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Evaluating distributed photovoltaic (PV) generation to foster the adoption of energy storage systems (ESS) in time-of-use frameworks

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ABSTRACT

Power distribution grids all over the world are experiencing exponential growth in the number of distributed generators (DG), especially for small-scale, residential, and commercial rooftop photovoltaic (PV) systems. Electrical energy storage systems (ESS) allow for the decoupling of generation from consumption, addressing the issue of PV supply intermittency in the traditional electricity grid, and improving the potential penetration and widespread deployment of PV on the distribution grid. Several articles were reviewed to list and better understand the different variables that influence the technical and economic evaluation of a PV + ESS system. By proposing and applying a novel hybrid Levelized Cost of Storage (LCOS) analysis, the effects of adopting ESS in the Brazilian regulatory framework were evaluated. The proposed method is universal, and the Brazilian case study is presented to illustrate it. Results are compared with an alternative of PV-only systems in a flat tariff scheme and show that a sharp drop in ESS initial costs is required before PV systems plus storage become the best investment alternative for the end user. However, the PV + ESS alternative results in a positive impact for the whole grid, suggesting that policies towards cost reductions and incentives, such as a wider Time-of Use tariff spread, should be designed to stimulate the adoption of ESS associated with DG solar PV.

1. Introduction

Brazil is experiencing an exponential growth rate (over 200% increase from 2018 to 2020, with over 3.3 GWp currently in operation) in the amount of distributed generation (DG) using solar photovoltaic (PV) systems (ANEEL, 2020). The high penetration of rooftop PV generation will lead to a reduction in the necessary generation of load following hydropower plants, while the regulation of voltage and frequency caused by the intermittency of PV generation should be serviced by fossil-fueled thermoelectric power plants. This should increase the total cost of power generation and the complexity of the operation of the country's electrical system, requiring measures such as energy storage and load management. The adoption of Energy Storage Systems (ESS) in this context can be carried out either by the utility itself, at strategic sites spread around its network, or at the consumer unit level, if appropriate policies (fiscal and economic incentives) are put in place.

Demand side management as a measure to shift energy consumeŕs habits can be achieved through the differentiation between peak and off-peak energy tariffs. Time-of-use (ToU) tariff schemes employ a dynamic variation for off-peak, intermediary, and peak hours. Peak hours and their corresponding tariffs are set by the distribution utility to reflect end-user load profile and supply costs. The implementation of the Brazilian ToU framework (the so-called White Tariff) is a strategy designed to reduce the energy demand of residential consumers at peak times. In a large electrical system such as the Brazilian, with a complex transmission and distribution (T&D) system spread over a vast territory (8.5 million km^2), which is highly dependent on rainfall regimes to maintain the generation of the predominant hydroelectric power plants, decreasing peak demand can reduce the need for thermoelectric power plants to come online every evening. More recently, climate change effects have also resulted in more frequent situations of seasonal droughts and an increasingly water-constrained hydropower plant fleet. Together with the support of rooftop PV for self-production, this strategy aims at reducing the effect of the growing need to use thermoelectric power plants that are less efficient, burn fossil fuels, and have high operating costs, thus reducing T&D losses and postponing investments to replace transformers and the associated infrastructure in distribution networks (Yunusov et al., 2016). This peak load reduction can be achieved both by changes in user load profiles, and by using ESS with distributed renewable energy sources such as PV, as long the

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combination is economically viable for the end-user. It is important to recognize the value of new investments in generation assets, and the avoided costs of T&D assets, represented by residential rooftop PV.

In 2016, El Hage and Rufín (2016) evaluated the effects of distributed generation, demand response, energy storage and efficiency on the Brazilian electricity framework. They concluded that a decoupling of energy and peak power billing must occur for small costumers, as well as ToU measures to foster energy efficiency. On that topic, the Brazilian electricity regulatory agency (ANEEL) opened in 2018 a public hearing for stakeholders on binomial tariff (decoupling of power and energy billing for residential customers) and to evaluate changes to the net metering framework, signaling that on a near future grid-connected PV systems will incur additional charges for using public grids as virtual batteries. Solano et al. (2018) evaluated the economic impact of implementing binomial tariffs, perceived by residential customers, over PV + ESS in Portugal and Spain. In this context, the addition of ESS with the right control strategy (either prioritizing self-consumption or peak shaving) could become viable in both countries, once allied with PV.

There are several economic indicators available for the consumer to evaluate whether investments on PV or ESS are feasible. The most common in the literature are the Net Present Value (NPV), the Internal Rate of Return (IRR), the Payback Time (PBT) and the Levelized Cost of Electricity (LCOE) (Sommerfeldt and Madani, 2017). While the first three are common tools of microeconomics, the LCOE is more specifically focused on energy sector economic evaluations. In this context, the LCOE is the average tariff at which PV-generated electricity must be sold over the lifetime of the PV generator to balance its costs and revenues. This analysis allows for consumers to decide whether to go solar or to keep meeting their energy needs with the local distribution utility conventional supply. Furthermore, the IRR allows the user to compare the investment on a PV system with different alternatives through different interest rates, while the NPV quantifies the potential profits (or losses) over the PV system lifetime.

For the economic evaluation of hybrid PV + ESS, additional revenue derives from the battery discharge in a tariff arbitrage scheme. This revenue potential depends mainly on the available energy from the PV generation, the hourly energy demand, ESS CAPEX and internal parameters, and the hourly tariff. The Levelized Cost of Storage (LCOS) approach was adapted from the LCOE concept, to reflect this different environment. Its formulation must consider the CAPEX and OPEX of the whole hybrid system, the cost of charging and the potential revenues from discharging the battery.

Levelized cost analyses are only as powerful as the quality of their inputs. As exposed by Branker et al. (2011), outdated or inaccurate data could lead to an overestimation of the results. Even the regulatory framework can impact on assumptions, for example, in a hybrid LCOS: using the LCOE of the PV system as a tariff basis for the ESS charging costs does not reflect the reality on a net-metering framework such as the Brazilian.

For the end user, the evaluation of different investment alternatives allows for the ideal allocation of resources, while for the distribution utility, it enables the study of the correct incentives that would foster the adoption of clean energy, and measures that would bring more stability to its network or the development of new business models. As discussed by Chattopadhyay et al. (2019), ESS economic evaluations are essential since their initial costs are still high and any business model should be designed around not only the economy from the spread between peak and off-peak tariffs, but all the ancillary services that energy storage can provide, even adding a Value of Lost Load (VoLL) as extra income due to the ESS service during potential PV generation curtailment events.

This work aims at establishing a general methodology and apply it in a case study in Brazil. The purpose is to evaluate the impact of different variables on the comparison of two investment alternatives: a rooftop PV system and a hybrid PV + ESS system under the Brazilian ToU framework. To achieve this, the interaction of a hybrid PV + ESS was simulated for a household and a novel LCOS that reflects the energy demand pattern was proposed.

Similar approaches have been proposed by Masebinu et al. (2017) and Koskela et al. (2019), who evaluated the sensibility of LCOS and NPV for a series of scenarios and different storage technologies under a ToU framework. Masebinu et al. concluded that for ESS feasibility, the peak tariff should be higher, while the off-peak tariff should be as low as possible with the current costs of rooftop PV deployed at sunny sites. Battke et al. (2013) used a Levelized Cost of Energy for storage applications approach (LCOEsa), with Monte Carlo simulations to compare different storage technologies. While these analyses contemplate the uncertainty of input variables, the formulation of LCOE for storage does not account for the ESS charging costs. Yu (2018) used a Profit Investment Ratio (PIR), an index that relates the grid tariff to the PV system LCOE and the residential self-consumption, to estimate that, circa 2030, PV + ESS systems might become economically feasible in France. Yu also discussed that on a scenario of grid parity of hybrid systems, policies must be adopted to smoothen the transition, as the massive adoption of PV self-consumption systems is expected.

Zakeri and Syri (2015) reviewed different storage technologies and how to compare them. To formulate a LCOS, they described two other parameters, namely the Total Capital Cost (TCC), and the Life Cycle Cost (LCC). The TCC accounts for all initial costs to purchase an ESS and gives costs as a function of ESS's power and capacity, while the LCC goes beyond, adding the maintenance, replacement, and disposal values. Finally, the proposed LCOS comes as a function of the LCC, operating hours, price of charging electricity and overall efficiency.

Braun et al. (2009) modeled a PV + ESS system's impact on the residential energy flow and the resulting economy, while evaluating the self-consumption before and after the installation. The model developed by Braun et al. provides a practical insight over the battery's mechanisms of degradation and uses high-resolution energy demand profiles to increase accuracy.

The impact of battery degradation is also addressed by Uddin et al. (2017), who analyzed lithium cells aging characterization tests to evaluate the annual reduction in its capacity and the increase of internal resistance over the annual revenue of a hybrid PV + ESS. Gitizadeh and Fakharzadegan (2014) underline that besides battery degradation, the energy dispatch strategy has a major impact on the ESS sizing and consequent financial analysis. Since 2016, Lazard Consulting (Lazard, 2018) has been publishing a LCOS evaluation of different storage technologies over six sets of applications (from wholesale to residential storage). The methodology uses a bottom-up approach: on a cash flow, it solves for the LCOS by setting the project IRR equal to equity. Hoppmann et al. (2014) investigated which are the conditions for the economic viability of residential lead-acid storage systems without subsidies in Germany. The authors used NPV with sensitivity analysis to demonstrate that storage alternatives would be profitable in all scenarios. Still, on the German framework, Merei et al. (2016) investigated the impact of PV + ESS systems on commercial applications, evaluating the increase in self-consumption on an already high coincident energy demand and PV generation profile, also forecasting that storage will only be profitable in 2025, when and if costs drop below 200 €/kWh.

2. Hybrid photovoltaic and energy storage systems

In many applications, an ESS allows the end-user to deploy distributed photovoltaic generation at evening peak times and allows for the possibility of maintaining energy supply in critical or contingency situations. Economic evaluation models for PV systems typically employ the following parameters: annual energy output (in kWh) as a function of installed PV power (kWp), which results in the annual energy yield (kWh/kWp.year); annual degradation (d_y); lifetime of system components (Lt) and all PV system costs including acquisition (CAPEX), O&M, replacements, financing, taxes and salvage/decommissioning (OPEX). ESS evaluations depend on characteristics like total capacity (kWh), Depth of Discharge - DoD (% of total capacity), efficiency (%), capacity

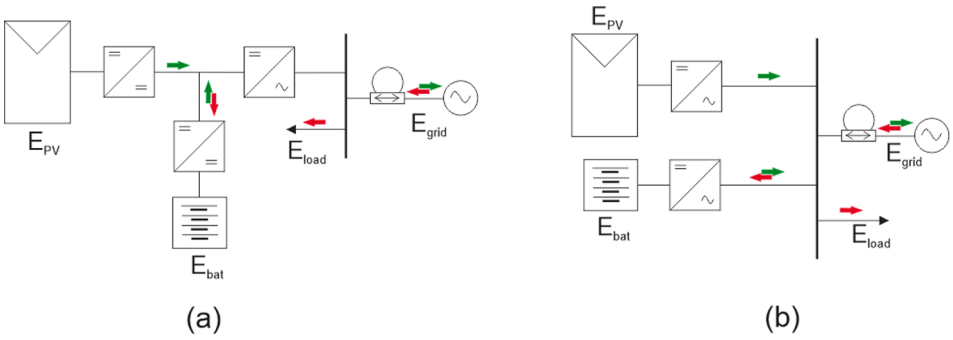


Fig. 1. Different topologies for ESS (a) DC-coupled (b) AC-coupled. Adapted from Ranaweera and Midtgård (2016).

Table 1
Cost reduction perspectives for PV + ESS system components.

	Inverters	Modules	BoS	Batteries	BBoS
Reduction	4–9%	15–23%	6–8%	8–20%	6–8%
References	Pena-Bello et al. (2017)			Merei et al. (2016); Curry (2017); Jülch et al. (2015)	Pena-Bello et al. (2017); Rüther et al. (2015)

degradation (d_y), the lifetime and power output (from power converter). The Depth of discharge (DoD) is defined as a percentage of the total capacity in which a battery can be repeatedly discharged and keep its integrity. Considering a safe 80% DoD, the lifespan of a Lithium-Ion battery could be as high as 10,000 cycles. The roundtrip efficiency of the storage system represents the ratio of the available output energy to the energy put into the ESS. Losses are due to self-discharge, auxiliary systems, thermal losses and internal resistance (Zakeri and Syri, 2015).

As for the electrical connection of the ESS to the home electricity network, this can be done in two ways: coupled to the DC bus next to the PV generation output and before the PV inverter, or coupled to the AC bus through a bidirectional inverter as can be seen in Fig. 1. A comparison between these two topologies is found in Ranaweera and Midtgård (2016), but the results do not show significant differences. A possible justification for the use of one or the other topology could be whether it would be installed on a retrofitted or on a new PV system. More recently, for new PV systems, PV-Battery hybrid inverters are available, while for the retrofit of existing installations the battery system can be integrated through a separate, bidirectional inverter system. The proposed energy flow for the hybrid system allows for the surplus PV energy to be fed to the grid if the storage is at its full capacity, but the ESS will not be charged with energy from the grid. Under this condition, the stored energy is a function of the PV generation that is not directly consumed nor exported to the grid, thus not metered by the utility or taxed.

Among different electrochemical battery options, lithium-ion technologies are seen as the most cost-effective from a life-cycle cost analysis perspective, due to a longer lifespan and number of cycles, higher efficiencies and much higher DoDs than the more traditional lead-acid or other battery chemistries (Schmidt et al., 2018). Even though lithium-based batteries have a higher initial cost, their longer lifespan results in the best return on investment among the commercially available battery technologies. Lithium-ion batteries have shown a sharp cost reduction in recent years due to the significant increase in their manufacturing volumes since 2010. Annual cost reductions of 19% for batteries used in electric vehicles a few years ago (Curry, 2017) are today as high as 22%/year (Citibank, 2020), and stationary applications are profiting from the economies of scale of this application. Further price reductions are expected for Li-ion batteries due to renewed interest in residential, automotive and portable electronics applications (IRENA, 2015). Furthermore, stationary ESS will soon start benefiting from the huge surplus of discarded electric vehicle batteries in second-life applications[1] (Drude et al., 2014; Rüther et al., 2015).

An ESS consists of the battery pack and the protection system, charge control and inverters, called the Battery Balance of System - BBoS. Although the average reduction in annual costs for batteries is between is today over 20%, BBoS's annual cost reduction (equivalent to 54% of total cost) is around 6% (IRENA, 2017). Table 1 shows the present value and annual cost reduction for PV plus storage systems.

3. Economic indicators

This section describes the tools to assess the economic viability of adopting an ESS, and to compare with the alternative of rooftop PV distributed generation only. The Net Present Value is a profit/loss indicator equal to the sum of the yearly cash flow over lifetime (T) capitalized through an interest rate (j) to the first year of the project subtracted by the initial costs (C_0). The cash flow is comprised of the yearly values of Revenues (R_n) subtracted by the Costs (C_n). The NPV is given by (1):

$$NPV = -C_0 + \sum_{n=1}^{T} \frac{R_n - C_n}{(1+j)^n} \quad (1)$$

A positive NPV represents profit for an investment for a given interest rate. This indicator is highly dependent on the interest rate and assumes that every future revenue is reinvested at the same rate. While increasing the interest rate reduces the NPV, the rate at which the NPV is zero is known as the Internal Rate of Return – IRR. Thus, the IRR is used to compare investment alternatives by their interest rate. For example, the Brazilian inflation rate for 2019 was an accumulated value of 4.13%, while the Certificado de Depósito Interbancário – CDI (Interbank Deposit Certificate) index that binds most funds is 5.95%. PV systems with an IRR superior to the CDI would in principle be a better alternative than most investment funds.

The photovoltaic LCOE is the average tariff value for the equilibrium of costs and revenues during the lifetime of a project, in which the revenues correspond to the economies obtained through annual PV generation ($E_{PV,n}$) multiplied by an average incident tariff, and the annual costs are equivalent to the costs of operation and maintenance ($C_{O\&M}$), periodic replacement of equipment (C_{equip}) and amortization of financing (C_{finc}).

$$C_n = C_{finc,n} + C_{O\&M,n} + C_{equip,n} \quad (2)$$

[1] In the so-called second-life of Li-ion electric car batteries, when batteries are discarded from electric vehicles after reaching 60–80% of their charging capacity, they are still fit for many stationary applications including residential ESS. The market for these batteries in 2025 is expected to be in the many tens of MWh/year.

Table 2
Different proposed equations for LCOS found in the literature.

Equations	Reference	Considerations
$LCOS = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{M_{el}}{(1+i)^t}}$	World Energy Council (2016)	Does not consider the costs to charge the battery
$LCOS = Capex + Opex.AF/W.AF$	Abdon et al. (2017)	OPEX considers the costs of charging with three different tariffs. AF is the annual correction factor
$LCOS = \frac{A_{bat}}{E_{frombat}} \cdot \eta_{inv}$	Quoilin et al. (2016)	LCOS appears as an additional term on the LCOE of hybrid systems equation
$LCOS = LCOE - \frac{chargingcosts}{roundtripefficiency}$	Zakeri and Syri (2015)	Separates the costs with charging the ESS
$LCOS = \frac{Capex + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{W_{Out}}{(1+i)^t}}$ $A_t = Opex + Capex_{re,t} + c_{el} \cdot W_{in} - R_t$	Jülch et al. (2015)	The costs due to charging the EES are considered as O&M costs
$LCOES = \frac{Capex + Opex}{\sum_{i=0}^{n} \frac{E_{dis}}{(1+r)^n}}$ $LVOES = \frac{\sum_{i=1}^{n} \frac{CF_i}{(1+r)^n}}{\sum_{i=0}^{n} \frac{E_{dis}}{(1+r)^n}}$	Pena-Bello et al. (2017)	The first indicator considers the costs over the discharged energy over its lifetime and the second is a levelized value considering the cash flow over the lifetime
$RADP = \frac{\sum_t \frac{(OCC_t + FOM_t + TCC_t)}{(1+r)^t}}{\sum_t \frac{MWh_t}{(1+r)^t}}$ $RAPS = RADP - \frac{\sum_t \frac{TCC_t}{(1+r)^t}}{\sum_t \frac{MWh_t}{(1+r)^t}}$ $RAOP = \frac{\sum_t \frac{(OCC_t + FOM_t)}{(1+r)^t}}{\sum_t \frac{MWh_t}{(1+r)^t}}$	Belderbos et al. (2017)	This article proposes three metrics of the needed tariffs for ESS profitability. The first is a transcription of LCOS, while RAPS considers the needed spread between charging and discharging. The last one describes the needed revenue by discharging to match the ESS's OPEX and CAPEX
$LCOE_{St} = \frac{\sum C_{St}}{\sum E_{OUT,St,t}} + K_t \frac{p_{int.0}}{\eta_{St}}$ $K_t = \frac{\sum_{t=1}^{T} E_{int,t} \frac{(1+PIF_{p_{int}})^t}{(1+i)^t}}{\sum_{t=1}^{T} \frac{E_{int,t}}{(1+i)^t}}$	Pawel (2014)	By using the charging energy multiplied by the initial tariff as a cost, the author uses the roundtrip efficiency to isolate a term that consists of a tariff, a developing tariff factor and the roundtrip efficiency

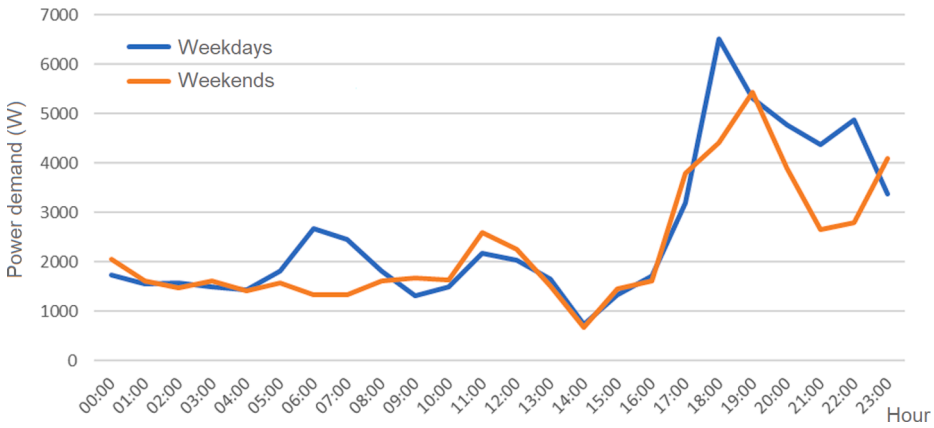


Fig. 2. Baseload (power demand) profile of the residential households considered for simulations.

For photovoltaic systems, the O&M cost is often reduced to an annual percentage of the initial cost to represent the expenses of connections repairs and PV modules cleaning among others; costs with financing are optional, and the replacement cost of equipment must consider the storage and inverter replacement at the end of its warranty (typically every ten years), also considering its future cost reduction. Therefore, from the equation of equilibrium of costs and revenues the annual PV generation ($E_{PV,n}$) can be rearranged and the LCOE isolated to provide (3):

$$LCOE = (C_0 + \sum_{n=1}^{T} \frac{C_n}{(1+j)^n}) / \sum_{n=1}^{T} \frac{E_{PV,n}}{(1+j)^n} \quad (3)$$

The result is the basic LCOE equation, which can be used to compare different power generation technologies, provided they are in similar

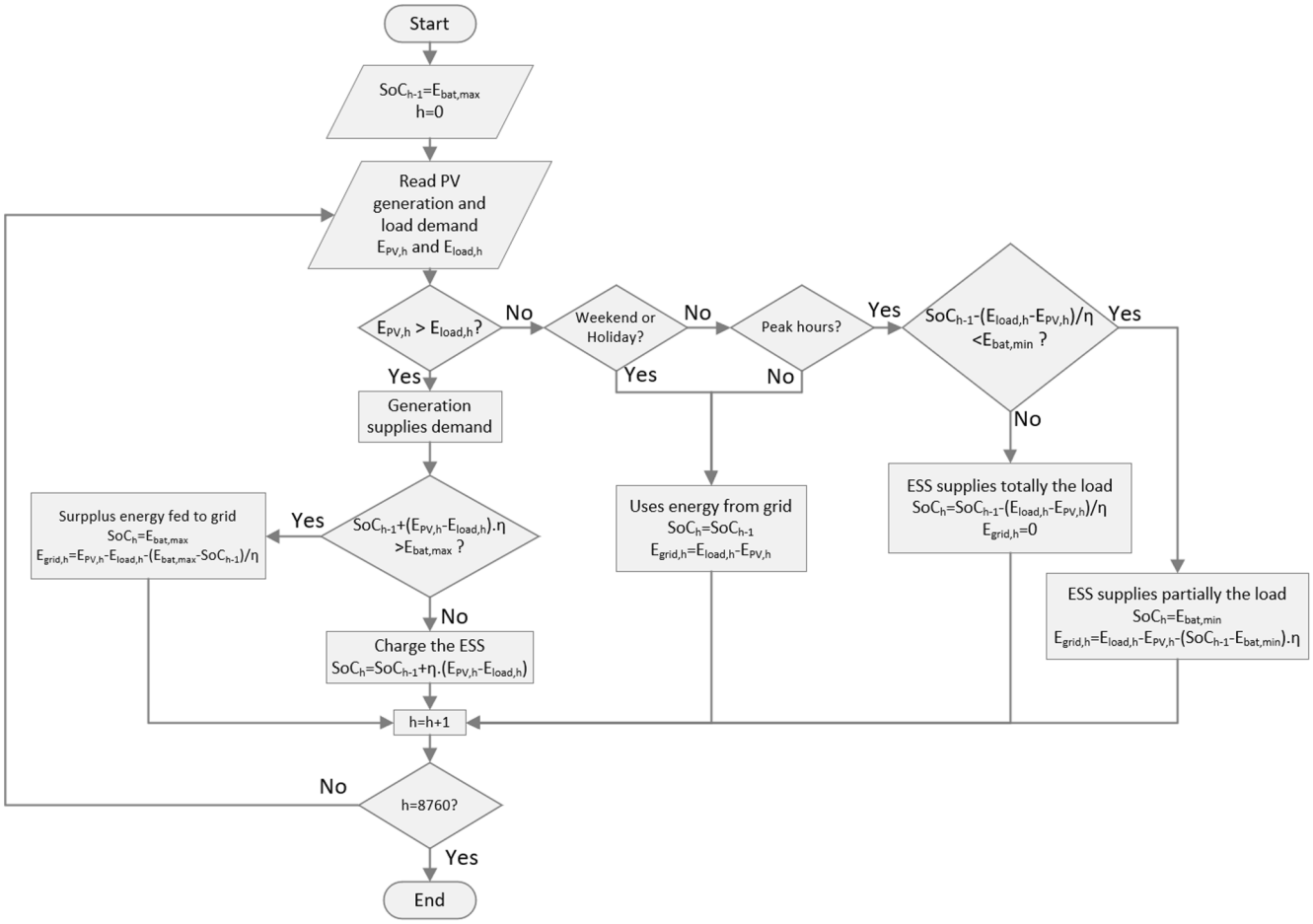


Fig. 3. Hybrid PV + ESS flowchart.

regulatory conditions: for example, large PV power plants can have their LCOE calculated and compared with diesel or large-scale wind turbines since they all offer their energy in the Brazilian *Câmara de Comércio de Energia Elétrica – CCEE* (Chamber of Commercialization of Electric Energy).

For distributed PV, the calculated LCOE can be used to compare with other distributed generation technologies, or with the local distribution utility's conventional energy supply tariff including taxes (avoided cost). Comparing the LCOE with the utility's rate allows determining the conditions under which an investment becomes feasible, or if it should be abandoned or postponed. The postponement of the investment is an alternative when the LCOE of the projected system results superior to the distribution utility's conventional energy supply tariff; in other words, when price parity with the network was not achieved.

Branker et al. (2011) reviewed 27 papers evaluating the LCOE of photovoltaic systems published between the years 2003 and 2010. According to the authors, when evaluating PV systems applying the LCOE, it is recommended that all the parameters that affect the system be duly modeled and justified. Known limitations of the method are: (i) the imprecision of the models leading to the different parameters; (ii) the fact that the method in its basic form does not consider the risks involved in the projects; and the fact that (iii) forecasts much later in the future may not be correct. Thus, the LCOE should be recognized as a picture of the economic viability of a system if current policies are maintained and the system performs as expected; however, a broader view can be obtained through a sensitivity analysis of the variables and parameters employed.

Levelized cost of storage - LCOS uses the levelized energy cost metric to stipulate the average tariff value at which the stored energy should be discharged to equalize the system costs over its lifetime (Belderbos et al., 2017). Similarly, it is used to compare the investment in a storage solution with the grid flat rate. There is no universally accepted equation for the LCOS since different authors use different analyses when referring to charge and discharge energy. Grid-connected storage systems contributing to the integration of renewable energy sources have attracted great interest from the scientific community, with a growing number of publications on the technical and economic aspects of the systems. While this paper is not a complete review of the literature on this topic, Table 2 presents a rather comprehensive list of different equations for the LCOS, their authors, and relevant considerations to the calculations. In the methodology proposed in this paper, a model for the description of the LCOS for the Brazilian regulatory and tariff context is presented.

4. Methodology

The HOMER Energy® (HOMER Energy LLC, 2016) software was used to generate hourly synthetic data for one year of PV generation and residential consumption. The software package, widely used for techno-economic analysis of hybrid systems, generates energy demand curves through a base curve, and variability parameters entered by the user. For the scope of this work, HOMER Energy® is considered as one of the most reputable simulation tools in the market. The curve used as the baseload for weekdays and weekend days is shown in Fig. 2, with an early evening peak, and a load factor of 38% (the ratio of the medium daily value and its maximum). Peak-hour demand and load factor are both essential parameters for the analyses carried out in this work, as they change the energy storage capacity requirement, its costs and thus its economic viability.

For hourly PV generation, synthetic data are generated by inserting the daily irradiation averages and clearness index in the HOMER Energy® software. The methodology used in the software for the generation of the synthetic series is described by Graham and Hollands (1990). Monthly irradiation data can be entered manually or imported directly from databases such as NREL (NREL, 2018), INPE (Pereira et al., 2017) and NASA (NASA, 2018) among others, by entering the location geographic coordinates. Whilst synthetic data for both PV generation and load curves were inputs from HOMER Energy® (based on field values), all the analyses were carried out using the methodology described as follows, outside the software.

Table 3
Global variables for PV and ESS systems simulations.

Technical Variables	
Storage Capacity	4 kWh
SoC_0 – Initial charge	4 kWh
DoD – Depth of Discharge	80%
η – Roundtrip efficiency	95%
P_{fv} – FV Power	2.5 kWp
G_{POA} – Average irradiance on plane of array	4.43 kWh/m^2.day
PR – Performance Ratio	85%
d – Degradation rate	0.5% / year
E_{med} – Energy demand	300 kWh/month
LF – Load Factor	38%
Economic Variables	
T - Lifetime	25 and 30 years
j – interest rate	3 to 15%
$C_{0,PV}$ - PV initial costs	790 to 1,840 $/kWp
$C_{0,bat}$ - Storage initial costs	260 to 1,840 $/kWh
$C_{10,20,inv}$ - Inverters replacement costs	26 and 29% of $C_{0,PV}$
$C_{O\&M}$ - O&M yearly costs	1% C_0
T_h – Flat energy tariff	0.1483 $/kWh
T_1 – Off peak Time of Use tariff	0.1266 $/kWh
T_2– Intermediary Time of Use Tariff	0.1685 $/kWh
T_3– Peak Time of Use Tariff	0.2572 $/kWh
Yearly increase in tariff	3.82%

For grid-connected PV systems, the highest benefits come from supplying peak demand. From the energy consumer point of view, meeting this demand is the main factor for the return of investment in a ToU tariff scheme. The sizing of the ESS can be carried out through simulations of the behavior of the storage system as performed in Bortolini et al. (2014) and Erdinc et al. (2015). The energy storage system can be simulated through the State of Charge (SoC, here in kWh of stored energy) and Depth of Discharge (DoD) equations, and system efficiencies as discussed in Ranaweera and Midtgård (2016), Zucker and Hinchliffe (2014), and Setlhaolo and Xia (2016), where:

$$SoC_h = SoC_{(h-1)} + Eff \cdot E_{bat,h} \tag{4}$$

$$E_{bat,min} \leq SoC_h \leq E_{bat,max} \tag{5}$$

$$E_{bat,min} = (1 - DoD) \cdot E_{bat,max} \tag{6}$$

$$Eff = \begin{cases} Eff = \eta & E_{bat,h} > 0 \\ Eff = \dfrac{1}{\eta} & E_{bat,h} < 0 \end{cases} \tag{7}$$

These equations drive the dynamics as energy flows in and out of the storage system, whose operation consists of a maximum storage capacity ($E_{bat,max}$ in kWh) and a lower limit ($E_{bat,min}$, also in kWh) related to a maximum DoD, to maximize the lifespan. At every hour (*h*), there will be a SoC (in kWh) that can be increased or reduced for energy arbitrage considering its overall efficiency *Eff*.

Based on the methodology applied in Colmenar-Santos et al. (2012), Bortolini et al. (2014) and later in Young et al. (2019), the interaction between the PV system and the ESS should be calculated to explain the economy due to the use of distributed generation and storage when applying the values of the ToU tariff (the aforementioned White Tariff in Brazil). The flowchart in Fig. 3 describes this interaction.

After processing the hourly energy flow, results are obtained for the PV generation supplied to the grid, resulting energy demand and battery charge and discharge cycles. Such data provide the resulting energy cost when multiplied by the corresponding hourly tariff (T_h), according to (8) and (9):

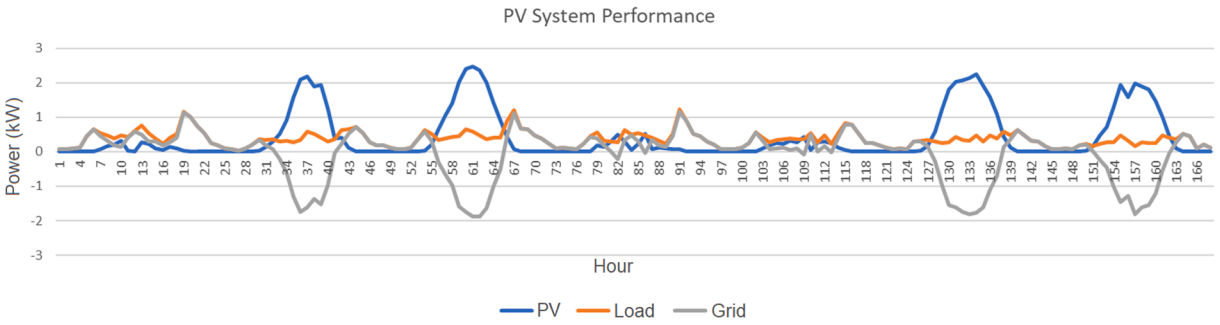


Fig. 4. Input data and PV system performance over the first simulated week for a PV installation without storage.

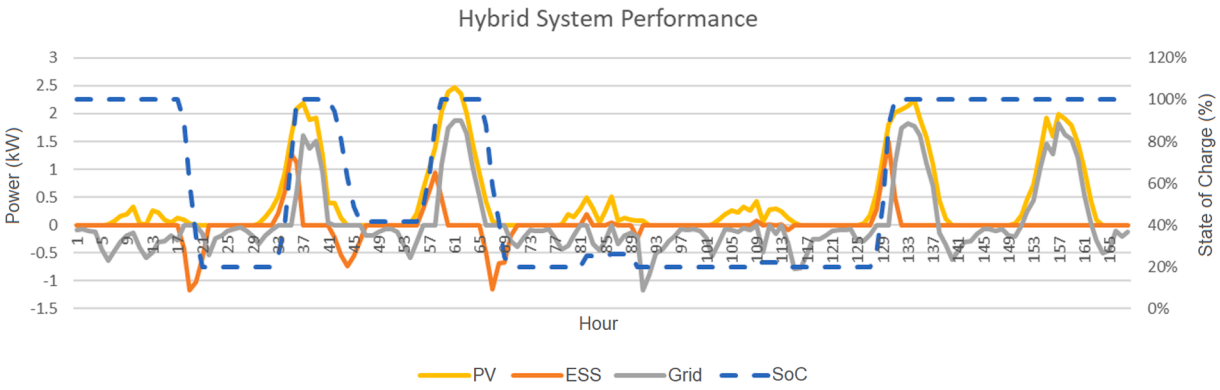


Fig. 5. Hybrid PV + ESS system performance over the first simulated week.

$$C_{grid,n} = \sum_{i=1}^{365} \sum_{h=1}^{24} T_h E_{grid,h} \tag{8}$$

where, T_1, T_2 and T_3 correspond to off-peak, intermediate, and peak-time tariffs, respectively. The hourly distribution of the tariffs is shown in (9).

$$T_h = \begin{cases} T_1 & h = 1 \rightarrow 17; 23; 24 \\ T_2 & h = 18; 22 \\ T_3 & h = 19; 20; 21 \end{cases} \tag{9}$$

Self-consumption (SC) is a metric defined as the ratio of the amount of generated energy that is instantaneously consumed and the total generation. In countries where feeding energy to the grid is not supported by legislation or is less incentivized (due to low feed-in tariffs), a higher SC is seen as a better alternative to avoid unnecessary expenses with larger PV systems (Luthander et al., 2015).

To better evaluate the impact of the addition of PV + ESS systems on the residential energy demand, the metric of Load Factor (LF) should be used. The LF is the daily average power demand divided by the peak power demand, with values close to 100% LF meaning a flat energy demand curve. From Gellings' (1985) demand-side management strategies, most of the benefits are met with a flat demand curve. It means increased predictability that would imply in a more stable and more cost-efficient grid since stable loads could be met with baseload

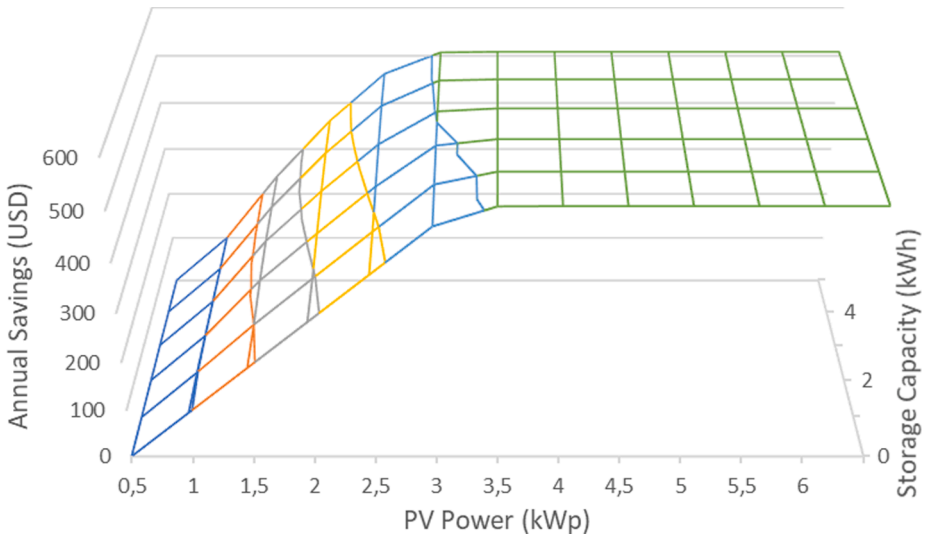


Fig. 6. Hybrid PV + ESS system yearly savings (in US$) for different sizes and capacities.

Table 4
Energy arbitrage contribution to the revenue of hybrid PV + ESS systems.

Contribution of Energy Arbitrage to annual revenue						
PV Power (kWp)	Storage Capacity (kWh)					
	0	1	2	3	4	5
0		100%	100%	100 %	100%	100%
0.5	0%	0.8%	1.0%	1.2%	1.5%	1.6%
1	0%	5.3%	10.7%	13.3%	14.3%	14.8%
1.5	0%	4.7%	10.9%	15.6%	18.7%	20.3%
2	0%	4.2%	9.6%	14.0%	17.1%	18.6%
2.5	0%	3.7%	8.4%	12.5%	15.2%	16.5%
3	0%	3.3%	7.5%	11.1%	13.6%	14.7%
3.5	0%	3.0%	6.8%	10.1%	12.3%	13.2%
4	0%	2.8%	6.2%	9.2%	11.2%	12.0%
4.5	0%	2.6%	5.7%	8.4%	10.3%	10.9%
5	0%	2.4%	5.2%	7.8%	9.4%	10.0%
5.5	0%	2.2%	4.9%	7.2%	8.7%	9.2%
6	0%	2.1%	4.5%	6.7%	8.1%	8.5%

Table 5
Fraction of self-consumption for different PV and ESS capacities.

Self-Consumption						
PV Power (kWp)	Storage Capacity (kWh)					
	0	1	2	3	4	5
0.5	98%	100%	100%	100%	100%	100%
1	79%	88%	94%	97%	98%	99%
1.5	61%	69%	75%	81%	85%	88%
2	50%	56%	62%	67%	71%	74%
2.5	42%	47%	52%	56%	60%	63%
3	36%	41%	45%	49%	52%	54%
3.5	32%	36%	40%	43%	46%	48%
4	29%	32%	35%	39%	41%	43%
4.5	26%	29%	32%	35%	37%	38%
5	24%	27%	29%	32%	34%	35%
5.5	22%	24%	27%	29%	31%	32%
6	20%	23%	25%	27%	29%	30%

generation. For the economic evaluation of the investment alternatives for distributed generation with storage, it is necessary to understand and consider all the costs and revenues related to a project. The initial costs can be obtained through price quotes from retailers and PV and EES system integrators and must include the costs of design, purchase, installation, and licensing of photovoltaic systems. Revenue data for the evaluation were obtained from the economy feeding the locally generated PV electricity to the grid in a net-metering scheme, or from energy arbitrage on the White Tariff mode, resulting in an energy bill savings when compared to the base case (without the use of DG or ESS). For the investment time horizon T, over at least 25 years (in line with PV modules warranties and the expected two-time replacement of inverters), an annual capitalization of costs and revenues is made to build a cash flow. Monetary values distributed over time must be capitalized for a defined starting point, through an appropriate discount rate, so that the project's economic and financial indicators can be calculated.

Analyses through the LCOE can be performed for PV systems through (10), taken from Bortolini et al. (2014).

$$LCOE_{PV} = (C_0 + \sum_{n=1}^{T} \frac{C_n}{(1+j)^n}) / \sum_{n=1}^{T} \frac{E_{PV}\cdot(1-d)^n}{(1+j)^n} \quad (10)$$

Annual PV generation is reduced by a degradation factor (d); this factor represents the losses due to different mechanisms of PV module degradation and aging. Jordan and Kurtz (2011) reported a median degradation value of 0.5%/year for crystalline silicon modules in their review in 2011. For the hybrid system LCOS under a ToU scheme, multipliers m_1, m_2, and m_3 are equivalent to the proportion in which each hourly rate varies from the conventional tariff, representing the off-peak, intermediate and peak periods, respectively, while $E_{bat,Th}$ represents the energy consumed or stored in each period. Thus, for PV interaction with the battery system, the LCOS under the White Tariff can be calculated as follows:

$$LCOS_{ToU} = \left(C_0 + \sum_{n=1}^{T} \frac{C_n.}{(1+j)^n}\right) \Bigg/ \sum_{n=1}^{T} \frac{E^n_{liq}\cdot(1-d)^n}{(1+j)^n} \quad (11)$$

Being E_{liq} the positive balance of the energy flow given by (12):

$$E^n_{liq} = m_1\cdot\left(E^n_{PV,T1} - E^n_{Bat,T1}\right) + m_2\cdot\left(E^n_{PV,T2} + E^n_{Bat,T2}\right) + m_3\cdot(E^n_{PV,T3} + E^n_{Bat,T3}) \quad (12)$$

This is a positive value since:

$$E^n_{Bat,T1} = (E^n_{Bat,T2} + E^n_{Bat,T3})/\eta \quad (13)$$

$$m_3 > m_2 > m_1 \quad (14)$$

It can be verified that for usual values of overall ESS efficiency (η) ~ 95%, even for null values of E_{PV} and $E_{bat,T3}$ (no PV generation nor ESS discharge on peak ToU period), E_{liq} would return a positive value. The only exception is if m_1 is bigger than m_2 divided by η. It should be noted that the methodology proposed here uses the concept of net energy, the result of the interaction of the battery cycles with the feed in of surplus PV generation to the grid. The energy used to charge the battery would only come from PV generation and, therefore, could not be considered a cost, as seen in the methodologies of Belderbos et al. (2017) and Pawel (2014), and should be regarded as a reduction of the possible revenue of the sale of PV electricity to the grid. For the sensitivity analysis, variations on initial costs and different interest rates were considered. For both the pure PV and the hybrid PV + ESS system, changes were made to the power of the PV system and the storage capacity. Factors such as PV degradation, depth of discharge, changes in the peak tariff and lifespan were also considered.

5. Results and discussion

Table 3 shows the variables used in the simulation of a pure PV and of a hybrid PV + ESS system, whose behavior was described in the flowchart shown in Fig. 3. Both alternatives have the same characteristics of load profile, installed PV power and storage capacity, making the variables in Table 3 applicable for both investment alternatives. For the first year, US$ 533.86 would be spent on energy bills, which would amount to US$ 23,064.94 over 25 years with energy bills if none of the previously described investments were made; when considering an interest rate of 5% this amount becomes US$ 12,095.20. As calculated with (1), an increase in the interest rate leads to a greater deduction of this value, and when compared with the horizon of 30 years the convergence of the values of the net present cost of the two terms can be observed. For an interest rate of 15%, the NPV difference between the 25- and 30-years horizon is just US$ 153.91.

Fig. 4 shows the grid load (E_{grid}), the difference from the PV generation (E_{PV}) minus the household energy demand (E_{load}); it provides the new energy demand to be supplied by the utility to the residence. When multiplied by the flat tariff, it provides the values of the new energy bill, which should be deducted from the annual base cost to provide the savings due to the installation of PV systems. These annual savings were calculated at US$ 480.46 for the 2.5 kWp system evaluated in this study and typical of Brazilian rooftop PV projects.

Through the hourly load curves and the corresponding tariff for each hour in the ToU scheme, the annual cost of electricity for this option can be calculated. Using a base tariff of 0.1483 US$/kWh and multipliers of 0.85, 1.13 and 1.73 for the off-peak, intermediate and peak periods

Table 6
NPV (in US$) and IRR (in %) results for pure PV and hybrid PV + ESS systems over different initial costs and interest rates. The red dashed line shows the break-even point for each case.

NPV															IRR
		Interest Rate													
		3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%	
PV Initial Costs (US$)	790	11087	9551	8256	7160	6228	5430	4745	4153	3640	3192	2800	2455	2151	30%
	1054	10248	8730	7452	6371	5450	4663	3987	3404	2898	2456	2070	1730	1430	22%
	1318	9409	7910	6649	5581	4673	3897	3230	2655	2156	1721	1340	1005	710	18%
	1582	8570	7090	5845	4791	3895	3130	2473	1905	1413	985	610	280	-11	15%
	1846	7731	6270	5041	4002	3118	2363	1715	1156	671	249	-120	-445	-732	13%
PV + Bat Initial Costs (US$)	792 + 264	9180	7739	6527	5502	4631	3887	3248	2697	2220	1804	1440	1120	838	19%
	792 + 528	7396	6037	4895	3930	3112	2414	1816	1301	854	466	127	-171	-434	13%
	792 + 792	5612	4334	3262	2359	1593	942	384	-96	-511	-872	-1187	-1463	-1706	10%
	792 + 1056	3828	2631	1630	787	75	-531	-1049	-1493	-1877	-2210	-2500	-2754	-2979	7%
	792 + 1320	2044	929	-3	-784	-1444	-2004	-2481	-2890	-3242	-3547	-3813	-4046	-4251	5%
	792 + 1584	259	-774	-1635	-2356	-2963	-3476	-3913	-4287	-4608	-4885	-5127	-5338	-5523	3%
	792 + 1848	-1525	-2477	-3268	-3928	-4482	-4949	-5345	-5683	-5973	-6223	-6440	-6629	-6795	2%
	1056 + 264	8350	6927	5730	4718	3859	3125	2495	1952	1481	1071	712	397	119	15%
	1056 + 528	6566	5224	4097	3147	2340	1652	1062	555	115	-267	-601	-894	-1153	11%
	1056 + 792	4781	3521	2465	1575	821	179	-370	-842	-1250	-1605	-1914	-2186	-2425	8%
	1056 + 1056	2997	1819	833	3	-698	-1293	-1802	-2239	-2616	-2943	-3228	-3477	-3697	6%
	1056 + 1320	1213	116	-800	-1568	-2216	-2766	-3234	-3636	-3981	-4280	-4541	-4769	-4969	4%
	1056 + 1584	-571	-1587	-2432	-3140	-3735	-4239	-4666	-5032	-5347	-5618	-5854	-6060	-6241	3%
	1056 + 1848	-2355	-3290	-4065	-4712	-5254	-5711	-6099	-6429	-6712	-6956	-7168	-7352	-7513	1%
	1320 + 264	7519	6114	4933	3934	3086	2362	1741	1206	742	338	-15	-325	-599	13%
	1320 + 528	5735	4411	3300	2363	1567	890	309	-191	-624	-1000	-1328	-1617	-1871	10%
	1320 + 792	3951	2709	1668	791	49	-583	-1123	-1588	-1989	-2338	-2642	-2908	-3143	7%
	1320 + 1056	2167	1006	35	-781	-1470	-2056	-2556	-2985	-3355	-3675	-3955	-4200	-4416	5%
	1320 + 1320	382	-697	-1597	-2352	-2989	-3528	-3988	-4381	-4720	-5013	-5268	-5492	-5688	3%
	1320 + 1584	-1402	-2399	-3230	-3924	-4508	-5001	-5420	-5778	-6086	-6351	-6582	-6783	-6960	2%
	1320 + 1848	-3186	-4102	-4862	-5495	-6026	-6473	-6852	-7175	-7451	-7689	-7895	-8075	-8232	1%
	1584 + 264	6689	5302	4135	3150	2314	1600	988	460	3	-395	-743	-1048	-1318	11%
	1584 + 528	4905	3599	2503	1579	795	127	-445	-937	-1363	-1733	-2056	-2340	-2590	8%
	1584 + 792	3120	1896	871	7	-724	-1345	-1877	-2334	-2728	-3071	-3369	-3631	-3862	6%
	1584 + 1056	1336	193	-762	-1565	-2242	-2818	-3309	-3730	-4094	-4408	-4683	-4923	-5134	4%
	1584 + 1320	-448	-1509	-2394	-3136	-3761	-4291	-4741	-5127	-5459	-5746	-5996	-6214	-6406	3%
	1584 + 1584	-2232	-3212	-4027	-4708	-5280	-5763	-6173	-6524	-6825	-7084	-7309	-7506	-7678	1%
	1584 + 1848	-4017	-4915	-5659	-6279	-6799	-7236	-7606	-7921	-8190	-8422	-8623	-8797	-8950	0%
	1848 + 264	5858	4489	3338	2366	1541	838	234	-286	-736	-1128	-1470	-1771	-2036	9%
	1848 + 528	4074	2786	1706	795	23	-635	-1198	-1683	-2102	-2466	-2784	-3063	-3308	7%
	1848 + 792	2290	1083	73	-777	-1496	-2108	-2630	-3079	-3467	-3803	-4097	-4354	-4581	5%
	1848 + 1056	506	-619	-1559	-2348	-3015	-3580	-4063	-4476	-4833	-5141	-5410	-5646	-5853	3%
	1848 + 1320	-1279	-2322	-3192	-3920	-4534	-5053	-5495	-5873	-6198	-6479	-6724	-6937	-7125	2%
	1848 + 1584	-3063	-4025	-4824	-5492	-6052	-6525	-6927	-7270	-7563	-7817	-8037	-8229	-8397	1%
	1848 + 1848	-4847	-5727	-6457	-7063	-7571	-7998	-8359	-8666	-8929	-9155	-9350	-9520	-9669	0%

(respectively) for the local distribution utility CELESC White Tariff, an annual cost of US$ 557.85 was calculated, which would amount to US$ 24,101.07 over 25 years (considering the annual tariff increase rate of 3.18%). When discounted at an interest rate of 5% this results in a NPV of US$ 12,638.55, which corresponds to a difference of 5% to the base cost outside the White Tariff, resulting in a loss when shifting between tariff modalities (White and Flat Tariffs). The interaction of the generation of the PV system with ESS can be evaluated through the flowchart in Fig. 3, based on the residential household energy generation and consumption data. The energy flow of the system, for the first week of the evaluated year, can be seen in Fig. 5. The economy resulting from adopting the hybrid system is calculated by multiplying the resulting energy demand (Grid, in gray) and the corresponding ToU tariff, and discounting the base cost for the White Tariff (the cost without any investment in PV or ESS). At the end of the first year, the energy bill, after the installation of the hybrid PV + ESS, results in US$ 53.40, an economy of US$ 504.44 when compared to the base cost.

As shown in the calculation of the ideal design for storage systems, changes in capacity can generate variations in the resulting economy. For hybrid systems, the changes in installed PV power would also be able to provide different profitability scenarios. To evaluate these different scenarios, steps of 0.5 kWp and 1 kWh of installed power and storage capacity respectively were used to prepare the graph shown in Fig. 6. The semi-flat format of the graph shows that the storage capacity variable has little influence on the profitability of the system, justified by the small difference between the values of ToU tariffs used in the calculation (and currently prevailing in Brazil). The plateau on the graph represents the maximum possible annual savings, limited to the charging of 30 kWh/month to cover the utility fixed costs. To verify this, the revenue contribution of PV generation and energy arbitrage were evaluated; the energy arbitrage fraction is shown in Table 4. This table shows that the highest contribution by energy arbitrage happens at 5 kWh capacity and

Table 7
LCOE and LCOS (in US$) results for pure PV and hybrid PV + ESS systems over different initial costs and interest rates. The red dashed line shows grid parity.

LCOE and LCOS		Interest Rate												
		3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
PV Initial Costs (US$)	790	0.042	0.045	0.049	0.053	0.057	0.062	0.066	0.071	0.075	0.080	0.085	0.090	0.095
	1054	0.056	0.061	0.066	0.071	0.077	0.082	0.088	0.094	0.100	0.107	0.113	0.120	0.126
	1318	0.070	0.076	0.082	0.089	0.096	0.103	0.110	0.118	0.126	0.133	0.142	0.150	0.158
	1582	0.084	0.091	0.099	0.107	0.115	0.124	0.132	0.141	0.151	0.160	0.170	0.180	0.190
	1846	0.098	0.106	0.115	0.125	0.134	0.144	0.155	0.165	0.176	0.187	0.198	0.210	0.221
PV + Bat Initial Costs (US$)	792 + 264	0.069	0.073	0.078	0.083	0.088	0.093	0.098	0.103	0.109	0.114	0.119	0.125	0.130
	792 + 528	0.097	0.103	0.110	0.116	0.123	0.129	0.136	0.143	0.150	0.157	0.164	0.171	0.178
	792 + 792	0.126	0.134	0.141	0.149	0.158	0.166	0.174	0.183	0.192	0.200	0.209	0.218	0.226
	792 + 1056	0.155	0.164	0.173	0.183	0.192	0.202	0.212	0.223	0.233	0.243	0.254	0.264	0.275
	792 + 1320	0.184	0.194	0.205	0.216	0.227	0.239	0.251	0.262	0.274	0.287	0.299	0.311	0.323
	792 + 1584	0.212	0.224	0.236	0.249	0.262	0.275	0.289	0.302	0.316	0.330	0.344	0.357	0.371
	792 + 1848	0.241	0.254	0.268	0.282	0.297	0.312	0.327	0.342	0.357	0.373	0.388	0.404	0.420
	1056 + 264	0.082	0.088	0.093	0.099	0.106	0.112	0.118	0.125	0.131	0.138	0.144	0.151	0.157
	1056 + 528	0.111	0.118	0.125	0.133	0.140	0.148	0.156	0.164	0.173	0.181	0.189	0.197	0.205
	1056 + 792	0.140	0.148	0.157	0.166	0.175	0.185	0.194	0.204	0.214	0.224	0.234	0.244	0.254
	1056 + 1056	0.168	0.178	0.189	0.199	0.210	0.221	0.232	0.244	0.255	0.267	0.279	0.290	0.302
	1056 + 1320	0.197	0.208	0.220	0.232	0.245	0.258	0.271	0.284	0.297	0.310	0.324	0.337	0.350
	1056 + 1584	0.226	0.239	0.252	0.266	0.280	0.294	0.309	0.323	0.338	0.353	0.368	0.383	0.399
	1056 + 1848	0.254	0.269	0.284	0.299	0.315	0.331	0.347	0.363	0.380	0.397	0.413	0.430	0.447
	1320 + 264	0.095	0.102	0.109	0.116	0.123	0.131	0.138	0.146	0.153	0.161	0.169	0.177	0.184
	1320 + 528	0.124	0.132	0.141	0.149	0.158	0.167	0.176	0.186	0.195	0.204	0.214	0.223	0.233
	1320 + 792	0.153	0.162	0.172	0.183	0.193	0.204	0.214	0.225	0.236	0.248	0.259	0.270	0.281
	1320 + 1056	0.182	0.193	0.204	0.216	0.228	0.240	0.253	0.265	0.278	0.291	0.304	0.316	0.329
	1320 + 1320	0.210	0.223	0.236	0.249	0.263	0.277	0.291	0.305	0.319	0.334	0.348	0.363	0.378
	1320 + 1584	0.239	0.253	0.267	0.282	0.297	0.313	0.329	0.345	0.361	0.377	0.393	0.410	0.426
	1320 + 1848	0.268	0.283	0.299	0.316	0.332	0.349	0.367	0.384	0.402	0.420	0.438	0.456	0.474
	1584 + 264	0.109	0.116	0.124	0.133	0.141	0.150	0.158	0.167	0.176	0.185	0.194	0.203	0.212
	1584 + 528	0.138	0.147	0.156	0.166	0.176	0.186	0.196	0.207	0.217	0.228	0.239	0.249	0.260
	1584 + 792	0.166	0.177	0.188	0.199	0.211	0.222	0.234	0.247	0.259	0.271	0.284	0.296	0.308
	1584 + 1056	0.195	0.207	0.220	0.232	0.246	0.259	0.273	0.286	0.300	0.314	0.328	0.342	0.357
	1584 + 1320	0.224	0.237	0.251	0.266	0.280	0.295	0.311	0.326	0.342	0.357	0.373	0.389	0.405
	1584 + 1584	0.252	0.267	0.283	0.299	0.315	0.332	0.349	0.366	0.383	0.401	0.418	0.436	0.453
	1584 + 1848	0.281	0.298	0.315	0.332	0.350	0.368	0.387	0.406	0.425	0.444	0.463	0.482	0.501
	1848 + 264	0.122	0.131	0.140	0.149	0.159	0.168	0.178	0.188	0.198	0.208	0.219	0.229	0.239
	1848 + 528	0.151	0.161	0.172	0.182	0.194	0.205	0.216	0.228	0.240	0.252	0.264	0.275	0.287
	1848 + 792	0.180	0.191	0.203	0.216	0.228	0.241	0.255	0.268	0.281	0.295	0.308	0.322	0.336
	1848 + 1056	0.208	0.221	0.235	0.249	0.263	0.278	0.293	0.308	0.323	0.338	0.353	0.369	0.384
	1848 + 1320	0.237	0.252	0.267	0.282	0.298	0.314	0.331	0.347	0.364	0.381	0.398	0.415	0.432
	1848 + 1584	0.266	0.282	0.298	0.315	0.333	0.351	0.369	0.387	0.406	0.424	0.443	0.462	0.480
	1848 + 1848	0.294	0.312	0.330	0.349	0.368	0.387	0.407	0.427	0.447	0.467	0.488	0.508	0.529

1.5 kW PV power; it also shows that for the same 5 kWh capacity, smaller PV systems are not enough to surpass the load demand and charge the ESS to increase the energy arbitrage revenue, while larger PV systems increase the PV generation export, thus reducing the energy arbitrage fraction. Hybrid PV + ESS systems use energy generated on-site, thus increasing residential self-consumption and changing the residential unit's load factor as seen by the distribution utility grid. When compared with the simple PV generation alternative without storage, the hybrid system can increase the self-consumption, as seen in Table 5.

As for economic indicators, at first, the NPV and the IRR of both alternatives were calculated. Table 6 shows the results for the NPV for a wide range of interest rates and initial costs; the red dashed line shows the point where the investments become profitable. Table 6 shows that for most hybrid systems the additional revenue from energy arbitrage is not enough to break even with the ESS initial cost, even at low-interest rate conditions. For both alternatives, LCOE and LCOS were calculated based on Eqs. (10) and (11), with the charging and discharging energy of the ESS resulting from the interactions described in the flowchart in Fig. 3. The resulting LCOE and LCOS for changes in the interest rate and initial costs are shown in Table 7. The red dashed line on the calculated values of Table 7 indicates the grid parity value, given by the current value of the flat energy tariff (0.1483 US$/kWh), implying that most of the investments in PV generation could be made immediately or in a near-term horizon, when considering the flat tariff growth rate. Investments in hybrid PV + ESS systems, however, should be postponed taking advantage of tariff increasing rates, and lower equipment costs that will occur with the growth of the storage systems market.

To verify the impact of how the change in technical and economic variables affects the LCOE and LCOS indicators, a sensitivity study of the variables of both investment alternatives was carried out, with a 20% variation of different variables, ceteris paribus. Fig. 7 shows results for the first alternative (adoption of PV generation), where the line slope shows the direct impact of each variable. The PV base scenario corresponds to 1,315 US$/kWp of initial costs, 6% annual interest rate, 25

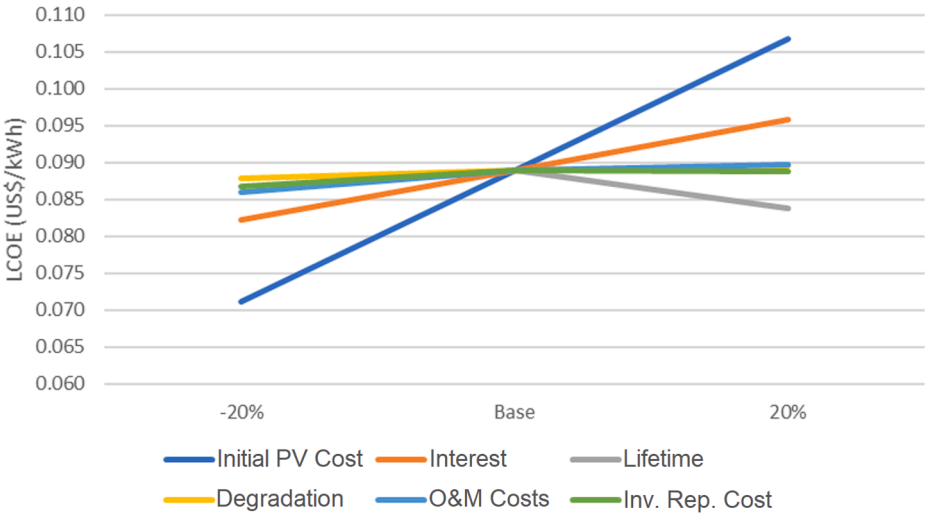


Fig. 7. Sensibility analysis of the LCOE for ±20% variations in PV system variables.

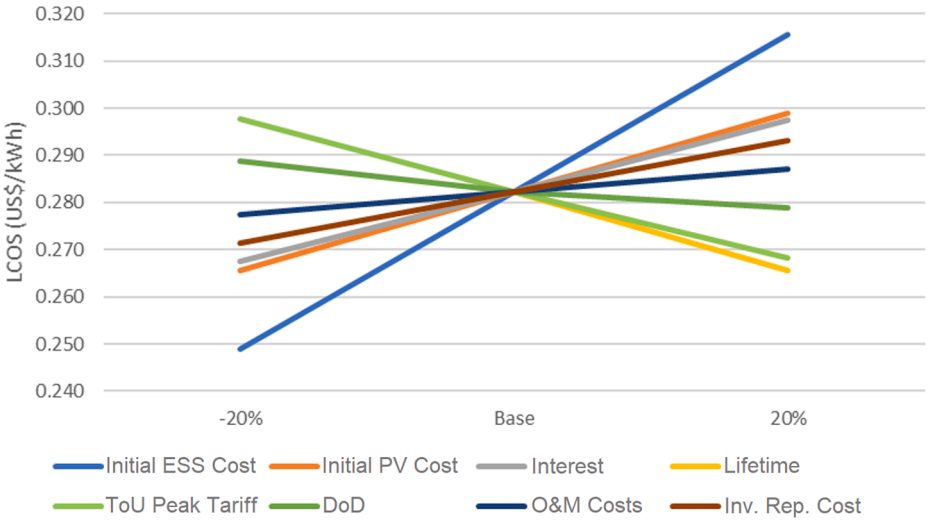


Fig. 8. Sensibility analysis of the LCOS for ±20% variations in hybrid PV + ESS system variables.

Table 8
Current, five and ten years forecast of ToU tariffs and initial and replacement costs for a 2.5 kWp + 4 kWh PV + ESS system.

	Hybrid		
	Current	five years	ten years
C_0	US$ 8,552.63	US$ 9,506.47	US$ 3,888.46
C_{10}	US$ 3,028.35	US$ 2,152.43	US$ 1,531.92
C_{20}	US$ 1,531.92	US$ 1,091.71	US$ 778.98
T_{out}	0.1266 US$/kWh	0.1527 US$/kWh	0.1842 US$/kWh
T_{inter}	0.1685 US$/kWh	0.2032 US$/kWh	0.2451 US$/kWh
T_{peak}	0.2572 US$/kWh	0.3102 US$/kWh	0.3741 US$/kWh

years of service life, and 0.5%/year of PV system output power degradation. Calculations show that the increase in the lifetime from 25 to 30 years corresponds to a reduction in LCOE of 5.8%, and that the initial cost is the most significant variable affecting the economics of PV systems. Finally, for hybrid PV + ESS distributed generation systems with a 1,578 US$/kWh storage cost, the results are shown in Fig. 8. The increase in the value of ToU peak tariff was not a determining factor, since, in this scenario of small difference between peak and out-of-peak tariffs, the profitability of the system is mainly provided by the sale of the excess energy in the net-metering mode. For hybrid systems, the reduction in the hardware costs (PV and batteries) would be the most striking factor for the improvement of the levelized cost. Thus, an analysis of the LCOS of hybrid systems was carried out when considering the postponement of the investment by five and ten years, to benefit from the reduction of equipment costs and annual tariff increase. Table 8 shows future initial values, replacement costs, and new ToU tariffs based on the most conservative predictions shown in Table 1 and tariff increase rates presented in Table 3.

It should be considered that PV generation systems in the current net metering scenario are immune to the load factor of residential demand, where only the total energy consumption matters. For the hybrid alternative, the load factor, together with the peak and off-peak tariff difference, represents a significant weight in the return on investment, requiring a deeper analysis of the impact these variables will have on the economic analysis. To investigate the impact of the load factor variation, scenarios with 20% variations on total load factor were simulated, while PV power, ESS capacity and monthly energy demand were kept constant as in Table 3. Fig. 9 shows the load profile variations for the sensitivity analysis. The results are summarized in Table 9. The first aspect to be observed is how the load factor affects the sizing of the ESS: the daily average of the energy consumed in intermediary and peak hours works

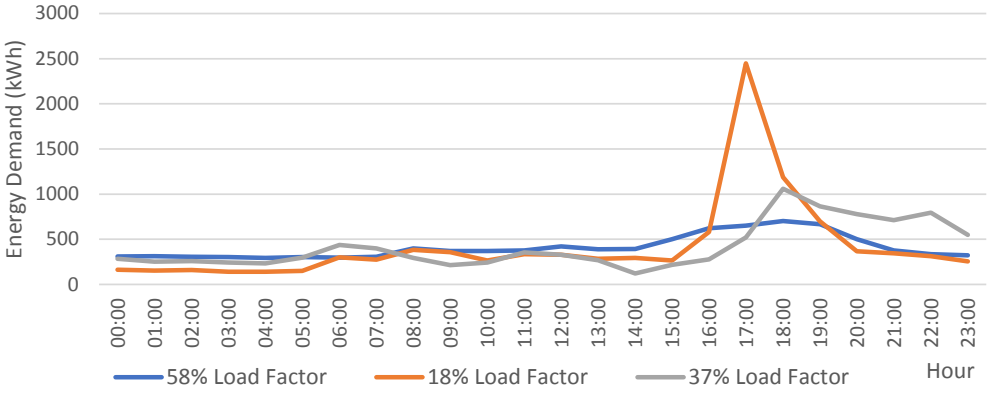


Fig. 9. Selected load factor variations for sensibility analyses.

Table 9
Sensibility analysis over changes on load factor for LCOS and annual energy costs.

		−20%	Base	+20%
Base costs	Energy for arbitrage	5.08 kWh	3.95 kWh	2.92 kWh
	ToU Annual Cost	US$ 563.54	US$ 561.65	US$ 531.02
	Cost Variation	0.3%		−5.5%
Hybrid system	LCOS	0.298 US $/kWh	0.278 US $/kWh	0.288 US $/kWh
	NPV	US$ −4,430.96	US$ −3,795.81	US$ −4,126.1
	IRR	1.2%	2.0%	1.6%
	Arbitrage Contribution	9.3%	15.5%	12.3%

as a rule of thumb for the correct sizing of the storage capacity. It guides the system designer on how much storage is needed and what is the possible revenue. The correct sizing impacts directly on the system's LCOS and can be seen as the contribution to revenue from energy arbitrage.

6. Conclusions

The methodology proposed and described in this paper was applied to different PV + battery scenarios so that economic indicators were determined and later compared to the results of other alternatives to establish useful parameters for guiding investment decisions. At each step of the methodology, the variables that allow the economic evaluation of investments were determined, namely all the costs, the revenues and the variables that are important for the projection of the cash flow for the entire project life, as well as the impact of the variation of these parameters.

For the simulated system options, the NPV, LCOE and LCOS indicators complement each other and provide means for a thorough economic evaluation, showing that under present conditions, the alternative to invest in distributed PV generation-only would be the most profitable option from a consumer's perspective, followed by the hybrid PV + ESS system investment alternative.

It was verified that for hybrid PV + ESS systems, revenues come essentially from the PV generation system in the current net metering scheme within the White Tariff environment. Due to the low profitability of the White Tariff alternative, PV systems lead to better economic performance when oversized, and undersized storage systems are the best option when the objective is to reduce the LCOS. The proposed LCOS equation for hybrid systems within the White Tariff scheme differs from other models presented in the literature by not considering the energy used to charge the system as an expense but as a reduction in revenue in the energy compensation system of PV-generated electricity. In this way, the energy tariff can be isolated in the equation, leaving only the multiplier factors that modify the base tariff for the different tariff-times within the White Tariff (or any ToU tariff for that effect).

The sensitivity analysis carried out showed that the initial equipment cost (CAPEX) is the main impact factor in the profitability when including PV generation, while CAPEX, lifetime and the ToU tariff structure are the main factors for ESS. Policies to encourage the adoption of distributed generation and energy storage technologies should focus on adjusting tariffs to lead to a more attractive environment, while the declining costs of PV and ESS follow their path and financing modalities of systems with attractive interest rates become more available.

The residential ToU White Tariff is the only factor controlled by the distribution utility, and it is, therefore, a major factor influencing the economic attractiveness for the adoption of ESS. Since the adoption of the White Tariff is not compulsory for the residential consumer, distribution utilities will play a major role in establishing policies and incentive mechanisms for ESS to become attractive to the residential consumer. In this context, distribution utilities must understand the whole spectrum of advantages that pulverized ESS can offer, to design mechanisms for the fast uptake of this technology. ESS technologies and services can be offered to the residential consumer by many different market agents (as much as rooftop PV generators are already), but distribution utilities are in a unique and most favorable position, since they already have a (energy distribution) contract with 100% of residential units in their concession area, and this contract can be easily extended to offer both rooftop PV and EES.

Because there is no obligation to adopt the White Tariff, residential consumers might see no reason to migrate to a new tariff structure that might increase their energy bill in the event of high consumption at peak hours, in case there are large differences between on- and off-peak-hour tariffs. Thus, to eliminate the harmful effects of high penetration from an intermittent source such as PV, utilities might decide to invest in their own mid- to large-size centralized storage systems scattered at strategic sites along with their distribution network.

While the methodology presented in this article was used to evaluate the Brazilian framework, the LCOS formulation could be deployed to evaluate the economic viability of hybrid systems for energy arbitrage over different tariff frameworks in many scenarios and all over the globe.

Taking advantage of increasing PV penetration in Brazil and elsewhere (due to the impressive cost reductions this technology is experiencing), technological evolution, wind energy development, and the substantial cost decreases expected for ESS, the scenarios for the energy mix over the medium and long terms become more attractive, provided that effective mechanisms are created and put in place to make the best use of benign and cost-effective technologies such as PV and ESS.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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