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Demand response cost analysis and its effect on system planning

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ABSTRACT

Demand response (DR) is an ideal option for development and deployment in electricity systems, especially in a high-renewable production context. This paper tries to identify the costs of implementing DR to have a fair comparison with other options, such as storage, since the current literature neglects the costs, obtaining over estimated savings for DR. However, determining the allocation of these DR costs remains challenging due to the lack of literature. This work uses an enhanced model capable of optimizing DR from various sources within the residential and commercial sectors. Through multiple iterations, which account for different investment, operating, and maintenance costs, the model identifies a range of fixed and variable costs that ensure the profitability of DR implementation. The analysis demonstrates that DR is profitable when the levelized cost of electricity (LCOE) for each DR technology is below 100 €/MWh. The findings indicate that heating and cooling is the most cost-sensitive DR technology, requiring lower costs to achieve profitability, followed by domestic hot water. In contrast, electric vehicles provide greater flexibility, allowing for a 40% wider cost range while remaining profitable. Moreover, the comparison between accounting for DR costs and ignoring them highlights their crucial role in making optimal investment and operational decisions.

1. Introduction

The paradigm of energy systems is evolving rapidly, driven by the imperatives of sustainability, reliability, and economic efficiency. Among the emerging solutions, demand-side flexibility (DSF) stands out as a pivotal mechanism capable of harmonizing supply–demand imbalances in the grid. DSF 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 renewable energy integration by reducing renewable curtailments [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, which rely on rare earth metals and specific materials, raise concerns regarding supply chain vulnerabilities and material constraints. On the contrary, among the different sustainable energy solutions, DSF represents another sustainable resource that can provide energy services and reduce technology investment requirements, mitigating these raw material challenges. Unlike renewable sources, demand response (DR) strategies primarily depend on behavioral patterns or consumption adjustments rather than material-intensive infrastructure. Therefore, DR is an alternative solution, providing resilience against potential raw material shortages and supply chain disruptions [3]. It has been demonstrated that it has significant potential as it is capable of avoiding renewable curtailments [4,5], and it also enhances the grid system operation by solving network congestion and reducing peak demand[6]. 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.

1.1. Literature review

Existing studies have emphasized the importance of DSF in enhancing grid resilience and reducing system costs [1,7,8,9]. Nonetheless, there is still a lack of comprehensive analysis regarding the specific and tangible costs related to DSF mechanisms also differentiating between investment and operating costs, as it is not clear which costs should be attributed to DSF implementation, as can be seen in Table 1.

Some studies obtain the savings that DSF can achieve with a particular application; however, those savings are overestimated since they neglect DSF costs, as demonstrated in this paper. Moreover, these studies establish a fixed amount of DSF available in the system

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Nomenclature

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

Table 1
Summary of DSF costs consideration in the literature.

Ref	Context	DSF analysis	DSF Cost Consideration
[7]	German Electricity System	Comparison of different DR scenarios to obtain savings of DR in an operational tool	No
[8]	UK electricity system	Estimation of DR costs as economic welfare and review of benefits	No
[9]	Spanish electricity system	Comparison of different DR scenarios to obtain savings of DR in a planning tool	No
[13]	Belgian electricity system	Comparison of different DR scenarios to obtain savings of DR in the day ahead operation	No
[14]	–-	Review the main topics, variables and indexes related to the profitability analysis on demand-side flexibility	Qualitative allocation
[15]	China distribution networks	Bottom up approach for DR services	No, only compensation costs for users
[15–18]	Reference distribution Network	Bottom up approach for DR services	No, only payments for DR actions but values not available.
[1]	Europe	Benefits of a full deployment of demand-side flexibility for the whole EU	A single capacity cost (€/MW/year) for all demand side flexibility is provided
[20–22]	User surveys	Willingness to pay for equipment's to participate in DSF	No
[24–27]	Local cases	Local DR contributions in Microgrids or Energy hubs	No, only payments for DR actions or compensation costs are considered with values based on hypothesis.
[28]	MV and LV reference networks	Distribution Network expansion planning articles where the load is managed to avoid reinforcements	No

[10,11,12] before running the planning tool. This study [7] 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 [13] to quantify the operation savings on the day ahead market with DR available from residential heating. With this limitation, between 6–7 % of operation savings are achieved. The approach presented in [8] 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 highlight the benefits, with few references mentioning costs and providing only a qualitative allocation of them [14]. The analysis presented in [15] 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 challenging to obtain. The approach presented in these articles [16–19], uses a multi-stage mechanism for energy management on a representative network, following a bottom-up methodology. Remark that in these articles, the value of the parameters representing flexibility payments at both the distribution and transmission levels are not provided, and the model assumes that the devices that make demand side management possible have no costs. The model presented in this paper could be enhanced by incorporating a multi-stage solving option; however, a top-down methodology would be more suitable for achieving the desired results, as the purpose is to optimize investment and operation from a system perspective.

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 interpreted as the cost associated with DR equipment and services that a user is willing to pay/receive. According to [20], consumers are more willing to enroll in these services with heating and electric appliances than EVs. Besides, consumers preferred financial incentives to environmental incentives. However, they are still insufficient to foster the electrification [21,22]. These studies are performed with population surveys, and the results only involve the end-user's perspective, providing qualitative recommendations without considering the effect on the system or detailing the costs of equipments.

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 [23] 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 [8]. However, assigning all the appliance costs for DR purposes is not fair since installing appliances does not mean their availability for DR. On the contrary, reference [9] concludes that DSF 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 policymakers on the most cost-efficient pathway for both the energy system and consumers. Large-scale numbers for the entire EU are presented without specific details for individual countries or technologies. For instance, a total investment cost of 120 €/MW/year for DSF is provided.

This paper uses the terms DR and DSF interchangeably to denote the same concept, and for this case, the industrial sector's flexible demand will be neglected as it has already been thoroughly studied [29]; therefore, they only refer to building's flexible demand. This paper considers two different costs for DSF; one is considered fixed (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 (e.g., the smart thermostat) and maintenance (it does not include the particular heat pump or particular EV) [30]

2) Customer service, information, control center, communication systems and cloud costs [14]. This is related with the algorithm deployment, communication with devices, the storage of data, and the operation of the company in charge of deciding the DR actions.
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.

1.2. Contribution

The literature gap is twofold: Firstly, the current literature (summarized in Table 1) treats the level of DR as an input, as developing a tool to estimate the optimal amount of DR is challenging due to the many uncertainties involved; and secondly, as there are no-cost references that determine the costs associated with implementing and operating DSF from a system perspective, there is no way to fairly compare the deployment of DR with other technologies, such as storage, since the cost of DR is neglected and its real potential is usually overestimated. This paper aims to clarify the costs for which DSF has a positive business case, offering a comprehensive global perspective on its economic efficiency and the optimal quantity of DSF for each scenario. This is relevant information for potential investors and for regulators who design the framework in which DSF plays a role. The DR cost range calculated in this study could support regulatory measures to reinforce DSF deployment in the system, and it could affect current firm capacity payments. DSF could act as a firm capacity agent, such as Storage and Gas Turbines, that could receive a capacity payment like those technologies, although this is not the purpose of this article.

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, which shows how this can affect the conclusions obtained until now.
2- The analysis that includes DR costs unlocked: These analyses include the possibility of determining the LCOE of the different DR alternatives for a positive business case and their merit order, the impact on system costs and emissions of the various optimal amounts of DR, the main competitors' deployment (batteries and hydro storage) and assessing the effect of considering or not the costs of DR in system planning analysis that could have implications in policy recommendations. Those analyses are relevant for academics (e.g., use these costs as hypotheses for planning purposes), technology providers, industry (e.g., help them to choose between storage or demand response options, development of business models), and policymakers (e.g., remuneration mechanism for the security of supply).

2. 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 [31]. Some upgrades performed to this initial version are presented in [32–34] to include policy constraints, to consider new storage technologies that can compete with flexible demand resources, and to add to the reserves market [9]. The model was implemented in GAMS and ran on a computer with the following specifications: Intel(R) Core(TM) i7-4770 CPU @ 3.40 GHz and 16 GB RAM (64-bit). On average, each case took 30 min to solve.

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 [10,11]. 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 heating and cooling (H&C), domestic hot water (DHW), and electric vehicles (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 [35]. 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 fixed 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 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 nonlinearities in the formulation, summarized in Fig. 1. 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

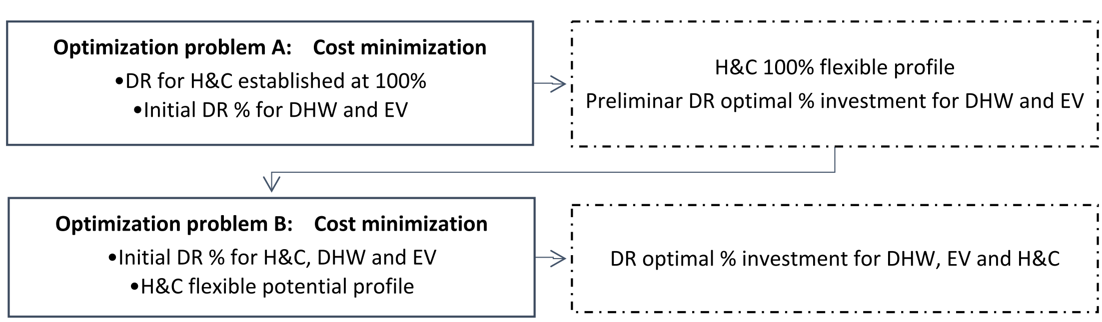

Fig. 1. Double step model sequence.

prevents an overestimation of DR potential and its role within the system.

2.1. Sets, parameters, and variables

The new formulation of the model, which aims to optimize the DR investment in the system, is presented hereinafter. Table 2 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.

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 3.

2.2. 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 represents 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, which 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 fixed consumption profile that would have resulted. Equations (5), (6) & (7) represent this comparison for H&C, DHW and EVs correspondingly.

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

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

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

2.3. Energy market balance

The wholesale market balance equation is affected by the final demand consumption profile. Therefore, equation (8) presents 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 investments in flexible demand categories. Where the only difference between problems A and B stands in the H&C demand.

$$\begin{aligned} energysell_{i,w,d,h} - energybough_{i,w,d,h} + dumped_{i,w,d,h} = & energyproduced_{i,w,d,h} \\ & - EVBASEDEM_{i,w,d,h}{*}(100 - DREV - addevsmart24) \\ & - evcharge_{i,w,d,h} + evcharge24_{i,w,d,h} - energypumped_{i,w,d,h} \\ & + producpv_{i,w,d,h} + DNI_{i,w,d,h}{*}(1 \\ & - LOSSESSPV){*}0,001{*}(INSTALLED_i + newinstall_i) \\ & + WIND_{i,w,d,h}{*}(INSTALLED_i + newinstall_i) \\ & - charge_{i,w,d,h} + discharge_{i,w,d,h} - erd_{i,w,d,h} - flexh\&c \\ & - H\&CDEMAND_{i,w,d,h}{*}(1 - DRH\&C_i \\ & - addpdrh\&c_i) \quad \forall \, w, d, h \end{aligned} \tag{8}$$

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

2.4. Demand assets constraints

The fixed DHW demand cannot be shifted, and 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).

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

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

The total number of EVs remains constant, therefore, the investment in new smart EVs, come from the conversion of non-smart EVs, hence investment in additional smart EVs can never be greater than the initial non-smart EVs energy. This restriction 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 h of the day they are considered to be connected to a recharging point.

$$(100 - DREV) \geq addevsmart24 \cdot \tag{12}$$

$$\begin{aligned} & EVCAP24_{ict}{*}(DREV + addevsmart24){*}CHARMAXEV \\ & \geq EVCharge24_{ict,w,d,h} + incEV_{ict,w,d,h} \, \forall \, ict, w, d, \mathbf{h} \end{aligned} \tag{13}$$

Table 2
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 [n°]
$EVBASEDEM_{i,w,d,h}$	Hourly demand from fixed EV [MWh]
$EVCAP24_i$	EV capacity available from the 24 h smart vehicles [MW]
$EVSMART$	Input data to indicate the amount of EVs that are smart during the night hours [n°]
$EVSMART24$	Input data to indicate the amount of EVs that are smart during the 24 h of the day [n°]
$EVSMARTDAY$	Input data to indicate the amount of EVs that are smart during the day hours [n°]
$EVTRAVEL_i$	Discharged power of an EV when it is not recharging (full capacity is discharged in 10 h for residential vehicles and in 14 h 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 (24 h) [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 [n° power plants]
$stop_{i,w,d,h}$ $stopR_{i,w,d,h}$	Stop a power plant in response to wholesale or reserve needs [n° power plants]

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

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).

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

2.5. Problem B parameters

New parameters are defined to establish 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.

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

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

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

2.6. Reserves market balance

Reserve needs have been estimated depending on the total energy sold decided for each hour, considering the ratio of requirements needed and the activation ratio of this requirement as in [36]. 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

Table 3
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	$NUM_{i,w}{}^{*}\left(inchp_{i,w,d,h} + incac_{i,w,d,h}\right)$	$DRH\&CPROD_{i,w,d,h}{}^{*}(DRH\&C_i + addpdrh\&c_i)$

DR obtained in problem B.

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

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

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.

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

3. Methodology & case study

The model requires a large amount of different input data, presented schematically in Fig. 2. The new inputs and outputs introduced in this paper are indicated in bold type. The previously required input data has been reused from the study presented in [9], 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.

Table 4
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

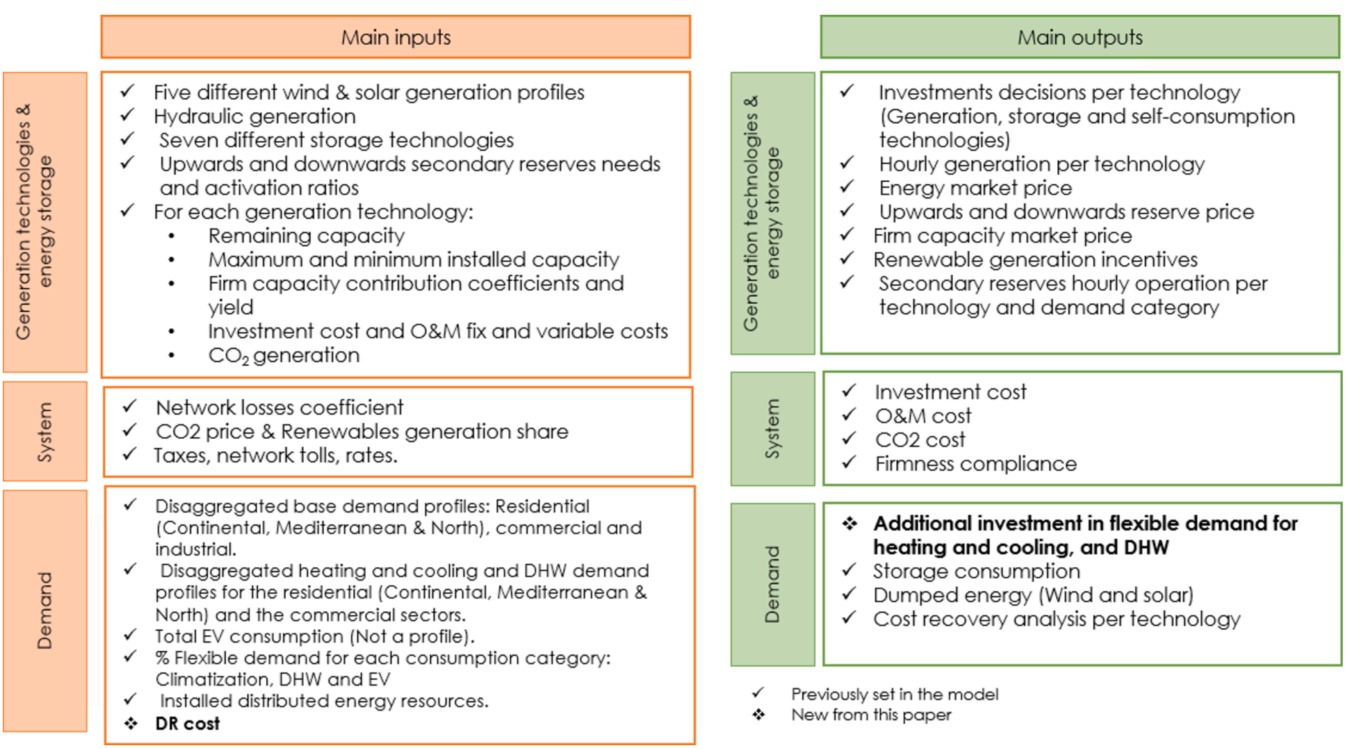

Fig. 2. SPLODER inputs and outputs.

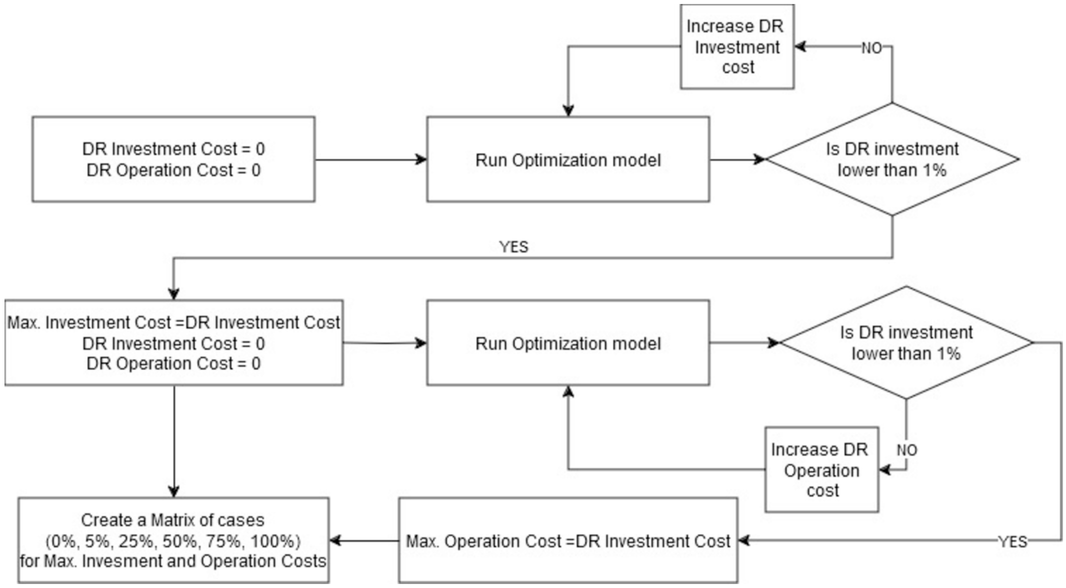

Fig. 3. Iteration process to define maximum cost levels and matrix of cases for each DR category.

- The fuel prices, CO_2 emission costs, and taxes for pollutant technologies.
- The five solar and wind generation profiles.
- The reserve needs.

The initial amount of DR for each demand asset would be established 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 for each demand category. The total demand for each consumption category is presented in Table 4. These data have been gathered from [9] and correspond with a full deployment of flexible demand (100 %DR) for each consumption category, although H&C consumption can slightly vary between scenarios as it depends on external temperatures.

The first objective is to know which DR level is achieved regarding different levels of investment and O&M costs. The investment cost for DR, is considered the cost that it is paid 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. The lack of transparency regarding the associated costs of DR has resulted on using the model the other way around, using a range of DR costs as an input to determine the DR level and the boundary costs at which the model no longer invest in DR anymore.

The first stage to conduct the study is based on running several iterations (Fig. 3) starting from 0, which were conducted independently for each demand category, to determine the maximum investment and O&M costs that result in a negligible amount of DR investment. This means that only one flexible demand category is available at a time. Then, a second stage, where additional points are presented between these cost limits to define the optimal DR level curve. These points have been selected as a percentage of the boundary costs: 0 %, <5%, 25 %, 50 %, and 75 % from the maximum cost.

Finally, the second objective is to compare the impact of considering these costs with an additional sensitivity at the same fixed DR level. Considering a case with no investment nor operational costs, as the analyses found in the literature (Table 11), enables the examination of the impact of considering or not both types of costs in the conclusions of the scenario.

4. Analysis and results

The results are divided into three sections that refer to the different analyses performed to analyze the possible range of costs for DR and the effects of considering them in planning tools. First, the result of the iterations to establish the maximum DR cost values are analyzed to conclude a maximum LCOE value per technology in part A. Then, how the different DR levels per technology affect the CO_2 emissions are assessed in part B. Thus, these two parts allow for quantifying the costs and the impact on the emissions for each DR category. However, allocating the costs should be further developed from a business model point of view. Finally, a case study is selected in part C to illustrate the main implications of DR costs in system analyses, such as those found in the literature (Table 11).

4.1. DR costs range analysis

With the different scenarios conducted, the investment and O&M costs range for each consumption category that makes DR profitable has been obtained (Table 6). This study performs its own cost distribution between investment and O&M costs. However, what really matters is DR's Levelized Cost of Electricity (LCOE), as the allocation depends only on the business strategy. The equivalent hours of production for each DR category have been obtained from the case where investment and O&M costs are null by dividing the flexibility used (MWh) over the flexible demand peak (MW). The resulting values are presented in Table 5.

The cost ranges are presented in Table 6 for the three consumption categories. However, to be able to compare them, the LCOE is required.

Table 5
Equivalent production hours for DR categories.

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

Table 6
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

Table 7
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 %

Table 8
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 9
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 10
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 %

Table 11
DR costs range contrast with literature.

Reference	Investment cost [€/MW]	O&M costs [€/MWh]
[1]	120	–
[10]	–	23.5
[27]	37,200	–
[24]	–	10
[25]	–	20
[26]	–	1
This study	**<43,540**	**<100**

Using the equivalent production hours, the investment cost was calculated in €/MWh and added to the O&M cost to determine the LCOE in €/MWh for each demand category. 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, EV flexibility is the one that has a wider cost range while still profitable.

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 some demand is already optimized and cannot be optimized more. Table 7 presents the optimal amount of DR for the H&C consumption category according to investment and O&M costs. The cost changes result in the amount of DR following a linear trend; thus, each small change is significant. The H&C digitalization and monitoring are quite complex; therefore, their deployment is the most restrictive.

The flexibility that comes from DHW and EV consumption categories has no external constraints. Therefore, when flexibility is free for DHW and EV consumption categories, the model decides to invest the whole available amount. However, depending on the O&M costs, the optimal operation solution does not use it. Therefore, to establish the cost range, it was checked when investment costs were 0 €/MW and when the available flexibility not used was above 95 %. Table 8 presents 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 costs are 100€/MWh, the amount of flexibility not used is above 95 %; therefore, this is the cost at which DR stops being profitable.

Table 9 & Table 10 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 with a linear trend. However, as we approach the extremes of the range, more minor changes in DR optimal amount are observed, which means that cost changes 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 greater for EV than for DHW and H&C.

These costs range represent the costs where the flexibility for that consumption category particularly is profitable. To understand if these costs are reasonable and to contrast them with the literature, six references have been found with comparable numbers and are presented in Table 11. 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 [37]. Besides, none of the references have different values for the fixed and variable associated costs to DR. Hence, only one of them is compared at a time.

The costs presented in Table 11 are all below the estimated limiting value obtained in this paper; therefore, the limit values found in this study are hereby validated since DR costs associated with a favorable business case from other studies are all within the estimated cost range. It is important to note that most references focus on remuneration or payments for load-shifting actions, assuming zero cost for shifting energy. Only these few references specifically address the costs associated

Table 12
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 13
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 14
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	

with DSF as a whole. There are also references that discuss compensation for flexibility actions during specific periods [38]; however, they do not account for the costs of thermostats and cloud services, making them incomplete and limiting their comparability with the results of this paper.

4.2. CO2 emissions analysis

DR availability decreases systems peak demand and renewable curtailments, 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 for the Spanish system, this results in more emissions when there is more DR in the system (Table 12, Table 13, and Table 14). However, as the model is an expansion planning model, the technology mix changes from one scenario to another, with emissions and renewable curtailments very closely linked to the ratio of storage and DR available over the total demand, including storage consumption.

Table 12, Table 13, and Table 14 present how CO_2 emissions do not follow a constant and intuitive trend. However, it is interesting to observe that for H&C, 28 % of DR (2.42Mton) corresponds to the optimal amount of flexibility from an environmental standpoint. For DHW, 21 % of DR (2.59MTon), and for EV, 100 % of DR (2.44MTon), would be the most favorable implementation quantities in terms of emissions. This difference in the technology mix makes comparing DR technologies difficult. Still, it can be observed that for the best-case scenario of each category where null costs are considered, the one that achieves the best emissions mix is the EV, followed by the DHW and H&C. This would have been the result that current analyses could have obtained. Still, this paper has shown the importance of how the cost of DR could affect the final energy mix and, thus, the conclusions related to emissions, which are often a regulatory target to satisfy.

Table 15
CO2 Emissions, renewable curtailments and peak demand for scenarios with and without considering DR costs.

Case	With costs	No costs
Emissions [MtonCO2]	2.51	3.38
Renewable curtailments [%]	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
Savings in system cost with respect 0DR case [%]	7.6 %	11.8 %

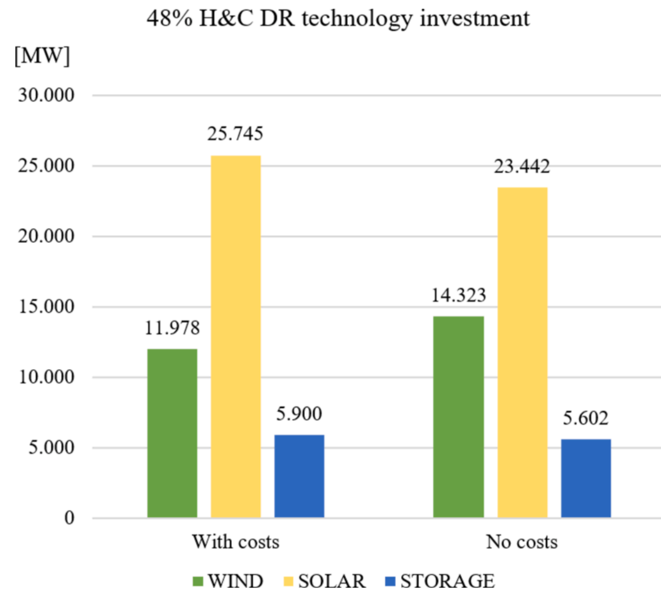

Fig. 4. Technology investment planning with and without considering DR costs.

4.3. DR costs consideration analysis

The case where H&C DR is optimized with 2,177€/MW as an investment cost and 20 €/MWh as operational cost has been the one chosen to be run with 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 curtailments, and the peak demand resulting from the two compared cases are presented in Table 15. Besides, the technology investment planning for these cases is presented in Fig. 4 to compare the optimal decisions taken.

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

- The investment in solar and storage capacity increases by 10 % and 5 %, respectively, when considering DR costs. It becomes more advantageous to invest in additional storage capacity, consequently decreasing investment in wind capacity by 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 implementation and operation have no associated costs, additional payments are needed to ensure the required firm capacity. These additional payments amount to 51.5 €/kW. This means that technologies providing firm capacity, such as storage systems, do not recover their investment through operation alone due to a 5 % decrease in the average market price and an 11 % reduction in price volatility. However, the increased investment in storage, driven by the inclusion of DR costs and a higher average market price, is sufficient to meet firm capacity needs. This can be seen in the null value of additional capacity payments, even with higher peak demand. Thus, accounting for DR costs is essential when making policy recommendations regarding the need for additional payments.
- When DR has costs, minimizing system costs prioritizes utilizing DR to decrease the CCGT operation, using it 26 % less, as preventing renewable curtailments is less cost-effective. Thus, more CO_2 emissions are avoided when DR has associated costs.
- As discussed in the literature review, not considering the cost could overestimate the savings achieved by DR from a system perspective. For this example, expected savings from DR were reduced by 35 % with respect to the case where DR cost was not considered.

5. 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 DSF is below 100€/MWh. It was found that the most profitable source of DR is the EV 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 H&C flexibility, as it allows for a 40 % higher cost while remaining profitable. 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 it is worth 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 investment planning, solar energy and storage increases, whereas wind capacity is reduced when DR costs are considered, which is the key in terms of additional remuneration mechanisms. Recognizing the impact of DR costs is pivotal in making recommendations 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 renewable curtailments, 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. Being able to allocate the costs (Capex and Opex) and estimate a current value for DR technologies could bring more clarity to the future energy mix, but it requires a specific business case perspective on the current costs of technological companies that offer these services and a geographical comparison since the business model will be particular on the regulation of each country. 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.

CRediT authorship contribution statement

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

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Data availability

Data will be made available on request.

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