Impact of Policy Incentives on the Promotion of Integrated PV and Battery Storage Systems: A Techno-economic Assessment

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Abstract: During the last two decades, the use of residential photovoltaic systems (PVs) has been widely promoted by governments through various support mechanisms such as feed-in-tariffs, net-metering, net-billing, etc. These support schemes have developed a secure investment environment, increasing the penetration level of PVs in low-voltage distribution grids. Nonetheless, increased PV integration may introduce several technical problems regarding the secure operation of distribution grids. Battery energy storage (BES) systems can mitigate such challenges, but the high capital cost is one of the most important limiting factors towards the widespread use of these systems. In fact, the financial viability of integrated PV and BES systems under different support schemes remains an open issue. In this paper, the profitability of PV and BES systems is evaluated through an advanced techno-economic model, that provides the optimal size of PV-BES system in terms of net present value, based on the electricity production and consumption profile of the installation, PV and BES systems costs, and electricity charges. The proposed model may be a useful tool for prosumers, grid operators and policy makers, to assess the impact of various incentive policy schemes and different BES operation strategies on the economic viability of PV-BES systems.

Nomenclature

Indices

k	billing period;
n	year of analysis;
r	pricing period;
t	year of investment (t=1 for an investment at the current year);
ti	time instant related to the BES system control.

Variables

$c^{t,n}$	annual electricity cost for a net consumer supplied exclusively by the grid;
$c_{SC}^{t,n}$	annual electricity cost for a prosumer with a PV-BES system operating under a self-consumption scheme;
$c_{NeB}^{t,n}$	annual electricity cost for a prosumer with a PV-BES system operating under a net-billing (NeB) scheme;
Cap^n	BES system capacity at year n;
$capex_{pv}^t$	capital expenditures for the PV system for an investment at year t;
$capex_{bat}^t$	capital expenditures for the BES system for an investment at year t;
$cf_{in}^{t,n}$	cash inflow of the n-th year;
$cf_{out}^{t,n}$	cash outflow of the n-th year;
$E_{ann,bat}^n$	energy provided by the BES system at year n;
$E_{cons}^{r,k}$	consumed energy within pricing period r of billing period k;
$E_{imp}^{r,k}$	energy imported from the grid within pricing period r of billing period k;
$E_{exp}^{r,k}$	energy exported to the grid within pricing period r of billing period k;
irr^t	internal rate of return for an investment at year t;
L^n	capacity degradation up to year n;
$nc^{t,k}$	electricity cost for the netted energy over a billing period k; refers to a prosumer with a PV-BES system operating under a net-billing scheme;
npv^t	net present value for an investment at year t;
oci^t	total investment cost; investment at year t;
$opex_{pv}^t$	operation & maintenance costs of the PV system;
$opex_{bat}^t$	operation & maintenance costs of the BES system;
P_{bat}^{ti}	charging/discharging power of the BES system at time instant ti;
$P_{\exp}^{ti}$	exported power to the grid at time instant ti;
P_{imp}^{ti}	imported power from the grid at time instant ti;
SoC^{ti}	BES system state of charge at time instant ti.

Parameters

a	inflation rate;
C_{max}	maximum charging/discharging cycles of the BES system for the calculation of $LCoS$;
E_{max}	maximum available capacity of the battery;
$ep_{r,k}^t$	electricity purchase cost for energy imported from the grid within pricing period r of billing period k;
i	discount rate;
$LCoS$	levelized cost of the BES system;

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N	system lifetime in years;
P_{load}^{ti}	consumed power at time instant *ti*;
P_{pv}^{ti}	PV produced power at time instant *ti*;
SP^{ti}	compensation price for the energy exported to the grid at time instant *ti*;
$sp_{r,k}^{t}$	compensation price for the energy exported to the grid within pricing period *r* of billing period *k*;
ToU^{ti}	electricity purchase cost at time instant *ti*;
U	usable capacity of the BES system;
$\Delta\tau$	time-step;
η	BES system charging/discharging efficiency.

1. Introduction

According to the recently published European Union (EU) directive 2018/2001, the new target of renewable energy sources (RESs) contribution has been set to 32% of the final energy consumption until 2030 [1], paving the way to the further increase of RES penetration in the power systems. Additionally, EU aspires to transform by 2030 the existing building stock to Nearly Zero Energy Buildings (NZEBs) [2], i.e., buildings that cover a high share of electrical and thermal needs using on-site RESs. Considering the integration of RES in the residential sector, photovoltaic (PV) generators seem to be the most convenient technology [3], due to their modular structure.

To achieve the above-mentioned targets, EU and European governments promoted the installation of PVs in the residential sector via various support schemes. Among them, feed-in-tariff (FiT) schemes were the most utilized ones [4], [5] and were initially designed to get PV installations off the ground. Nowadays, FiTs are being replaced with other incentive-based schemes such as the net-metering (NeM) and the net-billing (NeB) [3], [6], [7]. In NeM schemes, the electricity injected into the grid is generally valued the same as the electricity consumed from the grid. On the other hand, in NeB schemes, the electricity injected in the grid is usually compensated at a lower price compared to the electricity consumed from the grid.

Due to the above-mentioned support policies, an important number of PVs have been installed during the last two decades in low-voltage (LV) distribution grids [8], while a significant amount is also expected to be connected in the near future to facilitate the conversion of the existing building stock to NZEBs [9]. Nevertheless, the increased penetration of PVs in LV distribution grids may introduce several technical challenges for distribution system operators [10] – [12]. These technical issues are mainly observed during hours of high PV power injection and low demand. Nevertheless, they can be efficiently addressed by storing locally the surplus PV generated energy utilizing on-site energy storage systems [13]. Prosumers may reduce the mismatch between electrical production and demand by integrating energy storage systems, thus preserving the safe operation of the electrical power system. In this way, the further penetration of PVs in LV distribution grids will be allowed.

Residential energy storage systems are mainly based on battery technologies. However, an investment in an integrated PV and battery energy storage (BES) system presents a considerably higher cost for the prosumer compared with a standalone PV system. Therefore, the feasibility of such combined systems should be thoroughly investigated. Towards this objective, [14] and [15] examine the financial viability of residential BES systems in Germany and United Kingdom, while [16] reports the profitability margins for residential BES systems in Italy, Switzerland and United Kingdom. The above-mentioned studies investigate the effect of various parameters (e.g. the PV and the BES system cost, BES size, the electricity retail price, etc.) on the profitability of the integrated PV-BES system. However, these studies do not examine how different incentive schemes impact the economic feasibility of BES systems. To address this issue, in [17], a techno-economic model is developed to assess the economic viability of integrated PV-BES systems under different support policies. This techno-economic model operates assuming only a standardized control strategy for the BES system aiming to maximize self-consumption, while it does not support dynamic electricity tariffs and NeB schemes, which are widely adopted worldwide.

Scope of this paper is to further extend the applicability range of the techno-economic model presented in [17]. For this purpose, NeB schemes and dynamic electricity tariffs are incorporated into the model of [17]. Additionally, a new control algorithm for the BES system is proposed and incorporated in the existing techno-economic model. The primary objective of this control algorithm is to incentivize prosumers to charge/discharge their BES systems based on electricity price signals. Thus, it can be used by system operators and market regulators for several services (e.g. peak shaving, load shifting, etc.). Furthermore, the battery calendar and cycle aging mechanism is incorporated to enhance the accuracy of the techno-economic model of [17].

The developed model receives as inputs PV generation and load consumption profiles as well as typical PVs and BES system costs. The user can define the desired dynamic pricing scheme, the control strategy of the BES system, and the incentive policy under consideration. The developed model supports NeM and NeB policies, as well as incentives schemes that promote self-consumption, in which PV energy surplus is remunerated at a predefined price or not compensated at all. Based on the provided inputs, an exhaustive search optimization procedure is conducted and the ideal size, in terms of net present value (NPV), for the integrated PV-BES system is derived.

The remaining of the paper is structured as follows: Section 2 presents the examined BES system control strategies. Section 3 outlines the electricity charge mechanisms investigated in the paper, while Section 4 describes the developed techno-economic model. Section 5 conducts a comparison, in terms of NPV, between the examined BES control strategies, while Section 6 investigates the profitability of PV-BES systems under several incentive schemes. Section 7 evaluates the BES capacity degradation due to its operation under the different examined cases. Finally, Section 8 concludes the paper.

2. Examined BES System Operation Schemes

This paper considers two BES control schemes, namely the power-driven (PoD) and the price-driven (PrD) control algorithms. The former determines the control actions of the BES system with respect to the power exchanged with the grid, while the latter is a modified PoD control algorithm that additionally considers dynamic pricing.

The next subsections present in detail the examined BES system operation schemes.

2.1. *Power-Driven (PoD) BES Operation*

Scope of the PoD control scheme is to reduce the energy dependence of the prosumer on the utility by increasing the self-consumption rate (SCR) [18]. In terms of real-time implementation, this is attained by constantly monitoring, i.e., in every time interval ($\Delta\tau$), the generated and consumed active power. Specifically, the PoD BES operation scheme is illustrated in the flowchart of Fig. 1. For a given time instant (ti), in case the produced PV power (P_{pv}^{ti}) is greater than the load power (P_{load}^{ti}), the BES system absorbs the excess power, charging the battery up to its maximum available capacity $E_{\max}$. Otherwise, BES supplies the load demand according to the difference between production and consumption. Charging and discharging processes take into account the BES system operational limits, such as the maximum power ($P_{bat}^{\max}$), the charging/discharging efficiency (η), and the upper and lower state of charge (SoC) limits, i.e., SoC_{up} and SoC_{low}. Finally, the power imported (P_{imp}^{ti}) or exported ($P_{\exp}^{ti}$) to the grid, as well as the SoC of the next time instant ($SoC^{ti+\Delta\tau}$) can be directly calculated, as shown in Fig. 1. The process continues till the maximum number of time instants ($ti_{\max}$) is reached.

2.2. *Price-Driven (PrD) BES Operation*

Although the PoD control algorithm increases the SCR, it ignores the electricity pricing during the decision process. As a result, the charging/discharging process is activated irrespectively of the current electricity price, which may result in decreasing the revenues and increasing the payback period of the investment. This is a drawback of the PoD control scheme, especially when dealing with Time-of-Use (ToU) or dynamic electricity prices.

To overcome this issue, we modify the PoD scheme by incorporating the electricity pricing in the decision process, thus forming the PrD control algorithm of Fig. 2. In particular, prior to the activation of the charging/discharging process, the PrD control algorithm compares at each time instant the price at which the consumed energy is purchased (ToU^{ti}) or the surplus energy is compensated (SP^{ti}), with the levelized cost of storage (LCoS) system. Although the LCoS has been defined in [19], the therein adopted formula includes the cost of energy required to charge the BES system from the grid. Nevertheless, this approach is not valid in case of an integrated PV-BES system, since the BES system charges directly from the PV system. Thus, we propose the following modified LCoS formula:

$$LCoS = \frac{capex_{bat} + \sum_{n=1}^{N} \frac{opex_{bat}^{n}}{(1+i)^{n}}}{\sum_{n=1}^{N} \frac{E_{ann,bat}^{n}}{(1+i)^{n}}} \tag{1}$$

where $capex_{bat}$ and $opex_{bat}^{n}$ denote the capital investment cost

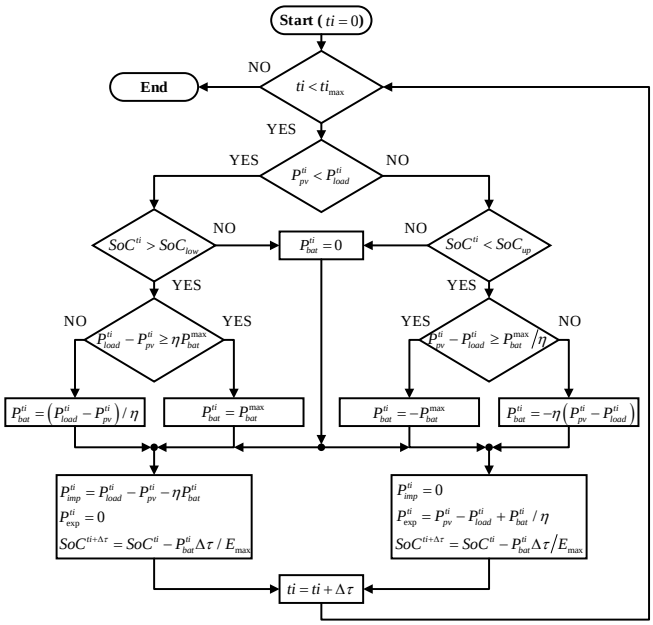

Fig. 1. *Flowchart of the PoD BES system operation scheme.*

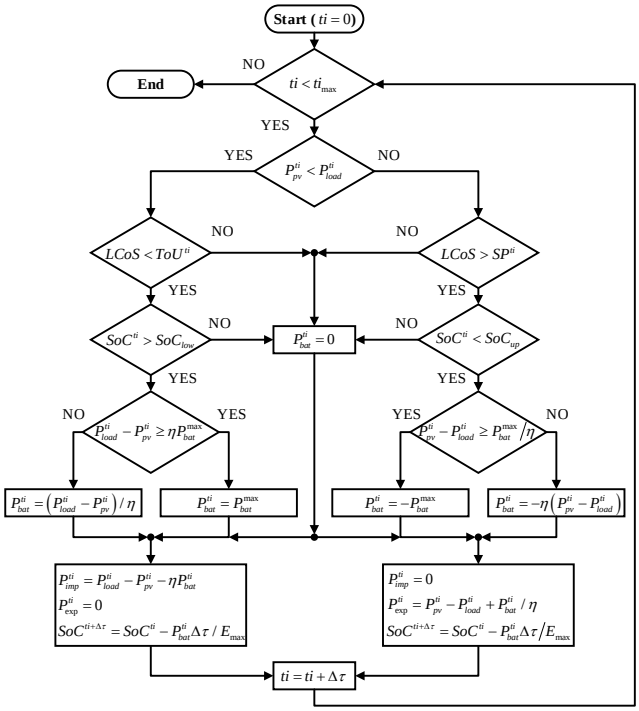

Fig. 2. *Flowchart of the PrD BES system operation scheme.*

and the operating expenses at year n of the BES system, respectively. Moreover, N is the system lifetime in years assuming that a full charge/discharge cycle occurs on a daily basis, i denotes the discount rate, and $E_{ann,bat}^{n}$ is the annual energy provided by the BES system to cover the on-site demand at year n. We consider a uniform allocation of the annual discharged energy calculated using (2).

$$E_{ann,bat}^{n} = \frac{\eta^{2} C_{\max} E_{\max} U}{N} \tag{2}$$

Here, $C_{\max}$ is the maximum charging/discharging cycles of the BES system, while U is a coefficient that determines the usable capacity of the BES system and varies between 0 and 1.

Concerning the comparison of the electricity prices with the LCoS, two cases, presented in Fig. 2, are considered:

- $P_{pv}^{ti} > P_{load}^{ti}$. There exists a surplus of generated power against the load demand. This surplus can be either used to charge the BES system or sold to the grid. The decision is made by comparing the LCoS with the corresponding selling price of the specific time instant (SP^{ti}). If $LCoS < SP^{ti}$, then the excess power is sold to the grid, since it is preferable from an economic point of view against charging the BES system. Otherwise, the charging process is activated similarly to the PoD control scheme.
- $P_{pv}^{ti} < P_{load}^{ti}$. In such a case, the load demand is greater than the generated power. This deficit of active power can be reduced by discharging the BES system. Prior to the activation of the discharge process, the PrD control algorithm compares the LCoS with the current ToU electricity price (ToU^{ti}). If $LCoS > ToU^{ti}$, the discharging process remains deactivated, since it is cheaper to cover this deficit from the grid. Otherwise, the discharging process is activated similarly to the PoD control scheme. The BES operational limits, i.e., the maximum permissible power and SoC limits, are respected by the control scheme as shown in Fig. 2.

3. Electricity Charge Mechanism

Generally, the electricity system marginal price (SMP) presents a strong correlation with the system load profile [20]. An indicative example is the fact that the maximum SMP usually coincides with the occurrence of the maximum network load [21]. The same correlation is also evident in the retail electricity prices when the ToU or the dynamic electricity pricing policy is adopted. For instance, assuming the system daily load profile of Fig. 3, the corresponding ToU tariff is presented in Fig. 4.

Considering the BES system operation schemes presented in Section 2, the performance of the PoD control scheme remains unaffected by the incorporation of the ToU tariffs, since the control actions of the BES system are determined based only on the active power exchange with the grid. On the other hand, the operation of the BES system in the PrD strategy depends on the adopted ToU tariff policy. Specifically, in case the ToU tariffs of Fig. 4 are applied, there is a strong possibility that the BES system will start discharging earlier in the afternoon, due to the fact that the electricity tariff exceeds the LCoS value. This early discharge can be regarded as a drawback by the system operators, since

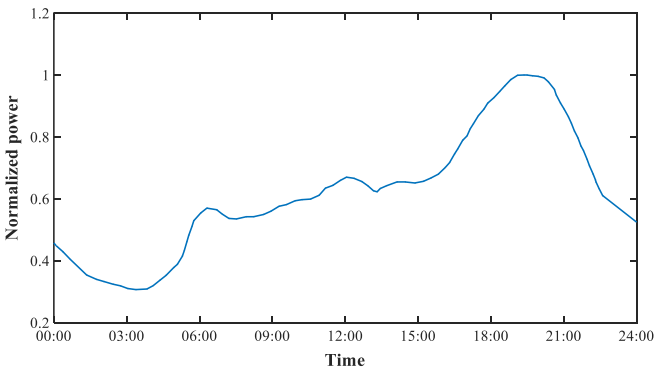

Fig. 3. *Daily system active power profile [21].*

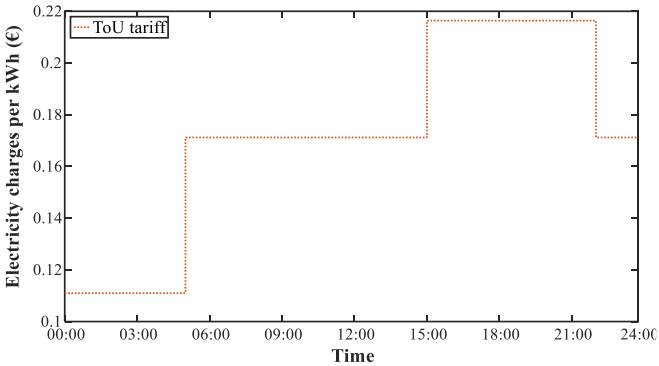

Fig. 4. *Daily ToU tariff [21].*

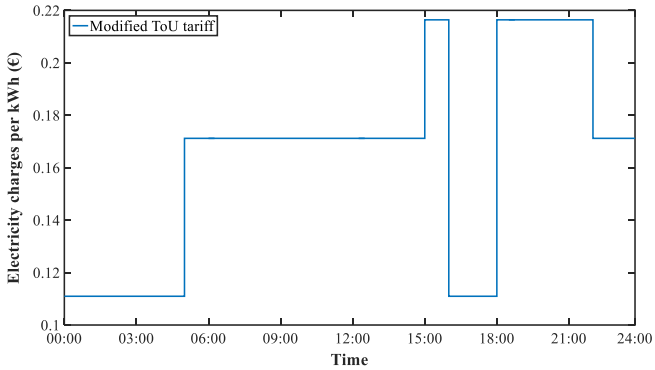

Fig. 5. *Modified daily ToU tariff.*

the BES system may not be capable of providing active power during the critical hours. For example, in Fig. 3, the most critical hour occurs at the evening where the maximum load demand is observed.

To address this issue, the ToU pricing levels are modified in Fig. 5 by adding a low-pricing zone in the afternoon. Scope of this low-pricing zone is to delay the discharging process of the BES systems equipped with the PrD control strategy, in order to contribute to the maximum load demand later in the evening. This low-pricing zone can be regarded as an indirect control of the discharging process. To offer a better insight, Fig. 6 illustrates the power profile of a BES system equipped with the PrD control algorithm prior and after the introduction of the low-pricing zone. It is obvious that the discharging process shifts to a later time instant. It is worth mentioning that similar modifications can be applied to other ToU tariffs profiles to drive the BES system operation under the PrD control strategy. This process can be readily adopted by network operators within the Smart Grid concept to indirectly control the discharging process of BES systems.

4. Proposed Techno-economic Assessment Methodology

This Section analyzes the proposed methodology for the techno-economic assessment of PV-BES systems feasibility under different support policy frameworks. The developed economic evaluation process incorporates self-consumption and NeB schemes, taking into consideration various renumeration rates for PV energy exported to the grid and different electricity charge mechanisms.

The economic evaluation approach is based on an exhaustive search that varies PV and BES capacity over a wide set of values. The NPV of the investment is calculated for every set of values of PV and BES system size. The proposed methodology uses a technical and an economic

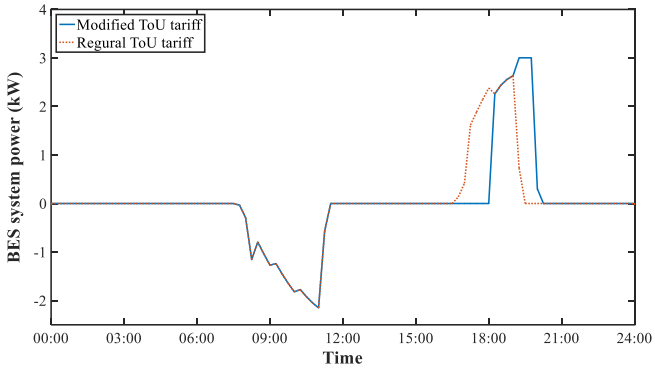

Fig. 6. *Daily active power profiles of the BES in case of PrD control scheme. Positive values correspond to discharging process.*

model to assess the performance of the system under examination. The former is used to calculate the energy amounts of the installation, while the latter evaluates the viability of a PV-BES system from an economic point of view.

4.1. *Technical Model*

The technical model aims to calculate the electrical energy amounts over specific time periods that correspond to the distinct pricing periods (*r*). Specifically, the energy imported from/exported to the utility grid, and the consumed energy are computed. To calculate these energies, the technical model computes the power profile of the BES system based on the BES operation scheme. It also derives the power profiles of imported and exported power. Note that the model takes into account the degradation of battery cells over the period of analysis. Since the degradation depends on the battery cycles, the SoC profile throughout the analysis period is also calculated.

The technical model receives as inputs the consumption profile of the prosumer and the PV generation power curve per kWp, in the form of timeseries over the entire period of analysis. Moreover, the desired BES system operation scheme is required as input. The derived energy amounts are provided as input to the economic model.

Energy amounts of each pricing period (*r*) are distinguished in the following categories: the consumed energy (E^r_{cons}), the energy imported from the grid (E^r_{imp}), and the energy exported (E^r_{exp}) to the grid. To facilitate the reading, the consumed, imported and exported energy, for a single day, are presented in Fig. 7, assuming a pricing period of a day. The areas of Fig. 7 are analyzed as follows:

- *A*, *F*: Energy consumption covered by the utility grid.
- *B*: Excess PV energy exported to the utility grid.
- *C*: Energy consumption supplied directly by PV system.
- *D*: Excess PV energy stored at BES system.
- *E*: Energy consumption supplied by BES system.

Using the notation of Fig. 7, E^r_{cons} , E^r_{imp} , and E^r_{exp} can be defined as:

$$E^r_{cons} = A + C + E + F \tag{3}$$

$$E^r_{imp} = A + F \tag{4}$$

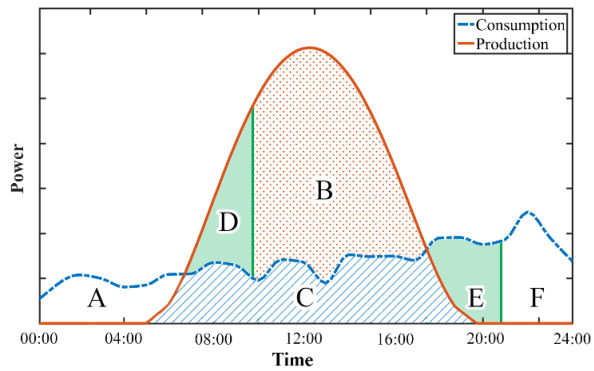

Fig. 7. *Illustrative consumption and production active power curves for the definition of distinct energy amounts.*

$$E^r_{\exp} = B \tag{5}$$

The calendar and cycle aging of the battery cells over the analysis period are evaluated using the aging model of [22]. Specifically, the BES capacity degradation (*L*) is calculated by the double exponential function of (6):

$$L = 1 - a_{sei} e^{-\beta_{sei} f_d} - (1 - \alpha_{sei}) e^{-f_d} \tag{6}$$

The first exponential term models the fast-aging stage of lithium-ion batteries at the early cycles. The fast aging is mainly caused by the formation of the solid electrolyte interphase (SEI) [23]. Parameters a_{sei} and β_{sei} are determined using experimental degradation data. The second exponential term models the degradation of the battery cells that is not related to the SEI formation. Degradation rate factor (f_d) represents the calendar and cycle degradation due to the operation of the BES. It depends on the number of cycles over the lifetime of the battery, the depth of discharge, the SoC, the cell temperature, as well as the calendar degradation over time. To identify the number of battery cycles caused by irregular battery operation, the rainflow counting algorithm of [24] is utilized. The irregular SoC profile is imported to the rainflow algorithm, and its outputs are used in the adopted aging model. More details on this procedure can be found in [22].

The technical model calculates the BES capacity annually using the SoC profile of the battery module over the elapsed years. The BES capacity of the following year, Cap^{n+1}, is defined by:

$$Cap^{n+1} = (1 - L^n) Cap^0 \tag{7}$$

where Cap^0 indicates the capacity of the newly installed BES, and L^n denotes the capacity degradation up to year *n*.

4.2. *Economic model*

The economic model aims at calculating the NPV of the investment. The main inputs of the model are the system investment and operation costs, the electricity charge mechanism, the incentive policy under study, and the energy amounts computed by the technical model. The model is analytically presented in the next paragraphs.

The NPV (npv^t) of an investment in combined PV and BES system at year (*t*) is calculated using (8):

$$npv^t = \sum_{n=1}^{N} \frac{cf^{t,n}_{in} - cf^{t,n}_{out}}{(1+i)^n} - oci^t \tag{8}$$

where $cf_{in}^{t,n}$ and $cf_{out}^{t,n}$ are the cash inflow and outflow of the *n*-th year, respectively. The total investment cost, oci^t, represents the sum of capital expenditures for the PV system, $capex_{pv}^t$, and BES system, $capex_{bat}^t$ as defined in (9).

$$oci^t = capex_{pv}^t + capex_{bat}^t \,. \tag{9}$$

The capital investment expenses are calculated for the investment at a specific period *t*, by the aid of (10), assuming an inflation rate *a*.

$$\left[capex_{pv}^t \quad capex_{bat}^t\right] = \left[capex_{pv}^1 \quad capex_{bat}^1\right](1+\alpha)^{t-1} \tag{10}$$

Additionally, the cash outflow is calculated by the aid of (11),

$$cf_{out}^{t,n} = \left(opex_{pv}^t + opex_{bat}^t\right)(1+\alpha)^{n-1} \tag{11}$$

where $opex_{pv}^t$ and $opex_{bat}^t$ denote the operation and maintenance (O&M) costs of the PV and BES systems, respectively, determined for a certain investment year *t* similarly to (10).

The internal rate of return (IRR) of the investment at year *t*, irr^t, is derived by solving (8) for $npv^t = 0$. The value of *i* obtained equals the irr^t.

Cash inflows are calculated by (12) and (15), based on the distinct characteristics of the incentive policy scheme under investigation.

4.2.1 Self-consumption incentive scheme: Considering a self-consumption incentive scheme, prosumer's revenue consists of the profit from the electricity cost avoidance and the reimbursement for the grid injected energy. Therefore, the cash inflow ($cf_{in}^{t,n}$) in (8) is calculated according to (12).

$$cf_{in}^{t,n} = (c^{t,n} - c_{SC}^{t,n}) + \left[\sum_{k=1}^{bp^n}\sum_{r=1}^{pp^{bp}} E_{exp}^{r,k} sp_{r,k}^t\right](1+\alpha)^{n-1} \tag{12}$$

Here, $c^{t,n}$ denotes the annual electrical energy cost of a net consumer supplied exclusively by the utility grid, while $sp_{r,k}^t$ represents the compensation price for the exported energy of each pricing period (*r*), with pp^{bp} being the last pricing period of each billing period (*bp*). Also, bp^n is the last billing period of year *n*. Furthermore, $c_{SC}^{t,n}$ is the corresponding cost for a prosumer equipped with an integrated PV-BES solution that operates under a self-consumption scheme. Note that $c^{t,n}$ and $c_{SC}^{t,n}$ can be calculated as follows:

$$c^{t,n} = \left[\sum_{k=1}^{bp^n}\sum_{r=1}^{pp^{bp}} E_{cons}^{r,k} ep_{r,k}^t\right](1+\alpha)^{n-1} \tag{13}$$

$$c_{SC}^{t,n} = \left[\sum_{k=1}^{bp^n}\sum_{r=1}^{pp^{bp}} E_{imp}^{r,k} ep_{r,k}^t\right](1+\alpha)^{n-1} \tag{14}$$

4.2.2 NeB incentive scheme: In the adopted NeB scheme, the corresponding cash inflow is derived through:

$$cf_{in}^{t,n} = (c^{t,n} - c_{NeB}^{t,n}) \tag{15}$$

where $c_{NeB}^{t,n}$ is the annual cost when a PV-BES system is considered operating under a NeB scheme. The prosumer is charged at each billing period *k* with the netted cost $nc^{t,k}$, as in (16). In case $nc^{t,k} < 0$, prosumer is not charged and this amount is credited to the next billing period. Nevertheless, after the last billing period of the year, the credit amount is eliminated and not transferred to the following year. $c_{NeB}^{t,n}$ is derived using (17).

$$nc^{t,k} = \sum_{r=1}^{pp^{bp}} (E_{imp}^{r,k} ep_{r,k}^t - E_{exp}^{r,k} sp_{r,k}^t) \tag{16}$$

$$c_{NeB}^{t,n} = \left[\sum_{k=1}^{bp^n} nc^{t,k}\right](1+\alpha)^{n-1} \tag{17}$$

Finally, $ep_{r,k}^t$ is the electricity price at investment year *t* calculated by (18).

$$ep_{r,k}^t = ep_{r,k}^1 (1+\alpha)^{t-1}, \forall r \in pp, \forall k \in bp \tag{18}$$

4.3. *Implementation of the proposed methodology*

The conceptual implementation of the proposed methodology is presented in Fig. 8 by means of a flowchart. As shown, the user initially provides as inputs to the proposed model the consumption profile of the installation as well as the generation profile per kWp. These power profiles are in the form of timeseries, with a time-step of $\Delta\tau$, and they correspond to the entire period of the analysis. Subsequently, the examined incentive scheme is defined, and the electricity charge mechanism is selected. Afterwards, the PV and the BES capacity are defined.

Using the above-mentioned parameters, the PV and BES system power profiles of the installation, as well as the BES degradation, are computed using the proposed technical model. Subsequently, the *npv* and the *irr* of the investment are calculated using the proposed economic model.

The user can examine several electricity pricing schemes and incentive policies. Additionally, the methodology of Fig. 8 can be executed iteratively for different

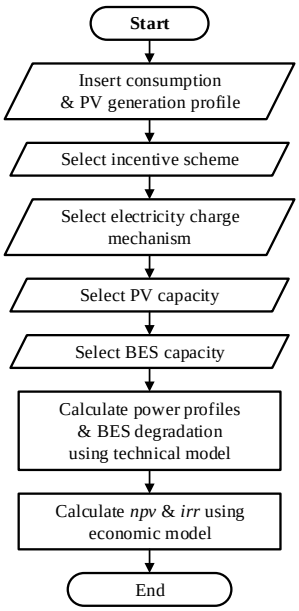

Fig. 8. *Conceptual implementation of the proposed methodology.*

combinations of PV and BES capacities. Following this approach, an exhaustive optimization search can be conducted to derive the optimal size of the integrated PV and BES system.

5. Economic Evaluation of the BES Control Schemes

In this section, the proposed methodology is employed to evaluate the BES system control schemes presented in Section 2. PoD and PrD control schemes aim to maximize the SCR and the revenues of the prosumer, respectively, assuming that any exported energy is not compensated.

A 20-year economic analysis is performed, assuming a three-phase installation. Consumption profile of the case under study is based on [7], while generation output power in kW/kWp is obtained using irradiation data from PVGIS online platform [25]. The methodology used to construct the power profiles over the analysis period are presented in the Appendix. SoC lower limit is set to 10% to avoid deep discharge of the battery module, while the upper limit is set at 90% to ensure an extended lifetime for the battery cells [26]. The charging/discharging rate of the BES system is set to 0.67C, maintaining a constant power-to-energy ratio for all examined BES sizes. Furthermore, in the analysis a 15-minutes time-step is used, i.e., $\Delta\tau = 15\ min$.

The inflation rate is considered equal to 2 %, while discount rate equal to 4 %, and the investment is performed at 2019, i.e., $t = 1$. Furthermore, typical PV and BES system costs are used for the analysis. These costs (including VAT) are presented in Table 1. In this paper, a dc-coupled BES is considered using a hybrid dc/ac converter. According to this approach, the PV module and the storage element are directly connected to a common dc-link at the hybrid converter. Thus, due to the use of hybrid converter, the cost is allocated between the PV and the BES system, as presented in Table 1.

If a replacement of the battery module is required due to its capacity degradation within the analysis period, the cost of the new battery module is considered increasing the cost of investment. The state of BES capacity degradation over the years of BES operation is evaluated through the adopted aging model.

Finally, to thoroughly evaluate the impact of the battery module cost on the economic feasibility of the integrated PV-BES solution, three different values are assumed, i.e., 200 €/kWh, 400 €/kWh, and 600 €/kWh. Considering the electricity charge mechanism, the ToU pricing system of Fig. 4 is considered [21].

The results of the performed economic analysis are presented in Figs. 9-12. Specifically, concerning the PoD control strategy, the NPV for several combinations of PV and BES system sizes, as well as for different battery module costs, is depicted in Figs. 9 and 10. Additionally, the corresponding results related to the PrD control algorithm are illustrated in Figs. 11 and 12.

Table 1 Typical PV and BES Cost Analysis

Type	Cost (€/kWp)
PV System (excl. inverter)	1440
Inverter Cost allocated to PV	160
Inverter Cost allocated to BES	160
O&M of PV system	2 % (of the overall cost)
O&M of BES system	2 % (of the overall cost)

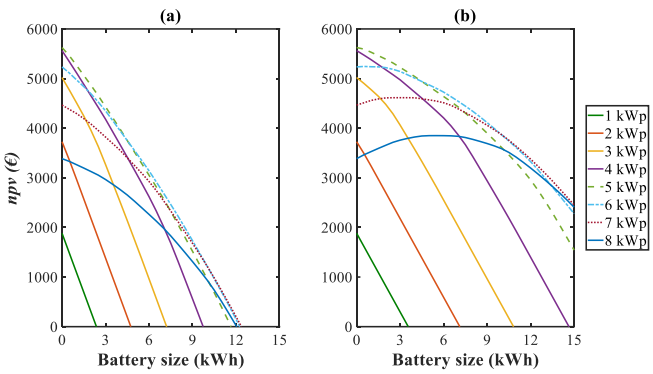

Fig. 9. *Economic analysis using the PoD control scheme. Battery module costs (a) 600 €/kWh and (b) 400 €/kWh.*

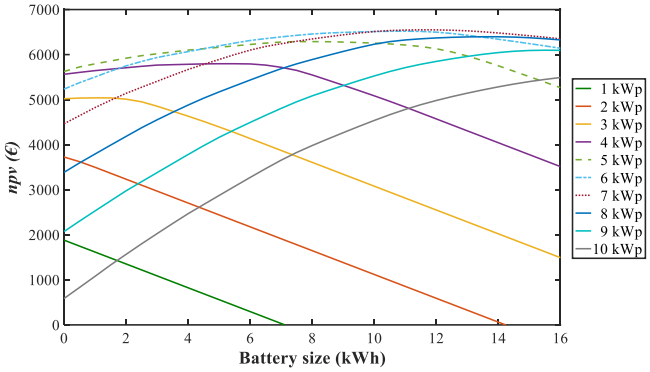

Fig. 10. *Economic analysis using the PoD control scheme. Battery module costs 200 €/kWh.*

It can be observed that both the PoD and PrD control strategies present a similar behavior at high battery module costs, i.e., 400 €/kWh and 600 €/kWh. In particular, the maximum NPV is observed for a PV system of 5 kWp without a BES system. This happens due to the relatively high cost of the battery module in combination with the lack of incentives for the widespread use of BES systems. Nevertheless, the graphs depicted in Figs. 9 and 11 can be a valuable tool in case of a predefined PV size to derive the ideal battery module size that produces the maximum NPV. For example, assuming the investment in an 8 kWp PV system and 400 €/kWh battery module cost, the best solution is to purchase a BES system with a nominal capacity equal to 5.5 kWh when either the PoD or the PrD algorithm is adopted.

Moreover, in the PrD algorithm, the LCoS strongly depends on the battery module cost according to (1). As a result, high cost leads to a significant increase of the LCoS compared to the ToU pricing levels of Fig. 4. Therefore, the corresponding battery module remains deactivated in the PrD control strategy, thus decreasing the NPV of the investment compared to the PoD control scheme. The associated results are depicted in Figs. 9a and 11a. A similar behavior is observed when comparing Figs. 9b and 11b for small values of battery capacity. Nevertheless, as the battery module size increases, the LCoS is reduced to a value close to the ToU pricing levels. Thus, the battery charging/discharging schemes are activated, leading to a step increase of the NPV, as shown in Fig. 11b.

The situation is improved for both the PoD and PrD control strategies with the decrease of the battery module cost to 200 €/kWh, as illustrated in Figs. 10 and 12, respectively. In particular, it is observed that for PV systems with an installed capacity above 5 kWp, the utilization of BES results

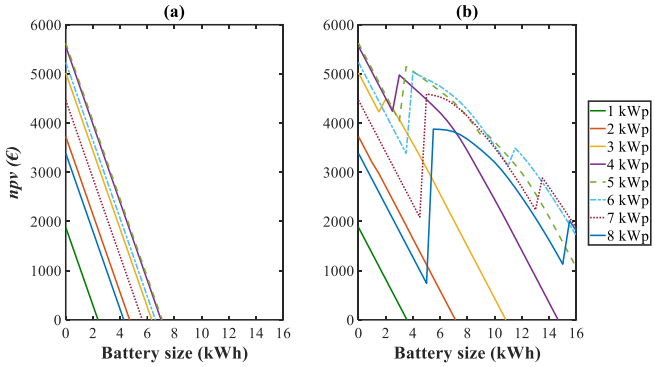

Fig. 11. *Economic analysis using the PrD control scheme. Battery module costs (a) 600 €/kWh and (b) 400 €/kWh.*

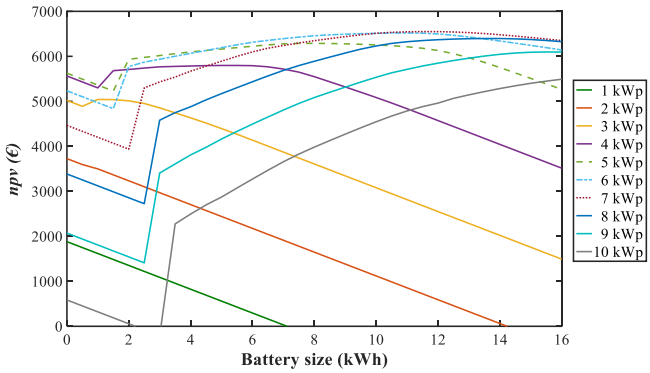

Fig. 12. *Economic analysis using the PrD control scheme. Battery module costs 200 €/kWh.*

in a significant increase of NPV investment. In contrast, the use of BES may not be profitable when considering PV systems below 2 kWp, since the surplus of produced energy is not adequate for the full exploitation of BES system capacity.

It is worth mentioning that no battery replacement is required according to the aging model outputs in the scenarios examined above. More details about the assessment methodology of battery aging and the results of some representative cases are provided in Section 7.

6. Economic Evaluation of BES under Different Incentive Schemes

In this section, the profitability of BES systems under three distinct incentive schemes is investigated, assuming the modified ToU tariff of Fig. 5. Specifically, the following incentive schemes are considered and examined:

- **S1**: This scheme represents a simple self-consumption incentive scheme aiming to maximize the SCR of the prosumer. In this scenario, PV energy fed to the grid is not compensated. This incentive scheme is identical to the one used in Section 5 to evaluate the performance of the examined BES system control strategies.
- **S2**: This scheme is similar to S1. However, in this case, the prosumer is remunerated for the exported PV energy at the price of SMP.
- **S3**: This scheme corresponds to a NeB policy, assuming a billing period of 2 months.

In Fig. 13, the two examined BES system control strategies are compared, for the S1 incentive scheme, in terms

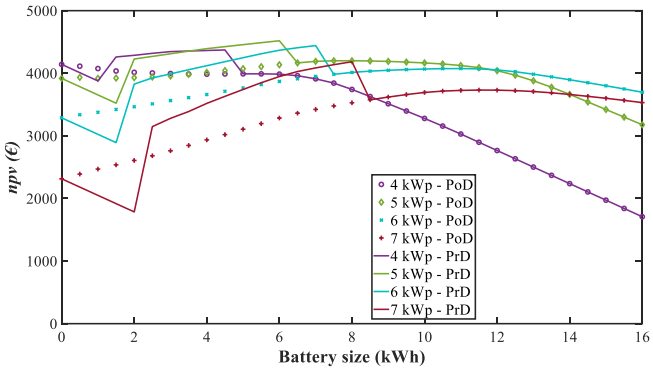

Fig. 13. *Comparative results of PoD and PrD control strategies under the S1 incentive scheme.*

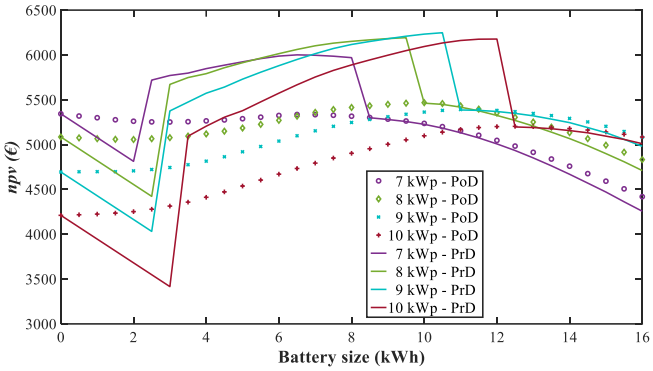

Fig. 14. *Comparative results of PoD and PrD control strategies under the S2 incentive scheme.*

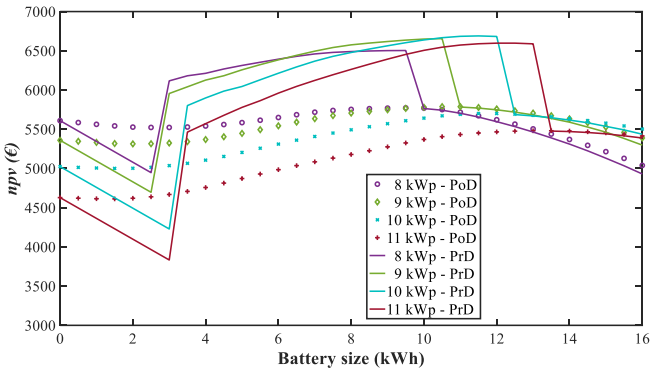

Fig. 15. *Comparative results of PoD and PrD control strategies under the S3 incentive scheme.*

of NPV. In these results, the battery module cost is considered equal to 200 €/kWh. As shown, in all cases, i.e., for all PV system sizes, the proposed PrD control scheme outperforms the PoD strategy. Indeed, in all cases, the maximum NPV is observed for the PrD strategy.

Similar results are also observed for the other two incentive schemes, i.e., S2 and S3. Specifically, Fig. 14 presents comparative results for the S2 policy, whereas Fig. 15 depicts results for the S3 incentive scheme. In both cases, the battery module cost is considered equal to 200 €/kWh. Based on the corresponding results, the use of the proposed PrD control strategy leads to the maximum NPV for all the examined PV system sizes.

A comparative assessment of the examined incentives schemes in terms of NPV is depicted in Fig. 16, assuming an 8 kWp PV system. For these comparisons, the battery is operated under the PrD control strategy, while the battery module cost is considered equal to 200 €/kWh. For all the

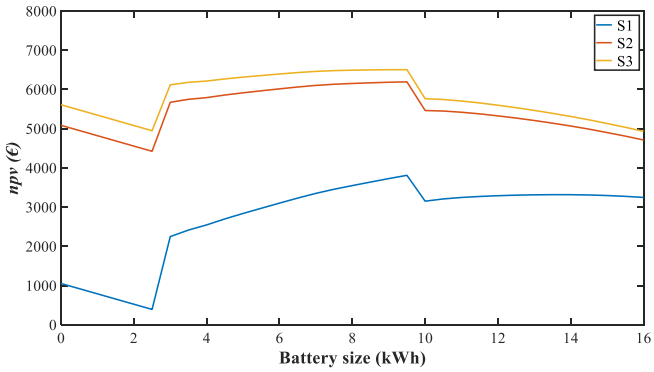

Fig. 16. *Comparative assessment of the examined incentive schemes for an 8 kWp PV system. The battery operates under the PrD control strategy.*

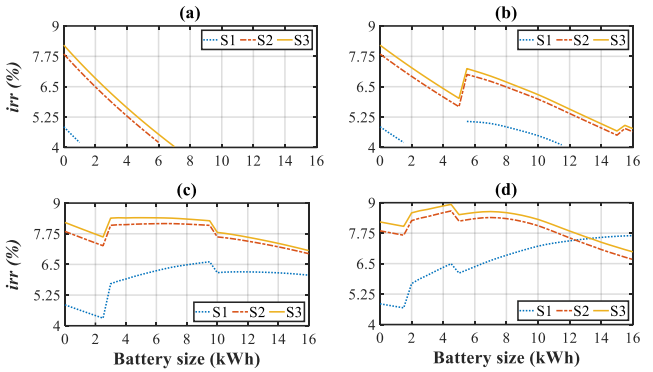

Fig. 17. *IRR for an 8 kWp PV system. PrD control strategy with battery module cost equal to: (a) 600 €/kWh, (b) 400 €/kWh, (c) 200 €/kWh, (d) 100 €/kWh. Note that in (b), for scheme S1, the IRR for battery sizes in the range of 2 - 5.5 kWh is negative.*

examined schemes, the maximum NPV is observed for a BES system equal to 9.5 kWh. However, it is evident that the NeB policy yields the maximum profit for the prosumer. Based on these results, it is clear that appropriate incentive schemes can facilitate the deployment of BES systems in the residential sector.

Furthermore, the impact of the battery module cost on the viability of integrated PV and BES systems is investigated in terms of IRR. The associated results are illustrated in Fig. 17, for the case of an 8 kWp PV system. Specifically, the attractiveness of the investment is evaluated for a battery module cost of 600 €/kWh, and future reduced costs of 400 €/kWh, 200 €/kWh, and 100 €/kWh. It is revealed that for battery costs equal to or higher than 400 €/kWh, the most attractive case is the purchase of a standalone PV system.

However, when BES costs reduce at 200 €/kWh, the investment on a BES system becomes an attractive case. IRR of investments in PV and BES is even more improved for the case of 100 €/kWh.

7. Assessment of BES capacity degradation

The capacity fade of battery module is assessed using the aging model described in Section 4.1. A lithium-ion battery of LMO technology is assumed, while the associated aging model parameters are obtained by [22, Table I].

Table 2 presents a statistical analysis of the values of battery capacity degradation rate, considering the examined cases of Section 6. The four most attractive PV size cases are considered per examined incentive scheme. It is shown that the mean capacity loss at the final year of analysis is around 0.3, i.e., the battery provides the 70 % of its rated capacity at the 20th year. The end of battery life is reached when its capacity drops to 80 % – 70% of its nominal capacity [27]. Based on this finding, a replacement of the battery module is not required during the examined period.

Table 2 Battery Capacity Degradation Rate (L^{20}) for a battery module cost of 200 €/kWh

Schemes / PV sizes considered	PoD control		PrD control	
	Mean	Std	Mean	Std
S1 / 4 - 7 kWp	0.2514	0.0263	0.2448	0.0252
S2 / 7 - 10 kWp	0.2910	0.0179	0.2751	0.0298
S3 / 8 - 11 kWp	0.3005	0.0152	0.2822	0.0329

8. Discussion and Conclusion

In this paper, a techno-economic model is developed aiming to assess the economic viability of integrated PV and BES systems under various incentive schemes. The proposed model receives as inputs the examined incentive scheme, PV generation and load consumption profiles, PV and BES system costs, as well as electricity charges. Using these data, an exhaustive optimization search is conducted to derive the optimal size of the integrated PV and BES system, in terms of NPV. The novel aspects and contributions of this work can be summarized as follows:

- The proposed model readily supports NeM and NeB policies, as well as incentives schemes that aim to maximize the SCR of the prosumers. Additionally, it can analyze incentive schemes in which the exported PV energy to the grid is compensated at a predefined price.
- The developed model is able to simulate various electricity charge mechanisms, including both dynamic pricing and constant electricity tariffs.
- In contrast to conventional approaches, the proposed model is able to analyze various BES operation schemes. Particularly, two distinct BES control strategies are incorporated. The first strategy is a conventional power-driven control scheme, aiming to maximize the SCR of the prosumer. The second strategy is a new price-driven control scheme that aims to maximize the revenues of the prosumer. This is achieved by the proper control of the charging/discharging process, based on the comparison between the electricity prices and an updated version of the levelized cost of storage system.
- The impact of the BES operation on the battery calendar and cycle aging is taken into account during the techno-economic assessment. The proposed model considers a replacement of BES module when it reaches the end of its life.

In this work, an assessment of the economic viability of integrated PV and BES systems is performed, examining three distinct incentives schemes, two BES control strategies and two different ToU tariffs. The following conclusions can be derived by the corresponding results:

- The profitability of integrated PV and BES systems significantly depends on the BES system cost. Considering the current market prices, an investment in integrated PV-BES systems may not be as profitable as an investment in standalone PV system, since it leads to a lower NPV. This

situation is likely to reverse in the next years with the current trends in the reduction of BES system cost. This is also confirmed by the IRR values of the examined scenarios.

- The comparative assessment of the examined incentive policies highlights their impact on the profitability of PV-BES systems. It is demonstrated that the NeB scheme is the most profitable for the prosumer. Therefore, it can be used along with appropriate ToU tariffs to further promote the use of BES systems in the residential sector.
- The results can be a valuable guide for policy makers and market regulators to design new incentive schemes and efficiently encourage the use of PV-BES systems in the residential sector.
- The findings of the paper show that electricity pricing signals can indirectly affect the operation of BES. The corresponding results can influence system operators to design new BES control strategies that offer ancillary peak-shaving services to the LV networks.

9. Acknowledgments

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11. Appendix

The techno-economic evaluation conducted in this paper assumes a residential prosumer with a three-phase electrical installation. Prosumer's generation and consumption over the period of 20 years are described by the corresponding power curves, in the form of timeseries with a 15-minutes time-step. These timeseries are based on the typical consumption and generation power profiles analyzed in this Appendix.

The typical generation power curves are constructed using solar irradiation data from the PVGIS platform of the EU Joint Research Centre [25], for the region of Thessaloniki, Greece. One typical daily power curve in kW/kWp is built per month. The obtained profiles are illustrated in Fig. 18. The complete timeseries of PV generation over the 20-years analysis period is then constructed, using the corresponding daily curves. It is worth mentioning that an annual degradation of 0.2 % at the PV production is taken into consideration.

On the other side, the 20-years timeseries of the prosumer's consumption is constructed based on the typical daily profiles of Figs 19-21. Particularly, two typical daily power curves are adopted per month; one corresponds to the working days, while the other to the non-working days of the month. These power profiles are based on the consumption profiles of [7].

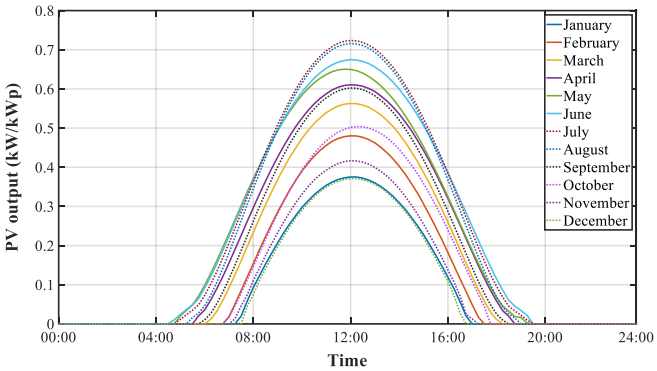

Fig. 18. *Adopted PV power profiles.*

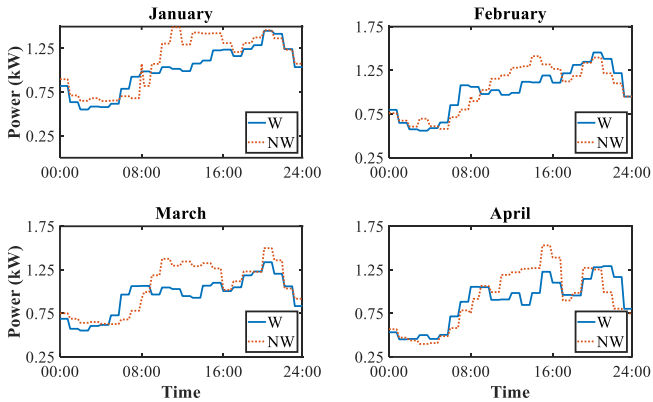

Fig. 19. *Typical daily consumption profile for months January – April; W and NW correspond to the profile of a working and a non-working day, respectively.*

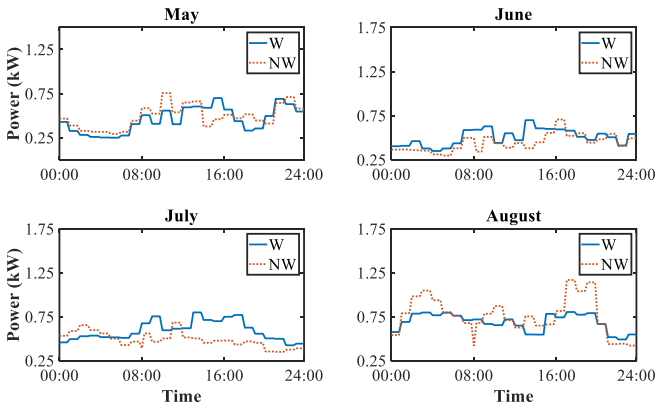

Fig. 20. *Typical daily consumption profile for months May – August; W and NW correspond to the profile of a working and a non-working day, respectively.*

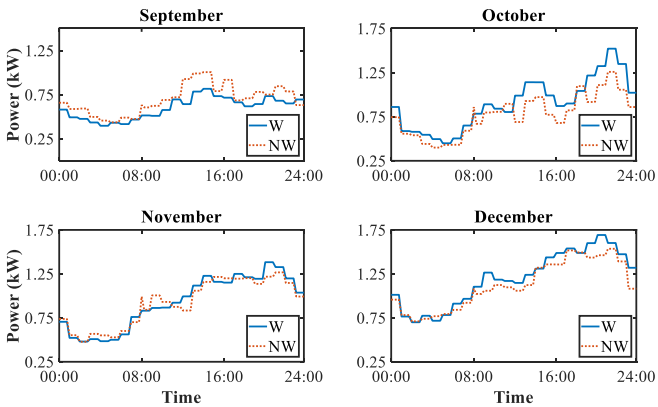

Fig. 21. *Typical daily consumption profile for months September – December; W and NW correspond to the profile of a working and a non-working day, respectively.*