Improving Reliability Indices of the Autonomous Power System of Crete Island Utilizing Extended Photovoltaic Installations

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Abstract: Renewable energy sources (RES) have significantly helped in meeting the electricity demand of Crete, with their share in the energy balance to account for about 25% of the annual electricity production for the past five years. The contribution of photovoltaics (PVs) has been especially significant for the past three years, offering 10% in the peak demand, during summertime. This paper investigates what the capacity credit would be, i.e., up to what extent increasing existing PV capacity by about 20% can be considered as certain, to avoid installing thermal power units. In order to do so, probabilistic techniques have been applied to quantify the load that the installed thermal units in the Cretan power system should be able to meet at any time. In addition, the effect of the additional PV capacity to power system’s reliability is evaluated, introducing a new reliability index and taking into account actual data, regarding the planned and unplanned thermal units’ maintenance. Two scenarios have been examined using actual hourly data for load demand, PV, and wind production from the island power system of Crete. In the first scenario, the calculations were carried out considering the operation of the Cretan power system in its current state, while in the second scenario it was assumed that the PV production has been increased by 20%. Furthermore, we examine how the maximum value of capacity credit can be achieved as the PV installations are extended. In this regard, there is an upper limit of the additional PV capacity that leads to the maximum value of capacity credit.

Keywords: photovoltaics; probabilistic analysis; capacity credit; reliability; island power systems

1. Introduction

Investors all over the world have been increasingly interested in installations of generating units that utilize solar power to provide electricity. A higher capacity of photovoltaic (PV) installations was installed globally compared to any other power generation technology in the last two years (2017, 2018), including large hydro and wind power technologies. According to a recent study [1], 102.4 GW of grid-connected PV capacity was installed during 2018, as much PV capacity as the world had been cumulatively installed by the end of 2012 (100.9 GW). As a result, the total capacity reached 500 GW. It is estimated that the world’s solar PV capacity could exceed 1 TW by the end of 2022 [1]. Solar thermal installations have also gained interest [2] with installations in Spain [3] and North Africa countries [4] utilizing mainly hybrid natural gas-solar thermal generating units. Recorded progress [5] has been significant both in solar collectors [6] and the optimization of thermodynamic cycles for hybrid power stations of solar thermal and gas turbines [7,8]. However, such installations cannot be as
much widespread in any power system as PVs as they are not modular with the exception of solar dishes [9] and face more sitting constraints than PVs. This is the reason for focusing on PVs and their potential reliability impact on island power systems like Crete.

There have been numerous studies regarding the potential benefits of PVs already since 90’s. In [10] the value of PVs for voltage support, loss, and peak reduction, distribution systems are studied while comparisons are made with the conventional and widely used methods for voltage control and loss minimization. In another study [11], the value of PVs for society have been examined from both the consumer and the utility perspective, claiming that the decentralized PV systems have a higher value for the society due to the fact that the customers are involved in their own electricity supply. Generally, the presence of solar electricity resources, such as any other distributed generation, can eliminate or delay the need for investments on transmission or distribution grid level [12]. According to a past study [13], strategically sited PVs provide grid support to substation transformers by reducing their oil temperature due to the lower demand caused by PVs.

PVs have greatly helped in electrifying rural areas such as in middle northeast Africa and southeast Asia countries [14], Honduras [15], and desert regions [16], as an alternative to grid extension or fossil fuels. In regions such as Crete and the Australian States of South Australia [17], the match between PV generation and peak load demand during summer period can lead to peak load shaving, which provides reliable network benefits. PV systems can also help reduce peak load demand in end user level and thus reduce the electricity bill [18], even utilizing building-integrated photovoltaics in warm and sunny climates [19]. In another study [20], roof integrated PVs have been applied as a peak electric load reduction strategy. In the island power system of Crete, the installed PV capacity has already reached 98.67 MW [21]. It has been noted that about 10% of the peak demand at each month of the summer period coincided with the annual peak demand and is met by PVs equivalent to two expensive gas turbines. A probabilistic methodology for the economic evaluation of PVs has been presented by some of the authors for Crete [22] and Cyprus [23]. Especially for Crete, the annual benefit in terms of fuel costs has been estimated at more than 100 €/kWp.

Net-metering and virtual net-metering are alternative mechanisms to feed-in-tariffs of small-scale photovoltaics, especially for the public sector. Until now, net-metering installations are 3.6 MW, but due to the interest of many parties, net-metering is expected to hold an active role in the coming years especially in the energy balance of Crete. More precisely, the region of Crete and all the municipalities of the island have decided coordinated application of an integrated plan of PV installations, as a means for reducing their own electricity consumption and the associated energy costs estimated at 150 €/kW-per year [24]. Therefore, in view of the increase of the installed capacity of PVs at about 20% of the currently installed capacity via the legislative framework of net-metering and virtual net-metering, with the active participation of the island’s public authorities, it would be interesting to investigate to what extent this additional PV capacity could replace firm capacity from thermal units. Such an assessment has been proposed for wind power for both microgrids [25] and large power systems [26]. However, the highest level of capacity credit that could be reached by increasing the solar generation plant capacity over the years cannot be answered. Under this perspective, the maximum PV capacity that could be installed to the power system of Crete succeeding the highest level of capacity credit still needs to be determined.

Additionally, the impact of PV generation on various reliability indices for the power system of Crete, such as expected energy not supplied (EENS), loss of load probability (LOLP) will be investigated to show the potential impact of PVs on the generation adequacy of the power system of Crete. Additionally, the methodology applied cannot only quantify the additional firm capacity that is required for obtaining 99.9999% generation adequacy for the island of Crete but to identify under which operating conditions and combinations this may be required. Such information can be very useful for the operator of a power system in order to perhaps rent generation capacity or apply the most appropriate demand side management (DSM) measurements [27,28].
The following methodology has been based on probabilistic techniques and actual data from the island power system of Crete, utilizing MATLAB software. Demand and RES generation have been modeled as random variables while well-known generation adequacy assessment techniques based on forced outage rate (FOR) have been applied. This methodology applies per group of hours and months to account for the inherent seasonal and daily variability of PV generation based also on similar approach, presented by some of the authors [22]. More details on this methodology have been described in Section 2. More details on the power system of Crete are provided in Section 3 and results from this analysis are provided in Section 4, either with or without considering installation of the additional PV capacity. Finally, conclusions are drawn in Section 5.

2. Methodology Followed

This section describes the methodology followed for the estimation of the capacity credit of the additional PV capacity along with their contribution in reducing EENS and improving other reliability indices, as far as generation adequacy is concerned. In order to evaluate these parameters, probabilistic techniques have been used. The analysis has been made by grouping actual hourly data for load demand, PV, and wind power production from the island power system of Crete for the last three years (2016, 2017, and 2018), per month (mo), and per hour type (hr) in order to derive corresponding random variables probability density functions (PDF). The proposed methodology consists of two steps.

2.1. Derivation of the Expected Thermal Generation Probability Density Function (PDF)

In Crete, as in most island power systems, a single buyer model and feed-in tariff schemes apply. In such a case, the load to be distributed to the thermal units of the power system is provided by Equation (1):

$$P_{\text{Th\textunderscore units}} = P_{\text{Load}} - P_{\text{Wind}} - P_{\text{PV}}$$

where $P_{\text{Load}}$ is the actual load demand while $P_{\text{Wind}}$ and $P_{\text{PV}}$ are the wind parks and PV production. The load that the installed thermal unit in the Cretan power system should be able to meet at any time varies. The season or more specifically the month of the year and the type of the day are two important factors that cause significant fluctuations in hourly load demand and RES production. Therefore, this is why the data and hence the results are classified per month and per hour. However, the load to be distributed to the thermal units cannot be accurately estimated as load demand varies considerably over time and weather conditions change. Figure 1 verifies that the examined actual hourly data of load demand ($P_{\text{Load}}$) and RES generation ($P_{\text{Wind}}$, $P_{\text{PV}}$) of the power system of Crete are very lowly correlated. Thus, it is confirmed that the corresponding PDFs $P_{\text{Load\textunderscore mo\textunderscore hr}}$, $P_{\text{Wind\textunderscore mo\textunderscore hr}}$, and $P_{\text{PV\textunderscore mo\textunderscore hr}}$ can be safely considered as independent random variables.

According to the examined hourly data for load demand, PV, and wind power production from the power system of Crete, $P_{\text{Th\textunderscore units}}$ cannot be lower than 0 MW, either for the current conditions or for the basic scenario of additional 20% of PVs. There is almost negligible probability that this will be lower than zero for specific hours in March combined with significant wind power generation probability if the PV capacity reaches 55 MW. In any case, in order to assure that no violation of the technical minimum of the generation units is expected, RES curtailment will take place. This is a policy already followed by the operator of the power system for wind power [29], but under circumstances PV power rejection can be also applied, as there are not yet energy storage systems in Cretan power system. Nevertheless, there have been several studies regarding the installation of energy storage systems on the island power system of Crete such as batteries and large pumped hydro storage systems [30]. In any case, the proposed probabilistic methodology can identify how probable such issues are expected to be in Crete and in any other system.
2. Methodology Followed

This section describes the methodology followed for the estimation of the capacity credit of the power system of Crete, including the derivation of the Expected Thermal Generation Probability Density Function (PDF). The proposed methodology consists of two steps.

2.1. Derivation of the Expected Thermal Generation Probability Density Function (PDF)

The load to be served by the conventional units is obtained, as described in Equation (2), as a result of the convolution of the independent PDFs $f_{PLoad}(mo, hr)$, $f_{PWind}(mo, hr)$, and $f_{PPV}(mo, hr)$ [31].

$$P_{Th\_units}(mo, hr) = P_{Load}(mo, hr) - P_{Wind}(mo, hr) - P_{PV}(mo, hr)$$

(2)

These PDFs have been extracted from hourly data of these three years, defining discrete steps of demand or production for each month and hourly type. The steps for the purposes of this paper are defined as:

- 10 MW for $P_{Load}(mo, hr)$
- 5 MW for $P_{Wind}(mo, hr)$
- 2.5 MW for $P_{PV}(mo, hr)$

The frequency bins for Equation (2) are provided by Equation (3).

$$f_{Th\_units}(mo, hr) = f_{PLoad}(mo, hr) \times f_{PWind}(mo, hr) \times f_{PPV}(mo, hr)$$

(3)

A typical graph for the final $P_{Th\_units}(mo, hr)$ PDF is shown in Figure 2.

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Figure 1. Scatter plots for the actual hourly data of the power system of Crete for the last three years (2016–2018). (a) $P_{Wind}$ and $P_{Load}$, (b) $P_{PV}$ and $P_{Load}$, (c) $P_{Wind} + P_{PV}$ and $P_{Load}$, (d) $P_{PV}$ and $P_{Wind}$.

In this study, the estimation of the random variable representing the load to be served by the conventional units $P_{Th\_units}$ is obtained, as described in Equation (2), as a result of the convolution of the independent PDFs $P_{Load}(mo, hr)$, $P_{Wind}(mo, hr)$, and $P_{PV}(mo, hr)$ [31].

$P_{Th\_units}(mo, hr) = P_{Load}(mo, hr) - P_{Wind}(mo, hr) - P_{PV}(mo, hr)$

(2)

These PDFs have been extracted from hourly data of these three years, defining discrete steps of demand or production for each month and hourly type. The steps for the purposes of this paper are defined as:

- 10 MW for $P_{Load}(mo, hr)$
- 5 MW for $P_{Wind}(mo, hr)$
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$$f_{Th\_units}(mo, hr) = f_{PLoad}(mo, hr) \times f_{PWind}(mo, hr) \times f_{PPV}(mo, hr)$$

(3)

A typical graph for the final $P_{Th\_units}(mo, hr)$ PDF is shown in Figure 2.
2.2. Reliability and Forced Outage Rate

All conventional units of any power system are subject to several random unplanned outages. Generation adequacy of a power system is the assessment of the ability of the conventional units to meet the consumption of the power system, based on reliability indices. The simplest stochastic method for considering the reliability of a production unit is the two-state model [31], provided by Equation (4). This model defines two possible states for each unit. Each generation unit may be either capable of producing at its rated power or not available due to a failure, each case with a corresponding probability. The probability of the unit being available is \( p_i \), while the probability of being unavailable is \( q_i \), which is called the forced outage rate (FOR):

\[
p_i + q_i = 1
\]  

(4)

Therefore, taking into account FOR and \( P_{\text{Th,units}}(mo,hr) \), a new PDF \( P_{\text{Load,loss}}(mo,hr) \), related to the load that available units cannot meet, is calculated by an iterative algorithm.

The system reliability based on generation adequacy can be evaluated, examining this new PDF. EENS, LOLP, and loss of load expectation (LOLE) [32] represent reliability indices. EENS defined by Equation (5) and is a measure of the amount of energy demand, which is expected not to be met by thermal units during a specified time period.

\[
\text{EENS} = \int_0^n P_{\text{Load,loss}}(t) \, dt
\]  

(5)

LOLP expresses the case when the available generating capacity exceeds the expected demand. It is a projected value of how high the probability is, in the long run, of the load of a power system is expected to exceed the capacity of the available generating resources. LOLE defines the time for which the load demand is expected to exceed the available capacity within a specified time period (T) and is given by (6).

\[
\text{LOLE}(mo,hr) = \text{LOLP}(mo,hr) \times T
\]  

(6)

The need to examine the load demand that cannot be served by the thermal, for a specified time period, thus led to the definition of a new reliability index. Therefore, a new index LWLOLE (load with LOLE) is introduced in this paper and defined by Equation (7), which represents the maximum value of load expected not to be supplied for duration longer than 0.1 s, corresponding to an availability of less than 99.9999%, “six nines” [33]. This will show how easy it is for the generation system to adapt to
the generation shortage, e.g., by renting gen-sets, by demand reduction, by generation expansion, or combination of actions.

\[
\text{LWLOLE}(mo,hr) = \text{LOLE}(mo,hr) > 0.1\text{sec} \tag{7}
\]

As was mentioned, the results of this study have been classified per month and per hour type. Thus, 0.1 s of interrupted power of a specific month and hour correspond to \(9.26 \times 10^{-5}\%\) unavailability and 99.9999\% availability, given by Equations (8) and (9), respectively. (there are 108,000 s in a month for an hour type).

\[
\text{Unavailability} = \frac{0.1\text{sec}}{108,000\text{sec}} = 9.26 \times 10^{-5}\% \tag{8}
\]
\[
\text{Availability} = 100\% - 9.26 \times 10^{-5}\% = 99.9999\% \tag{9}
\]

3. The Power System of Crete

Crete is the largest Greek island and the fifth largest island in the Mediterranean Sea. Crete has population of 623,065 people [34]. The population significantly increases during the summer due to tourists influencing the peak demand.

The island of Crete has the largest autonomous power system in Greece with instantaneous peak demand that has reached 707 MW and annual energy demand of 3.2 TWh [21].

A large number of conventional units with different technologies and response characteristics (steam turbines, Internal Combustion Engines (ICE), Open Cycle Gas Turbines (OCGT), and one combined cycle (CC) unit with total capacity of 824.8 MW have been installed in three power stations, namely Xylokamara, Linoperamata and Atherinolakos, on the island as is depicted in Figure 3. In Table 1, the capacity per unit type and power station is provided [35].

![Figure 3. Power stations location.](image)

<table>
<thead>
<tr>
<th>Power Station</th>
<th>Steam</th>
<th>ICE</th>
<th>OCGT</th>
<th>CC</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Linoperamata</td>
<td>111.3</td>
<td>49.2</td>
<td>118.6</td>
<td>-</td>
<td>279.1</td>
</tr>
<tr>
<td>Xylokamara</td>
<td>-</td>
<td>-</td>
<td>202.2</td>
<td>132.3</td>
<td>334.5</td>
</tr>
<tr>
<td>Atherinolakos</td>
<td>93</td>
<td>118.2</td>
<td>-</td>
<td>-</td>
<td>211.2</td>
</tr>
<tr>
<td>Total capacity</td>
<td>204.3</td>
<td>167.4</td>
<td>320.8</td>
<td>132.3</td>
<td>824.8</td>
</tr>
</tbody>
</table>

Crete is among the regions with the highest solar potentials in Europe, reaching up to 2100 kWh/m²/yr, and also high average wind speed that in many locations exceeds 8.5 m/s. These characteristics make the island an ideal place for the installation of wind and solar technologies [36]. There are more than 1000 small PV parks (mainly of 80 kW each) and 1800 roof PVs (≤10 kW, of about 17 MW) installed. Only five PV parks have capacity higher than 100 kW with a total capacity of about 0.9 MW. The largest has a capacity of 0.3 MW [37]. There are also 38 wind parks with total installed capacity about 200 MW. Currently, the total installed capacity of the RES stations amounts to 296 MW and it is also estimated the development of new RES stations such as hybrid stations, solar thermal stations, and biomass stations. In 2017, the total yearly RES generation amounted to 652.9 GWh, while in 2018 to 644.9 GWh.
The energy production balance of Crete is as shown in Figure 4 [21]. More details about the distribution of demand in each one of the four prefectures of the island can be found in [38].

![Power generation breakdown in 2018.](image)

**Figure 4.** Power generation breakdown in 2018.

The latest overview of the autonomous power system of Crete is based on actual operational data from the SCADA system of HEDNO SA. Only for 46 h load demand exceeded 600 MW, while for 942 h the load exceeded 500 MW. In Figure 5, the load duration curve for $P_{\text{Th\_units}}$ of the Cretan Power System for the year 2018 is presented showing that only for 88 h, i.e., for 1% of the year, 520 MW of thermal capacity would be necessary to operate. However, the maximum actual demand to be served by the thermal units, as derived by Equation (2), has a small but not negligible possibility to be as high as 630 MW.

![Duration curve for the actual demand to be served by the thermal units. Emphasis on the highest 1% values (HEDNO 2018).](image)

**Figure 5.** Duration curve for the actual demand to be served by the thermal units. Emphasis on the highest 1% values (HEDNO 2018).

4. Results

4.1. Capacity Credit Estimation

Examining the results from applying the first part of the methodology (Section 2.1), the effect of 20 MW additional capacity, which is the limit for additional PV capacity provided by the Regulatory Authority of Energy of Greece, is evaluated. This additional capacity decreases the load that the thermal units have to meet for some hours of the day, as well as manages to decrease the maximum monthly capacity required especially during the summer months. Figure 6 depicts the probability
that the demand to be met by thermal units is expected to be higher than 600 MW, considering the additional installation of PVs. July has the highest reduction (−24.23%) regarding this criterion, while in June the difference between the two states is almost negligible. In June, in particular in the second half of June, values of load demand greater than 600 MW have been observed, during 20:00–22:00, which is a time period that the solar PV plants cannot marginally contribute to the total generation.

According to the Table 2, the maximum load that thermal units have to meet is by 7.5 MW lower than the respective in the current state of Cretan power system. This load corresponds to the peak demand that the thermal units of the system are expected to meet, thus is estimated that 7.5 MW capacity of firm thermal units could be replaced, because of the additional capacity of PVs.

As stated by Table 2, the peak load demand has been observed in July during 14:00–15:00. By adding PV installations to the system, the required thermal generation keeps decreasing, but up to a certain extent, as the PVs can contribute only during the daytime. PV installation may finally lead to shift the peak load for the thermal units to early night hours, no matter how much their capacity is increased. Figure 7 depicts how the capacity credit and the maximum load to be met by thermal units, are changing through the increment of PV capacity.

The examined variables of capacity credit and maximum load change as the PV capacity is increased, but up to the extent of 55 MW of additional PV installations. In that instance, the maximum capacity credit that can be achieved, reaches the value of 20 MW and as a result the maximum load to be met by thermal units decreases to 610 MW. This maximum load is also observed in July during 20:00–22:00, in case the additional PV capacity exceeds 55 MW.

Figure 6. Expectation of the demand to be met by thermal units to exceed 600 MW.

Table 2. Maximum load to be met by thermal units (MW).

<table>
<thead>
<tr>
<th>Months</th>
<th>Current State</th>
<th>+20% PV</th>
<th>Hour</th>
</tr>
</thead>
<tbody>
<tr>
<td>June</td>
<td>610</td>
<td>610</td>
<td>20:00–22:00</td>
</tr>
<tr>
<td>July</td>
<td>630</td>
<td>622.5</td>
<td>14:00–15:00</td>
</tr>
<tr>
<td>August</td>
<td>610</td>
<td>602.5</td>
<td>13:00–14:00</td>
</tr>
</tbody>
</table>
with high solar irradiation. Nevertheless, the maximum LOLE which is summarized for each month cannot be decreased by this additional PV capacity. For all months except February, this can be achieved. That proves the great impact of PV generation on system’s reliability for periods November 0.19% for EENS and 0.25% for LOLE.

In this section, reliability indices of the Cretan power system are evaluated from the generation adequacy of thermal units’ perspective, examining two different scenarios. The results are provided by comparing the reliability indices of the system in its current state and with the assumption that the PV production has been increased by 20%. Figure 8 shows the EENS for five examined months. February and November are two months with low values of load demand. The EENS in the former case is 0.22 MWh while in the latter case was calculated as 1.54 MWh. This significant difference is because of which units are maintained in each case. It was assumed that in February those units could be a diesel unit of the power station of Linoperamata (10 MW) and a gas turbine (27 MW), while in November a part of the combined cycled (52 MW) unit could be out for service in addition to the steam turbines 4, 5 (24 MW each) of the power station of Linoperamata. Lower capacity of the available units during November justifies higher EENS values compared to February. During summer, although FOR is the only probability that was included for generation outages, high load demand leads to high EENS values.

Similar results are obtained for LOLE as is depicted in Figure 9. In July, 20% of additional PV generation could decrease the EENS by 15.93% and the LOLE by 15.71% for the whole month, while in November 0.19% for EENS and 0.25% for LOLE.

It is interesting to examine the change in LOLE during daytime. Figure 10 presents LOLE for July, grouped by hour type. Clearly, a high reduction of LOLE that exceeds 45% during hours 12:00–15:00 can be achieved. That proves the great impact of PV generation on system’s reliability for periods with high solar irradiation. Nevertheless, the maximum LOLE which is summarized for each month in Table 3 cannot be decreased by this additional PV capacity. For all months except February, this maximum value is observed, during the first night hour, when the solar PV cannot produce.
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Figure 11 shows the value of LWLOLE in July for each hour type. The effect of additional PV capacity is observed during the daytime with the highest reduction in LWLOLE being achieved at 13:00–14:00 by 15 MW ($-14.3\%$), while 22.2% ($-10$ MW) reduction in LWLOLE at 09:00–10:00 can also be achieved.

However, this effect cannot decrease the additional firm capacity that is required for obtaining 99.9999% generation adequacy, due to the maximum LWLOLE which appears at night hours as confirmed by Table 4.

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**Figure 8.** Expected energy not supplied for five representative months.

**Figure 9.** Sum of loss of load expectation for each representative month.

**Figure 10.** Loss of load expectation for each hour in July.
Table 3. Maximum loss of load expectation (LOLE) for each month and hour type.

<table>
<thead>
<tr>
<th>Months</th>
<th>Max LOLE (s)</th>
<th>Hour</th>
</tr>
</thead>
<tbody>
<tr>
<td>February</td>
<td>16.65</td>
<td>19:00–20:00</td>
</tr>
<tr>
<td>June</td>
<td>47.21</td>
<td>21:00–22:00</td>
</tr>
<tr>
<td>July</td>
<td>90.04</td>
<td>21:00–22:00</td>
</tr>
<tr>
<td>August</td>
<td>88.40</td>
<td>20:00–21:00</td>
</tr>
<tr>
<td>November</td>
<td>99.25</td>
<td>18:00–19:00</td>
</tr>
</tbody>
</table>

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Figure 11. Load with loss of load expectation >0.1 s for each hour in July.

However, this effect cannot decrease the additional firm capacity that is required for obtaining 99.9999% generation adequacy, due to the maximum LWLOLE which appears at night hours as confirmed by Table 4.

Table 4. Maximum load with loss of load expectation (LWLOLE) > 0.1 s for each month.

<table>
<thead>
<tr>
<th>Months</th>
<th>Max LWLOLE (MW)</th>
<th>Hour</th>
</tr>
</thead>
<tbody>
<tr>
<td>February</td>
<td>90</td>
<td>19:00–20:00</td>
</tr>
<tr>
<td>June</td>
<td>115</td>
<td>20:00–22:00</td>
</tr>
<tr>
<td>July</td>
<td>125</td>
<td>21:00–22:00</td>
</tr>
<tr>
<td>August</td>
<td>125</td>
<td>20:00–21:00</td>
</tr>
<tr>
<td>November</td>
<td>110</td>
<td>18:00–19:00</td>
</tr>
</tbody>
</table>

It is worth mentioning that by decreasing the reliability requirement of six nines to fewer nines for LWLOLE determination as provided by Equation (7), the values of this index are reduced. More specifically, Figure 12 shows the decrease of the maximum value of LWLOLE for each month by changing the acceptable duration of demand disconnection from 0.1 s to 1 s and 10 s. The new examined cases, for LOLE > 1 s and LOLE > 10 s correspond to 99.999% and 99.99% generation adequacy, respectively.
probable thermal units loading expected to appear during early afternoon hours of July.

potential capacity credit additional capacity of PVs on the island was evaluated. The obtained results showed that 20 MW of PVs can offer 7.5 MW capacity credit or can reduce by 1.2% the maximum probable thermal units loading expected to appear during early afternoon hours of July.

This paper makes a step forward to identify the maximum capacity credit that could be achieved, by adding PV installations to the power system of Crete without any other regulatory restriction. Thus, the capacity credit could be extended to the value of 20 MW whether the additional PV installations had been reached the extent of 55 MW. It has to be noted that 55 MW of additional PV capacity is the saturation point for the capacity credit of PVs. In fact, the time period that the maximum thermal units loading has been observed (630 MW in current state), differs in the case that PV installations reach 55 MW and corresponds to the time period of 20:00–22:00 (14:00–15:00 before).

The impact of the additional PV capacity on other reliability indices was then evaluated taking into account actual data on FOR and the typical maintenance schedule. Clearly, reduction in EENS and LOLE for summer months like July can exceed 15.5%. However, this reduction is mainly expected during periods when solar irradiation is apparent and unfortunately EENS and LOLE are rather high during the first hour of the night hours.

5. Conclusions

One of the questions that the operators of autonomous power systems have to address for the generation expansion studies of their systems is to what extent volatile RES, such as PVs, can provide capacity credit to the power system they manage. This paper proposes a methodology not only to assess the potential impact of PVs on the capacity credit of a generation system but also to give further insight on assessing the potential impact that additional PV capacity could cause on the various reliability indices for the generation system.

The example case study was the largest autonomous power system in Greece, the island power of Crete, an island with already significant PV capacity reaching 100 MW. For this power system the additional capacity limit for PV is considered by the Regulatory Authority of Energy of Greece equal to 20 MW corresponding to increase by 20% of the currently existing PV capacity. The legislative framework of net metering and virtual net metering makes such an assumption rather reasonable in the forthcoming years.

Utilizing probabilistic techniques, MATLAB software and actual hourly data for load demand, PV, and wind power production from the island power system of Crete for the last three years, the potential capacity credit additional capacity of PVs on the island was evaluated. The obtained results showed that 20 MW of PVs can offer 7.5 MW capacity credit or can reduce by 1.2% the maximum probable thermal units loading expected to appear during early afternoon hours of July.

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Additionally, in this paper, an index in capacity terms (MW), LWLOLE is introduced to reflect the possibility of having inadequate capacity with expected disconnection time higher than 0.1 s for a specific hour of a month. This may show the magnitude of required firm capacity for the power system for each hour. Therefore, this information seems to be beneficial for the operator of the system in order to adapt to the generation shortage, applying the most appropriate corrective actions, such as generation expansion or DSM. This index can be introduced for variable values of time shortage. PVs can decrease significantly this index by up to 15 MW during July.

The applied methodology can be replicated by other power systems utilizing data that are usually available to the operators of power systems. It can be estimated that if the evening demand is high, then the PV capacity credit might be even lower than the case of Crete. Moreover, if reliability indices of Crete are to be improved there is clearly the need of using stored energy during the first couple of nighttime hours.

In a future work, this probabilistic method can be used to determine the expected load demand in a lower level, i.e., in substation level, as well as to evaluate its local reliability. This study will give to the operator of the system further information about the loading of each substation in order to apply corrective actions, if necessary, or capacity expansion of substations’s elements such as transformers or transmission lines.

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Nomenclature

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>CC</td>
<td>Combined Cycle</td>
</tr>
<tr>
<td>DSM</td>
<td>Demand Side Management</td>
</tr>
<tr>
<td>EENS</td>
<td>Expected Energy Not Supplied</td>
</tr>
<tr>
<td>FOR</td>
<td>Forced Outage Rate</td>
</tr>
<tr>
<td>HEDNO</td>
<td>Hellenic Electricity Distribution Network Operator</td>
</tr>
<tr>
<td>LOLE</td>
<td>Loss of Load Expectation</td>
</tr>
<tr>
<td>LOLP</td>
<td>Loss of Load Probability</td>
</tr>
<tr>
<td>LWLOLE</td>
<td>Load with Loss of Load Expectation</td>
</tr>
<tr>
<td>ICE</td>
<td>Internal Combustion Engine</td>
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<tr>
<td>OCGT</td>
<td>Open Cycle Gas Turbine</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>RES</td>
<td>Renewable Energy Sources</td>
</tr>
<tr>
<td>PDF</td>
<td>probability density function</td>
</tr>
<tr>
<td>kWp</td>
<td>kiloWatt peak of photovoltaic power</td>
</tr>
<tr>
<td>$P_{\text{Load}}(m,o,h)$</td>
<td>Probability density function of load demand</td>
</tr>
<tr>
<td>$P_{\text{Load loss}}(m,o,h)$</td>
<td>Probability density function of the load that available units cannot meet</td>
</tr>
<tr>
<td>$P_{\text{PV}}(m,o,h)$</td>
<td>Probability density function of photovoltaics production</td>
</tr>
<tr>
<td>$P_{\text{Th_units}}(m,o,h)$</td>
<td>Probability density function of load to be served by the thermal units</td>
</tr>
<tr>
<td>$P_{\text{Wind}}(m,o,h)$</td>
<td>Probability density function of wind parks production</td>
</tr>
<tr>
<td>$T$</td>
<td>Time period</td>
</tr>
<tr>
<td>$f_{\text{Load}}(m,o,h)$</td>
<td>Probability density function of frequency of load demand</td>
</tr>
<tr>
<td>$f_{\text{PV}}(m,o,h)$</td>
<td>Probability density function of frequency of photovoltaics production</td>
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<tr>
<td>$f_{\text{Th_units}}(m,o,h)$</td>
<td>Probability density function of frequency of the load to be served by thermal units</td>
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<td>$f_{\text{Wind}}(m,o,h)$</td>
<td>Probability density function of frequency of wind parks production</td>
</tr>
<tr>
<td>$p_i$</td>
<td>Probability of the unit being available</td>
</tr>
<tr>
<td>$q_i$</td>
<td>Probability of the unit being unavailable</td>
</tr>
</tbody>
</table>
References


