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Can photovoltaic systems be profitable in urban areas? Analysis of regulation scenarios for four cases in Valencia city (Spain)

Carlos Vargas-Salgado *, Isabel Aparisi-Cerdá, David Alfonso-Solar, Tomás Gómez-Navarro

Institute for Energy Engineering, Universitat Politècnica de València, Camí de Vera s/n, Valencia, Spain

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A B S T R A C T

Costs of photovoltaic systems have fallen over the last decade, while the energy prices have risen. As a result, PV system is being proposed as a cost-effective option for power generation in the built environment. However, some authors consider that better regulatory support is still needed to deploy the PV potential in cities. In this research, four illustrative cases, analyzed under five scenarios, show that the latter could be the case in a Mediterranean city with high annual solar radiation, such as Valencia. Unlike most previous research based on statistics, this research uses real data and real market equipment information to develop the analysis. The Software HOMER is used to simulate the performance of the study cases. The findings show how the regulation's change would improve the viability of these urban renewable systems. However, although the four cases are technically sound, further changes in the regulation are found necessary to be economically viable. The results show one of the main limitations to reducing the LCOE is the impossibility of selling energy when revenues are greater than purchases (Current regulation in Spain). Without such limitation, the LCOE would be reduced (cases 1 and 3 reduces LCOE from 17.5 to 15.2 c€/kWh and from 18.5 to 17.3 c€/kWh, respectively). With a net metering system not yet permitted in Spain, the payback of the investments would be reduced by one-third. Finally, recommendations for regulatory development are proposed to meet the expectations for the deployment of PV generation potential.

1. Introduction

The interest and support for photovoltaic (PV) solar energy has been continuously growing worldwide, especially in Europe, to solve climate change and fossil fuel depletion. PV is already competitive in conventional power plants (REN21, 2020). Therefore, public administration is recently fostering the deployment of PV in the built environment. Furthermore, it is expected to play a major role in the urban energy transition (Osseweijer et al., 2018) As a result, various public policies and regulations have been put in place to subsidize and promote PV in cities in Europe and around the world (Ramírez et al., 2017), namely:

- Investment subsidies, tax reductions, and soft loans.
- Simplified administrative procedure. Exemption from the application for access to the electricity grid and connection permit
- Public power purchase agreements and call for tenders.
- Feed-in-tariff and feed-in premium, tradable green certificates.
- Net-metering and net billing
- R & D subsidies and demonstration programs.

The revised renewable energy directive 2018/2001/EU (European Parliament, 2018) establishes a new target for 2030: at least 32% of the total energy needs of the EU covered by renewables, with a clause for a possible revision by 2023. Photovoltaic systems play an important role in reaching this goal, and the potential in urban areas like cities is not negligible. For example, in Valencia, on the South-East coast of Spain, the climate conditions are especially favorable for PV generation. Apart from possible shadows, there is a potential of yearly in-plane irradiation of 2000–2100 kWh/m^2 for south-oriented panels mounted on a 36° tilt fixed structure (European Commission, n.d.).

Several comparative studies have recently been published for different regions discussing the pros and cons of these public policies. Some recent examples can be found in (Raluy et al., 2005; UNEF, 2005). In doing so, the authors develop economic models to evaluate the profitability of PV projects combining the aforementioned public support schemes (Ramírez et al., 2017). However, these studies are not based on real cases but on regional average data, estimated prices, oversimplified PV systems, etc.

In Spain, regulation for self-consumption purposes has been modified twice from 2015. The Royal Decree RD 900/2015 (Ministerio de

* Corresponding author.
E-mail addresses: carvarsa@upvnet.upv.es (C. Vargas-Salgado), isapcer@etsii.upv.es (I. Aparisi-Cerdá), daalso@iie.upv.es (D. Alfonso-Solar), tgomez@dpi.upv.es (T. Gómez-Navarro).

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Nomenclature

β	PV panel tilt angle (°)
β_{Isc}	Temperature coeficient of Isc (%/°C)
$\beta_{P_{MPP}}$	Temperature coeficient of PMPP (%/°C)
β_{Voc}	Temperature coeficient of Voc (%/°C)
γ	Azimuth (°)
BOE	Boletín oficial del estado (Official Spanish Gazette)
$C_{ann,tot}$	Total Annualized cost (€/year)
C_{NPC}	Total net present cost (€)
$C_{oper,tot}$	The total operating cost
$CRF(\ )$	Capital recovery factor
$E_{grid,sales}$	Total grid sales (kWh/year)
$E_{prim,AC}$	AC primary load served (kWh/year)
G	total solar irradiance (W/m^2)
G_{NOCT}	Solar radiation at which the NOCT is defined (W/m^2)
H_d	Average global solar irradiation per square meter (W/m^2 year)
i	Interest rate (%)
I_{MPP_inv}	Inverter current at the maximum power point (A)
I_{MPP_panel}	Panel current at the maximum power point (A)
IRR	Internal rate of return (%)
LCOE	Levelized cost of the energy
MPPT	Maximum power point tracker
N	Project lifetime (years)
$N_{max\_panel\_series}$	Maximum number of photovoltaic panels in series
$N_{max\_panel\_parall}$	Maximum number of photovoltaic panels in parallel
N_{inv}	Number of inverters
N_{panels}	Number of photovoltaic panels
NB	Net billing
NB_NL	Net billing no limit
NM	Net Metering
NOCT	Nominal Operating Cell Temperature (°C)
NPC	Net present cost
NS	No Sales
O&M	Operation and Maintenance
PERC	Passivated Emitter and Rear Cell
$P_{max\_in\_DC}$	Maximum input power in direct current (kW)
P_{max_MPP}	Maximum power in the maximum power point (kW)
P_{MPP_STC}	Power at the maximum power point at standard test condition (kW)
P_{inst}	Peak Power to be installed (kW)
P_{peak_panel}	Photovoltaic panels peak Power (kW)
PV	Photovoltaic
RD	Royal decree
REE	Red Eléctrica de España
R_{proj}	Project lifetime (year)
$T_{a,NOCT}$	Ambient temperature at which the NOCT is defined (°C)
$T_{maxcell}$	Maximum cell temperature (°C)
$T_{mincell}$	Minimum cell temperature (°C)
T_{amb_max}	Maximum ambient temperature (°C)
T_{amb_min}	Minimum ambient temperature (°C)
T_{STC}	Temperature at standard test condition (°C)
V_{OC_max}	Maximum open-circuit voltage (V)
V_{OC_STC}	Open-circuit voltage at standard test condition (V)
V_{MPP_inv}	Inverter voltage at the maximum power point (V)
V_{MPP_panel}	Panel voltage at the maximum power point (V)
VAT	Value added tax (€, %)

industria energía y turismo, 2015) legally allowed to set up grid-tied PV systems in homes, constituting a step forward. However, it was not enough for homeowners to decide to invest in this technology as a feasible option. The main reason was that the surplus energy was not economically compensated; even more, prosumers (producers + consumers) were forced to install anti-reverse systems, avoiding the exploitation of the real potential of the PV system. But, also, the bureaucratic procedure could take from months to years. Finally, an extra tax was added if the PV systems were grid-tied. In consequence, the impact of the RD 900 on the promotion of urban PV systems was not significant, even though PV panels cost decreased year after year.

In 2018 and 2019, the regulation was modified and went into effect the Royal Decree-Law RD-L 15/2018 (Ministerio de industria energía y turismo, 2015) and the Royal Decree RD 244/2019 (Ministerio para la transición ecológica, 2019), both currently in force. Key aspects of these new regulations are the following:

- RD-L 15/2018 establishes key principles that will regulate self-consumption activity which are: recognition of the right to self-consume electric energy without charge, the right to self-consumption shared by one or various consumers (to take advantage of economies of scale) and the principle of administrative and technical simplification, especially for systems with installed power lower than 100 kW.
- RD 244/2019 establishes that self-consumed energy of renewable origin will be exempt from all types of charges and tolls, and establishes a simplified compensation mechanism for systems not exceeding 100 kW. This mechanism consists of economic revenue for photovoltaic excesses in the specific billing period, but maximum economic value of the excess cannot be greater than the economic value of the energy consumed from the network in the billing period. Additionally, installations with power production equal to or less than 15 kW, located on urbanized land, are exempted from requesting electricity grid access and connection permit.

Furthermore, these new regulation does not allow a net metering (NM) scheme but a net billing (NB) scheme. NM and NB are defined in (López Prol and Steininger, 2017) by Lopez Prol and Steininger. NM allows self-consumed electricity and surplus electricity to be valued at the same price, while in NB, the surplus electricity is valued at a lower price than the price at which it is bought from the grid.

Because of the regulation change, the capacity of the self-consumption installations increased from 236 MW in 2018 to 459 MW in 2019 and 623 MW in 2020 (Red Eléctrica de España, 2020; UNEF, 2019), being the changes in the regulation a boost to the PV systems. According to the Spanish operator of the system, in 2020, the average self-consumption surplus energy price for the simplified revenue mechanism was 3.38 c€/kWh, while the default tariff of active energy invoicing price was 9.43 c€/kWh, and the two periods tariff price was 7.39 c€/kWh (DHA tariff in Spanish) ("Analysis | ESIOS electricity · data · transparency," n.d.).

Different authors have recently studied the Spanish regulation of self-consumption systems from different perspectives. Escobar et al. studied the profitability of the self-consumption solar PV system in Spanish households, under RD900/2015, compared with several European regulations (Escobar et al., 2020). They conclude the PV system for residential consumption was not profitable. Lopez et al. analyzed the profitability of the alternative regulatory schemes such as the net billing and net metering balance (López Prol and Steininger, 2017) and the impact of the regulations. They found that under the RD 900/2015 conditions, the direct economic impact of PV self-consumption on both aggregate government and electricity system revenues is positive for investments in the residential segment (unlike Escobar et al. (Escobar et al., 2020)), negligible for those of the commercial segment, and negative for those of the industrial segment, stating than for promoting

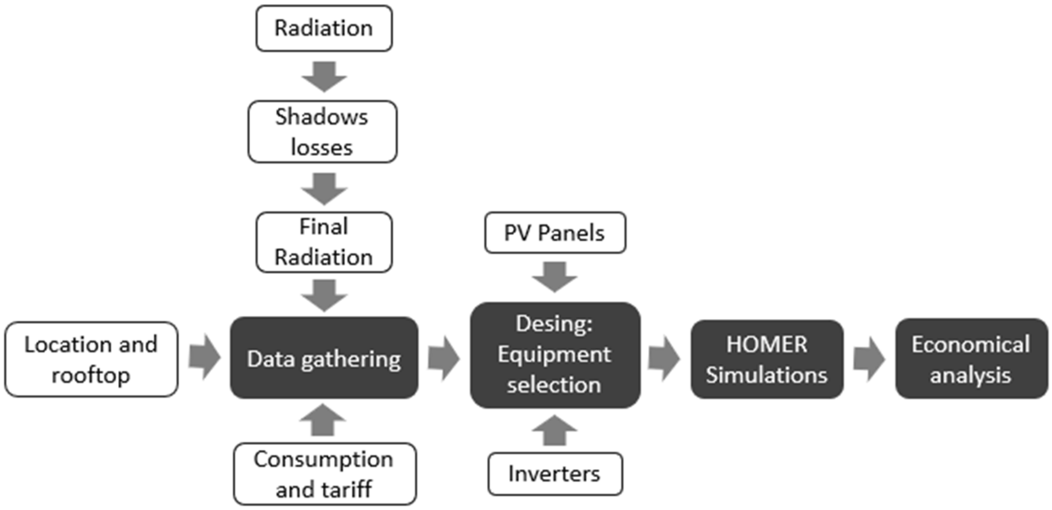


Fig. 1. Methodology scheme for every case under study.

PV deployment, at least a net billing system was required. In a later publication, (López Prol and Steininger, 2020) they conclude that RD-L 15/2018 and RD 244/2019 has completely changed the situation, and now all segments obtain positive profitability in average conditions. Whereas the residential segment has the lowest profitability level, it has the highest potential by decreasing installation costs and increasing the share of self-consumption, given its higher retail prices.

Regionals analyses have been carried in Spain for self-consumption applied to energy communities under the RD 244/2019 (Ministerio para la transición ecológica, 2019). Gallego-Castillo et al. (Gallego-Castillo et al., 2021) conclude that under RD 244/2019, self-consumption in buildings is cost-effective in all the Spanish regions, with optimal self-consumption installations, i.e., only to a certain extent. They also conclude that improvements to the current legislation would be economically beneficial. Mir-Artigues and del Río (Mir-Artigues and del Río, 2021) also conclude that current regulation only encourages prosumer plants that are strictly focused on self-sufficiency, and appropriate technical and regulatory conditions are promoted, for example, at the municipal level. Additionally, Gómez-Navarro et al. has analyzed the potential for PV rooftop prosumer production, modeling the entire city of Valencia (Gómez-Navarro et al., 2021). They conclude that rooftop PV systems could cover almost the whole of domestic electricity consumption. However, they claim further regulation development is needed to achieve this goal economically.

Nevertheless, all these studies have used regional average data, national average energy prices, stylized PV systems, idealistic rooftops, etc. In urban areas, the possibility of a profitable PV system decreases due to the limitations for installing PV panels at the right orientation, the suitability of the rooftops, the impact of the shadows on energy production. Shading effect on panels in urban environments has been analyzed by Calcabrini et al (2018), Revesz et al (2018). Also, the economic viability is highly affected by the performance and price of real available equipment, detailed energy prices, etc. This work analyzes the feasibility of installing PV systems in urban areas for self-consumption purposes in four real cases (2019 data). They were chosen to be illustrative of several similar situations; all of them counted on owners interested in installing PV systems, applying the RD 244/2019. This approach with real cases sheds light on the gap from theory to practice, as discussed by Wilkinson et al. (Wilkinson et al., 2020) and recently Hernández et al. (2020). The cases include two apartments, one public building, and one entire building block, all of them grid-tied systems. Real data of energy consumption and the type of tariff are used to carry out the analysis. The shared self-consumption (several owners share a PV system) is compared with the individual self-consumption to analyze the viability of both schemes.

Furthermore, this work aims to confirm or disprove the predicted influence of regulation on the profitability of the PV system in urban areas. For this, the most common scenarios are selected, representing several cases in Spain (and elsewhere in cities of high solar radiation). Then, the effects of regulation are studied, the regulation that has evolved from RD 900/2015 (where it was not allowed selling to the grid) to the current regulation, RD 244/2019, where the net billing scheme is applied. Based on the differences in feasibility, recommendations for future policy reform are proposed to increase the PV systems' viability in urban areas.

The paper is structured as follows: Section 2 introduces the research design, methodology, and case studies, followed by the empirical results in section 3. Finally, the results are analyzed and discussed in section 4, while the conclusions are presented in Section 5.

2. Methodology

A scheme of the followed methodology is shown in Fig. 1. First, the potential power generation is analyzed considering the available area for the PV location in the rooftops and the incident irradiation, assessing the shading losses. Besides, for each case, the consumption and the contracted rate are defined. Once the data is gathered, the PV system is designed, choosing the number of PV panels and inverters and its features. These data are used as input in the simulation, analysis, and comparison of the different alternatives.

The radiation data is obtained from PVGIS®, an online tool developed by the Joint Research Centre from the European Commission (European Commission, n.d.). Given the location, the azimuth, and the slope, PVGIS provides the average global solar irradiation per square meter at the chosen tilt (H_d). The platform gives the option to take the information from different databases, so the global solar irradiation provided by every database could be compared. There are slight differences in the results depending on the database. Since it is the most conservative option, the PVGIS-CMSAF database has been chosen in this study.

After obtaining the radiation data, the losses due to shadow must be considered for the specific location. Such losses have been estimated employing two different tools, Huellasolar® ("huellasolar visor Open-Platform « huellasolar. Aplicación Web. Mapas de soleamiento y radiación de ciudades," n.d.) and the CE3X® ("CE3X / CE3X / CEX Programa para la certificación energética de edificios," n.d.). The Huellasolar platform allows the visualization of solar radiation maps of cities. In this work, Huellasolar is used to obtain the radiation data of shaded areas and at what time nearby obstacles provoke these shadows on the PV panels. On the other hand, CE3X allows obtaining the shadow pattern of

Table 1
Datasheet of the selected PV panels for all the cases ("SolaX Power – The Home Of Energy Storage," n.d.; "Techno Sun Webportal B2B," n.d.).

Parameter	Abbreviation	Value	Units
Peak Power	P_{peak}	500	W
Maximum Power Point Voltage	V_{MPP}	42.8	V
Maximum Power Point Current	I_{MPP}	11.69	A
Open Circuit Voltage	V_{OC}	51.7	V
Short Circuit Current	I_{SC}	12.28	A
Module Efficiency	η	20.7	%
Module Dimensions		2187 × 1102 × 35	mm
Area		2.41	m^2
Cost (VAT included)		172	€

Table 2
Datasheet of the selected grid tied inverters for every case ("SolaX Power – The Home Of Energy Storage," n.d.; "Sunny Tripower 15000TL / 20000TL / 25000TL | SMA Solar," n.d.; "Techno Sun Webportal B2B," n.d.).

Case	1	2	3	4	Units
Brand	SolaX	SolaX	SolaX	SMA	
Model	X1 Boost 4.2	X3 MIC-15	X1 Boost 5	STP25000TL	
Number of inverters	1	2	1	4	
INPUT (DC)					
Max. PV array power	5200	22,500	5200	45,000	W
Maximum DC Voltage	600	1000	600	1000	V
Maximum input Current	12*	12*	12*	33*	A
Maximum Short Circuit Current	12.8*	14*	12.8*	43*	A
MPPT voltage range	70–580	160–850	70–580	390–800	V
No MPPT/Max strings per MPPT	2/1	2/2	2/1	2/3	%
OUTPUT AC					
Phases	1	3	1	3	
Nominal AC power	4200	15,000	5000	25,000	VA
Euro efficiency	97	97.8	97	98.1	%
Cost	**688**	**2055**	**726**	**2566**	€

*per MPPT tracker

an object on a surface over a solar chart. Both tools allow calculating the shadows on a surface (i.e., the potential location of the PV panels). Huellasolar can analyze a vast zone, while CE3X analyses a specific area, introducing the distance from the obstacles to the PV panels. In this sense, CE3X provides more accurate results than Huellasolar; by employing CE3X, the information given by Huellasolar is validated.

Finally, to estimate the viability of the analyzed PV systems, the software HOMER® was used (Homer Energy, 2020). Hybrid Optimization Model for Multiple Energy Resources (Homer) was originally developed by National Renewable Energy Laboratory and later improved and distributed by Homer Energy (NREL, 2020). Homer has been chosen because it is widely used by the scientific community to simulate energy production and choose the best option in both off-grid and grid-tied systems (Pérez-Navarro et al., 2016; Rajbongshi et al., 2017), for planning installation of hybrid energy systems (Bahramara et al., 2016; Hurtado et al., 2015; Lal et al., 2011; Montuori et al., 2014; Suresh et al., 2020), to estimate its feasibility (Alfonso-solar et al., 2020; Baiyin et al., 2020; Gómez-Navarro et al., 2021) and for integrating non-conventional source into a grid such as biomass gasification(Chambon et al., 2020; Ribó-Pérez et al., 2021). The software calculates the best size of a system, the initial investment, the LCOE, the payback and the IRR based on different energy sources.

From the aforementioned H_d and the location (latitude and longitude), HOMER could generate radiation data in the selected point for an entire year with an algorithm based on the V.A. Graham method (Homer Energy, 2020), but it is also possible to introduce the radiation data from other databases such as PVGIS (European Commission, n.d.). Adding the real electricity consumption curves (hourly data), the installation's sizes to consider, and the available solar resource, the program performs simulations to obtain the costs of the possible alternatives. It simulates an entire year, estimating each hour if the source(s) meets the energy demand, categorizing according to LCOE (Levelized cost of the energy), and choosing the best alternative. The analyzed cases are grid-tied systems. For regulated rates, the grid energy cost is established and daily published in ESIOS, the platform of the Spanish electricity system operator (Red eléctrica de España, REE) ("Analysis | ESIOS electricity · data · transparency," n.d.). Finally, the payback can be obtained by employing the software information, the best size of the PV system, and the initial investment.

2.1. Components of the installation

The PV panels were chosen by comparing different alternatives available in the market (see Table 11 in Annex 1). Due to the room limitations for setting up PV systems in an urban environment and its cost per kWp, panels with an efficiency of close to 20% have been preferred. To reduce the cost per kW_p and increase efficiency, most PV panels use Passivated Emitter and Rear Cell (PERC) and half-cut technologies, being the peak power bigger than 350 W. Different options of PV panels are compared in Table 11. The panel selected is the Vertex TSM-DE18M of 500 W. It cost is 0.35 €/W VAT included. The PV panel datasheet is shown in Table 1.

Similarly, different types of inverters have been compared, as shown in Table 12 of Annex 1. The cost of the inverter and selection depends on the size of the PV system and the kind of grid where the installation will be connected (single phase of three-phase). The inverter datasheet is shown in Table 2. The cost as a function of the installed peak power, used as input in the simulation, is estimated using Table 11, Table 12 and Fig. 7.

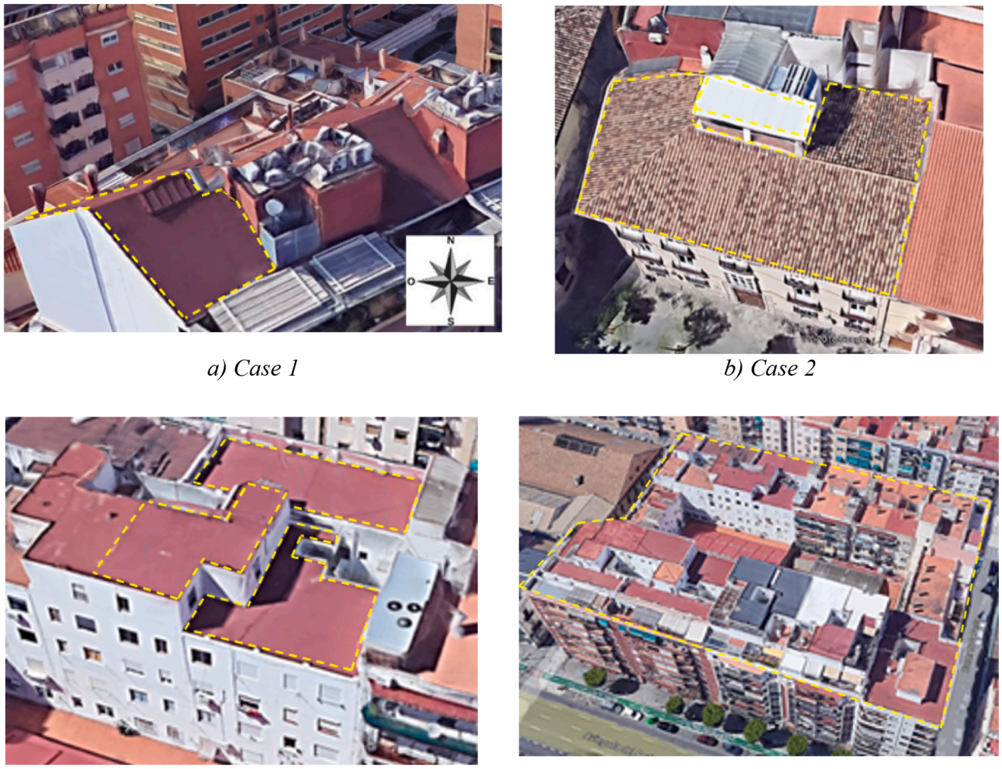
2.2. Cases of study and its locations

The 4 cases analyzed are located in Valencia, Spain, and are shown in Fig. 2. The cases include two apartments (cases 1 and 3), one public building (case 2), and one block of apartments (case 4).

Case 1 is an apartment located in Serrería street. The available area in the rooftop is formed by two gable roofs with a slope of 33°, so two roof-areas orientated to the North-West and two to the South-East (azimuth = −45°; due South is 0°, due East is −90°, due West is 90°) (Fig. 2a). Case 2 is a public building, the roof is oriented to the South-West (azimuth = 10°), and the slope is 20° (Fig. 2b). Case 3 is another apartment located in Felipe Salvador street; the panel's slope would be 33° oriented to the South-West (Azimuth = 30°), employing a structure facing South (Azimuth = 0°). The rooftop of the building is shown in Fig. 2c. Finally, case 4 is an entire block of buildings. The location is the same as in case 3; thus, the panels are configurated at the same azimuth and slope of case 3. In this last case, the photovoltaic system covers the demand of all the apartments, analyzing the advantages of sharing self-consumption. The block consists of 13 buildings with 229 apartments, and the study is focused on the electrical consumption of the flats. The block is located between del Puerto avenue, Felipe Salvador, Los Hierros, and de la Fusta streets.

2.3. Energy consumption and cost of the electricity

The electricity fees and contracted tariffs were obtained from the electricity distribution company by the one-year hour-by-hour energy consumptions. Tariff, yearly consumption and peak power of cases 1 to 4 are summarized in Table 3. The prices include VAT (21%) and electric tax (5.113%). The energy price also includes the measuring equipment



a) Case 1 *b) Case 2*

c) Case 3 *d) Case 4*

Fig. 2. Picture of all the cases. Source: ("Google Maps," n.d.).

Table 3
Tariff of the cases under study.

	Tariff	Case 1 2.0 DHA	Case 2 3.0 A	Case 3 2.0 A	Case 4 2.0 A & 2.0 DHA
Contracted power (kW)	P1	3.5	31	3.3	–
	P2	3.5	41	–	–
	P3	–	10	–	–
Power fee (€/kW·month)	P1	4.297	4.523	4.297	4.297
	P2	4.297	2.719	–	4.297
	P3	–	1.814	–	–
Energy price (€/kWh)	P1	0.166	0.172	0.155	0.155
	P2	0.077	0.139	–	–
	P3	–	0.067	–	–
Consumption (MWh/year)		2.02	41.25	2.74	624.88
Peak power (kW)		3	47	2.8	642

rental.

The 2.0A is a flat tariff. The schedule for tariff 2.0 DHA (two periods) and 3.0A (three periods) is shown in Fig. 3.

In general, the consumption is lower in August due to the summer holidays and a little higher in winter due to heating systems (Fig. 4). The average daily consumption profile is shown in Fig. 5.

In case 4, since neither a device to measure the block of a building's energy consumption nor every apartment's consumption is available, the energy demand must be estimated. Considering the apartments of both buildings are very similar, energy bills and load curves of cases 1 (2.0 DHA) and 3 (2.0 A) are used to estimate the energy demand of case 4. The obtained profiles (Fig. 6) are compared to the energy profiles published in the BOE of 28 December 2017 (MINISTERIO DE ENERGÍA TURISMO Y AGENDA DIGITAL, 2017) for tariff 2.0 A and 2.0 DHA; in this way, it was possible to validate the estimated profile.

According to the Ministry for Ecological Transition in 2019 in Spain, 27.5 million homes contracted the tariff 2.0; 84% of them contracted the one-period tariff (2.0 A), and 16% contracted the two-period tariff (2.0 DHA) (Comisión Nacional de los Mercados de la Competencia (CNMC), n.d.). The curve of case 4 is estimated by weighting case 1 (16%) and case 3 (84%). According to calculations, on average, the yearly estimated consumption was 2514 kWh per apartment, this consumption is slightly smaller than the estimated for the statistics office of the Valencia city council (Oficina de estadística - Ayuntamiento de Valencia, 2020) which estimate the consumption of Valencia city in 1.03 GWh for a total of 377,000 contracts in the domestic sector, obtaining on average 2730 kWh per home in 2019. Scaling the demand profile of case 4 to this value, the total energy demand for the block of buildings would be 816 MWh. However, the first estimation of 624.88 MWh/year has been considered as explained in Table 3 and Table 9. The obtained profile is shown in Fig. 5d. The profile obtained is similar to the obtained by weighting the profiles of tariff 2.0 A and 2.0 DHA published in the BOE of 28 December 2017 (MINISTERIO DE ENERGÍA TURISMO Y AGENDA DIGITAL, 2017).

According to the Spanish operator of the system, in 2019, the average surplus energy price for the simplified revenue mechanism was 4,5 c€/kWh, so this price has been considered for simulation purposes (Analysis | ESIOS electricity · data · transparency, n.d.).

2.4. PV system cost

The total PV system cost includes equipment cost and installation cost. Real market costs have been used as input for HOMER simulations. Equipment cost includes PV panels (see Table 11) and inverter (see Table 12).

The installation cost includes PV panel structure, wiring, protections, other consumable material and labor cost (including company profit margin). Installation costs were estimated from the information from the Climate-KIC, ProSumE European project ("ProSumE - Spain," n.d.) who have estimated the cost based on data from companies dedicated to solar photovoltaic installations in Valencia (Fig. 7). The figure shows how the

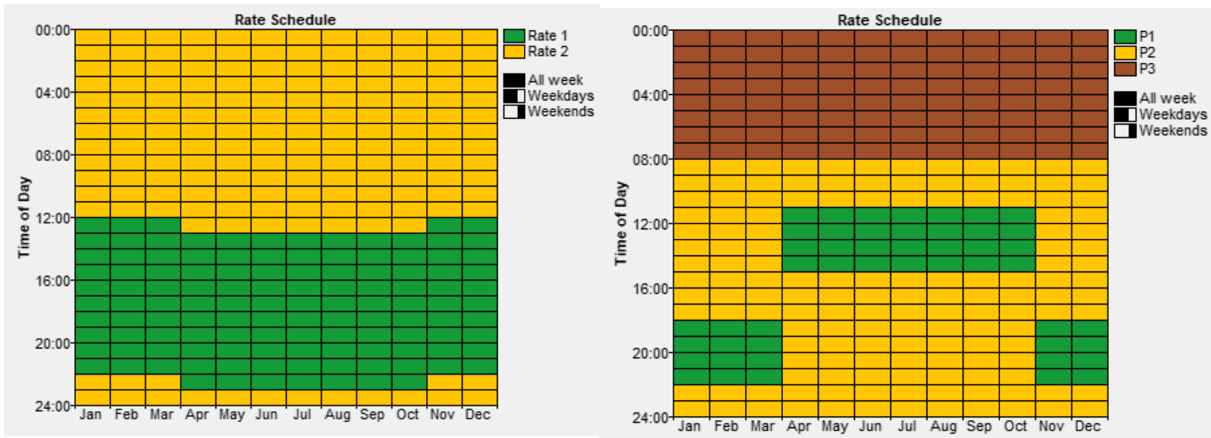


Fig. 3. The energy consumption and the peak power of every case.

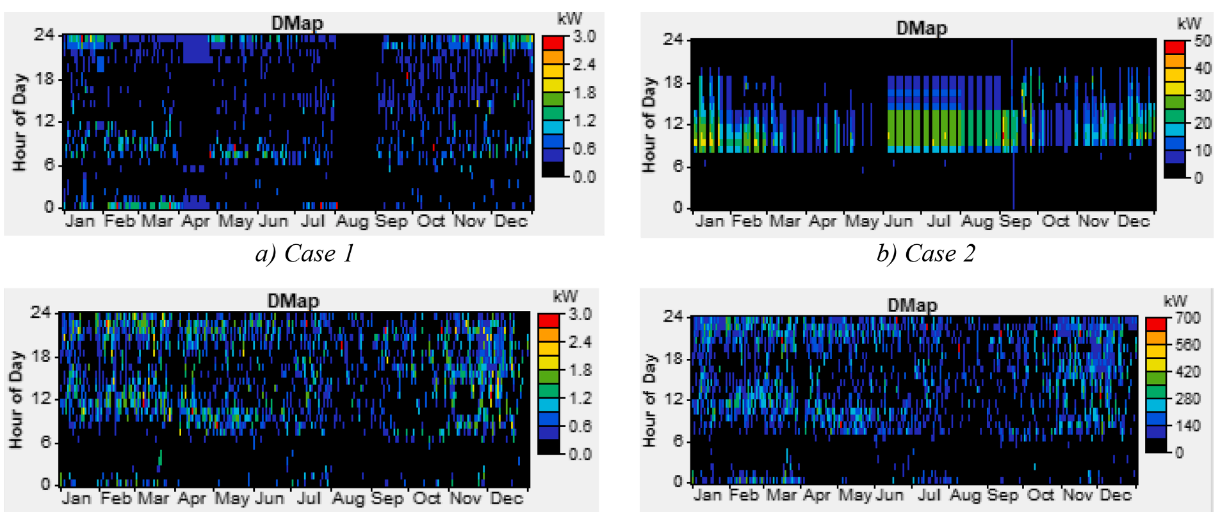


Fig. 4. Yearly consumption profile.

installation costs are based on several real projects in flat and sloping roofs. Additionally, for economic feasibility analysis, annual O&M costs of 25 €/kW·year have been considered (IDAE, 2011).

2.5. Radiation

The in-plane global irradiation for each case study is shown in Fig. 8. Shading losses are not included. This information was taken from the PVGIS database (European Commission, n.d.). The values are not the same between study cases due to the different locations, tilt angle (β), and azimuths (γ). However, for cases 3 and 4, the location, azimuth, and slope are the same, so the irradiance profile is also the same.

2.6. Shading losses

The irradiation estimated employing PVGIS does not consider the effect of shadowing in the solar panels. Hence, if the panels are shaded, the estimated energy must be reduced. The tools Huellasolar and CE3X are used to estimate the shading losses. After the estimation, a new irradiance profile that includes the shadows is used as an input.

The available surface (red line) and the potential surface to locate the panel considering shadows (blue line) is shown in Fig. 9. In locations with complex rooftops (cases 1 and 3), CE3X were used to create the shadow patterns of the roofs' obstacles. It was used local measurements and available data about the height and location of the objective building and surrounding buildings. Then, CE3X projects the pattern on a solar chart, as shown in Fig. 10. This figure represents the location of the surrounding building in a graphic where the x-axis is azimuth, and the y-axis is the elevation angle (angular height of the sun measured from the horizontal plane or ground).

Huellasolar sunny maps estimate, on average for one year, the potentially available surface for PV panels location (Fig. 11). Only the areas with a minimum of 85% sunshine received hours have been considered to locate PV panels. Shading losses for every case are included in Table 4. While in cases 1 and 2 the percentage of losses is close to 4%, not all the available surface has such good radiation conditions in the third case. In the block of apartment buildings, the potential areas to install PV panels were previously restricted. In Case 4, on average, losses of 1.6% were obtained, having zones without losses and others with up to 5%. Hence, the usable area is drastically reduced from 5000 m^2 to 975 m^2. Considering the estimated shadows, the final irradiation for each case is shown in Table 5.

2.7. PV panels and inverters – Sizing and configuration.

The sizing of the system intends to give information about the number of PV panels and their configurations (series and parallel connection) and the number of the required grid-tied inverters. The peak

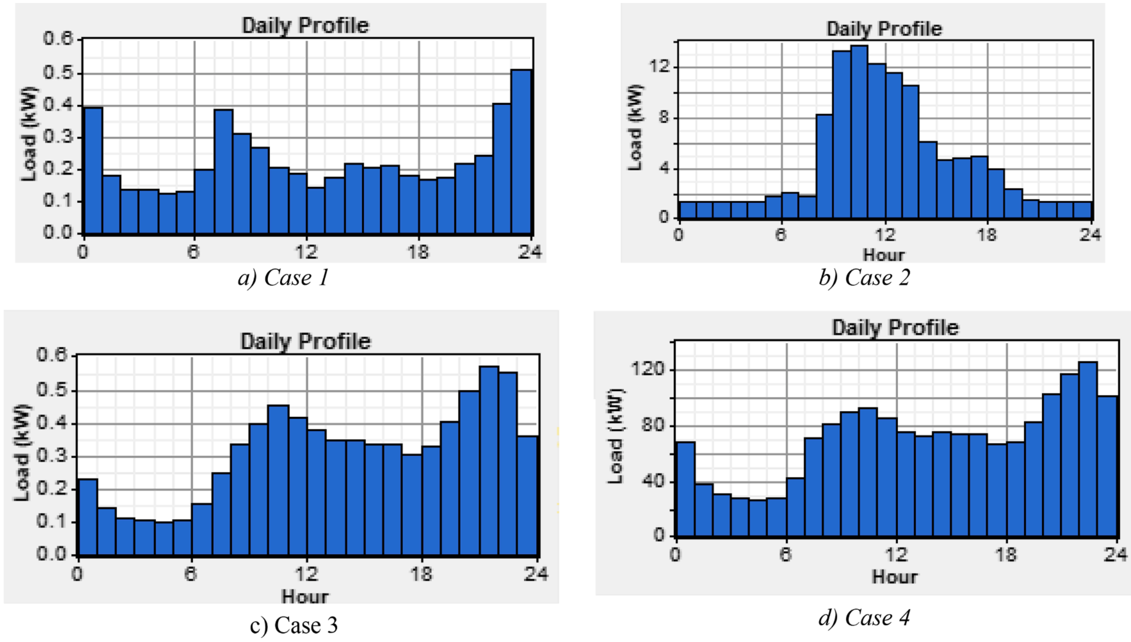


Fig. 5. Average daily consumption profile (Homer Energy, 2020).

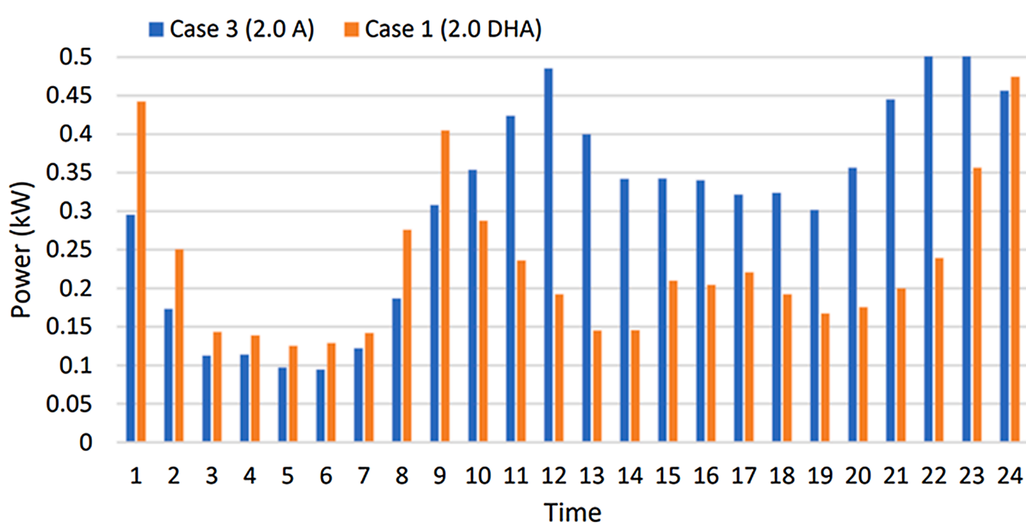


Fig. 6. Average consumption profile cases 1 and 3.

power (Pints) to be installed is the maximum value between the peak power able to be installed as a function of the available surface (Aavailable) and the value with the lowest NPV estimated by Homer. The available surface was estimated in point 2.6. To calculate the power to be installed and the number of PV panels, equations (1) and (2) are used.

$$P_{inst} = \min[P_{optimum\ \ according\ \ to\ \ simulations}, P_{max\ \ according\ \ available\ \ area}] \tag{1}$$

$$N_{panels} = \frac{P_{inst}}{P_{peak\_panel}} \tag{2}$$

The number of required inverters is estimated by equation (3).

$$N_{inv} = \frac{P_{max\_MPP}}{P_{max\_in\_DC}} \tag{3}$$

The maximum number of PV panels to be connected in series and in parallel is estimated by equation (4) and (5).

$$N_{\max\_panel\_series} = \frac{V_{MPP\_inv}}{V_{MPP\_panel}} \tag{4}$$

$$N_{\max\_panel\_parall} = \frac{I_{MPP\_inv}}{I_{MPP\_panel}} \tag{5}$$

To verify the voltage and current are in the admitted range of the inverter, voltage and current must be corrected considering the temperature effect. The maximum voltage and current are estimated using equations (6) and (7).

$$V_{OC\_max} = V_{OC\_STC} \cdot [1 + (\beta_{V_{OC}} \cdot (T_{\mathrm{mincell}} - T_{STC})] \tag{6}$$

$$I_{sc\_max} = I_{sc\_STC} \cdot [1 + (\beta_{I_{SC}} \cdot (T_{\mathrm{maxcell}} - T_{STC})] \tag{7}$$

Last results could be contrasted with maximum input power, estimated by equation (8).

$$P_{max\_MPP} = P_{\mathrm{MPP}\_STC} \cdot \left[1 + (\beta_{P_{MPP}} \cdot (T_{\mathrm{mincell}} - T_{STC})\right] \tag{8}$$

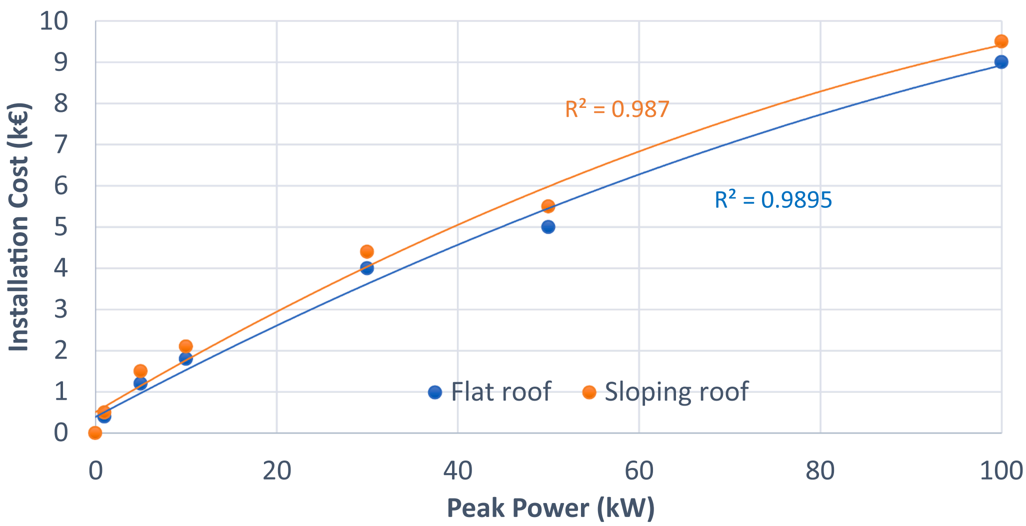


Fig. 7. Installation cost as a function of the peak power for a flat and sloping roof.

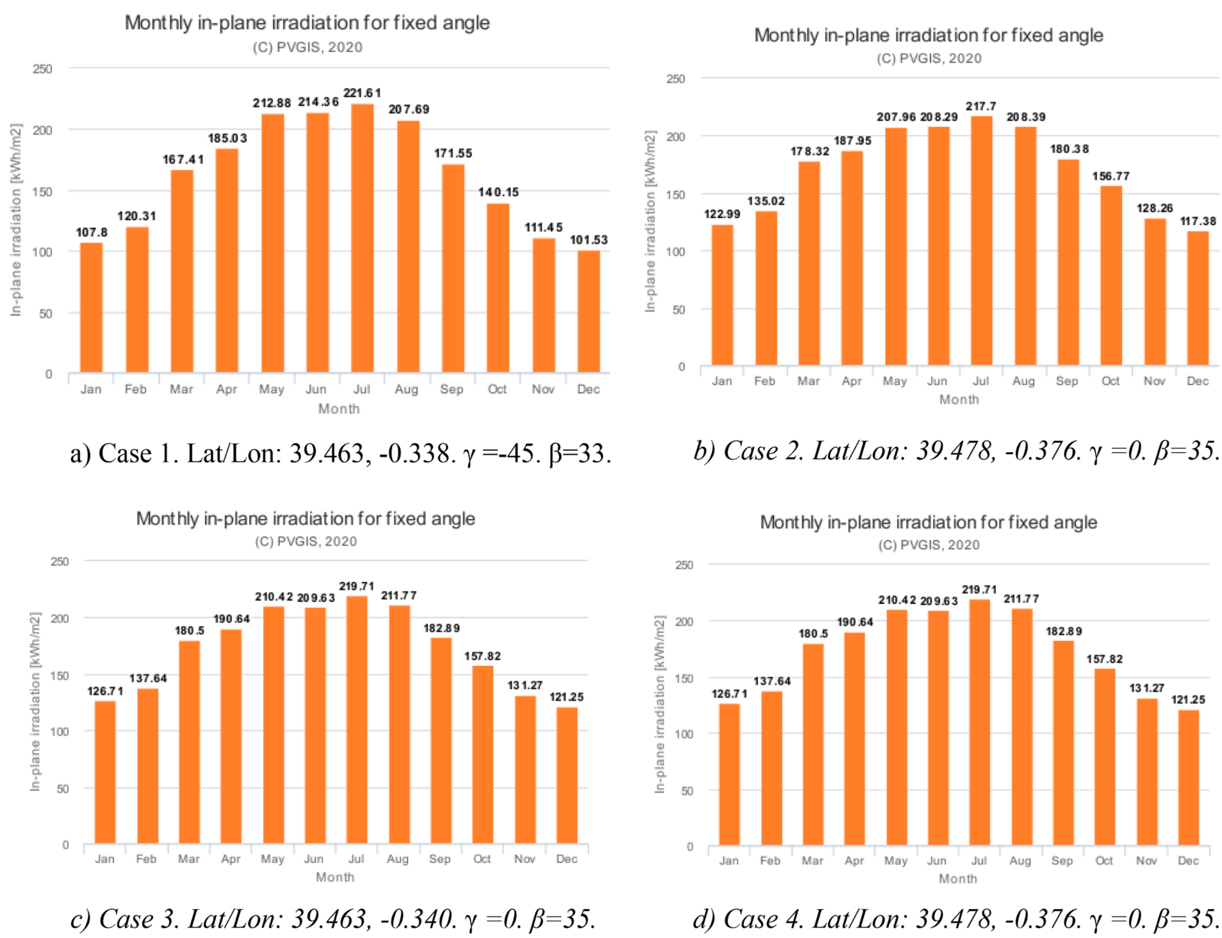


Fig. 8. Global radiation in W/m^2 for every studied case (Source: (European Commission, n.d.)).

The maximum and minimum values of the cell temperature are estimated by equations (9) and (10).

$$T_{min\_cell} = T_{amb\_min} + G \cdot \frac{NOCT - T_{a,NOCT}}{G_{NOCT}} \tag{9}$$

$$T_{\max\_cell} = T_{amb\_max} + G \cdot \frac{NOCT - T_{a,NOCT}}{G_{NOCT}} \tag{10}$$

2.8. Analyzed scenarios

Different regulatory scenarios have been analyzed (Table 6). The scenarios are applied to the specific cases under study, but they can also be applied to any case in Europe and globally.

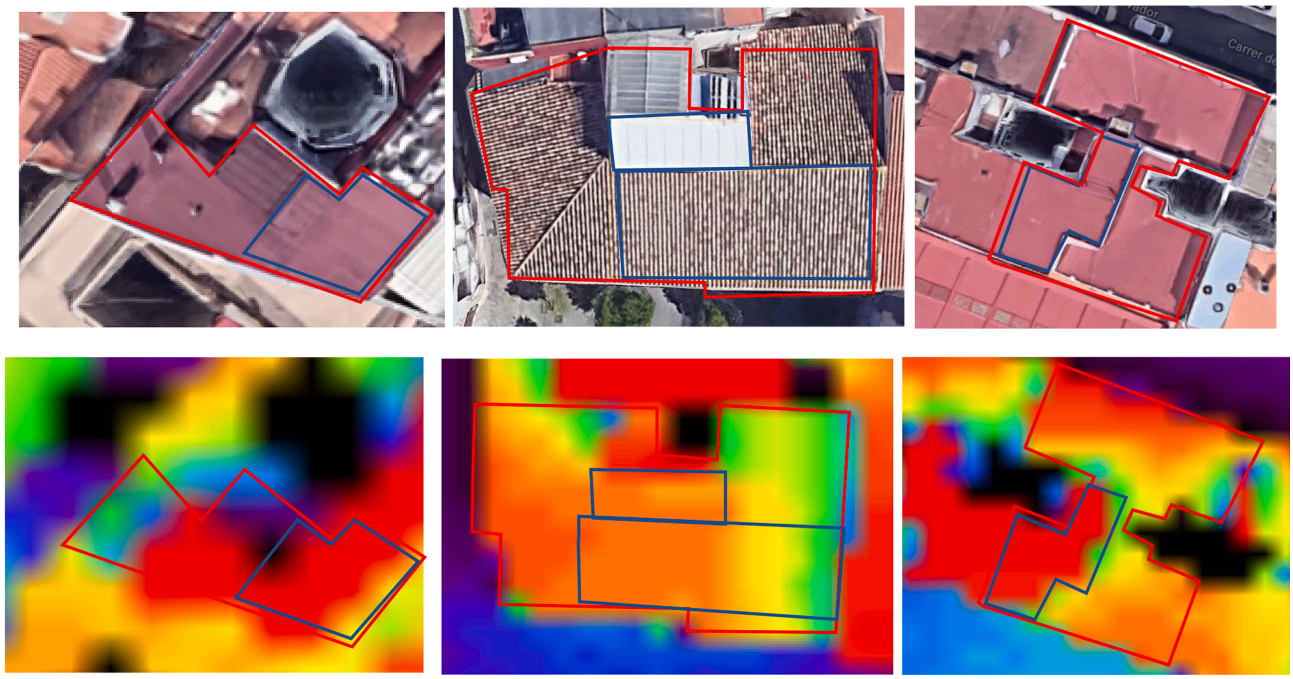


Fig. 9. Chosen area for locating the PV panels, case 1 (left), 2 (center) and 3 (Right) ("Google Maps," n.d.).

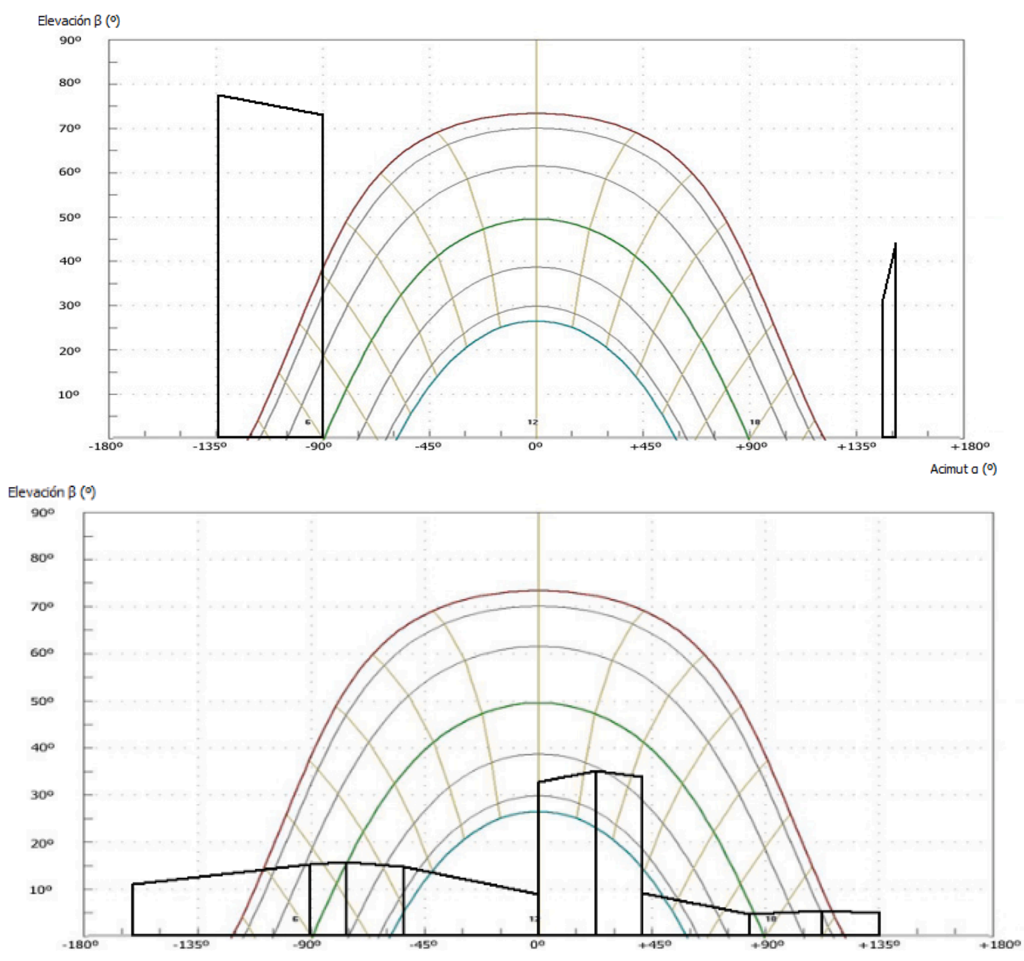


Fig. 10. Shadow pattern rectangular area case 1 (up) and 3 (down). (CE3X).

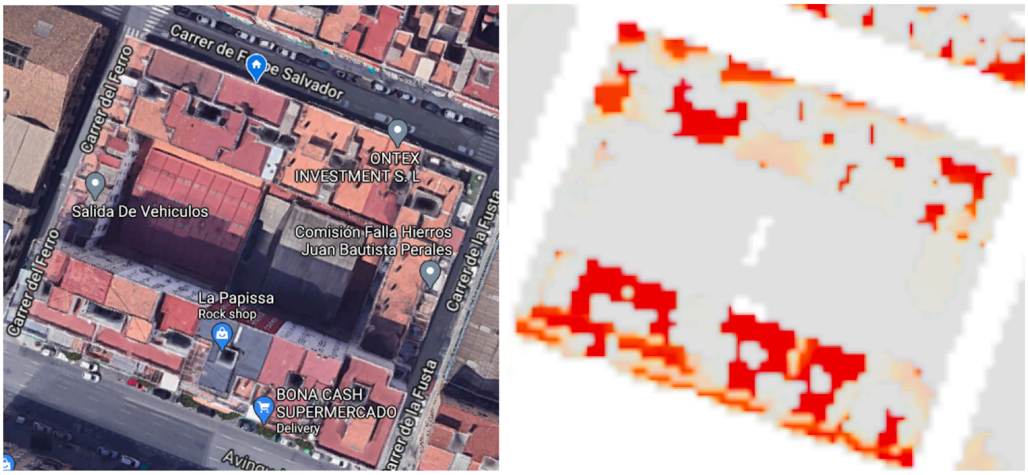


Fig. 11. Areas with at least 85% of sunshine hours received. Case 4 example. ("huellasolar visor OpenPlatform « huellasolar. Aplicación Web. Mapas de soleamiento y radiación de ciudades," n.d.).

Table 4
Shading losses and surface reduction. Cases 1 to 4.

Case	1	2	3	4
Available surface (m^2)	148	516	375	5000
Potential surface considering shading (m^2)	65	225	103	975
Surface reduction (%)	56.1	56.4	72.5	80.5
Shading energy losses (in potential surface) (%)	4.19	4	13.10	1.60
Max PV panels peak power (kW)	10	35	10	120

Table 5
Global Horizontal Radiation, considering Shading losses (kWh/m2/d).

Month	Case 1	Case 2	Case 3	Case 4
January	3.48	3.15	1.48	3.24
February	4.30	4.15	3.49	4.24
March	5.40	5.11	5.33	5.35
April	6.01	5.96	5.96	6.11
May	6.12	6.78	6.78	6.83
June	6.35	7.03	7.02	7.10
July	6.41	7.07	7.06	7.11
August	6.48	6.48	6.43	6.64
September	5.72	5.60	5.60	5.69
October	4.52	4.15	3.70	4.49
November	3.72	3.36	1.67	3.60
December	3.28	3.03	1.47	3.00

2.9. Energy balance

Energy balances for the scenarios have been carried out in the simulation as shown in Fig. 12. The energy demand is covered, giving priority to the PV system (PV production to load). If the PV production cannot feed the load, the utility grid makes up the difference (Purchases). The surplus is sent to the grid when the PV system production is bigger than the energy demand (Sales). Excess is the potential energy that the PV system can produce, but either is unpaid or not produced (modifying the operating point of the inverter power point tracker, PPT).

2.10. Economic analysis

The analyzed economic indicators are Annualized Cost, Total NPC, Levelized Cost of Energy, Internal Rate of Return, and Payback.

Total Annualized cost ($C_{ann,tot}$): The total annualized cost is the sum of the annualized costs of each system component, plus the other annualized cost. The annualized cost of a component is equal to its annual operating cost plus its capital and replacement costs annualized over the project lifetime (Homer Energy, 2020).

Capital Recovery Factor (CRF): The capital recovery factor is a

Table 6
Scenarios description.

Scenario	Description
GRID	Business as usual. In this case, all the energy is taking from the grid. It is the situation before installing the PV system.
NS (no sales)	In this scenario, it is not allowed to sell energy to the grid through simplified scheme; the maximum peak power to be installed must be less than the contracted capacity, and multiple clients cannot share a PV system. In Spain, this scenario was represented by previous regulation (RD900/2015).
NB (net billing)	In this case, net billing is applied but, in a regular billing period (normally one month), if the value of the revenues results bigger than the purchase's (excluding taxes and access tolls), the surplus will not be paid to the user. According to the current regulation in Spain (Ministerio para la transición ecológica, 2019) the bureaucracy is drastically reduced for installation up to 100 kW (in the inverter), simplifying the legalization of the installation. In case 4, more than 100 kW could be installed, and selling energy would be possible. However, the installation must meet the requirements of a traditional power plant as explained in (IDAE, 2019), which has been necessary for its registration as an Electricity company through a long, complex, and bureaucratic process. To avoid such barrier, only installations smaller than 100 kW are analyzed. This scenario represents the current situation in Spain through RD244/2019.
NB_NL (net billing no limit)	Same as NB, but all the energy sent the grid is paid to the user, even if the value of the revenues results in bigger than the purchases. According to the contracted tariff, the maximum power stipulates the limit for revenues. For tariff 2.0, it is 10 kW; for collective self-consumption is the sum of all the costumer's capacity. This scenario is not possible in Spain at the moment.
NM (net metering)	In this scenario, the utility grid allows customers to sell power to the grid at the retail rate. At the end of the monthly billing period, the customers are charged for the net amount purchased (purchases minus sales). If the 'net grid purchases' value is negative, meaning the sold energy is bigger than the energy bought over the billing period, the utility pays according to the sell-back rate (NREL, 2020). According to the contracted tariff, the maximum power stipulates the limit for revenues. For tariff 2.0, it is 10 kW; for collective self-consumption is the sum of all the costumer's capacity. However, this latter scenario is not currently possible in Spain.

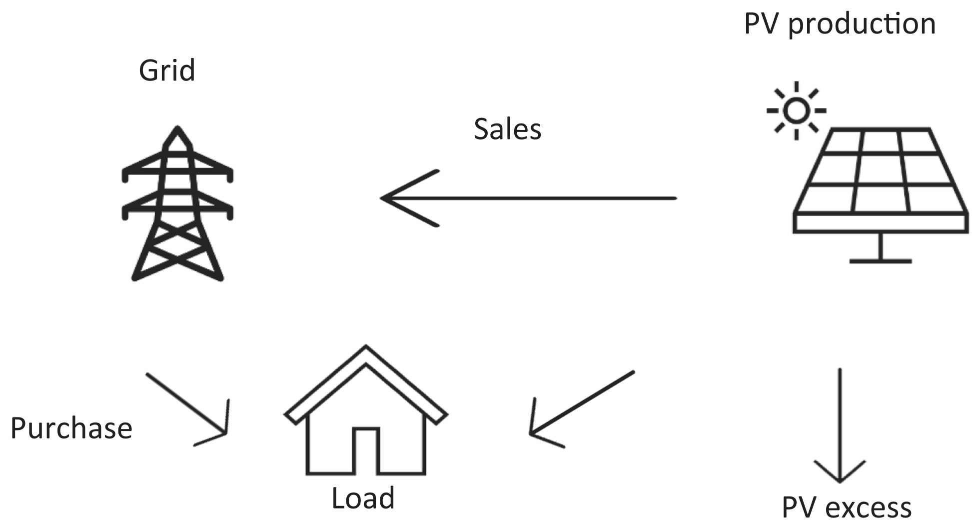


Fig. 12. Energy balance carried out in the simulations.

Table 7
Size of the PV system. Cases 1 to 4.

Case	PV (kWp)	Inverter (kW)	Cost of the systemVAT included (€)	Specific cost (€/kW)
1	5	4.2	5366	1278
2	35	30	32,594	1086
3	5	5	5867	1173
4	120	100	103,149	1031

Table 8
Number of PV panels per inverter, panels per string, strings per MPPT and inverters required.

Case	1	2	3	4
PV Panels required	10	70	10	240
Number of inverters	1	2	1	4
PV panels in series per MPPT	5	9	5	10
PV panels in parallel per MPPT	1	2	1	3
Number of MPPT per inverter	2	2	2	2

ratio used to calculate the present value of an annuity (a series of equal annual cash flows). The equation for the capital recovery factor is:

$$CRF(i,N) = \frac{i(1+i)^N}{(1+i)^N - 1}$$

Total NPC (C_{NPC}): The total net present cost of a system is the present value of all the costs that it incurs over its lifetime, minus the present value of all the revenue that it earns over its lifetime. Costs include capital costs, replacement costs, O&M costs, fuel costs, emissions penalties, and the costs of buying power from the grid. Revenues include residual value and grid sales revenue. The total net present cost uses the following equation (Homer Energy, 2020):

$$C_{NPC} = \frac{C_{ann,tot}}{CRF(i, R_{proj})}$$

Levelized Cost of Energy (LCOE): It is the average cost per kWh of the electrical energy produced by the system. LCOE is calculated by dividing the annualized cost of producing electricity by the total useful electric energy production. The equation for the LCOE is as follows (Homer Energy, 2020):

$$LCOE = \frac{C_{ann,tot}}{E_{prim,AC} + E_{grid,sales}}$$

Payback: Payback is the number of years at which the cumulative cash flow of the difference between the current and base case systems switches from negative to positive. It is calculated by dividing the difference in capital costs between the chosen system and the grid by the difference in operating costs. Payback indicates how many years it will take to recover an investment (Homer Energy, 2020).

Internal rate of return (IRR): It is the discount rate at which the grid and chosen PV system have the same net present cost. The IRR is calculated by determining the discount rate that makes the present value of the difference of the two cash flow sequences equal to zero (Homer Energy, 2020).

3. Results

3.1. Size and configuration of the system

The PV system size has been chosen according to the best option applying the current regulation (NB scenario) according to available surface. The results of the best option are shown in Table 7. All the regulation scenarios have been analyzed using the same PV system size and the same initial capital for every case; thus, the comparisons are carried out under the same conditions. In case 4, since it is a shared self-consumption system, the NS scenario cannot be applied. Nevertheless, the same analysis has been carried out, omitting this consideration. Hence, the results are based on the four cases under study.

The number of PV panels per inverter, panels per string, strings per MPPT and inverters required is shown in Table 8. The information was obtained according to the procedure explained in point 2.7. The obtained values are typical for this kind of installations.

3.2. Energy balance

The grid purchases, the potential production from the chosen PV system, and the load every month are shown in Fig. 13. The PV solar system produces as much energy as possible according to the irradiation. If more energy is required to cover the load, it is supplied by the utility grid. Independent from regulation, the energy flows of Fig. 13 are the same for all 4 cases. Due to cases 1 and 3 are individual homes, the energy demand is smaller than cases 2 and 4. The PV production to load ratios are 4.1, 1.6, 2.9, and 0.4 for cases 1, 2, 3, and 4. Considering an important part of the consumed energy is required during the day, cases 1 and 3, in proportion to the load, require less energy from the utility grid (Fig. 13 a and c) and can potentially sell energy to the grid (Fig. 14). The renewable electricity production to the total energy consumed is

Table 9
Summary of the energy balance – Case 1 to 4.

Case	Option		Supply			Consumption			Renew (%)
			PV	Grid purchases	Total	Load	Grid sales	Total	
1	Grid	kWh/year	0	2022	2022	2022	0	2022	0.0
	NS	kWh/year	8195	1293	9488	2022	0	2022	
		%	86	14	100	100	0	100	86.4
	NB	kWh/year	8195	1293	9488	2022	6292	8314	
		%	86	14	100	24	76	100	86.4
	NB_NL	kWh/year	8195	1293	9488	2022	7164	9186	
		%	86	14	100	11	78	100	86.4
	NM	kWh/year	8195	1293	9488	2022	7164	9186	
		%	86	14	100	24	78	100	86.4
2	Grid	kWh/year	0	41,245	41,245	41,245	0	41,245	0.0
	NS	kWh/year	66,132	24,771	90,903	41,245	0	41,245	
		%	73	27	100	100	0	100	72.8
	NB	kWh/year	66,132	24,771	90,903	41,245	37,380	78,625	
		%	73	27	100	52	48	100	72.8
	NB_NL	kWh/year	66,132	24,771	90,903	41,245	37,380	78,625	
		%	73	27	100	52	48	100	72.8
	NM	kWh/year	66,132	24,771	90,903	41,245	37,380	78,625	
		%	73	27	100	51	48	100	72.8
3	Grid		0	2741	2741	2741	0	2741	0.0
	NS	kWh/year	7828	1755	9583	2741	0	2741	
		%	82	18	100	100	0	100	81.7
	NB	kWh/year	7828	1755	9583	2741	5920	8661	
		%	82	18	11	32	68	100	81.7
	NB_NL	kWh/year	7828	1755	9583	2741	6519	9260	
		%	82	18	100	30	70	100	81.7
	NM	kWh/year	7828	1755	9583	2741	6519	9260	
		%	82	18	100	30	70	100	81.7
4	Grid		0	624,880	624,880	624,880	0	624,880	0.0
	NS	kWh/year	235,812	559,234	795,046	624,880	0	624,880	
		%	30	70	100	100	0	22,798	29.7
	NB	kWh/year	235,812	559,234	795,046	624,880	76,787	701,667	
		%	30	70	100	89	11	100	29.7
	NB_NL	kWh/year	235,812	559,234	795,046	624,880	76,787	701,667	
		%	30	70	100	89	11	100	29.7
	NM	kWh/year	235,812	559,234	795,046	624,880	76,787	701,667	
		%	30	70	100	89	11	100	29.7

86.4%, 72.8%, 81.7%, and 29,7% for cases 1, 2, 3, and 4 (Table 9). For the NS scenario, were delivering power to the grid is not allowed, a smart meter is required to control the energy produced by the PV system to avoid sending energy to the grid. For economic analysis purposes, due to energy being delivered for free to the grid, to send energy to the grid or not to produce it has the same effect on the analysis of the system. Fig. 15.

Since load, grid purchase, and PV production are the same for the scenarios analyzed in every case, the economic remuneration for the energy delivered to the grid makes the difference. The surplus energy that can be delivered to the grid with revenues according to the compared regulation is shown in Fig. 14. Since the NS scenario does not allow electricity delivery to the grid, this value is zero. On the other hand, the NB scenario allows revenues for selling the energy, improving the system's economic viability. Finally, if the limitation to energy sales is eliminated, so scenario NB_NL, the profitability would increase when the sales revenues exceed purchases, as shown in Figures 16a and 16c.

On the other hand, if purchases exceed revenues, the effect of scenario NB on the cost of energy is the same compared to the NB_NL scenario (Fig. 14 b and d). The type of remuneration is not considered in Fig. 14, and it only analyses the energy balance. Despite the energy balance being the same, the profitability is better under the NM scenario, as explained in the economic analysis section.

The different scenarios of the 4 cases, which are individually discussed focused on energy sales, are summarized in Table 9.

Case 1: The total energy produced (PV + Grid) equals 9.5 MWh/year (PV = 86%; Grid = 14%). The energy produced by the PV system would be 8.2 MWh, of which 7.2 MWh could be delivered to the grid. In the NS scenario, the delivered energy (or not produced) is not economically compensated in none of the cases. If the NB scenario is applied, 6.3 MWh could be compensated, reducing the bill's energy cost. The total energy delivered would be paid if either NB_NL or NM is applied.

Case 2: The total energy produced (PV + Grid) equals 90.9 MWh/year (PV = 73%; Grid = 27). The energy produced by the PV system would be 66.1 MWh, of which 37.4 MWh would be delivered to the grid in all of the cases: NB, NB_NL, or NM. Unlike the rest of the cases, the hours of consumption are working hours during the day, making better use of the PV production due to the direct use of the energy from Monday to Friday, but delivering to the grid almost all the produced energy on weekends. In this way, surplus revenues play an important role in reducing costs.

Case 3: The total energy produced (PV + Grid) is equal to 9.6 MWh/year (PV = 82%; Grid = 18%). The energy produced by the PV system would be 7.8 MWh, of which 6.5 MWh could be delivered to the grid. If NB is applied, 5.9 MWh could be compensated, reducing the bill's energy cost. If either NB_NL or NM is applied, the total energy delivered would be compensated and paid.

Case 4: The total energy produced (PV + Grid) is equal to 795 MWh/year (PV = 30%; Grid = 70). The energy produced by the PV system would be 236 MWh, of which 77 MWh could be delivered to the grid in all of the cases: NB, NB_NL, or NM.

3.3. Economic analysis

The economic analysis of every case is shown in Table 10. Below, the economic feasibility of the different scenarios of the 4 cases are individually discussed:

NS: In this scenario, most PV installations are not profitable. When most energy consumption is produced while the solar resource is available (Case 2), profitability increases, but long payback periods are

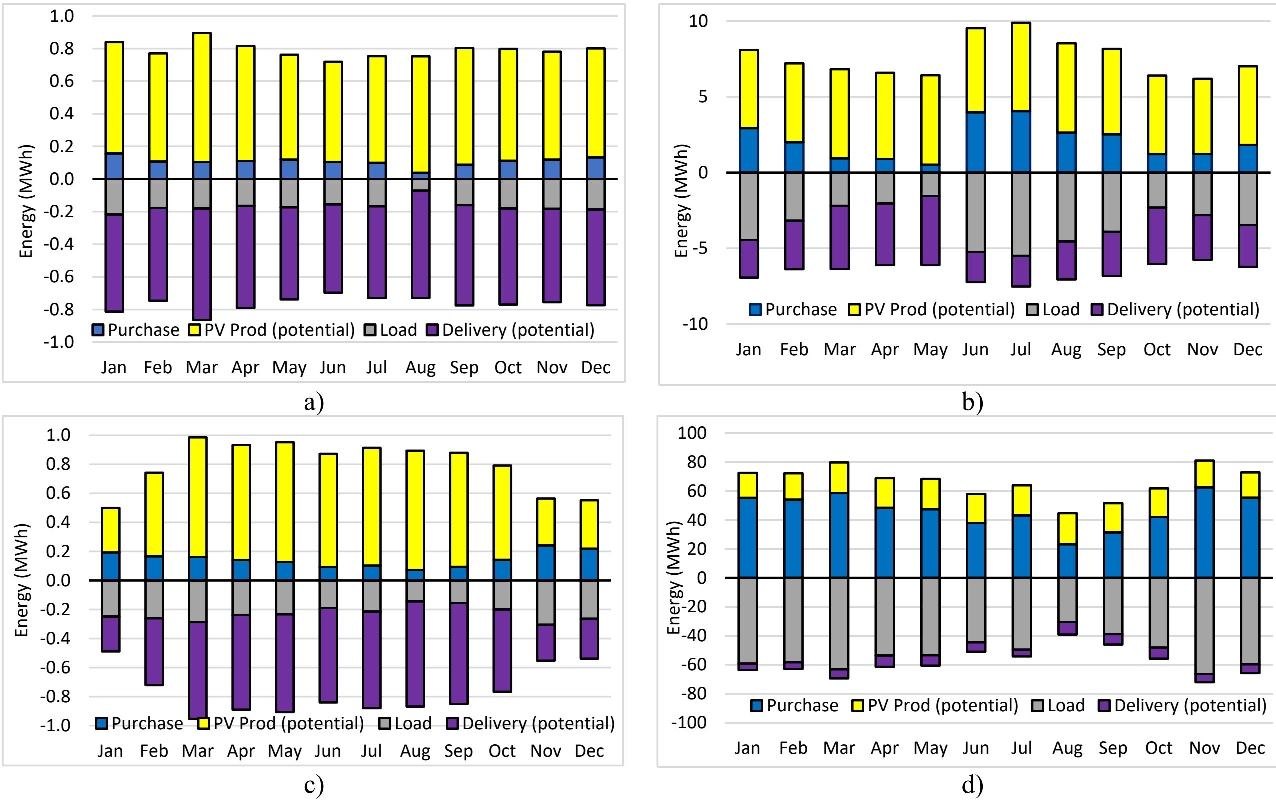


Fig. 13. Monthly energy balance - cases 1 to 4 (figures a to d).

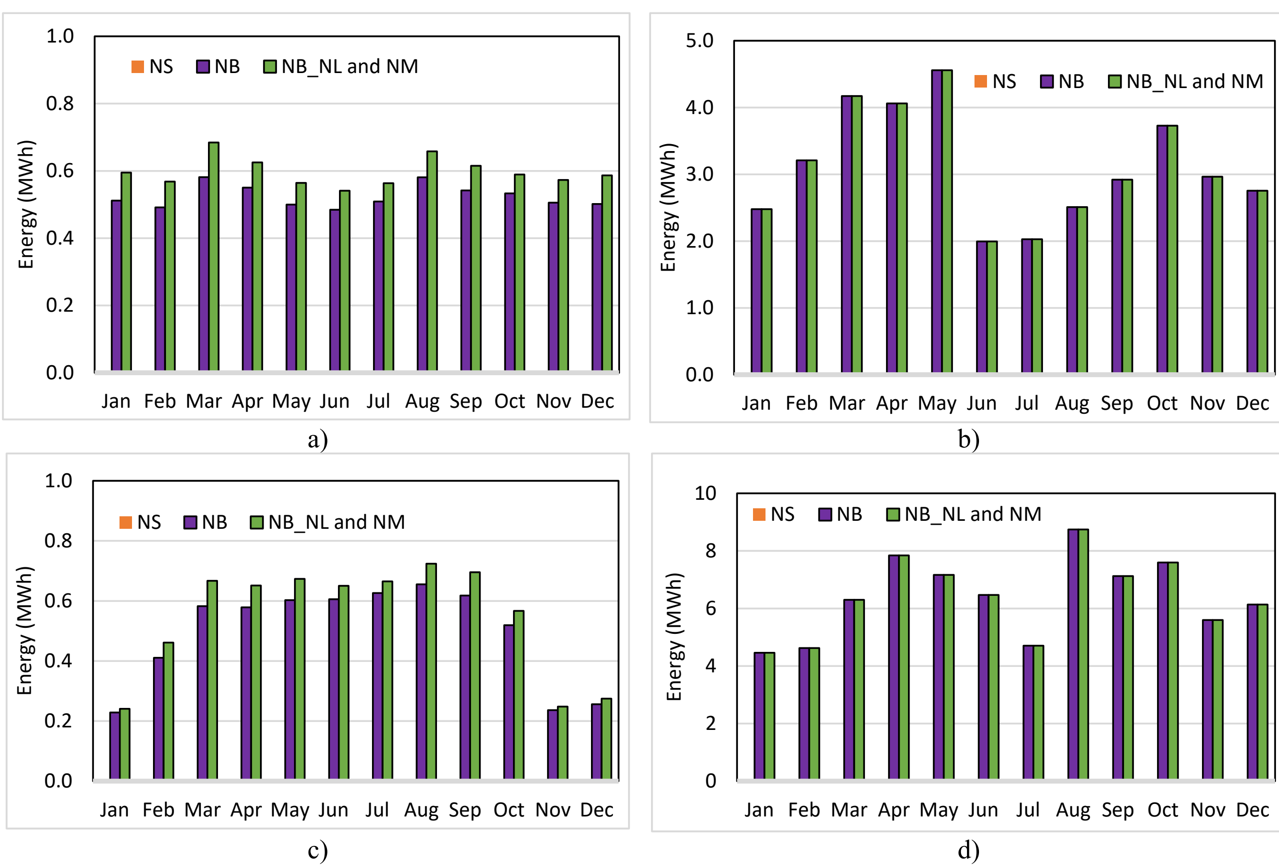
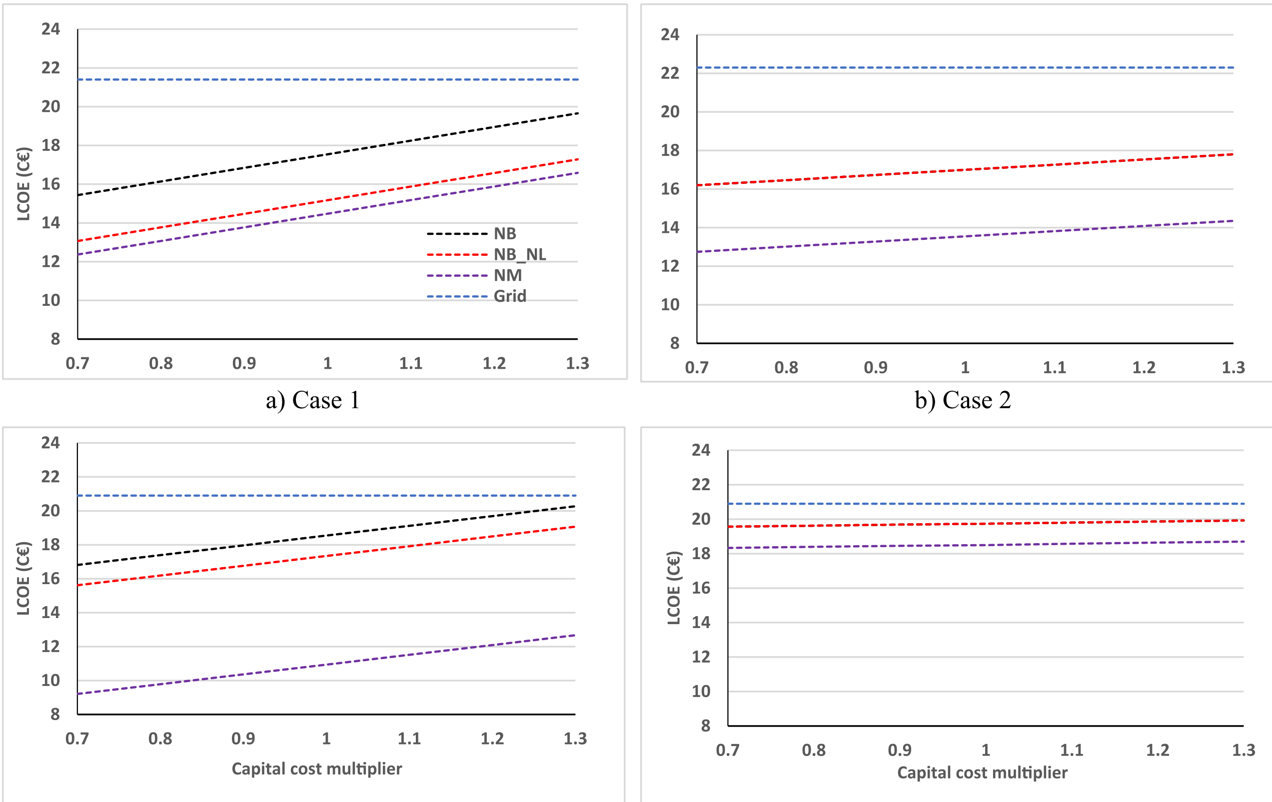


Fig. 14. Monthly energy delivered to the grid with revenues - cases 1 to 4 (figures a to d).



a) Case 1 b) Case 2 c) Case 3 d) Case 4

Fig. 15. Sensitivity analysis, LCOE as a function of the capital cost multiplier (PV panels + support structure cost) in the four cases.

Table 10
Summary of the economic analysis – Cases 1 to 4.

Case	Option	Initial capital (€)	Annual cost (€/year)	Total NPC (k€)	LCOE (€/kWh)	Payback (years)	IRR (%)
1	GRID	0	433	7.5	0.214	0.0	0.0
	NS	4435	446	12.2	0.347	–	–
	NB	4435	100	6.2	0.175	12.0	5.6
	NB_NL	4435	52	5.3	0.152	10.0	8.0
	NM	4435	−10	4.3	0.121	9.2	8.9
2	GRID	0	9210	160.4	0.223	0.0	0.0
	NS	26,937	7520	157.9	0.22	18.2	3.8
	NB	26,937	5464	122.1	0.17	6.8	13.6
	NB_NL	26,937	5288	122.1	0.17	6.8	13.6
	NM	26,937	4042	97.3	0.136	5.0	19.4
3	GRID	0	572	10.0	0.209	0.0	0.0
	NS	4849	572	14.5	0.304	–	–
	NB	4849	230	8.9	0.185	12.1	5.0
	NB_NL	4849	197	8.3	0.173	11.2	6.0
	NM	4849	21	5.2	0.109	8.0	10.7
4	GRID	0	130,838	2273	0.209	–	–
	NS	85,247	122,726	2222	0.204	10.4	7.8
	NB	85,247	118,503	2149	0.197	6.9	13.7
	NB_NL	85,247	118,503	2149	0.197	6.9	13.7
	NM	85,247	110,824	2015	0.185	4.2	23.3

obtained. In this way, the viability of a scenario without grid sales is relegated to systems without energy surpluses, forcing to selecting small power plants that increase the cost per kW. This way, much of the potential for electricity generation is discarded, even causing the non-viability of the project (Escobar et al., 2020; López Prol and Steininger, 2017). In the cases analyzed, only in case 2 could the investment be recovered in 18 years. In all others, it would not be recovered.

NB: The Payback for installing PV urban system goes from 6.8 to 12 years. In the individual households analyzed (Cases 1 and 3), the payback is around 12 years. In case 2, the payback is 6.8 years. When a PV system is shared, the payback would be reduced to 6.9 years (Case 4). The IRR goes from 5.6 to 13.7 in all the analyzed cases. The viability is incremented when the energy produced by the PV system is self-consumed as much as possible (cases 2 and 4).

NB_NL: in this scenario, the payback would be reduced only when the revenues are bigger than sales. In cases 1 and 3, the payback is reduced from 12 to 10 years and 12.1 to 11.2, respectively.

NM: Since the energy produced by the PV system could be "stored" into the grid without losses (electricity supplied to the grid is later recollected), it is the best scenario. The payback goes from 4.2 to 9.2

Table 11
Comparison of different PV panels available on the market. Source (Technosun, n.d.)

Model	A (m^2)	PV panel cost (€)	Cost VAT incl. (€)	P_{peak} (W)	η (%)	€/W (VAT incl.)
500 W TSM-DE18M VERTEX, TRINA SOLAR	**2.39**	**142**	**172**	**490**	**20.51**	**0.35**
400 W mono Red solar PERC SRP-400-BMA-HV	2.02	119	144	400	19.81	0.36
400 W mono Red solar. SR-M672400HL	2.01	135	163	400	19.88	0.41
370 W-72 M.Red Solar	1.94	129	157	370	19.07	0.42
350 W Trina Solar Poli	2.01	125	151	350	17.40	0.43
335 W Red Solar Poli	1.98	123	149	335	16.92	0.44
330 W-144P.Red Solar RED330-72P	1.98	127	154	330	16.67	0.47

Table 12
Comparison of different grid-tied inverters available on the market. Source (Technosun, n.d.)

Model	Rated Power (kW)	Cost (€)	Cost VAT included (€)	€/kW
SMA STP25000TL 3Ph	**25**	**2120**	**2566**	**103**
INGETEAM Sun 3play 3Ph	20	1845	2233	112
SolaX X3 MIC-15.0-T 3Ph	**15**	**1698**	**2055**	**137**
SolaX X1 Boost 5 kW 1Ph	**5**	**600**	**726**	**145**
SolaX X3 MIC-10.0-T 3Ph	10	1336	1617	162
SolaX X3 MIC-12.0-T 3Ph	12	1703	2061	172
SolaX X1 Boost 4.2 kW 1PH	**4.2**	**569**	**688**	**164**
SolaX AIR 3kVA 1Ph	3	448	542	181
SolaX X3 MIC-8.0-T 3Ph	8	1225	1482	185
SolaX X1 Boost 3.6 kW 1 Ph	3.6	560	678	188
SolaX X3 MIC-9.0-T 3Ph	9	1415	1712	190
SolaX AIR 3.3kVA 1Ph	3.3	520	630	191
INGETEAM Sun 1 play 1Ph	6	976	1181	197
SolaX AIR 2.5kVA 1Ph	2.5	407	492	197
SolaX X1 Boost 3.3 kW 1Ph	3.3	542	656	199
SMA STP8000TL 3Ph	8	1321	1598	200
SolaX X3 MIC-7.0-T 3Ph	7	1181	1429	204
INGETEAM Sun 1 play 1Ph	5	878	1062	212
SolaX X1 Boost 3 kW 1Ph	3	530	641	214
SolaX X3 MIC-6.0-T 3Ph	6	1151	1393	232
SolaX X3 MIC-5.0-T 3Ph	5	1018	1232	246
INGETEAM Sun 1 play 1Ph	3.68	764	925	251

years instead of 6.8 to 9.4. When the PV system is shared (Case 4), the best scenario is obtained, and the IRR obtained is 23.3%.

3.3.1. Sensitivity analysis

The estimated LCOE for every analyzed scenario has considered the last year's cost of the PV panels and support structure. Nevertheless, because the cost of the panel and the support structure are constantly changing (the trend in the PV system cost before the pandemic was downward while post-pandemic it is being upward), the degree of uncertainty is significant. In a post-pandemic scenario, it is even more unpredictable. In this subsection, a sensitivity analysis of LCOE is carried out as a function of different possible capital costs (PV panels + support structure cost). The cost of capital has been modified from 0.7 to 1.3 (the capital cost multiplier is equal to 1 if the last year's cost is used for the analysis). In all cases analyzed, the LCOE is smaller when PV panels are installed compared to the LCOE when the electricity supplier provides all the required energy.

Additionally, in all cases, energy is cheaper when the NM scenario is applied, but the LCOE largely depends on the percentage of energy produced from the PV system. For example, in scenario 4, the LCOE is the highest because 70% of the energy required comes from the grid; while in cases 1, 2, and 3, the imported energy from the grid is 14, 27, and 18%, respectively. Another point to note in cases 2 and 4 is that NB_NL scenarios have the same LCOE. The reason is that in cases 2 and 4, the energy exported to the grid (48 and 11% of the energy demanded plus exported energy) is not enough to reach the limit where the energy is not paid for. The opposite situation occurs in cases 1 and 3 (78 and 40% of the energy demanded plus exported energy).

4. Discussion

One of the first findings of the analysis of the real cases and the regulation scenarios is that the net billing (NB) scenario, which is the current regulation in Spain (RD244/2019), significantly improves the option of installing large systems, compared to the no sale (NS) scenario of the previous regulation. Profitability increases when the energy produced by the PV system is self-consumed as much as possible (cases 2 and 4). In the cases analyzed under the NB scenario, the LCOE increases from 17 to 19.7 c€/kWh, one of the main limitations to reducing the LCOE being the impossibility of selling energy when revenues are greater than purchases.

If such limitation is eliminated (scenario NB_NL), the payback would be reduced when the revenues are greater than purchases, such as cases 1 and 3, where the LCOE is reduced from 17.5 to 15.2 c€/kWh and from 18.5 to 17.3 c€/kWh respectively. Then, a further improvement would be to force the cost of the kWh bought to be the same as the cost of kWh sold. This situation is represented by scenario NM where the LCOE would be reduced to 10.9 c€/kWh in the best case (Case 3) and 18.5 c€/kWh in the worst one (Case 4). However, in case 4, there is still one unsolved limitation: the power plant's size, the PV plant covers only 29.7% of the electricity demand. Therefore, NM or a conveniently priced NB has been discussed worldwide. Furthermore, several studies discuss its profitability and recommend its promotion (Ramírez et al., 2017). However, only 34% of world countries currently resent net billing/net metering policies (Rehman et al., 2020). In Europe, only 15 out of the 28 EU-27 European countries (55%) have these policies (REN21, 2020).

Applying the NS scenario for the illustrative cases analyzed makes most PV installations unprofitable. In the NS scenario, as electricity sale is not allowed, only systems without surplus energy may be viable, forcing the choice of a small power plant which increases the LCOE above the cost compared to the grid. Besides, a large fraction of the potentially PV production is wasted.

Since in urban areas, the influence of the shadows is not negligible compared to in ground-mounted installation, another point to consider is the losses due to shadows, which are close to 4% in cases 1 and 2, 13% in case 3, and 1.6% in case four. Moreover, the surface reduction is close to 56% in cases 1 and 2, 73% in case 3, and 81% in case 4. Although optimal peak power is higher in case 3 than 1, both cases have similar consumption and LCOE because the shadows are also higher in case 3, compensating in this manner the smaller peak power. In case 4, the best location to install the PV panels has been chosen, reducing the shadows due to losses, at the expense of a drastic reduction of the available area. The irregularity of the obstacles and the heights of the buildings is an inconvenience since it causes a relevant number of shady areas during a significant part of the day.

Finally, other factors affect the profitability of the PV systems like subsidies to the investment (or alternatively, discounts on urban taxes), the possibility of decreasing the contracted power if peak consumption aligns with PV production, the continuous decrease of equipment price etc. Based on the results of the simulations, they can be incorporated into the policy recommendations.

5. Conclusions

Most authors propose photovoltaic power systems as cost-effective options for power generation in the built environment where high annual solar radiation is received. The main reason is that the costs of the PV systems have drastically reduced over the last years, while the energy prices have increased. However, the full potential of the PV systems is still far from being deployable under market conditions. The main limitations come from the current regulation.

Different regulatory scenarios have been simulated to determine their influence on the PV system profitability. For that, four illustrative cases have been simulated with real data as inputs. Unlike most previous research based on statistics and general data, and idealized conditions and equipment, this research uses real hourly electricity consumption data for three out of the four cases, real equipment performance and costs, real installation costs, real costs of electricity purchased from the grid (variable and fixed prices, taxes), real rooftops with their not-idealistic slopes and orientations and real calculation of shading losses. The methodology hereby provided is replicable to any other region, allowing discussing the benefits or drawbacks of regulations in other regions.

The results show that all four cases are technically sound, but most of them are not profitable or not economically attractive under current regulation. Indeed, the comparison of the previous regulation with the current one, together with the proposed scenarios, show how a policy reform would further improve the viability of these urban renewable energy systems. Hence, taking as a starting point the present regulation, i.e. RD244/2019 in scenario NB, to boost the deployment of PV generation potential in the urban environment, under market conditions (either off-grid or combined), the policy reforms are:

- Promote Net Metering: Net Metering was the best option for prosumers, citizens, and PV systems' potential deployment in the four cases studied. Economic feasibility was strongly improved. IRR would be incremented to values in the range 9 to 20%, so, on average, about 71% higher than the present scenario (NB), and obtaining a lower LCOE (from 23 to 38% lower than in NB). This implies a greater effort for electricity trading companies and may not be directly possible from a market perspective. However, they could be subsidized by the public administration in certain cases, following the lessons learned form previous experiences like feed-in tariffs: start-up energy communities, innovative energy demonstrators, rural areas, subsidies limited in time, etc.
- Eliminate limitations on Net Billing: this means that all energy sent to the grid is paid to the user, even if the value of the revenues results greater than the purchases. Net Billing without limitation (simulated as scenario NB_NL) provides much higher IRR values, (in the range of 20 to 43%) and lower LCOE (around 7–17% cheaper) in those cases in which high availability of roof area per consumer (single apartment or houses, case 1 and 3) allowed for larger installations, and thus higher excess photovoltaic generation. This measure would have no impact on public buildings and houses, where almost all the produced energy can be self-consumed.
- Eliminate, or at least increase, the limit of PV power installation (in Spain it is 100 kW_p) that can be implemented in the present NB scenario, for example, for large buildings or clusters of buildings in shared self-consumption. These large plants would contribute to the balance and performance of the grid. In fact, the available surface could be optimally used if there were no shading. Case 4, with its 975 m^2 available, could have installed up to 135 kW_p, increasing by one-third its profitability and renewable electricity generation. Such limitations are another common constraint to PV development in the in-built environment in other countries.
- Reduction of the contracted power to the hourly real needs in both cases: individual prosumer or energy community with self-consumption (variable contracted power). Between 25% (case 2) and 40% (case 1) of the electricity costs are due to the contracted power and constitute a fixed cost, regardless of the real hourly demand, energy savings or self-consumption. Furthermore, this contracted power is used to determine the available capacity of the distribution line. Therefore, changing the fixed contracted power to an hourly one could reduce costs on the one hand, and allow the distribution line to be more available to supply or accept more electricity at specific times
- Finally, investment subsidies, tax reductions, and soft loans would improve PV systems' profitability proportionally. In addition, public power purchase agreements in cities and calls for tenders would stimulate the PV business model, with projects in which LCOE can be reduced to acceptable values and investment loans are more readily available.

In Spain, although regulation has improved the feasibility of PV installations with RD-L 15/2018 and RD 244/2019, and the effects on installed PV power for self-consumption are studied, this research with four real cases shows that a relevant fraction of PV potential in the built environment will be lost and/or potential implementation may be slower if further improvements in regulation are not performed.

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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Appendix

See Tables 12-13.

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