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Improving the traditional levelized cost of electricity approach by including the integration costs in the techno-economic evaluation of future photovoltaic plants

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Summary

The levelized cost of electricity (LCOE) is a techno-economic parameter used to evaluate the cost of a kilowatt-hour of energy produced from a selected power plant. The initial investment, annual operation and maintenance costs together with the annual energy production are some of the input data needed to determine the LCOE. The most typical approach to calculate the LCOE does not account for the interaction of the new power plant with the existing energy system, assuming indirectly the power plant as stand-alone. This can be misleading in scenarios with high variable renewable energy sources (VRES) penetration as costs related to overproduction, reinforcement of the grid and additional efforts of existing fossil fuels power plants to satisfy the electricity demand that is not instantly covered by VRES production are not accounted for. The aim of this work is to define a general methodology of easy application for the estimation of these additional costs, called integration costs, of the photovoltaic (PV) technology with the corresponding parameter called system LCOE. In order to demonstrate the importance of the new definition, the methodology is applied to the future Italian energy system and PV sector foreseen for the year 2030. The Italian PV LCOE in 2030 calculated with the usual methodology ranges from 12.55 to 15.93 €/MWh, while the system LCOE can be as high as 22 €/MWh with a relevant increase by on average 50%. In case of addition of storage to PV systems, the system LCOE after the addition of the integration costs ranges from 45 to 51 €/MWh. However, even when batteries and integration costs are included, PV remains competitive compared to the market price.

KEYWORDS

integration costs, photovoltaic, PV economics, system LCOE

List of Abbreviations: BESS, battery energy storage system; BIPV, building-integrated photovoltaics; CCGT, combined cycle gas turbine; DSO, distribution system operator; GSE, Gestore dei Servizi Energetici; LCOE, levelized cost of electricity; O&M, operation and maintenance; PNIEC, Piano Nazionale Integrato Energia e Clima; PV, photovoltaic; RES, renewable energy sources; TSO, transmission system operator; VRES, variable renewable energy sources.

1 | INTRODUCTION

Following the Paris Agreement of the year 2015, it has become clear that countries must face a substantial and fast energy transition to reduce environmental impacts and the unsustainable consumption of nonrenewable natural resources. In particular, the electricity production shall change from a centralized configuration based on fossil fuels to a more distributed system based on RES, among which solar and wind should play the major role. At the same time, high levels of safety and reliability of the electricity grid shall be guaranteed even with this strong penetration of intermittent and not directly controllable generation sources.[1] Hence, new services will be asked from VRES sector in terms of better production forecast and dispatchability, for example, through the installation of storage systems, and active participation to the electricity market.[2] The expected energy transition will bring undoubted benefits for both the environment and the society, thanks to the improvement of air and environment quality and the potential creation of new business sectors and jobs.[3] However, it requires additional costs for the current energy system since investments in new generation capacity, grid infrastructures, and digitalization are necessary to adapt to this significant and rapid change.[1] This study focuses on how these additional costs should be included in the future techno-economic evaluation of power plants to avoid that they will be completely socialized and paid by the community.

The techno-economic evaluation of power plants is usually based on the Levelized Cost of Electricity (LCOE) that is equivalent to the cost of producing a kilowatt-hour with a selected type of power plant. In general, the LCOE is calculated as the total costs incurred by the power plant divided by the total energy produced during the lifetime. The costs typically include the initial investment, the operation and maintenance (O&M) expenditures, the fuel and consumable costs (when applicable), while the total amount of energy produced can be adjusted considering the degradation rate of the power plant and its components. This definition is described in Reference 4. For PV systems, other LCOE formulations have been proposed by References 5-7. The basic formulation can be extended as in Reference 5 with more details regarding the calculation of the annual electricity production and substituting the discount rate with the WACC (Weighted Average Cost of Capital). The formulation is here given just as an example of classical LCOE:

$$\mathrm{LCOE}=\frac{\mathrm{CAPEX}+\sum_{t=1}^{n}\frac{\mathrm{OPEX}(t)}{(1+\mathrm{WACC_{nom}})^{t}}}{\sum_{t=1}^{n}\left[\frac{\mathrm{Utilisation_0}*(1-\mathrm{Degradation})^{t}}{(1+\mathrm{WACC_{real}})^{t}}\right]}\ [€/\mathrm{kWh}] \qquad (1)$$

where CAPEX is the total investment expenditure of the system in the year $t = 0$, OPEX(t) the operation and maintenance expenditure in year t, $\mathrm{WACC_{nom}}$ the nominal weighted average cost of capital per year, $\mathrm{WACC_{real}}$ the real weighted average cost of capital per year, $\mathrm{Utilization_0}$ is the initial utilization in the year $t = 0$ (without considering degradation), Degradation is the annual degradation of the nominal power of the system, n is economic lifetime of the system, and t the year of lifetime (1,2,...,n). In Reference 6, the study is focused on ground-mounted PV systems and the authors added the land costs (ie, costs related to the acquisition of the land required for the installation of the PV plant), the insurance costs, the tracking factor, and performance factor. The tracking factor adjusts the solar resource to the real incident solar energy as a function of the PV plant orientation and it is equal to one for optimally inclined and south-oriented modules. The performance factor, instead, converts the total available solar resource into the real amount of electricity produced by the system per Watt installed. In Reference 7, the residual value concept has been introduced to include the possible earnings coming from the disposal or resale of the power plant at the end of its useful life.

The authors defined also a more complex LCOE involving other financial parameters that can be applied for the commercial and industrial PV sector such as: the project costs minus any investment tax credit or grant, depreciation, interest paid, loan payment, and the tax rate.

It is possible to notice from these approaches that no parameters accounting for the interaction between the new power plant and the existing energy system are included. These simplified approaches can be appropriate for engineers to select the power generation technologies during the planning phase but they can be misleading when the LCOE is used by public institutions to identify the optimal energy strategies among different technologies because (a) it is strongly affected by the cost of capital and to a lesser extent by the technological parameters and (b) it considers the power plant as stand-alone not accounting for the impacts of connecting the power plant to the existing grid and energy system. Therefore, the classical formulation of the LCOE is not able to reflect the technical and economic challenges that must be faced with the significant increase of VRES production in terms of grid stability and change of the usual operating conditions of thermal power plants, which eventually affect the electricity market and prices.

Some research studies[8-12] have been proposing methodologies to overcome these limits by estimating the impacts of high VRES penetration on the LCOE. They have determined the so-called integration costs that can be combined with the LCOE to include the impacts of adding new intermittent generation in the existing energy systems. In this way, a new parameter can be defined which in this work is called "system LCOE" consistently with a previous work done by other authors in Reference 8. The system LCOE is defined as follows

$$\text{System LCOE} = \text{LCOE} + \Delta[€/\text{kWh}] \quad (2)$$

where Δ represents the integration costs as the sum of balancing costs, grid costs, adequacy costs (or backup costs), full-load hours reduction, and overproduction costs. All these cost components are determined by the authors in Reference 8, with a top-down approach and a formalization of system LCOE with a mathematical definition of integration costs that directly relates to economic theory. For Reference 8, the integration costs are all the additional costs for the nonrenewable part of the power system when VRES are added. However, the formulation as given in Reference 8, might not be of easy implementation and the integration costs may also be split into different costs components applying a bottom-up approach instead of a top-down approach. For example, examining the geographical distribution of the added installed VRES capacity, there could be the need to extend as well as to reinforce the existing grid infrastructure to prevent problems like overvoltage or reverse power flows. This necessity is reflected into investments in transmission and distribution grids that are referred as grid costs.[8-11] Additionally, since the VRES production is not directly controllable and programmable, its fluctuations are currently managed by fossil fuel power plants that change their role from baseload to peak plants when VRES production is not available or not enough. This means that fossil fuel power plants will be forced to operate at partial load conditions and the consequent costs arising are called balancing costs[8,9,12] since additional balancing services are necessary to overcome the unpredictable VRES electricity output. The non-programmability of VRES production introduces also issues related to the system reliability and security of supply that can be represented by the capacity costs,[9,12] also called adequacy costs.[8] Other aspects that can be included in the integration costs are related to storage addition,[10,11] VRES production curtailment,[11] and profile costs,[8] which put together the effects of VRES production on the fossil fuel power plants in terms of full-load hours decrease, overproduction costs, and backup costs.

Other more recent attempts to go beyond the classical LCOE formulation are represented by Levelized Avoided Cost of Electricity developed by the US Energy Information Administration [13] and the value-adjusted LCOE (or VALCOE) developed by the IEA.[14] LACE is an alternative assessment of economic competitiveness between generation technologies which is gained by considering the avoided cost, a measure of what it would cost the grid to generate the electricity that would be displaced by a new generation project. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a level annualized value that is divided by average annual output of the project to develop its levelized avoided cost of electricity. The value-adjusted LCOE (or "VALCOE") incorporates information about both costs and the value provided to the system. Based on the LCOE, estimates of energy, capacity, and flexibility value are incorporated to provide a metric of competitiveness for power generation technologies. This metric provides a more robust approach to compare dispatchable technologies and variable renewables. Both methodologies focus on the added value of power plants (eg, market electricity price, flexibility in providing services in terms of regulation, reserve power, and capacity) and not on the costs related to the integration of renewables in the energy system.

Starting from the new emerging approach of system LCOE to the profitability analysis of VRES power plants, the aim of this study is to define a methodology to estimate the overall integration costs of VRES and include them to the classical LCOE calculation, understanding how the future VRES generation costs will be affected. The developed methodology is based on the bottom-up approach: starting from the effects of VRES on the power system, the integration costs are split into different cost components that are then mathematically defined. An energy modeling tool is used in this study to simulate future energy scenarios and evaluate the integration costs. Since these are strictly related to the power system and grid infrastructure, the methodology, which is general and applicable to any energy system, needs to be tested on a real case with actual numbers of investments and technologies. In this work, it is applied to the Italian case study, focusing the attention on the utility-scale PV sector and its future generation costs.

2 | METHODOLOGY

2.1 | System LCOE general definition

Starting from the LCOE methodological improvements shown in References 8-12 and discussed in the previous section, the system LCOE is defined in this paper as the sum of power plant costs, that is, PV, or PV plus storage, and the integration costs. Integration costs are divided into two main subcategories, grid and balancing costs. The grid costs consider the investments required for the transmission and distribution grids to foster the transport of additional VRES electricity while guaranteeing at the same time the grid reliability and security of supply. Therefore, the grid costs are determined as the sum of reinforcing of transmission/distribution network, adequacy, and curtailment costs. The balancing costs, instead, accounts for impacts of additional VRES production on the existent fossil fuel power plants in terms of the efficiency decay and the start-up costs. Grid costs and balancing costs are strictly dependent on the energy system configuration, that is, grid infrastructure, number, and geographical distribution of the existing power plants.

The system LCOE structure is schematically represented in Figure 1 and the corresponding formulation is reported in Equation (7).

$$S_{\mathrm{LCOE}} = C_{\mathrm{pp}} + C_{\mathrm{distr}} + C_{\mathrm{trans}} + C_{\mathrm{adequacy}} + C_{\mathrm{curt}} + C_{\mathrm{decay}} + C_{\mathrm{start-up}} \tag{3}$$

where C_{pp} is the power plant costs, C_{distr} the reinforcing distribution network costs, C_{trans} the reinforcing transmission network costs, C_{adequacy} the adequacy costs, C_{curt} the curtailment costs, C_{decay} the decay of efficiency costs, and $C_{\text{start-up}}$ the start-up costs. All these cost components are expressed in €/MWh and are mathematically expressed in the following subsections.

The following section details the different costs components of the system LCOE. It must be stressed out that the definitions provided hereafter coincide theoretically for the PV and PV plus storage cases. However, the calculated values will be different between the two cases as the adoption of BESS significantly reduces the integration issues. This point will be better discussed in the following sections.

2.1.1 | Power plant costs

The power plant costs (C_{pp}) represent the electricity generation costs of a certain power production technology and are usually evaluated with the LCOE, the calculation method of which depends on the technology considered.

In the case of PV power plant without storage system, these costs are calculated with Equation (1) as shown before; whereas, if the combined PV plus storage system is considered, the methodology proposed in Reference 13 is applied as summarized in Equation (4):

$$C_{\mathrm{pp}} = \frac{\sum_{t=0}^{n} \frac{C_{\mathrm{system},t}}{(1+i)^t}}{\sum_{t=0}^{n} \frac{E_{\mathrm{system},t}}{(1+i)^t}} = \frac{C_{\mathrm{pvsurplus}} + C_{\mathrm{storage}} + C_{\mathrm{pvdirect}}}{E_{\mathrm{storage}} + E_{\mathrm{pvdirect}}} \tag{4}$$

where $C_{\mathrm{system,t}}$ is the total cost of the PV plus storage system at time t in €, $E_{\mathrm{system},t}$ is the sum of the electricity

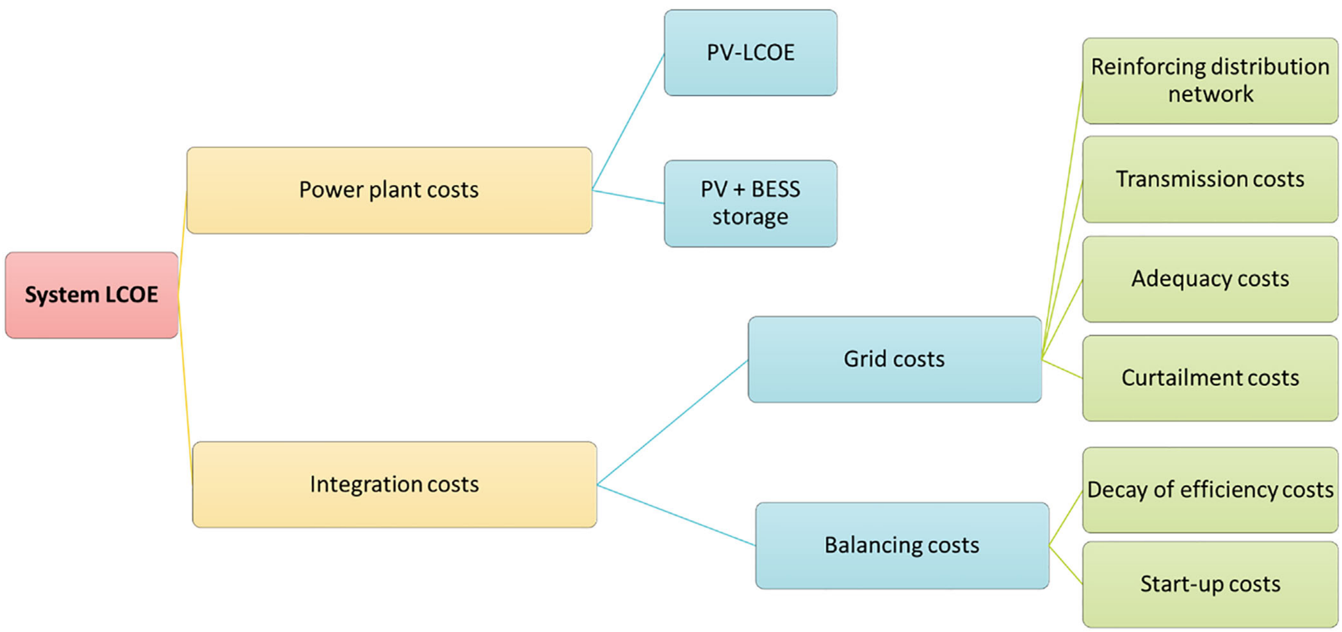

FIGURE 1 Schematic representation of the system LCOE [Colour figure can be viewed at wileyonlinelibrary.com]

delivered by the storage at time t ($E_{storage}$), and the energy produced by the PV plant and directly consumed by the load at time t ($E_{pvdirect}$) in MWh, $C_{pvsurplus}$ the cost at time t for generating the PV surplus energy in €, $C_{storage}$ the storage cost at time t in €, $C_{pvdirect}$ the cost at time t for generating the energy directly consumed by the load in €.

The power plant costs are calculated subdividing the reference geographical area into smaller regions, called macro regions, to consider the change of the solar irradiation at different latitudes and obtain a more precise geographical estimation of $E_{system,t}$ and the corresponding LCOE.

2.1.2 | Reinforcing distribution network costs

PV technology is largely used on residential and commercial buildings to increase the self-consumption and reduce the energy bill costs. Therefore, most of them are connected to the distribution grid, that is, the low and medium voltage grid. However, the electricity network was originally meant to transport electricity from the power production units, typically large-scale fossil fuel power plants, to the distributed final users, allowing the electricity to flow in one direction through the distribution grid. For this reason, the widespread diffusion of PV plants at this lower voltage level may bring about problems related to the injection of electricity in a part of the grid infrastructure not designed for accepting it. To solve this issue, the distribution network might need to be reinforced and renovated with certain investment costs especially outside of urban areas.

The reinforcing distribution network costs may need some network computations (eg, a power flow model of the distribution grid, but also short-circuit computations, protection settings, voltage drop computations) to be correctly estimated, but the creation of it is beyond the scope of this analysis. Another approach can consist of using investment costs determined in other works/projects. In this work, the figures determined in the PV Parity Project,[10] which provides some numerical examples of reinforcing distribution network costs for different countries are adopted.

2.1.3 | Reinforcing transmission network costs

The transmission grid, like the distribution network, has faced new challenges in the recent years due to the spread of VRES production. On one hand, the increase of self-consumption at distribution level modifies the national demand profile[1] and the residual VRES production injected might cause problems of overvoltage, reverse power flows at the connection points between distribution and transmission grids and dynamic issues related to the decrease of the system inertia and short-circuit levels. On the other hand, the diffusion of large-scale VRES power plants connected to the transmission grid stresses the grid infrastructure that shall accept an additional share of variable and intermittent electricity. Similarly to the distribution grid, sometimes these issues might be fixed by reinforcing grid infrastructures and expanding transport capacity of powerlines; however environmental concerns make more and more difficult to get permissions to build new lines, especially overhead lines. Other possible solutions are control systems and devices able to reroute power flows in such a way that, whenever possible, power system security is kept acceptable in the presence of large VRES injections. Further to new infrastructures (lines and substations), many flexibility tools can be used for this goal, ranging from new control devices, that is, phase-shifters and flexible AC transmission systems (FACTS), to tools provided by the electricity markets (Ancillary Service markets, for example, demand response, etc). The former solutions are characterized by investment costs that can be embedded into reinforcing transmission network costs.; the latter solutions have a cost currently very difficult to estimate, given that there is no experience about them all over the world.

Like for the reinforcing distribution network costs, in this case, it is also necessary to compute the reinforcement actions needed to keep the power system security in any operating conditions. This computation requires many detailed network studies, basically power flow computations as well as dynamic stability studies, for the most frequent operating conditions. This makes it necessary, for each envisaged operating conditions, to carry out steady-state power flow computations, and to run dynamic simulations for the most probable and the most significant perturbations, in order to identify any reasonable bottleneck to be removed of mitigated. This should be done as a function of the VRES and storage systems penetration. For each binding technical constraint (either a congestion or an instability issue), it is necessary to identify the yearly number of hours it occurs, and the energy not supplied due to it (ie, its cost); at the same time, it is necessary to identify possible solutions and their cost. The TSO, then, can run a cost-benefit analysis (CBA) to identify the most effective solutions to mitigate or remove the most expensive technical issues at the transmission level. This task is of course possible only for a TSO, which has full knowledge of the massive data needed. A simpler approach which is adopted in this work being the development of a power flow model beyond the scope, consists of estimating the transmission costs from the investment planned by the national transmission system operator (TSO) for RES integration as given in its Annual Development Plan. The resulting formulation is the following Equation (5).

$$C_{\text{trans}} = \frac{\sum_{m}^{\text{macroregions}} \text{Inv}_{\text{TSO, RES int}}(m)}{\sum_{m}^{\text{macroregions}} \text{Prod}_{\text{VRES, 2030}}(m) * \text{PV\_lifetime}} \tag{5}$$

where $\text{Inv}_{\text{TSO,RES int}}(m)$ is the total investment made by the national TSO for RES integration in the macro region m expressed in €, $\text{Prod}_{\text{VRES,2030}}(m)$ the added production of VRES (wind and PV) expected in the future in the macro region m in terms of MWh, and PV_lifetime the service lifetime of PV power plants in years.

2.1.4 | Adequacy costs

The adequacy costs, which we consider in this analysis, are issues related to the system reliability and security of supply due to the increase of VRES penetration, are evaluated similarly to the transmission costs starting from the TSO investments aimed to guarantee the quality of the service when they are coupled with the RES integration objective. Also in this case, similar steady-state and dynamic studies are necessary for a reasonable estimation of these costs; like in the previous case, such analysis can only be carried out by a TSO and it is beyond the scope of this paper.

The Equation (6) is applied in this case as follows

$$C_{\text{adequacy}} = \frac{\sum_{m}^{\text{macroregions}} \text{Inv}_{\text{TSO, Q\&S}}(m)}{\sum_{m}^{\text{macroregions}} \text{Prod}_{\text{VRES, 2030}}(m) * \text{PV\_lifetime}} \tag{6}$$

where $\text{Inv}_{\text{TSO,Q\&S}}(m)$ is the total investment made by the TSO for quality and security of the grid in the macro region m in €.

2.1.5 | Curtailment costs

The curtailment costs are introduced in this analysis as indirect costs to evaluate the economic losses due to the curtailed energy to prevent grid instability. This cost component is evaluated as a reduction of PV production directly in the power plant costs formulation. The reduction is represented by a percentage of PV curtailed for each macro region in respect of the macro regional PV production.

The PV curtailment is estimated by using an energy system model that performs an hourly energy balance of the available power plants and the possible overgeneration that will appear in the energy system nodes characterized by high RES penetration. The PV overgeneration in each node is the macro regional curtailment used in this cost component calculation. The energy model used in this analysis is described more in detail in the Subsection 3.2.

2.1.6 | Balancing costs

The balancing costs are introduced to include the impacts of VRES on the existing fossil fuel power plants, which will be increasingly exploited to cover the peak demand arising when VRES are no more available or not enough. The balancing costs include in this analysis the decay of efficiency and the start-up costs. They are estimated by enlarging the energy system model to take into account the time-dependency of transient operations of fossil fuel power plants when the hourly dispatch optimization of the available energy sources is performed, as explained in Reference 14. The added time-dependent constraints are the start-up costs and ramp constraints as a function of the downtime hours of the plant and the type of technology, and the decay of efficiency at partial load that happens when the power plant is not working at nominal conditions. The latter is implemented as additional fuel consumption in respect of the nominal condition and the resulting decay of efficiency costs are calculated with the following Equation (7).

$$C_{\text{decay}} = \frac{\sum_{u}^{\text{units}} \sum_{t}^{\text{time}} \left[\Delta F_{\text{additional}, u(t)} * C_{\text{fuel}}\right]}{P_{\text{tot}}} \tag{7}$$

where $\Delta F_{\text{additional},u(t)}$ is the additional fuel consumption of unit u at time t due to decay of efficiency in MW, C_{fuel} the specific fuel cost in €/MWh, and P_{tot} the total electricity generated by fossil fuel power plants in MWh.

The start-up costs, instead, are estimated with the Equation (8).

$$C_{\text{start-up}} = \frac{\sum_{u}^{\text{units}} \sum_{\text{start-up}}^{\text{starts}} \sum_{t}^{\text{time}} \left[C_{\text{start-up},\Delta t} * P_{\text{nom}} * X(t)\right]}{P_{\text{tot}}} \tag{8}$$

where $C_{\text{start-up},\Delta t}$ is the specific start-up cost depending on downtime Δt in €/MWh, P_{nom} the nominal power in MW and $X(t)$ is a Boolean variable that returns 1 if the power plant at time t has been down for an interval of time equal or higher than the downtime Δt, otherwise it returns 0.

The balancing costs calculated in this way are strictly related to the operational limits of fossil fuel power plants. It is also possible to directly use the prices coming from the balancing markets, but they might be influenced by the economic strategies adopted by the market participants. For this reason, it is interesting to compare the balancing costs calculated as shown above with the balancing market prices.

3 | METHODOLOGY APPLICATION

The main purpose of this work is the discussion of the system LCOE and the procedure for its calculation. However, the relevance of this parameter and the difference with the standard LCOE definition must be demonstrated by applying the methodology to a real case. This section describes how to determine the system LCOE and all the different parameters to a real case. The selected real case corresponds to the Italian one as the authors have access to more data. It is important to stress that the procedure is general and can be applied to any other region or country once the input data are available.

3.1 | Case study

In response to the Paris Agreement, the European Union fixed targets for each Member State in terms of CO_2 emissions reduction and RES penetration within the years 2030 and 2050. Within this framework, Italy introduced further incentives for RES power plants with the Decree FER 1[15] in July 2019 and approved the National Energy and Climate Plan (PNIEC acronym from Italian Piano Nazionale Integrato per l'Energia ed il Clima, PNIEC) in the end of the year 2018, the legislative commitment that sets the Italian targets to be achieved within the year 2030 as established by the European Union.

The PNIEC establishes (a) the 40% reduction of the CO_2 emissions by 2030 with respect to the emissions registered in the year 1990 and (b) more than 30% of the overall gross energy demand covered by RES with different shares in the three major sectors: 55.4% in the power, 33% in the heat and 21.6% in the transport sectors respectively.[16] The RES coverage in the power sector must be achieved considering an increase of around 5% of the annual electricity demand in the year 2030. According to the PNIEC projection is, the PV technology will give the most significant contribution by producing around 200% more than what is producing nowadays. Wind technology is also planned to increase significantly its share rising its production from the current 17.7 to 40.1 TWh in the year 2030. The combined cycle gas turbine (CCGT) power plants will still have a significant role in the energy mix since they must partially replace the coal power stations that are planned to be completely phased-out within 2025. The comparison of the Italian energy mix in the years 2017, taken as the baseline scenario, and 2030, used as reference in this analysis to estimate the future generation costs of PV, is shown in Table 1.

The Italian RES penetration will be supported on one side by making better use of the existing pumped hydro storage systems with additional 3 GW, on the other side, by sustaining a widespread use of batteries storage systems (BESS) both centralized (for a total installed capacity of 24 GWh) and decentralized combined with residential and commercial PV systems (for further 15 GWh of added capacity). Finally, the transmission grid infrastructure needs to be reinforced to transport and better manage the significant increase of VRES production. In this regard, the Italian TSO includes the grid infrastructure development in its Development Plan of the year 2019.[1] This is the framework used to build the reference 2030 scenario for which the future Italian system LCOE is calculated.

3.2 | System LCOE: Input data and main assumptions

The power plant costs for the Italian utility-scale PV plants (with and without storage system) has been

TABLE 1 Comparison of the Italian energy mix nowadays (Baseline 2017) and that expected for the year 2030 (PNIEC 2030)

	Baseline 2017 (TWh)	PNIEC 2030 (TWh)
Import	42.9	28.7
CCGT	133.6	123
Coal	32.4	0
Others (oil, etc)	24.1	0
Hydro (total)	38	49
Biomass	19.1	16
PV (total)	24.4	75
Wind	17.7	40
Geothermal	6.2	7
Total production	338.4	338.7
Demand	320.6	337.3

Note: The data are taken from Reference 17 and 1 respectively.

estimated following the methodology explained in Reference 18. The Italian territory is subdivided into macro regions according to the national electricity market zones: North, Central North, Central South, South, Sicily, and Sardinia. For each of them, an average irradiation annual profile has been extrapolated from the Italian weather station data available in the software Meteonorm v.7.[19]

The reinforcing distribution network costs for the Italian case study are taken from the PV Parity Project,[10] in which a maximum value of 0.9 €/MWh is calculated considering 7% of PV penetration in the Italian electricity system. Even though the report highlights that this cost significantly decreases to 0.25 €/MWh with the increase of PV penetration up to 16%, to be conservative, the maximum value has been chosen for this analysis and applied to all macro regions.

To have an estimation of the transmission and adequacy costs, the Italian TSO Development Plan of the year 2019[1] and its annexes on the progress of work from the previous Development Plans[20,21] are considered. The scheduled investments in the short- and midterms including also the interventions required to reach the PNIEC targets for the year 2030 are described in detail in these documents. The Italian TSO estimates the financial commitment through a costs and benefits analysis.[22] It subdivided the intervention for each macro region and classified them based on four different purposes (decarbonization, market efficiency, security, quality and resilience, and sustainability) and eight different objectives (RES integration, quality of the service, interconnections, congestions resolution, resilience, connection to the national transmission grid, integration of the national railway, and energy transition). The investments aimed at the RES integration are taken as reference to calculate the transmission costs in this analysis, whereas the investments for the quality of the service are considered to estimate the adequacy costs. These investments are summarized in Table 2 for each macro region. In case an intervention involves more than one macro region and/or more than one objective, the investment is equally split among the macro regions, and/or the objectives to avoid double counting and because no detailed information is available on how the amount of money is spent in one region or for one objective in respect of the others.

The total macro regional expenditure for RES integration or quality of the service are calculated and then proportionally allocated to the macro regional additional PV and wind production for the year 2030 and spread over the plants lifetime that is assumed equal to 30 years. Since the TSO calculated the investments for the year 2030 including both the installed capacities of power production technologies and BESS according to the PNIEC, it is difficult to analyze how transmission and adequacy costs could evolve considering different combinations of VRES and distributed and/or centralized BESS. To understand this, the national grid shall be modeled and studied by means of suitable network studies including power flow computations and dynamic simulations, as mentioned in the previous subsection. However, given that detailed data of it are not available and that its modeling is beyond the scope of this analysis, these two costs components are here applied only to the case of PV plus storage systems.

TABLE 2 Italian TSO investments for RES integration and quality of the service used to estimate the transmission and adequacy costs respectively

Macro region	TSO investment for RES integration (M€)	TSO investment for quality of the service (M€)
North	523.4	532.2
Central North	307.9	127.9
Central South	976.3	189.1
South	407.2	293.0
Sardinia	389.3	100.4
Sicily	891.7	521.8

Note: These values are elaborated using the data provided by the TSO itself in References 1, 20 and 21.

As explained before, curtailment is considered for each macro region as a reduction of PV production that will be curtailed in the year 2030 and thus reduce the utilization rate as defined in, for example, Equation (1) with a subsequent increase in the LCOE. The total macro regional overgeneration is proportionally split between PV and wind based on the power output value at a specific timestamp. The simulations carried out with the energy system model give as result no curtailment in the PNIEC 2030 scenario whereas 4.2 TWh of PV electricity is curtailed at national level for the year 2030 in case no additional storage systems are planned.

As a first step, the balancing costs are taken from Reference 14 and are those referred to a RES penetration of around 50%, since the average RES penetration level in the PNIEC 2030 scenario simulated is around 59.8% with the specific decay of efficiency costs and start-up costs of around 1.6 and 4.8 €/MWh, respectively. Thus, the total balancing costs are 6.4 €/MWh and are applied to all macro regions, since no macro regional difference is provided in Reference 14. As a second step, these balancing costs are compared to those coming from the Italian balancing market price, as calculated in Reference 23.

3.3 | Energy system model

The PNIEC provides aggregated values on a national basis of installed capacities and production for different technologies projected to the year 2030 according to the RES penetration and CO_2 emissions reduction targets. However, the Italian electricity system is not managed as a whole but it is divided into macro areas defined as electricity market zones. These macro regions are used by the Italian TSO to control the electricity markets and the transmission grid infrastructure. Hence, an energy system model is needed to transform the aggregated national values into regional production profiles. The model should be capable of simulating the dispatch of generation sources located in different areas that are connected by transmission constraints. In this work, the Oemof framework[24] was selected as tool. Oemof is an open source energy system modeling tool written in Python that applies a multinode approach for dispatching the energy sources at regional scale, minimizing the total variable costs of power production technologies.[25] The six Italian macro regions determine the nodes of the model that are characterized by electricity demand and installed capacity for each technology (including storages) and connected considering the transmission constraints from one node to the others. The dispatch of energy sources is performed on an hourly basis for a reference year thus, the hourly annual profiles of demand and RES production are needed and built as in Reference 26.

A baseline scenario, corresponding to the Italian electricity system configuration in the year 2017, is set for the validation of the model: in particular, the energy mix resulting from Oemof's simulation with that provided by the Italian TSO for the year 2017 and the CO_2 emissions calculated by the model with those provided in different literature sources[27-29] are used as validation parameters. The baseline 2017 scenario is characterized both technically, that is, giving as input the electricity demand and production profiles as well as the installed capacity of each technology[30,31] and transmission grid constraints,[32,33] and economically, that is, defining the specific technology costs,[34-39] fuel costs, and CO_2 emissions.[40] Some of these input data are briefly summarized in Tables 3 and 4, whereas the validation results are shown in Table 5 and Figure 2.

Since the analysis is focused on the PV sector, it has been decided to investigate more deeply how different PV technologies are distributed by the energy model in the future scenarios. Thus, the PV sector has been divided into four technologies: PV rooftop, PV utility-scale fixed (ie, without tracking system), PV utility-scale with monoaxial tracking system, and BIPV (Building-integrated Photovoltaics) as PV installed on facades. The installed capacities of these PV configurations for the baseline 2017 scenario are taken from national statistics made by the Italian institution GSE (Gestore dei Servizi Energetici),[30] which subdivided the PV plants according to the power class. It has been assumed that the PV plants with an installed capacity lower than 1 MW are rooftop PV, whereas those with higher installed capacity are considered as utility-scale PV. Moreover, it has been supposed that the PV plants with an installed capacity higher than 5 MW are equipped with a tracking system. The costs for PV systems included in Table 3 come from an analysis of the value presented in References 36 and 38.

To evaluate how much installed capacity for each technology will be installed in the PNIEC 2030 scenario, it has been assumed that the current regional distribution of these four configurations remains the same also in the future. Thus, the total PV installed capacity planned in the PNIEC has been proportionally allocated among all

TABLE 3 Costs assumptions made for the baseline 2017 scenario and the PNIEC 2030 scenario

Technology	Unit	Investment costs Baseline 2017 (€/unit)	Investment costs PNIEC 2030 (€/unit)
CCGT	MW	1.362	1.362
Wind	MW	1.348	1.233
PV rooftop	kW	1367	945
PV utility fixed	kW	730	458
PV utility tracker	kW	813	520
BIPV	kW	2102	1494
River hydro	kW	3300	3300
Reservoir hydro	kW	3300	3300
Biomass	kW	2102	2102
Hydro pump	kW	600	600
Hydro turbine	kW	600	600
Pumped-hydro	MWh	7500	7500
Geothermal	kW	4450	4550
Batteries storage	kWh	—	362.7

TABLE 4 Assumptions on specific fuel costs and CO_2 emissions for the year 2017 and 2030[16,27]

Fuel	Specific fuel costs 2017 (€/MWh)	Specific fuel costs 2030 (€/MWh)	Emission factor 2017 (kg/MWh)	Emission factor 2030 (kg/MWh)
Coal	9.4	12.2	354.6	354.6
Oil	24.3	55.1	262.4	262.4
Natural gas	24.9	33.2	204.8	204.8

TABLE 5 Validation of Oemof model for the baseline 2017 scenario

	Baseline 2017 Oemof (TWh)	TSO 2017 (TWh)[17]
Import	37.8	42.9
CCGT	117.5[a]	133.6
Coal	32.4	32.4
Others (oil, etc)	24.1	24.1
Hydro (total)	42.4	38
Hydro reservoir	19.3	20.3
River hydro	23.1	17.7
Biomass	19.2	19.1
PV (total)	23.8	24.4
PV utility fixed	4.4	—
PV utility tracker	1.1	—
PV rooftop	18.3	—
BIPV	0	—
Wind	17.8	17.7
Geothermal	5.9	6.2
Total production	320.8	338.4
Demand	320.6	320.6

Note: The results obtained with the simulation are compared with the production levels provided by the Italian TSO.
[a]Includes both CCGT and cogeneration CCGT and comes from subtracting the coal and others power plants provided by the Italian TSO to the total CCGT estimated by Oemof.

the macro regions and PV technologies as they are distributed today. This assumption comes from the supposition that the current PV technologies distribution is representative of the potential for PV development considering the specific features of a region, in terms of geography, irradiation, and legislative constraints.

The model validation based on the 2017 scenario is shown in Table 5, which compares the electricity produced by each technology of the Italian energy mix resulting from the Oemof model and the statistics made available by the Italian TSO. The model is validated with only a slight deviation of the calculated values with respect to those provided by the TSO. The comparison also highlights how the different PV technologies are contributing to the energy mix.

The model is then used to simulate the PNIEC 2030 scenario updating the techno-economic inputs as expected in the year 2030 and obtaining the hourly dispatch and energy mix at macro regional scale for that year (see Table 6).

Since Oemof model optimizes the hourly dispatch of the generation sources, RES overgeneration does not appear in the results of the PNIEC 2030 scenario, mostly thanks to the storage capacity to be added within the year 2030. In fact, for the optimization carried out without including storage systems, the RES overgeneration corresponds to around 4.2 TWh.

4 | RESULTS

4.1 | System LCOE

In the previous sections, the system LCOE has been defined as the sum of (a) power plant costs of PV plants or PV plus battery storage systems based on the LCOE methodology; (b) grid costs that include the investments needed to reinforce the distribution and transmission infrastructures as well as to increase the reliability of grid avoiding curtailment even with significant increase of intermittent generation; (c) balancing costs that cover the impacts of adding new VRES generation on the existing CCGT power plants in terms of decay of efficiency and start-up costs.

The results of the system LCOE calculated for the six macro regions of Italy are reported in Figure 3 and in Table 7, in which the case of utility-scale PV plus storage system is reported and the cost composition of the system LCOE is highlighted.

The conventional LCOE for utility-scale PV plus storage plants in the year 2030 is between 33.12 and 41.95 €/MWh.

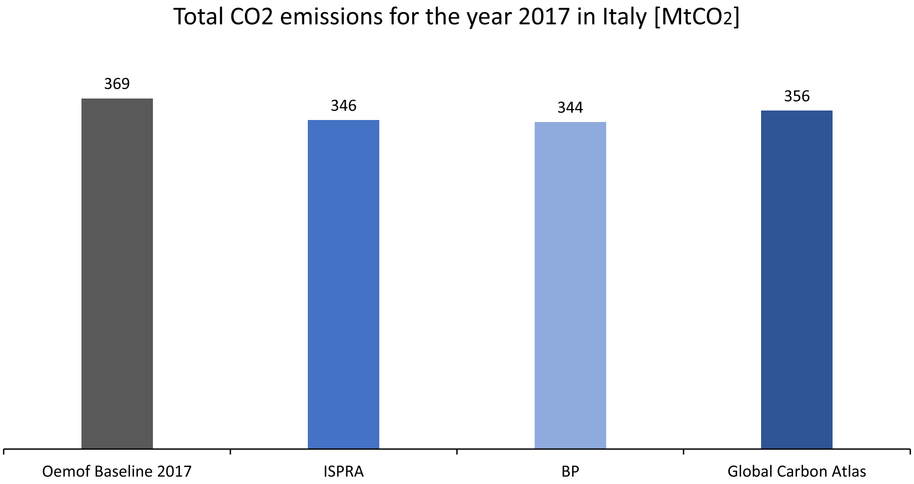

FIGURE 2 Oemof model validation based on the CO_2 emissions comparison [Colour figure can be viewed at wileyonlinelibrary.com]

TABLE 6 Italian energy mix resulting from Oemof simulations in the year 2030 according to the installed capacities of different technologies established in the PNIEC

	PNIEC 2030 Oemof (TWh)
Import	28.7
CCGT	109.5**
Coal	0
Others (oil, etc)	0
Hydro (total)	66
Hydro reservoir	19.3
River hydro	46.7
Biomass	17.4
PV (total)	72.3
PV utility fixed	13
PV utility tracker	4.4
PV rooftop	54.9
BIPV	0
Wind	39.6
Geothermal	6.9
Total production	340.4
Demand	337.3

**Includes both CCGT and cogeneration CCGT and comes from subtracting the coal and others power plants provided by the Italian TSO to the total CCGT estimated by Oemof.

When integration costs are accounted, the system LCOE has an average value of 46.97 €/MWh, with a minimum value of 44.10 €/MWh in the South and a maximum value of 51 €/MWh in the North.

The power plant costs represent on average the 77.8% of the system LCOE, with a minimum value of around 71.6% in Sicily and a maximum value of 82.3% in the North. The balancing costs are on average the 13.7% of the system LCOE, ranging from 12.5% in the North to 14.5% in the South. The reinforcing transmission costs correspond averagely to the 4.7% of the system LCOE, with a wide geographical variation from the 1.5% in the South to the 8% in Sicily. The adequacy and the reinforcing distribution network costs are the two costs components that contribute less to the system LCOE. While the latter are around the 1.9% of the system LCOE with a very narrow variety at macro regional scale, the adequacy costs are on average the 2% but range from 1.1% of the system LCOE in South to 4.7% in Sicily.

While for the case of PV plus storage in 2030, we can rely on the data provided by the Italian TSO and the figures included in the PNIEC, this is not the case for the scenario with no storage additional capacity. For this reason, not all costs components are included in the system LCOE for PV without storage system because no national grid network model was used to evaluate how the transmission and adequacy costs change with different penetration of VRES and BESS. In fact, the transmission and adequacy costs are estimated from the Italian TSO to reach the PNIEC target, which include the positive impact of the foreseen additional storage capacity. Moreover, the curtailment costs, calculated as explained in Section 2.1.5, are applicable only in the case of PV plants without storage, since no curtailment results from the simulation done for the PNIEC 2030, where storage is present. For this reason, another simulation has been done to consider the 2030 scenario without the additional storage capacity, resulting in a total curtailment of 4.2 TWh.

The system LCOE cost composition for utility-scale PV plants without storage system in the year 2030 is illustrated in Figure 4 and Table 8. The resulting values correspond to a scenario with 4.2 TWh of curtailment and no investments in the reinforcing of the transmission grid.

The conventional LCOE for utility-scale PV plants in the year 2030 is between 13.07 and 16.25 €/MWh, less

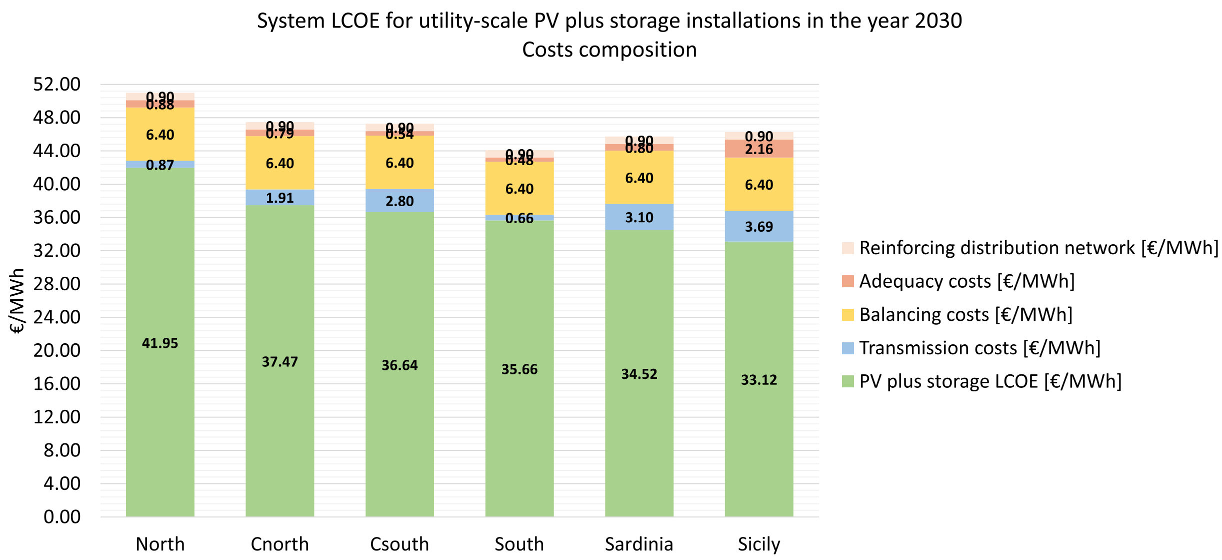

FIGURE 3 System LCOE costs composition for each Italian macro region for utility-scale PV plus storage systems in the year 2030 [Colour figure can be viewed at wileyonlinelibrary.com]

TABLE 7 System LCOE cost components for each Italian macro region for utility-scale PV plus storage systems in the year 2030

Macro region	LCOE PV plus storage (€/MWh)	Reinforcing transmission network costs (€/MWh)	Balancing costs (€/MWh)	Adequacy costs (€/MWh)	Reinforcing distribution network costs (€/MWh)	System LCOE (€/MWh)
North	41.95	0.87	6.40	0.88	0.90	51.00
Central North	37.47	1.91	6.40	0.79	0.90	47.47
Central South	36.64	2.80	6.40	0.54	0.90	47.28
South	35.66	0.66	6.40	0.48	0.90	44.10
Sardinia	34.52	3.10	6.40	0.80	0.90	45.72
Sicily	33.12	3.69	6.40	2.16	0.90	46.27

than half of the conventional LCOE of PV plants plus storage systems. When integration costs are accounted, the system LCOE has an average value of 21.67 €/MWh, with a minimum value of 20.37 €/MWh in Sicily and a maximum value of 23.55 €/MWh in the North.

The power plant costs represent on average the 66.2% of the system LCOE, with a minimum value of around 64.2% in Sicily and a maximum value of 69% in the North. The balancing costs are on average the 29.6% of the system LCOE, ranging from 27.2% in the North to 31.4% in Sicily. The reinforcing distribution network costs are the costs component that contributes less to the system LCOE in this case: on average they are around the 4.2% of the system LCOE with a very narrow variety at macro regional scale. The curtailment cost, which is directly included in the PV LCOE formula, increases the power plant costs of a percentage equal to the percentage of PV curtailed in that specific macro region, as shown in Table 9.

Overall, the system LCOE of utility-scale PV plus storage systems in the year 2030 is around 65% higher than the conventional LCOE and it can modify the cost ranking with respect to the conventional approach. For example, Sicily was the cheapest with the conventional approach while the South is the most economical with the system one. In the case of PV plants without storage in the year 2030, the system LCOE is on average 50% higher than the conventional PV LCOE but this does not change the cost ranking for which Sicily remains the cheapest region.

It is also worthwhile to look for a relationship between the VRES production and the integration costs, defined as the sum of transmission, adequacy, balancing, and reinforcing distribution network costs (see Figure 5). It can be noted that the higher the RES production the higher are the integration costs with the only exception of the South macro region. However, the

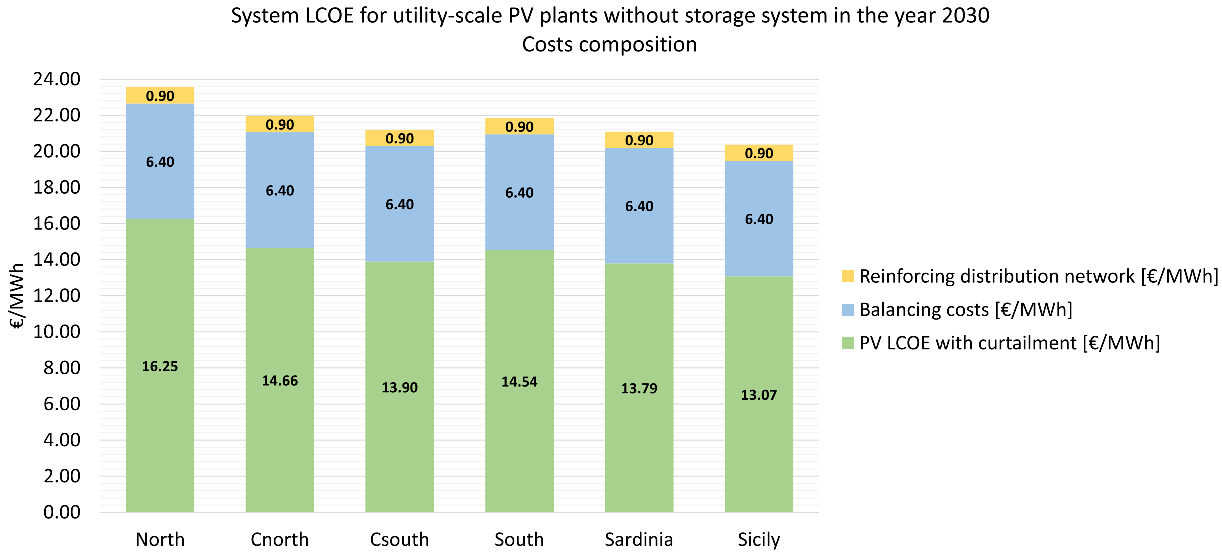

FIGURE 4 System LCOE costs composition for each Italian macro region for utility-scale PV plants without storage system in the year 2030 [Colour figure can be viewed at wileyonlinelibrary.com]

TABLE 8 System LCOE cost components for each Italian macro region for utility-scale PV plants without storage system in the year 2030

Macro region	PV LCOE with curtailment (€/MWh)	Balancing costs (€/MWh)	Reinforcing distribution network costs (€/MWh)	System LCOE (€/MWh)
North	16.25	6.40	0.90	23.55
Central North	14.66	6.40	0.90	21.96
Central South	13.90	6.40	0.90	21.20
South	14.54	6.40	0.90	21.84
Sardinia	13.72	6.40	0.90	21.09
Sicily	13.07	6.40	0.90	20.37

TABLE 9 Comparison between the PV LCOE calculated with and without curtailment

Macro region	PV LCOE (€/MWh)	PV LCOE with curtailment (€/MWh)	% of PV production curtailed in each macro region (%)	% difference between PV LCOE with and without curtailment (%)
North	15.93	16.25	2	2
Central North	14.22	14.66	3	3
Central South	13.90	13.90	0	0
South	13.52	14.54	7	7
Sardinia	13.10	13.72	5	5
Sicily	12.55	13.07	4	4

graph contains too few points to be sure that this tendency is statistically relevant and can be generalized for other countries.

Figure 6 shows the variation of the system LCOE for PV plus storage plants as a function of the minimum and maximum value of its cost components as estimated in

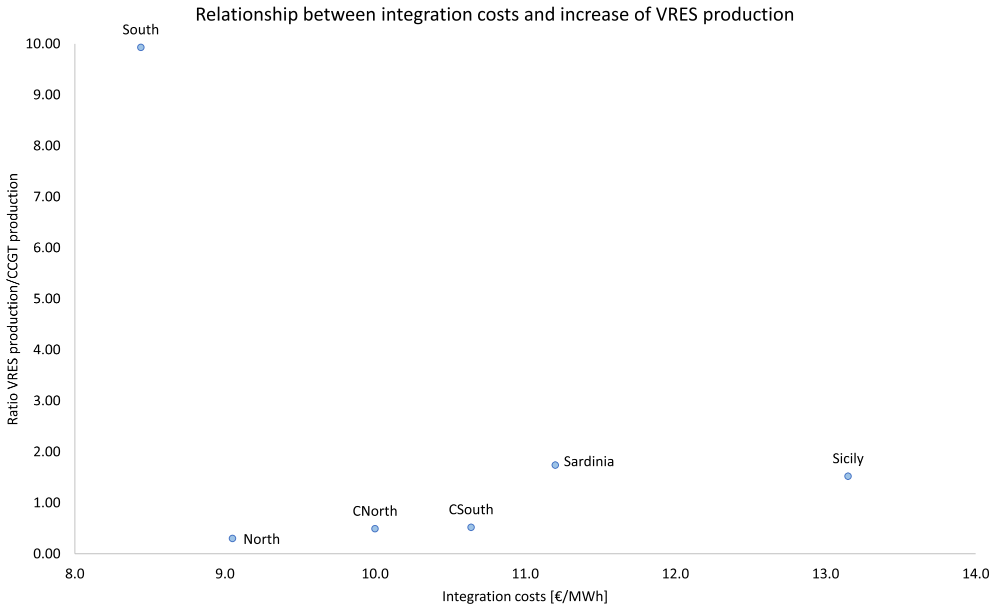

FIGURE 5 Relationship between integration costs and VRES penetration in the Italian energy system in the year 2030. The VRES penetration is defined as the ratio of VRES production and the CCGT production [Colour figure can be viewed at wileyonlinelibrary.com]

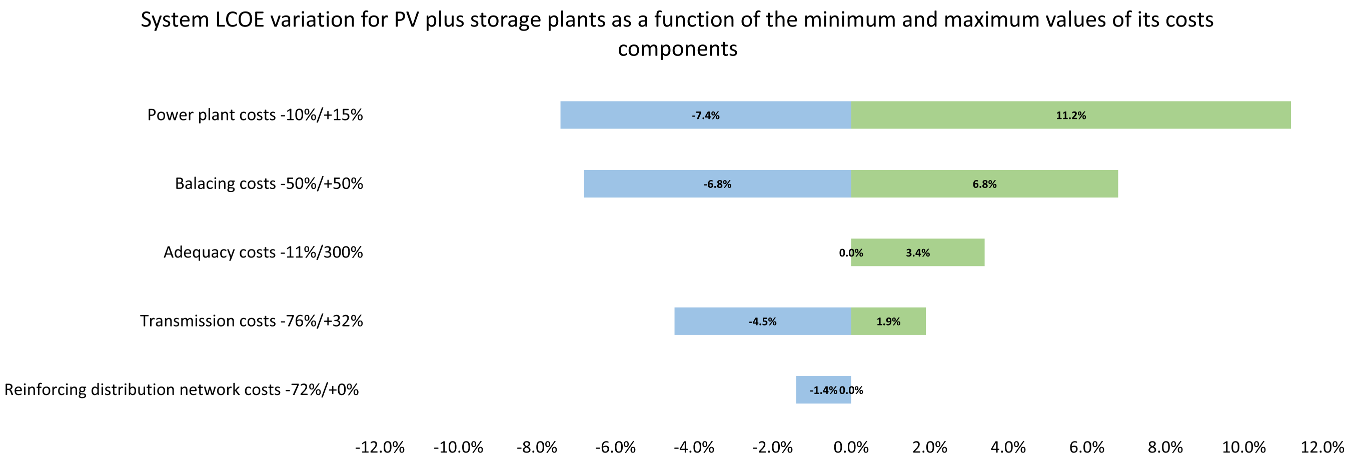

FIGURE 6 System LCOE variation with respect to the variation of costs components in their minimum and maximum values taking as reference the Central South macro region [Colour figure can be viewed at wileyonlinelibrary.com]

this analysis. In this case, the Central South macro region is taken as reference for the comparison since its system LCOE is the nearest to the average value: it has a PV plus storage LCOE of 36.64 €/MWh, transmission costs of 2.8 €/MWh, balancing costs of 6.4 €/MWh, adequacy costs of 0.54 €/MWh, and reinforcing distribution network costs of 0.9 €/MWh.

This is not a real sensitivity analysis since the variation of the system LCOE is based only on the minimum and maximum values that each cost component reaches in this analysis. For example, comparing the minimum and maximum value of power plant costs they are 10% lower and 15% higher than those of the reference case, without varying the WACC. These two values are substituted in the reference case cost composition to see how the system LCOE changes: for example, the variation of the power plant costs of −10%/+15% corresponds to a variation of −7.4%/+11.2% of the system LCOE. This procedure is repeated for all cost components with the exception of the balancing costs and reinforcing distribution network costs. In this latter case, the minimum value is that provided in Reference 10 equivalent to 0.25 €/MWh. The balancing costs, instead, since they are equal for all macro regions are changed in the range of ±50%.

The system LCOE most affecting cost component is the power plant costs. The second most affecting parameter is the balancing costs, which ranging in ±50% make the system LCOE varying around ±7%. Although reinforcing transmission network and adequacy costs show a wide variation from the minimum to the maximum values, the system LCOE changes of only around −4.5%/+1.9%, and 0%/+3.4%, respectively. The system LCOE is only marginally affected by the reinforcing distribution

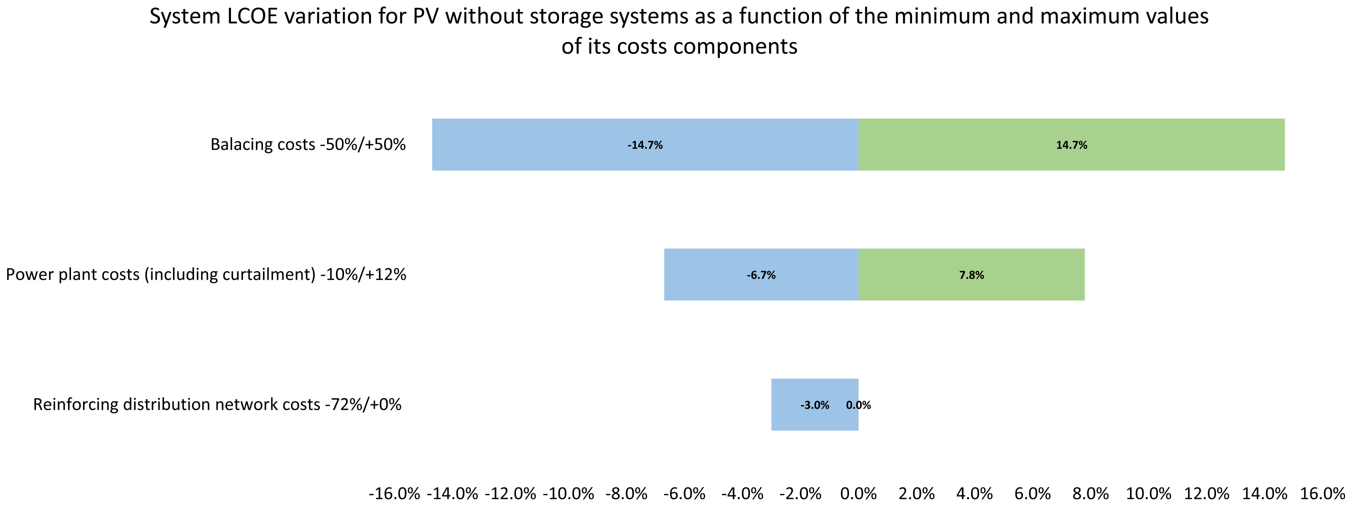

FIGURE 7 System LCOE variation with respect to the variation of cost components in the range of their minimum and maximum values taking as reference the South macro region [Colour figure can be viewed at wileyonlinelibrary.com]

network costs, reducing around −1.4% with a reduction of −72% of this cost component.

The same analysis is performed for the case of PV plants without storage systems, which results are shown in the Figure 7. In this case, the reference is the South macro region characterized by PV LCOE with curtailment of 14.54 €/MWh, balancing costs of 6.40 €/MWh, and reinforcing distribution network costs of 0.9 €/MWh.

Also in this case, the most affecting cost component to the system LCOE variation is the power plant costs. In fact, even though the highest system LCOE variation of ±14.7% is obtained by varying the balancing costs of ±50%, the power plant costs have a narrower range of variation of −10%/+12% causing the system LCOE changing in the range from −6.7% to 7.8%. As in the previous case, the reinforcing distribution network costs have the smallest impact on the system LCOE.

Last, if the market balancing costs, that are currently around 19.45 €/MWh in Italy, are used, the system LCOE can increase around 20% and 60% in the case of PV with and without storage, respectively.

To conclude, since the integration costs are strictly country-dependent, it is useful to compare these results with those determined by other authors for the Italian case study.[10] The total integration costs calculated in this analysis are in the range of 8.4 to 13.2 €/MWh and similar to those calculated in Reference 10, which are in the range of 5.2 to 15.9 €/MWh.

5 | DISCUSSION

It is important to make some consideration regarding the future profitability of utility-scale PV plants if this metric is adopted in the techno-economic evaluation of new PV plants and it is used to design new electricity markets that make the PV plants to pay these system cost. In fact, it might seem that internalizing these system costs to the PV plants would disadvantage the PV plants in respect of the other power production technologies. Assuming that the future Italian national electricity market price does not go under the average level of today, that is, around 50-60 €/MWh, it can be noticed that the market parity is still guaranteed in most of the cases, as shown in Figure 8. The system LCOE of PV plus storage system can be reduced if the grid services that these combined systems can provide will be remunerated somehow in the future, with additional economic benefits for both the energy system and the PV plant owner. The most future critical scenario from a system cost point of view comes from the high balancing costs as the current balancing market. However, this issue could be mitigated by adding more players like PV plus storage plants in the balancing market so to reduce the balancing costs by a more efficient market. For these reasons, it can be reasonably assumed that the profitability of future PV plants will be still guaranteed even by applying a more systemic approach to the power production costs estimation.

However, this analysis is aimed to provide a general methodology to evaluate the electricity production costs and the integration costs associated to the PV sector toward the transition to future scenarios with higher VRES penetration. This study represents a first step toward a methodology that allows a fair techno-economic evaluation of future generation costs but there is still room for improvement. For example, the grid costs are complex to be precisely evaluated because they require a comprehensive analysis of the grid infrastructure at two

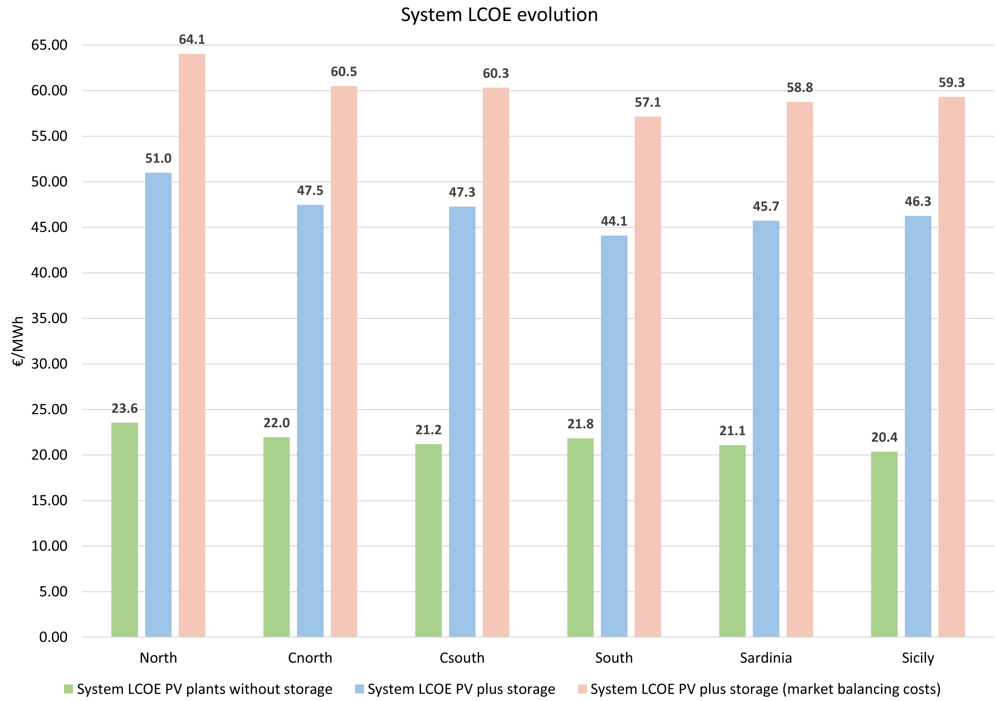

FIGURE 8 System LCOE comparison considering (i) basic system LCOE for only PV; (ii) system LCOE adding the cost of storage to the power plant costs; (iii) the system LCOE of PV plus storage systems considering the market balancing costs [Colour figure can be viewed at wileyonlinelibrary.com]

levels: the distribution and the transmission networks. The costs evaluation on both two levels needs the model of the grid infrastructure and the connection nodes of the existent and future power plants. Usually, there are network models useful to evaluate the effects on grid stability due to distributed VRES increase, for example in terms of reverse power flows or large perturbations. However, this kind of analysis turned out to be challenging for the Italian case study since there is a lot of difficulty in finding data on the network morphology and connection points of power plants at national scale. In fact, there are a lot of Distribution System Operators (DSOs) in Italy that manage the grid in different ways and the grid elements can change a lot from one case to the other. At transmission level, even though it is monopolized and managed by a TSO, the infrastructure is considered strategic for the country, that is, no detailed model is available. Thus, the simplification introduced in this analysis for the transmission and adequacy costs estimation is the use of the real investments planned by the TSO, since it is known that TSO uses a detailed model of the Italian energy system to estimate them. Moreover, the profitability analysis of utility-scale PV plus storage systems needs to be enlarged by including the grid services t when they will be completely able to participate to the electricity market. Finally, it is difficult to predict the future evolution of electricity prices during this transition period but it is clear that it is necessary to introduce new electricity market models to go beyond the marginal cost approach used nowadays since it will be no more sustainable in energy markets dominated by zero-marginal costs technologies.

6 | CONCLUSIONS

A new formulation for the system LCOE methodology has been explained and tested in this paper to estimate the production costs of utility-scale PV plants during the transition period from the current low RES penetration to the future high RES penetration scenarios. The LCOE concept commonly used for the techno-economic evaluation of power production technologies has been enlarged to include the impacts of new utility-scale PV plants on the existent electricity system. Thus, a metric has been defined and called system LCOE since it embraces a broader vision on the electricity system as a whole.

New parameters have been added in the system LCOE (a) to include the costs of adapting and renovating the existing grid infrastructure to accept an increasing share of intermittent electricity while guaranteeing at the same time system reliability and security of supply; (b) to account for the impacts of additional VRES production on the operating conditions of the existing fossil fuel power plants. The latter are called balancing costs and cover the decay of efficiency and the start-up costs; the first are called grid costs and are the sum of transmission, reinforcing of distribution network, adequacy, and curtailment costs.

The Italian electricity sector has been taken as reference to test the methodology. Its energy sector has been modeled with Oemof to apply a multinode approach for the characterization of the production profiles of different technologies at a macro regional scale, starting from total national installed capacity as expected for the year 2030 by the Italian Energy and Climate Plan. The macro regional power production profiles are used to evaluate the power plant costs and integration costs included in the system LCOE.

The system LCOE estimated for the Italian utility-scale PV plants in the year 2030 is in the range of 20.37 to 23.55 €/MWh for the case without storage system, otherwise the system LCOE is higher and between 44.1 and 51 €/MWh. Looking at the system LCOE cost composition in percentage, the power plant costs give the greatest contribution covering around 66% and 78% of the system LCOE for PV plants without and with storage system, respectively. The balancing costs are the second greater cost component representing on average the 14% and 30% of the system LCOE for the PV with and without storage system, respectively. Looking at the influence of each cost component on the system LCOE variation, the parameter that affects mostly the system LCOE is the power plant costs followed by the balancing costs. All the other cost components affect the system LCOE of less than 5% even with wide range variations.

This study opens new paths for further research and methodology improvement. For example, different scenarios of VRES and storage penetration can be evaluated to find the most cost-effective strategy to be adopted to reduce the curtailment, that is, the optimal combination between increasing the installed storage capacity and reinforce the grid infrastructure. Moreover, a set of many network studies (both at steady-state and following significant perturbations) shall be structured to better study the variation of integration costs as a function of VRES penetration and to highlight the possible dependency among the cost components. It is also useful to understand if the foreseen future scenarios are physically feasible by evaluating the real location and connection points of future installed power plants. For this reason, a detailed GIS study of the VRES potential could be another step to be implemented in this analysis, which implies, for the Italian case study, a good knowledge of the legislation applied to this regard on a regional level. Finally, to complete the profitability analysis of future PV plants with storage systems, it is necessary to study different business models and power plant management strategies to make them actively participating to the electricity market by providing grid services and being profitable for both the energy system and the PV plant's owner.

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DATA AVAILABILITY STATEMENT

The data that support the findings of this study are available from the corresponding author upon reasonable request.

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