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Review article

Large-scale estimation of electricity distribution grid reinforcement requirements for the energy transition – A 2030 Spanish case study

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ABSTRACT

The increasing interest in distributed energy resources (DER) challenges electricity distribution grids to host the required distributed generation (DG) capacities and the expected load increase from electrification. However, a large-scale estimation of costs for integrating DER into low, medium, and high voltage distribution networks has yet to be addressed. This paper contributes a model for the large-scale estimation of the impact of distributed generation, electric vehicles and heat pumps on network reinforcement requirements. The model allocates future DER geographically to 8000 Spanish peninsular municipalities. The large-scale model considers low, medium and high voltage distribution grids. The resulting distribution grid investment is determined via individualised reinforcement costs for each of the 47 peninsular Spanish provinces, distinguishing between urban, semi-urban, rural concentrated and rural dispersed configurations of distribution networks. A 2030 case study shows that the geographical allocation of DG is not aligned with the allocation of load electrification, leading to total investment requirements of 2627 MEUR. This finding points out that distribution system operators covering different parts of the territory are likely to face a variety of challenges that are not aligned across the territories, requiring regulation to account for a variation of distribution grid expansion requirements for the energy transition.

1. Introduction

Distribution system operators (DSOs) face growing distributed energy resources (DERs) penetrations. These comprise utility-scale generation units connecting to distribution grids and low voltage (LV) customers seeking to generate their own electricity. Decarbonising the heat and transport sectors also leads to further demand electrification and additional DER penetration. Ambitious decarbonisation targets are expected to impact electricity grids (IEA, 2024a), and its evaluation requires certain assumptions on the geographical allocation of future DER capacities to be made first.

Some authors have proposed methods for the large-scale allocation of Renewable Energy Resources (RES) generation throughout predefined regions of a given country based on general data and simplified grid representation. In these cases, only transmission grids are considered. The authors of (Sun et al., 2022) employ a data envelopment analysis to allocate Chinese RES targets optimally among the 30 Chinese provinces. Renewable portfolio standards are assigned according to indicators related to electricity consumption so that each province might cover a share of domestic electricity consumption via RES. An approach for allocating RES capacity throughout Chinese provinces by minimising the levelised cost of electricity (LCOE) and transmission costs is presented in (Xu et al., 2021). In (Drechsler et al., 2017), the authors propose an approach for the efficient and equitable spatial allocation of photovoltaic (PV) and wind resources throughout Germany. The approach searches for the social optimum of "the evenness of burdens from renewable electricity production across the German population", accounting for transmission expansion requirements between different zones of the country.

Other studies focus on the DER allocation within a specific distribution grid, considering the electrical characteristics of the network. The allocation of DER within the distribution grid is also the subject of literature (Pesaran H.A.A et al., 2017; Ehsan and Yang, 2018). An algorithm for the optimal allocation of wind, PV, gas turbines and storage devices on a 69-bus distribution system case study is proposed in (Home-Ortiz et al., 2019). The optimal location and size of multiple distributed generation (DG) units for minimising losses are evaluated in (Lee and Park, 2009). The methodology is demonstrated on the 30-bus IEEE medium voltage (MV) test system. In (Lee and Park, 2013), the work of the previously mentioned paper is improved by enhancing the

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representation of RES sizes. The study works with the MV IEEE 31-bus benchmark system. The integration of PV, electric vehicles (EVs) and heat pumps (HPs) into a low voltage (LV) system with 170k households in Switzerland is analysed in (Gupta et al., 2021). The authors work with a DSO to define network reinforcement requirements. Network reinforcement costs from the DSO area are assumed to apply to the rest of the country.

Due to the size and complexity of distribution grid feeders, literature on RES allocation in distribution networks commonly focuses on the location within one selected feeder of one voltage level. Extrapolation to a national scale is not a frequent part of the analysis. The authors of (Gupta et al., 2021) estimate nationwide grid costs for integrating DER into LV grids. The analysis does not include MV and high voltage (HV) distribution networks. Grid reinforcement requirements are assessed on a national level for German low, medium and high voltage networks in (Vu, 2018). In various scenarios, the authors assess the reinforcement required for integrating DG (i.e. PV, wind and biomass) and EVs into 238 different regions. A method for assessing distribution reinforcement requirements for integrating EV chargers is proposed in (Ferreira et al., 2020). The large-scale study considers 25,000 low voltage networks. The impact of residential load electrification and EV integration into Californian electricity grids is evaluated in (Elmallah et al., 2022). The authors consider temporal and spatial aspects of future loads. Costs are computed according to a catalogue, and the available capacity of the circuits is considered to determine reinforcement needs. To the best of the authors' knowledge, there is no large-scale study to assess the costs of integrating DER into low, medium and high voltage distribution networks, contemplating distributed generation, electric vehicles, and heat pumps.

This paper contributes a model to estimate large-scale distribution electricity grid reinforcement requirements for accommodating distributed energy resources throughout the Spanish peninsular territory. The model considers electricity distribution systems at low, medium and high voltage. DER technologies comprise multiple technologies for distributed generation and load electrification. DG is represented via PV and wind generation; load electrification is carried out via residential EVs and HPs. The spatial distribution of the new resources is determined via deterministic input parameters rather than via optimisation to depict that promoters do not always follow the economically optimal allocation. The allocation is carried out via so-called scaling factors. Scaling factors are comprised of attributes that describe the likelihood of a technology being installed in a given area, such as the availability of natural resources (i.e. wind speed, irradiation) or a household's purchase power. Grid expansion costs are individualised for each of the 47 peninsular Spanish provinces and distinguish between urban, semi-urban, rural concentrated and rural dispersed distribution areas. Provincial unit expansion costs are extrapolated from the cost database of a Spanish DSO. The contributions can be summarised as follows:

- Methodology for the geographical allocation of DG and demand electrification technologies (EVs and HPs) with a resolution of Local Administrative Units (> 8000 municipalities in the case of Spain).
- Consideration of all voltage levels classified as distribution-level in Spain, i.e. from low to high voltage.
- Deployment of unit expansion costs extracted from the database of a Spanish DSO, as well as extrapolation methodology to the whole country.

The remainder of this paper is organised as follows: Section 2 illustrates the criteria employed for the geographical DER allocation. The approach for calculating grid reinforcements is presented in Section 3. Section 4 presents the case study. Section 5 concludes the paper.

Fig. 1. Peninsular autonomous communities (NUTS 2).

2. Geographical allocation methodology

The Spanish peninsular territory comprises 15 autonomous communities (CA, Fig. 1), 47 provinces (Fig. 2) and over 8000 municipalities (Fig. 3). Autonomous communities represent the regional classification at the NUTS[1] 2 level, provinces at NUTS 3, and the municipalities are Spanish Local Administrative Units (LAU).[2] The allocation of DG, EVs and HPs is carried out at the municipality level. However, the other territorial classifications are relevant for data processing and will be referenced throughout the document.

The allocation of DER to municipalities is made via scaling factors (SFs). The criteria for calculating the SFs differ for DG and demand electrification technologies. Fig. 4 provides a generalised representation of the SF calculation methodology. Mixed SFs are employed. They allow the definition of scaling factors that consider several criteria. The mixed SFs, SF_m^{mix}, of each municipality m are calculated from n individual SFs, SF_m^{ind}, and their weights w. Individual scaling factors allow considering different criteria C deemed relevant for allocating future DG, EVs and HPs. Examples of these criteria are resource availability and household income. An overview of the criteria employed is shown in Table 1; further details are described in Section 2.1 for DG and 2.2 for load electrification.

It must be noted that, due to the large scale of the model, regional differences in the uptake of DER are captured via the criteria employed for the SFs only. Other differences, such as regional policies to foster certain technologies, are not considered explicitly in the model. Hence, the geographical allocation of future DER carried out by the model might deviate from the actual conditions. However, individual scaling factors, such as the geographical distribution of the population, allow for a reasonable estimation of load electrification trends. Furthermore, the criteria employed for utility-scale DG represent the most relevant criteria for selecting optimal generation sites (MITECO and REE, 2024). All data for the geographical allocation is employed with a geographical granularity level of municipalities (LAUs), enhancing the level of detail observed in previous studies. The scaling factors will be described in more detail throughout this section.

The sum of the weights of all the criteria for determining the mixed SF is unity (Eq. 1). Consequently, the sum of all municipalities' mixed SFs is unity, meaning that SF_m^{mix} represents the share of DER allocated to each municipality. Hence, the final capacity of each of the DG technologies (i.e. PV and wind), number of EVs or demand via HPs of a particular municipality can be obtained by multiplying the total amount by its SF_m^{mix}.

[1] Nomenclature of Territorial Units for Statistics (NUTS) is a classification of countries' regions for statistical purposes, deployed in the European Union. It is used for harmonising European regional statistics and allows to carry out socio-economic analyses of the regions (Eurostat, 2024a).

[2] Local administrative units (LAU) represent a subdivision of NUTS 3 regions and comprise municipalities and communes in the European Union (Eurostat, 2024b).

Fig. 2. Peninsular provinces (NUTS 3).

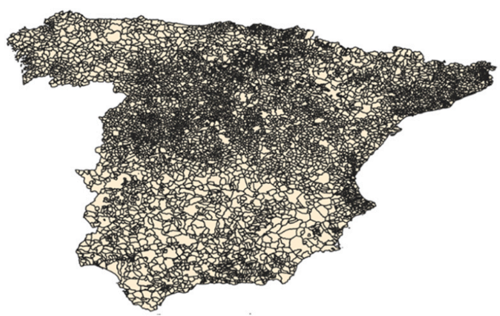

Fig. 3. Peninsular municipalities (LAU).

$$SF_{1,m}^{ind} = \frac{C_{1,m}}{\sum_m C_{1,m}}$$

$$SF_{2,m}^{ind} = \frac{C_{2,m}}{\sum_m C_{2,m}}$$

$$\vdots$$

$$SF_{n,m}^{ind} = \frac{C_{n,m}}{\sum_m C_{n,m}}$$

$$SF_m^{mix} = \sum_{i=1}^{n} \left(SF_{i,m}^{ind} * w_i \right)$$

Fig. 4. Scaling factor calculation for the geographical allocation.

$$\sum\nolimits_{i=1}^{n} w_i = 1 \tag{1}$$

It is relevant to consider whether the capacity is installed in urban or rural areas, as network expansion costs vary according to grid characteristics (Prettico et al., 2016). Table 2 indicates the four categories established in Spanish regulation, their number of supply points (Ferreira et al., 2020), and the abbreviated denomination of each distribution zone type used in this paper. Municipalities are assigned a supply zone type according to an estimation of the number of supply points obtained through the methodology presented in Appendix A.

2.1. Geographical allocation of distributed generation

The methodology differentiates between small prosumer installations and utility-size installations. Prosumer installations are allocated according to criteria expressing the likelihood of a household investing in a rooftop PV installation. Utility-scale installations are expected to seek profit maximisation or, as a proxy, the maximisation of electricity generation. Fig. 5 summarises the generation capacity allocation process. Prosumer installations comprise those connected to low voltage (LV), whereas utility-size DG connects to medium voltage (MV) and high voltage (HV). The extra high voltage level (EHV) is part of the transmission system and, hence, is excluded from this analysis. The allocation criteria for prosumer and utility-scale installations are detailed in Sections 2.1.1 and 2.1.2, respectively.

Table 1
Summary of criteria used for the determination of mixed SFs.

	DG		Electrification	
	Prosumer	Utility-scale	EVs	HPs
Household income	X			X
Contracted power	X			
Building amount	X			
Resource availability		X		
Environmental sensitivity (ES)		X		
Hosting capacity (HC)		X		
EV substitution rate			X	
Required thermal energy demand (RTED)				X

2.1.1. Prosumer allocation

Prosumer is a denomination for grid users that are producers and consumers, commonly referring to LV customers opting to install DG capacity. Hence, LV connecting generation capacity is considered for prosumer allocation. Wind energy connected to LV grids is assumed to be negligible, and the prosumer analysis is limited to residential behind-the-meter PV systems. Three indicators are considered for prosumer deployment: their contracted capacity, the average household income, and the building density (Table 1).

Reducing the electricity consumed from the grid is one of the main drivers for prosumer installations (UNEF, 2023). Consequently, the contracted capacity of grid consumers is one indicator to estimate the geographical distribution of future prosumer development. The Spanish ministry publishes the contracted capacity of secondary substations (MV and below) for each province in the continuity of supply statistics (MITECO, 2023a). The database contains the contracted capacity and the number of supply points for each type of electricity supply zone (Table 2) within each province (Fig. 2). This data allows to determine the installed capacity per supply point for each province according to the supply zone. Total contracted capacity S for municipality m, subject to their electricity supply zone sz, is obtained with Eq. 2, where SP represents the number of supply points determined via the methodology described in Appendix A, and pr indicates the provinces.

$$S_{m(sz)} = \left(\frac{S}{SP} \right)_{pr(m),sz} * SP_m \tag{2}$$

However, a household's decision to purchase a PV system is not solely based on the size of its electricity demand but also on the purchasing power of the household. Thus, the average household income of the municipalities is also considered (INE, 2022a).

Furthermore, the building density of the territory is included as a third indicator (INE, 2022b). This indicator expresses that, although households may have similar electricity demand and purchase power levels, urban areas have less available surface per supply point for installing PV panels than rural areas. As people are more likely to live in apartment buildings in urban areas, not every household disposes of an

Table 2
Classification of electricity distribution grid types according to supply points (Ministerio de Economía, 2000).

	Denomination	Number of supply points
Urban	U	> 20k
Semi-urban	SU	2k to 20k
Rural concentrated	RC	200 to 2k
Rural dispersed	RD	< 200

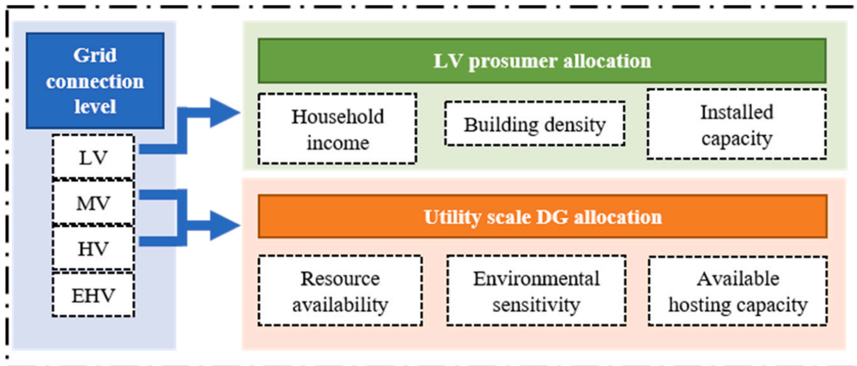

Fig. 5. Flowchart of the generation capacity allocation process.

individual rooftop for PV. On the contrary, people are more likely to live in separate houses in rural communities, disposing of surfaces for PV installations for individual households.

The individual scaling factors of contracted capacity, household income, and building density are computed for the prosumer allocation mixed SF according to Fig. 4 with equal weight of every individual SF.

2.1.2. Utility-scale allocation

The geographical allocation of utility-scale generation connected to MV and HV grids is split into two steps to account for the considerations of DG promoters when deciding the location of a new plant, as shown in Fig. 6.

Firstly, the most suitable region (NUTS2) for RES deployment is selected using resource availability as a primary indicator. Additionally, the Spanish ministry's environmental sensitivity (ES) classification (MITECO, 2023b) is considered. The surface of the Spanish territory is classified according to its environmental suitability for developing PV and wind energy, respectively. It expresses the likelihood of a favourable environmental evaluation of the project. Next, the capacity is assigned to the municipalities of each region. The available hosting capacity (HC) is considered an additional indicator. Spanish DSOs are required to publish the available HC for distribution voltage levels (i.e. from 1 kV up to 132 kV). For the sake of simplicity, the methodology considers the HC published by the five biggest DSOs in Spain, supplying over 75 % of total electricity consumers (e-distribución, 2023; E-REDES, 2023; i-DE, 2023; UFD, 2023; Viesgo, 2023; CNMC, 2020).

The scaling factors for both steps are calculated as shown in Fig. 4. Resource availability and ES are computed as equivalent areas ($km^{2eq}_{t,m}$), derived via Eq. 3. Both criteria are different for the technologies t, i.e. PV and wind. The terrain of each municipality is classified into groups g. In the case of resource availability, the groups rank the terrain's potential for RES production. For ES, the groups express the likelihood of a positive environmental evaluation of a generation installation.

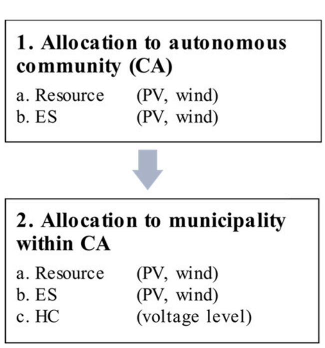

Fig. 6. Two-step utility-scale DG allocation process.

Table 3
Weighting criteria for the determination of equivalent km^2.

Group	1	2	3	4	5
Weight	0	0.1	0.3	0.7	1

$$km^{2eq}_{t,m} = \sum_{g} \left(w_g * km^2_{g,t,m} \right) \tag{3}$$

Five groups are employed for both criteria, ranging from no suitability (i.e., very low resource availability/very low probability of a successful environmental evaluation) to high suitability. The weights of the five groups for the computation of Eq. 3, w_g, are presented in Table 3.

The units of the criteria and the weights for the computation of the mixed SF for utility-scale DG allocation are provided in Table 4. Step 2 indicates two different weight options for the criteria. This approach is introduced because some CAs have no available HC. Consequently, this factor is only accounted for when capacity is available to guarantee that the Step 2 mixed SF of the municipalities within each CA sums to unity.

2.2. Mapping of demand electrification technologies

2.2.1. Electric vehicles

Spanish EV adoption has been more measured compared to other European nations, with a fleet electrification rate below 1.5 % in 2023 (European Commission, 2024a). The Spanish National Energy and Climate Plan[3] (NECP) aims at 5.5 million EVs by 2030, encompassing various vehicle categories such as cars, motorbikes, vans, and buses (Spanish Government, 2023). Private cars are anticipated to constitute 3.5 million of these vehicles, representing 14 % of the existing fleet. This analysis only addresses the implications of the private charging infrastructure (home and workplace) on the distribution grid, which is expected to account for approximately 70 % of the total amount of EVs anticipated for 2030 (LaMonaca and Ryan, 2022; Transport and Environment, 2020).

Given the varying reliance on private cars across regions within the country and the disparate rates of infrastructure development, it is unrealistic to assume a uniform EV penetration across municipalities. This study extrapolates from historical EV registration data from 2015–2022 for each municipality to project the distribution of the EV fleet in 2030

[3] As mandated by the Energy Union Strategy, EU Member States publish their mid-term decarbonisation targets in the form of National Energy and Climate Plans (NECPs) (European Commission, 2024b). In those plans, the Member States describe their ambitions for 2030, covering decarbonisation, energy efficiency, energy security, internal energy market, and research, innovation and competitiveness (European Commission, 2022). The NECPs are updated every two years.

Table 4
Criteria units and weights for two-step DG allocation SF.

Criterion	Unit	Weight Step 1 CA	Weight Step 2 Municipality
Resource availability	km^{2eq}	0.6	0.33 / 0.5
ES	km^{2eq}	0.4	0.33 / 0.5
HC	MW	-	0.33 / 0

(Dirección General de Carreteras, 2024). The country is segmented into 89 categories, each estimated to have different EV ownership rates. These categories include non-urban and urban municipalities with populations ranging from 5000 - 20,000 to 20,000 - 50,000 and 86 distinct Urban Areas (UA). Note that the municipality classification for allocating future EVs differs from the power distribution service zones presented in Table 2. The reason is that the electricity grid classification is based purely on the number of electricity supply points within the municipality, which is deemed insufficient to capture all factors relevant to the adoption of EVs accurately. Instead, municipalities are classified based on the *Statistical Atlas of Urban Areas* published by the Spanish Government, which considers additional indicators such as population density, demographics, housing characteristics, price indices, and existing and planned transport infrastructure (Ministerio de Vivienda y Agenda Urbana, 2023). This approach is considered better suited for EV allocation.

Fig. 7 shows that, by the end of 2022, the rate of EV ownership in municipalities ranged from 0.9 to 1.6 EVs per 1000 residents. However, to achieve the target of 3.5 million EVs by 2030, the rate of EV ownership must escalate to between 66 and 115 EVs per 1000 residents, contingent on the specific region.

Under these growth assumptions, the projected number of EVs per municipality can be determined based on their territory type. The distribution capacity needed to accommodate the home charging infrastructure for the expected fleet of every municipality is calculated under the assumption that every new EV is expected to increase the contracted capacity on the customer side by up to 3.6 kW (Hall and Lutsey, 2024).

2.2.2. Heat pumps

The mixed SF for HP allocation shows similarities to the prosumer PV allocation: average household income represents purchase power. Furthermore, the Required Thermal Energy Expenditure (RTEE) model is employed.[4] The model provides theoretical expenses for each municipality and considers factors such as the building type, the climate zone of the municipality (Barrella and Blas-Álvarez, 2024), and the average household size. This paper estimates the required thermal energy demand (RTED) by using the RTEE model, given in kWh/(household*yr), scaled to each municipality via the number of supply points (Appendix A). This is a proxy of the number of households in each municipality. The RTED per municipality indicates the relative distribution of heat demand throughout municipalities. The mixed SF is calculated according to Fig. 4, with equal weight of average household income (EUR) and RTED per municipality (MWh/yr) (see Table 1). The former has been demonstrated to be a key barrier to heat pumps' adoption (Barrella et al., 2020; Sunderland and Gibb, 2024; Duarte et al., 2021), while the latter is a crucial variable in a diverse climate such as the Spanish one (Barrella and Blas-Álvarez, 2024).

With that, HPs' thermal energy demand is allocated to each municipality. Then, the corresponding electricity demand is calculated according to Eqs. 4–8, following the assumption that a household covers all its annual thermal energy requirements (heating and cooling) via the installed HP. First, Eq. 4 determines the number of HPs, n^oHP, per municipality m as the ratio of thermal energy assigned via the mixed SF, E^{th},

[4] The RTEE models the annual theoretical expenses of a household for heating and cooling (Barrella et al., 2023), (Barrella et al., 2021)

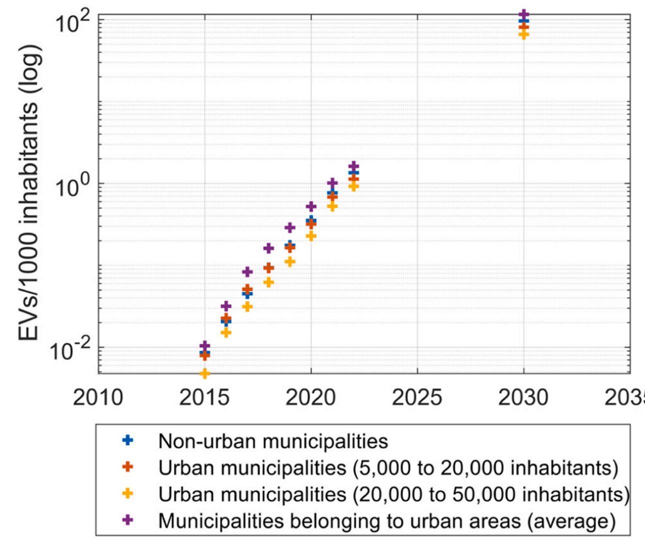

Fig. 7. Evolution of the EV ownership rate by type of territory (2015–2030) (Dirección General de Carreteras, 2024).

and the annual thermal energy demand *RTED* of a dwelling *d* in the municipality *m*. This allocation is subject to the restriction in Eq. 5 to avoid that small municipalities with high per-capita RTED and high average household incomes being assigned thermal energy above their total RTED. The peak thermal energy requirement of a dwelling in each municipality, $\overline{E^{th}_{d,m}}$, is determined via Eq. 6. The unit peak thermal energy requirement per square meter is an input to the model, derived from the methodology of (Barrella et al., 2020). The average dwelling size within a municipality, $m^2{}_{d,m}$, is derived from the same input dataset. The peak electrical energy requirement of a dwelling, $\overline{E^{el}_{d,m}}$, is determined by dividing the peak thermal energy demand by the performance factor *PF*, which is the Coefficient Of Performance (COP) in the case of the heating peak and the Energy Efficiency Ratio (EER) in the case of the cooling peak (Eq. 7). The COP and EER vary by municipality according to the climate zone. Finally, the electric capacity of installed HPs for each municipality, P^{el}_m, is derived as the product of maximum electrical energy to be supplied per dwelling and the number of dwellings expected to install a HP in the municipality.

$$n^oHP_m = \frac{E^{th}_m}{RTED_{d,m}} \tag{4}$$

$$E^{th}_m \leq RTED_{d,m} * SP_m \tag{5}$$

$$\overline{E^{th}_{d,m}} = \frac{\overline{E^{th}_m}}{m^2} * m^2{}_{d,m} \tag{6}$$

$$\overline{E^{el}_{d,m}} = \frac{\overline{E^{th}_{d,m}}}{PF_m} \tag{7}$$

$$P^{el}_m = \overline{E^{el}_{d,m}} * n^oHP_m \tag{8}$$

3. Distribution grid reinforcement

3.1. Unit grid expansion costs

DER-driven distribution reinforcement costs depend on several factors, such as whether the feeder is an urban or a rural network feeder (Herding et al., 2021). For example, rural networks commonly show longer lines to serve fewer customers (Prettico et al., 2016), as areas are less densely populated than urban zones.

The unit costs applied in this study are actual costs based on the database of a Spanish DSO. Costs considered refer to grid expansion works for connecting third-party installations. The cost database details construction works over the last few years, including the size of the installation, the related cost, and the municipality. The costs are classified into the electricity grid service zones according to the municipality (Table 2). Only those provinces with sufficient data are considered for determining an average expansion cost. Table 5 shows the provinces with data availability on average unit costs per distribution grid zone. RD areas show significantly lower data availability.

The data is analysed to identify the most fitting extrapolation for covering the 47 provinces of the peninsular territory. Fig. 8 shows the annualised costs converted into normal distributions considering each grid type's average cost and standard deviation. For the annualisation of electricity grid asset costs carried out throughout this document, the asset lifetime is assumed to be 40 years, and the discount rate is set at 7 % (Herding et al., 2021).

For statistical analysis of the distributions, the p-value test is carried out and confirms the 3rd-degree normal distribution. Extrapolation to the remaining provinces is carried out by randomly assigning a probability value to each province, allowing for assigning costs based on the distribution function. These costs are applied to MV and HV grids. LV costs are determined via two cost terms charged to customers of Spanish distribution networks. These costs must be paid for new connections and increasing the contracted capacity (Villasur, 2023). They represent access and extension rights (Table 6).

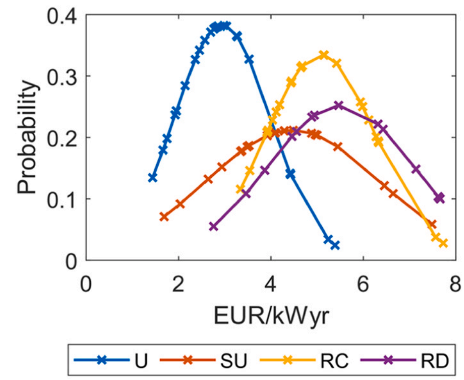

Fig. 8. Normal distributions of unit grid costs per grid type extracted from the database.

Table 6
Regulated costs for increasing contracted LV capacity (Villasur, 2023).

Term	Cost
Access rights	19.70 EUR/kW
Extension rights	17.37 EUR/kW

3.2. Determining grid reinforcement requirements

Distribution grid reinforcement is calculated for each municipality based on the allocation performed via the criteria presented in Section 2. DER integration might trigger reinforcements for various reasons, such as voltage and frequency deviations or thermal line loading limits. The maximum capacity that can be connected to a network node without causing any threat to the safe network operation is denominated hosting capacity. The proposed model employs HC as a threshold of DER that can be connected without requiring new network assets, as will be specified in the following subsections.

The municipality-specific reinforcement is then aggregated for MV and HV according to the province and grid type. Reinforcement costs can then be calculated via the cost catalogue described in 3.1. For LV, costs are assigned according to Table 6. The reinforcement requirements are determined differently for DG (3.2.1) and demand electrification (3.2.2).

3.2.1. Distributed generation

Network reinforcement for connecting DG is calculated via the existing nodal HC. DG connections are contrasted to the HC of the connection voltage level and the available HC in the upstream networks. The MV network must accommodate both MV and LV connecting DG capacities. Correspondingly, the HV network must accommodate HV, MV and LV capacities. Available HC published by the five biggest Spanish DSOs is considered (e-distribución, 2023; E-REDES, 2023; i-DE, 2023; UFD, 2023; Viesgo, 2023). Spanish regulation requires DSOs to publish HC for all network nodes above 1 kV (CNMC, 2021a). HC is subject to regulatory requirements to ensure the safe operation of distribution grids. DSOs are required to consider aspects such as thermal line loadings, bus voltage levels, and the node's short-circuit power. HC is further limited by pre-existing generation and load facilities and their output/withdrawal (CNMC, 2021b). Hence, this data can only be applied to MV and HV DG installations. Network upgrades are necessary in municipalities where the allocated capacity surpasses available HC. In those municipalities *m*, the magnitude of the required additional capacity *P_add* for each voltage level *kV* is determined via Eq. 9, where *DG* expresses the total capacity assigned to the municipality at the voltage level under consideration and downstream of it, and *HC* the available HC.

$$P\_add_{m,kV} = \quad DG_m - HC_{m,kV} \tag{9}$$

However, the data of available HC published by DSOs might show HC across nodes within a limited geographical zone when the HC is only available at one node. Requesting access to one node eliminates the HC at the remaining nodes. This may happen due to upstream network congestion. Consequently, the HC of a municipality cannot be considered the sum of all nodes' HC. Hence, the approach of Eq. 9 represents an upper limit of available HC. A sensitivity will be calculated in which the HC is considered zero.

Due to the lack of HC data for LV grids, the entire LV PV is expected to require reinforcement to avoid underestimating costs.

Table 5
Number of provinces with sufficient data available per grid type.

	U	SU	RC	RD
Nº	23	24	24	14

3.2.2. Demand electrification

The impact of demand electrification is determined via the increase in peak demand. The base load for each municipality is determined via the contracted capacity and a representative LV load profile (MITECO, 2023a; REE, 2023). The municipalities' contracted capacity is obtained from Eq. 2. The municipality's base load profile provides the base load peak. The EV load profile is extracted from (REE, 2023), and the HP load profile from (Barrella et al., 2020). The impact of the peak demand increase on grid reinforcement depends on simultaneity factors (Fig. 9). They are employed by DSOs for system planning and vary per voltage level. They represent hypotheses on the coincidence of peak load. The simultaneity factors employed are provided in Table 7 (Pieltain Fernandez et al., 2011). An LV simultaneity factor of 0.4 is found in the literature. However, non-optimal residential load management might increase the simultaneity factor, i.e. due to simultaneous heat demand (Röder et al., 2021). Hence, a sensitivity evaluation with increasing LV simultaneity factors from 0.4 to 1 in steps of 0.1 is included in the result discussion. Distribution grid HC for connecting new loads is not published by Spanish DSOs. A conservative approach is chosen, which considers the entirety of the peak load increase after applying the simultaneity factor to trigger reinforcement. This is depicted in Fig. 9.

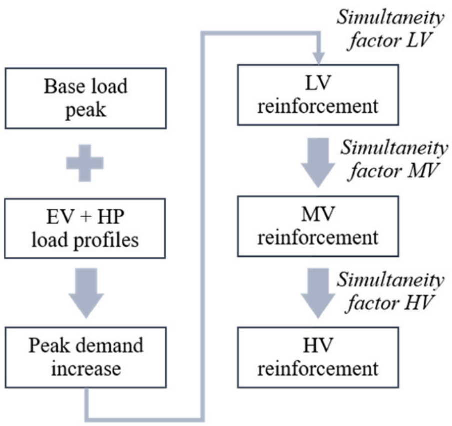

Fig. 9. Determination of reinforcement requirements from demand electrification.

Table 7
Load simultaneity factors (Pieltain Fernandez et al., 2011).

	LV	MV	HV
Simultaneity factor	0.4	0.85	0.95

4. Case study

4.1. Case study input

A case study is carried out to evaluate the model's functionality. The scope is the target scenario of the 2019 Spanish NECP (Spanish Government, 2023). Table 8 provides an overview of the capacities to be added for 2030.

First, the classification according to voltage level is carried out (Fig. 5). The amount of DG per voltage level is estimated with historical data (CNMC, 2022). Table 9 shows the share of PV and wind capacity connected per voltage level as of September 2023. It underlines that wind installations at the LV level are neglectable. Additionally, the table presents the DG capacity installed per voltage level for the case study.

Maps of the input data for the mixed SFs are presented in the following figures. All data is provided at the municipality level (Fig. 3). Fig. 10 presents the average household income. In general terms, income is highest in the country's capital, the northeast of the country, and in other bigger cities such as Murcia (southeast). Fig. 11 presents the annual RTED employed for HP thermal demand allocation. As RTED is expressed as a sum of heating and cooling demand, coastal areas with milder winters have lower RTED. Fig. 12 presents the number of buildings in each municipality for rooftop PV potential evaluation. The geographical distribution of the 2030 EV fleet derived from 2.2.1 is presented in Fig. 13. Fig. 14 and Fig. 15 present the equivalent surface according to the ES of PV and wind, respectively. The highest values are found around the coast in the country's southeast and in the centre of Andalusia. The geographical distribution of terrain suitability of both technologies shows high similarities due to impeding factors (i.e. natural protected areas) applying to both. Fig. 16 and Fig. 17 show the equivalent surface according to resource availability for PV and wind, respectively. PV shows high potential in the South. The map of wind resource availability indicates only a few hotspots throughout the territory.

Table 8
Case study input – added capacities (Spanish Government, 2023).

Technology	PV (MW)	Wind (MW)	EV (num)	HP (ktep)
Capacity	30,110	22,300	3500,00	2894

Table 9
DG capacity per voltage level in Spain (CNMC, 2022).

	LV	MV	HV	EHV
Share of capacity per voltage level				
PV	8 %	15 %	16 %	61 %
Wind	1 %	4 %	35 %	60 %
Resulting capacity per voltage level (MW)				
PV	2526	4552	4683	18,348
Wind	-	885	8062	13,353

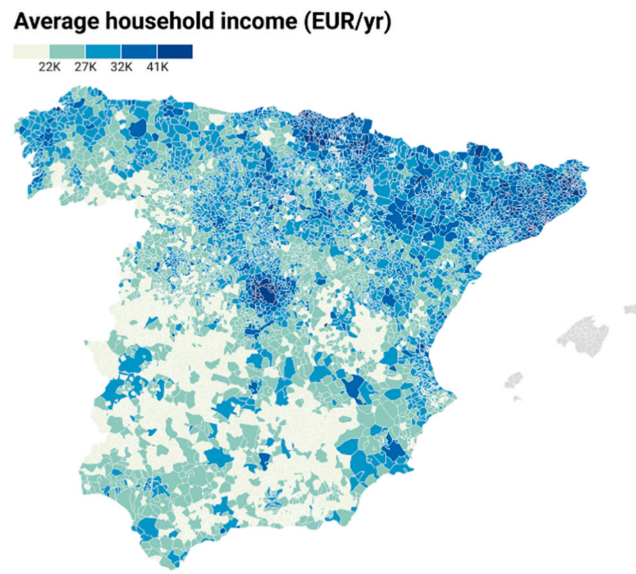

Fig. 10. Average household income (EUR/yr).

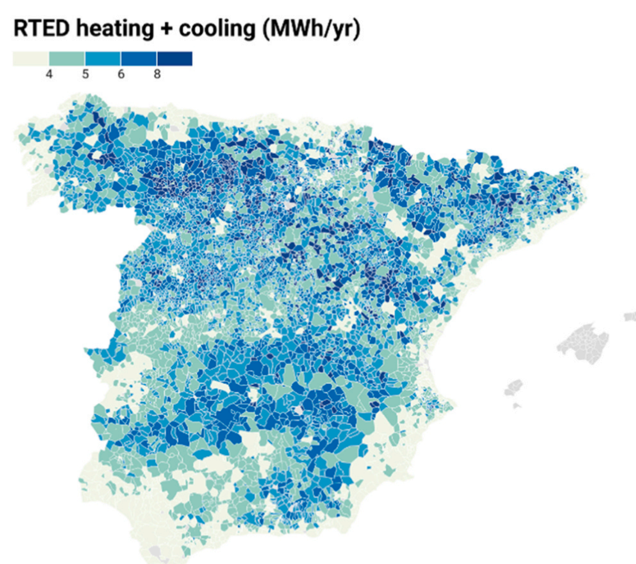

Fig. 11. Annual required thermal energy demand (MWh/yr).

4.2. Case study results

4.2.1. Technological allocation

Fig. 18 presents the resulting geographical distribution of DG capacity and peak load increase. Fig. 18 a) shows that DG capacities are installed predominantly in the South due to the favourable ES (Fig. 14 and Fig. 15) as well as the resource availability for PV installations (Fig. 17). Fig. 18 b) points out that the load increase is concentrated in

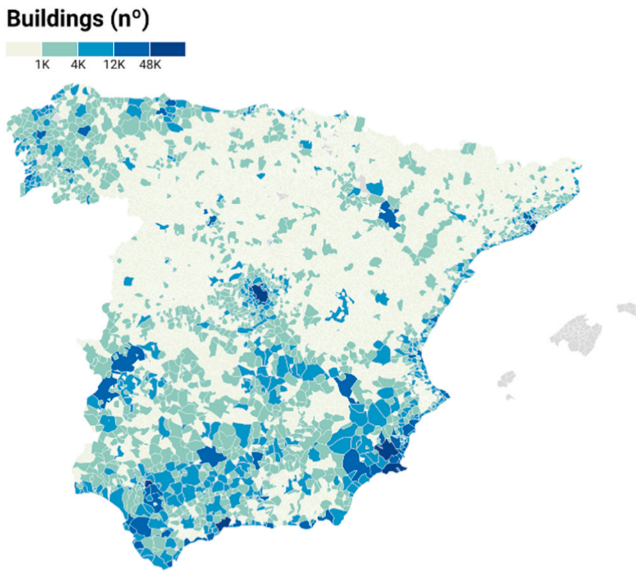

Fig. 12. Number of buildings.

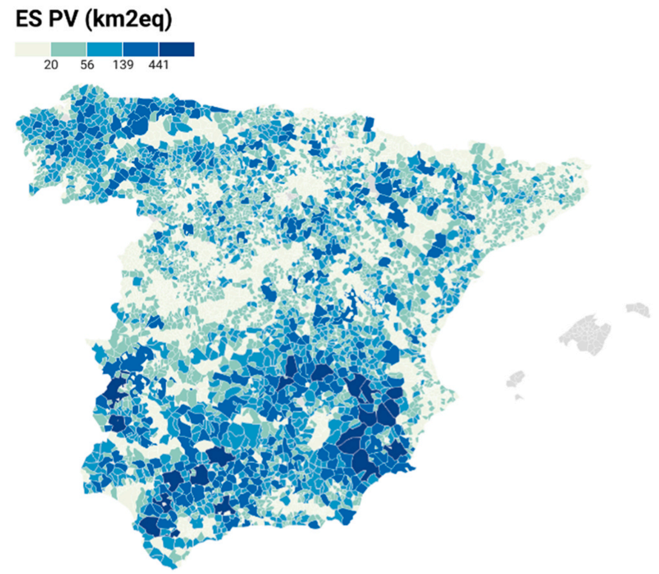

Fig. 14. Environmental sensitivity (km2eq) – PV.

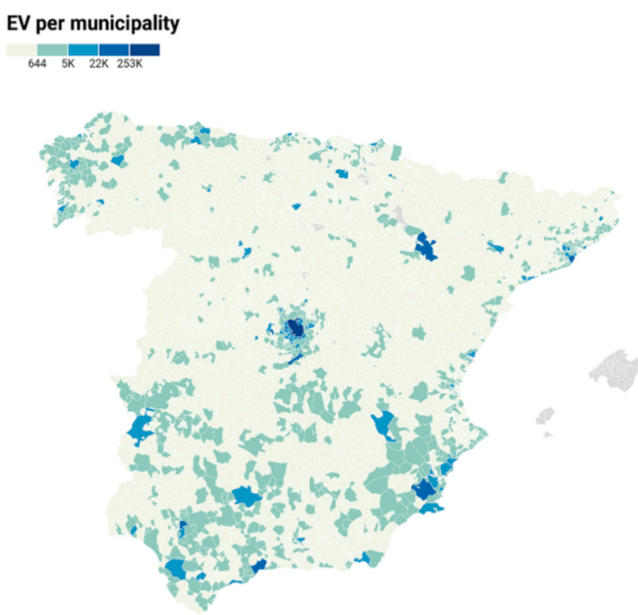

Fig. 13. Geographical distribution of the 2030 EV fleet.

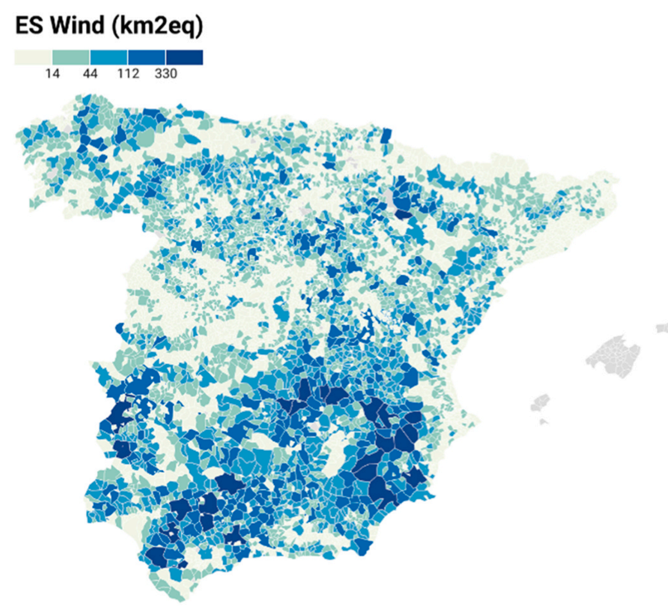

Fig. 15. Environmental sensitivity (km2eq) – Wind.

bigger cities. The cities' population density increases the number of EVs assigned and the total RTED due to more dwellings per municipality. Future electricity demand will not be located in the same municipalities as DG capacities. Consequently, DSOs cannot largely profit from possible synergies between DG availability and load to reduce electricity grid requirements. The correlation between the assignation of DG and the peak load increase is 0.25.

Fig. 19 shows the allocation of DG to the different distribution supply zones. The majority is assigned to SU and RC municipalities. A total of 8.8 GW is assigned to RC municipalities. SU municipalities account for 6.3 GW. U and RD municipalities are assigned below 5 GW of DG due to the low weight of those zone types in the municipalities with the highest DG potential. Figs. 14–17 show that both criteria of equivalent km2 are higher in the South, where most municipalities are classified as SU or RC (Fig. 26).

The allocation of EVs and HPs increases peak electricity demand by 17,078 MW. Applying the simultaneity factors (Table 7) results in required capacities of 6831 MW at LV, 5807 MW at MV and 5516 MW at HV. Fig. 20 shows the peak demand increase per grid zone. It shows an even distribution in all grid zones except RD zones. This result is in line with the geographical distributions of the allocation criteria. Population density increases the RTED of urban municipalities, driving HP allocation. SU and RC municipalities represent 70 % of the Spanish peninsular municipalities (Table 11), leading to a high representation of these zones.

4.2.2. *Distribution grid reinforcement requirements*

Fig. 21 shows maps of the annualised reinforcement costs per municipality. Fig. 21 a) shows the costs for integrating DG, and Fig. 21 b) shows the costs triggered by the peak load increase. The distribution of costs aligns with the allocation of capacities presented in Fig. 18.

Fig. 22 shows the total reinforcement requirements derived from the geographical allocation. Network upgrades are quantified in capacity as well as in annualised investment costs. Upgrades amount to 44 GW of

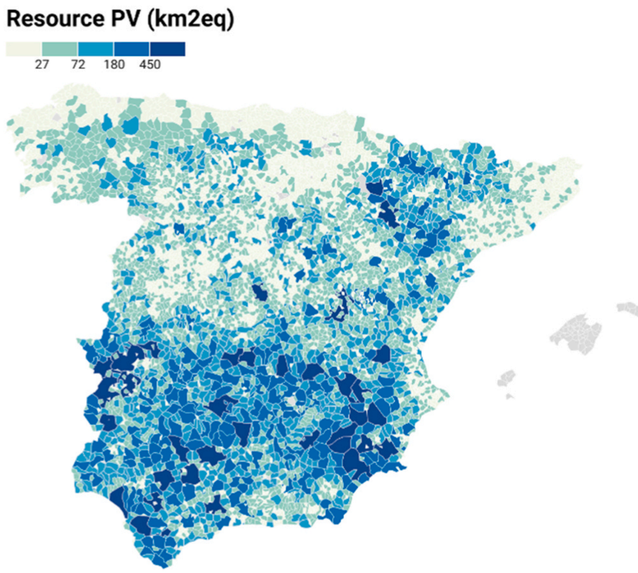

Fig. 16. Resource availability (km2eq) – PV.

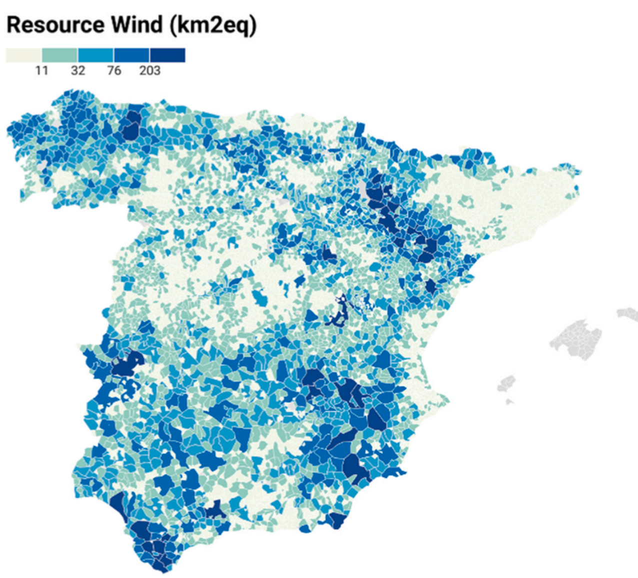

Fig. 17. Resource availability (km2eq) -Wind.

network assets, translating to 197 MEUR/yr of investment. The current regulated investment into the Spanish electricity distribution system is 2012 MEUR (CNMC, 2024). The investment presented in Fig. 22 represents a total of 2627 MEUR, amounting to 130 % of Spain's annual distribution grid investment limit, to be realised by 2030. However, it must be considered that those updates do not include any investment into digitalisation or replacement of assets due to end-of-life, which are expected to require significant investments (IEA, 2024b; Eurelectric, 2024). Furthermore, the upgrades for EV integration are limited to private charging infrastructure and do not account for commercial EV fleets or public charging infrastructure.

Fig. 23 shows the sensitivity results over available HC (3.2.1). Fig. 23 a) represents the stacking of investment requirements for integrating DG when accounting for the municipalities' HC as the sum of the nodes' HC. The magnitude is lower than the costs presented in Fig. 22 b) because the figure is limited to the costs induced for integrating DG; load is not included. Fig. 23 b) shows the investment in case no HC was available. The total costs amount to 131 MEUR/yr in a) and 149 MEUR/yr in b), representing a 14 % increase in the latter. This relatively small increase indicates that the geographical allocation of DG does not optimally exploit HC. Only 5.4 % and 7.6 % of HC are exploited at MV and HV level, respectively. Fig. 24 provides further insight into the issue by showing the total available HC (MV+HV) according to the distribution zone. It shows that most HC is in U and SU municipalities. However, DG capacity is assigned mainly to RC municipalities (Fig. 19). Although this is not an optimal result in terms of exploiting existing grid capacity, factors such as resource availability and environmental sensitivity play a significant role in site selection, driving DG away from municipalities with available HC.

Fig. 25 presents a disaggregation of the distribution grid reinforcement costs triggered by DG (Fig. 21a) and those triggered by load electrification L (Fig. 21b). The different columns for load represent the costs associated with the sensitivities according to the different LV load simultaneity factors described in 3.2.2. The figure shows that, at the LV simultaneity factor of 0.4 (Table 7), the network upgrade costs for load electrification are half the DG integration costs. Grid expansion for integrating DG cannot offset the requirements for load increase due to the different geographical allocations of DG and load (Fig. 18). As LV load simultaneity factors increase towards 0.8, grid costs approach the magnitude of DG. At LV load simultaneity factors of 0.9 or 1, grid costs for load surpass those for DG. Realistic values of future LV simultaneity factors might be between 0.4 and 0.8, as the coefficient describes the simultaneity of the entire load. The base load will likely follow historical simultaneity factors, while electricity demand for EVs or HPs might show higher simultaneity factors. Consequently, the simultaneity factor of the entirety of the load is not expected to reach 1. In any case, the efficient management of future electricity demand is crucial for maintaining distribution grid costs at a reasonable magnitude.

5. Conclusions

This paper presents a deterministic model for calculating distribution grid reinforcement requirements for integrating distributed generation (DG), electric vehicles (EVs) and heat pumps (HPs) throughout Spain. DG covers PV and wind installations. The assessment is carried out for the over 8000 peninsular municipalities and includes LV, MV and HV grids. Electricity distribution expansion costs for MV and HV networks are extracted from the project database of a Spanish DSO and extrapolated to the rest of the territory.

All municipalities are first classified into urban (U), semi-urban (SU), rural concentrated (RC), and rural dispersed (RD) distribution zones according to the Spanish regulation. DG, EVs and HPs are then geographically allocated to the municipalities via individual criteria. DG is allocated differently for prosumer and utility-scale installations.

Distribution grid reinforcement requirements are determined differently for DG and load electrification. The network's nodal HC for accommodating DG is publicly available for voltage levels above 1 kV. Due to the lack of information below 1 kV, zero available HC is assumed for LV PV integration. For load, reinforcement is determined via the peak load increase associated with EV and HP allocation. The resulting reinforcement for each voltage level is determined via simultaneity factors, considering zero available HC for load.

The model's functionality is demonstrated by implementing a 2030 NECP case study. The case study shows that future DG installations are allocated to networks in semi-urban and rural concentrated municipalities. Both resource availability and environmental sensitivity are favourable in SU and RC municipalities. The main part of DG capacity is assigned to HV networks due to the employment of historical data for allocating DG to voltage levels. Despite the availability of HC, a significant part of DG triggers reinforcement due to the location in mainly RC municipalities, while HC availability is dominant in U and SU municipalities.

The peak load increase is allocated equally to all grid zone types except RD due to the low population density of RD municipalities. The

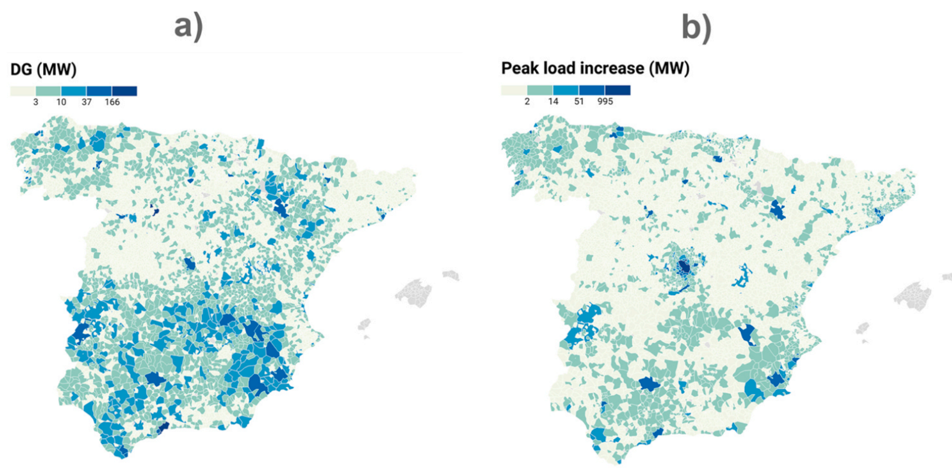

Fig. 18. Geographical allocation of a) peak load increase, b) DG capacity.

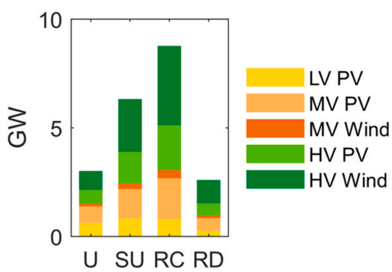

Fig. 19. Stacking of relative DG allocation to distribution supply zone type.

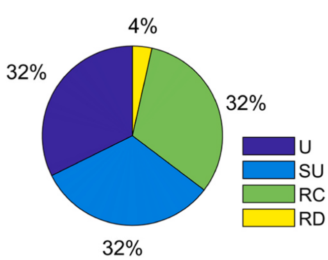

Fig. 20. LV peak demand increase per grid zone.

reinforcement due to load increase is around half the costs for integrating DG. However, a sensitivity analysis of the LV load simultaneity factor indicates that increasing simultaneity due to electrification may lead to load-induced costs surpassing DG-induced costs at an LV simultaneity factor of 0.8 and above. This highlights the importance of the efficient management of EVs and HPs so as not to aggravate their impact on distribution grid reinforcement.

The allocation maps of DG and load increase throughout the territory show that future DG capacities are not geographically aligned with the peak load increase. This finding points out that the DSOs covering different parts of the territory are likely to face a variety of challenges

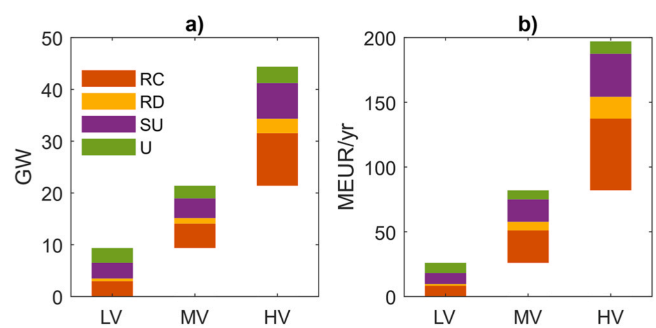

Fig. 22. Reinforcement requirements – a) Capacity and b) annualised investment.

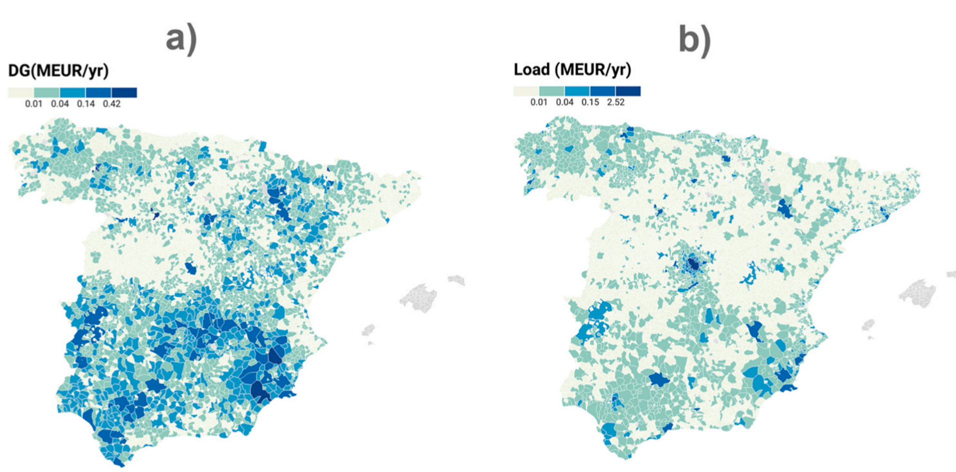

Fig. 21. Map of reinforcement cost triggered by a) DG integration, b) peak load increase.

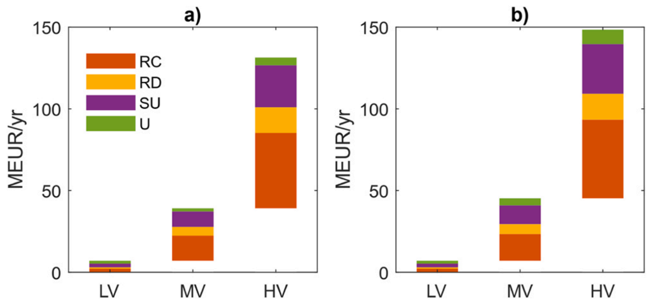

Fig. 23. DG-related investment requirements considering a) available HC and b) 0 available HC.

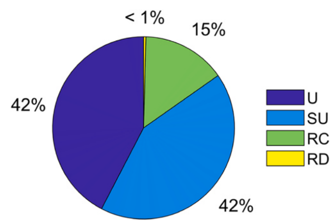

Fig. 24. HC according to grid supply zone.

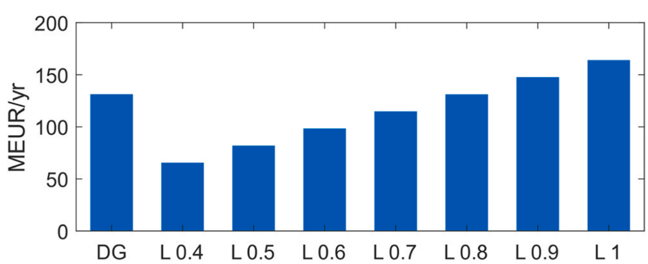

Fig. 25. Annualised investment for DG integration and load electrification sensitivities.

that are not aligned between the territories. The total required investment is 2627 MEUR, representing 130 % of Spain's annual electricity distribution investment limit.

The model represents a tool to efficiently assess the impact of the geographical allocation of DG and load electrification on distribution grids of the whole Spanish peninsular territory based on the costs of actual projects in a Spanish DSOs' network. The model can be employed for other non-Spanish electricity systems when the corresponding input data is provided. Future work should focus on further disaggregating the cost catalogue to contemplate different costs for MV and HV grids and consider the asymmetric nature of costs for integrating generation and load. Furthermore, adding other aspects of electrification, such as public charging infrastructure, electrolysers or the electrification of industrial energy demand, can help further deepen the understanding of the impact of electrification on distribution networks.

CRediT authorship contribution statement

Leslie Herding: Writing – original draft, Visualization, Methodology, Investigation. **Manuel Pérez-Bravo:** Writing – original draft, Visualization, Methodology, Conceptualization. **Michel Rivier:** Writing – review & editing, Supervision, Methodology, Investigation, Funding acquisition, Conceptualization. **Roberto Barrella:** Writing – review & editing, Methodology, Conceptualization. **Rafael Cossent:** Writing – review & editing, Supervision, Methodology, Investigation.

Declaration of Competing Interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Leslie Herding reports financial support was provided by Ministry of Science ˆfand Innovation and the Spanish State Research Agency. If there are other authors, they 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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Appendix A. : Classification of Spanish municipalities according to distribution grid type

The Spanish municipalities are assigned to a distribution grid service zone according to an estimation of the number of residential supply points in the municipality. The Spanish Statistical Institute publishes the number of households for municipalities with over 2,000 inhabitants (INE, 2023a). This number is employed as an indicator of the number of residential electricity supply points for urban and semi-urban areas. It cannot be used to distinguish rural concentrated from rural dispersed areas because both consist of less than 2,000 supply points. The number of supply points for rural areas is simplified as the inhabitants (INE, 2023b).

The methodology is evaluated on the municipalities in the cooperating DSO's service territory. Table 10 shows the comparison. In the first step, the number of municipalities for each service zone is presented for both, the DSO data and the classification from the algorithm. The results from the algorithm are reduced to the municipalities of the DSO's service territory. The right side evaluates the correct assignations by the algorithm. Results show that urban and semi-urban areas are approximated closely to the DSO's classification of municipalities. The approach for the total zones leads to a shift from RC zones towards RD zones. Still, the majority of municipalities are classified correctly. Applying this approach to the entirety of the Spanish peninsular territory results in the identification of 24,796,759 residential service points. This amounts to 84% of the total registered Spanish service points in 2020 (CNMC, 2020). The final assignation of supply points to the peninsular municipalities is shown in Fig. 26.

Table 10
Verification of municipal grid type estimation via mixed criteria with the DSO's data

	Municipality classification		Correctly identified by the algorithm	
	DSO data	Algorithm	Total	Relative (of algorithm)
U	99	86	82	95%
SU	554	520	469	90%
RC	1957	1879	1649	88%
RD	1136	1264	977	77%

Table 11 evaluates the assignation regarding the number of municipalities and share of surface assigned to each service zone. The table points out that, in terms of the number of municipalities and surface, the majority of the peninsular territory is classified as a rural concentrated distribution grid service zone, while urban zones represent only a minor part of the territory. Rural dispersed areas represent only 13% of the surface despite accounting for 29% of the municipalities.

Table 11
Analysis of municipality service zone assignation

	Share of peninsular municipalities	Share of peninsular surface
U	2%	6%
SU	17%	30%
RC	52%	51%
RD	29%	13%

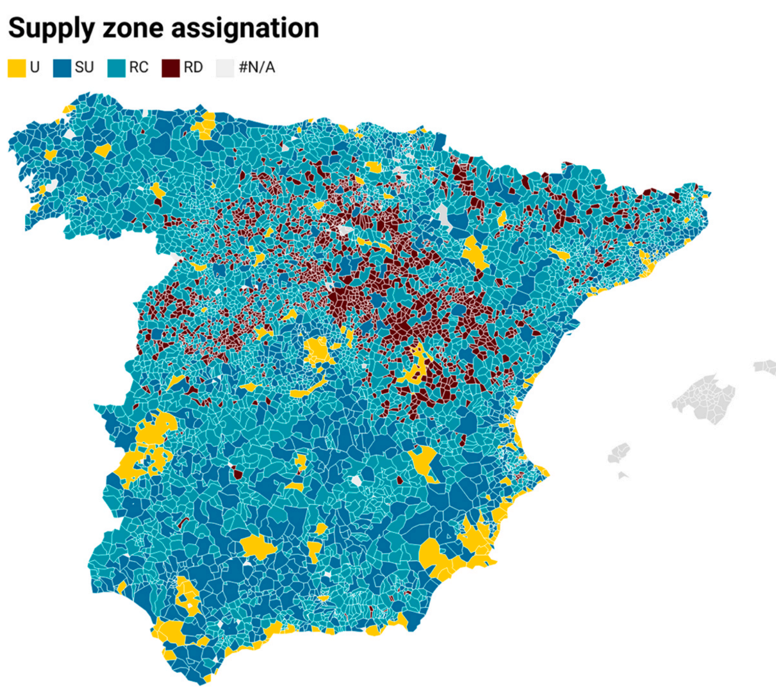

Fig. 26. Supply point assignation of Spanish municipalities.

Data Availability

Data will be made available on request.

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