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Techno-economic Evaluation of Micro Energy Market and Strategies for Decentralised Control

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The worst thing we can do
is to do nothing

– Brad Henry

Contents

Abstract

The increasing penetration of renewable energy sources (RESs) in the low voltage distribution grid and the electrification of transport and heating/cooling sectors bring opportunities for a sustainable energy landscape. Concurrently, variable RESs and uncontrolled electricity demand affect the reliability of the electricity system. An alternative to the business as usual (BAU) approach of reinforcing the grid infrastructures consists in promoting the deployment of distributed energy resources (DERs) like stationary storages and demand side response (DSR). In this dissertation a comparison of different scenarios for the deployment and control of distributed stationary storage is presented. Centralized and decentralized control are performed with real time, and optimized based on generation and demand forecast for a United Kingdom context. A micro energy market (MEM) to allow peer-to-peer (P2P) energy trade within a distribution grid with high PV and battery energy storage system (BESS) penetration will be implemented. In addition, a micro balancing market (MBM) to balance the system and to face the unforeseen events is proposed. Finally, a techno-economic evaluation from both prosumers and distribution system operator (DSO) side is carried out to advice grid operators and policy makers towards the implementation of a smart, clean, efficient, reliable and affordable electricity system. Before doing this, a market research on current costs and future projection of small-scale PV plants and stationary battery energy storage systems (BESSs) in UK is presented, to evaluate the economic attractiveness from an user point of view about the DERs available in the market in absence of incentives designed to promote the uptake of small-scale renewable and low-carbon electricity generation technologies (feed-in-tariff), that are ending soon in many countries, including UK.

Sommario

La crescente penetrazione di fonti di energia rinnovabile (RES) nella rete di distribuzione di bassa tensione e l'elettrificazione dei settori di trasporto e riscaldamento/raffrescamento aprono a nuove opportunità per un panorama energetico sostenibile. Contemporaneamente, le fonti di energia rinnovabile e la curva di domanda non controllata influenzano negativamente l'affidabilità del sistema elettrico. Un'alternativa all'approccio del business as usual (BAU) di rafforzare le infrastrutture di rete consiste nel promuovere la diffusione di risorse di energia distribuita (DER) come dispositivi stazionari di stoccaggio dell'energia e la gestione della domanda (demand side response: DSR). In questa tesi viene presentato un confronto tra diversi scenari inerenti la diffusione e controllo di dispositivi stazionari e distribuiti di stoccaggio dell'energia elettrica. Controlli sia centralizzati che decentralizzati delle batterie vengono eseguiti in tempo reale e ottimizzati in base alla previsione della generazione e domanda di energia, in un contesto ambientato nel Regno Unito. Un micro mercato dell'energia (MEM) viene implementato per consentire il commercio di energia peer-to-peer (P2P) all'interno di una rete di distribuzione di bassa tensione con alta penetrazione di sistemi fotovoltaici e sistemi di accumulo di energia a batteria (BESS). Inoltre viene proposto un micro mercato del bilanciamento (MBM) decentralizzato con lo scopo di bilanciare il sistema e fronteggiare gli eventi non prevedibili. Infine viene effettuata una valutazione tecnico-economica dal punto di vista dei prosumer e degli operatori del sistema di distribuzione (DSO) al fine di fornire suggerimenti agli operatori di rete e ai policy maker riguardo all'implementazione di un sistema elettrico intelligente, pulito, efficiente, affidabile ed economicamente competitivo. Prima di fare ciò viene presentata una ricerca di mercato sugli attuali costi e future proiezioni di prezzo di impianti fotovoltaici su piccola scala e sistemi di accumulo di energia a batteria nel Regno Unito. Il fine è quello di valutare l'attrazione economica, dal punto di vista di un utente, delle risorse di energia distribuita disponibili sul mercato in assenza di incentivi istituiti per promuovere l'adozione di tecnologie di generazione di energia elettrica a basse emissioni su piccola scala (es. feed-in-tariff), ormai arrivate al loro termine in molti paesi, incluso il Regno Unito.

Chapter 1

Introduction and Literature review

During the last decade the entire electricity sector has been experiencing rapid and continuous changes. The energy systems are becoming much less passive, more diffuse and more dynamic as energy generation, transmission and management becomes increasingly complex. This has been driven mainly by the deployment and transition towards distributed, low carbon energy technologies. The widespread deployment of renewable energy sources (RES) recently started creating a series of new technical challenges.[1]
For example the RESs (solar PV and wind generator) do not contribute to the "system inertia", essential to keep the system frequency stability and resilience to sudden changes arising from loss of generation or transmission faults. Furthermore, they make more challenging to balance the system, in fact RESs are more precisely classified as variable RES (VRES), and given their nature, a strong mismatch between peak generation and peak demand is present. This has caused in the last 2 years the daytime minimum demand fall over the overnight demand in UK. [2] The high deployment of RES in the low-voltage (LV) distribution grid creates a revolution of the original paradigm of it. Distribution grids were traditionally designed as 'passive' networks, and the power flows were unidirectional. As a consequence of the increasing penetration level of distributed energy resources (DERs), the era of energy simply traveling from power plants to residential plugs has come to the end in recent times. Distribution grids are now 'active' systems. That imply bi-directional power flows between distribution and transmission systems, since distribution grids export power at times when local generation exceeds consumption. [3]
This evolution brings higher complexity in the management of the distribution system: in fact it could lead to a rise of the voltage profile beyond its allowed limit, and create congestions that reduces the reliability and may create problems to maintain the quality of supply to all customers connected to the distribution network, that was not designed to accommodate a large amount of DERs.[4]
The increasing deployment of RESs was mainly due to policy makers and regulators decision to apply financial incentives and remuneration schemes on the generation and injection of energy generated by RES, in turn stimulated by environmental targets.
Other emerging challenges are due to the electrification of air conditioning and transport sectors. The electricity demand is hence expected to grow up consid-

erably in the next decade. The first one with the deployment of heat pump, the second one with the deployment of electric vehicle (EV). Both are key points of the decarbonization in UK. Such these regulations are part of the framework dictated by the climate Change Act 2008 and Paris Agreement of 2015.[5] Through these acts, the UK government has committed to:

- reduce emissions by at least 80% of 1990 levels by 2050
- contribute to global emission reductions, to limit global warming to well below 2°C above pre-industrial levels.

To meet these targets, the government has set five-yearly carbon budgets which currently run until 2032. The UK is currently in the third carbon budget period (2018 to 2022). While it is going to meet its next carbon budget, it is not on track to meet the following. This will require the government to apply more challenging measures. The new variables introduced in the system are presenting new challenges that require a more flexible network from the point of view of infrastructures and management to integrate the emerging solutions [1, 6]. A digitalization of the system is in place but this is not enough. A rethinking of the whole integrated electrical system is needed. Therefore, important investment decisions have to be taken. In the previous years policy makers have been discussed a lot about the need of re-conceptualize the existing power grid on behalf of one that supports an efficient transition towards a distributed and smart system, and enable new low carbon technology to be deployed, as underlined in [1] and [7]. To achieve these targets, and ensure energy security and quality supply, the develop of a smart grid is considered to be a promising option. A smart grid according to the Office of Gas and Electricity Markets (Ofgem) is a "modernised electricity grid that uses Information and communication technology (ICT) to monitor and actively control the electricity generation and demand in near real time".[1] Interest in and commitment to developing smart grids has been growing internationally over the last decade. With the introduction of distributed generation (DG), renewable sources, energy storage, and microgrids, the classic Distribution Network Operator (DNO) model is changing into Distribution System (DSO), since it will be required to take on system operator functions, such as active and real time network management [8]. Indeed, they are called to an upgrade on the way of thinking to a new one that accounts for and manages multiple points of variable supply and consumption. The main idea is that, when many DERs are distributed in a wide network, it can be very complex and difficult to control. Thus, a potential way to manage this complexity is by breaking the entire grid down into smaller microgrids, containing only a limited amount of DERs. [4]. Many projects and studies have been carried out to help the government and the grid operators in these decisions. UK can claim to be one of the 'European' leaders in terms of level of investment in smart grid research and demonstration projects, together with Germany and France, as reported in [9]. Since all the parts of the electricity system and many stakeholders are influenced by the deployments of DERs, the same problem can be scanned from many points of view: power stations, electricity market system operator, TSO, DSO, customers etc., and all these parts will need to coordinately develop all together. Clearly all the challenges presented above require investments to be made on the distribution grid. This is necessary to avoid overloading of the lines, curtailments of supply or demand, larger voltage fluctuations, besides higher losses on the entire grid. Consider to curtail generation is to avoid since in contrast with environmental issues. There are two main strategies to invest in the network:

- Following the Business as usual (BAU) “Fit-and-forget” approach: respond to the increasing photovoltaic (PV) penetration by increasing the capacity of the wires, installing additional voltage regulators, and investing in other network equipment, with consequent increases in the total network cost.

- Adopt innovative ways that facilitate an efficient transition towards a distributed and smart system and that put in place an active network management to facilitate the deployment and utilization of DERs in a smart grid concept. This could reduce network cost and obtain the most value from DERs. Moreover DERs can enable networks to use existing physical infrastructure more efficiently, reducing or deferring reinforcement needs and so investments for DSO and grid operators in general.

In [10] it has been proved that this second approach could lead to lower costs compared to the conventional fit-and-forget BAU paradigm. Therefore starting from:

- the challenges discussed above and the need to invest on the grid

- the penetration of solar PV installations will increase at residential level

- the end of financial incentives in some countries (UK included) both for generation and export tariff

- BESSs are falling in cost

- DERs and the decentralization of the system control are a promising chance of reducing costs for everyone and make the system more efficient

In this dissertation, the impact of deployment of stationary storage coupled with solar PV system for different battery smart control strategies (BSCS) and from both the DSO’s and users/prosumers’ perspectives is evaluated. The aim is to advice the DSO on the necessary investments for the reinforcement and modernization of the grid. Three cases are presented: a base case, a centralised case and a decentralised case. Seven different scenarios have been created, characterized by different battery smart control strategies (BSCS) and market structure/architecture. A total of three different BSCS, based on the forecast generation and demand profiles with a rolling window approach, are presented. In the decentralised case, energy is traded in a micro energy market (MEM) to allow a peer-to-peer (P2P) energy trading at a price lower than the spot market, whose tariff is assumed to be a real time price (RTP) tariff. Further, a micro balancing market (MBM), whose purpose is to balance the system and to face unforeseen events (contingencies and congestions), is introduced and resulting benefits are evaluated. The proposed methodology is applied to a branch of a typical UK

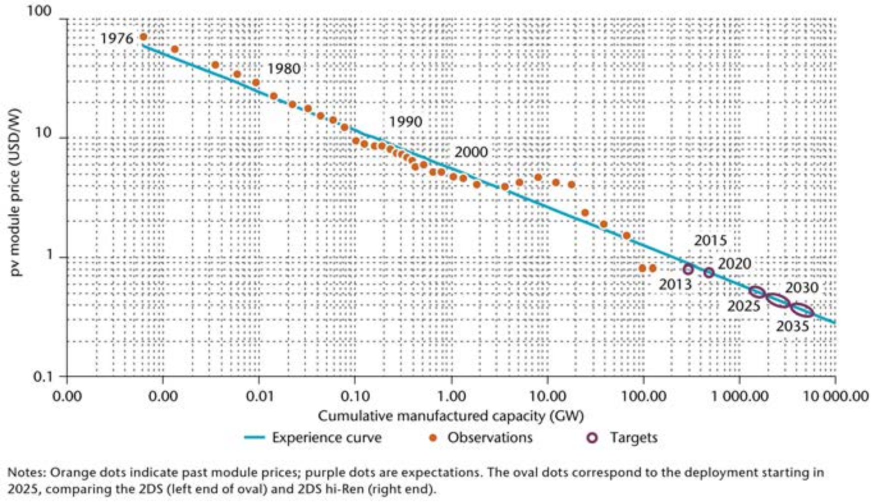


Figure 1.1: Past module prices and projection to 2035 based on learning curve

distribution network model during a period in June and December 2017. A techno-economic evaluation is then performed in order to critically analyse the performance of the proposed control strategies. Before that, a market study on the current costs and future projection of PV plants and BESSs at residential level will be done.

The remainder of this dissertation is organized as follow: In the rest of this chapter a literature review on the main topics of this project will be presented. First of all, a literature review on the PV systems and BESSs current and future cost will be presented in section 1.1 and section 1.2. In section 1.3 an introduction on the most common tool and strategies to perform a forecast of PV generation and household load profile will be presented. Finally a literature review on the decentralized market and BSCS will be done in section 1.4. In the next chapter (chapter 2) a detailed explanation of the methodology used for this study is presented. In chapter 3 all the case studies simulated are introduced and then results are presented and discussed in chapter 4. Finally, the dissertation ends with chapter 5 where conclusions are summarized.
For the comprehension of the acronyms, parameters and variables present in the text, please refer to the Appendix.

1.1 Solar PV system: recent developments and future projection

1.1.1 Solar PV modules

The PV module price has seen a considerable reduction along the years. The PV module price is assumed to follow the learning curve[1] that has been observed for many years. The learning curve observed for the PV modules is between 18% and

[1]The learning curve expresses the module price decrease varying the market size.

25%. In particular, in [11] a long-term learning rate[2] ranging between 19% and 23% has been observed; in [12], researches suggest a learning rate of about 20% - 25% instead. Figure 1.1, reported in [13], confirms these values and expects the module costs to fall at 0.3 $/Wp to 0.4 $/Wp by 2035.

The last annual report for 2018 by Fraunhofer [14] reports that in the last 37 years each time the cumulative production doubled, the price went down by 24%. This fast reduction of the PV module price has driven down the cost of PV system globally, as confirmed by International Renewable Energy Agency (IRENA) in [15], with declines in balance of system (BoS) costs being a smaller contributor to the overall cost decline. In the same report it has been observed that the global weighted average cost of utility-scale solar PV projects declined by around 56% between 2010 and 2015.

1.1.2 Total installed cost of residential solar PV system

The total installed cost reduction for residential PV systems has been following a similar path, although some cost differentials remain within and between countries: in some cases, these costs differential are represented by structural factors (as labor cost, infrastructure or administrative cost), in other cases they are not easily explained [16]. Indeed, the reason for the huge variation in the reported costs for solar PV system within individual markets is not well understood [17]. The average total installed cost for residential PV systems in the markets declined sharply in a wide range of countries from 2010. Indeed, it decreased from a range of between 4.3 $/Wp and 8.6 $/Wp in Q2 2010, to a range of 1.5 $/Wp to 4.7 $/Wp in Q2 2016, i.e. between 46% and 74% [16]. Note the wide difference between the different market in Figure 1.2. Anyway, we can see that the costs differences among the markets have declined in the last years and are expected to continue to decline. Last IRENA publication [18] reports a decline in the residential PV system costs of 47%-78% for the markets with the longest historical data (Germany, Japan, US).

As an example, the history of a very advanced market like Germany can be observed, as shown in Figure 1.3 [16]. Data collected from a data-set of offers presented by installers to end-customer show that the median installed residential cost in Germany decreased from 4.50 $/Wp in 2010 to 1.79 $/Wp in 2016 (a 60% decrease). In pounds, the cost is more or less from 3.33 £/Wp to 1.33 £/Wp.

The total installed cost (capital cost) of a PV system is composed by the PV module cost and the BoS cost. [7] The cost of the PV module includes the raw material costs, the cell processing costs and module assembly costs. The BoS includes the cost of the structural system, the electrical system costs and the soft costs. A detailed breakdown of solar PV cost components is presented in Figure 1.4. As previously said, the PV module price has driven the lowering of the capital cost until now. However, with PV module prices at all-time lows, the importance of the BoS cost increased, particularly the soft costs. Therefore, BoS costs and financing costs will be mainly responsible for future reduction of the

[2] The learning rate expresses the price decrease with each doubling of the cumulated module production.

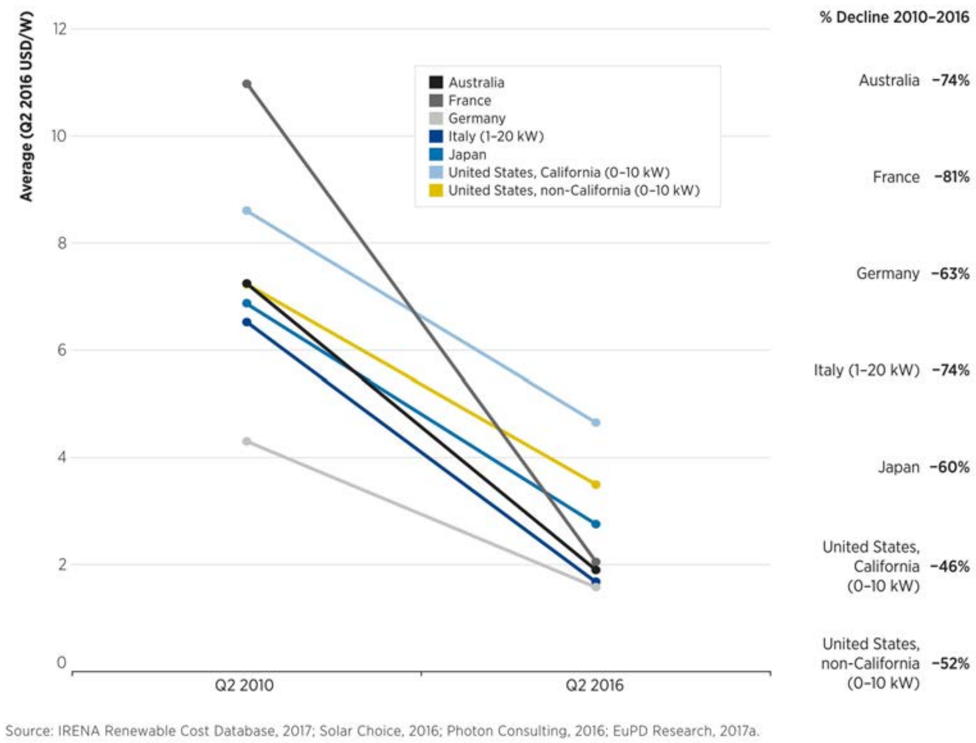


Figure 1.2: Average total installed cost of residential solar PV systems by country, Q2 2010 and Q2 2016.

total system cost. Total installed costs for solar PV systems have fallen rapidly since 2008 as deployment has experienced exponential growth, driving down not only module costs, but BoS costs as well. The Figure 1.5 shows the average total installed cost of residential solar PV system by country, from 2006 to 2014. The relevant part here is represented by the UK: as we can see the large-scale deployment of PV system in this country began quite late with respect to the other countries, but in 2014 costs were at quite competitive levels of between 2800 \$/kW to 3100 \$/kW. Figure 1.6 highlights the competitive level of UK price with respect to other countries in 2014.

Applying the 2014 average exchange rate USD/£ [19] as indicated by IRENA, we can find values in accordance with the ones collected during the years by the UK government. In [17] a projection for a cost reduction is proposed. In here, it is stated that if BoS costs can be pushed down to very competitive levels, average installed costs could range from 1600 \$/kW to 2000 \$/kW by 2025. In accordance with the IEA hi-Ren scenario [13] the average cost will be halved by 2040 or before. From Figure 1.7 a decrease of ∼33% from 2015 to 2025 and a decrease of ∼70% from 2015 to 2050 was extracted. Moreover, the wide span presents for the different market will narrow significantly, and the system costs are likely to converge towards the lowest value, except in places where the soft costs are higher.

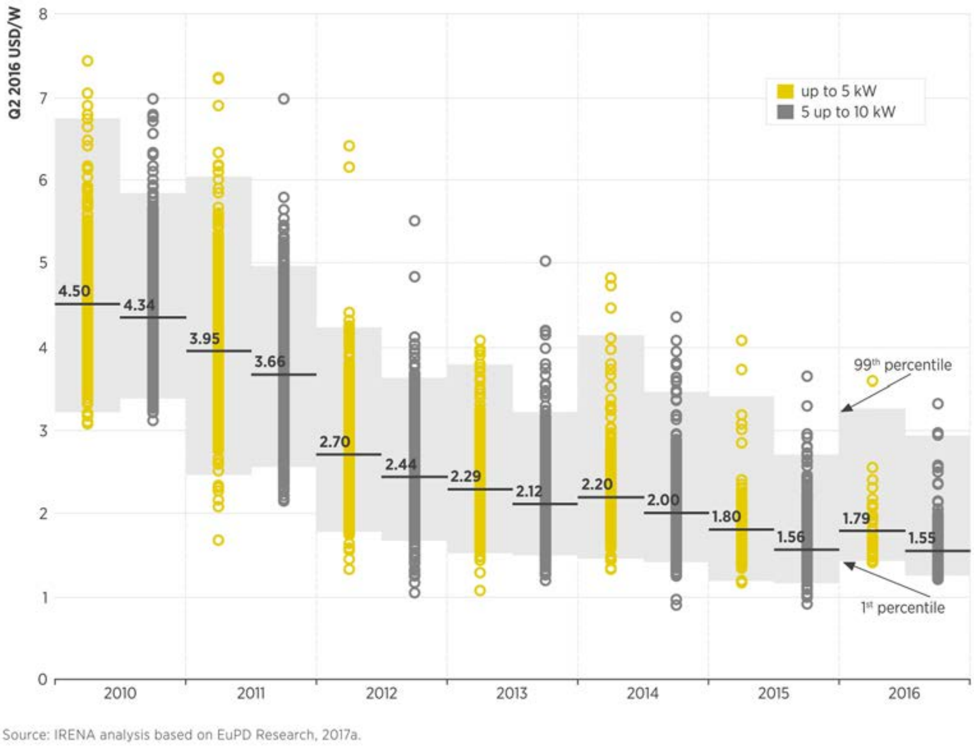


Figure 1.3: Residential PV system costs in Germany by size category

1.1.3 LCOE: levelised cost of electricity

The decline in total installed costs has been driving the decline in the levelised cost of electricity (LCOE)[3] of solar PV between 2010 and 2014. The LCOE of residential solar PV has declined to between 0.14 $/kWp and 0.46 $/kWp in 2014 in eight major residential markets IRENA has data for; it means that the average LCOE in these markets declined by between 42% and 64% in only 4 years. Figure 1.8 shows that. This trend won't stop in the next years, indeed IRENA forecasted that by 2025 the global weighted average LCOE of solar PV could fall by as much as 59% with respect to the 2015 value.[15] With equipment costs reaching low levels; future cost reductions could be driven by reducing BoS costs, and lower operation and maintenance and finance costs.[17]

Photovoltaic is expected to become one of the cheapest forms of electricity generation during the next decades.[12] The LCOE has already reached parity with retail electricity prices in many European market segments (residential, commercial or industrial) all over Europe. Moreover, in contrast to conventional energy sources, renewable energies are still the only ones to offer the prospect of a reduction rather than an increase in prices in the future.[20] "Grid parity (or socket parity) occurs when an alternative energy source can generate power at a levelised cost of electricity that is less than or equal to the price of purchasing power from the electricity grid". However, this doesn't mean that the PV plant is

[3]LCOE: It is defined as the average generation cost, i.e. including all the cost involved in supplying PV at the point of connection to the grid: manufacturing, installation, project development, operation and management, inverter replacement, dismantling, etc. Residual value of the PV system after dismantling is not considered

PV Module

Semiconductor
- Raw materials (Si feedstock, saw slurry, saw wire)
- Utilities, maintainence, labour
- Equipment, tooling, building, cost of capital
- Manufacturer's margin

Cell
- Raw materials (eg. metallization, SiNX, dopants, chemicals)
- Utilities, maintainence, labour
- Equipment, tooling, building, cost of capital
- Manufacturer's margin

Module
- Raw materials (eg. glass, EVA, metal frame, j-box)
- Utilities, maintainence, labour
- Equipment, tooling, building, cost of capital
- Shipping
- Manufacturer's margin
- Retail margin

Inverter
- Magnetics
- Manufacture
- Board and electronics (capacitors)
- Enclosure
- Power electronics

BOS/Installation
- Mounting and racking hardware
- Wiring
- Other
- Permits
- System design, management, marketing
- Installer overhead and other
- Installation labour

Figure 1.4: Detailed breakdown of solar PV cost component

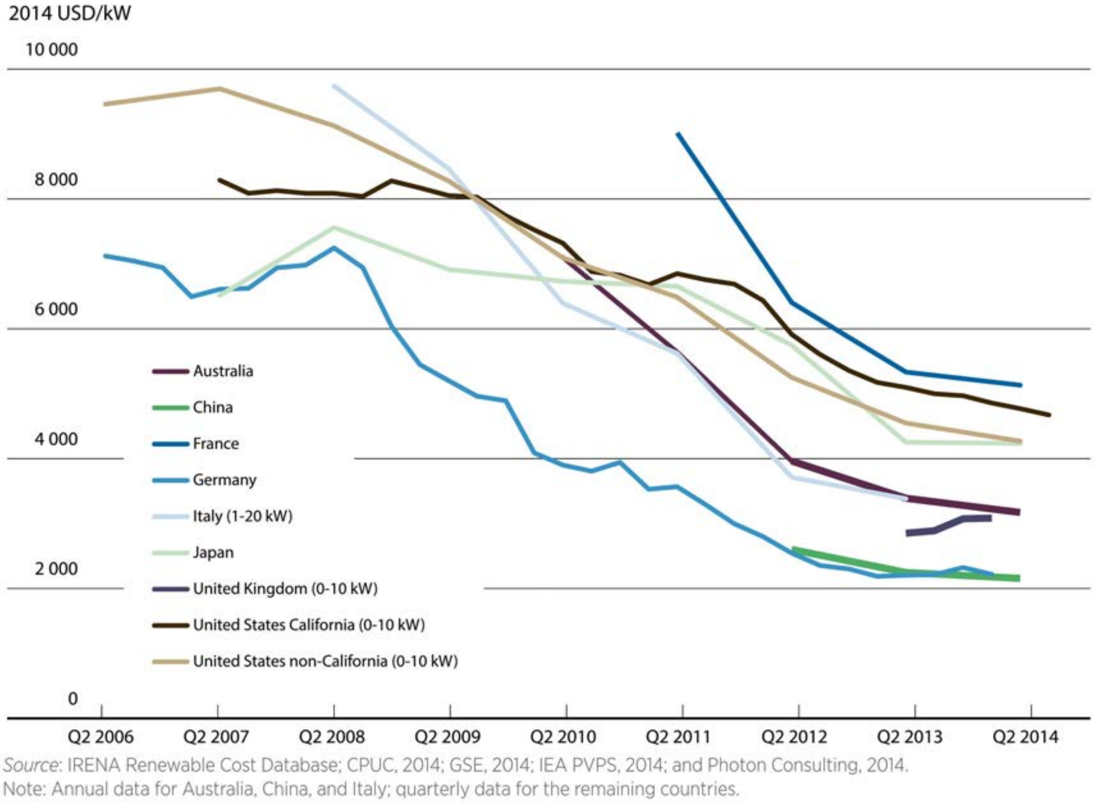


Figure 1.5: Average total installed cost of residential PV system by country, 2006 to 2014 [17]

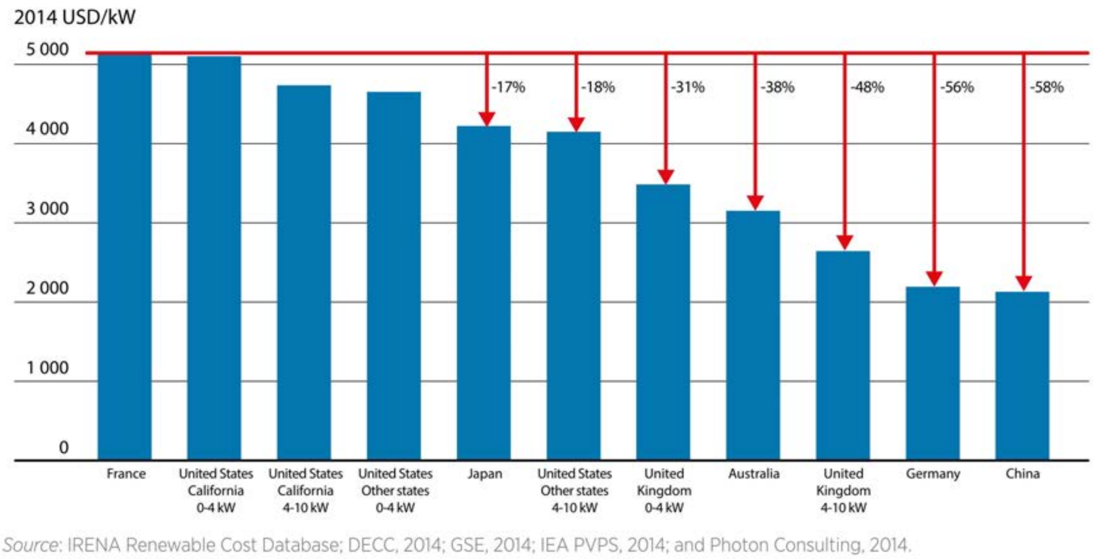


Figure 1.6: Estimated average total installed PV system costs in the residential sector by country,2014 [17]

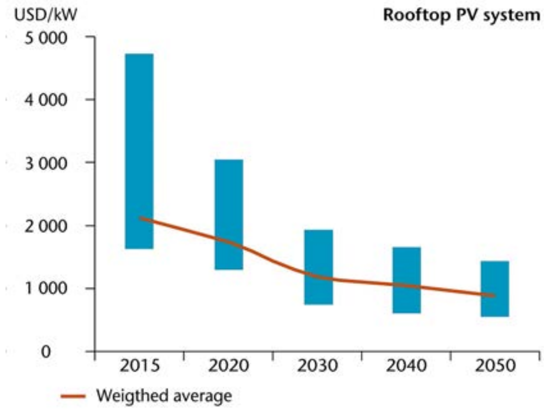


Figure 1.7: PV investment cost projection in the hi-Ren scenario [13]

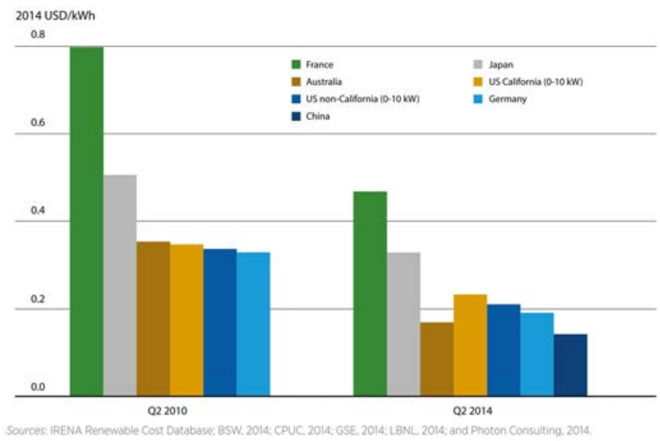


Figure 1.8: Levelised cost of electricity of residential solar photovoltaic systems by country, 2010 to 2014 [17]

cost-effective. With the progressive conclusion of subsidies and support schemes, the ratio of self-consumption (SC) is at the core of the prosumers' competitiveness . The competitiveness occurs when the PV LCOE value is lower than the real value of energy (RVE), that depends on the SC. The RVE (also PV electricity value) counts that the energy surplus injected into the grid is valued at a price lower than the retail price, without support scheme. Usually, this energy is priced at the wholesale electricity price reduced by an administrative fee. The following equations shows how the LCOE is computed.

$$LCOE = \frac{Total\ life\ cycle\ cost}{Total\ lifetime\ energy\ production}$$

$$LCOE = \frac{CAPEX + \sum_t \left[\frac{OPEX(t)}{\left(1+WACC_{\text{real}}\right)^n}\right]}{\sum_t \left[\frac{Yield(0)(1-Degr\cdot t)}{\left(1+WACC_{\text{real}}\right)^n}\right]} \tag{1.1}$$

$$WACC_{\text{real}} = \frac{(1+WACC_{\text{nom}})}{(1+Infl)} - 1 \tag{1.2}$$

$$CAPEX = \ Modules\ +\ BoS \tag{1.3}$$

Where:

- t : year, from 1 to the economic lifetime of the system
- CAPEX : total investment expenditure of the system, made at t = 0 in £/kWp
- OPEX(t) : operation and maintenance expenditure at year t in £/kWp
- Yield(0) : initial annual yield at year 0 in kWh/kWp
- Degr : annual degradation of the nominal power of the system
- WACC_{nom} : nominal weighted average cost of capital per annum
- $\text{WACC}_{\text{real}}$: real weighted average cost of capital per annum
- Infl : annual inflation rate

While we have already discussed about the CAPEX, let's explain the other elements. The OPEX(t) for residential application is mostly null. However it usually counts for 1-2% of CAPEX. A common value is 20€/(kWp*year).[12] This value is also expected to halve by 2050.
The annual yield of a PV system depends on the local irradiation and performance ratio (PR).
The degradation is what affects the yield along the years. Most PV module manufacturers guaranties at least 80% of nominal powers after 25 years. This would mean a maximum average degradation of 0.9% per year. In reality, most systems degrade less in Europe: an average degradation of 0.2% per year has been

reported for German rooftop systems[21]. A very conservative value of 0.5% per year is typically used.
Obviously, the degradation rate affects the system lifetime. An economic system lifetime of 30 years was recommended by IEA PVPS Task 12 and 13 for life cycle assessment studies.[22, 23]
WACC is here used as a discount rate to actualize the future cash flows. The real WACC, with respect to the nominal value, is affected by the inflation rate.

A study conducted to investigate the true competitiveness of solar PV in Europe concluded that some countries already reached the true grid parity, others will reach the true grid parity in the next few years (analysis is presented for a SC=50%). This depends on the nominal WACC taken into account, on the retail and wholesale price of electricity, on CAPEX and OPEX and others more. Some parameters affect the results more than the others, as shown in [12]. Figure 1.9 summarizes the results of the analysis.

Based on the literature review, some conclusions can be done. For the financial attractiveness of the PV systems without considering support schemes, the PV self-consumption is a key parameter to be increased. However, for residential PV prosumers, the mismatch between the PV generation and the load profiles is rather inconvenient since social activities are often at other places during daytime, and for the times of high electricity demand in the buildings, which is typically in the evening hours, the PV generation is typically low or zero. In fact, for typical households and PV system designs the average direct self-consumption rate is about 25-35%.[24, 25] Therefore, a way to increase the SC should be found. Increasing the SC by reducing the size of PV installation is not desirable as it reduces the share of renewable energy content in the energy mix of the household. Moreover, an increasingly PV penetration represents a non-dispatchable power that, if not properly faced, results in higher systemic costs in terms of electricity network reinforcement, short-term supply-demand balancing and reserve capacity.[26] Two main methods exist to increase the SC of solar electricity and make the PV system more profitable[20, 25]:

- Load shifting, controllable loads
- Application of a battery storage system

Both the ways aim at increasing the competitiveness of the PV system and the flexibility of the entire system. Even if the first method is related to only a few loads, it is a useful way to improve load profile by reducing the peak load and peak valley difference [27] reducing the stress on the power system. We'll talk about flexibility in the next subsection. Then, load management can help in reducing the annual electricity demand that PV cannot supply, and it can reduce the minimum load level, during the daytime, of the conventional power plants, in particular if they require a long starting time, avoiding high specific CO_2 emissions.[28]
The second way involves the use of a battery storage. An entire chapter will be dedicated to it.

Flexibility: the cornerstone of tomorrow's power systems

The rapid growth of renewable energy in recent years has been remarkable. In order to meet climate goals a lot of investments in this field have been made and thanks to that, RESs costs decreased massively. This price reduction along with a strong government policy support contributed to a large deployment of renewable energy source, solar PV in particular. [29] The renewable power sources also come with a new set of challenges not faced before, like the variability of the power generation that creates some uncertainties for the security and continuity of electricity supply in the modern power system. Therefore, as variable renewable energy (VRE) penetration increases, power system flexibility needs to be improved. To achieve this, investments in many different fields can be made[30]:

- Power plants
- Grids
- Energy storage
- Demand-side response

Flexibility, as defined by IEA(2011), "expresses the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise". In other word it is the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across all relevant timescales. In particular, this concept become fundamental with the increasing penetration of VRE.[29] The need to improve flexibility can be illustrated by the foreseen evolution of the net load curve of spring days in California, called the "duck chart" showed in Figure 1.10. It reveals how PV has modified the curve during daytime but has kept almost unchanged the demand peak of the early evening.

1.2 BESS: the heart of the energy transition

The 2015 United Nations Climate Change Conference in Paris set the framework for a rapid global shift to a sustainable energy system in order to avoid the risk of catastrophic climate change.This is a task that demands urgent action. Greenhouse gas emissions must peak in the near future if the world is to steer clear of the costly and dangerous effect of climate change. Given the sharp, and often rapid, decline in the cost of renewable power generation technologies in recent years, the electricity sector has made concrete progress on decarbonisation. Renewable power deployment, however, needs to accelerate. All this has brought into sharp relief the significant potential, and the crucial importance, of electricity storage to facilitate deep decarbonisation. In today's power systems, solar and wind power still have limited impact on grid operation. As the share of VRE rises, however, electricity systems will need not only more flexibility services, but potentially a different mix that favors the rapid response capabilities of electricity storage.[31] Recently, battery storage technologies have seen rapid cost declines, and now start to become financially attractive.[12] They could increase the flexibility in the short-term timescale in the future power system. [29] In fact, they increasingly compete with gas-fired peaking plants to manage short fluctuations in supply and demand[30], and they are fundamental to shift PV surplus generation to other consumption times.[13] In general, energy storage technologies can capture energy during periods when demand or costs are low, or when the electricity supply exceeds the demand, and they can surrender stored energy when demand or energy costs are high. Doing this, they provide system benefits and flexibility to customers, system operator and utilities, also if applied at household level, reducing peak demand charges and increasing SC from rooftop PV panels.[32] An advantage of the battery storage system, as Braun ae al. underlined in the French-German Sol-ion project [33], is that it increases the PV SC without changing people's consumption habits. California and Germany were the firsts in providing subsidies for distributed storage, followed by other countries. The increasing interest is due to the fact that BESS can defer investment in other infrastructures of the grid and in the near future they can provide ancillary services for the safe operation of the grid. From now on, only BESS Li-ion technology will be considered.

1.2.1 Battery: Cell and pack level

From 2010 to 2016 the cost decline for Li-ion BESS systems was impressive. In 6 years the cost of an EV battery pack have fallen by 73% from 1000 to 273 $/kWh.[31, 34] According to[12] the learning rate of batteries is about 15-20%. Bloomberg new energy finance (BNEF) forecasts a learning rate of 19% and a continuous dropping up to 74 $/kWh in 2030.[34] At the cell level, Tesla announced to probably do better than 100 $/kWh at the end of 2018 and to achieve this result at pack level by 2020.[35, 36]

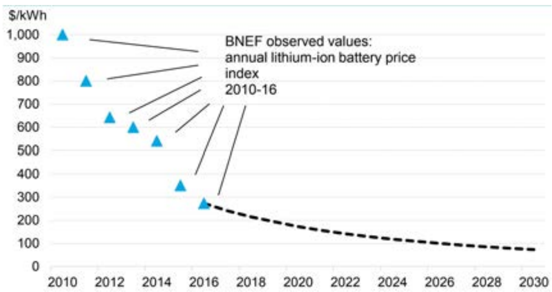


Figure 1.11: BNEF forecast Li-ion battery pack prices. Source: Bloomberg new energy finance[34]

1.2.2 Battery system

In the lasts years some policies to support deployment of energy storage were emitted. Germany has been supporting the deployment of small-scale battery energy storage system (BESS) since 2013. It offers a variety of incentive programs. California also emitted support policies. Then, others states and territories followed the Germany and California's lead. Italy, for example, provides a tax rebate for battery storage in solar PV system.[32] For the moment, the most emerging market segment includes the pairing of storage with residential or commercial rooftop solar PV to increase SC through leveling the load curve. In the last few years, thanks to financial support, about the 40% of small-scale solar PV systems in Germany have been installed coupled with battery system.[31] Something similar happened in Australia even without financial support. At present, where the right regulatory structure is in place (Germany) or in areas with high electricity prices and low feed-in remuneration, a significant fraction of new PV installation are coupled with a battery storage. It has to be underlined that in stationary applications not only Li-ion technology is present and different storage technologies will prosper, however this one is the most promising and is expected to dominate the market. For this reason, only Li-ion technology is discussed here. As already said in the previous section, the cost of Li-ion batteries for transport, have fallen down a lot in the last decade. However, Li-ion batteries in stationary application have higher installed cost due to more challenging charge-discharge cycles and battery management system. Figure 1.10 shows that between Q4 2014 and Q1 2017 the median system price offered to German customers has fallen by around 60%.[31] Since a lot of improvements are expected in the next few years, we expect this price to fall down with the same rapidity. According to [12], in 2016 the battery system cost in Germany ranged from 750 €/kWh to 2500 €/kWh, with offers from the top 3 battery system suppliers for less than 1000 €/kWh available in the market. Moreover, the cost of battery systems declines by about 18%, which will lead to an accelerated market in the coming years. To compete in this rapidly growing market, i.e. the power sector, several companies advanced new home storage options, like Daimler AG in Germany[32].

1.2.3 Li-ion BESS: future projection

Let's now present some studies taken into account. The different results will be then discussed in the following. All the values are reported in table 2.2.

Fuchs et al.[28] from ISEA (Institut fur Stromrichtertechnik und Elektrische Antriebe) in a study conducted on behalf of Smart Energy for Europe Platform GmbH (SEFEP), provided an overview of electricity storage technologies and their potential application, with regards to the transition to an electricity system with high share of renewable energies, motivated by the threat of global warming. At the end a description of important electricity storage technologies with their technical parameters and their deployment potential is presented. In particular, a total installation cost between 364 £/kWh and 811 £/kWh for 2012 and a projection between 150 £/kWh and 296 £/kWh for 2030 is reported.

Muller et al.[37] presented an analysis based on literature and their own studies of 212 commercially available residential Li-ion BESS. A price based on that for 2016 and then a projection for 2025 is presented. 2016 BESS prices for a complete system price range from 578 £/kWh to 1052 £/kWh and is projected to a range from 266 £/kWh to 484 £/kWh for 2025. A decrease of 54% in 10 years can be observed.

Naumann et al.[38] presented a scenario based on their own investigations on current prices of household BESS. As indicated an annually decrease of 4.96% is assumed and an installation cost accounting for 5% of the whole investment price is taken. Data are reported snd discussed in the next chapter.

Schmidt et al.[39] using market growth models, developed an experience curve and defined a timescale for the future cost of Lithium-ion residential BESS. They noticed also that the already marketable products (i.e. Tesla powerwall) have a commercial price lower than the one expected from the analysis, therefore the real situation is promising for better results and to achieve the forecasted future price sooner.

To have a comparison with a marketable product, Powerwall 2 of Testa is taken into account.[40] Its total installation cost in UK, as reported in the official site, range between 577 and 715 £/kWh.

In [34] BNEF reports a projection for the expansion of the energy storage system (ESS) market. In particular, BNEF expects a growth from 1GWh of installed capacity in 2017 to 81GWh in 2024. Then a further demand of 65GWh is expected in 2025, ending with a 200 GWh of behind-the-meter ESS in 2030.

An analysis on the learning rate of Li-ion BESS was made by IRENA in [31]. In particular a LR between 12% and 16% is reported.
Two market size projection are reported in "Renewable Energy Roadmaps" by IRENA: the REmap Reference scenario and the REmap Doubling scenario.[31] The battery electricity storage energy capacity growth in stationary small scale application for the period 2017-2030 is visible in Figure 1.13. The Reference scenario forecasts a market growth from an installed capacity of 1 GWh in 2017 to an installed capacity ranging between 56 and 94 GWh in 2030. The Doubling scenario forecasts instead a growth that ranges between 101 and 236 GWh in 2030. A graphical representation of the market growth is shown in Figure 1.14. From these data we can observe that the Bloomberg projection is more or less in the middle of Remap Doubling scenario.

Finally, KPMG, in a report for the Renewable Energy Association (REA), estimated the total cost of installation reduction profiles for Li-ion BESS in domestic sector.[41] The projections for high and low price and the annual declines are shown in Table 1.1.

1.2.4 Financial plan

We wonder now if the additional cost due to the storage system paired to the PV investment makes sense. Some studies concerning this topic have been analysed. [20] reports that the additional storage costs already make sense in market with high peak electricity costs in the evening, where a shift of only a few hours is required to the energy stored in the battery. Moreover, according to various reports and as showed in the previous section, the electricity battery storage market's growth, together with a further retail price increase and a PV system price reduction, could lower the levelised cost of electricity (LCOE) of a PV system, coupled with storage, below average European electricity retail prices and

Table 1.1: Total cost projection for domestic Li-ion BESS according to results reported in [41]

year	2015	2016	2017	2018	2019	2020	2021	2022
%/year		12%	12%	12%	12%	12%	8%	7%
cost high [£/kWh]	1410.00	1240.80	1091.90	960.88	845.57	744.10	684.57	636.65
cost low [£/kWh]	845.00	743.60	654.37	575.84	506.74	445.93	410.26	381.54
year	2023	2024	2025	2026	2027	2028	2029	2030
%/year	6%	5%	4%	3%	3%	3%	3%	3%
cost high [£/kWh]	598.45	568.53	545.79	529.42	513.53	498.13	483.18	468.69
cost low [£/kWh]	358.65	340.72	327.09	317.27	307.76	298.52	289.57	280.88

make PV electricity the lowest cost option for more than 230 million Europeans within the next 5 years.

Eusebio et al. [42] in 2016 demonstrated that in Portugal, where prosumers receive a very low price for the surplus energy injected to the grid, the PV couped with a battery system has obtained the grid parity, thanks to an increased self-consumption and self-sufficiency; consequently the energy efficiency has increased, since the energy is produced locally.

A study conducted in France in 2017 by Yu [43] assessed the future economic attractiveness of French residential PV system coupled with lithium-ion batteries in 2030. It concluded that the PV system coupled with lithium-ion battery will be competitive in France before 2030 under IEA scenarios.

Both these studies and even others highlight how a high level of self-consumption is of importance for a cost-effective system in absence of feed-in tariff. Therefore it's time to see if the BESS coupled with a residential solar PV system can be a cost-effective and worthwhile solution for a UK landscape. It will be analysed in the next chapter about the methodology.

1.3 Forecast

1.3.1 PV power production

The deployment of variable renewable generation is introducing new requirements on forecasting techniques. Moreover single PV plants may be exposed to market trades, and microgrid operations with self-consumed PV electricity require forecast at building or district level.[44] In fact, the development of micro-grids and combined PV+storage systems requires local energy management which, for optimal operation, relies on predictive control. Single-system or neighborhood-level power forecasts on timescales from a few minutes to 24 hours are therefore necessary. The first approach in PV power forecasting relies mostly on the prediction of relevant weather parameters (temperature and irradiance at least, then humidity etc.) followed by a calculation of the power output. This approach may be based on existing weather tools: these tools can be based on satellite data, ground stations or a mix of them. Many techniques for medium-short time horizon exist. Among all, numerical weather predictions (NWP) techniques are mainly used. Benghanem et al. used a radial basis function network for modeling and predicting the daily global horizontal irradiance (GHI) data using other meteorological data such as air temperature and sunshine duration as an input, and it was found a correlation coefficient of 98.80%. [45] In [46], a practical multilayer perceptron (MLP) network forecasting of 24 hours ahead of solar irradiance has been developed, and a correlation coefficient of 98% for sunny days and 95% for cloudy days resulted. GHI forecast is then performed by different companies. Meteotest [47], for example, deliver forecasts and measurements for power grid management, power trading, monitoring and operation of PV plants, building automation and facility management. In particular, they offer a forecast service based on sophisticated calculation tools and interpolation models, with more than 30 years of experience and data, and that uses a wide combinations of weather stations, geostationary satellites and a globally calibrated aerosol climatology to perform forecasts. A number of weather professional companies that offer these kind of services can be found. Then, from weather data, the PV power output is computed. In [48] a number of PV performance modeling tools are analysed. The study assesses that all tools achieve annual errors within $\pm 8\%$ and hourly RMSE$<7\%$ for all systems. These tools count on mathematical equations related to physics. Otherwise, methods based on stochastic learning techniques can be used. These can be separated in two classes: univariate methods and multivariate methods. In the second one, exogenous variables such as GHI, temperature, humidity or pressure are fed into the model together with the target model. This family includes:

- MLR: multi-linear regression model
- SVM: support vector machine
- ANN: artificial neural network
- Regression tree

A case study presented in [44] uses an ANN approach to estimate the PV power production. In particular, a feed-forward MLP with a single hidden layer is used. The goal is to estimate the PV power production as a function of the ambient temperature and the GHI. It was found that, for all the cases, the relative mean bias error (MBE) ranged between 1.36% and 5.2%, the relative root mean square error (RMSE) varied between 5.26% and 8.99%, while the correlation coefficient was between 0.9862 and 0.9954. Another study by Mellit et al. [49] proposed an ANN developed and implemented on experimental climate and electrical data for predicting the performance of a roof-top grid-connected photovoltaic (GCPV) plant. In particular, a multivariate model based on the solar irradiance and the air temperature is presented, and the results show a good effectiveness between the measured and predicted power produced by the plant. In fact, the found correlation coefficient is in the range of 98–99%, while the MBE varies between 3.1% and 5.4%.

Performance parameters

Many parameters are used to evaluate the performance of the forecasting method. Here some of them are presented.

- Mean Bias Error

$$MBE = \frac{1}{N}\sum_{i=1}^{N}(Y_{\text{forecast}} - Y_{\text{real}}) \tag{1.4}$$

- Mean Absolute Error

$$MAE = \frac{1}{N}\sum_{i=1}^{N} \mid Y_{\text{forecast}} - Y_{\text{real}} \mid \tag{1.5}$$

- Root Mean Square Error

$$RMSE = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(Y_{\text{forecast}} - Y_{\text{real}})^2} \tag{1.6}$$

As stated in [44], it is good practice to integrate the error only over day hours, since PV production is sure to be zero in the night, and to normalise the error by the nominal peak power of the system.

1.3.2 Residential load forecasting

Many studies concerning methodologies for aggregated load forecasting are present in literature, and these have helped network operators and retailers in optimizing their planning and scheduling. Therefore, utilities focused on a cluster of loads. Nowadays, forecasting for the entire grid has been achieved with relatively high accuracy. However, the increasingly deployment of distributed generation (mainly PV) and storage systems has generated new demand for disaggregated load forecasting techniques for a single customer,[50] mainly to perform a home energy management system (HEMS) for planning the operation of storage systems in the context of upcoming schemes for demand response, accordingly to real-time and dynamic pricing.[51, 52] Indeed, a transition to a more distributed energy generation is focusing the attention towards a decentralization of the electricity market and demand side control systems. Therefore in the near future the scale of management will move from a centralised control down to microgrid and single household level.[51] However, the load forecasting at residential level is more challenging than for a commercial building or some larger loads that has periodic loads characteristics. Indeed, at the single residential household level, the hourly energy consumption is small and highly variable, since it depends on the number of people inside the home, the kind of electrical appliances running at that time, stochastic people's behavior and so on.[52] Many different techniques have been used up to now for the electricity load forecasting. We can group them in three classes:

- Statistical methods including time series analysis techniques and regression methods (ARMA and ARIMA, MLR)
- Artificial intelligence methods that use SVM or ANN. Stochastic models like Markovian models have been recently developed for electricity load prediction.

1.4 Peer-to-Peer electricity trade and BSCS: literature review

As previously said in the introduction chapter, if a decentralization of energy generation is taking place, a decentralization of all the entire system may perform better than the conventional one. In particular, the market for the P2P trading of energy and a decentralized and active control of generation and demand have to be performed, in order to increase the value of the DERs. In literature, several studies tried to face this problem form different point of view, however it is still widely open and needs to be examined in depth.
Luth at al. [53] optimised a model to represent the P2P interaction for a small community with stationary storage located at the customer level or a central battery shared by the community. However some limitation can be detected: in fact, they assume that prosumers cannot feed-in to the grid and they analyze only a decentralised control of the batteries.
In [54] a market procedure for a community microgrid in presence of the utility grid is presented. Within this microgrid, each node has full control over its local energy resources and its energy plan is based on its own personal benefit. It is shown that both sellers and buyers will always benefit from participating in this market.
In [55] a battery strategy based on an easy feasible persistence forecast and on a perfect forecast is presented. From the comparison of both the strategies it has been demonstrated that a storage system management based on forecasts has a higher potential to relieve the grid than a system that only maximizes self-consumption, as it is used nowadays.
In [56] three different market paradigms are proposed to apply P2P energy trading in a community microgrid. It was found that energy trading resulted in a reduction of community energy cost. The limitation of this work lies in the fact that no batteries are present in the analysed microgrid.
In [57] a home energy management system model based on PV and load forecast that controls a residential battery system connected to a rooftop PV system is presented and the impact of forecast error on household economics is examined.
In [58] a third party entity controls distributed batteries owned by clients performing a two-stage (day ahead and real time) aggregated control to realize P2P energy sharing in a community microgrid. Economic benefits, compared to conventional peer-to-grid (P2G) energy trading, are observed for all the prosumers and consumers within the community microgrid.
In [59] the influence of electricity pricing models on the profitability and management of residential BESSs has been investigated. In particular is has been

demonstrated that opportune price structures, like the proposed enhanced Time of Use pricing policy, are able to opportunely drive private BESS investments and to increase the network hosting capacity.
In [60] Zhang et al. designed a P2P energy trading platform where the energy trading was simulated using game theory, and they found that P2P energy trading is able to improve the local balance of energy generation and consumption.
In [4] possible microgrid control architectures from highly centralized to fully distributed P2P techniques are classified. Then a control paradigm based on coupled microgrids, P2P communication and autonomous control, is proposed, as suggestion of an appropriate strategy to face the increasing penetration of DERs. It must be noted that the realization of P2P energy trading mostly depends on the national regulatory as well as enabling technology. A number of trials and projects on P2P energy trading have been carried out in recent years. Some of them focus on business model and energy market platform, some others are targeted at the local control and Information and Communications Technology (ICT) system for Microgrids [61, 62]. Among the technology and paradigm to realise an energy trading system in or among local Microgrids, the idea of Blockchain was used in many trials [62, 63] and seems to be a promising technology to regulate energy market system, as shown in Australian trials [63]. Based on the challenges discussed at the beginning of this chapter and the relevant studies that can be found in literature just presented, this project aims to examine deeper on the topic, evaluating techno-economic benefit of different control strategies and proposing a decentralised market structure. From the next chapter the methodology of the project to fulfill the targets will be presented in all the details.

Location	Nominal WACC			
	0%	2%	4%	6%
Stockholm	2018	2022	2027	2034
Helsinki	2017	2022	2027	2033
Amsterdam	Parity	Parity	2018	2023
Paris	Parity	Parity	2019	2024
Brussels	Parity	Parity	2017	2021
Istanbul	Parity	Parity	2017	2020
London	Parity	Parity	Parity	2017
Berlin	Parity	Parity	Parity	Parity
Madrid	Parity	Parity	2017	2021
Rome	Parity	Parity	Parity	Parity
Sofia	Parity	2019	2023	2028
Prague	2018	2023	2028	2035
Copenhagen	Parity	Parity	Parity	2019
Tallinn	2018	2022	2027	2034
Dublin	Parity	Parity	2018	2022
Athens	Parity	Parity	Parity	Parity
Zagreb	Parity	2017	2022	2027
Nicosia	Parity	Parity	Parity	Parity
Riga	Parity	2017	2021	2026
Vilnius	2017	2022	2027	2033
Luxembourg	Parity	Parity	2020	2024
Budapest	Parity	2020	2025	2030
Valletta	Parity	Parity	Parity	Parity
Wien	Parity	Parity	2017	2020
Warsaw	Parity	2019	2024	2029
Lisbon	Parity	Parity	Parity	Parity
Bucharest	Parity	Parity	2019	2024
Ljubljana	Parity	Parity	2019	2024
Bratislava	Parity	2018	2022	2027
Oslo	2023	2028	2036	2045
Zurich	Parity	Parity	Parity	2020

Figure 1.9: Summary of the time when true grid parity is reached in the residential segment with SC=50%, for different values of nominal WACC

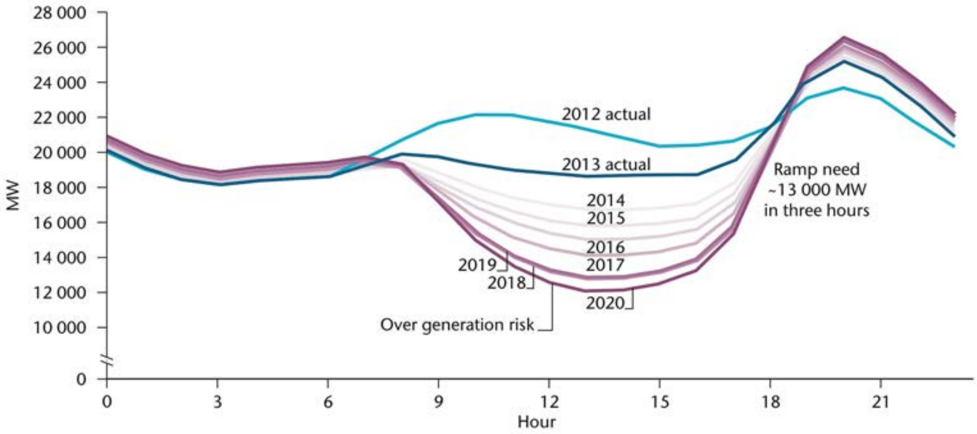


Figure 1.10: Expected evolution of the net load in a typical spring day in California[13].

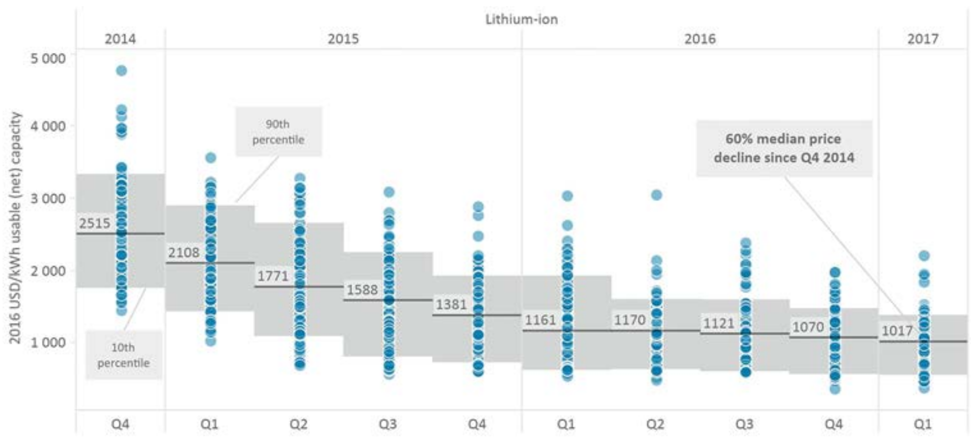


Figure 1.12: Home storage lithium-ion system offers in Germany from Q4 2014 to Q1 2017. Source: IRENA, based on EuPD Research,2017.

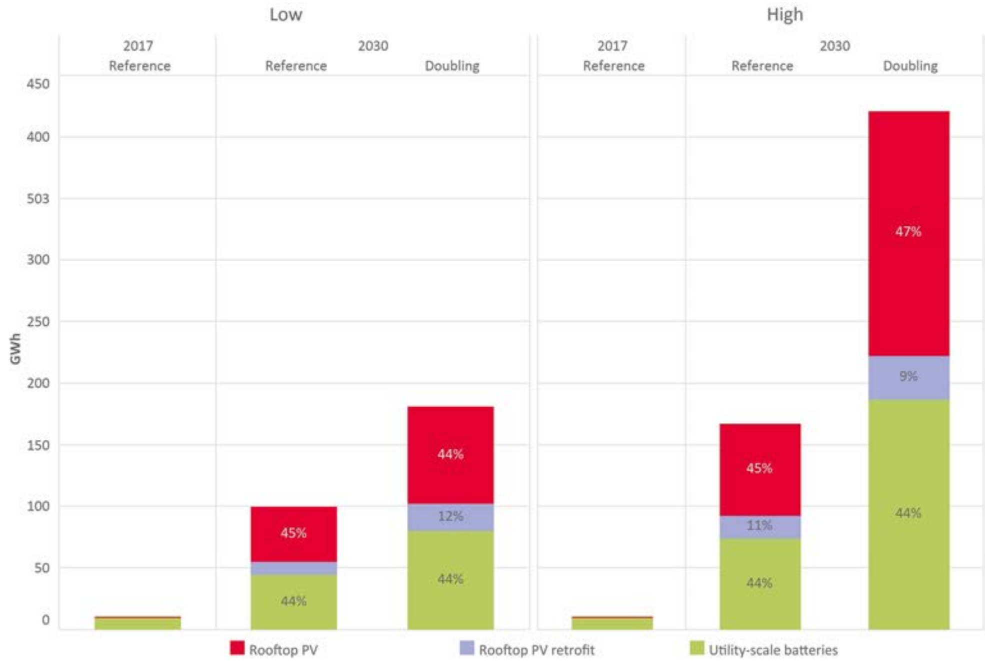


Figure 1.13: Battery electricity storage energy capacity growth in stationary application by sector, 2017-2030. Source: IRENA[31]

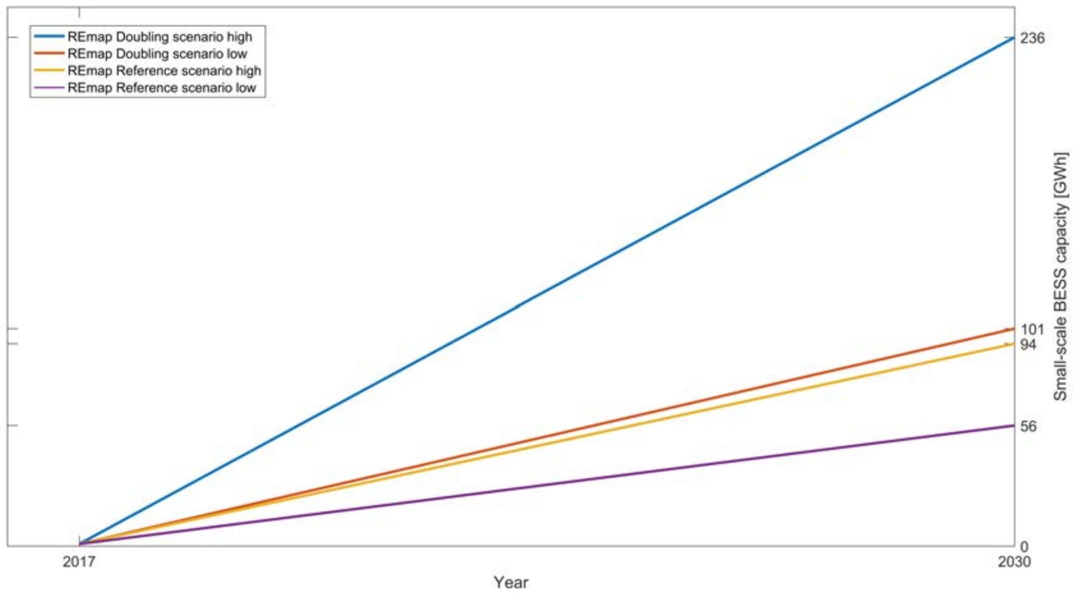


Figure 1.14: Small-scale BESS growth scenario: REmap Reference scenario and REmap Doubling scenario by IRENA

Chapter 2

Methodology

Linking to the literature review, this chapter will present the personal data processing, all the methods used in the formulation of the problem and all the instruments that have been chosen to do it. Everything in this chapter will be needed to introduce the case study of the next chapter.

2.1 Solar PV system in small-scale application: Future system installation cost projection

Starting from data collected from literature review presented in section 1.1 a projection for the future prices of the residential solar PV system is here proposed.

From the data collected by the UK government and using the range of future cost development in different scenarios based on IEA projection [13] and a study based on that [11], a future forecast for the total cost of a residential PV system in the UK has been computed. According to the future scenarios from IEA, a cost reduction of 19% to 36% by 2025 and a cost reduction of 40% to 72% by 2050, compared to 2014 cost, is expected. Table 2.1 reports the data collected by the UK government [64] for years 2014 and 2018. Data in 2025 and 2050 are the result of the computed forecast. In Figure 2.1 the result of the forecast is presented.

Table 2.1: Residential small-scale PV system collected by UK government[64] and future projection according to [11, 13]

		Year			
		2014	2018	2025	2050
Cost [£/Wp]	max	2.08	1.85	1.68	1.25
	mean	2.07	1.84	1.49	0.91
	min	2.06	1.83	1.31	0.58

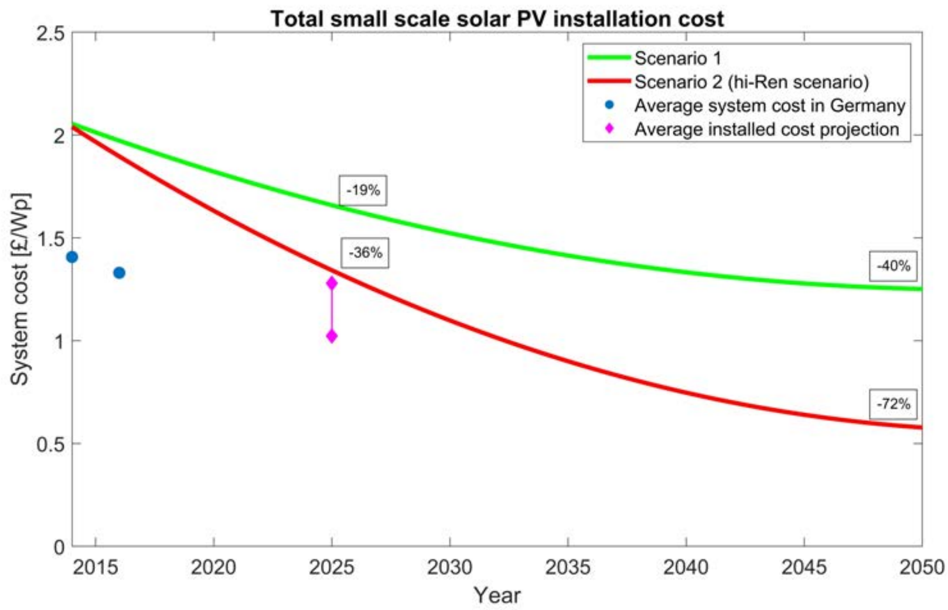


Figure 2.1: Forecast of small-scale PV system in UK

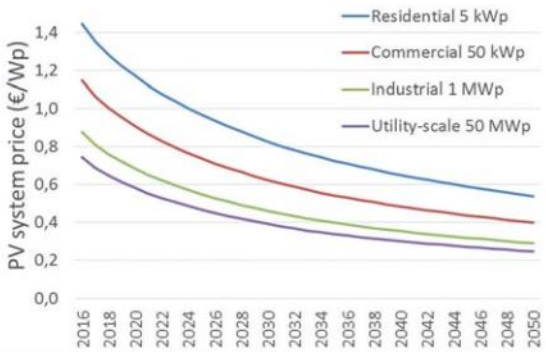


Figure 2.2: PV system CAPEX development 2016-2050 for different market segments.

2.1.1 Discussion: results evaluation

The curves in Figure 2.1 are only indicative, indeed the history of UK PV market is recent and it will likely have a better progression in the next few years. Moreover, while the mean value reported for 2018 by UK government is 1840 £/kWp, the median value is 1700£/kWp. A comparison can be made with the already mature German market, where the average residential PV system cost was already 1407 £/kWp in 2014, it was lower than utility-scale projects in many countries. [17] In 2016 it was 1.33 £/Wp instead. [16] Moreover, if BoS costs can be pushed down to very competitive levels, average installed costs could range from 1023 £/kWp to 1279 £/kWp by 2025.[17] Since the market is expanding a lot and in a global way it's likely to expect greater improvements in the UK residential system price in the next few years. The validity of this forecast is finally confirmed by the provision made by the European Technology and Innovation Platform (ETIP) Steering Committee[12] showed in figure 2.2.

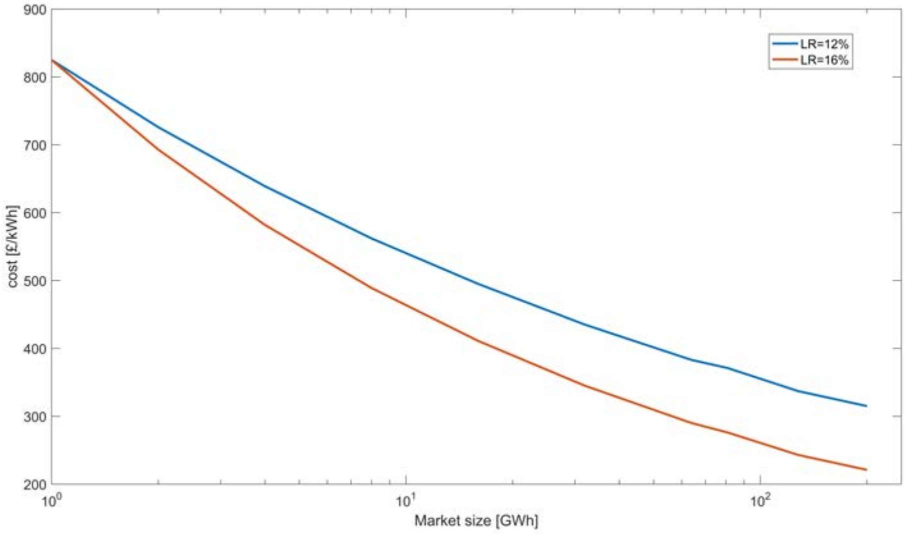


Figure 2.3: BESS's cost projection in terms of the market size

2.2 Li-ion BESS for small-scale application: actual price and future projection

Future cost projections for the Li-ion BESS solar PV system from the literature, previously presented in section 1.2, are here recalled. Two projections to 2030 have been developed to be compared to data found in literature. They are now presented.

The expansion of the BESS market projected by Bloomberg was considered.[34] In particular, BNEF expects a growth from 1GWh of installed capacity in 2017 to 81GWh in 2024. Then, a further demand of 65GWh more is expected in 2025, ending with a 200 GWh of behind-the-meter BESS in 2030. A learning rate of 12% and 16% is considered as suggested by IRENA.[31] The starting point of this analysis can be found in [37]; it was chosen because it reflects the average cost of 212 commercially available residential Li-ion BESS. Given the two learning rate and the future size of the market, two curves representing the cost reduction of the BESS system in terms of the market size have been computed and showed in Figure 2.3. Then, after that the price in the future years have been computed, two fitting curves using MATLAB fitting tool were found in order to make a projection of the system cost along the time. The results are shown in Figure 2.5 with the labels "BNEF proj. LR=12%" and "BNEF proj. LR=16%". Results will be discussed below.

Another projection has been made taking into account the Renewable Energy Roadmaps by IRENA. In particular, the REmap Reference scenario and the REmap Doubling scenario already presented in section 1.2.3 are used. Choosing a price of 850 £/kWh in 2017 as starting point and computing a future price based on the 2 above mentioned scenarios and the two learning rate of 12% and

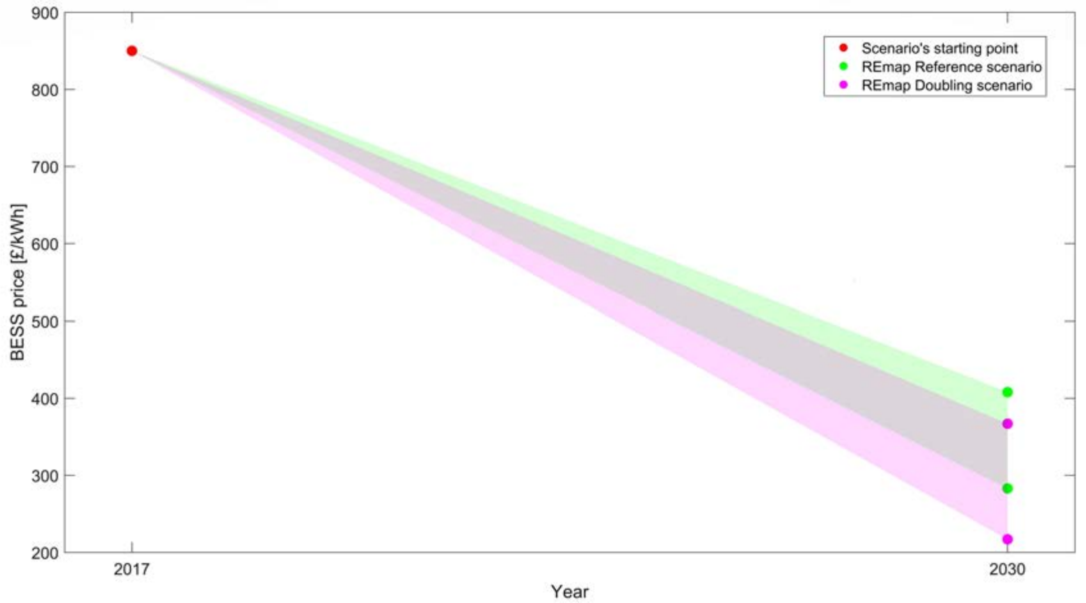


Figure 2.4: Small-scale BESS price projection according to REmap Reference scenario and REmap Doubling scenario by IRENA

16% previous discussed, a forecast of 2030 system price can be done. The scenario's starting point is the average price of commercial products available for UK market, taken from [65]. The projected future battery system price range between 283 £/kWh ad 408 £/kWh in the Reference scenario and between 217 £/kWh and 367 £/kWh in the Doubling scenario, as shown in Figure 2.4. An evolution path is not present because of insufficient data. The results are reported in Table 2.2 with the labels "IRENA reference scenario" and "IRENA doubling scenario". Then, to make results more compact, only border data are shown in Figure 2.5, identified by the label "IRENA analysis".

Finally, all the projections analyzed in section 1.2.3 and the two ones discussed above are presented in Figure 2.5. All the results and data collected are summarized in Table 2.2.

2.2.1 Results and discussion

First of all, finding the values for the analysis has not been simple at all since the technologies are quite recent and the application in this field even more. Li-ion technologies have benefitted from significant investment in recent years due to their versatility that enables them to be deployed in a wide variety of applications, but the utilization of a BESS coupled with PV is recent, and due to the fact that the price of the technologies decreased steeply. Indeed, many values that are easily found in literature refer to EV batteries and not to stationary applications, and most of the time, if related to stationary applications, most of researches refer to utility-scale applications. Other times instead, values are not reported numerically but only graphically. As visible in Figure 2.5, nowadays there's a wide span on the cost of technologies. This is due to the fact that there are a lot of different sub-technologies of Li-ion batteries, each one characterized

Table 2.2: Prices of the Li-ion BESS for small-scale application in accordance to the literature and personal data processing as previously explained. NB: All the prices are in £/kWh

	Year								
	2012	2014	2015	2016	2017	2018	2024	2025	2030
BNEF proj. LR=12%				825			371		315
BNEF proj. LR=16%				825			276		221
ISEA for SEFEP	811 364								296 150
IRENA reference scenario					850				408 283
IRENA doubling scenario					850				367 217
Muller et al.				1052 578				484 266	
Naumann et al.		591		550		506	376	355	248
Schmidt et al.			1235	1152		977		508	345
KPMG for REA			1410 845	1241 744	1092 654	961 576	569 341	546 327	469 281
Tesla powerwall 2						715 577			

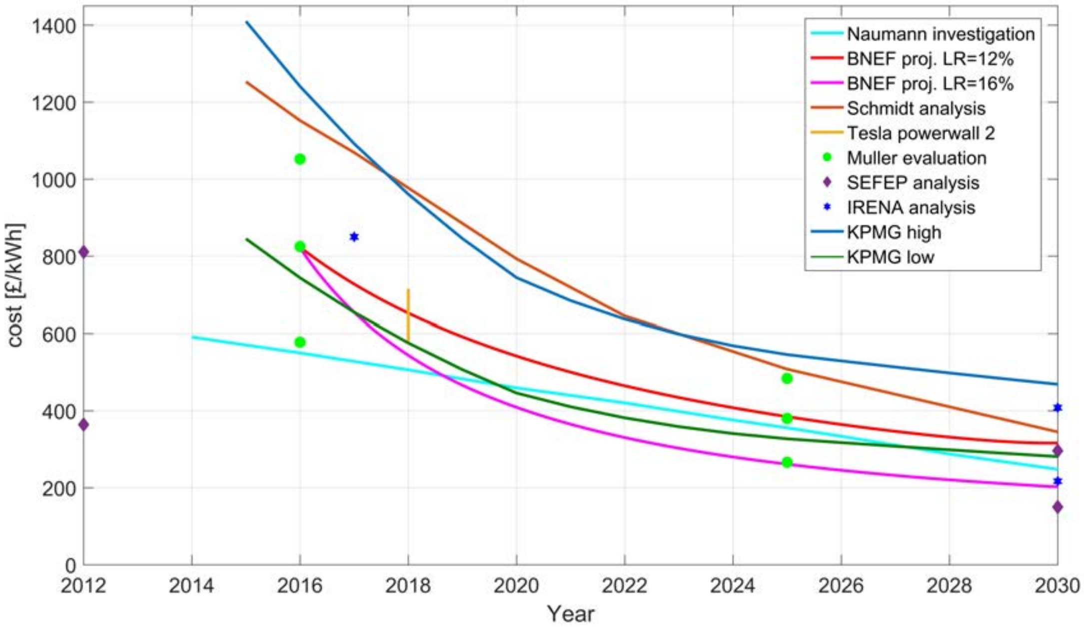


Figure 2.5: BESS future cost projection for small-scale application

by different maturity and cost, and also because the scarce data and the high uncertainty in the forward-looking analysis for a technology that is rapidly innovating. Fortunately, the Lithium Iron Phosphate (LIP) [37] and Lithium-nickel-manganese-cobalt-oxide (NMC) [66] chemistry setups, that are nowadays used for stationary storage thanks to a long lifetime, high cycle stability and very high safety conditions, also have a moderate cost with respect to other chemistries. Then, we can observe that different studies have a similar path and all converges towards a narrower range. For these reasons, on the base of the knowledge that can be found in literature, the forecast is considered effective. In Figure 2.6 a common area of the several projection has been bounded with a yellow dotted line. Prices of Li-ion BESS for small-scale applications are expected to belong to this area with a certain confidence. Then, only the outlook for 2030 is presented, indeed, the technology uncertainty beyond 2030 renders any further discussion highly speculative. On the base of that, the results of any analysis presented should be treated with cautions, as also suggested in [31]

It's visible that all the different market growth scenarios by Bloomberg and IRENA expect a huge development of the market, therefore a question is immediate: Is the manufacturers ready to face a so huge growth?
As reported by some analyst at Bloomberg NEF [67] the demand of Li-ion batteries for EV and stationary energy storage purposes is growing as never seen before and the supply is struggling to keep up. Up to now the market have been dependent on a few producers, like Panasonic (Japan), Samsung SDI and LG Chem (Rep. f Korea), BYD and Contemporary Amperex Technology(CATL) (China), Tesla (USA), E.ON and Sonnen and Deutsche Energieversorgung and Daimler AG (Germany) [32]. That's why the demand just necessitates new suppliers. Anyway, on average, prices have nonetheless fallen this year. The reason may be simple enough. In fact, new manufacturing capacity is being added quickly, par-

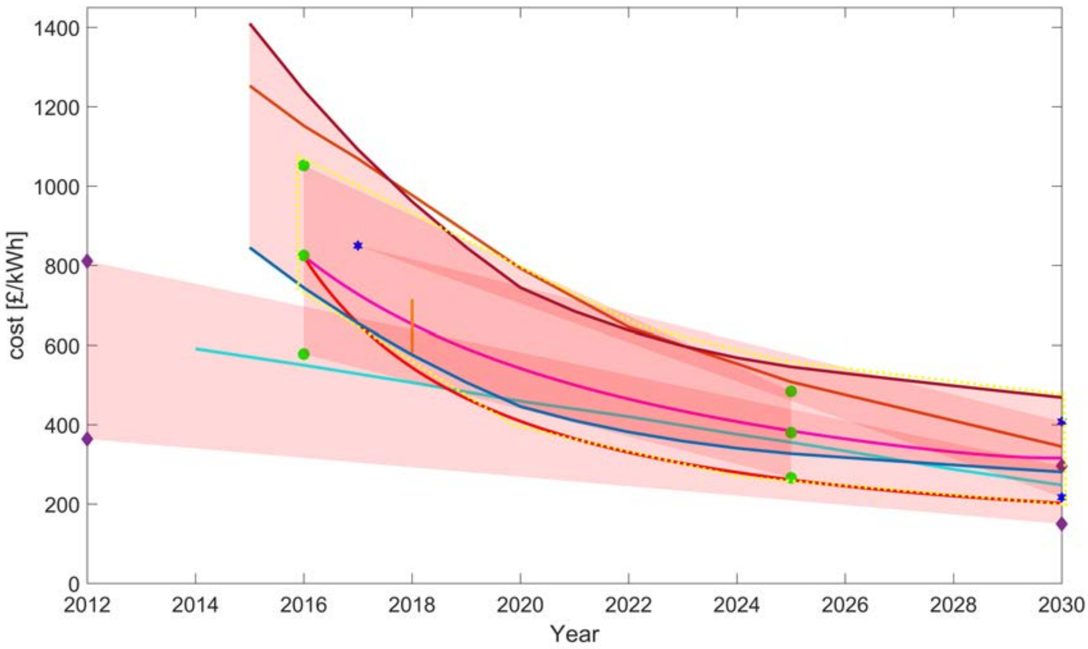


Figure 2.6: BESS future cost projection for small-scale application: common area of different projection

ticularly in China. This is confirmed by BNEF's energy storage analyst Sekine, that sees enough manufacturing capacity in China planned over the next three years to meet the total global battery demand for batteries.[67] CATL and BYD are building huge factories in China and Germany, and also South Korean battery giants are planning to expand the production in the next few years. Currently, automakers are holding off on their own production until there are further advances in battery technology, but they are investing a lot on their suppliers. Several companies, by the way, advanced new home storage options to compete in this new rapidly growing market, and in the near future new companies are expected to emerge and join the market. Therefore, the market growth is massive. Existing suppliers are investing a lot and new suppliers are expected to join the market since it's profitable and in expansion. Moreover, the constantly lowering of the price is a sign that the suppliers are facing the market demand and the investments already planned represent a sign that hopefully the manufacturers are ready to face the future demand.

2.3 Financial evaluation: PV system and Li-ion BESS in UK

Is it worth to have a Li-ion BESS coupled with the residential PV system in UK? This is the question we want to answer to.

Feed-in Tariffs (FITs) is a Government scheme designed to encourage uptake of a range of small-scale renewable and low-carbon electricity generation technologies. On 19th July 2018 the government confirmed the FiT scheme to close in full (the export tariff alongside the generation tariff) to new applications after 31st March 2019. Currently the government has not announced that there will be another incentive scheme to replace it.[68, 69] However, having received comments on the importance of maintaining a route to market for small-scale low-carbon generation after 31 March 2019, Government published a call for evidence on the future of small-scale low-carbon generation in the summer and they will follow this up with specific proposals for future arrangements in due course. In fact, the arguments put forward included that it would be unfair for small-scale generators to provide free electricity to the grid when not self-consuming.
The Renewable UK's executive director Emma Pinchbeck released that "the good news, as we look beyond FITs, is that solar is coming of age and while solar always makes great environmental sense it now makes economic sense for most investors without public subsidies given fair treatment by government. An average domestic solar system cost £12,000 in 2010. It is more like £5,000 today."[70]
On the base of that, it's fundamental to understand if installing a PV system in the residential sector is cost effective for an user in UK. Now, an answer to this question will be given.

2.3.1 Data definition: PV

For the PV system, real data from an existing 4kWp PV plant sited in an household rooftop in Loughborough (UK) are taken. Data have been collected for an entire year, from 01/01/2017 to 31/12/2017, with a 5 minutes resolution. For this analysis, a coarser hour resolution is considered. Data are reported in table 2.3. Afterwards, all the data have been scaled to the similar (same characteristics) PV plant but with a smaller capacity of 3kWp, since it is a common installed size. The average daily profiles per each month for a 3kWp PV system installed on a household's rooftop sited in Loughborough are presented in figure 2.7a. From calculus, an annual yield of 888 kWh/kWp resulted for the considered plant. This value appears to be extremely low. Indeed, as reported in [71], in 2014 the average annual yield for solar PV system in UK was found to be close to 960 kWh/kWp. Therefore, thanks to an improved module performance and reduced system losses we should expect an higher value. For this reason, a second value of 1000 kWh/kWp is taken into consideration for the analysis. A this little value (888 kWh/kWp) can be due to:

- Measurements' errors. Data were affected by errors, noticeable in the nigh registration where values must be zero. To clean data from these uncertainties a simple Matlab code was written

- A particularly rainy and cloudy year
- Missing values in the data. Indeed, data had to be manipulated since, due to failures of the meter, several data were missing or classified as 'NaN' (Not a Number). Some data have been handled personally, some others with a simple code written in Matlab.

In figure 2.7b the average annual daily production for the two different values of annual yield are presented and in Table 2.4 the corresponding values can be found.

Loughborough 4kWp PV system													
t	gen	feb	mar	apr	mag	giu	lug	ago	sett	ott	nov	dec	Average
1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	0.000	0.000	0.000	0.000	0.000	0.009	0.000	0.000	0.000	0.000	0.000	0.000	0.001
5	0.000	0.000	0.000	0.004	0.113	0.177	0.124	0.012	0.000	0.000	0.000	0.000	0.036
6	0.000	0.000	0.000	0.149	0.278	0.308	0.261	0.183	0.032	0.000	0.000	0.000	0.101
7	0.000	0.001	0.084	0.381	0.504	0.521	0.445	0.397	0.233	0.047	0.000	0.000	0.218
8	0.000	0.071	0.303	0.723	0.769	0.728	0.718	0.677	0.483	0.283	0.072	0.000	0.402
9	0.105	0.270	0.526	0.971	1.055	0.932	0.998	0.961	0.718	0.492	0.322	0.129	0.623
10	0.236	0.484	0.822	1.293	1.459	1.288	1.208	1.205	1.042	0.719	0.603	0.387	0.896
11	0.423	0.676	1.158	1.499	1.694	1.544	1.273	1.415	1.260	0.946	0.844	0.579	1.109
12	0.547	0.766	1.369	1.540	1.715	1.524	1.510	1.524	1.445	1.077	0.927	0.692	1.220
13	0.607	0.805	1.496	1.532	1.708	1.663	1.543	1.611	1.312	0.973	0.829	0.712	1.232
14	0.532	0.761	1.367	1.513	1.543	1.508	1.629	1.547	1.260	0.823	0.744	0.555	1.149
15	0.373	0.632	1.171	1.406	1.373	1.366	1.567	1.270	1.130	0.691	0.492	0.295	0.981
16	0.223	0.370	0.902	1.086	1.133	1.178	1.270	1.084	0.752	0.390	0.272	0.211	0.739
17	0.123	0.213	0.528	0.744	0.839	0.867	0.882	0.793	0.445	0.230	0.113	0.054	0.486
18	0.001	0.085	0.261	0.470	0.559	0.592	0.616	0.485	0.267	0.092	0.000	0.000	0.286
19	0.000	0.000	0.095	0.231	0.238	0.270	0.286	0.253	0.124	0.001	0.000	0.000	0.125
20	0.000	0.000	0.000	0.082	0.205	0.208	0.210	0.151	0.005	0.000	0.000	0.000	0.072
21	0.000	0.000	0.000	0.000	0.061	0.172	0.139	0.011	0.000	0.000	0.000	0.000	0.032
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Daily production	3.170	5.134	10.082	13.624	15.245	14.855	14.679	13.579	10.510	6.763	5.217	3.614	9.706
Monthly production	98.272	143.745	312.547	408.716	472.604	445.654	455.057	420.956	315.299	209.639	156.503	112.024	
Annual production [kWh]	3551												
Yield [kWh/kWp]	0.888												

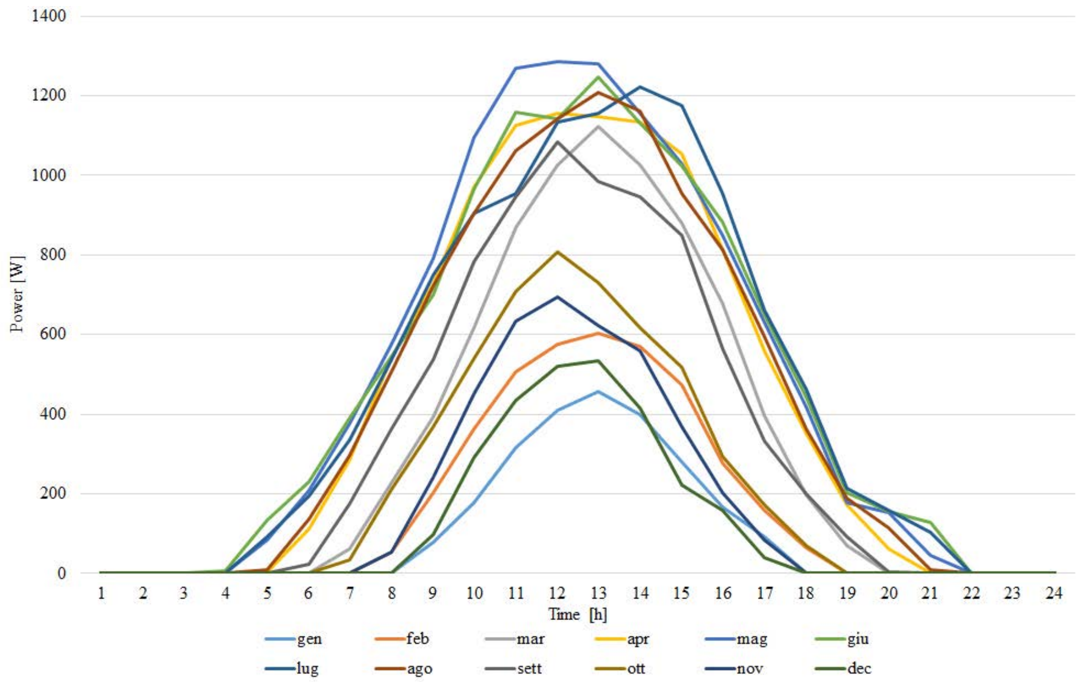
Table 2.3: Average hourly production for a 4kWp rooftop PV system installed in an household located in Loughborough (UK). All the data are reported in kWh

Table 2.4: Daily average profile for a 3kWp rooftop PV system sited in Loughborough (UK) for two different annual yield's values

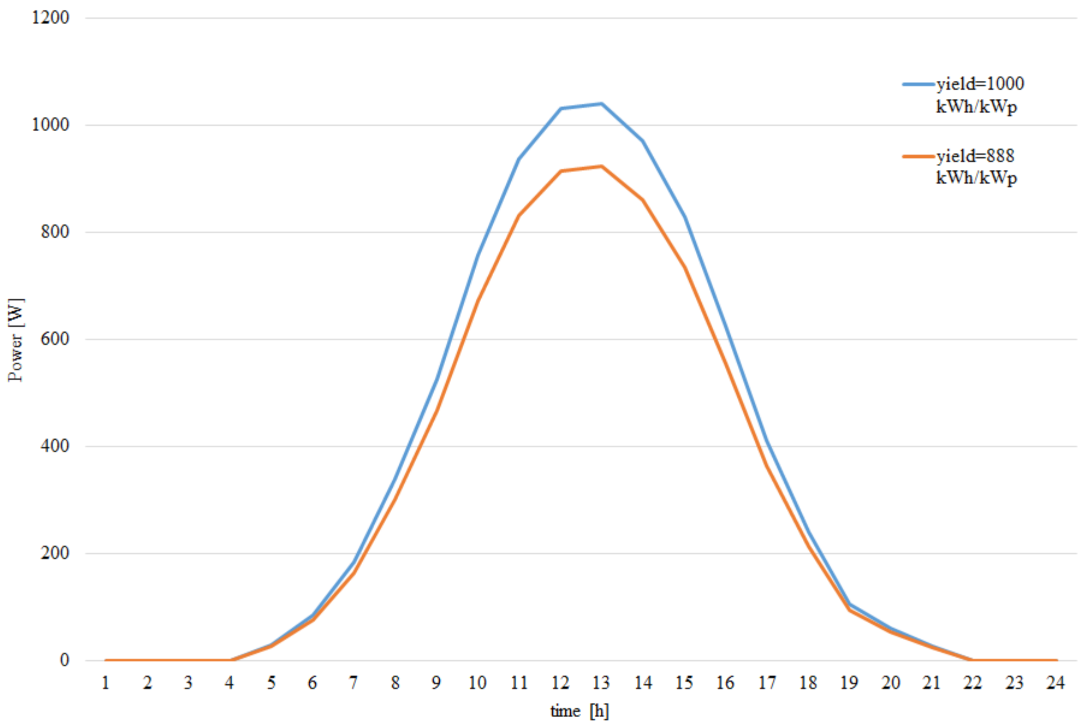
t	Average profile 1	Average profile 2
1	0.000	0.000
2	0.000	0.000
3	0.000	0.000
4	0.001	0.001
5	0.027	0.030
6	0.076	0.085
7	0.163	0.184
8	0.302	0.340
9	0.467	0.526
10	0.672	0.757
11	0.832	0.937
12	0.915	1.030
13	0.924	1.041
14	0.861	0.970
15	0.735	0.828
16	0.555	0.625
17	0.364	0.410
18	0.214	0.241
19	0.094	0.106
20	0.054	0.061
21	0.024	0.027
22	0.000	0.000
23	0.000	0.000
24	0.000	0.000
Daily production [kWh]	7.280	8.200
Annual production [kWh]	2663.298	3000
Yield [kWh/kWp]	887.766	1000

2.3.2 Data definition: Household load profile

For this analysis, two very different household demand profiles are chosen.
Load profile of 'house 1' in table 2.5 was obtained using the CREST Demand Model, that is a high-resolution stochastic model of domestic thermal and electricity demand that can be found in [72]. The model produces one-minute resolution demand data, dis-aggregated by end-use, using a bottom-up modeling approach based on patterns of active occupancy and daily activity profiles derived from time-use survey data. From a generated profile, the load profile with hourly resolution was computed and reported in Figure 2.8. The load profile of 'house 2' in table 2.5 was found in a database of the Northumbria University and is and average load profile of a residential unit. The first profile is related to an annual consumption of 4776 kWh and the second one to an annual consumption of 3800 kWh more or less. Those two values make sense since, in accordance with



(a) *Average daily production per month for a 3kWp PV system in Loughborough (UK).*



(b) *Average daily production for different yield.*

Figure 2.7: PV production based on a real PV plant installed in an household's rooftop in Loughborough (UK)

Table 2.5: Daily average load profile for two different households

t	house 1	house 2
1	0.367	0.235
2	0.091	0.235
3	0.097	0.205
4	0.085	0.200
5	0.081	0.195
6	0.096	0.200
7	0.110	0.480
8	0.205	0.480
9	1.358	0.400
10	0.290	0.390
11	0.103	0.320
12	0.375	0.330
13	0.359	0.480
14	0.266	0.400
15	2.100	0.320
16	0.218	0.310
17	0.103	0.320
18	0.179	0.650
19	0.867	0.660
20	1.815	0.850
21	1.572	0.830
22	0.771	0.700
23	0.658	0.700
24	0.918	0.500
Total [kWh]	13.085	10.390
Annual cons. [kWh]	4776.206	3792.350

a national statistic of the Department for Business, Energy & Industrial Strategy, the average household consumption in the last 10 years (from 2008 to 2017) was of about 3880 kWh.[73]

2.3.3 Financial evaluation

To evaluate the cost-effectiveness of the PV plant and eventually of the PV plant coupled with a Li-ion battery storage, the LCOE (see subsection 1.1.3) and the net present value (NPV) will be evaluate.

The NPV is the difference between the present value of cash inflows and the present value of cash outflows over a period of time. It is used to analyze the profitability of a projected investment. NPV is defined as:

$$NPV = \sum_t \left(\frac{R_{\mathrm{t}}}{(1 + WACC_{\mathrm{real}})^t} \right) \tag{2.1}$$

where:

- $\mathrm{R_t}$: net cash inflow-outflows during a single period t
- $\mathrm{WACC_{real}}$: real discount rate

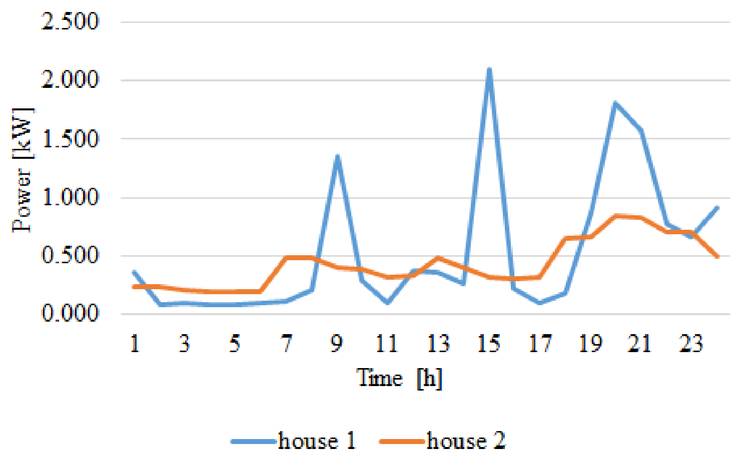


Figure 2.8: Household profile chosen for the financial analysis.

- t: number of time periods (years)

In this analysis, according to the literature presented, some assumptions are made:

- Lifetime of the PV system: 30 years
- CAPEX: 1800 £/kWp
- OPEX(t)= 18 £/kWp/year
- PV system degradation: 0.5%
- Lifetime of battery: 10 year. This value is considered taking into account warranty on the batteries given by manufacturers[74]
- No O&M costs related to the battery
- SOC_{min}=0%, SOC_{max}=100%
- Unitary battery efficiency
- BESS cost, according to analysis of section 2.2 is considered 570 £/kWh for installation at year 0, 230 £/kWh for replacement at year 10, and 200 £/kWh for replacement at year 20.
- Inflation: 2.20% fixed along the years. This value is the average computed on the historic inflation rates of the last 10 years.[75] This is an optimistic value if we consider that inflation rate in 2017 was about 2.7% and in 2018 was 2.5% [76, 77], but the last projections shows a decreasing trend in the near future[78], therefore a this value should be representative (even if an higher level would give a better result).
- $WACC_{nom}$=4%

Table 2.6: Case study for the financial evaluation of the PV system, eventually coupled with the BESS, in UK

	Annual cons. [kWh]	PV power [kWp]	Yield [kWh /kWp/year]	BESS capacity [kWh]
Case 1	4776	3	1000	2
Case 2	4776	3	888	2
Case 3	3792	3	1000	2
Case 4	3792	3	888	2

- Given these data of WACC_{nom} and Inflation, the $\text{WACC}_{\text{real}}$ results equal to 1.76%, in accordance with Equation 1.2.
- Annual consumption fixed during the years
- The variable retail electricity price equal to 0.16 £/kWh and an average fixed cost of 77 £/year are kept constant over the years.
  To choose these values, various reports of the Office for National Statistic were evaluated. In particular in [79] an average variable unit price of 0.144 £/kWh and an average fixed cost of 72.03 £/year for 2017 was presented, with a change on the average annual domestic standard electricity bill in the period 2016-2017 of +5.7%[80]. The same study for 2018 [81] reports an average variable unit price of 0.158£/kWh and an average fixed cost of £77.02 £/year.
- Price of fed-in surplus PV generation paid by the grid: 4.614 c£/kWh. This has been computed as the average of day ahead base-load contracts in 2017/2018 in the UK reported by Office of Gas and Electricity Markets (Ofgem) [82] reduced by a 10% administrative fee, as suggested in [12].
- The price offered in the market for surplus PV generation is considered to be the LCOE of the system

Four case study presented in Table 2.6 have been analysed from a financial point of view. To perform the analysis an Excel worksheet is used. Here, just one case is presented and then a discussion about the sensitivity of the results for the other cases is presented.

2.3.4 Financial analysis: Results

Case 1

In Figure 2.9, the household load profile and the solar PV generation profile for case 1 are visible. From here, a SC=47.24% is computed. After that, input data are entered in the excel worksheet shown in Figure 2.10. Then, the financial plan is computed and shown in Figure 2.11.

We can notice that from this evaluation, with these input data and without incentives, the PV system seems not to be cost-effective. In fact, the NPV at 30

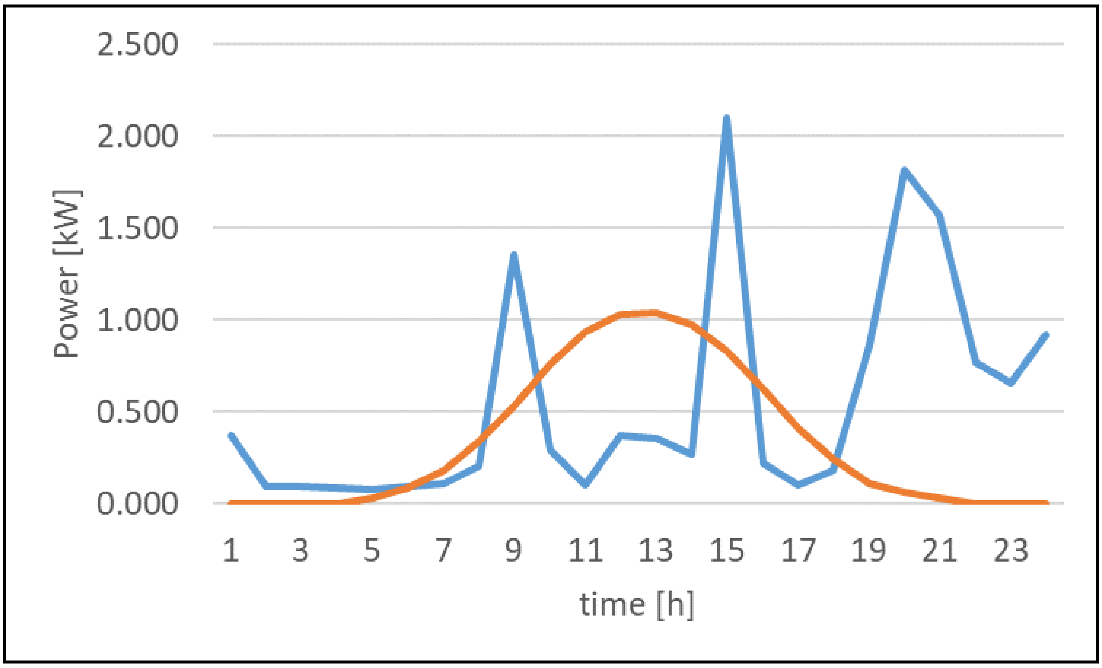


Figure 2.9: Household load profile (blue) and average PV production profile (orange) in case 1

years is negative and the real value of energy is lower than the LCOE. Things get better if an installation cost of 1700 £/kWp that is the real median value reported by UK government (see section 2.1) is considered since the 300£ less in CAPEX bring to a positive NPV and equal to 127£ thanks to a reduced LCOE=0.0979 £/kWh that is lower than the RVE=0.0999£. Therefore, we ask now what rate of SC should be achieved for this plant to become cost effective for the user. To answer to this question, the SC is varied ad the result is then plotted and visible in Figure 2.12. Results show that, with these input data, the solar PV plant become cost effective for a SC=49.6%. In the case of an installation cost of 1700 £/kWp, this value decrease to 45.5%. Therefore, it's clear how much the expected reduction in installation cost analysed in section 2.1 will determine the cost-effectiveness of the solar PV system in UK. The battery system is now added. Let's assume that the battery can do 1 full cycle per day. The SC increases to a level of 71.63%. New input data are shown in figure 2.13, results are shown in figure 2.14 instead.

We can observe that the LCOE of the system increased because of the presence of the battery. The outcomes due to the battery system can be observed in the first column of costs in Figure 2.14, at year 0, 10 and 20. The LCOE increased from 0.1025 £/kWh to 0.1304 £/kWh (that is anyway lower than the variable cost of energy), but also the real value of the energy increased from 0.0999 to 0.1277£/kWh. Note that the NPV got worse of only 5£. Many simplifying assumptions were made on the battery and therefore results must be treated with cautions, but we can certainty affirm that the battery coupled with the PV system almost repay itself. This will make Li-ion desirable soon, especially if UK government won't renew support scheme of feed-in tariff. Let's now suppose the

DATA AND FEATURES OF THE SOLAR PV SYSTEM		
Power	3.0 kWp	
Yield	1,000.0 kWh/kWp	
Annual production	3,000 kWh	Power*productivity
Degradation	0.50% year	
Self-consumption	47.24%	
Energy self-consumed	1,417 kWh	Annual production*self consumption
Energy injected	1,583 kWh	Annual production-energy self-consumed
Annual consumption	4,776 kWh	
Energy purchased	3,359 kWh	Annual consumption- energy self-consumed
Fixed annual cost	77.00 £/year	
Variable cost of energy	0.16 £/kWh	
Price received for fed-in energy	0.046 £/kWh	
Saving thanks to SC	227 £	Energy self-consumed* cost of energy
Income by selling	73 £	Energy injected* price of energy injected
Installation cost	1,800 £/kWp	
System installation cost	5,400 £	
OPEX(t)	54 £/year	

Figure 2.10: Data and features of solar pv system, case 1

Year	Costs (outcome)			Revenues (income)			NPV	Production			
	CAPEX + various		Tot. cum.	Save + Sell		Tot. cum.		Energy		Tot. cum.	LCOE
	Value	VA	VA	Valore	VA	VA		Valore	VA	VA	
0	5,400	5,400	5,400	0	0	0	-5,400				
1	54	53.07	5,453	300	294	294	-5,159	3,000	2,948	2,948	1.850
2	54	52.15	5,505	298	288	582	-4,923	2,985	2,883	5,831	0.944
3	54	51.24	5,556	297	281	864	-4,693	2,970	2,818	8,649	0.642
4	54	50.36	5,607	295	275	1,139	-4,468	2,955	2,756	11,405	0.492
5	54	49.49	5,656	294	269	1,408	-4,248	2,940	2,694	14,099	0.401
6	54	48.63	5,705	292	263	1,671	-4,034	2,925	2,634	16,733	0.341
7	54	47.79	5,753	291	257	1,928	-3,825	2,910	2,575	19,308	0.298
8	54	46.96	5,800	289	251	2,179	-3,620	2,895	2,518	21,826	0.266
9	54	46.15	5,846	288	246	2,425	-3,421	2,880	2,461	24,287	0.241
10	54	45.35	5,891	286	240	2,665	-3,226	2,865	2,406	26,693	0.221
11	54	44.56	5,936	285	235	2,900	-3,035	2,850	2,352	29,045	0.204
12	54	43.79	5,980	283	230	3,130	-2,850	2,835	2,299	31,344	0.191
13	54	43.04	6,023	282	224	3,354	-2,668	2,820	2,247	33,592	0.179
14	54	42.29	6,065	280	219	3,574	-2,491	2,805	2,197	35,788	0.169
15	54	41.56	6,106	279	214	3,788	-2,318	2,790	2,147	37,936	0.161
16	54	40.84	6,147	277	210	3,998	-2,150	2,775	2,099	40,034	0.154
17	54	40.13	6,187	276	205	4,202	-1,985	2,760	2,051	42,085	0.147
18	54	39.44	6,227	274	200	4,403	-1,824	2,745	2,005	44,090	0.141
19	54	38.75	6,266	273	196	4,598	-1,667	2,730	1,959	46,049	0.136
20	54	38.08	6,304	271	191	4,789	-1,514	2,715	1,915	47,964	0.131
21	54	37.43	6,341	270	187	4,976	-1,365	2,700	1,871	49,836	0.127
22	54	36.78	6,378	268	183	5,159	-1,219	2,685	1,829	51,664	0.123
23	54	36.14	6,414	267	178	5,337	-1,077	2,670	1,787	53,451	0.120
24	54	35.52	6,450	265	174	5,512	-938	2,655	1,746	55,197	0.117
25	54	34.90	6,484	264	170	5,682	-802	2,640	1,706	56,904	0.114
26	54	34.30	6,519	262	166	5,849	-670	2,625	1,667	58,571	0.111
27	54	33.70	6,552	261	163	6,011	-541	2,610	1,629	60,200	0.109
28	54	33.12	6,586	259	159	6,170	-415	2,595	1,592	61,791	0.107
29	54	32.55	6,618	258	155	6,325	-293	2,580	1,555	63,346	0.104
30	54	31.98	6,650	256	152	6,477	-173	2,565	1,519	64,866	0.1025

RATES		
Nominal	Real	Inflaction
4.00%	1.76%	2.20%

P batt	B(0)	B(10)	B(20)
kWh	£ / kWh	£ / kWh	£ / kWh
0	570	230	200
£	0	0	0

Annual consumption	4,776 kWh
Annual production	3,000 kWh
Energy self-consumed	1,417 kWh
Energy injected	1,583 kWh
% sold to LM	0%
Energy purchased	3,359 kWh
Price sell to LM	0.1025 £ / kWh
Price sell to grid	0.046 £ / kWh
Fixed cost	77.00 £ / year
Variable price	0.16 £ / kWh
C bill without PV	**841.16** £
C bill with PV	**541.60** £
C saved thanks to SC	226.75 £
C saved by selling	72.81 £
Real value of energy	**0.0999** £/kWh
LCOE	**0.1025** £/kWh
NPV(30)	**-173** £

Figure 2.11: Output of financial evaluation, case 1

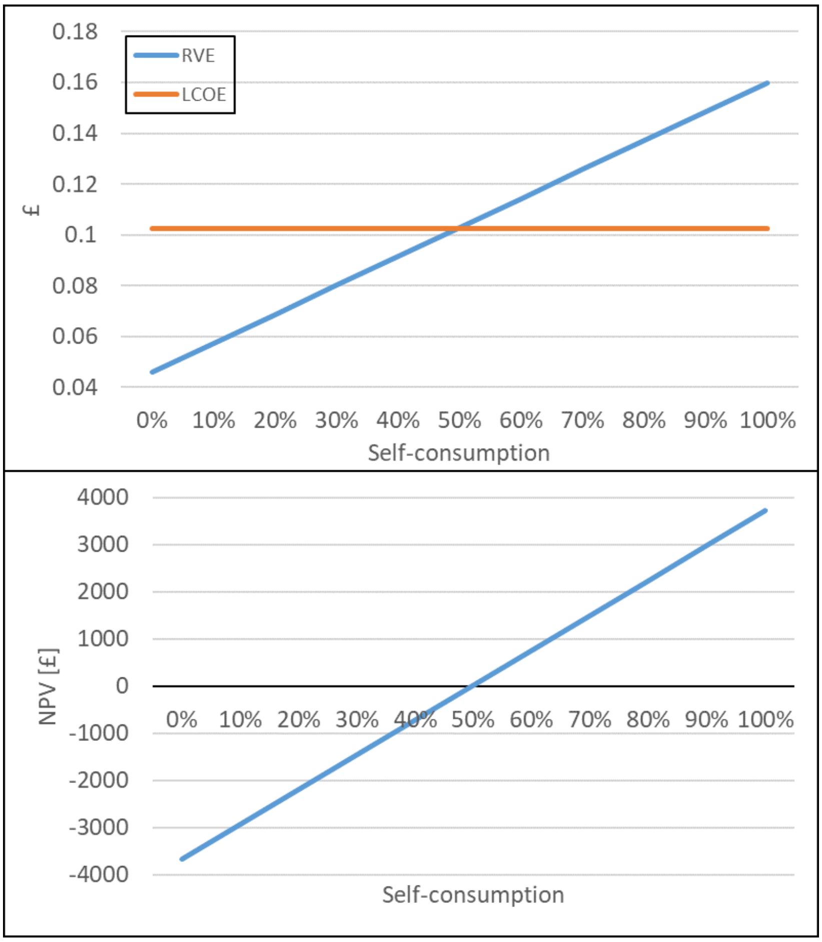


Figure 2.12: Trend of NPV and RVE when varying the SC rate in case study 1

DATA AND FEATURES OF THE SOLAR PV SYSTEM		
Power	3.0 kWp	
Yield	1,000.0 kWh/kWp	
Annual production	3,000 kWh	*Power * productivity*
Degradation	0.50% year	
Self-consumption	71.63%	
Energy self-consumed	2,149 kWh	*Annual production * self consumption*
Energy injected	851 kWh	*Annual production - energy self consumed*
Annual consumption	4,776 kWh	
Energy purchased	2,627 kWh	*Annual consumption- energy sef consumed*
Fixed annual cost	77.00 £/year	
Variable cost of energy	0.16 £/kWh	
Price received for fed-in energy	0.046 £/kWh	
Saving thanks to SC	344 £	*Energy self-consumed * cost of energy*
Income by selling	39 £	*Energy injected * price of energy injected*
Installation cost	1,800 £/kWp	
System installation cost	5,400 £	
OPEX(t)	54 £/year	

Figure 2.13: Data and features of solar PV system, case 1+BESS

Year	Costs (outcome)			Revenues (income)			NPV	Production			
	CAPEX + various		Tot. cum.	Save + Sell		Tot. cum.		Energy		Tot. cum.	LCOE
	Value	*VA*	*VA*	*Valore*	*VA*	*VA*		*Valore*	*VA*	*VA*	
0	6,540	6,540	6,540	0	0	0	-6,540				
1	54	53.07	6,593	383	376	376	-6,217	3,000	2,948	2,948	2.236
2	54	52.15	6,645	381	368	744	-5,901	2,985	2,883	5,831	1.140
3	54	51.24	6,696	379	360	1,104	-5,592	2,970	2,818	8,649	0.774
4	54	50.36	6,747	377	352	1,456	-5,291	2,955	2,756	11,405	0.592
5	54	49.49	6,796	375	344	1,800	-4,996	2,940	2,694	14,099	0.482
6	54	48.63	6,845	373	336	2,136	-4,709	2,925	2,634	16,733	0.409
7	54	47.79	6,893	371	329	2,465	-4,428	2,910	2,575	19,308	0.357
8	54	46.96	6,940	370	321	2,786	-4,153	2,895	2,518	21,826	0.318
9	54	46.15	6,986	368	314	3,100	-3,885	2,880	2,461	24,287	0.288
10	514	431.66	7,417	366	307	3,408	-4,010	2,865	2,406	26,693	0.278
11	54	44.56	7,462	364	300	3,708	-3,754	2,850	2,352	29,045	0.257
12	54	43.79	7,506	362	294	4,001	-3,504	2,835	2,299	31,344	0.239
13	54	43.04	7,549	360	287	4,288	-3,261	2,820	2,247	33,592	0.225
14	54	42.29	7,591	358	280	4,569	-3,022	2,805	2,197	35,788	0.212
15	54	41.56	7,633	356	274	4,843	-2,790	2,790	2,147	37,936	0.201
16	54	40.84	7,674	354	268	5,111	-2,563	2,775	2,099	40,034	0.192
17	54	40.13	7,714	352	262	5,373	-2,341	2,760	2,051	42,085	0.183
18	54	39.44	7,753	350	256	5,628	-2,125	2,745	2,005	44,090	0.176
19	54	38.75	7,792	349	250	5,879	-1,913	2,730	1,959	46,049	0.169
20	454	320.19	8,112	347	244	6,123	-1,989	2,715	1,915	47,964	0.169
21	54	37.43	8,150	345	239	6,362	-1,788	2,700	1,871	49,836	0.164
22	54	36.78	8,186	343	233	6,595	-1,591	2,685	1,829	51,664	0.158
23	54	36.14	8,222	341	228	6,823	-1,399	2,670	1,787	53,451	0.154
24	54	35.52	8,258	339	223	7,046	-1,212	2,655	1,746	55,197	0.150
25	54	34.90	8,293	337	218	7,264	-1,029	2,640	1,706	56,904	0.146
26	54	34.30	8,327	335	213	7,477	-850	2,625	1,667	58,571	0.142
27	54	33.70	8,361	333	208	7,685	-676	2,610	1,629	60,200	0.139
28	54	33.12	8,394	331	203	7,888	-506	2,595	1,592	61,791	0.136
29	54	32.55	8,427	329	199	8,087	-340	2,580	1,555	63,346	0.133
30	54	31.98	8,458	327	194	8,281	-178	2,565	1,519	64,866	0.1304

RATES		
Nominal	Real	Inflaction
4.00%	1.76%	2.20%

P batt	B(0)	B(10)	B(20)
kWh	£ / kWh	£ / kWh	£ / kWh
2	570	230	200
£	1140	460	400

Annual consumption	4,776 kWh
Annual production	3,000 kWh
Energy self-consumed	2,149 kWh
Energy injected	851 kWh
% sold to LM	0%
Energy purchased	2,627 kWh
Price sell to LM	0.1304 £ / kWh
Price sell to grid	0.046 £ / kWh
Fixed cost	77.00 £ / year
Variable price	0.16 £ / kWh
C bill without PV	**841.16** £
C bill with PV	**458.19** £
C saved thanks to SC	343.82 £
C saved by selling	39.15 £
Real value of energy	**0.1277** £/kWh
LCOE	**0.1304** £/kWh
NPV(30)	**-178** £

Figure 2.14: Output of financial evaluation, case 1+BESS

Table 2.7: NPV for case 1, with and without battery, if LM is present

Power sold to LM [kWh]	NPV case 1	
	no BESS	BESS
425.5	362	599
851	866	1375
1583	1761	-

presence of a local market (LM) where a P2P energy trading is implemented and let's suppose that the 50% of the surplus PV energy injected into the grid is sold among users in this market at the LCOE of the system. The results of Figure 2.15 is cheering. Indeed, a positive NPV(30) of 599£ is obtained, this value increases up to 1375£ when all the surplus injected energy is sold within the local market.

Let's turn back to the case 1 without the BESS and let's consider the possibility to sell in the local market at the LCOE the surplus energy injected into the grid. It results that selling the same amount of energy considered previously is not as profitable as the case with battery; if there's the possibility to sell all the energy produced, it is more profitable instead. Data are shown in Table 2.7 and compared with the case with battery. This table shows us that having the battery in this case is more profitable than not having, at least up to a certain

Annual consumption	4,776 kWh
Annual production	3,000 kWh
Energy self-consumed	2,149 kWh
Energy injected	851 kWh
% sold to LM	50%
Energy purchased	2,627 kWh
Price sell to LM	0.1304 £ / kWh
Price sell to grid	0.046 £ / kWh
Fixed cost	77.00 £ / year
Variable price	0.16 £ / kWh
C bill without PV	**841.16** £
C bill with PV	**422.27** £
C saved thanks to SC	343.82 £
C saved by selling	75.07 £
Real value of energy	**0.1396** £/kWh
LCOE	**0.1304** £/kWh
NPV(30)	**599** £

Figure 2.15: Output of financial evaluation, case 1+BESS+P2P in LM

value of energy.

Discussion on the financial plan for case 2,3,4

Based on the case presented above and all the other cases analyzed (see Table 2.6), some results are now illustrated and discussed.

- From the analysis, it emerges that for the cases 2 and 4, where the PV yield is very low (888 kWh/kWp) the PV plant is cost effective with at least a SC=60.90%. An empiric curve that shows, for each value of the yield, the minimum SC needed to make the NPV positive after 30 years for the data presented, can be found in figure 2.16. Obviously, lower the yield, higher the minimum SC needed.

- Case 4 presents the same PV plant of case 1 but an higher SC, equal to 52.98%. As shown in Figure 2.12 this value is sufficient to make the investment of the PV system profitable, indeed the NPV results equal to 251£.

- In all the cases, the battery system repays itself in the lifetime and therefore it represent, from the financial point of view, an interesting choice for the next future.

- in all the cases, the LCOE of the PV plant is lower than the variable retail energy price (grid parity).

- In all the cases, the possibility of selling the surplus energy (or part of it) within a local market at the LCOE of the system improves the money balance.

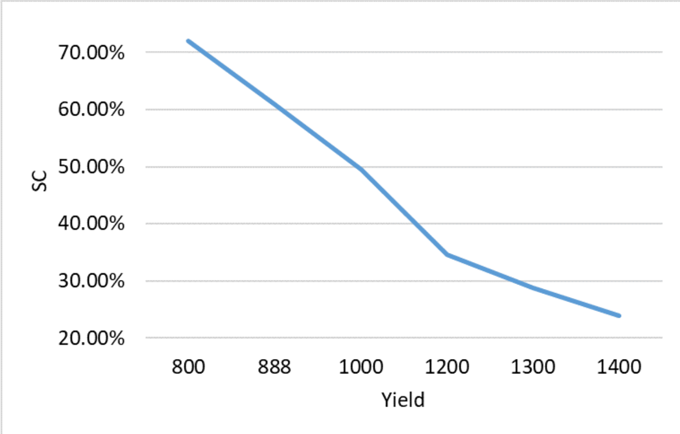


Figure 2.16: Minimum SC to have NPV positive after 30 years for different values of the yield and prices previously presented

- The battery increased the self-consumption of about 25% in the cases presented here.
- The PV system not always appeared to be cost effective, but things get a bit better if the median value of the PV system installation cost reported by UK government (see section 2.1) is considered.

In conclusion, based on the data found in literature, the solar PV system in UK seems not to be always cost effective without incentives, even if the grid parity has already been reached. The installation of BESS represents a possible solution to increase the SC, particularly in absence of remuneration for the fed-in energy. The presence of a decentralised (local) market for the trading of surplus energy represent a beneficial option to reduce not only the PV system owners' (prosumers) bills but also other consumers' bills since energy at a lower value than retail price is trade.

2.4 Forecast

2.4.1 Solar PV plant generation profile

Based on the literature review, I tried to develop a forecasting model for the PV production of a real roof-top grid connected PV system, based on weather information and calendar data. After several tries, an acceptable model was found using the "nntool", a Matlab Artificial Neural Network Toolbox. A MLP with the back-propagation (BP) was selected for the time-series prediction. In particular a feed-forward neural network with 2 layers and 12 neurons in the hidden layer is visible in figure 2.17. To train the network, a training function that updates weight and bias values according to gradient descent with momentum (GDM) is chosen. This function was used, instead of the more common network-training function that updates weight and bias values according to Levenberg-Marquardt optimization, since better results were obtained. The Mean squared normalized error performance function (mse) is used to measure the network performance

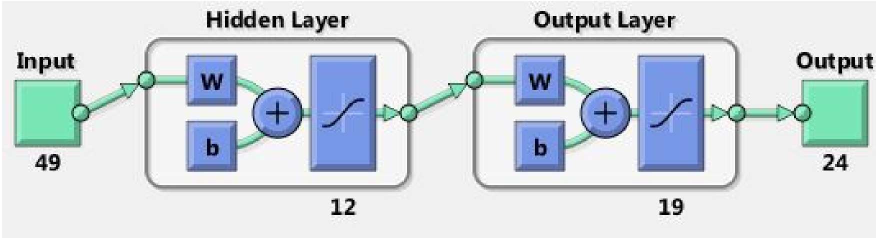


Figure 2.17: Representative scheme of the ANN used for PV power production forecasting

Table 2.8: Performance parameters of forecast tool

MAE [%]	MBE [%]	RMSE [%]	R [%]
4.63	0.32	6.50	94.67

function. Then, the Hyperbolic tangent sigmoid transfer function (tansig) was chosen as neural transfer function. This is the function that calculates layer's output from its net input. After that the training was concluded, a correlation coefficient of almost 95% was found for training, validation and test set, as shown in figure 2.18.

As you can see from figure 2.18, the NN takes in input 49 elements:

- 1-24: hourly Global horizontal irradiation (GHI) at ground level, collected from Copernicus Atmosphere Monitoring Service (CAMS) [83]
- 25-48: hourly air temperature, collected from the Global Forecast System (GFS), a weather forecast model produced by the National Centers of Environmental Prediction (NCEP) [84]
- 49: calendar effect was considered through the use of the following function: $f(x) = sin(2\pi/365(x - 91.25)) + 1$ where x is the number of the corresponding day along the year, from 1 to 365.

After the training, the neural network was ready to forecast the 24h ahead PV power production. To improve the offset error in the forecast, a reasonable filter that put to zero the forecasted data when the GHI is zero was implemented. Eventually, some performance parameters have been computed and reported in table 2.8. These parameters are the MBE, the MAE and the RMSE as defined by equation 1.4 1.5 and 1.6, respectively (see Table 2.8). The results obtained are in line with the ones found in literature (see subsection 1.3.1), even if not in all the parameters. Considered the aim of the project, the errors and uncertainties related to input data, and the inexperience in this field, these data were considered acceptable. Moreover, data come from different sources, therefore a full correlation among them is not assured. Now, some results of the forecast will be presented. Doing that, some considerations about the correlation between GHI and real values, and between forecast results and real data will be deduced.

In figure 2.19 the time interval between 17/04 and 26/04 is presented. A satisfying forecast can be observed in the firsts 6 days, a bit less in the others.

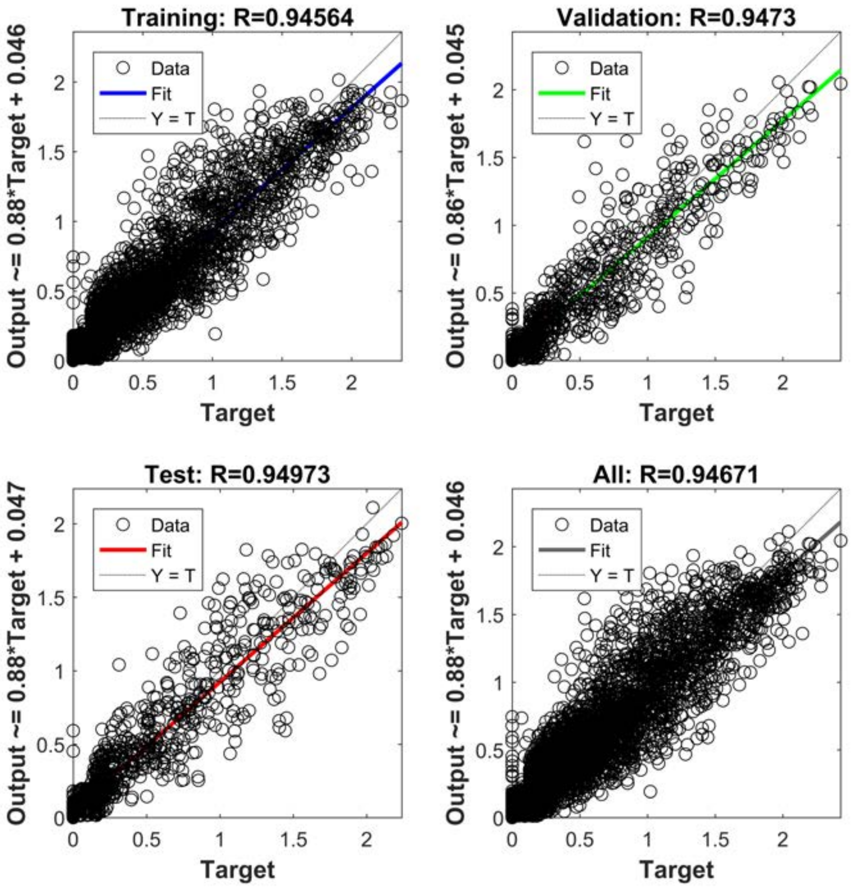


Figure 2.18: Linear training regression in output from "nntool" Matlab Toolbox

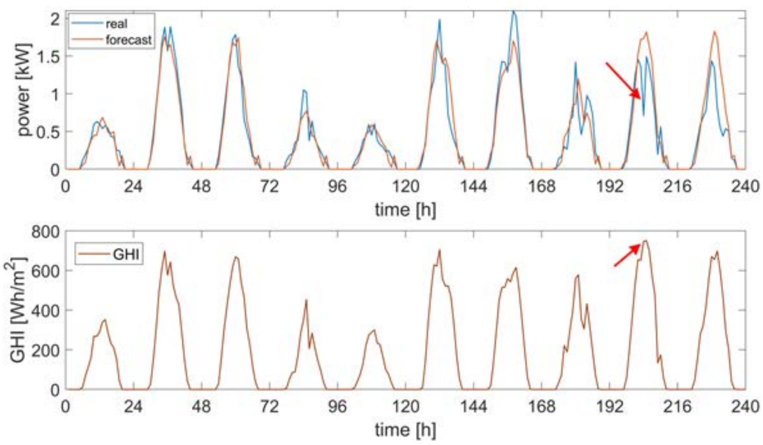


Figure 2.19: Forecast and real PV power production, and GHI. Period from 17/04 to 26/04

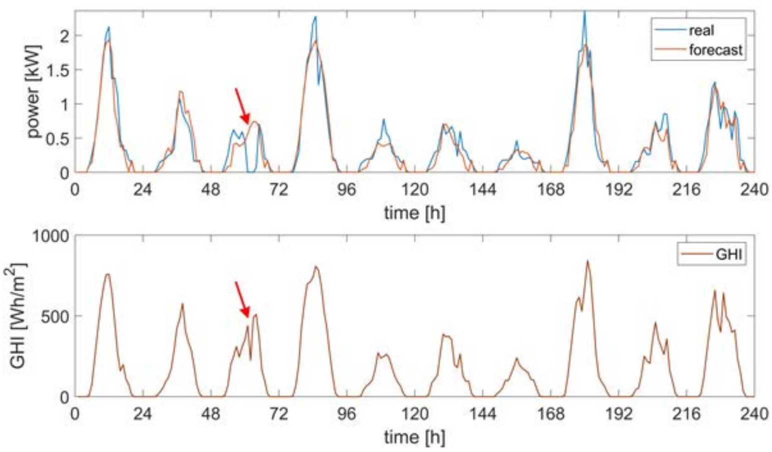


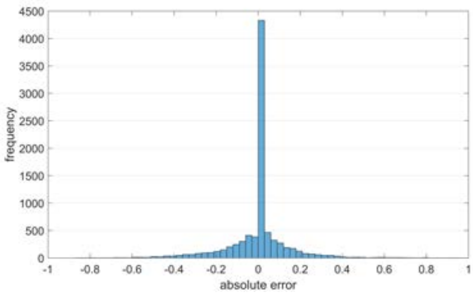
Figure 2.20: Forecast and real PV power production, and GHI. Period from 11/05 to 20/05

At day nine of the set, the real production shows a strange behavior not well explained by the GHI. This anomalous behavior can be due to:

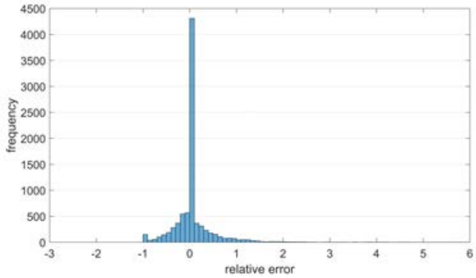
- Uncertainties in the measurement of the pv production (the meter proved to be not always reliable)
- Scarce correlation between GHI and PV production
- Other parameters not present in the input data can affect the pv production

the period from 11/05 to 20/05 is shown in figure 2.20. Here, something anomalous in day 3 can be observed. T real production's line (in blu) has a period of null generation, while according to GHI, it should have a peak in it. This is probably due to a failure of the measurement system.

During the analysis of data, a failure of the measurement system lasting for an entire day has been noticed, and this increased the error. Therefore, a better



(a) *Absolute error.*



(b) *Relative error.*

Figure 2.21: Absolute and relative error for the PV forecast with ANN

data collection system together with a more correlated weather data are desired for future analysis and to get better results. Moreover, an improvement of the ANN and further training is desirable to get a better forecast performance.
Finally, the absolute and relative errors have been computed as:

$$absolute\,error\,(t) = y_{\text{forecast}}\,(t) - y_{\text{real}}\,(t) \tag{2.2}$$

$$relative\,error\,(t) = \frac{y_{\text{forecast}}\,(t) - y_{\text{real}}\,(t)}{y_{\text{real}}\,(t)} \tag{2.3}$$

Both those graphs are shown in figure 2.21a and 2.21b.

Then, the same histograms have been divided in a number of clusters based on the generation power, and some conclusions regarding the performance of the ANN have been educed. Since the maximum output power is more or less 2.428kW, 20 clusters of 0.1214kW each have been created. Figure 2.22 shows the absolute error. Note that the ANN tends to overestimate the low level of power, it tends to underestimate the high levels of power instead.

In figure 2.23 the relative error splitted in the same intervals is presented, instead. It's clear that the scale changes considerably, but what is notable is that, while the sum of absolute error is negative, the sum of relative error is positive. Indeed:

- Sum of absolute error: -46.2701
- Sum of relative error: 447.2245

This means that the forecast tool makes mistakes in excess less frequently than in defect, but more seriously. From the practical point of view, in the following it will be shown if these uncertainties represent an issue for the management of the batteries.

2.4.2 Households: electricity load forecast model

An ANN architecture to forecast the electricity load profile of a household in Loughborough, whose consumption had been metered for one year, was developed, but not good results were found. The reasons of the failure can be due to

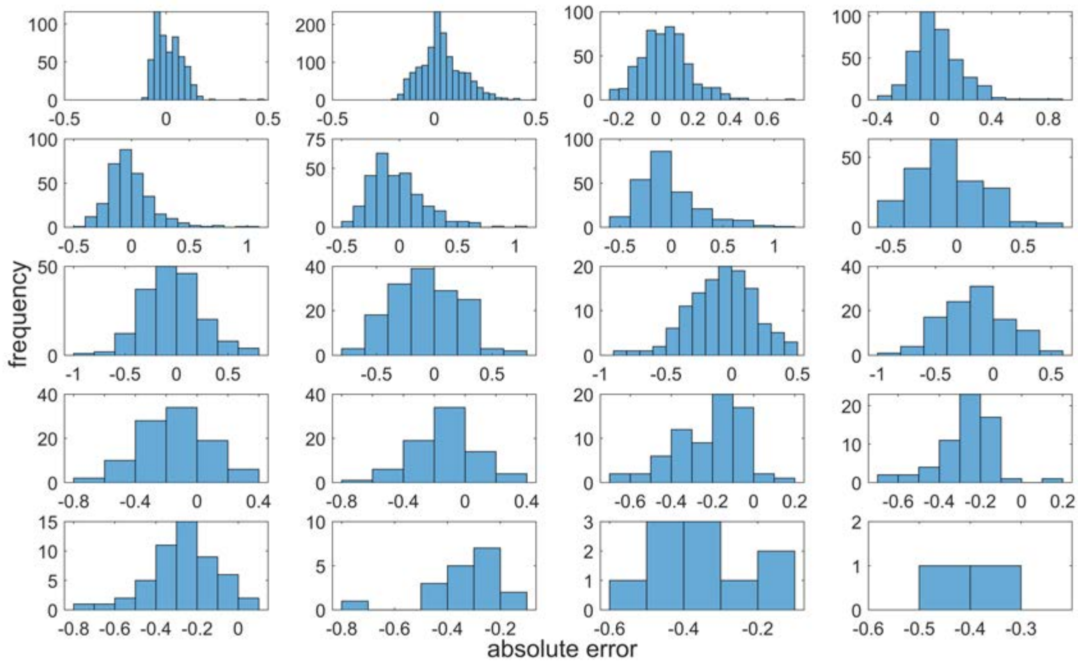


Figure 2.22: Absolute error splitted in clusters of power

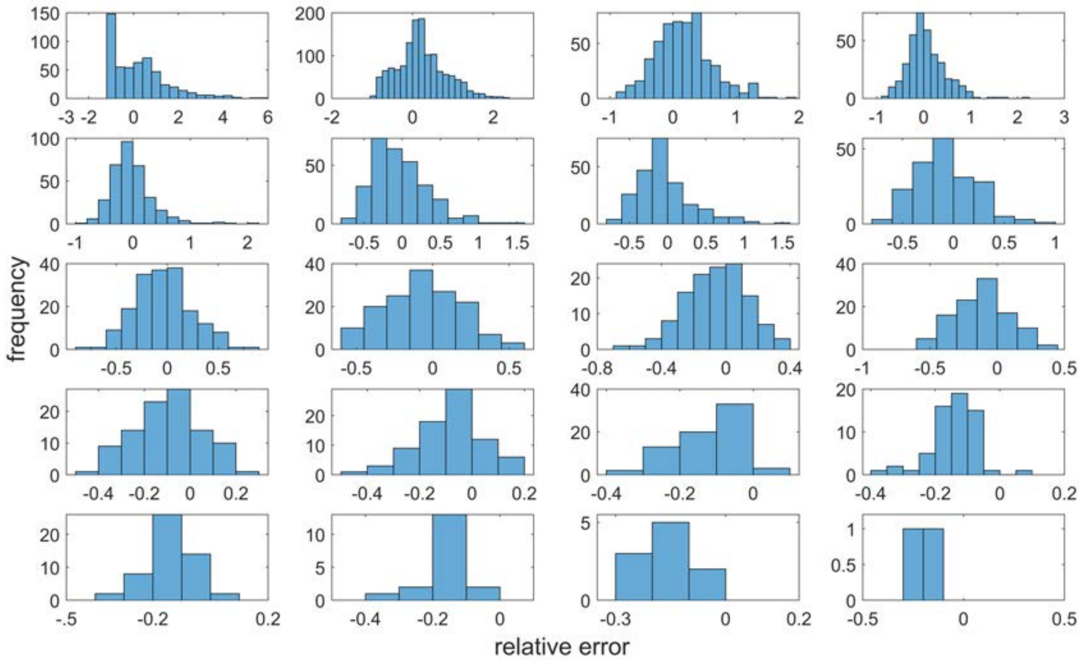


Figure 2.23: Relative error splitted in clusters of power

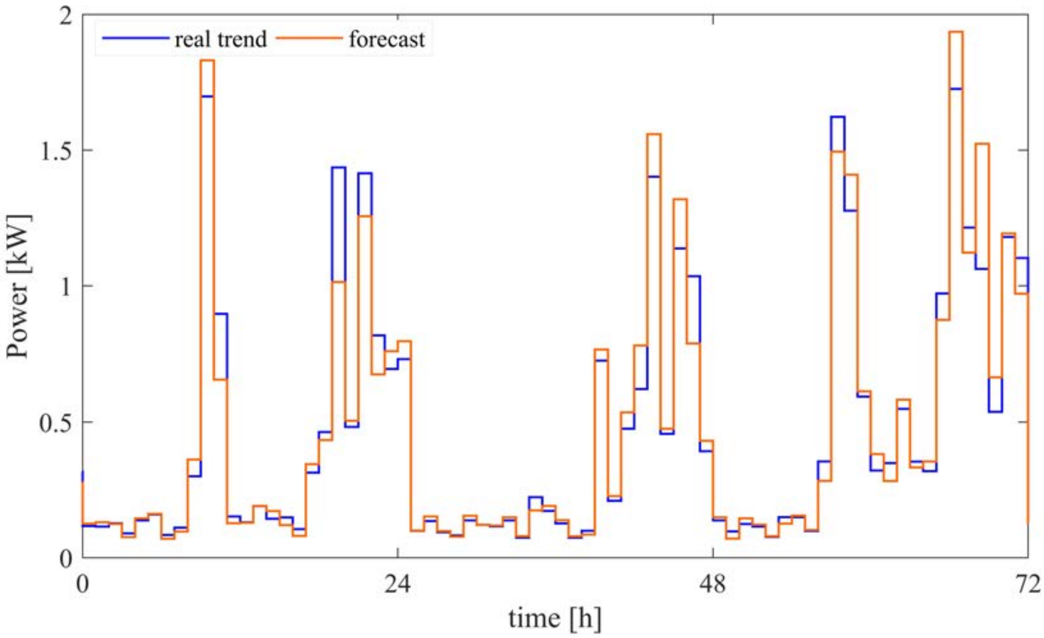


Figure 2.24: Example of real and forecast trend for a single household

the recurrent faults of the measurement system, to the really strange and inexplicable pattern consumption, and to the little experience in developing those types of ANN. Then, a single household presents a large variation in pattern from day to day, due to high unforeseeable people behaviors and irregularities in the power consumption not always easy to predict, as discussed in Figure 2.24. Moreover, not enough different load profiles and data were available to be applied to the case study that will be presented in the next chapter.

For this reason, the forecast of the household's electricity demand is carried out with a different approach.
Referring to equation 2.4 starting from the real values P(t), to simulate the forecasted value P*(t) a random error of $\pm e_f$ with e_f=10% is added. Subsequently, a superimposed Gaussian error e_g with mean value $\mu = 0$ and standard deviation $\sigma = 10\% \cdot P(t)$ is further added, as proposed in [85].

$$P^{*}\left(t\right) = \left(1 + R\left\{-1, +1\right\} \cdot e_{f}\right) \cdot P\left(t\right) + e_{g} \tag{2.4}$$

An example of the real trend and the forecast for a single household is shown in Figure 2.24. It must be pointed out that for real-life applications, information on the past demand patterns should be collected and a forecast based on that should be performed.

2.5 Control/operating strategies

In this section we go deep in the scenarios that have been choose to be studied and precisely in the design of BSCS. The case studies and all the scenarios mentioned in the introduction chapter are summarized in Table 2.9.

Table 2.9: Summary of the implemented scenarios

	Base case		Centralised case	Decentralised case			
Control strategy	/	/	Aggregated control	Grid support		Market approach	
Scenario	S1	S1m	S2	S3	S3e	S4	S4e
BESS	✗	✗	✓	✓	✓	✓	✓
MEM	✗	✓	✓	✓	✓	✓	✓
MBM	✗	✗	✗	✗	✓	✗	✓

Two scenarios belong to the base case:

- S1 Reference scenario: The lack of BESS and the presence of a traditional energy market characterize this scenario.
- S1m Reference+MEM scenario: Differently from S1, the MEM for the P2P energy trading is implemented here. However, BESS are still not deployed in this scenario.

The centralised case represents one scenario:

- S2 Aggregated control: A hypothetical but plausible distributed deployment of stationary storages (BESSs) is considered, and an aggregated BSCS to control all the batteries present within the grid is implemented.

Four different scenarios are implemented for a decentralised case:

- S3 Grid support: BESSs are deployed in a distributed way in this scenario. The batteries are independently controlled by their owners. The aim is to provide grid support, reducing the variability of the net power exchange with the grid at the point of delivery (POD).
- S3e Enhanced grid support: This scenario differs from S3 by the presence of MBM through which the prosumers that own BESSs contribute to the system balancing and environmental benefits.
- S4 Market approach: This scenario provides an effective customer side BSCS based on prosumers' interest.
- S4e Enhanced market approach: This scenario is still based on prosumers' interest; however, the same MBM as in S3e is implemented here to provide a service to DSO for the benefit of the grid.

Figure 2.25 shows the structure related to the centralised and decentralised cases. Two different lines are used to visualize power flow as well as the data flow inside the microgrid. Parameters exchanged between the elements of the system are reported in the two tables at the bottom of the figure.

The control strategies of the stationary storage within a micro-grid are now presented. Three BSCS have been developed, namely aggregated control, grid support and market control for S2, S3 and S3e, S4 and S4e, respectively. All the strategies are optimized over a period of time T. The meaning of the variables are presented in the appendix.

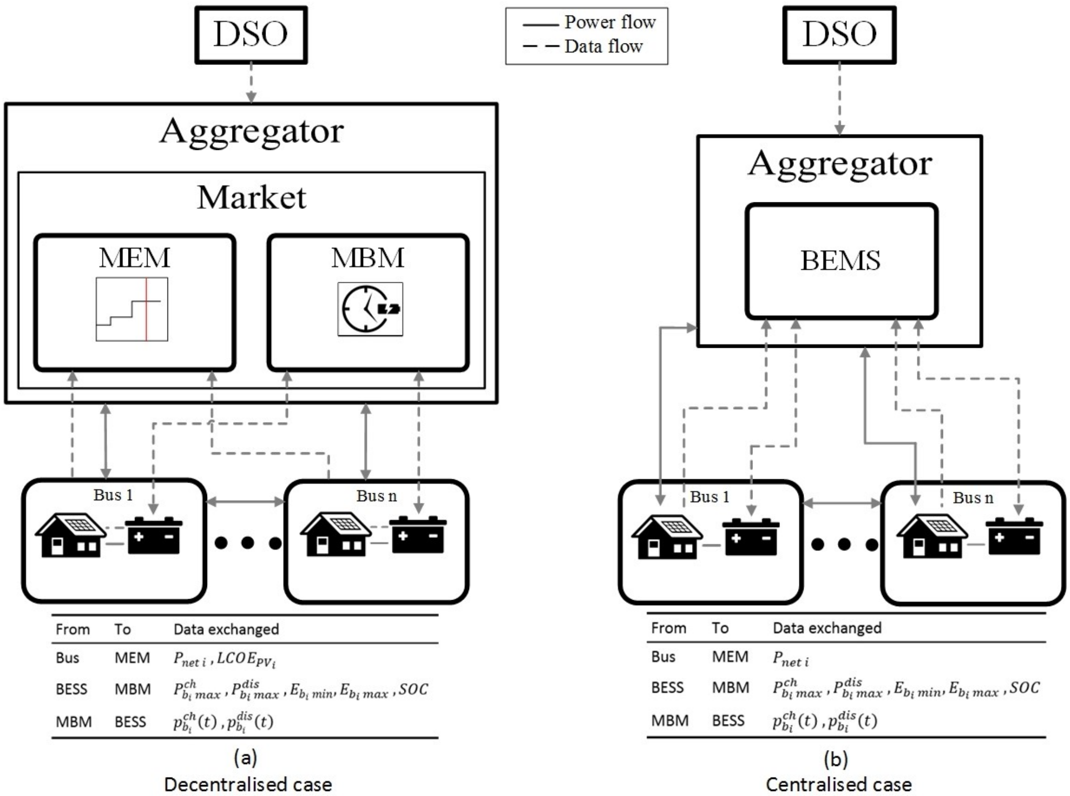


Figure 2.25: Schematic representation of the centralised and decentralised structure

2.5.1 Aggregated control

In this scenario, decentralised deployed batteries are centrally controlled by an aggregator in order to reduce the standard deviation (or variance) of the net power exchange at the point of common coupling (PCC). Hereafter, all the variables are assumed to be constant within a time-step. The optimal batteries scheduling is formulated in the following optimization problem.

$$\min \sum_{t=1}^{T} \frac{\left(P_{net}^{PCC}(t) + \sum_{b_i}\left(p_{b_i}^{ch}(t) - p_{b_i}^{dis}(t)\right)\right)^2}{T} \tag{2.5}$$

$s.t.$

$$P_{net}^{PCC}(t) = \sum_{i=1}^{B}\left(P_{load_i}(t) - P_{PV_i}(t)\right) \tag{2.6}$$

$$0 \leq p_{b_i}^{ch}(t) \leq p_{b_i\,max}^{ch} \qquad \forall t\,, \forall b_i \tag{2.7}$$

$$0 \leq p_{b_i}^{dis}(t) \leq p_{b_i\,max}^{dis} \qquad \forall t\,, \forall b_i \tag{2.8}$$

$$E_{b_i\,min} \leq E_{b_i}(t) \leq E_{b_i\,max} \qquad \forall t\,, \forall b_i \tag{2.9}$$

$$E_{b_i}(t) + \left(\eta_{b_i}^{ch} \cdot p_{b_i}^{ch}(t) - \frac{1}{\eta_{b_i}^{dis}} \cdot p_{b_i}^{dis}(t)\right) \cdot \Delta t = E_{b_i}(t+1) \qquad \forall t\,, \forall b_i \tag{2.10}$$

In Equation 2.5 the aim is to minimise the variance of the net power exchange at the PCC, respecting the underlying constraints. Equation 2.6 defines the net power at PCC, expressed by the sum of all the loads and generation units within the micro-grid. Equation 2.7 and Equation 2.8 set the limits of the charge/discharge power of batteries, and Equation 2.9 expresses the lower and upper bound of battery capacity. Finally, Equation 2.10 defines the energy stored in the battery for each time step, which depends on the power charged in/discharged from the battery in that time-step. The objective function adopted in this scenario is non-linear, therefore convex optimization algorithms have been employed for resolving the problem [86].

2.5.2 Decentralised control strategy: grid relief

In this scenario, locally deployed batteries are individually controlled by their owners in order to reduce the variability of their own net power exchange. The objective function adopted in this and the previous scenario are non-linear, therefore convex optimization algorithms have been employed for resolving the following problem. Every bus i that has a BESS optimizes the following problem:

$$\min \sqrt{\frac{\sum_{t=1}^{T} \left(P_{net\,i}(t) + p_{b_i}^{ch}(t) - p_{b_i}^{dis}(t)\right)^2}{T}} \tag{2.11}$$

$$s.t.$$

$$P_{net\,i}(t) = P_{load_i}(t) - P_{PV_i}(t) \tag{2.12}$$

$$0 \leq p_{b_i}^{ch}(t) \leq p_{b_i\,max}^{ch}(t) \qquad \forall t \tag{2.13}$$

$$0 \leq p_{b_i}^{dis}(t) \leq p_{b_i\,max}^{dis}(t) \qquad \forall t \tag{2.14}$$

$$E_{b_i\,min} \leq E_{b_i}(t) \leq E_{b_i\,max} \qquad \forall t \tag{2.15}$$

$$E_{b_i}(t) + \left(\eta_{b_i}^{ch} \cdot p_{b_i}^{ch}(t) - \frac{1}{\eta_{b_i}^{dis}} \cdot p_{b_i}^{dis}(t)\right) \cdot \Delta t = E_{b_i}(t+1) \qquad \forall t \tag{2.16}$$

The objective of the problem formulated in Equation 2.11 is to minimise the standard deviation of the net power exchange of the bus with the grid. It is subject to the underlying constraints, which are equivalent to the first scenario, but referred to only one battery since decentralised control is implemented. Equation 2.12 defines the net power at bus i without the battery, given by the difference between the load and the power generated by the PV system at bus i. Equation 2.13 and Equation 2.14 express the maximum battery power during charging and discharging mode. Equation 2.15 controls the operation of the battery within the allowed maximum and minimum battery capacity. Equation 2.16 is equivalent to Equation 2.10. As with aggregated control, convex optimization has been employed due to the non-linearity of the objective function.

2.5.3 Decentralised control strategy: market approach

In the following problem, battery owners individually control their assets in order to minimize their own cost function. To this end, the optimization problem has been implemented as a mixed-integer linear programming (MILP).

$$\min \sum_{t=1}^{T} \left[c^*_{p\,i}(t) \cdot x_{p\,i}(t) - c^*_{s\,i}(t) \cdot x_{s\,i}(t) + C^{degr}_{b_i} \cdot \left(p^{ch}_{b_i}(t) - p^{dis}_{b_i}(t) \right) \cdot \Delta t \right] \quad (2.17)$$

$s.t.$

$$P_{net\,i}(t) + \eta^{ch}_{b_i} \cdot p^{ch}_{b_i}(t) - \frac{1}{\eta^{dis}_{b_i}} \cdot p^{dis}_{b_i}(t) - x_{p\,i}(t) + x_{s\,i}(t) = 0 \qquad \forall t \quad (2.18)$$

$$E_{b_i}(t) + \left(\eta^{ch}_{b_i} \cdot p^{ch}_{b_i}(t) - \frac{1}{\eta^{dis}_{b_i}} \cdot p^{dis}_{b_i}(t) \right) \cdot \Delta t = E_{b_i}(t+1) \qquad \forall t \quad (2.19)$$

$$E_{b_i\,min} \leq E_{b_i}(t) \leq E_{b_i\,max} \qquad \forall t \quad (2.20)$$

$$p^{ch}_{b_i}(t) \leq p^{ch}_{b_i\,max}(t) \cdot k^{ch}_{b_i}(t) \qquad \forall t \quad (2.21)$$

$$p^{dis}_{b_i}(t) \leq p^{dis}_{b_i\,max}(t) \cdot k^{dis}_{b_i}(t) \qquad \forall t \quad (2.22)$$

$$k^{ch}_{b_i}(t) + k^{dis}_{b_i}(t) \leq 1 \qquad \forall t \quad (2.23)$$

$$x_{p\,i}(t) \leq \alpha \cdot k_{p\,i}(t) \qquad \forall t \quad (2.24)$$

$$x_{s\,i}(t) \leq \alpha \cdot k_{s\,i}(t) \qquad \forall t \quad (2.25)$$

$$k_{p\,i}(t) + k_{s\,i}(t) \leq 1 \qquad \forall t \quad (2.26)$$

Equation 2.17 expresses the cost function to be minimised, where the energy to be purchased or sold in each time-step is evaluated based on the corresponding forecasted cost of energy for the same time, whereas the charge and discharge of the battery is evaluated based on the degradation cost. Equation 2.18 expresses the load and supply balance of the single household at time step t; $P_{net\,i}(t)$ is defined by Equation 2.12. Equation 2.19 and Equation 2.20 control the energy stored in the battery, Equation 2.21 and Equation 2.22 control the maximum charge and discharge power of the battery instead. As in [87], Equation 2.23 and the binary variables $k^{ch}_{b_i}$ and $k^{dis}_{b_i}$ are introduced as charge and discharge of the battery cannot coexist. The parameter α defined for the MILP problem in Equation 2.24 and Equation 2.25 is an arbitrary value that is larger than $x_{p\,i}$ or $x_{s\,i}$, and is set to 1000. Equation 22 ensures that selling and purchasing electricity do not coexist in the same time step, using other two binary variables, $k_{p\,i}$ and $k_{s\,i}$.

2.6 Micro market

The proposed micro market is applied to the decentralised control and it is implemented in a platform coordinated by an aggregator. The market comprises two separated sections: one to allow P2P trading of energy and the other to allow capacity trading (micro balancing market, reserved to prosumers that have BESSs). Both are here presented.

2.6.1 Micro energy market: peer-to-peer trading

The proposed MEM platform allows prosumers to trade their surplus energy with other prosumers/users within the micro-grid. The market is run every time step

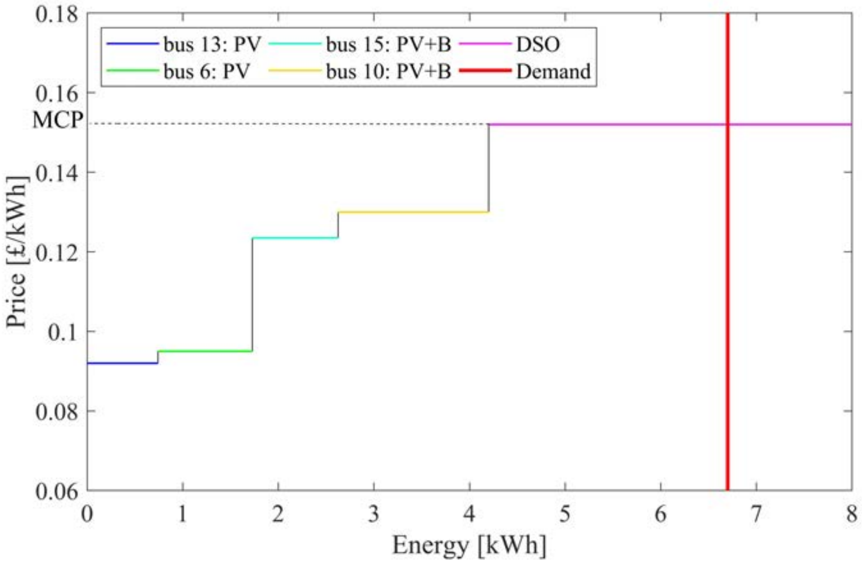


Figure 2.26: Example of the MEM equilibrium for a time step. In this example the total PV generation within the microgrid is lower than the total energy demand

and enables P2P energy trading at a price that could differ from the retail price. In the event of generation surplus, the market price will be set to a value lower than the spot price. Electricity consumers (users) simply communicate the power they need to buy, whereas each prosumer, after having calculated their net power, communicates the prospective energy that they intend to trade. The prosumers sell their surplus energy at the LCOE of their systems. The submitted energy demands are cumulated under a demand curve that is assumed inelastic, and the offers of energy are ordered in ascending price order. The DSO is always the last participant in the marked and is assumed to have unlimited capacity. Finally, the equilibrium in the market is found and the market-clearing price (MCP) is determined, as shown in Figure 2, where the total PV+BESS generation within the microgrid is lower than the total demand. This represents the trading price, set for the buyers and sellers in the MEM. If any energy offer is not sold within the MEM, it is then purchased by the DSO at a price lower than the clearing price. In particular, the price paid for this energy ($D^{DSO}_{trade} = 0.046£/kWh$) has been chosen for the reasons explained in subsection 2.3.3. The spot price offered in the market by the DSO is a RTP that reflects the trend of the N2EX Day Ahead Auction Prices [88], scaled to the average price of 0.16 £/kWh (see subsection 2.3.3). An example of this is given in Figure 2.27.

2.6.2 Micro balancing market: congestions and contingencies balance

The proposed micro balancing market (MBM) is an additional platform where prosumers can subscribe the capacity of their batteries to the aggregator. Battery owners may commit all or part of their total battery capacity in the negotiated time steps, in order to balance the grid in case of contingencies or congestion, or any unforeseen events that need extra power. The providers are payed an avail-

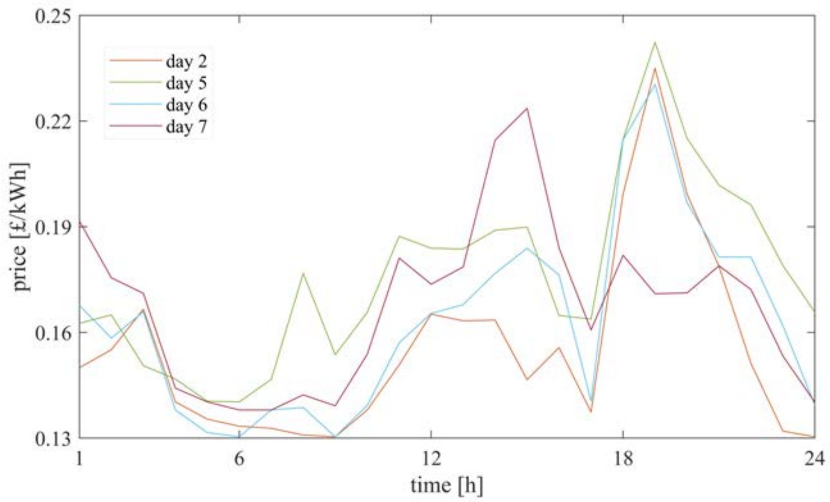


Figure 2.27: Examples of the real time spot price for the month of december.

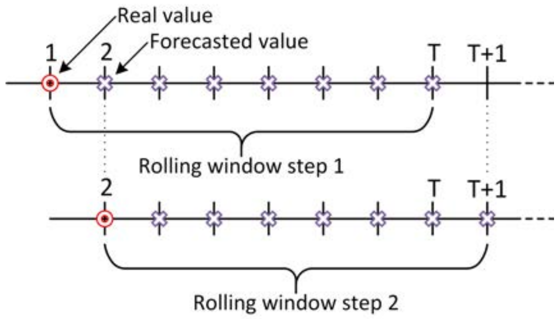


Figure 2.28: Schematic representation of the rolling window operation

ability rate (per kW committed for all the commitment hours) and a utilization rate for the actual energy exchanged. In this work, the contracted prices have been set to 0.0043 £/kW/h for availability and 0.14228 £/kWh for utilization, as the average contracted price in the short-term operation reserve annual market report 2016/17 [89]. A number of 275 interventions/year will be considered in the analysis (as reported in [89]).

2.7 Rolling window optimization

The real-time optimal scheduling of BESSs proposed in section 2.5 are implemented with a rolling window of length T, where T is the number of time step. For this study $\Delta t = 1$ hour resolution and T=24 time steps have been chosen in order to cover a day. A graphical representation of the concept of the rolling window is shown in Figure 2.28. Measurements and predictions of the electricity demand and PV generation are employed in this approach. In the first, and current, time step t of the rolling window, measurements of the electricity demand and PV generation are available. On the contrary, for the remaining time steps, t = t+1,. . . , T, the aforementioned parameters are forecasted. The optimization is then performed over the whole window and only the scheduling for the first time step is implemented. For the following time step t+1, the horizon window slides one step forward and then the process is repeated.

2.8 Assessment metrics

In this section, I present some metrics that quantify the techno/economic benefits of the different scenarios. To evaluate the results from an economic point of view, two cost parameters, for the customer and for the DSO, are defined in Equation 2.27 and Equation 2.28 respectively.

$$\begin{aligned} C_i\left(t\right) =& E_{PV_i}(t) \cdot LCOE_{PV_i} + \left(E_{b_i}^{ch}(t) + E_{b_i}^{dis}(t)\right) \cdot C_{b_i}^{degr} + \\ &+ E_{buy_i}(t) \cdot MCP(t) + E_{sell_i}^{LM}(t) \cdot MCP(t) + \\ &+ E_{sell_i}^{DSO}(t) \cdot C_{trade}^{DSO} + E_{losses_i}(t) \cdot C_{losses}(t) \end{aligned} \tag{2.27}$$

$$C_{DSO}\left(t\right) = E_{sell}(t) \cdot C_{selling}^{profit} - E_{buy}(t) \cdot \left(C_{sell}^{average} - C_{trade}^{DSO}\right) \tag{2.28}$$

Subsidy schemes for renewable energies or any other incentives are not considered in this study. For the users, the PV generation is valued at the levelized cost of electricity ($LCOE_{PV_i}$) of the installation. Prosumers with ESS incur in battery degradation, which has been quantified as $C_{b_i}^{degr}$. The energy purchased and sold in the MEM are valued at the MCP while the energy sold to the DSO receives a different remuneration C_{trade}^{DSO}. The term $E_{losses_i}(t)$ is computed after and AC power flow is computed, and it is the proportion of network losses assigned to bus i. This term is calculated splitting the total losses in proportional way to the use of the grid, i.e. proportionally to the net exchange at the point of delivery (POD) of bus i. Finally, losses are valued at the spot price in the same time step.
Regarding Equation 2.28, it is assumed that the DSO has a profit of $C_{selling}^{profit} = 0.02£/kWh$ on every kWh sold to customers, then the surplus energy purchased from the microgrid at C_{trade}^{DSO} is assumed to be sold at an average price of $C_{sell}^{average} = 0.16£/kWh$.
To assess the performance of the scenarios some technical assessment metrics are defined. The self-consumption (SC) and self-sufficiency (SS) calculated at the POD are defined in Equation 2.29 and Equation 2.30, and at the PCC in Equation 2.31 and Equation 2.32. The SC is the ratio between the energy directly consumed from the PV plant and the overall PV energy generated. The SS is the energy directly consumed from the PV plant over the total demand.

$$SC_{POD_i} = \frac{\sum_t min\left(P_{PV_i}(t), P_{load_i}(t) + p_{b_i}^{ch}(t)\right)}{\sum_t P_{PV_i}(t)} \tag{2.29}$$

$$SS_{POD_i} = \frac{\sum_t min\left(P_{PV_i}(t), P_{load_i}(t) + p_{b_i}^{ch}(t)\right)}{\sum_t P_{load_i}(t)} \tag{2.30}$$

$$SC_{PCC} = \frac{\sum_t min\left(\sum_{i=1}^{B} P_{PV_i}(t), (\sum_{i=1}^{B} \left(P_{load_i}(t) + p_{b_i}^{ch}(t)\right)\right)}{\sum_t \sum_{i=1}^{B} P_{PV_i}(t)} \tag{2.31}$$

$$SS_{PCC} = \frac{\sum_t min\left(\sum_{i=1}^{B} P_{PV_i}(t), (\sum_{i=1}^{B} \left(P_{load_i}(t) + p_{b_i}^{ch}(t)\right)\right)}{\sum_t \sum_{i=1}^{B} P_{load_i}(t)} \tag{2.32}$$

Chapter 3

Case study

3.1 Residential low voltage distribution grid

The proposed methodology is applied to a Low Voltage (LV) feeder of a typical UK distribution network model [90]. A portion of a residential area located in Newcastle upon Tyne (UK) is shown in figure 3.1. For an efficient simulation in line with the scope of the present work, a symmetric and balanced three-phase system is assumed, hence a single-phase equivalent circuit is considered. Then, the feeders connected to the 327 houses are neglected and a distance of 10 meters between each house in the other branches is assumed. Three nominal cross section area are presents, type parameters of cables are specified in table 3.1. Overall, 19 households are connected to this network. A 40% of roof-top solar PV is considered, randomly distributed, in line with [91]. Moreover, all the PV plant are assumed to have the same standard capacity of 3kWp, and since the households are distributed in a small area, the PV production profiles are taken the same. Then, a 50% of BESS coupled with the PV systems are assumed. A schematic representation of the simulated distribution grid is presented in figure 3.2 and the characteristics of the lines are summarized in table 3.2. Bus 'a' at the substation transformer (corresponding to the PCC) is assumed as slack bus and its voltage is fixed at 1pu. The Points of Delivery (PODs) correspond to the connection points of the buses to the grid. Both active and reactive power flows are considered with a power factor pf=0.9 for every residential load. Differently, PV output and power exchanged with BESS are assumed to have pf=1.

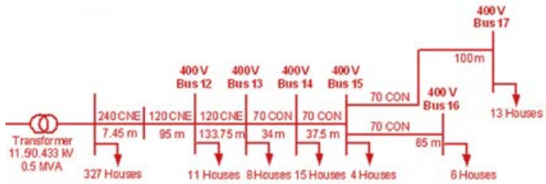


Figure 3.1: Typical UK distribution network

3.2 Load and photovoltaic profiles

Daily households demand profiles for the 19 different houses showed in the network in 3.2 were obtained from the Centre for Renewable Energy Systems Tech-

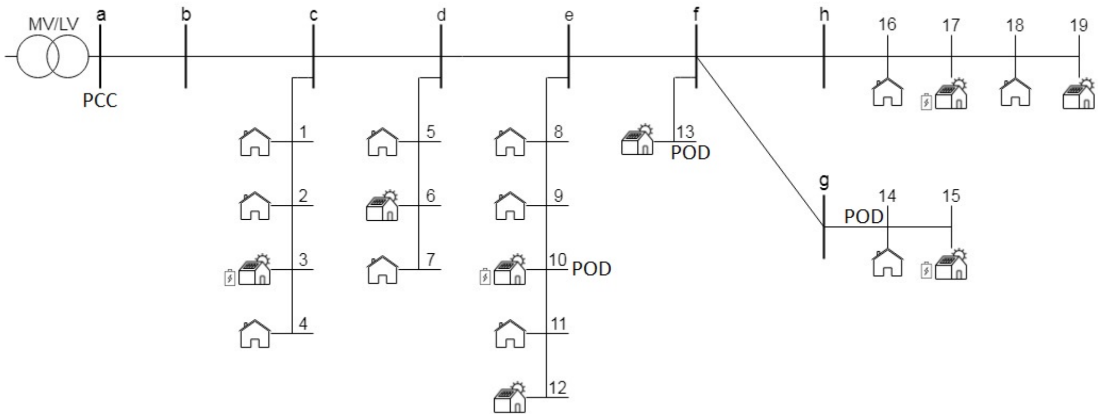


Figure 3.2: Representative framework of the network

Table 3.1: Type of cables and main parameters

Cable impedances and max current

	I_{max} [A]	R/km	X_L/km
Al Consac 240 mm^2	218	0.125	0.068
Al Consac 120 mm^2	150	0.253	0.0685
Al Consac 70 mm^2	110	0.443	0.0705

Table 3.2: Network's characteristics

Line	R [Ω/Km]	X [Ω/Km]	L [m]	I_{max} [A]
a-b	0.125	0.068	7.45	218
b-c	0.253	0.0685	95	150
c-d	0.253	0.0685	133.75	150
d-e	0.443	0.0705	34	110
e-f	0.443	0.0705	37.5	110
f-g	0.443	0.0705	65	110
g-h	0.443	0.0705	100	110
leftovers	0.443	0.0705	10	110

Table 3.3: Percentage of residents/house in UK [92, 93]

People/house	Percentage
1	30%
2	25%
3	35%
4+	10%

Table 3.4: Percentage of residents/house considered for the network in figure3.2

People/house	Percentage
2	32% (6 houses)
3	37% (7 houses)
4	26% (5 houses)
5	5% (1 house)

nology (CREST) demand model tool [72], choosing for each house, manually and randomly, a set of appliances. Therefore for each household and for each day simulated a daily electricity demand profile was generated. Data were generated with one minute resolutions, then hourly averages were computed. The number of residents for the houses was chosen taking into account some statistics. In particular, from [92, 93] an average of 2.4 people/home was extracted, and in table 3.3 is showed the number of people per dwelling extracted from the two references. However, since the area is meant to be residential with single houses, the assumption of an higher average number of residents/house and a different percentage distribution is considered. In particular, the new distribution of houses presented in table 3.4 has an average of 3 residents per house.

Generation profile of PV system is the result of one year metering (year 2017) on a real rooftop solar PV system installed in a household located in Loughborough, a city in the East Midlands of the UK. Data were collected with 5 minutes resolutions, then hourly averages were computed. More information have been previously presented in 2.3.1 and won't be replicated.

3.3 PV plant and BESSs: specifications

The PV systems and BESSs deployed in the distribution network are considered to be all the same size and to have the same characteristics. The system specifications for all the network components are reported in Table 1. Moreover, only stationary Li-ion batteries are considered in this study. In line with the UK government values a range of prices between 1600 and 1900 £/kWp was chosen to give a variability to the LCOE of all the PV systems. Then, all the other data chosen for the simulations are the ones presented in subsection 2.3.3. To account for the degradation of residential stationary BESS, the market research and future projection analysed in section 2.2 is take into account. Current and future installation costs (10 and 20 years), resulting from the projections, are reported in Table 3.5. The economic life of the BESSs is taken as 10 years and it is assumed that they perform at their best during their life. To quantify the cost

Table 3.5: PV and BESS parameters used in simulations

PV system	
Nominal capacity	3 kWp
Yield	1000 kWh/kWp
Degradation	0.50%/year
CAPEX	1600÷1900 £/kWp
OPEX(t)	18 £/kWp/year
Life time	30 years
$WACC_{nom}$	4%
Inflation	2.20%
$WACC_{real}$	1.76%
BESS	
Nominal capacity	2 kWh
$E_{b_i\,max}$	2 kWh
$E_{b_i\,min}$	0 kWh
$P^{dis}_{b_i\,max}$	2 kW
$P^{ch}_{b_i\,max}$	0.820 kW
Efficiency	100%
Life time	10 years
CAPEX(0)	570 £/kWh
CAPEX(10)	230 £/kWh
CAPEX(20)	200 £/kWh
OPEX(t)	0 £/kWh

of degradation, 5000 charge/discharge cycles are considered. Investment has been actualized as explained in subsection 1.1.3. A final average cost of degradation of 0.028 £/kWh was obtained (see Equation 3.1) and a conservative degradation cost of $C^{degr}_{b_i} = 0.03£/kWh$ was used for this study. This is in line with the current market practice, as some manufacturers already give 10 years or 10000 cycles warranty on their batteries (with an expected residual capacity of 80%) [94].

$$C^{degr}_{b_i} = \frac{\frac{570}{2*5000}}{(1+0.0176)^{10}} + \frac{\frac{230}{2*5000}}{(1+0.0176)^{10}} + \frac{\frac{200}{2*5000}}{(1+0.0176)^{10}} = 0.028 \qquad (3.1)$$

Note that the obtained value is similar to the contribution the BESS gave to the LCOE in subsection 2.3.4. To be thorough, the parameters of interest for the simulations are also summarized in Table 3.5.

3.4 Time periods and simulation details

As anticipated, the months of June and December 2017 have been chosen for the simulations since they are the months of maximum and minimum PV generation of the analyzed PV system. For each month, the simulation was run for an 8 days' period. All the scenarios presented at the beginning of the previous section have been simulated. The results and a comparative analysis will be presented in the next section. For those scenarios where the MBM is present, the contracts are stipulated for periods where critical operation can happen. In this study a minimum SOC=0.2 of all the BESS in the grid is reserved for the MBM from 4:00 pm to 11:00 pm. As anticipated in the subsection 2.6.2, a number of 275 interventions per year will be considered. For further study, also some contracts regarding the max SOC allowed in some time period could be considered.

3.5 Matlab implementation

All the simulations were carried out on a PC having 3.5GHz AMD PRO A4-8360B, and 8GB of RAM running MATLAB software version R2018a.
All that has been previously introduced has been implemented in Matlab, starting from the definition of the buses and the grid, to proceed with the MEM and MBM and the BSCS of the batteries. Two different solvers were employed for the optimization: the nonlinear programming solver 'fmincon' [95] performing interior point algorithm for S2 and S3 and the mixed-integer linear programming solver 'intlinprog' for S4 [96].
The power flow (or load flow as often called) is computed using the Newton-Raphson Algorithm, as explained in [97]. For the Matlab implementation, the code implemented by Neelam Kumar [98], available on MATLAB Central's File Exchange, has been used. Then, appropriate modifications to adapt the code to the project and to the rest of the code have been made.

Chapter 4

Results and discussion

This work aims to evaluate the effects of the different BSCS and to make a comparison between the scenarios presented at the beginning of 2.5 and observe from different points of view which is the best for the stakeholders, in particular for the customers and for the DSO. The scenarios have been compared from many aspects. A first discussion is based on the visualization of trends over time of demand and DERs (PV and BESS). A qualitative comparison of the main characteristics of scenarios is thus presented. A quantitative analysis on physical parameters and techno-economic assessment is carried out in the following. In particular, the scenarios considered have been compared using the following criteria:
Technical assessment:

- The net power exchange at PCC: Total value, mean value and standard deviation
- Total micro-grid losses
- Voltage at the farthest bus (19): magnitude and standard deviation
- Max demand peak power and reverse peak power flow at PCC
- SC and SS at bus level (POD) and at PCC level

Economic assessment:

- Economic benefit

For the month of June 2017, base scenario S1 is first analysed, then scenarios S3, S4 and finally S2 are here presented.
Figure 4.1 represents the series over the time with hourly resolution of load demand and PV generation for two random buses of the grid that have a PV system installed. Then, Figure 4.2 shows the same time-series at the aggregated level (at PCC). It's visible that the cumulated load presents a characteristic pattern with two visible peaks, typically one in the morning and one in the evening. Another consideration can be made on the PV production: except for day 2 and 3 (from h=24 to h=72) that represents two cloudy days, during some hours on sunny days the PV production exceeds the microgrid demand and the power flow

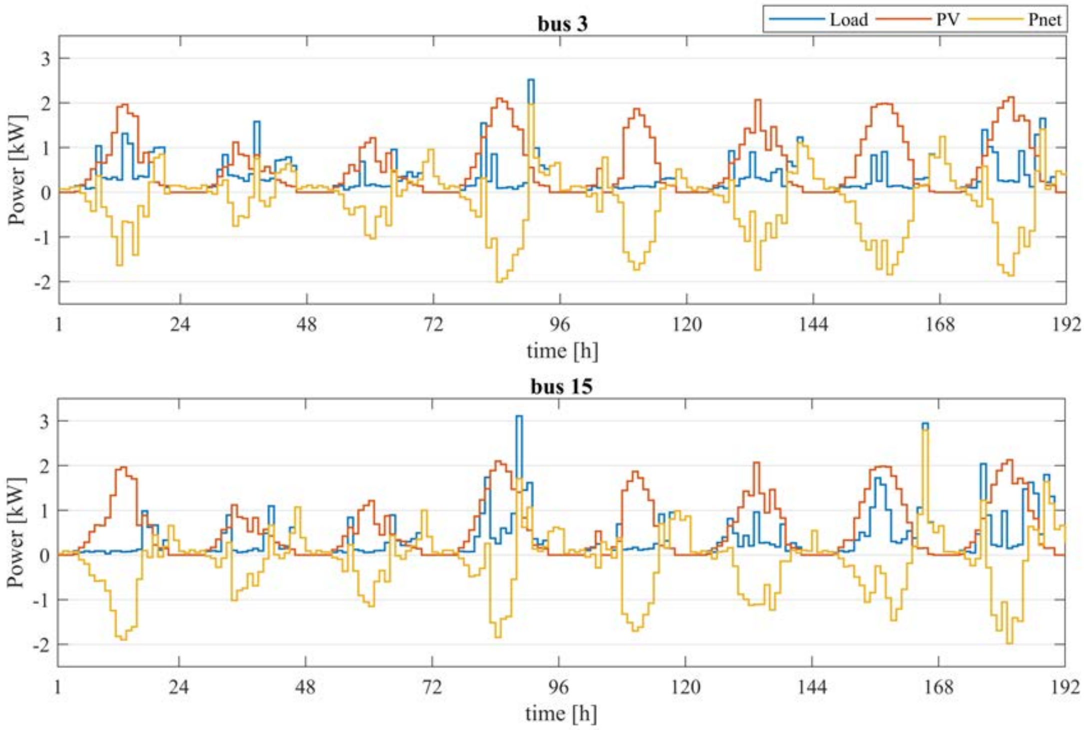


Figure 4.1: Metering at bus level for scenario S1 in June

reverses in the medium-voltage grid. This reverse power flow appear huge and highly variable.

In the following scenarios BESSs are introduced. Comparing Figure 4.3 with Figure 4.1 it's clear that the presence of the battery coupled to the PV system at bus level visibly affects the Pnet curve, reducing generously the variance of the power exchanged at the POD on the bus. Clearly, the Pnet injected into the microgrid is not completely leveled because of the errors due to the PV and load forecast. Nevertheless, results with the assumptions of a perfect forecast is not here presented since not of interest for the project.

A benefit at PCC level is also shown in Figure 4.4 even if in a less visible way. Quantitative analysis in the following will help to clarify the benefits given to the grid.

The SOC of the batteries distributed in the microgrid is shown in Figure 4.5. In this image image the same curve for the scenario S3e is shown for comparison. It's visible that in the presence of the contingency market, the batteries discharge less or postpone the discharge since they have to guarantee a minimum SOC as settled with the contract.

In Figure 4.6 the load demand, PV generation and BESS charge/discharge in scenario S4 for the same two buses as before is presented. A completely different behavior of the battery can be observed, since now a minimization of a cost function is performed. Therefore the battery charges when the price to buy energy is forecasted low and discharges during time slots in which the forecasted price to sell the energy is high, in accordance to Equation 2.17.

A wider vision is given in Figure 4.7, where the results of the simulation at

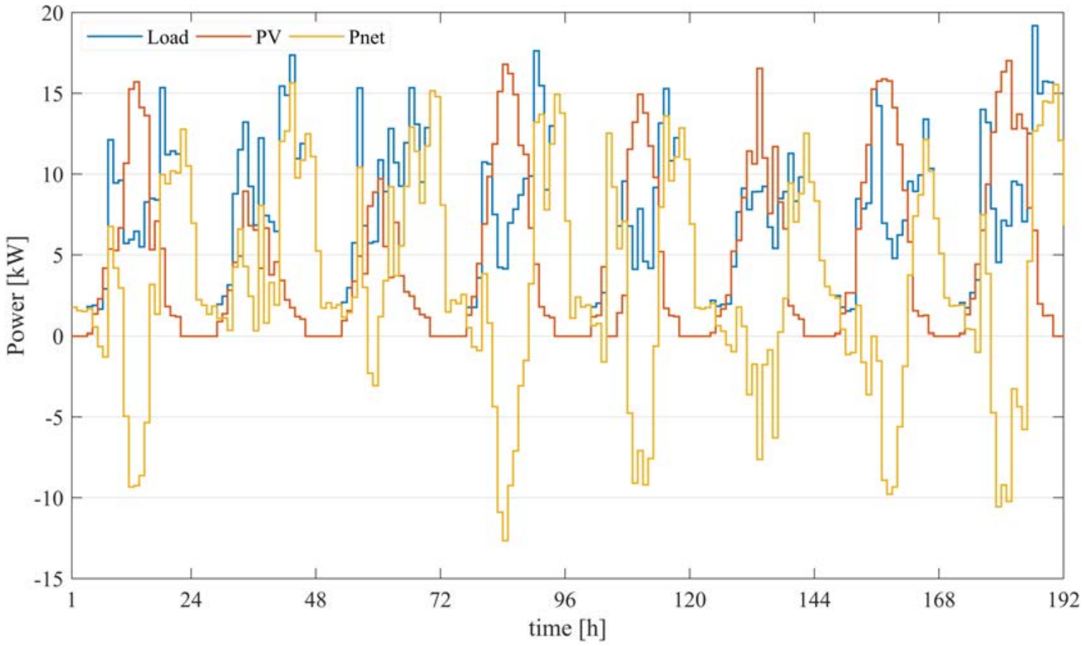


Figure 4.2: Metering at PCC level for scenario S1 in June

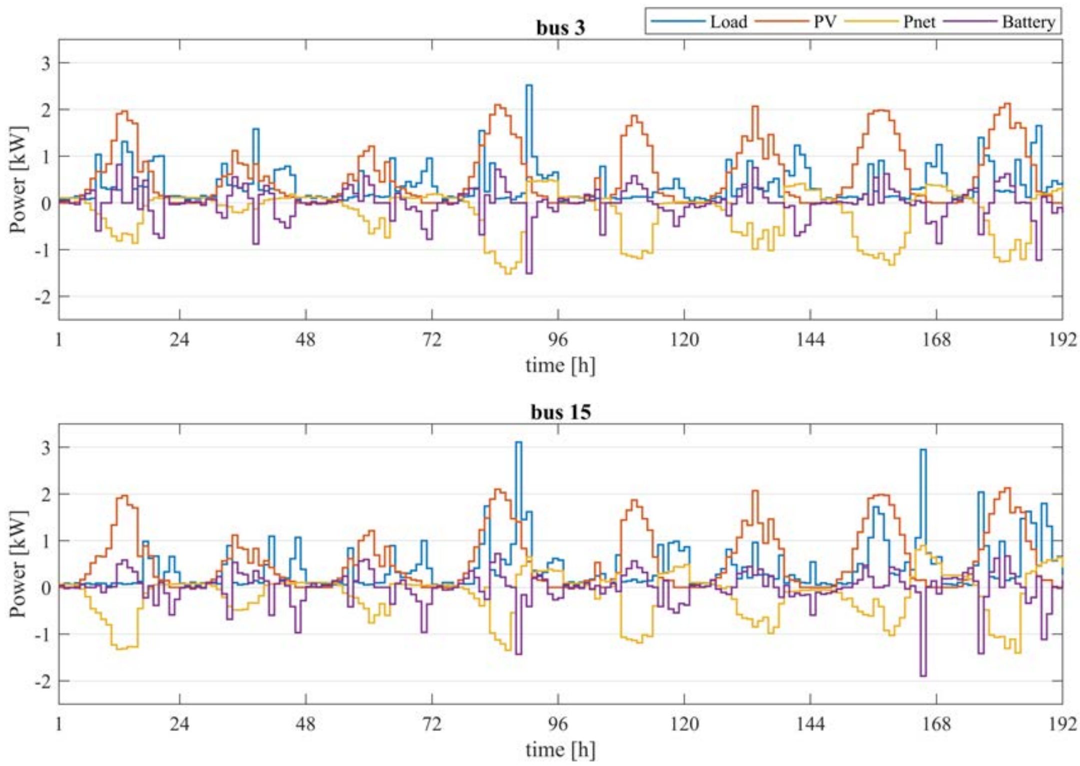


Figure 4.3: Metering at bus level for scenario S3 in June

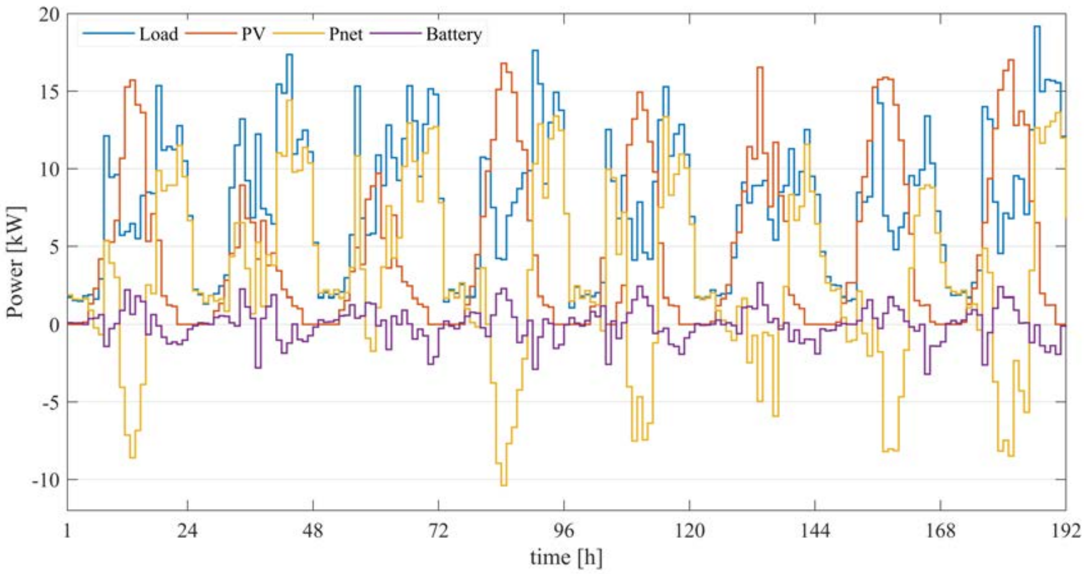


Figure 4.4: Metering at PCC level for scenario S3 in June

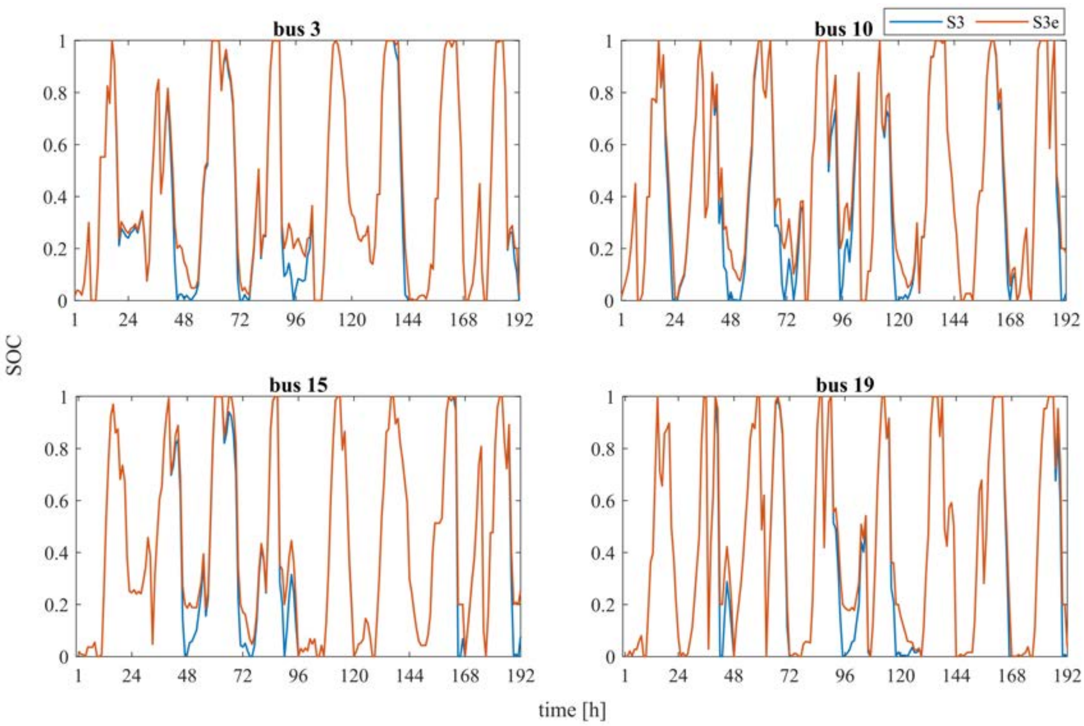


Figure 4.5: SOC of distributed BESSs for scenario S3 and S3e in June

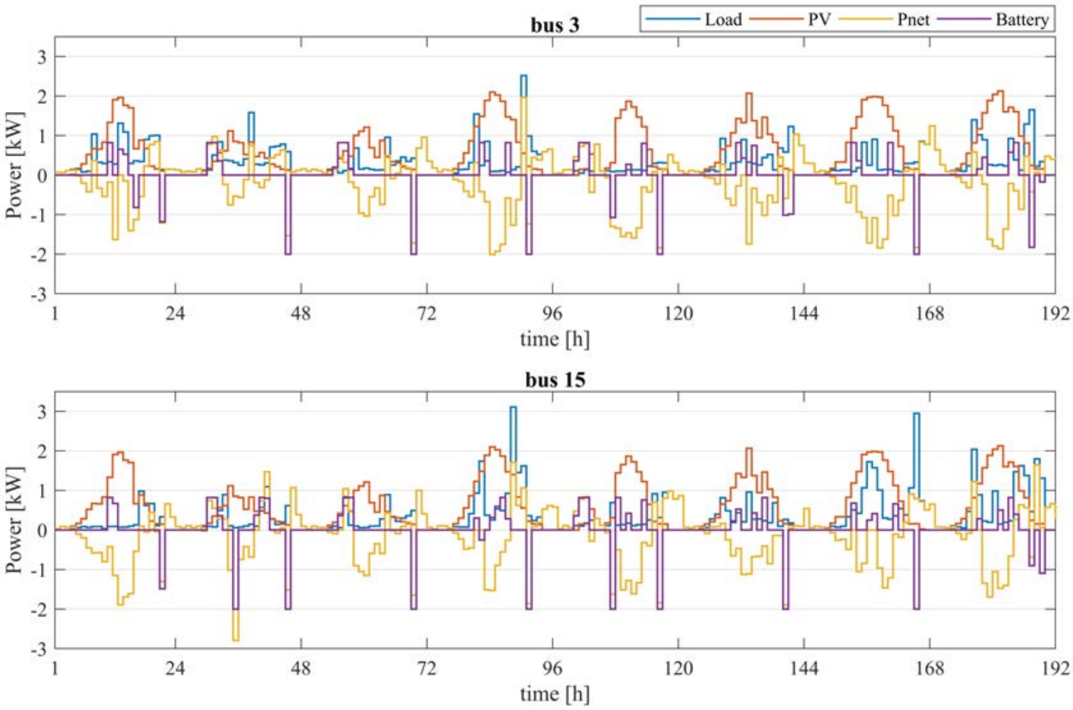


Figure 4.6: Metering at bus level for scenario S4 in June

PCC level is shown. Here also the spot price is shown. It's visible that the batteries charge when there's surplus of generation given by RES, i.e. when the price of the energy is low. Differently batteries discharge in the evening, when PV generation is missing and precisely in the time step in which the spot price is the highest.

Figure 4.8 shows the SOC of batteries present in the micro-grid. A comparison with Figure 4.5 highlights the differences between the two BSMS. Moreover, the comparison of the curves for the S4 and S4c scenario underlined what previously said about the S3 scenario. This time the differences due to the presence of the contingency market are more significant, however here it's not shown the calls to operate in the contingency market. Adding the operations in that market would reduce the differences between the scenarios S4 and S4e.

Finally results of simulation of scenario S2 are presented. Figure 4.9 shows what happen at house level in ths scenario, however since batteries are centrally controlled this figure is not discussed because it's not significant.

High relevance has Figure 4.10 instead, where the metering at the transformer for scenario S2 is shown. The optimization of the battery management is performed at the PCC level with the aim of reducing the variance of energy exchanged with the MV grid, as previously explained. The benefit on the grid is visible here on the reduction of variability of net power exchanged, specially compared to the previous scenarios presented.

Figure 4.11 finally underlines that the batteries in this scenario are exploited the most. Further discussions are presented afterwards.

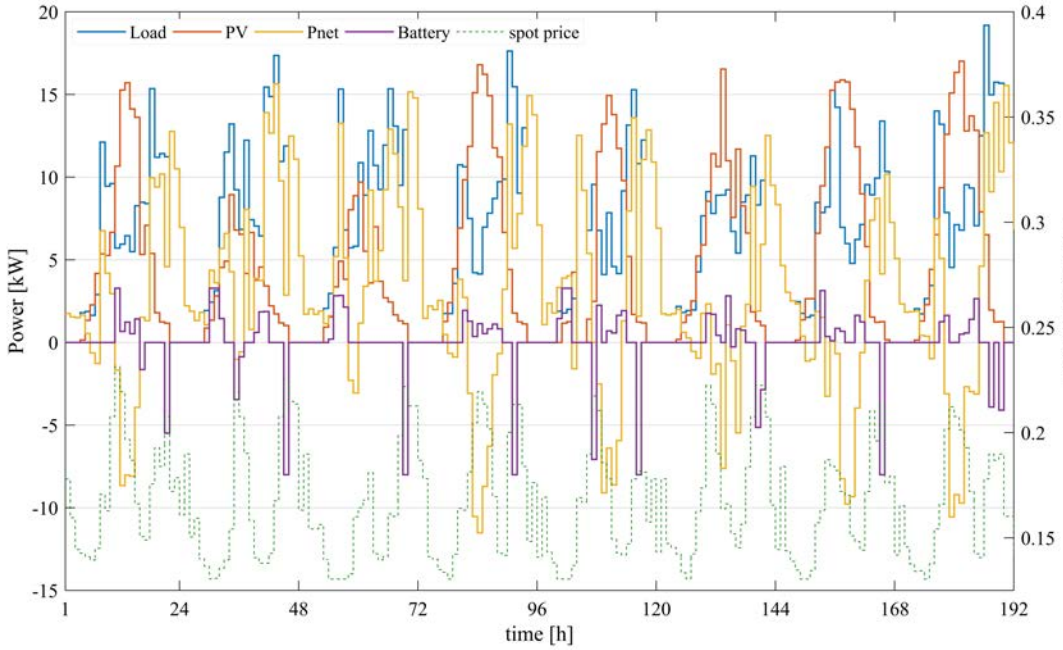


Figure 4.7: Metering at PCC level for scenario S4 in June

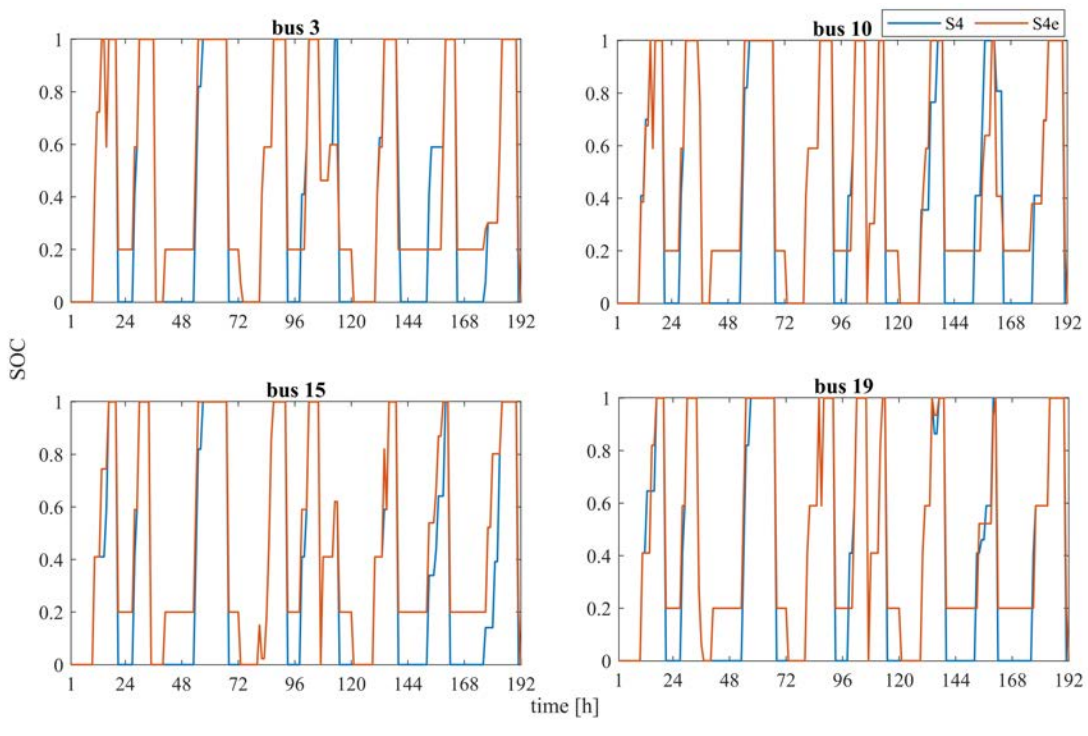


Figure 4.8: SOC of distributed BESSs for scenario S4 and S4e in June

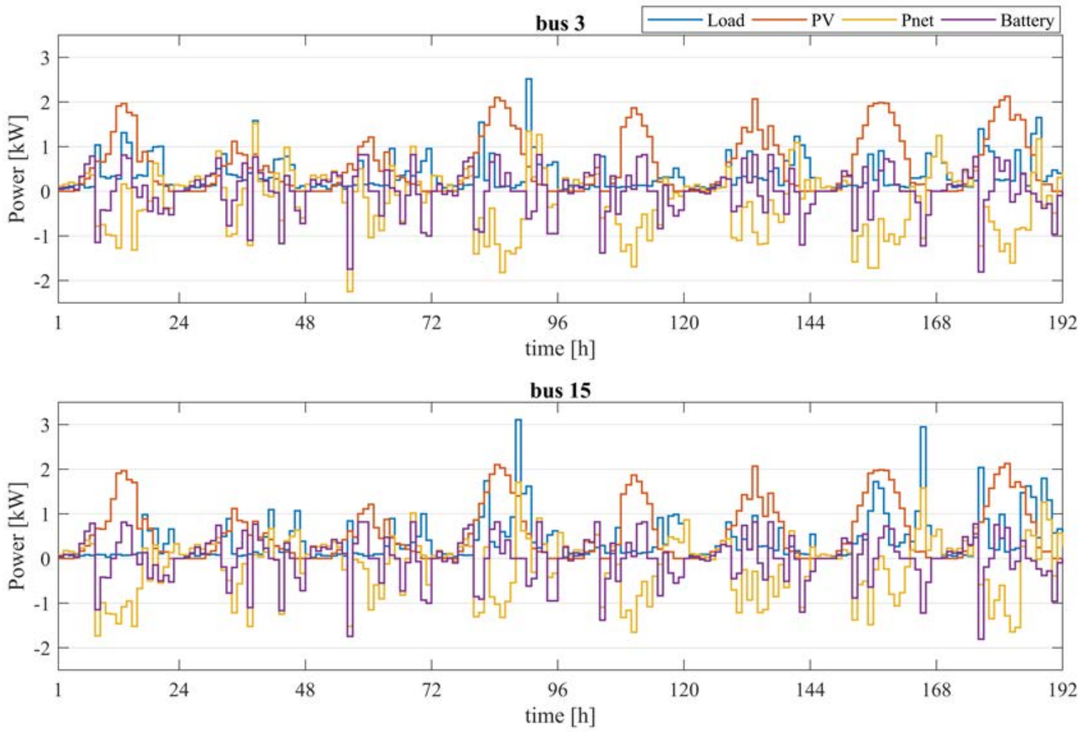


Figure 4.9: Metering at bus level for scenario S2 in June

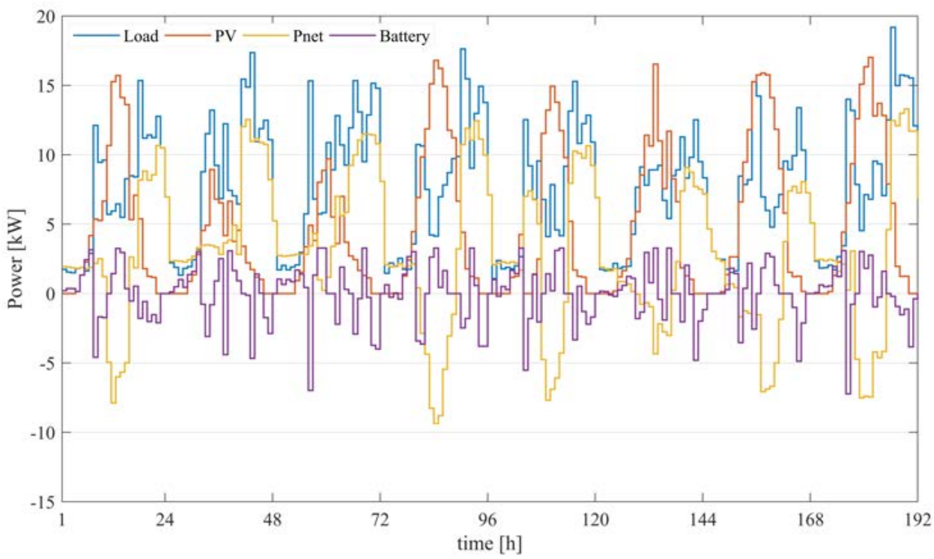


Figure 4.10: Metering at PCC level for scenario S2 in June

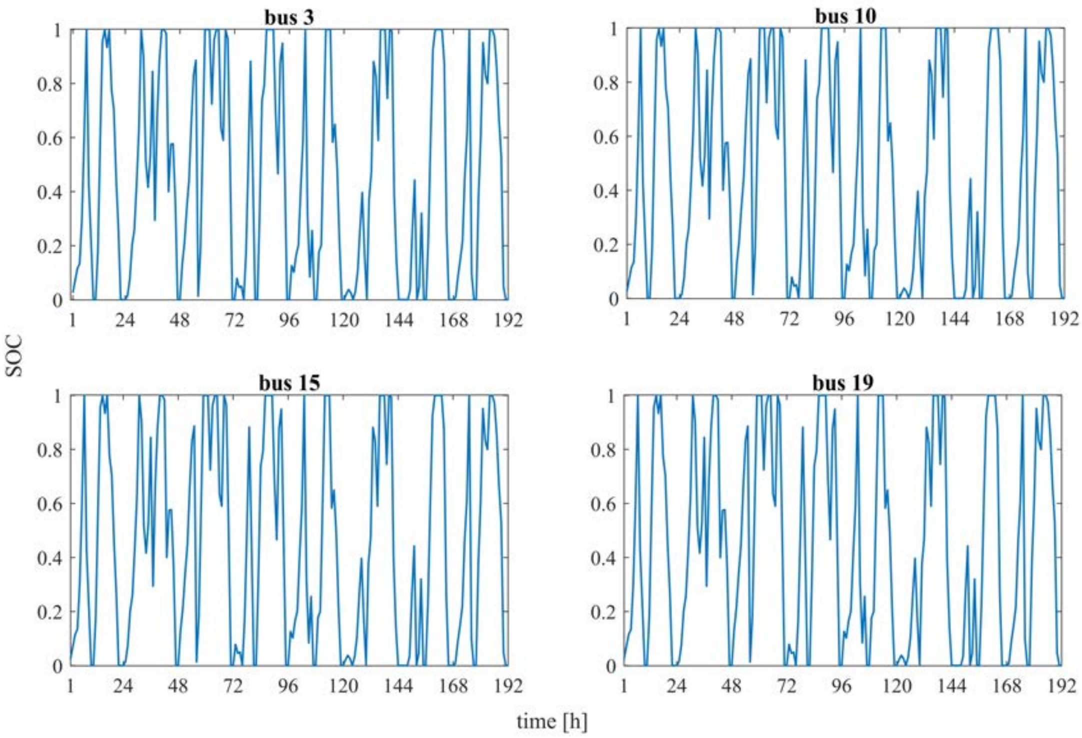


Figure 4.11: SOC of distributed BESSs for scenario S2 in June

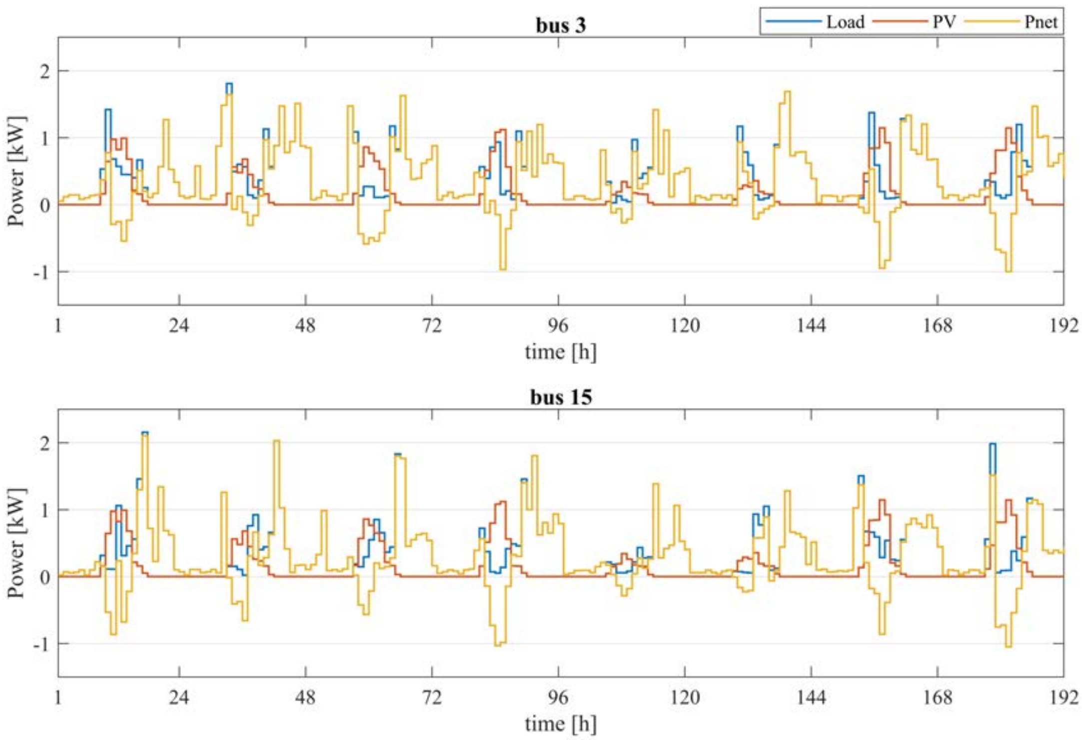


Figure 4.12: Metering at bus level for scenario S1 in December

The same analysis is now carried out for the simulation in December. As before, the base scenario S1 is first analysed, then scenario S3, S4 and finally S2 are presented.
Figure 4.12 represents the series over the time with hourly resolution of load demand and PV generation for two random buses of the grid that have a PV system installed. The PV generation is much lower compared to June, and the load consumption is higher compared to June instead. This will give rise to new discussions.

Figure 4.13 shows the same time-series at the aggregated level (at PCC). We can again observe that the PV generation profile varies day by day. Sunny and cloudy days are noticeable. Because of the lower PV generation compared to June, the reverse power flow at PCC is not frequent. Only two events are present in this simulation. Moreover, the entity of this events are much lower than the ones in June. Then, comparing to the June simulation in Figure 4.2, it's noticeable that the cumulated demand in December is higher. This is essentially due to the higher consumption of lights and heating in the winter season, compared to summer season.

In the following scenarios BESSs are introduced. Comparing Figure 4.14 to Figure 4.12 it's clear that the presence of the battery coupled to the PV system at bus level visibly affects the Pnet curve, reducing generously the variance of the power exchanged at the POD on the bus. As for the case in June, the errors due to the PV and load forecast are the cause of a non completely paved curve.

A benefit at PCC level is also shown in Figure 4.15 even if in a less visible way. We can observe that sometimes the peak demand is not lowered much;

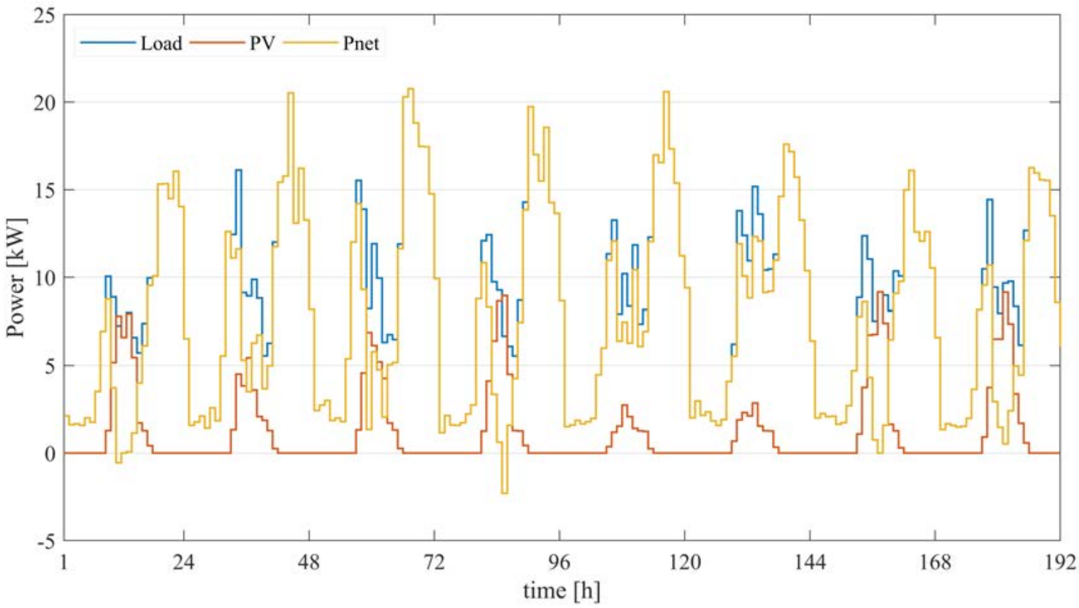


Figure 4.13: Metering at PCC level for scenario S1 in December

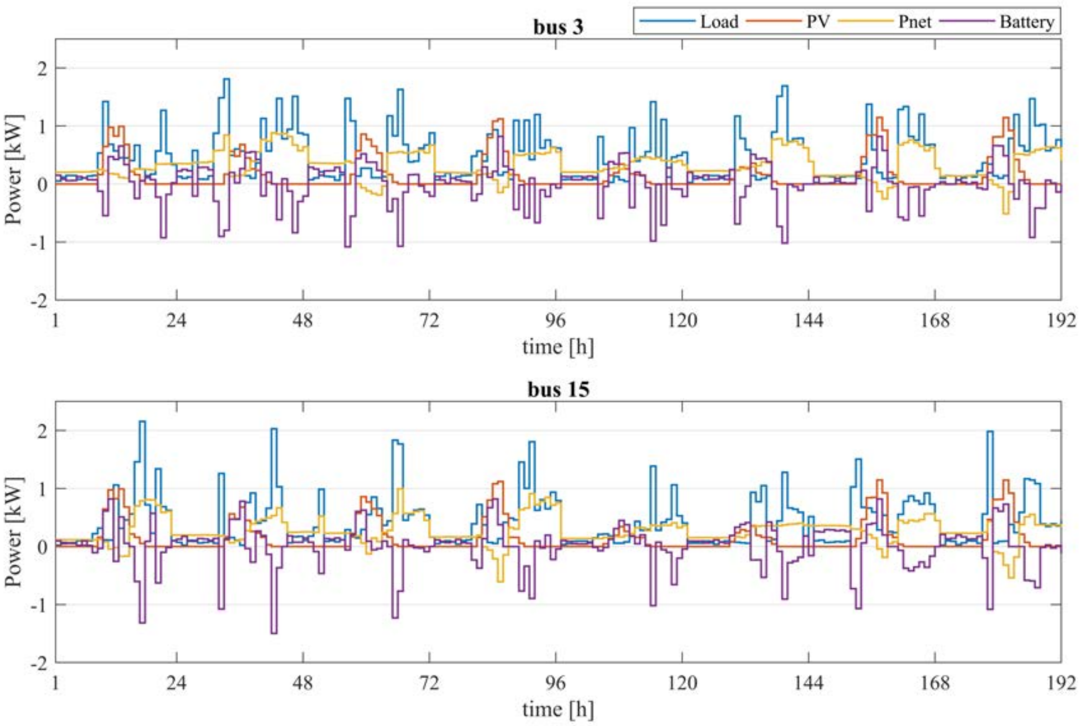


Figure 4.14: Metering at bus level for scenario S3 in December

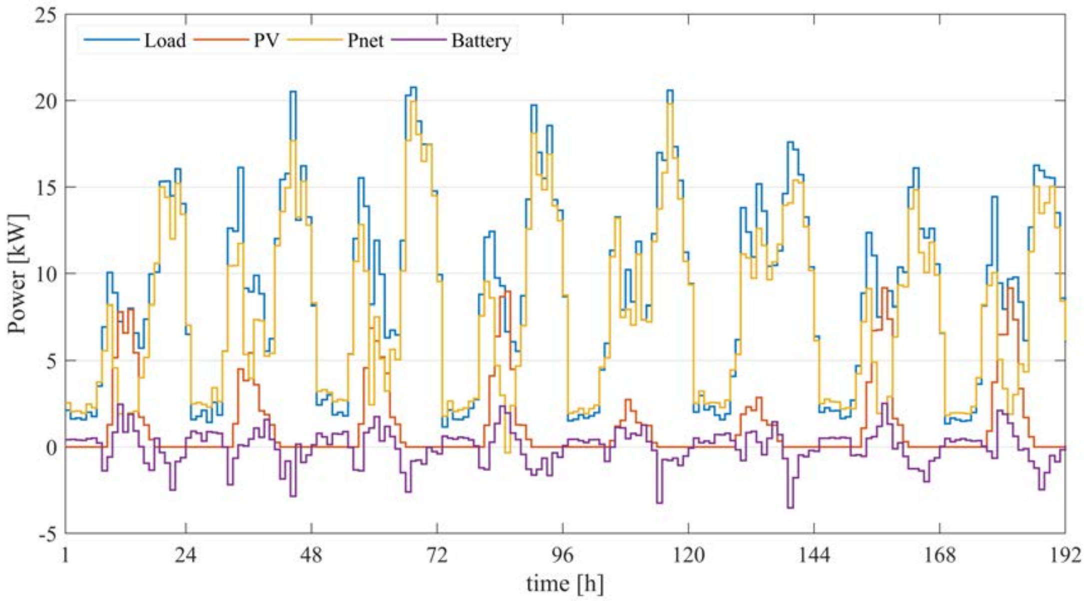


Figure 4.15: Metering at PCC level for scenario S3 in December

this happen because the battery is individually optimized, without being aware of the existence of a cumulated peak. When the cumulated peak corresponds to the peak demand of users having the BESS, the peak of demand is lowered successfully instead. Quantitative analysis in the following will help to clarify the benefits given to the grid.

The SOC of the batteries distributed in the microgrid is shown in Figure 4.16. Same discussion as before can be made.

In Figure 4.17 the load demand, PV generation and BESS charge/discharge in scenario S4 for the same two buses as before is presented. A completely different behavior of the battery can be observed, since now a minimization of a cost function is performed. Therefore the battery charges when the price to buy energy is forecasted low and discharges during time slots in which the forecasted price to sell the energy is high, in accordance to Equation 2.17.

A wider vision is given in Figure 4.18, where the results of the simulation at PCC level is shown. Here also the spot price is shown. It's visible that the batteries charge when the spot price is the lowest. Differently batteries discharge in the evening, when the spot price is the highest.

Figure 4.19 shows the SOC of batteries present in the micro-grid. A comparison with Figure 4.16 highlights the differences between the two BSMS once again.

Finally results of simulation of scenario S2 are presented. Figure 4.20 shows what happen at house level in this scenario, however since batteries are centrally controlled this figure is not discussed because it's not significant.

High relevance has Figure 4.21 instead, where the metering at the transformer for scenario S2 is shown. The benefit on the grid is visible here on the reduction of variability of net power exchanged and on the reduction of max peak of demand, specially compared to the previous scenarios presented.

Figure 4.22 finally underlines that the batteries in this scenario are exploited

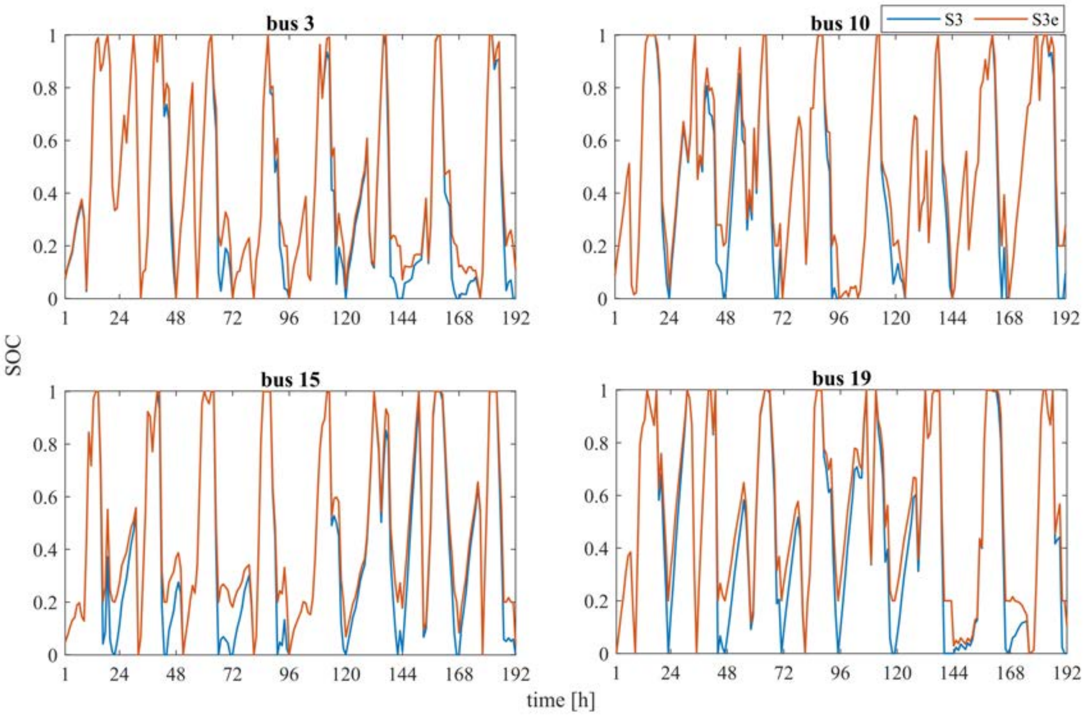


Figure 4.16: SOC of distributed BESSs for scenario S3 and S3e in December

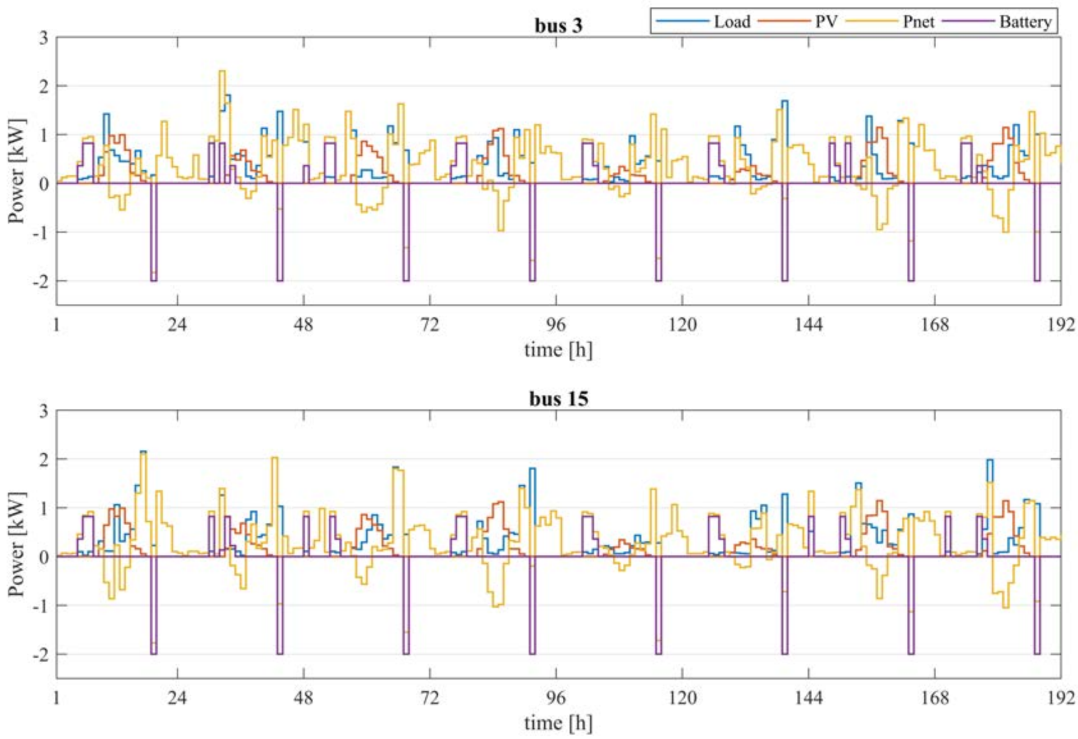


Figure 4.17: Metering at bus level for scenario S4 in December

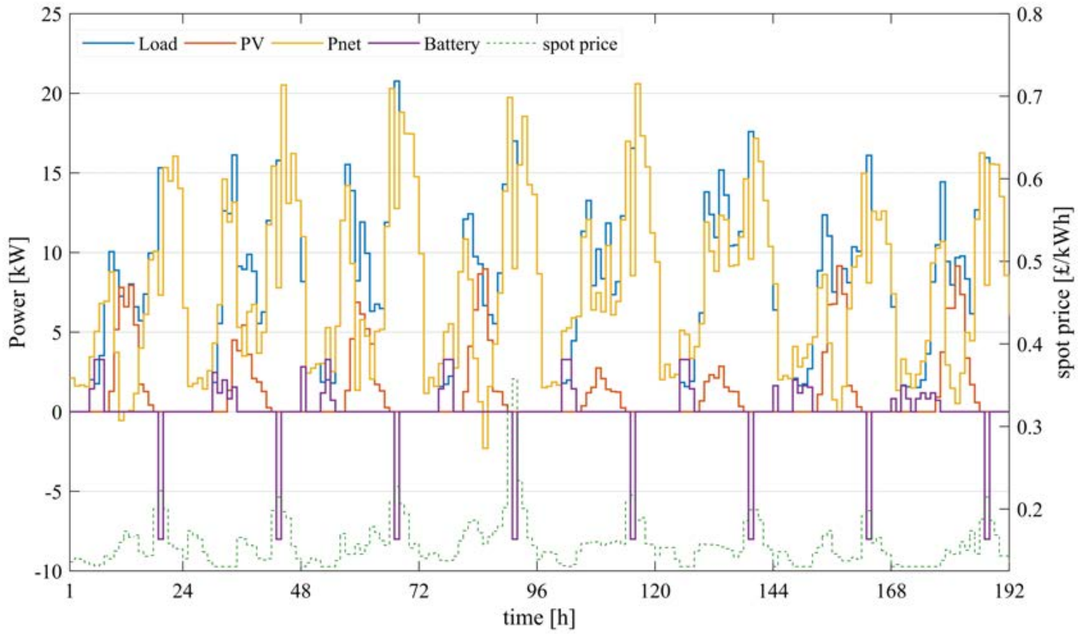


Figure 4.18: Metering at PCC level for scenario S4 in December

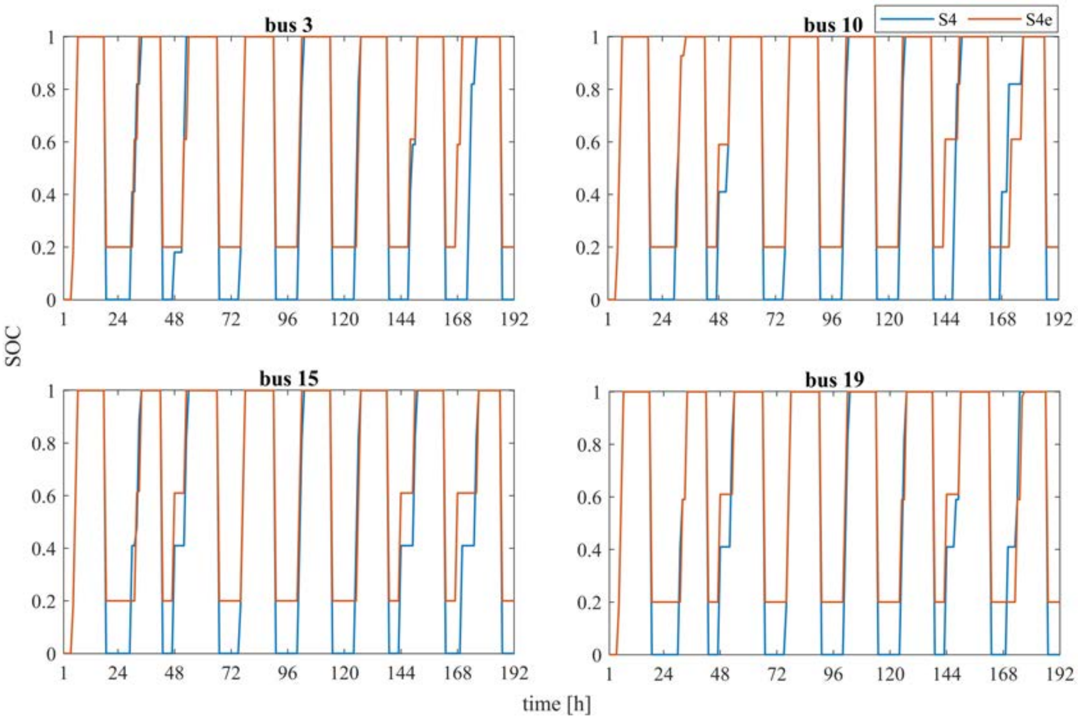


Figure 4.19: SOC of distributed BESSs for scenario S4 and S4e in December

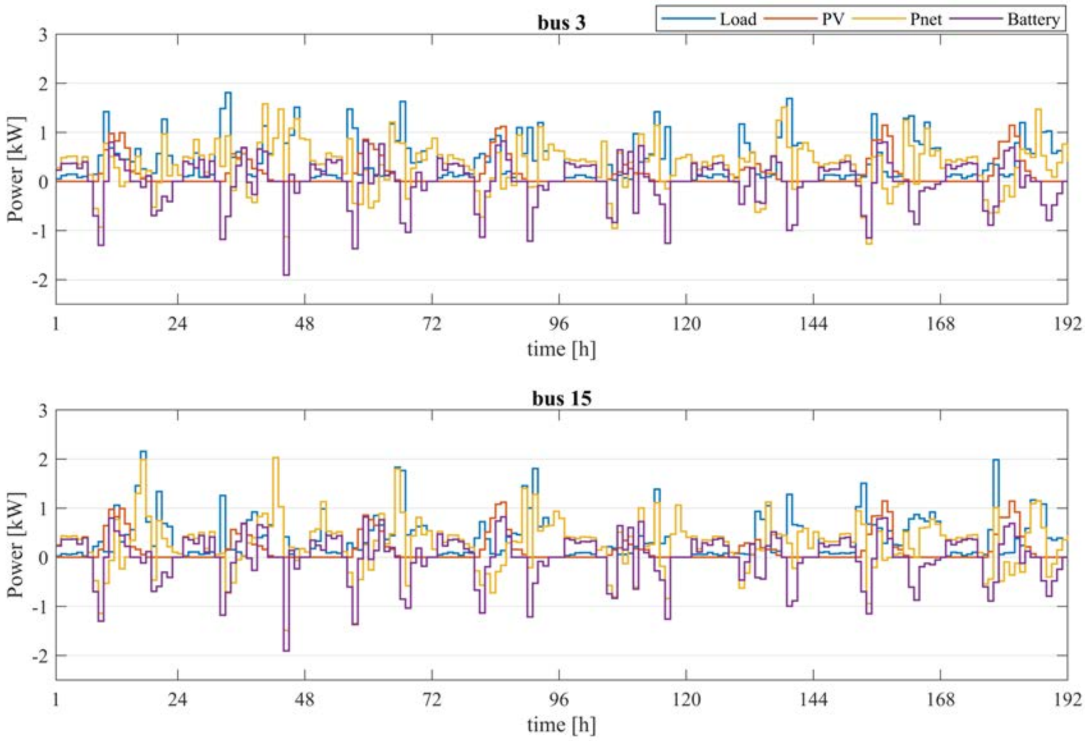


Figure 4.20: Metering at bus level for scenario S2 in December

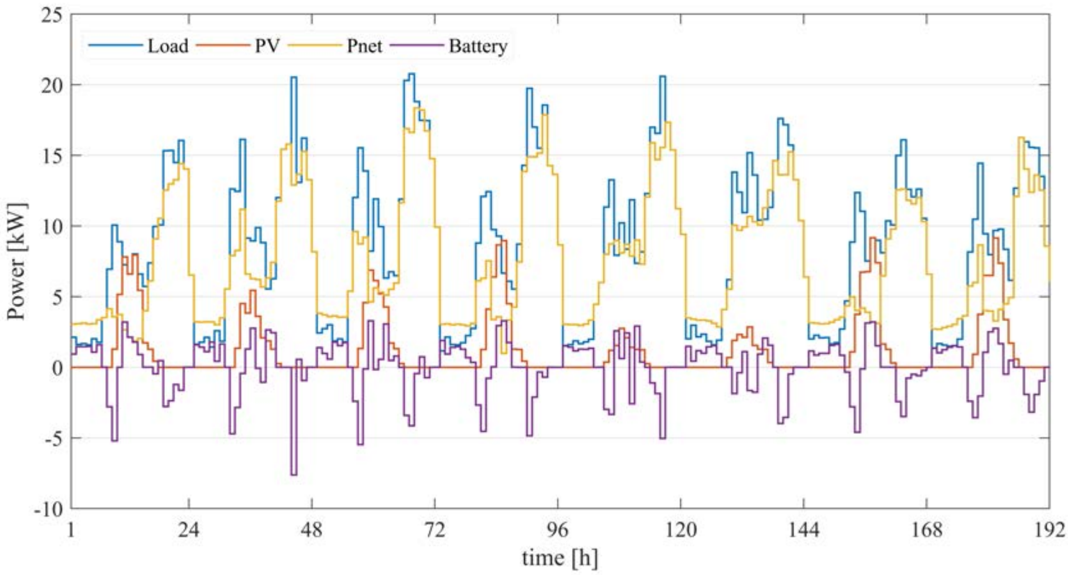


Figure 4.21: Metering at PCC level for scenario S2 in December

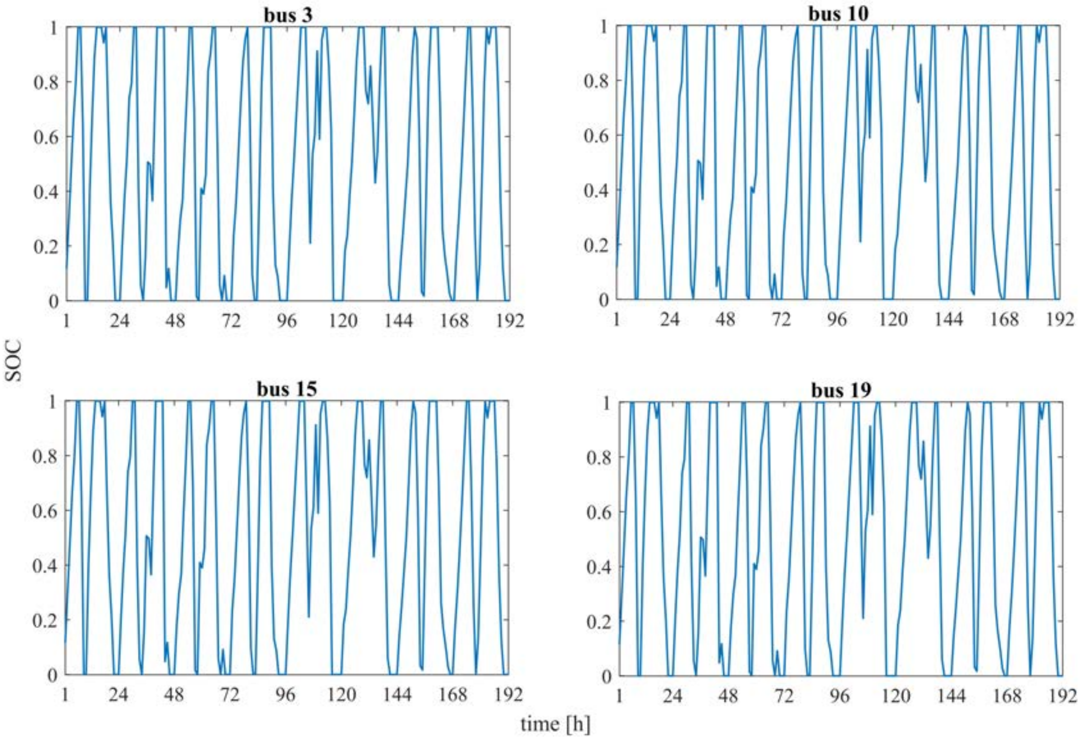


Figure 4.22: SOC of distributed BESSs for scenario S2 in December

the most compared to the others scenarios. Further discussions are presented in the following.

Now, as anticipated at the beginning of this chapter, a techno-economic evaluation and comparison among the scenarios is presented. The results of the simulation of the grid under the different scenarios in June 2017 are graphically presented in Figure 4.23 whereas numeric values are shown in Table 4.1.

From a first analysis, it turned out that the total and mean value of P_{net}^{PCC} and the mean value of voltage magnitude at bus 19 are the same in all the scenarios. Since they are not of interest to draw conclusions they are no longer discussed. Consequently, Figure 5 shows the standard deviation of the net power at the PCC for the different scenarios. The standard deviation of P_{net}^{PCC} in scenarios S2, S3 and S4 is lowered compared to scenario S1. Better results are obtained in S2, thanks to a wide view on the entire state of the grid given by the central control. The better redistribution of power flows within the micro-grid due to the use of the batteries affect the total micro-grid losses. The same happens also in the evaluation of the standard deviation of the voltage magnitude at bus 19. It is visible that S2 performs better from a DSO point of view on all the assessment here presented: S3 also brings grid relief, but to a lesser extent, since the BSCS is performed as a decentralised case. Regarding to the P_{max}^{PCC}, it can be noticed that in scenario S4 the control of the batteries does not allow to lower the peak of demand. Scenario S3 does not perform as good as scenario S2 since the peak of demand of the houses that have batteries does not always coincide with the peak demand at the PCC. Finally, the reverse power flow at PCC is evaluated. For the same reason as before, the scenario S2 performs better than S3. However, this time a reduction is appreciable also for scenario S4.

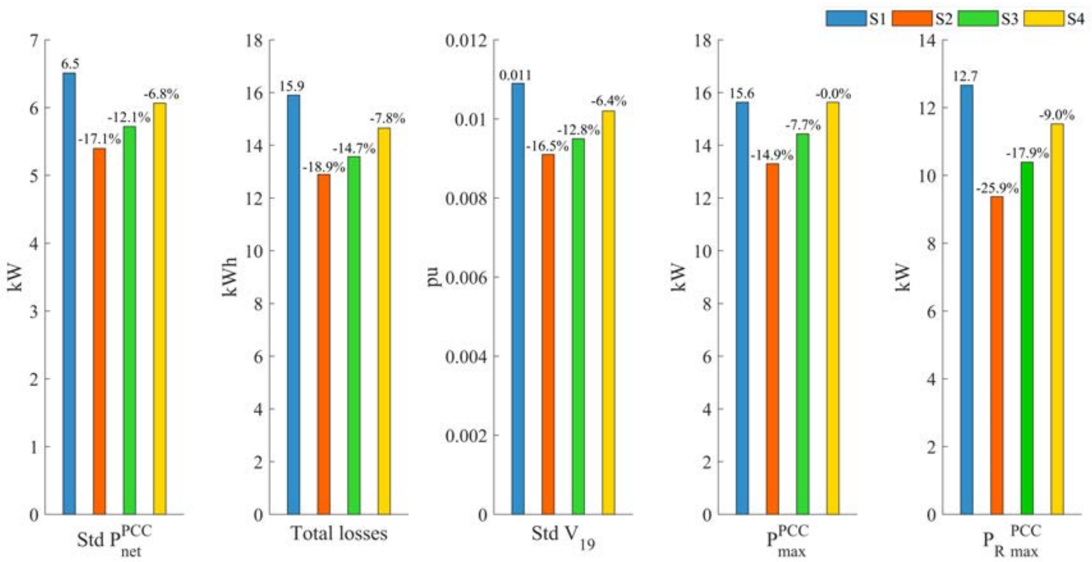


Figure 4.23: Comparison of main metrics for different scenarios for the month of June 2017

A similar analysis is carried out for December 2017. Results are graphically shown in Figure 4.24 whereas numeric values are shown in Table 4.2. This period is characterized by a much lower PV generation than June. This, in combination with an expected higher electricity demand in winter, results in average net power exchanged at PCC more than double the volume with respect to the period in

Table 4.1: Assessment metrics for the June 2017's simulation

	S1	S2	S3	S4
P_{net}^{PCC} [kW]	580.790	580.790	580.996	580.790
Mean [kW]	3.025	3.025	3.026	3.025
Std [kW]	6.511	5.397	5.721	6.066
Total losses [kWh]	15.901	12.894	13.569	14.654
Reduction [%]	/	18.91	14.67	7.84
V_{19} mean [pu]	0.995	0.995	0.995	0.995
Std [pu]	0.0109	0.0091	0.0095	0.0102
P_{max}^{PCC} [kW]	15.63	13.30	14.43	15.63
Reduction [%]	/	14.91	7.68	0.00
$P_{R\,max}^{PCC}$ [kW]	12.66	9.376	10.39	11.52
Reduction [%]	/	25.94	17.93	9.00

June. Even for this case the total and mean values of P_{net}^{PCC} are the same in all the scenarios presented. The average voltage magnitude in scenarios S2, S3 and S4 improves slightly (0.2%) as compared to S1 instead. However, since they are not useful for further discussions, they are no longer considered. All the other results obtained are presented in figure. Similar conclusions to the simulation in June presented before can be derived. Due to a higher demand, the losses are much higher than in the period of June. The results confirm the better performances of scenario S2 over scenario S3, thanks to the wider view of the control strategies of the batteries. S4 gives lower benefits with regards to the network parameters. Once again, the BSCS adopted in this scenario is not able to considerably reduce the peak power demand at the PCC and it does not reduce at all the reverse power flow. This is because the price signals are not always coincident with the peak demand. Reverse power flow is finally eliminated in S2 scenario.

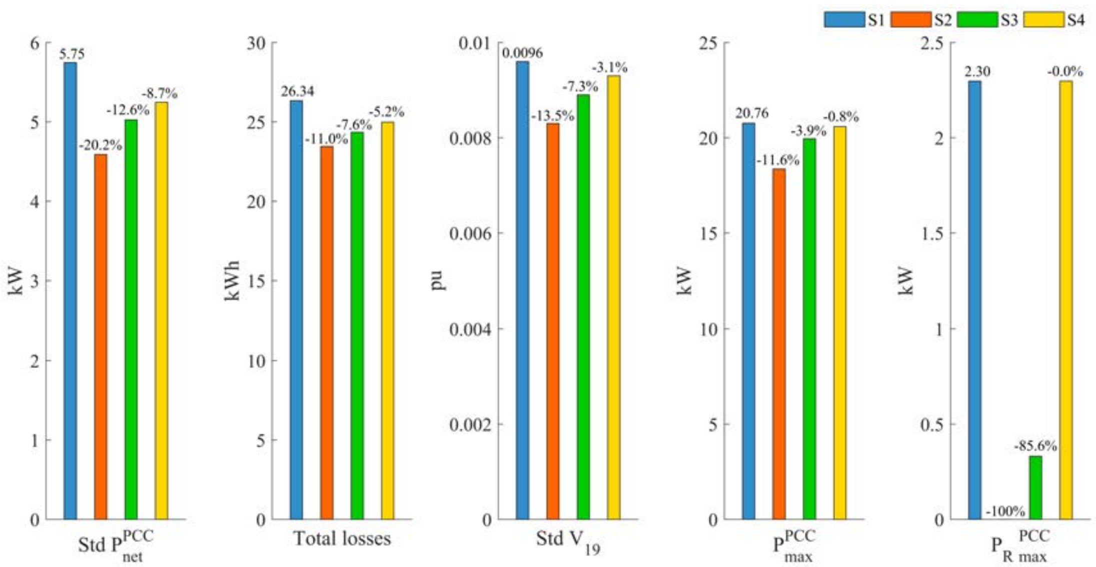


Figure 4.24: Comparison of main metrics for different scenarios for the month of December 2017

Table 4.2: Assessment metrics for the December 2017's simulation

	S1	S2	S3	S4
P_{net}^{PCC} [kW]	1456.26	1456.26	1456.45	1456.26
Mean [kW]	7.585	7.585	7.586	7.585
Std [kW]	5.747	4.589	5.026	5.247
Total losses [kWh]	26.338	23.453	24.347	24.979
Reduction [%]	\	10.95	7.56	5.16
V_{19} mean [pu]	0.9849	0.987	0.987	0.987
Std [pu]	0.0096	0.0083	0.0089	0.0093
P_{max}^{PCC} [kW]	20.76	18.36	19.95	20.59
Reduction [%]	\	11.56	3.90	0.82
P_{Rmax}^{PCC} [kW]	2.297	\	0.332	2.297
Reduction [%]	\	\	85.56	0.00

Table 4.3: Comparison of the average number of charge/discharge cycles per day of BESS

	S2	S3	S4
June	2.19	1.45	1.19
December	2.03	1.54	1

The results presented above have been achieved by different BSCS that characterize the scenarios, aimed to optimize different functions, and that implies different batteries utilization. In fact, during June, the BESSs are used in average 2.19, 1.45 and 1.19 cycles/day for scenarios S2, S3 and S4 respectively. Similarly, the average utilization in December is 2.03, 1.54 and 1 cycles/day, as shown in Table 4.3. Therefore, the centralized control strategy exploits storages the most for the benefit of the grid. In fact, from the previous results it is visible that S2 is the scenario that ensures the highest grid relief.

Other aspects to be considered are the self-consumption and self-sufficiency, which have been defined in section 2.8. Table 4.4 shows the average value of these parameters computed at POD and at the PCC. Since S2 employs centralized control, SC and SS at a house level would not provide any insight, therefore they are omitted. Analyzing the two decentralized scenarios, it is clear that S3 is able to increase the SC and SS more than S4. The first one is due to the fact that the control strategies in S4 is driven by price signals. The lower utilization of the batteries highlighted above is mainly the cause of the lower SS. At the PCC, S2

Table 4.4: Self-consumption and self-sufficiency from POD and PCC level in different time periods.

		June				December			
		S1	S2	S3	S4	S1	S2	S3	S4
POD	SC	36.82%	/	53.44%	48.86%	57.69%	/	91.26%	58.08%
level	SS	49.64%	/	72.20%	65.89%	17.59%	/	28.17%	17.72%
PCC	SC	71.49%	79.31%	77.22%	75.66%	98.78%	100%	99.86%	98.78%
level	SS	43.14%	47.86%	46.60%	45.65%	13.71%	13.88%	13.86%	13.71%

performs better than S3 and S4 both in June and December, since the aggregator has a global view on the entire grid. This fact is meaningful since it increases the energy autonomy of the micro-grid that may delivers social, financial and environmental benefits. In the following, the economic analysis for S1, S3 and S4 is presented, as the economic profitability of S2 could only be assessed on a case by case basis and therefore is beyond the scope of this work. For analysis of S2, additional information regarding the investment, ownership and operation of batteries is required.

The first analysis determines the most beneficial scenario from the customers' perspective. Results regarding the total cost are shown in Figure 4.25. To present a comparative analysis, all the results are referred to scenario S1, whose value is scaled to 100. The MEM is beneficial for all the customers in every scenario; although prosumers have the most benefits from the introduction of a MEM, the electricity consumers also take advantage from it by purchasing the electricity from the MEM at a lower price as compared to the utility price. This agrees with other results achieved in the literature [54, 56, 58]. Prosumers with only PV installations can achieve higher electricity bill reduction, since they have an LCOE lower than the prosumers owning both PV and BESS. However, it should be pointed out that with high penetration of RES, there would be significant reverse power flow if BESS were not in place. Since the cost of degradation of the battery is included in the objective function, a reduction in the total cost means that the BESS repays itself. Whereas it may have been expected for prosumers that they own a battery, since the control strategy in this scenario aims to minimize a cost function, the same cannot be said for the other users. Finally, the introduction of the MBM in S3e and S4e adds a source of income for those who have a BESS without significantly affecting the benefits of the other customers. The slight increment of expenditures of the other customers in S4e is mainly due to the higher energy bought from the DSO instead of buying it from the prosumers that own a BESS.

In Figure 4.26, scenarios S3 and S4 are compared to S1m, which is scaled to 100. As can be seen, with the MEM implemented, the expenditure of simple users and users with PV systems do not change significantly in all scenarios. On the other hand, the change in the expenditure of prosumers equipped with a BESS is considerable. Note that the presence of the battery in S3 results in a higher cost of 0.8%, which means that scenario S3 will not encourage installations of BESS in future MEM. Therefore, some incentives would be required to make the economic case profitable for the prosumers. The introduction of the MBM, which adds an additional source of income as can be seen in Figure 4.26, could be a good option to lower the energy bill and incentivize new BESS installations. Therefore, it can be concluded that S4 is the best scenario from the point of view of customers while S3 requires some incentives to stimulate new BESSs installations. Also, although from the DSO perspective S3 is the best approach for a decentralised BESSs control, it requires additional incentives to encourage the participation of the prosumers.

The DSO's profit for the different scenarios considered is presented in Table 4.5. As mentioned earlier, the economic evaluation of S2 is beyond the scope of this study, therefore only scenarios S1, S1m, S3, S3e, S4 and S4e are analyzed

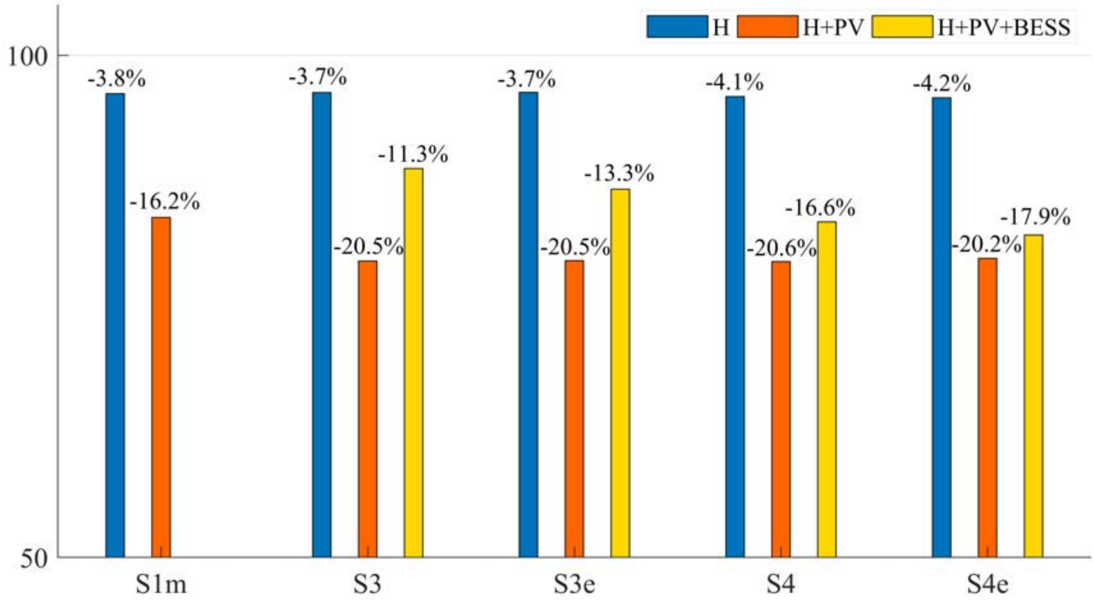


Figure 4.25: Customers' expenditures for different scenarios compared to S1 (S1=100)

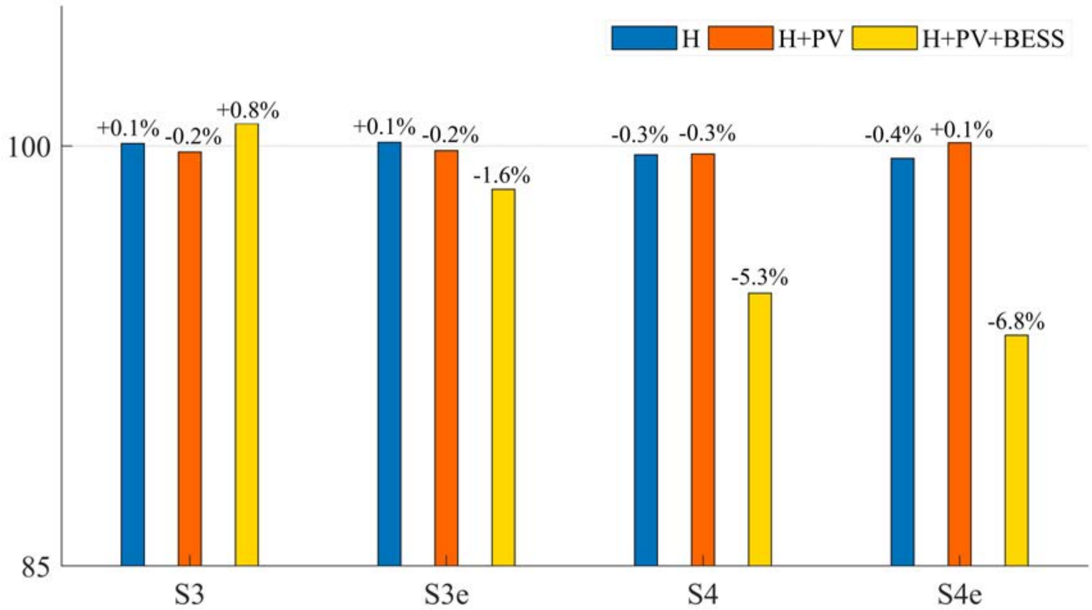


Figure 4.26: Customers' expenditures for different scenarios compared to S1m (S1m=100)

Table 4.5: DSO's profit for different scenarios

	S1	S1m	S3	S3e	S4	S4e
E_{sell} [kWh]	2291.819	2291.819	2241.973	2243.835	2256.879	2262.688
E_{buy} [kWh]	672.4	254.77	204.52	204.73	219.83	222.44
$C_{selling}^{profit}$ [£/kWh]	0.02	0.02	0.02	0.02	0.02	0.02
C_{trade}^{DSO} [£/kWh]	0.046	0.046	0.046	0.046	0.046	0.046
$C_{sell}^{average}$ [£/kWh]	0.16	0.16	0.16	0.16	0.16	0.16
Profit from E_{sell} [£]	45.836	45.836	44.839	44.877	45.138	45.254
Expense from E_{buy} [£]	-30.93	-11.719	-9.408	-9.418	-10.112	-10.232
Revenue from E_{buy} [£]	107.584	40.763	32.723	32.757	35.173	35.59
Expense for MBM [£]	/	/	/	-3.42	/	-3.42
Total profit [£]	122.49	74.88	68.15	64.8	70.2	67.19

(for June and December together). The data in this table refer to the items of the economic assessment (see Equation 2.28). The first row represents the energy sold by DSO to customers, the second row shows the surplus energy purchased by the DSO from the microgrid. In the second block, the profits and costs related to the energy purchased and sold by the DSO are presented. Then, all the cost/revenue elements are shown in the third block and the total profit of the DSO is shown in the last row.
As expected, the results show that S1 ensures the highest income for DSO. However, this scenario may necessitate grid reinforcement to ensure enough grid capacity and reliable electricity provision. Note that under this scenario, reverse power flow and voltage variability are at their highest. Further, it is assumed that the DSO can sell all the energy purchased from the MEM outside the micro-grid, which is not guaranteed. If this is not the case, than S1 will provide less revenues. The presence of the MEM in S1m reduces considerably the energy purchased from the micro-grid since part of that is now traded between prosumers and consumers. Having batteries in S3 and S4 further reduces the energy purchased from the micro-grid (since BESS increases the SS at PCC level). Accordingly, the total revenue is decreased. Note that S4 leads to a higher revenue for the DSO as compared to S3, however this scenario does not ensures grid relief as much as S3, as previously presented. Also, the presence of the MBM reduces the DSO's revenues one again but encourages prosumers participation and avoids keeping expensive peak-plants on standby (to provide for contingencies). A subsequent analysis could be made by the DSO to evaluate the cost of an investment on BAU approach and to see which approach is more cost-effective.

To demonstrate the capability of BESSs to deal with congestions, an unforeseen congestion was created in a way that the voltage magnitude in some buses dropped below the threshold of 0.94 pu. Also, the current in the section 'b-c' of the network of Figure 3.2 exceeded the maximum capability of that feeder, as shown in Table 4.6, where results for the scenarios S4 and S4e are presented. The simulation showed that distributed BESS with the presence of a MBM could deal with these events and maintain the grid quantities (voltage and current magnitude) within the allowed range (see Figure 4.27). Therefore, they can reduce over-capacity required from the distribution grid to face unexpected contingen-

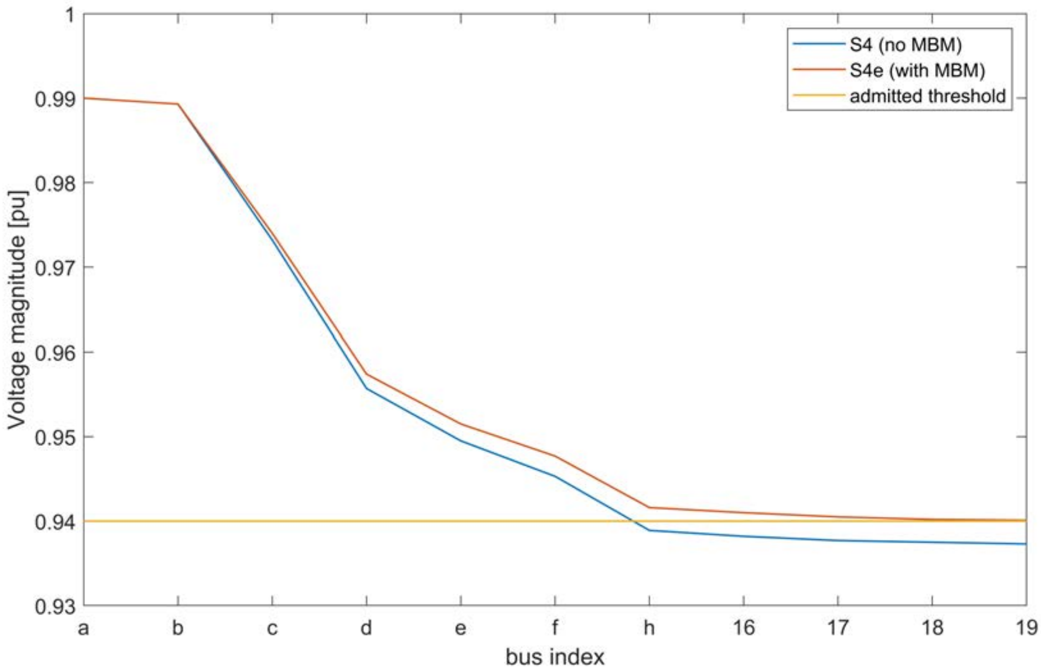


Figure 4.27: Voltage magnitude in the case that an unforeseen congestion happen without the MBM (S4) and with the MBM (S4e).

cies. Note that a distributed injection of power in the opposite direction of the congestion in the section 'b-c' is the only way to solve it. Finally, it resulted that scenario S3, for its peculiar modus operandi, can face this type of situations better than scenario S4.

Based on the obtained results, it emerged that the centralized control, since it has control on the whole system, performs better from the point of view of the parameters of the grid. However, it is worth pointing out that the centralised control requires higher communications and computational costs and provides lower flexibility and reliability as compared to decentralised control [99]. In fact, the computational time to upload data and perform the optimization problem was on average 0.2754 s, 0.1632 s and 0.1397 s for scenarios S2, S3 and S4 respectively. Moreover, whilst computational cost in S2 rise in a quadratic way with the numbers of controlled devices, it does not change at all in scenarios S3 and S4. The computational effort required for S2 would constitute a major obstacle as the size of the grid increases. The results obtained show that decentralization of the system and the development towards a smart grid and active prosumers is an attractive investment option for future energy systems with high penetration of DERs. Between the two decentralised cases considered, S3 provides better benefits for the grid, as it can defer or avoid investments in grid reinforcement, but does not provide the same revenues as S4 for the final customer and the DSO. Therefore, S3 would require some incentives for the prosumers to encourage new BESS installations. This is not necessary in scenario S4, where all the customers

Table 4.6: Bus and line congested in the case of an unforeseen event without the MBM (S4) and with the MBM (S4e).

	V magnitude [pu]	
bus	S4 (✗ MBM)	S4e (✓ MBM)
h	0.9389	0.9416
16	0.9382	0.9410
17	0.9377	0.9405
18	0.9375	0.9402
19	0.9373	0.9401
	I/Imax	
line	S4 (✗ MBM)	S4e (✓ MBM)
b-c	1.010	0.9639

are incentivize by lower energy bills.

Chapter 5

Conclusions

The expected increase of customers' electricity demand and the need to reinforce the grid provides business opportunities for the DSO and customers to invest in BESSs. In this work, a techno-economic evaluation of several scenarios simulated in a typical UK residential LV distribution grid with a high penetration of DERs is presented. Five scenarios dealing with different BSCS and market structures in addition to two reference scenarios are considered: these include one central control (S2), and four with distributed control (S3, S3e, S4, S4e). Since P2P energy trading is one of the promising frameworks of future smart grids, a decentralised MEM controlled by an aggregator was introduced in the four scenarios with decentralised control. Moreover, a MBM was also introduced in scenarios S3e and S4e to balance the micro-grid in the case of unforeseen events. The results provided useful insights, as follows:

- As expected, the BAU reference scenario (S1) does not need management effort. It ensures the higher profit for the DSO but it requires significant investment in grid infrastructures.
- The aggregated control (S2) is the scenario that performs better in terms of grid relief. However, it requires significant management effort from a computational cost and communication technology point of view. Then, it exploits stationary storages the most for the benefit of the grid.
- Between scenarios where the MEM is implemented:
  - Market approach (S4) is the best for customers (lower electricity bill) but it does not provide the best benefits for the DSO. In fact, it does not provide grid relief and consequently it does not defer investments in grid infrastructures. The introduction of the MBM in S4e is an option to provide services that defer reinforcement of the network.
  - The S3 scenario provides higher grid relief, but does not stimulate new BESS installations, therefore some incentives are needed. Adding MBM is an option to get the most value from DERs for both the users and DSO.

Based on this work, key points to be investigated for future research to ensure a more thorough analysis are the following:

- Increase the network size and period of simulations
- Add performance degradation to the system
- Diversify sizes of PV systems and BESSs
- Include responsive demand (Controllable loads)
- Consider the presence of EV and electric heat-pump
- Move to a multi-conductor approach

Appendices

Appendix A

Acronyms

ANN Artificial neural network
BAU Business as usual
BESS Battery Energy Storage System
BNEF Bloomberg New Energy Finance
BoS Balance of System
BP Back-Propagation
BSCS Battery start control strategy
CAMS Copernicus Atmosphere Monitoring Service
CAPEX Capital expenditure
CL Controllable load
DER Distributed Energy Resource
DG Distributed generation
DNO Distribution network operator
DSO Distribution system operator
DSR Demand Side Response
ETIP European Technology ad Innovation Platform
EV Electric vehicle
FiT Feed in tariff
GCPV Grid connected PV
GDM Gradient descent with momentum
GFS Global forecast system
GHI global horizontal irradiation
ICT Information and Communication Technology
IEA International Energy Agency
IRENA International Renewable Energy Agency
ISEA Institut fur Stromrichtertechnik und Elektrische Antriebe
LCOE Levelised cost of energy
LIP Lithium Iron Phosphate

LM Local market
LV Low voltage
MAE Mean absolute error
MBE Mean bias error
MBM Micro balancing market
MCP Market clearing price
MEM Micro energy market
MILP Mixed-integer linear programming
MLP MultiLayer Perceptron
MSE Mean squared error performance function
NCEP National centers of environmental production
NMC Nichel Manganese cobalt oxide
NN Neural network
NPV Net Present Value
NWP Numerical weather prediction
Ofgem Office of gas and electricity market
O&M Operation & Maintenance
OPEX Operating expenses
P2G Peer-to-grid
P2P Peer-to-peer
PCC Point of common coupling
POD Point of delivery
PV Photovoltaic
PVPS Photovoltaic Power Systems Programme
REmap Renewable Energy Roadmap
RES Renewable Energy Source
RMSE Root mean square error
RTP Real time price
RVE Real value of energy
SC Self Consumption
SEFEP Smart Energy for Europ Platform GmbH
SOC State of charge
tansig Hyperbolic tangent sigmoid transfer function
VRES Variable RES
WACC Weighted Average Cost of Capital

Parameters

$\mathbf{B}$ Number of buses in the network

$\mathbf{T}$ Optimization window length

$\mathbf{\Delta t}$ Time-step resolution

$\eta^{\mathbf{ch}}_{\mathbf{b_i}}, \eta^{\mathbf{dis}}_{\mathbf{b_i}}$ Charge/discharge efficiency of b_i

$\mathbf{P^{ch}_{b_i max}}, \mathbf{P^{dis}_{b_i max}}$ Maximum charge/discharge power of b_i

$\mathbf{E_{b_i min}}, \mathbf{E_{b_i max}}$ Minimum/maximum storage energy of b_i

$\mathbf{C^{degr}_{b_i}}$ Degradation cost for charge/discharge of b_i

α Constant arbitrary value for MILP implementation

$\mathbf{LCOE_{PV_i}}$ LCOE of solar PV plant installed in bus i

$\mathbf{C^{DSO}_{trade}}$ Price payed by DSO/received by the prosumers for the energy traded

$\mathbf{C^{profit}_{selling}}$ Profit of DSO every kWh sold to customers ($E_{sell}(t)$) at time t

$\mathbf{C^{average}_{sell}}$ Average price at which the DSO sell $E_{buy}(t)$

$\mathbf{e_r}$ Random error used for the household load forecast model

Variables

$\mathbf{i}$ Index referring to bus i

$\mathbf{b_i} \in \mathbf{B}$ Stationary BESS installed in bus i

$\mathbf{t} \in \mathbf{T}$ Time slot t in the optimization window T

$\mathbf{P^{PCC}_{net}(t)}$ Net power exchange at PCC at time step t

$\mathbf{p^{ch}_{b_i}(t)}, \mathbf{p^{dis}_{b_i}(t)}$ Charge/discharge power of bi at time step t

$\mathbf{E_{b_i}(t)}$ Energy of bi at time step t

$\mathbf{P_{neti}(t)}$ Net power at bus i without battery

$\mathbf{c^*_{pi}(t)}, \mathbf{c^*_{si}(t)}$ Forecasted price the prosumer in bus i expect to purchase/sell energy at time step t

$\mathbf{x_{pi}(t)}, \mathbf{x_{pi}(t)}$ Energy to be purchased/sold by the prosumer in bus i at time step t

$\mathbf{k^{ch}_{b_i}(t)}, \mathbf{k^{dis}_{b_i}(t)}$ Binary decisional variables governing the charge and discharge of b_i

$\mathbf{k_{pi}(t)}, \mathbf{k_{pi}(t)}$ Binary decisional variables governing the energy traded by the prosumer in bus i

$\mathbf{E_{PV_i}(t)}$ Energy produced by solar PV plant installed in bus i at time t

$\mathbf{E_{b_i^{ch}}(t)}$ Energy charged in b_i at time t

$\mathbf{E_{b_i^{dis}}(t)}$ Energy discharged from b_i at time t

$\mathbf{E_{buy_i}(t)}$ Energy bought by bus i at time t

$\mathbf{E^{MEM}_{sell_i}(t)}$ Energy sold by bus i to the MEM at time t

$\mathbf{E^{DSO}_{sell_i}(t)}$ Energy sold by bus i to the DSO at time t

$\mathbf{E_{losses_i}(t)}$ Losses assigned to bus i for the use of the grid at time t

$\mathbf{E_{sell}(t)}$ Energy sold by the DSO to the customers at time t

$\mathbf{E_{buy}(t)}$ Surplus energy from micro-grid bought by the DSO at time t
$\mathbf{MCP(t)}$ Market clearing price at time t
$\mathbf{C_{losses}(t)}$ Cost of the losses inside the micro-grid at time t
$\mathbf{C_{spot}(t)}$ Spot price at time t
$\mathbf{P_{PV_i}(t)}$ Power generated by PV plant in bus i at time t
$\mathbf{P_{load_i}(t)}$ Load power of bus i at time t
$\mathbf{P^{PCC}_{max}(t)}$ Max net power demand at PCC in the simulation
$\mathbf{P^{PCC}_{R\,max}(t)}$ Max reverse power flow at PCC in the simulation
$\mathbf{e_g(t)}$ Gaussian error for the household load forecast model

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