d,h} \quad (63)$$

$$energyselldownR_{i,w,d,h} = energyproduceddownR_{i,w,d,h} \quad (64)$$

2.10. Flexible demand participating in reserve limitations

Shifted demand to provide reserves should be scheduled for another hour on the same day to keep daily consumption constant. Constraints (65), (66), (67), and (68) ensure that this shifted consumption is moved to another hour of the day for all consumption categories.

$\sum_h incerd_{ict,w,d,h} = \sum_h decerd_{ict,w,d,h} \forall ict, w, d(65).$

$\sum_h inchpt_{ict,w,d,h} = \sum_h dechpt_{ict,w,d,h} \forall ict, w, d(66).$

$\sum_h incac_{ict,w,d,h} = \sum_h decac_{ict,w,d,h} \forall ict, w, d(67).$

$\sum_h incev_{ict,w,d,h} = \sum_h decev_{ict,w,d,h} \forall ict, w, d(68).$

3. Scenarios and case studies

The previously required input data has been reused from the study presented in [46] which had the same time horizon as this study, which is the year 2030. The data previously defined and also used for this study include:

- The firm capacity coefficients assumed for each technology
- The 2019 existing generation capacity is expected to still be available in 2030
- The investment costs and the fixed and variable maintenance costs for both conventional and renewable technologies
- The fuel prices, CO_2 emission costs, and taxes for pollutant technologies

The newly required and some updated input data when applied to the Spanish system include:

1) The inclusion of five wind and five solar generation areas to invest in, whose difference remains in their generation profile in accordance with different geographical areas. Table 3 presents the geographical representation within Spain of the five solar and wind generation areas.

These profiles have been gathered from [51]. Besides, in order to take a small network representation into account, the grid access and connection capacity allowance published by Red Eléctrica de España (REE) [52] have been considered as limits of the maximum installed capacity for each geographical zone and technology, as presented in Table 4.

DR can involve different sources and technologies, such as distributed solar PV generation and battery storage. The deployment effect of these two technologies have been thoroughly studied as flexible sources, with the aim of justifying the need for investment in distributed solar PV [53,54] and for distributed batteries [55], although batteries are still not competitive. In this study, distributed solar PV generation capacity is previously installed, as an investment option its high cost makes it an undesirable choice, and distributed batteries are modelled, although neither are considered when referring to flexible demand analysis, as done in [56]. Therefore, the PV distributed investment is forced according to the roadmap [57] for each geographical zone. Solar technologies broken down into geographical zones refer to centralized PV, which has better efficiency than distributed PV. Therefore, the initial capacity was multiplied by a reduction factor to force the installation of a “Centralized capacity equivalent to the real distributed capacity” per zone. This reduction factor was obtained from [58], and the results are presented in Table 5.

Table 4
Maximum installed capacity in each solar and wind area.

Technology	Max Install [MW]
WIND1	15,469
WIND2	6,984
WIND3	5,123
WIND4	2,199
WIND5	1,746
SOLAR1	247
SOLAR2	14,576
SOLAR3	69,661
SOLAR4	14,273
SOLAR5	2,526

Table 5
Distributed solar generation installed capacity.

Zone	Distributed installed capacity [MW]	Distributed/ Centralized Ratio	Equivalent centralized capacity [MW]
A1	182	0.90	163
A2	1412	0.79	1110
A3	5940	0.76	4539
A4	339	0.76	258
A5	339	0.77	261

Table 6
Energy consumption and average traveled distance per type of vehicle.

Type of vehicle	Percentage of total EVs [%]	Energy consumption [KWh/100 km]	Distance [km/year]
Cars	71 %	20	15,000
Vans and buses	10 %	26	18,000
Motorcycles	19 %	6	12,000

Table 7
Amount of EVs for each EV category considered with the SPLODER model.

SPLODER EVs TYPES	Number of EVs	Percentage [%]
BASE	2,065,863	41 %
SMART NIGHT	1,910,170	38 %
SMART DAY	491,211	10 %
SMART 24 h	606,241	12 %
TOTAL	5,073,484	100 %

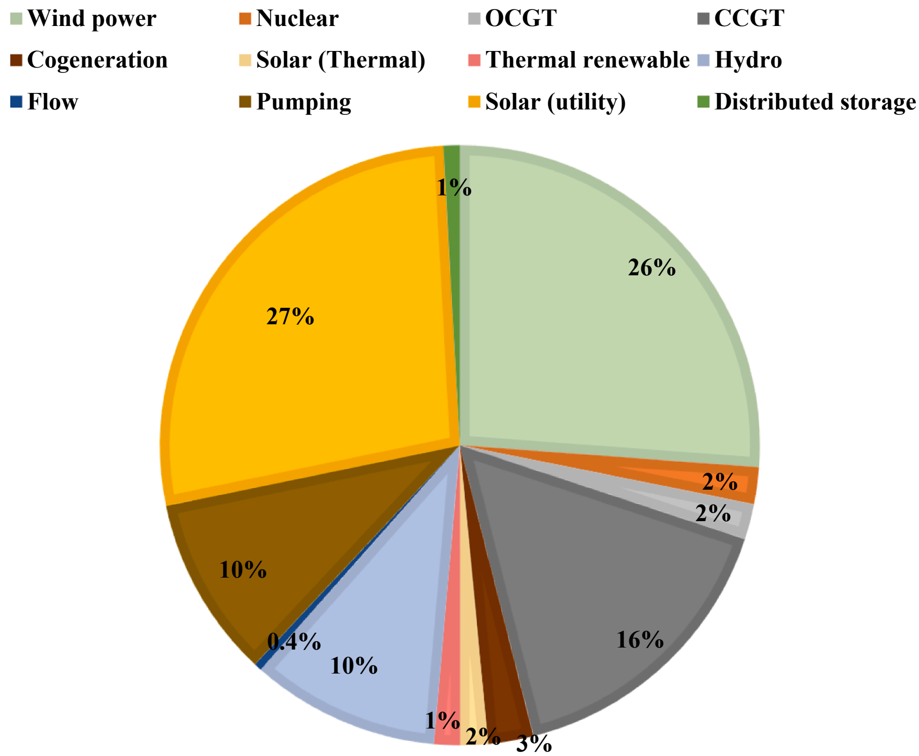

Fig. 3. Fixed installed electricity generation technology mix.

2) Disaggregated demand profiles, for the residential and services sector, into different consumption categories (DHW, H&C, lighting and others). These sensitive data can be found in [51]. The demand profiles are considered to be at the power plant busbars, so the losses in the network are zero, where, the energy generated (290TWh) = energy consumed (290TWh).
3) EV consumption data has also changed from previous studies. However, its formulation remains the same. The number of EVs was estimated considering different reports with the expected fleet growth through 2030 [59]. The consumption per vehicle [KWh/km] was adjusted according to data from [60] and [61], distinguishing between cars, motorcycles, and vans. The annual average distance driven by each type of vehicle was gathered from [62] data, all presented in Table 6.

The type of vehicle classification among the model options was calculated by using detailed information on the charging points, including their location and whether they are for private or public use [51]. The final input data for SPLODER is presented in Table 7.

4) Secondary reserves need and activation ratios. In this case, the publicly available information in [26] has been used to create a 5 year averages, from June 1, 2017 to May 31, 2022, of secondary reserve needs and activation, for upwards ($ASIGUR_{w,d,h}$ and $ACTRU_{w,d,h}$) and downwards reserve ($ASIGDR_{w,d,h}$ and $ACTRD_{w,d,h}$). The reserve needs ratio was calculated according to demand on an hourly basis, and the activation ratio was set according to reserve requirements. These average profiles have been suitably adapted to the time granularity of the model. Thus, the resulting hourly amount of reserve needed and activated in each scenario depends on the input demand profiles.

Table 8
Scenarios for the fixed and freely installed electricity generation technology mix.

Case Name	Reserves consideration	Amount of Flexible demand	Demand participation in reserves
20DR	No	20 %	No
RR_20DR	Yes	20 %	No
RR_0DR_dem	Yes	0 %	Yes
RR_20DR_dem	Yes	20 %	Yes
RR_40DR_dem	Yes	40 %	Yes
RR_60DR_dem	Yes	60 %	Yes

Table 9
Flexible energy available for each percentage of DR.

FLEXIBLE ENERGY [GWh]	0DR	20DR	40DR	60DR
H&C	0	13,589	27,177	40,766
DHW	0	8,067	16,134	24,201
EV	0	8,160	8,160	8,160

All scenarios have been studied under two different case studies for the installed electricity generation technology mix. First under an optimized technology mix (free installation is permitted) and subsequently under a fixed installed technology mix (no installation is allowed). The fixed installed electricity generation technology mix considered corresponds with the optimized installation of the most restrictive scenario from the freely installed case, which is the RR_0DR_dem scenario. The fixed installed electricity generation technology mix considered to perform under these conditions is presented in Fig. 3. This technology mix includes the solar and wind installed capacity committed to 2030 in the Spanish NECP[59]. With this condition, it is easier to draw conclusions about operating results and compare one scenario to another, as technology investment decisions do not distort results.

The scenarios considered address the role of DR providing reserves and its impact on electricity system costs and generation and storage investment planning. First, the comparison of two scenarios that have the same amount of flexible demand, with and without reserves market consideration, would give the value of considering reserves when

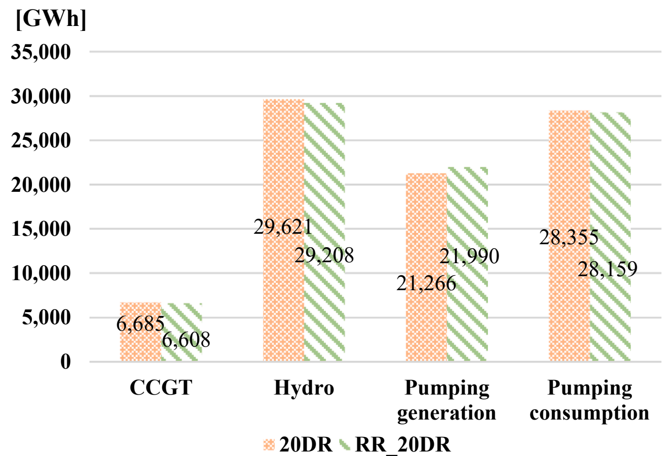

Fig. 4. Wholesale market operation with and without considering reserves market for technologies able to provide reserves with a fixed installed generation technology mix.

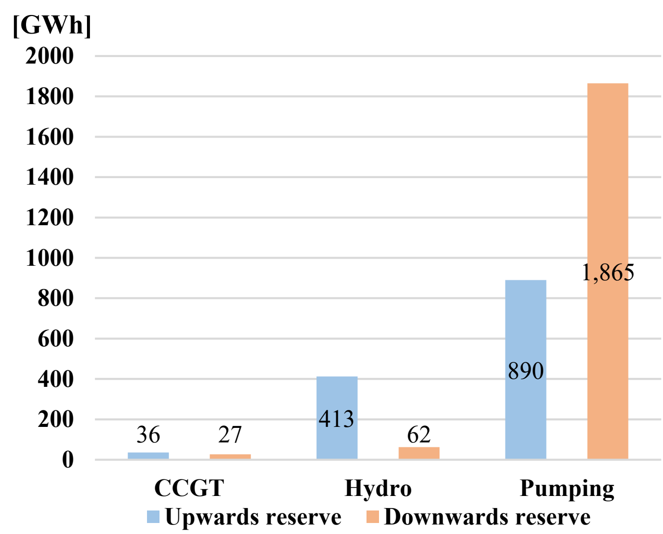

Fig. 5. Upward and downward reserves operation for the RR_20DR with a fixed installed generation technology mix scenario.

planning generation operation and expansion investment. Subsequently, different levels of flexible demand participating in the reserves market would be analyzed, both when the installed electricity generation technology mix is fixed and when it is optimized to compare operation and investment correspondingly. Finally, to determine the impact of demand participating in the wholesale and reserves market on system costs, scenarios where the investment is settled are needed to be able to compare total system costs.

Thus, each scenario is defined by three characteristics: reserves consideration, amount of flexible demand, and the participation of demand in reserves. The first term in the name indicates whether or not the scenario considers the reserves market. If the reserves market is considered, the name begins with RR; in any other case the reserves market is neglected. The second part of the scenario name refers to the percentage of flexible demand considered for heating, cooling, and DHW consumption categories (0DR, 20DR, 40DR, 60DR). In order to be consistent with the EV flexibility estimates presented in Table 7, where the EV is estimated to have around a 60 % of flexibility and see the DR effects with enough perspective, DR usage ranges from 0 % DR to 60 % DR in the other consumption categories, as there is not a clearly-defined amount of DR in 2030. Lastly, the term “dem” is indicated when demand is allowed to participate in the reserves market. Table 8 presents the different scenarios with their main distinguishing features.

The flexible energy available for each DR usage scenario is defined by the input consumption profiles and the preset percentage of DR. Table 9 presents the total flexible energy for each consumption category that applies to both the fixed and the freely installed generation technology mix scenarios for each percentage of DR.

4. Analysis and results

In this section, the results are organized into four blocks to set out the main takeaways of the paper. For this purpose, each block uses the most appropriate scenarios that can be compared and analyzed to draw the relevant conclusions. In brief, the four blocks are: the operation of the system, which uses the fixed installed technology mix scenarios; the total system costs that compare both the fixed and the freely installed generation technology mix scenarios; the investment decisions, which can only be analyzed in the freely installed generation technology mix scenarios; and finally, the flexibility analysis, which in this case is performed over the freely installed generation technology mix scenarios, although conclusions for the fixed installed generation technology mix scenarios are the same.

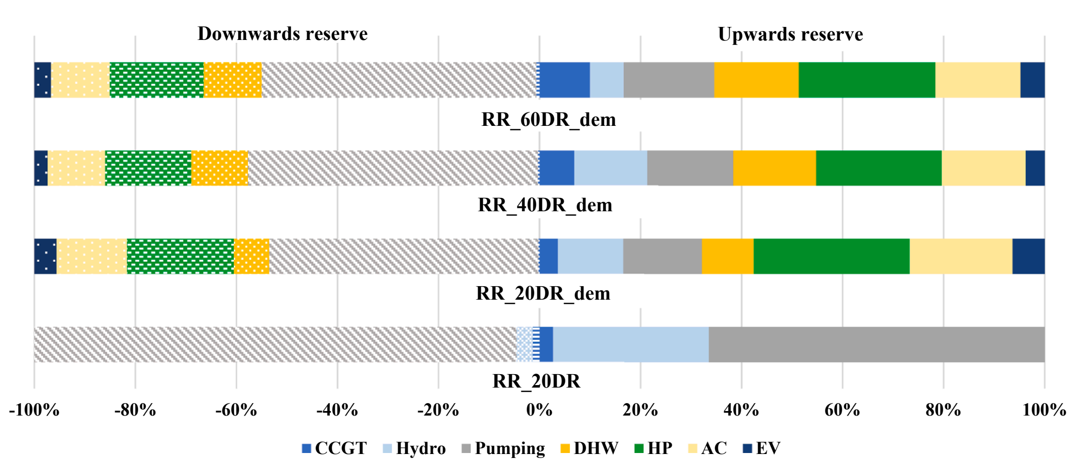

Fig. 6. Reserves market operation for the fixed installed generation technology mix scenarios.

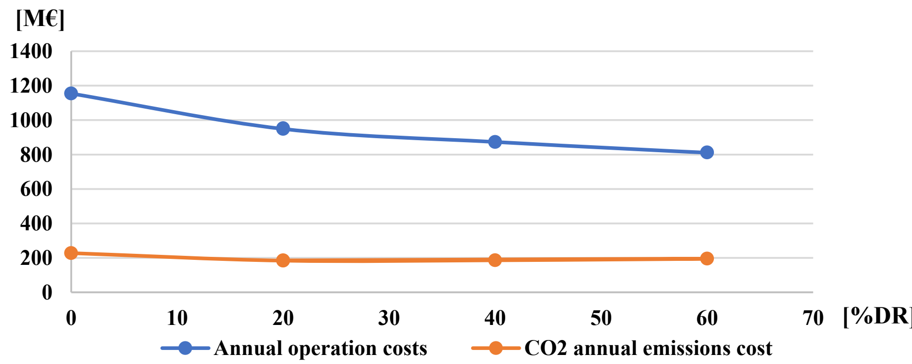

Fig. 7. Operation and CO_2 costs for the wholesale and reserves market in the fixed installed generation technology mix scenarios.

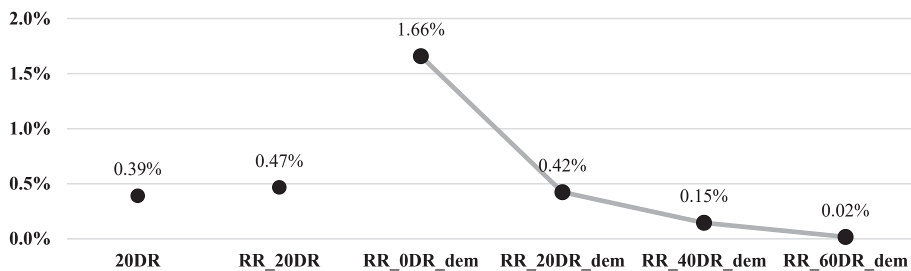

Fig. 8. Solar and wind spillages for fixed installed generation technology mix scenarios.

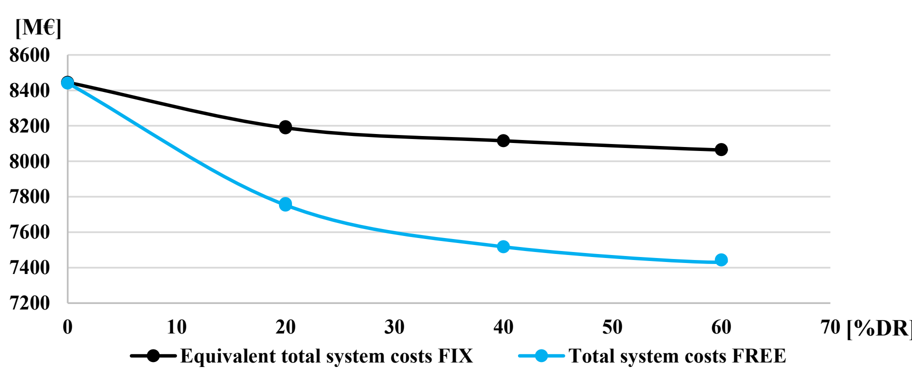

Fig. 9. Total system costs for the fixed and freely installed generation technology mix sensibilities.

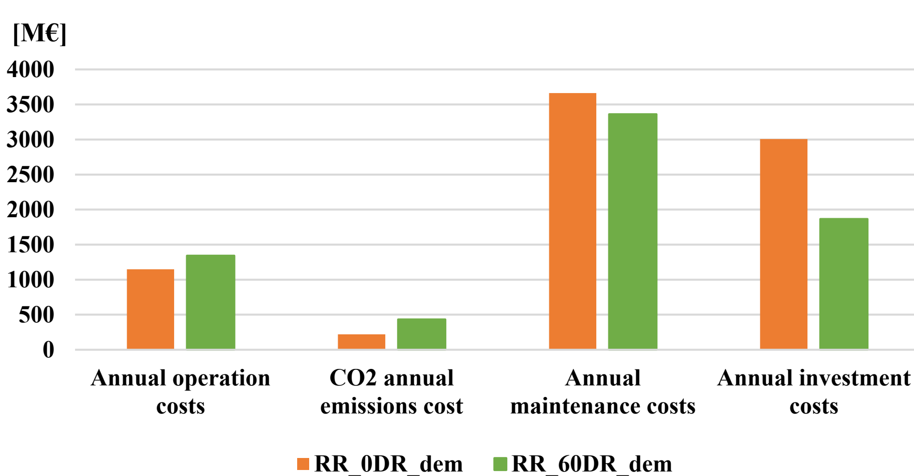

Fig. 10. Comparison from 0 to 60% of DR of system costs for the freely installed generation technology mix sensibilities.

4.1. Operation of the system considering reserves

With the purpose of comparing and analyzing the changes in system operation when considering the reserves and when demand participation in reserves is allowed, fixed generation installed generation technology mix scenarios have been used. Thus, the impact of different investment decisions is avoided.

Technologies that can provide reserves operate differently on the wholesale market when reserves are considered. Fig. 4 compares wholesale market generation with and without considering the reserves market. Fig. 4 show that both CCGT and hydro decrease their operation on the wholesale market to have more availability and increase their generation for the reserves market. However, pumping increases its production in the wholesale market when considering reserves while decreasing their consumption (Fig. 4). Pumping technology has a very high potential to provide downward reserves. It accounts for 95 % of total downward reserve needs. Therefore, its increase in wholesale market generation is to have more capacity available to provide this service (Fig. 5). Conversely, CCGT and hydroelectric technologies are used to a greater extent to provide upwards reserve.

In all scenarios, the downward reserve requirement is greater than the upwards reserve requirement. Pumping is the technology that mainly provides this downward reserve until demand participates in the reserve market. When demand is participating in this market, is responsible for providing about 67 % of the upwards reserve requirement and about 45 % of the downward reserve requirement. This removes a relevant part of the role of pumped storage hydroelectric. Fig. 6 presents the percentage of upward (positive side) and downward (negative side) reserve needs that each available source provides for all scenarios that consider the reserves market. The amount of demand used for upward and downward reserve should always be the same, as shifted demand must be supplied at some point. When demand starts participating in the reserve market it gains relevance, where heating and cooling have flexible demand, the most used consumption sector. However, the more DR that is available in the system does not result in more demand quota providing reserves. As this source defends [13], it is more profitable to use DR for optimizing the wholesale energy market than for balancing needs.

4.2. Wholesale and reserves market system costs and savings

For the fixed installed generation technology mix scenarios, the costs that most differ from one scenario to another are the operation and CO_2 costs. Fig. 7 presents the sum of wholesale and reserves operations as annual operation costs versus the CO_2 costs for all the fixed installed generation technology mix scenarios that consider the reserves market. There are two different scenarios with 20 % DR (RR_20DR and RR_20DR_dem), although they almost overlap, and their difference is not relevant. Reserves market costs account for less than 0,1% of total operating and CO_2 costs. Therefore, its cost does not have a relevant effect on global results.

The decrease in total system costs with the increase in DR is mainly due to the decrease in operating costs in the wholesale market. Undoubtedly, the leap from having no DR at all to having 20 % DR is the most substantial (Fig. 7). It leads to a significant decrease in spillages by making better use of them and preventing other more expensive technologies from producing this energy. The CO2 emission costs remain almost flat, no matter how much available DR there is in the system. This is because with a fixed installed generation technology mix, CCGT operation does not change, and the use of DR is replacing pumping operations.

Fig. 8 presents the percentage of renewable spillages for all scenarios. Under these conditions, DR prioritizes diminishing spillages, and reducing operating costs from the energy market, which results in lower total system costs (Fig. 9). Fig. 8 also reveals that considering reserves increases spillages by 20 % (20DR compared to RR_20DR) if demand does not participate in the reserves markets. Furthermore, spillages are negligible when 60 % DR is available in the system.

Fig. 9 presents the total system costs for the fixed and freely installed generation technology mix scenarios when considering the reserves market. For the fixed installed generation technology mix scenarios, the investment required to attain the pre-installed generation technology mix considered was added to make it equivalent to the total system costs that are being compared.

When increasing from 0 to 60 % DR, the system would experience savings of 5 % with a fixed installed generation technology mix due to the reduction of operating costs. On the other hand, in the case study with the investment decision, savings from considering in advance a percentage of DR from 0 to 60 % would achieve savings of up to 12 % of total expenses, mainly due to decreasing investment costs by considering DR in advance.

Fig. 10 compares the different system costs for the RR_0DR_dem and the RR_60DR_dem scenarios when investment is allowed (freely installed generation technology mix conditions). First, operating costs increase up to 30 % from 0 to 60 % of DR, including CO_2 emissions costs. This is because it tries to avoid technology investment and take advantage of the existing resources with higher operating costs than new technologies. For this same reason, CO_2 costs also increase. Second, the investment costs experience a reduction of 38 % from 0 to 60 % of DR. These costs are responsible for the shape of the total system costs curve (Fig. 9). Finally, maintenance costs also decreased by 8 % from having no DR to counting 60 % of it.

4.3. Generation technology investments with a system that considers the reserves market

To analyze investment decisions, the scenarios where free installation is allowed are assessed. Comparing the scenarios with and without considering reserves (20DR compared to RR_20DR), the total capacity invested for each technology does not undergo relevant changes. This is because reserves represent approximately only 1 % of the total energy requirements. Likewise, DR consideration have a small effect on

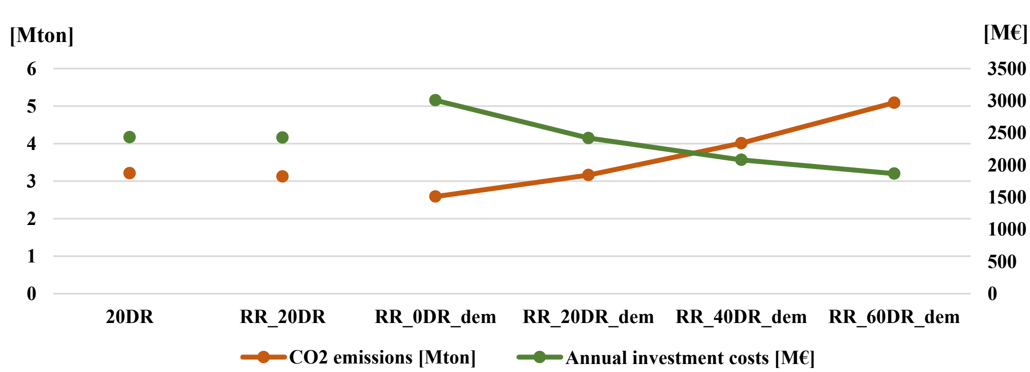

Fig. 11. Investment costs and CO_2 emissions in the freely installed generation technology mix scenarios.

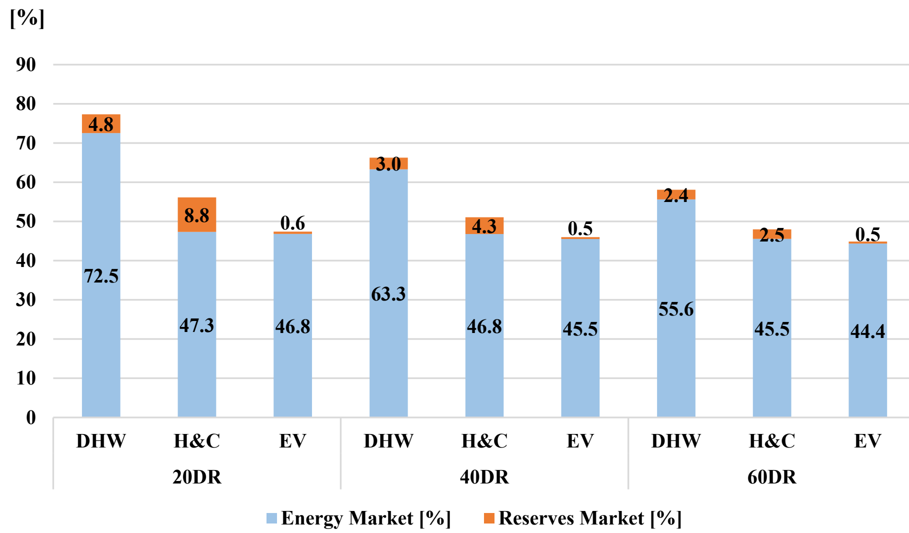

Fig. 12. Flexible demand use with the different consumption categories for the energy and reserves markets for the freely installed generation technology mix scenarios.

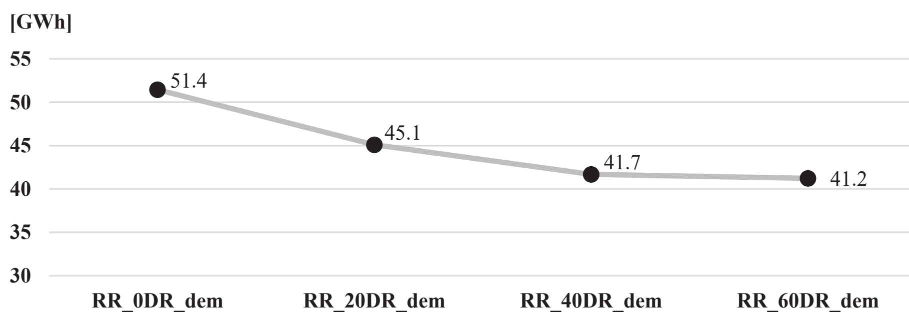

Fig. 13. Peak demand for the freely installed generation technology mix scenarios.

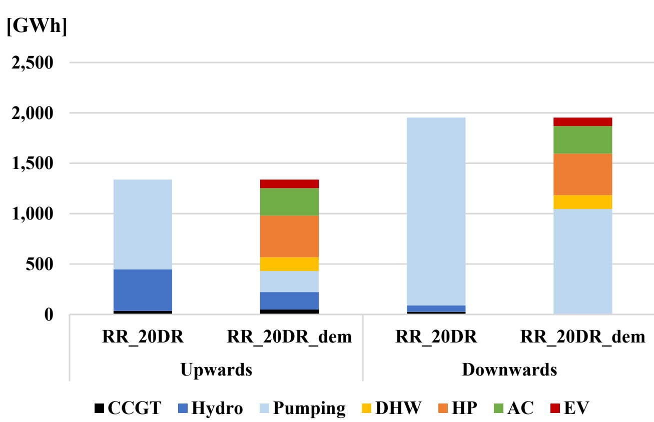

Fig. 14. Upwards and downwards reserves market operation for fix installed generation technology mix scenarios.

investment decisions. When comparing scenarios RR_20DR and RR_20DR_dem which the only difference lies in the demand participation in reserves, 1 % of technology investment expenditures are avoided, mainly from renewables, as energy requirements decrease with the increase in DR. Furthermore, the greater the availability of DR in the system, the less investment is required. DR mainly reduces investment in firm capacity, thus avoiding pumping hydroelectric storage installation. Therefore, the lower the investment in pumping, the higher the use of CCGT or other pollutant technologies that are already available in the system to provide energy during sun and wind scarcity periods. Hence, more CO_2 emissions are generated, as this study concludes for the northern European energy system[63]. This effect is presented in Fig. 11. A trade-off between costs and emissions can be seen in around 33 % DR penetration.

4.4. Flexible demand participation in energy and reserves markets

Fig. 12 represents the amount of flexibility used and how much it has been used for power and for the reserves market from the total available flexibility of each consumption category for the freely-installed generation technology mix scenarios. This has been done by comparing the energy moved with respect to the non-flexible profile consumption.

An increase in available DR does not mean an increase in DR opportunities. In fact, the flexible demand used according to the flexible demand available is decreasing for the sum of both markets when there is more DR in the system. This means that a specific amount of flexibility is needed in the system. One relevant constraint that explains this behavior is that all flexible demand that is not consumed at its scheduled hour must be consumed at another time. Hence, results reveal that part of the flexible demand is not of interest to move in any of the markets due to this limit.

Analyzing this figure in detail, the different consumption categories also have different potential providing energy services. DHW use on average a 67 % of their total available flexibility, while H&C and EV, on average, use close to 50 % of their total available flexibility. However, H&C provides more in relative and absolute terms (Fig. 14) in reserve services. This is due to a higher amount in GWh of flexible demand available from this category (Table 9). The methodology of considering temperature constraints limits the changeable demand possibilities, thus reducing its possibilities on the wholesale market and facilitating opportunities on the reserves market compared to EV and DHW.

In addition, DR decreases firm capacity needs, which are directly proportional to the decrease in peak demand (Fig. 13). About 60 % DR decreases peak demand by 20 %. Thus, the more DR there is in the system, the less pumping hydroelectric storage investment there is. Hence, the reserves market remains in the background due to the use of DR.

Fig. 14 compares the two scenarios with 20DR that consider reserves, but one has demand participation and the other does not. When demand participates in the reserves market for upward reserve, it supplies around 67 % of the needs of total reserve needs. On the other hand, it supplies around 45 % of the downward reserve needs, although it merits mention that in absolute terms, both directions use the same amount of demand participation due to model constraints, but the share of upward reserve is higher, meaning that less total energy is required.

5. Conclusions and future work

This study analyzes the impact of considering balancing services in the operation and investment decisions when planning the future electricity system, besides the role of DR and its effect when participating in the energy and reserves markets.

Thus, this study, proves that there is a difference between whether or not the reserves market is considered for system operation and investments. The operation of the sources can provide changes in reserves. CCGT and hydroelectric reduce their generation in the energy market in order to have more available energy to provide upward reserves. In contrast, pumping storage increases its generation and reduces its consumption for the energy market in order to be able to provide more downward reserve. Regarding CO_2 emissions, their decrease is not directly related to a decrease in spillages or an increase in DR available in the system. The reduction of CO_2 emissions implies an increase in total system costs. When the objective is to minimize the system costs, the increase of available DR raises the usage of existing polluting technologies to avoid investments in storages. Therefore, in the case where lowering CO_2 emissions was the target, an additional constraint should be taken into consideration to optimize investment and operation from that perspective instead of from the cost minimization point of view. Investment decisions about generation technologies do not change due to considering or not considering reserves, as this market represents only 1 % of total energy supply needs.

This study demonstrates that demand participation in the reserves market has a non-neglectable role. Although, only a 1 % of technology investment expenditures can be avoided and the percentage of flexible demand used for reserves is low compared to wholesale use, more than 45 % of the reserve energy needs could be met with demand assets. Results show that H&C is the category that provides the majority of energy in reserves due to their larger energy presence in the system. However, results also reflect that the two other categories, DHW and EV, offer more relative flexibility. This is because their demand has fewer shifting constraints, whereas H&C is limited by outdoor temperatures and indoor comfort maintenance, which constrains the possibilities of shifting demand.

Finally, DR participating in the energy and reserves market would be responsible for savings of at least 5 % whether or not investment considers new generation technologies. If DR availability was considered before technology investments are decided, up to 12 % of total system costs could be saved with a high penetration of DR (60 % of its total potential) although CO_2 emissions increase by 95 %. A decision between desired savings and emissions establishes a trade-off point of around 33 % DR participation from DHW and H&C demands. This finding has important policy implications since it shows that while demand response leverages existing infrastructure, it should be complemented with new storage investments (against the minimum cost alternative) to deal with the increase in emissions effectively. Due to the use limitations established for the different flexibility sources, the estimated total system savings are below what literature forecasts (between 15 and 30 %).

There are many other services where DR could add value to the system when the aggregator figure is more mature, such as congestion management. Therefore, all these services should also be assessed. Other future lines to continue with this study would be to achieve DR operating and investment costs to be able to optimize the amount of DR in the system and include other sources of flexible demand, such as industrial processes or refrigeration, that could increase total system savings.

CRediT authorship contribution statement

Teresa Freire-Barceló: Data curation, Formal analysis, Investigation, Methodology, Writing – original draft. **Francisco Martín-Martínez:** Funding acquisition, Supervision, Validation, Writing – review & editing. **Álvaro Sánchez-Miralles:** Conceptualization, Funding acquisition.

Declaration of competing interest

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

Data availability

Data will be made available on request.

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PAPER 4

- DR is profitable if LCOE of each technology is lower than 100 €/MWh.
- The minimum emissions are achieved with different DR deployment levels depending on the DR type.
- EV flexibility have a better business case than DHW and H&C flexibility.
- DR costs consideration change additional payments needs to play in a secure market.

Demand response cost analysis and its effect on system planning

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***Abstract*—Demand response (DR) is becoming a necessity rather than a choice since its environmentally friendly nature makes it an ideal option for development and deployment in the electricity system, particularly in the high-renewable penetration landscape. However, determining the system costs associated with DR is challenging, as there is ambiguity regarding their allocation. This work uses an enhanced model that optimizes the amount of DR from the residential and services sectors within the system, thereby establishing a range of fixed and variable costs that guarantee a profitable business case for DR implementation. The findings highlight that H&C is the most restrictive technology, as it requires lower costs to achieve a positive business case, followed by DHW and finally the EV flexibility is the one that has wider cost range while still profitable. Furthermore, the consideration of DR costs has been compared with not considering them, thereby justifying their necessity in making optimal investment and operational decisions.**

***Keywords*—Demand response cost, Electricity system planning, LCOE, buildings flexibility, profitability analysis.**

HIGHLIGHTS

- DR is profitable if LCOE of each technology is lower than 100 €/MWh.
- The minimum emissions are achieved with different DR deployment levels depending on the DR type
- EV flexibility have a better business case than DHW and H&C flexibility
- DR costs consideration change additional payments needs to play in a secure market

NOMENCLATURE

CCGT	*Combined cycle gas turbine*
DHW	*Domestic hot water*
DR	*Demand response*
DR cost	*Include: investment in smart devices, operation costs, consumer remuneration…*
EDF	*Explicit Demand Flexibility*
EU	*European Union*
EV	*Electric Vehicle*
H&C	*Heating and cooling*
LCOE	*Levelized Cost of Electricity*
OCGT	*Open cycle gas turbine*

I. Introduction

The paradigm of energy systems is evolving rapidly, driven by the imperatives of sustainability, reliability, and economic efficiency. Among the myriad solutions emerging, explicit demand flexibility (EDF) stands out as a pivotal mechanism capable of harmonizing supply-demand imbalances in the grid. EDF consists of empowering consumers to actively adapt their usage patterns in response to supply fluctuations, price variations, and system requirements. It can be used to optimize the grid operation and it fosters the integration of renewable energy sustainably by reducing spillages [1].

Moreover, the energy transition towards wind and solar technologies, while pivotal for decarbonization efforts, faces challenges concerning the availability and geopolitical dependencies of critical raw materials [2] [3]. Wind turbines and solar panels, reliant on rare earth metals and specific materials for their production, raise concerns about supply chain vulnerabilities and material constraints. Conversely, among the different sustainable energy solutions, EDF is another sustainable resource that can provide energy services and decrease technology investment requirements, avoiding these raw material challenges. Unlike renewable sources, demand response (DR) strategies primarily rely on behavioral and consumption pattern adjustments rather than material-intensive infrastructure. Therefore, DR is an attractive solution within the energy transition, offering resilience against potential raw material shortages and supply chain disruptions [3]. It has been demonstrated that it has a large potential as it is capable of avoiding spillages in the system hence, integrating renewables sustainably[4][5]. Finally, EDF also enhances the grid system operation, by solving network congestions and reducing peak demand. However, while the sustainable quality and the theoretical prospects of demand flexibility are compelling, a critical gap exists in understanding the costs associated with its implementation.

A. Literature review

Existing studies have emphasized the importance of demand-side flexibility in enhancing grid resilience and reducing system costs [1][6][7][8]. Nonetheless, there is still a lack of comprehensive analysis regarding the specific and tangible costs related to EDF mechanisms also differentiating between investment and operating costs, as it is not clear which costs should be attributed to EDF implementation.

There are studies that obtain the savings that EDF can achieve with a particular application, however those savings neglect EDF costs, therefore are overestimated. Moreover, these studies establish a fix amount of EDF available in the system [9] [10]. This study [6] compares the different uses of DR separately within the German context, concluding that load shifting is where the most significant economic opportunities are, achieving 2,83% of operational savings. However, it does not mention which are the associated DR costs. The Belgium electricity system has also been analyzed [11] to quantify the operation savings on the day ahead market with DR available from residential heating. With this limitation, only 6-7% of operation savings are achieved. The approach presented in [7] focuses on estimating the benefits of DR for the UK, emphasizing the quantification of economic welfare. It also reviews related literature on DR costs and benefits. However, most existing studies primarily highlight the benefits, being limited references the ones that mention costs, providing only a qualitative allocation of them [12]. The analysis presented in [13] explores diverse interaction methods among energy producers, aggregators, and users when there is DR in the system, determining the most advantageous approach that maximizes benefits for all parties involved. Although the study estimates the operational benefits of using DR, the associated costs are not mention as they are difficult to obtain.

There is another branch of studies which estimate the willingness to pay of the consumers to invest in new electric equipment in order to be able to participate in EDF services. This could be the cost associated with DR equipment and services that a user is willing to pay/receive. According to [14] heating and electric appliances have a higher consumers' willingness to enroll than EVs. Besides, consumers preferred financial incentives to environmental incentives. However, they are still not enough to foster the electrification [15] [16]. These studies are performed with population surveys and the results only involve the end-user's perspective, providing qualitative recommendations, without considering the effect in the system.

Other studies compare the system costs with and without EDF in the system. However, they do not specify who the DR providers are and which are their costs. Results in [17] reflects that system investment costs increase while operating costs decrease when there is EDF because the full cost of the equipment, such as the heat pumps, are considered, which is the opposite to what most studies argue [7]. However, assigning all the costs of the appliance for DR purposes is not fair since the installation of appliances does not mean their availability for DR. On the contrary, reference [8] concludes that EDF decreases system investment costs, mainly from storage technologies and instead increases operating costs, taking advantage of old previously installed power plants and manageable loads.

The potential benefits of a full deployment of demand-side flexibility for the whole EU by 2030 are quantified in [1]. The study, intends to inform policy makers on the most cost-efficient pathway for both, the energy system and consumers.

Large-scale numbers for the entire EU are presented, without offering specific details for individual countries. For instance, a total investment cost of 120 €/MW/year for demand side flexibility is provided.

This paperuses the terms DR and EDF interchangeably to denote the same concept, and for this case the industrial sector flexible demand will be neglected, therefore they only refer to buildings flexible demand. Two different costs for EDF are considered in this paper, one is considered fix (investment cost) and the other is a variable cost as it depends on the amount of flexibility used (O&M cost). The expenses that these costs should recover, and therefore, each involved party should define its financial strategy to be sustainable include, from the system perspective:

1) The smart meter investment and maintenance (it does not include the particular heat pump or particular EV) [18]
2) Information, Control and Communication System and cloud costs [12]. This is related with the operation of the devices.
3) Other operation costs, such as, customer service, control center…
4) Minimum end-user and aggregator remuneration. The user will change their normal behavior due to an economic incentive.

B. Contribution

The literature gap is twofold: Firstly, current literature considers the level of DR as input; and secondly, as there are no cost references that clearly determine the costs associated with implementing and operating EDF from a system perspective, there is no way to fairly compare the deployment of DR with other technologies as storage since the cost of DR is 0 which oversize their real deployment. This paper aims to clarify the costs for which EDF has a positive business case, offering a comprehensive global perspective on its economic efficiency and the optimal quantity of EDF for each scenario. This is relevant information for potential investors and for regulators that design the framework in which EDF plays. The DR cost range calculated in this study could support regulatory measures to reinforce EDF deployment in the system, emphasizing its role as a resilient and sustainable solution amidst the complexities of the evolving energy landscape.

This paper improves an existing generation expansion planning model by incorporating DR as an additional resource within the system for investment and energy service provision. Through this model the range of investment and operation costs at which DR is profitable are obtained.

The main contributions of the paper are two:

1- The development of a generation expansion planning model that incorporates DR as an additional available source within the system considering investment and operation costs for the provision of energy services. This approach optimizes the quantity of DR, diverging from the treatment of DR as a fixed input in prior literature.

2- Determining a range of DR investment and operation costs for the case of Spain in which DR have a positive economic balance. The impact in system costs and emissions of the different optimal amount of DR are also assessed.

II. MODEL FORMULATION

The linear optimization model used to perform this study has been developed by the authors, this model is named SPLODER. The initial version of the model was fully described in [20]. Some upgrades performed to this initial version are presented in [21–23] to include policy constraints, to consider new storage technologies that can compete with flexible demand resources, and to add the reserves market [8], respectively.

Up to now, the system's quantity of DR for each demand category was an input to the model as a percentage of the total consumption [9][10]. However, the current approach contributes to optimizing this quantity through appropriate upgrades and necessary input data. The model now treats the DR as another available technology in the system to also optimize its investment for H&C, DHW and EV categories, providing the result again as a percentage of the total consumption for each demand category. To enable the model to do this, H&C and DHW consumption input profiles are needed and have been gathered from [24]. The changes and enhancements developed include a double step model. DHW and smart EVs energy consumption is the same no matter how much of it is flexible, this is because the rebound effect is considered in the problem and the energy moved at one time is consumed at another time. This means that the total energy is equal between flexible or fix profile. Therefore, the sequence of a two step model is only required for H&C consumption category, as it uses a thermal model that considers the comfort temperature inside a building to decide whether to consume or not, making a more efficient use of energy when there is DR available in the system, and thus changing the total energy consumed for H&C. This allows to avoid non linearities in the formulation. The first step (Problem A), uses the consumption input profiles to build an 'ideal' consumption profile assuming all H&C demand were completely flexible. Subsequently, in the second step (Problem B) considering the DR investment cost, this 'ideal' profile is employed, to determine the feasibility of investing in DR. The investment in flexible DHW and smart EVs are both decided in the second step, which is where the model has the global picture of the available resources and their particular constraints to optimize their investment. This approach prevents an overestimation of DR potential and its role within the system.

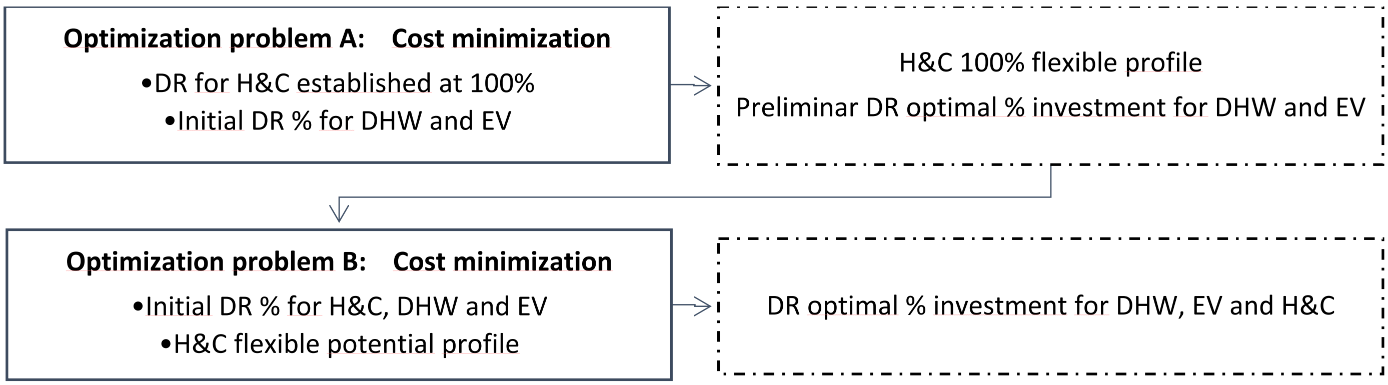

Figure 1 Double step model sequence

Sets, parameters, and variables.

The new formulation of the model with aims to optimize the DR investment in the system is presented hereinafter. Table 1 presents the sets, parameters, and variables used in the new and changed constraints to optimize the amount of DR for DHW, EV and H&C for the different climate zones presented in the model.

Table 1 Sets, parameters and variables defined for SPLODER

Sets	
d	Day of the week {1-7}
h	Hour {1-24}
i	Technology type {Nuclear, CCGT, OCGT, Coal, Cogeneration, Pumping Storage, Batteries, Solar, Wind, Solar Thermal, Hydro, Flowing, Biopower, Thermal renewable, Demand}
$ict \in i$	Consumption categories without industry {Continental, Mediterranean, North and Commercial}
tdr	Demand response sources { DRDHW, DRH&C, DREV }
tder	Distributed energy resource type {PV, ES, HP, ERD}
w	Week {1-4}
Parameters	
$ACTRD_{w,d,h}$	Activated downwards reserves ratio over capacity requirement [%]
$ACTRU_{w,d,h}$	Activated upwards reserves ratio over capacity requirement [%]
$ASIGDR_{w,d,h}$	Downwards reserve requirement ratio over total demand [%]
$ASIGUR_{w,d,h}$	Upwards reserve requirement ratio over total demand [%]
CHARMAXEV	Maximum SOC capacity for each EV [MWh]
$CO2EMI_i$	Tons of CO_2 emitted for each MWh generated with each technology [tonCO_2/MWh]

$COSTDR_{tdr}$	DR sources installation cost [€/%]
$COSTINSTALL_{i}$	Installation cost [€/MW]
$COSTOMFIX_{i}$	Operation and maintenance fix costs [€/MW]
$COSTOM_{tder}$	Maintenance DER Cost [€/MW]
$COSTOMV_{tdr}$	Operation and maintenance variable costs for DR [€/MWh]
$DEMANDTHER_{i,w,d,h}$	DHW demand profiles [MWh]
$DNI_{i,w,d,h}$	Solar Direct Normal Irradiance for the different zones [W/m^2]
$DRDHW_{i}$	Preset DR percentage for DHW demand [%]
DREV	Preset percentage for smart EVs demand [%]
$DRH\&C_{i}$	Preset DR percentage for H&C demand [%]
$DRH\&CPRO_{i,w,d,h}$	H&C consumption profile with 100% of DR [MWh]
$DRH\&CPROD_{i,w,d,h}$	H&C downwards reserve profile with 100% of DR [MWh]
$DRH\&CPROU_{i,w,d,h}$	H&C upwards reserve profile with 100% of DR [MWh]
EFFCHAREV	EV charging efficiency [%]
EMICOST	Cost per ton of CO2 [€/MtonCO_2]
$ERDCAP_{i}$	ERD Power already installed for each agent [MW]
$ESCAP_{i}$	ES Power already installed for each agent [MW]
EVBASE	Input data to indicate the amount of EVs that are not smart [nº]
$EVBASEDEM_{i,w,d,h}$	Hourly demand from fix EV [MWh]
$EVCAP24_{i}$	EV capacity available from the 24h smart vehicles [MW]
EVSMART	Input data to indicate the amount of EVs that are smart during the night hours [nº]
EVSMART24	Input data to indicate the amount of EVs that are smart during the 24 hours of the day [nº]
EVSMARTDAY	Input data to indicate the amount of EVs that are smart during the day hours [nº]
$EVTRAVEL_{i}$	Discharged power of an EV when is not recharging (full capacity is discharged in 10h for residential vehicles and in 14h for commercial) [MWh/h]
$H\&CDEMAND_{i,w,d,h}$	H&C input demand profiles [MWh]

Positive Variables (>=0)

$acinput_{i,w,d,h}$	Hourly consumption of one heat pump that is cooling [MWh]
addevsmart24	Additional investment in smart EVs [%]
$addpdrdhw_{i}$	Additional investment in DHW flexible demand [%]
$addpdrh\&c_{i}$	Additional investment in H&C flexible demand [%]
$charge_{i, w, m, h}$	Storage charge at each hour [MW]
costs	Total system costs [€]
dempeak	Peak demand [MW]
$discharge_{i, w, m, h}$	Storage discharge at each hour [MW]
$dumped_{i,w,d,h}$	Energy dumped [MWh]
$energybought_{i,w,d,h}$	Hourly energy bought by each technology *i* [MWh]
$energyproduceddownR_{i, w, d, h}$	Hourly energy produced by each technology i for downward reserves [MWh]
$energyproduced_{i,w,d,h}$	Hourly energy produced by each technology *i* [MWh]
$energyproducedupR_{i, w, d, h}$	Hourly energy produced by each technology i for upwards reserves [MWh]
$energypumped_{i, w, d, h}$	Energy pumped with old pumped hydro power plants [MWh]
$energyselldownR_{i, w, d, h}$	Hourly energy sold by each technology i for downward reserves [MWh]
$energysell_{i,w,d,h}$	Hourly energy sold by each technology *i* [MWh]
$energysellupR_{i, w, d, h}$	Hourly energy sold by each technology i for upward reserves [MWh]
$erd_{i,w,d,h}$	Electric radiator consumption for each device [MWh]
$evcharge24_{i,w,d,h}$	EV Charging for vehicles considered smart all along the day (24h) [MWh]

$evcharge_{i,w,d,h}$	EV Charging for smart vehicles during the day or at night [MWh]
fixcosts	Maintenance costs [€]
$flexDHWused_{i, w, d, h}$	Flexible CLI demand that has been moved [MWh]
$flexEVused_{i, w, d, h}$	Flexible EV demand that has been moved [MWh]
$flexH\&Cused_{i, w, d, h}$	Flexible H&C demand that has been moved [MWh]
$hptemp_{i,w,d,h}$	Hourly consumption of one heat pump that is heating [MWh]
$incac_{i, w, d, h}$ $decac_{i, w, d, h}$	Hourly increase and decrease in cooling consumption to supply reserves [MWh]
$incerd_{i, w, d, h}$ $decerd_{i, w, d, h}$	Hourly increase and decrease in DHW consumption to supply reserves [MWh]
$incev_{i, w, d, h}$ $decev_{i, w, d, h}$	Hourly increase and decrease in charging electric vehicles to supply reserves [MWh]
$inchpt_{i, w, d, h}$ $dechpt_{i, w, d, h}$	Hourly increase and decrease in heating consumption to supply reserves [MWh]
installcosts	Costs related with installation [€]
$newinstall_i$	New installed capacity for each technology *i* [MW]
operationcosts	Operation costs of generators including start-up and CO_2 emissions costs [€]
$producpv_{i, w, d, h}$	Energy produced from distributed solar PV panels [MWh]
$start\text{-}up_{,i, w, d, h}$ $startupR_{,i, w, d, h}$	Start-up of a power plant in response to wholesale or reserve needs [nº power plants]
$stop_{i, w, d, h}$ $stopR_{i, w, d, h}$	Stop a power plant in response to wholesale or reserve needs [nº power plants]

The formulation described includes some terms related to the H&C consumption that change when solving problem A or problem B. The two variations for each term are presented in Table 2.

Table 2 Different terms for solving problem A and B

	Problem A	***Problem B***
$costh\&c$	0	$COSTDR_{DRH\&C} * addpdrh\&c_i$
$flexh\&c$	$NUM_{ict,w} * (hptemp_{ict,w,d,h} + acinput_{ict,w,d,h})$	$DRH\&CPRO_{i,w,d,h} * (DRH\&C_{ict} + addpdrh\&c_{ict})$
uph&c	$NUM_{i,w} * \left(dechpt_{i,w,d,h} + decac_{i,w,d,h}\right)$	$DRH\&CPROU_{i,w,d,h} * (DRH\&C_i + addpdrh\&c_i)$
downh&c	$NUM_{i,w} * \left(inchp_{i,w,d,h} + incac_{i,w,d,h}\right)$	$DRH\&CPROD_{i,w,d,h} * (DRH\&C_i + addpdrh\&c_i)$

Objective function

The objective function was revised to incorporate the investment cost ($COSTDR$) associated with the additional flexible demand, this cost is provided in €/%, where the percentage represent the flexible demand for each consumption category per total available demand for that category. In the first step, only the investment costs from additional flexible DHW ($addpdrdhw_{ict}$) and smart EVs ($addevsmart24$) apply. For solving problem B, the investment cost associated with additional flexible demand from H&C ($addpdrh\&c_{ict}$) is incorporated. Furthermore, operational costs for the flexible demand used are also included for the three consumption categories.

The objective function of the model is to minimize total system costs and is presented in equation (1). Equations (2) to (4) calculate the corresponding installation, maintenance, and operating costs that comprise the objective function.

$$costs = installcosts + fixcosts + operationcosts \tag{1}$$

$$\begin{aligned} installcosts = \sum_{i} & newinstall_i * COSTINSTALL_i + COSTDR_{DRDHW} * addpdrdhw_i + COSTDR_{DREV} \\ & * addevsmart24 + costh\&c \end{aligned} \tag{2}$$

$$\begin{aligned} fixcosts = \sum_{i} & (COSTOMFIX_i * (INSTALLED_i + newinstall_i) + PVCAP_i * COSTOM_{PV} + HPCAP_i \\ & * COSTOM_{HP} + ESCAP_i * COSTOM_{ES} + ERDCAP_i * COSTOM_{ERD}) \end{aligned} \tag{3}$$

$$\begin{aligned} operationcosts = \sum_{i,w,d} & MONTHDAYS_{w,d} \sum_{h} (COSTOMV_i + INDTAX_i) * (energysell_{i,w,d,h} + dumped_{i,w,d,h} \\ & + energysellupR_{i,w,d,h} - energyselldownR_{i,w,d,h}) + (energyproduced_{i,w,d,h} \\ & + energyproducedupR_{i,w,d,h} - energyproduceddownR_{i,w,d,h}) * CO2EMI_i * EMICOST \\ & + (startup_{i,w,d,h} + startupR_{i,w,d,h} + stop_{i,w,d,h} + stopR_{i,w,d,h}) * STARTUP_i \\ & + flexH\&Cused_{i,w,d,h} * COSTOMV_{DRH\&C} + flexDHWused_{i,w,d,h} * COSTOMV_{DRDHW} \\ & + flexEVused_{i,w,d,h} * COSTOMV_{DREV} \end{aligned} \tag{4}$$

To calculate the operating costs of DR, the amount of demand moved need to be calculated. For each consumption category the flexibility used is obtained by comparing the final consumption profile with the equivalent fix consumption profile that would have resulted. Equations (5), (6) & (7) represent this comparison for H&C, DHW and EVs correspondingly.

$$flexH\&Cused_{ict,w,d,h} \geq H\&CDEMAND_{ict,w,d,h} * (DRH\&C_{ict} + addpdrh\&c_{ict}) - flexh\&c \ \forall \ ict, w, d, h \tag{5}$$

$$flexDHWused_{ict,w,d,h} \geq DEMANDTHER_{ict,w,d,h} - \ erd_{ict,w,d,h} \ \forall \ ict, w, d, h \tag{6}$$

$$\begin{aligned} & flexEVused_{ict,w,d,h} \\ & \quad \geq \ EVBASEDEM_{ict,w,d,h} * (EVSMART + EVSMART24 + EVSMARTDAY + addevsmart24) \\ & \quad - \ evcharge_{ict,w,d,h} - evcharge24_{ict,w,d,h} \ \forall \ ict, w, d, h \end{aligned} \tag{7}$$

Energy market balance

The wholesale market balance equation is affected by the final demand consumption profile. Therefore, equation (8) present the new balance equation considering the additional investment in H&C, DHW and smart EVs. On the other side, equation (9) calculates the new peak demand with these additional investment in flexible demand categories. Where the only difference between problem A and B stands in the H&C demand.

$$energysell_{i,w,d,h} - energybough_{i,w,d,h} + dumped_{i,w,d,h} = energyproduced_{i,w,d,h} - EVBASEDEM_{i,w,d,h} * (EVBASE - addevsmart24) - evcharge_{i,w,d,h} + evcharge24_{i,w,d,h} - energypumped_{i,w,d,h} + producpv_{i,w,d,h} + DNI_{i,w,d,h} * (1 - LOSSESSPV) * 0{,}001 * (INSTALLED_i + newinstall_i) + WIND_{i,w,d,h} * (INSTALLED_i + newinstall_i) - charge_{i,w,d,h} + discharge_{i,w,d,h} - erd_{i,w,d,h} - flexh\&c - H\&CDEMAND_{i,w,d,h} * (1 - DRH\&C_i - addpdrh\&c_i) \quad \forall\, w,d,h \tag{8}$$

$$dempeak \geq \sum_i EVBASEDEM_{i,w,d,h} * (EVBASE - addevsmart) + evcharge_{i,w,d,h} + evcharge24_{i,w,d,h} + erd_{i,w,d,h} + flexh\&c + H\&CDEMAND_{i,w,d,h} * (1 - DRH\&C_i - addpdrh\&c_i) \quad \forall\, w,d,h \tag{9}$$

Demand assets constraints

The fixed DHW demand cannot be shifted, this is restricted in equation (10). In addition, the initial percentage of flexible demand for DHW plus the investment in additional flexibility, cannot be greater than 100%, which is limited in equation (11).

$$erd_{ict,w,d,h} - decerd_{ict,w,d,h} \geq DEMANDTHER_{ict,w,d,h} * (1 - DRDHW_{ict} - addpdrdhw_{ict}) \quad \forall\, ict,w,d,h \tag{10}$$

$$1 \geq DRDHW_{ict} + addpdrdhw_{ict} \quad \forall\, ict \tag{11}$$

The new smart EVs, come from the conversion of non-smart EVs, therefore investment in additional smart EVs can never be greater than the non-smart EVs, this is limited in equation (12). Smart EVs, have their maximum charging capacity limited by constraint (13). Moreover, constraint (14) forces the smart EVs to charge the discharged power throughout the 14 hours of the day they are considered to be connected to a recharging point.

$$EVBASE \geq addevsmart24 \tag{12}$$

$$EVCAP24_{ict} * (DREV + addevsmart24) * CHARMAXEV \geq EVCharge24_{ict,w,d,h} + incEV_{ict,w,d,h} \quad \forall\, ict,w,d,\mathrm{h} \tag{13}$$

$$\sum_h (EVCharge24_{ict,w,d,h} + incEV_{ict,w,d,h} - decEV_{ict,w,d,h}) * EFFCHAREV = EVTRAVEL_{ict} * EVCAP24_{ict} * (DREV + addevsmart24) \quad \forall\, ict,w,d \tag{14}$$

The initial percentage of flexible demand for H&C plus the investment in additional flexibility, cannot be greater than 100%, this is limited in equation (15).

$$1 \geq DRH\&C_{ict} + addpdrh\&c_{ict} \quad \forall\, ict \tag{15}$$

Problem B parameters

New parameters are defined to stablish the flexible consumption profile available for H&C demand. This profile is divided in three, energy market, upwards and downwards reserve, and are presented in equations (16) to (18) accordingly.

$$DRH\&CPRO_{i,w,d,h} = NUM_{i,w} * \left(hptemp_{i,w,d,h} + acinput_{i,w,d,h}\right) \tag{16}$$

$$DRH\&CPROU_{i,w,d,h} = NUM_{i,w} * \left(dechpt_{i,w,d,h} + decac_{i,w,d,h}\right) \tag{17}$$

$$DRH\&CPROD_{i,w,d,h} = NUM_{i,w} * \left(inchp_{i,w,d,h} + incac_{i,w,d,h}\right) \tag{18}$$

Reserves market balance

Reserve needs have been estimated depending on the total energy sell decided for each hour, considering the ratio of requirements needed and the activation ratio of this requirement as in [25]. Reserve balance equations (19) and (20) change from problem A to problem B in order to use the defined flexible profile in problem A, for the optimal amount of DR obtained in problem B.

$$\begin{aligned}\sum_i (energysellupR_{i,w,d,h} + decERD_{i,w,d,h} + uph\&c + decEV_{i,w,d,h}) \\ = \sum_i energysell_{i,w,d,h} * ASIGUR_{w,d,h} * ACTRU_{w,d,h} \ \forall\, w,d,h\end{aligned} \tag{19}$$

$$\begin{aligned}\sum_i (energysellDownR_{i,w,d,h} + incERD_{i,w,d,h} + downh\&c + incEV_{i,w,d,h}) \\ = \sum_i energysell_{i,w,d,h} * ASIGDR_{w,d,h} * ACTRD_{w,d,h} \ \ \forall\, w,d,h\end{aligned} \tag{20}$$

For heating and cooling purposes, heat pumps (HP) are the available electric devices. The total amount of electric heating and cooling installed capacity should always be higher than the total consumption. This is limited in equation (21) with the consumption profile defined for each problem.

$$HPCAP_{ict} \geq flexh\&c + downh\&c \ \ \forall\, w,d,h \tag{21}$$

III. METHODOLOGY & CASE STUDY

The SPLODER model requires large amount of different input data, presented schematically in Figure 1, with bold type indicating the new inputs and outputs introduced in this paper. The previously required input data has been reused from the study presented in [8] which had the same time horizon as this study, which is the year 2030. These data include:

- ✓ The firm capacity coefficients assumed for each technology

- ✓ The 2019 existing generation capacity is expected to still be available in 2030
- ✓ The investment costs and the fixed and variable maintenance costs for both conventional and renewable technologies
- ✓ The fuel prices, CO_2 emission costs, and taxes for pollutant technologies
- ✓ The five solar and wind generation profiles
- ✓ The reserve needs stablished

The lack of transparency regarding the associated costs of DR, has resulted on using the model the other way around. Where DR costs should be an input, as they are not available in the literature, the approach has been to determine the boundary costs at which the model no longer invest in DR anymore. This has been achieved through multiple iterations involving different investment, operating and maintenance costs. As a result, limiting costs for each demand consumption category has been obtained, and intermediary points have been assessed accordingly to see the global picture.

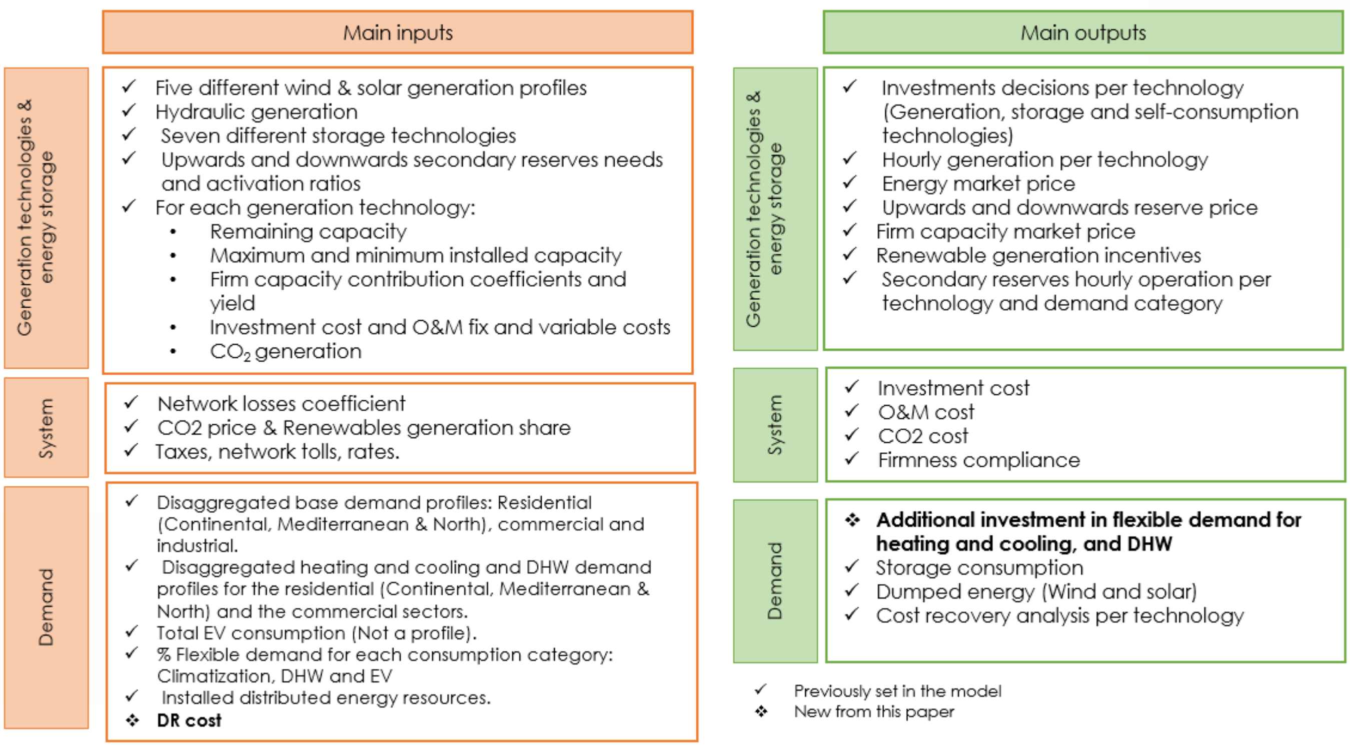

Figure 1 SPLODER inputs and outputs

The initial amount of DR for each demand asset would be stablished at 0, in order to optimize and play with this result. Thus, each scenario is defined by two characteristics, the investment cost for flexibility for the three available categories and the O&M costs for the flexibility used of each demand category. The total demand for each consumption category is presented in Table 3, which would correspond also with a full deployment (100%DR) for each consumption category, although H&C demand can slightly vary between scenarios as it depends on external temperatures.

Table 3 Total demand for the three consumption categories

Consumption category	*Total demand [MWh]*
H&C	67,964,032
DHW	40,340,452
EV	13,769,490

Several iterations were conducted independently for each demand category to determine the maximum investment and O&M costs at which result in a negligible amount of DR investment. This means that only one flexible demand category is available at a time. Subsequently, additional points were tested between these limiting costs to delineate the optimal amount of DR curve (0,<5%, 25%, 50% and 75%). The investment cost for DR, is considered the cost that it is payed once for the available flexible capacity in €/MW. The O&M costs correspond to the ones associated to the use of that available flexibility, and it is also given in €/MWh.

Furthermore, one additional sensitivity has been ran with the same fixed amount of DR. Considering no investment nor operational costs. These sensitivity analyses enable the examination of the impact of considering both types of costs.

IV. Analysis and Results

The results are divided in two different sections that refer to the different analysis performed with the results obtained. First, the DR costs range is analyzed, and then the CO_2 emissions are assessed.

A. *DR costs range analysis*

With the different scenarios conducted, the investment and O&M costs range for each consumption category at which DR has a positive business case has been obtained and are presented in Table 4. This study performs its own costs distribution between investment and O&M costs. However, what really matters is the Levelized Cost of Electricity (LCOE) of DR, as the allocation depends only on the particular business strategy. The equivalent hours of production for each DR category are presented in Table 4.

Table 4 Equivalent hours of preduction for DR categories

	Equivalent Hours of production [h]
H&C	2,177
DHW	1,786
EV	608

The costs ranges are presented in Table 5 for the three consumption categories, however, to be able to compare them the LCOE is required. From comparing the LCOE for the three categories, it can be concluded that H&C is the most restrictive technology, as it requires lower costs to achieve a positive business case, followed by DHW and finally the EV flexibility is the one that has wider cost range while still profitable.

Table 5 Boundary investment and operation costs for disaggregated demand categories

	INVESTMENT COST RANGE [€/MW]		*O&M COST RANGE [€/MWh]*		*LCOE [€/MWh]*
H&C	0	43,540	0	80	100
DHW	0	35,720	0	100	120
EV	0	24,320	0	100	140

The H&C consumption is modeled considering external temperatures. Consequently, when H&C flexibility has no cost, the model optimizes the need for flexibility by investing 76% of the total available flexibility. This is because there may be demand that is already optimized, and cannot be more optimized. Table 6 present the optimal amount of DR for H&C consumption category according to investment and O&M costs. The changes in costs result in the amount of DR following a linear trend, thus each small change is significant. The H&C digitalization and monitoring is quite complex, therefore its deployment is the most restrictive one.

Table 6 Optimal DR percentage for H&C consumption category according to investment and O&M costs.

%DR H&C		**Investment cost [€/MW]**					
		0	**2,177**	**10,885**	**21,770**	**32,655**	**43,540**
O&M costs [€/MWh]	**0**	76%	73%	52%	28%	9%	0%
	20	57%	48%	28%	9%	0%	0%
	40	44%	28%	9%	0%	0%	0%
	60	9%	8%	0%	0%	0%	0%
	80	0%	0%	0%	0%	0%	0%

The flexibility that comes from DHW and EV consumption categories do not have any external constraints, therefore, when flexibility is free for DHW and EV consumption categories, the model decides to invest the whole available amount. Although, depending on the O&M costs the optimal operation solution do not make use of it. Therefore, in order to stablish the costs range, it has been checked when investment costs are 0 €/MW, when the available flexibility not used is above 95%. Table 7 present the amount of flexibility not used for DHW and EV consumption categories when investment costs are 0 €/MW and the full flexible potential is deployed, for both cases when O&M cost are 100€/MWh the amount of flexibility not used is above 95% therefore, this is the costs at which DR stops being profitable.

Table 7 Flexibility not used for DHW and EV when investment costs are null

O&M costs [€/MWh]	*FLEX NOT USED DHW*	*FLEX NOT USED EV*
0	47%	16%
25	77%	83%
50	84%	93%
100	96%	99.8%

Table 8 & Table 9 present the optimal amount of DR for DHW and EV consumption categories correspondingly, according to investment and O&M costs. For DHW cases, there is a range of costs where there is a linear trend, however, as we approach the extremes of the range, smaller changes in DR optimal amount are observed, which means that changes in costs are not that relevant close to the extremes. In EV cases, the range of both costs to determine the investment decision seems to be smaller. However, the higher LCOE indicates that the range of costs within DR deployment is convenient is greater for EV than for DHW and H&C.

Table 8 Optimal DR percentage for DHW consumption category according to investment and O&M costs.

%DR DHW		**Investment cost [€/MW]**					
		0	**1,786**	**8,930**	**17,860**	**26,790**	**35,720**
O&M costs [€/MWh]	**0**	100%	93%	63%	14%	4%	0.8%
	25	100%	92%	30%	4%	2%	0.6%
	50	100%	59.1%	21.6%	3%	1%	0%
	100	100%	40%	13%	0%	0%	0%

Table 9 Optimal DR percentage for EV consumption category according to investment and O&M costs.

%DR EV		Investment cost [€/MW]					
		0	608	6,080	12,160	18,240	24,320
O&M costs [€/MWh]	0	100%	100%	100%	38%	8%	3%
	25	100%	100%	100%	5%	2%	0%
	50	100%	100%	14%	3%	1%	0%
	100	100%	100%	5.2%	2%	0.7%	0%

These costs range, represent the costs in-between the flexibility for that consumption category particularly is profitable. To understand if these costs are reasonable and contrast them with literature, six references have been found with numbers and are presented in Table 10. The conversion factors needed to compare numbers in the same units have been: conversion ratios of 1$ /0,93€ and 1 CNY/0,13 € (Conversion for February 19th 2024) and considering a smart device lifespan of 30 years [26]

Table 10 DR costs range contrast with literature

Reference	*Investment cost [€/MW]*	*O&M costs [€/MWh]*
[1]	120	-
[9]	-	23.5
[27]	37,200	-
[28]	-	10
[29]	-	20
[30]	-	1
This study	**43,540**	**100**

The costs presented in Table 10 validate the findings of this study, indicating that DR costs associated with a favorable business case, align with the estimated cost range for other studies.

B. *CO2 emissions analysis*

DR availability decreases systems peak demand and spillages, thus reducing firm capacity investment needs, which results in less storage investment. Therefore, the system leverages existing firm capacity resources during solar and wind scarcity periods, although they pollute, as it primarily relies on combined-cycle generation, this results in more emissions when there is more DR in the system. However, as the model is an expansion planning model, the technology mix changes from one scenario to another, consequently it has been proven that emissions and spillages are very closely linked to the ratio of storage and DR available over the total demand, including the storage consumption.

Table 11,Table 12Table 13, present how CO_2 emissions do not follow a constant and intuitive trend. Consequently, it is interesting to observe that for H&C, 28% of DR corresponds to the optimal amount of flexibility from an environmental standpoint. For DHW, a 21% of DR, and for EV, 100% of DR, would be the most favorable implementation quantities in terms of emissions.

Table 11 CO_2 emissions [MtonCO2] when H&C DR is available in the system

CO_2 Emi [MtonCO2]		Investment cost [€/MW]					
		0	2,177	10,885	21,770	32,655	43,540
O&M costs [€/MWh]	0	3.52	3.43	3.19	2.42	2.45	2.62
	20	2.71	2.51	2.44	2.51		
	40	2.55	2.51	2.48			
	60	2.51	2.46	2.64			
	80	2.60					

Table 12 CO_2 emissions [MtonCO2] when DHW DR is available in the system

CO_2 Emi [MtonCO2]		Investment cost [€/MW]					
		0	1,786	8,930	17,860	26,790	35,720
O&M costs [€/MWh]	0	3.00	2.92	2.74	2.79	2.71	2.61
	25	3.04	3.00	2.66	2.69	2.68	2.61
	50	3.10	2.70	2.59	2.70	2.64	
	100	3.99	2.73	2.70			

Table 13 CO_2 emissions [MtonCO2] when EV DR is available in the system

CO_2 Emi [MtonCO2]		Investment cost [€/MW]					
		0	608	6,080	12,160	18,240	24,320
O&M costs [€/MWh]	0	2.47	2.47	2.44	2.81	2.71	2.61
	25	2.66	2.66	2.65	2.64	2.67	2.64
	50	2.51	2.50	2.67	2.62	2.65	
	100	2.67	2.64	2.66	2.62	2.60	

C. *DR costs consideration analysis*

The case where H&C DR is optimized with 2,177€/MW as investment cost and 20 €/MWh as operational cost, have been the one chosen to be ran with the 48% of DR as a fixed amount to compare the optimal investment and operational decisions taken with and without considering costs. The CO_2 emissions, renewable spillages and the peak demand resulting from the two compared cases are presented in Table 14. Besides, the technology investment planning for these cases is presented in Figure 2 to compare the optimal decisions taken.

Table 14 CO2 Emissions, renewable spillages and peak demand for scenarios with and without considering DR costs

Case	***With costs***	***No costs***
Emissions [MtonCO2]	2.51	3.38
Spillages [%]	2%	0.5%
Peak demand [GW]	44,858	44,763
Additional firm capacity payment [€/kW]	0	51.5
Average marginal price [€/MWh]	45.8	43.5
Price standard deviation [€/MWh]	27.4	24.3

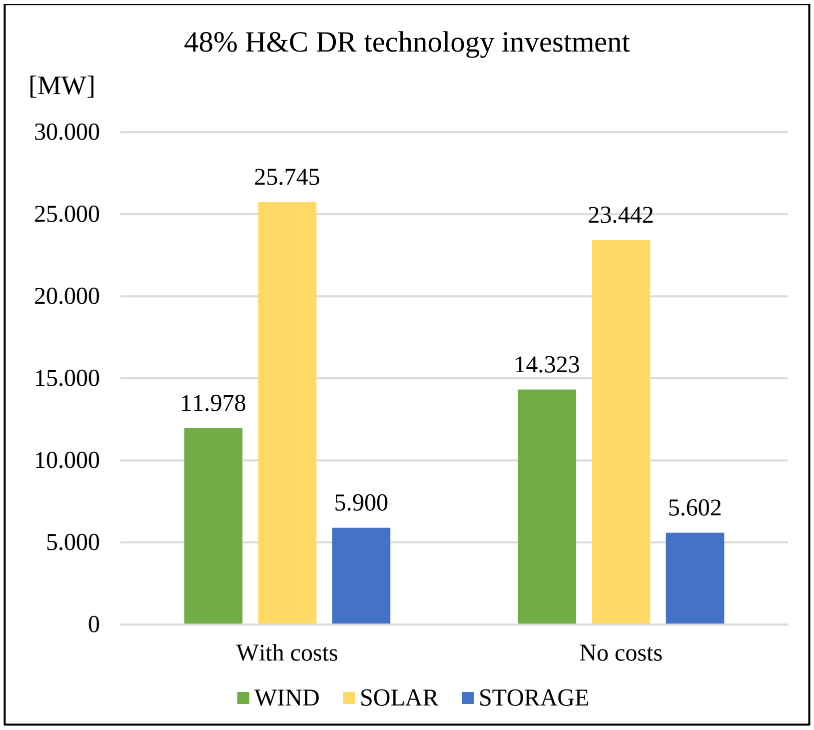

Figure 2 Technology investment planning with and without considering DR costs

The main differences arising from considering both DR investment and operational costs compared to not considering them at all are:

- The investment in solar and storage capacity increases in a 10% and a 5% respectively when considering DR costs. It becomes more advantageous to invest in additional storage capacity, consequently decreasing investment in wind capacity in a 16% as solar is cheaper to supply the energy required. This is attributed to the competition between DR and storage capacity sources, such as pumping-hydro storage.

- When DR is free, additional payments of 51.5 €/kW are required to guarantee the firm capacity required. This means that technologies that provide firm capacity, such as storages, do not recover their investment with their operation due to the decrease of a 5% in the average market price, and the 11% decrease in the price standard deviation. On the other hand, the increased storage investment due to the consideration of DR costs and the higher average market price is enough to satisfy firm capacity needs. This can be seen in the null value of additional capacity payment with a higher peak demand. Thus, considering DR costs is key for giving political recommendations about additional payments needs.
- When DR has costs, minimizing system costs prioritizes utilizing DR to decrease the CCGT operation, using it a 26% less, as preventing spillages is less cost-effective. Thus, more CO_2 emissions are avoided when DR has associated costs.

V. CONCLUSIONS AND FUTURE WORK

The model presented in this paper is able to optimize the amount of DR for the different consumption categories with flexibility potential (H&C, DHW and EV) available in buildings, which has not been previously studied. Traditionally, the literature has treated DR as an input without delving into its potential optimization across different consumption categories.

After conducting the investment and O&M cost case sweeping optimizing DR investment, a range of costs have been obtained for a positive business case for implementing and operating DR assets in the residential and services sectors. The threshold LCOE required to ensure the profitability of EDF is below 100€/MWh. It is found that the most profitable source of DR is the EVs demand, followed by DHW, and lastly H&C DR, due to its temperature constraints which limit its potential. Results present a better business case for EV DR than for DHW and H&C flexibility. These results have been validated through comparison with existing literature proving that previous work supports these numbers. With them, possible investors and interested entities can work on their own business case and decide where to allocate the different costs and how much is it worth it to invest in DR deployment.

The impact of considering DR costs has been assessed by comparing two cases with and without DR costs. The change in the investment planning, solar energy and storage increases whereas wind capacity is reduced when DR costs are considered, is key in terms of additional remuneration mechanisms. Recognizing the impact of DR costs is pivotal in making advices about policy decisions regarding supplementary payments.

Furthermore, the results show that determining the optimal amount of DR is not straightforward. It depends on the priorities which differ depending on whether the perspective is focused on minimizing system costs, minimizing emissions, reducing spillages, or decreasing price deviation. The relationship between these variables and DR availability is not directly proportional. Factors such as technology mix and total demand also play a significant role in influencing the profitability and optimal quantity of DR.

Future research lines would include a cost recovery analysis. This would involve clarifying the costs associated with DR and examining the primary sources of income for DR, including the energy market, reserves market, or other subsidies and additional payments. On the other hand, estimating the optimal amount of DR simultaneously for each demand category in Spain would be another area of focus. This would involve identifying a trade-off point between minimizing costs and avoiding compromises to system emissions.

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