Electric Power Systems Research 80 (2010) 547–555

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Installation of PV systems in Greece—Reliability improvement in the transmission and distribution system

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ARTICLE INFO

Article history:
Received 17 June 2008
Received in revised form
17 September 2009
Accepted 24 October 2009
Available online 27 November 2009

Keywords:
Photovoltaic power systems
Distributed energy resources
Reliability improvement
Peak shaving
Interruption cost

ABSTRACT

Photovoltaic (PV) power systems are becoming one of the most developing investment areas in the field of Renewable Energy Sources (RES). A statement of the status quo of PV power systems in Greece, and their contribution towards the improvement of power system reliability, is the scope of the present paper. Siting and installation of PV power systems is performed according to a recent Greek law, along with environmental and geographical constraints. Meteorological data are computed, formulated and imported to appropriate software in order to simulate the PV units and generate their power output. Data for unserved loads, resulting from load shedding during peak hours, are compared to the above estimated power production. Assuming that a proportion of the eventually unsupplied power could be provided by the accessed power generation of the PV units, the reliability of both transmission and distribution system is improved. The impact on the transmission system is shown by an improvement of LOLP and LOEP indices, whereas peak shaving for the Interconnected Greek Transmission System (IGTS) is also illustrated. For the distribution system the impact is quantified using the distribution system reliability indices SAIDI, SAIFI, and CAIDI. Finally, the resulting improvement is also expressed in financial terms.

1. Introduction

Electric power systems (EPS) have been developed over the past decades based on the scheme of centralized generation, transmission and distribution of electric energy. However, recent trends have reformed this scheme by integrating various distributed energy resources (DER), among them power generation units using renewable resources, such as wind generators and PV systems. The penetration of these new distributed generation (DG) units has posed important technical issues, such as protection coordination, islanding, harmonics, short-circuit levels, etc. However, it also brings a number of technical, economic and environmental benefits, such as feeder relief, power quality improvement, peak shaving, minimization of losses and emission-free power generation. Researchers are trying to overcome the technical issues, while at the same time governments around the world are launching projects in order to give investors incentives for installation of new equipment, to enter this new market. Such a project was launched by the recent Greek law "Generation of Electricity, using Renewable Energy Sources and High-Efficiency Cogeneration of Electricity and Heat and Miscellaneous Provisions" [1].

The installation of a great number of new PV power systems is therefore a reality for the immediate future in Greece. Their spatial siting is bound to follow the provisions of the above mentioned law, concerning the allocation to 11 different regions and the categorization into four types according to their power capacity [2]. The final installation sites within a region are also expected to meet with environmental and geographical constraints, as well as to have an optimal power output. It has to be noted that the voltage level where these PV units are going to be connected to will depend on their nominal power. Their total power capacity is specified to be 590 MW, as far the IGTS is concerned, and it is scheduled to be fully available until the year 2010.

Reliability concerning an EPS is a measure of its ability to constantly meet the energy demands of all its consumers. In the present work a methodology is provided, in order to evaluate the contribution of PV units to the reliability of the Greek power transmission and distribution system. According to the siting of PV units across the country and using meteorological data about radiation and temperature, the estimated PV power production is compared to data concerning load shedding, assuming that a specific proportion of the eventually unsupplied power could be supplied by the accessed power generation of the PV units. The contribution of PV power systems in the reliability of the IGTS is expressed by a reduction of indices LOLP and LOEP, whereas the peak shaving is also depicted. On the other hand, the improvement in the distribution system reliability is shown by means of the well-known distribu-

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doi:10.1016/j.epsr.2009.10.018

Table 1
Distribution of PV units in Greece.

No	Region name	Total installed capacity P_p from PV units by 2010 (MWp)					
		≤20 kWp	>20 kWp and ≤150 kWp	>150 kWp and <2 MWp	≥2 MWp	Insular parts of IGTS	Sum for region
1	East Macedonia and Thrace	4.45	14.50	12.50	12.00	3.00	46.45
2	Central Macedonia	5.45	24.50	15.00	15.00	0.15	60.10
3	West Macedonia	4.00	12.00	12.00	12.00	0.00	40.00
4	Epirus	1.80	5.40	5.40	5.40	0.00	18.00
5	Thessaly	5.34	16.02	16.02	16.02	3.20	56.60
6	Ionian Islands	0.00	0.00	0.00	0.00	15.00	15.00
7	West Greece	6.00	18.00	18.00	18.00	0.00	60.00
8	Central Greece	5.67	17.06	17.06	17.06	6.30	63.15
9	Peloponnese	12.18	36.59	36.59	86.59	0.15	172.10
10	Attica	3.64	10.92	10.92	10.92	7.20	43.60
11	Prefecture of Thessaloniki	1.50	4.50	4.50	4.50	0.00	15.00
	IGTS	50.03	159.49	147.99	197.49	35.00	590.00

tion system indices SAIDI, SAIFI, and CAIDI, as well as through a reduction of interruption costs, regarding the economic point of view. For the computation and formulation of the meteorological data METEONORM©, a comprehensive climatological database for solar energy applications, has been used [3]. Moreover, PVSYST©, a software package for the study, sizing and data analysis of complete PV systems, has been used for the simulation of the PV units and the generation of their power outputs [4].

The paper is organized as follows. Section 2 concerns the detailed distribution of the PV systems across Greece and their resulting power output. Section 3 deals with reliability, presenting a project by the Hellenic Transmission System Operator (HTSO) [5], which investigates the development of energy demand for the period 2003–2007. This project aims to determine the additional capacity required to be installed in order to ensure that load demands within the examined period will be covered. It also provides information about the values of indices LOLP and LEOP for this time period. Moreover, the distribution indices are investigated and the contribution of the PV systems production to the distribution system is theoretically analysed. In Section 4 the methodology for the contribution of the PV production in reliability improvement is demonstrated using various scenarios. Results about the improvement of the indices and peak shaving are given. Section 5 presents an economic assessment of the above results and finally Section 6 summarizes the main conclusions.

2. Siting and power production of PV

In this section, the criteria for the distribution of the PV units across Greece are presented, according to the provisions of [1] and other constraints. Their total resulting power output is afterwards calculated, using simulation tools. It is important to note at this point that the present work is referred exclusively to the IGTS, which also includes a few insular parts of Greece.

2.1. Siting

The IGTS contains the continental part of Greece, along with a small number of islands, and consists of 46 prefectures. According to [2], the area of the IGTS is separated in 11 regions, as shown in Table 1, each one having a different limit for power capacity from PV that can be installed there. Furthermore, the PV units to be installed are categorized into four types, according to their rated power capacity P_p and a limit for the installed power capacity of each type is also imposed. The installed capacity from PV units in the insular part of the IGTS is considered separately, as shown in Table 1.

A more detailed analysis about the allocation of PV units in the 11 aforementioned regions is being held, following the general limits set by the provisions of [1] and [2]. First of all, it is assumed that the total power capacity of each region is equally distributed to the prefectures that comprise this region. The only exception is Arcadia prefecture in the region 9 (Peloponnese) in southern Greece, in which a large PV unit of 50 MWp installed capacity is scheduled to be constructed by the Greek Power Public Corporation (PPC). Thereafter, in order to estimate the siting of the PV units inside the area of a prefecture, additional constraints, regarding environmental and geographical issues, have been imposed. More specific, investigating the IGTS, sites lying inside areas protected by environmental treaties (such as the European Directive 92/43/EK concerning NATURA 2000 Network) have been excluded from possible installation sites. Furthermore, dense populated urban areas as well as areas close to the seashore or mountain slopes having north orientation have not been chosen for installation of PV. A final assumption, needed for the following calculation of the power production of the PV units, is that all the PV units of one type are concentrated in one wide area for each prefecture, thus each prefecture will be simulated having four large PV units installed.

2.2. Power production

Following the previous analysis, METEONORM© database has been used to obtain meteorological data for each one of the installation sites. METEONORM© is a global meteorological database for engineers, planners and education, developed by METEOTEST [3]. For the present work, statistical data for about 30 years in the near past have been analysed in order to calculate hourly values for the air temperature and mean irradiance of global horizontal radiation for a whole year. The method used by METEONORM© couples extended databases and algorithms and provides the above mentioned meteorological data for all sites.

The data acquired from METEONORM© are structured in a proper way to be imported to PVSYST© software, in order to simulate the PV units and generate their power output in an hourly basis for the whole year. PVSYST©, a software developed by GROUPE ENERGIE (CUEPE) at the University of Geneva, combines meteorological data along with commercial available PV panels, dc–ac inverter models and other equipment needed for the installation of a PV unit and calculates its power production for the modelled configuration. The power production is calculated for one unit of each of the four types (see Table 1) and is then multiplied by the number of the corresponding PV units to be installed in the prefecture according to the power capacity limits set by the law. The sum of power production by all four types of units produces the total amount of power from PV for each prefecture. In a final step, the

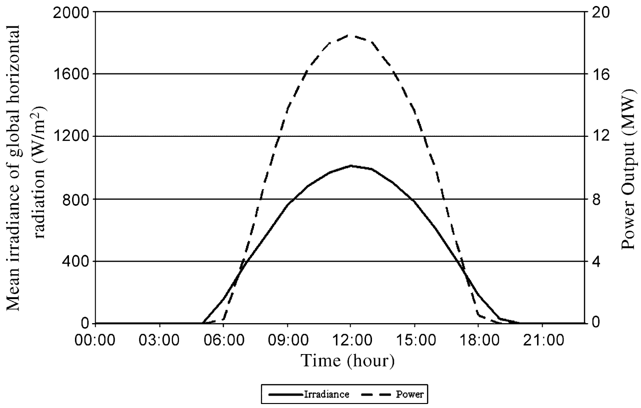

Fig. 1. Example for a 25.24 MWp PV unit. Irradiance is calculated in METEONORM© and Power Output in PVSYST©.

PV units for each prefecture (simulated as one large PV unit) were placed sequentially in the northern and the southern half of the prefecture and their total power output was calculated. The best site concerning power production was chosen as the final installation site.

In Fig. 1 an example about the results from the two software packages is presented, concerning a PV unit of total power capacity 25.24 MWp, installed in Corinthia prefecture in region 9 (Long. 22°20′, Lat. 37°40′), at an altitude of 695 m. This power capacity is the real future installed capacity for the Corinthia prefecture according to [2], which was simulated as a large PV unit sited in one specific location. The time period for this example was the 24th of July 2007, a sunny summer day with a mean temperature for the productive hours being 32.4 °C. The curve with the continuous line measured on the left axis is calculated in METEONORM© and depicts the hourly values of mean irradiance of global horizontal radiation. The curve with the dashed line measured on the right axis is calculated in PVSYST© and depicts the power output of the PV unit. It can be seen clearly that the power production of the PV unit is directly proportional to the radiation.

3. Reliability

In order to evaluate the contribution of PV units to the reliability of the transmission and distribution system, various indices are used. In the following section these indices and their corresponding values for the Greek system are presented.

3.1. Transmission system indices

For the transmission system, Loss of Load Probability (LOLP) and Loss of Energy Probability (LOEP) are used. LOLP index provides the probability that the system demand will exceed the production capacity during a time period and it is expressed as the estimated number of hours over this period. For a time period of 1 year, which is the case examined in this paper as well, the probability for every hour that the system demand will exceed the available capacity is found by dividing LOLP by 8760 h. LOEP index is similar to LOLP and expresses the energy over a time period that the system cannot serve. Initial values for the above indices have been taken for the Greek system from a report of the HTSO [5], and were obtained via software simulation for alternative scenarios concerning various levels of capacity and accordingly different values of energy production. The simulations have taken in account the energy demand in Greece for the time period 2003–2007, which among others was determined by the following factors:

Table 2
Initial LOLP and LOEP values for two hydro production scenarios, taken from HTSO study.

Energy production by hydroelectric units (GWh)	LOLP (h)	LOEP (GWh)
3000	123.9	35.5
3700	75.2	24.2

- The economic development of the country (rated using the Gross Domestic Product).
- Changes in consuming habits (air conditioning, electricity for means of transportation, etc.).
- Significant improvement of living conditions of special groups of citizens (e.g. economic immigrants).
- Parameters of energy and electricity market (i.e. price level of kWh).
- Special events (such as Olympic Games in 2004).
- National policy regarding energy savings and environmental issues.

Regarding the capacity in Greece, the following assumptions were made:

- The capacity of the IGTS was 11,739 MW in 2002.
- Regarding the imported power through the interconnections to the IGTS, HTSO's project adopts the following cases:
  - Imported power up to 300 MW (partial utilization of northern interconnection capability). This case is simulated by a base unit with a capacity of 300 MW.
  - Imported power up to 600 MW (complete utilization of the northern interconnection capability). This case is simulated by two base units with a total capacity of 600 MW.
  - Imported power up to 1 GW (similar to the previous case with further utilization of the western interconnection of 400 MW capability with Italy). The simulation is implemented by an additional base unit with a capacity of 400 MW.
- Hydroelectric production varies due to water availability. In specific, two production scenarios are examined:
  - medium energy production, 3000 GWh/year;
  - high energy production, 3700 GWh/year.
- *Renewable Energy Sources*: Only wind units contribute in energy production.

In the analysis presented in this paper, the capacity of the installed PV units, which will reach 590 MW by 2010 as defined in [1], is assumed to be available during 2007, although the existent level of PV penetration in energy production is still a relative small proportion of it. Using this approach, it becomes feasible to investigate the contribution of PV power on reliability improvement for the base year 2007 with a very good approximation. This assumption is justified as potential readjustments are expected due to the great investment interest that has been so far aroused.

Finally, the determination of LOLP and LOEP values, shown in Table 2, chosen among the resulted pairs by HTSO's project, was based on the following:

- The examined year is 2007.
- The total interconnection capability (northern and western) is modelled with two base units with a capacity of 300 MW each, and with one more base unit with a capacity of 400 MW. The total imported power can reach up to 1 GW.
- Regarding the annual energy production by hydroelectric units, both values (3000 and 3700 GWh) are considered, thus two pairs of values for LOLP and LOEP are examined.

Table 3
Levels of PV power production P_a, their corresponding probability and the new calculated LOLP and LOEP values for two hydro production scenarios.

Pa (MW)	Probability (%)	3000 GWh hydro production		3700 GWh hydro production	
		LOLP (h)	LOEP (GWh)	LOLP (h)	LOEP (GWh)
190	99.00	85.06	24.1	52.78	16.82
200	98.91	83.01	23.5	51.6	16.42
210	98.37	80.97	22.9	50.42	16.04
220	97.28	78.93	22.3	49.24	15.65
230	95.11	76.88	21.7	48.06	15.25
240	91.85	74.84	21.1	46.88	14.87
250	86.95	72.79	20.5	45.7	14.48
260	79.89	70.75	19.9	44.52	14.09
270	70.65	68.7	19.3	43.34	13.7
280	60.33	66.67	18.7	42.16	13.31
290	57.83	64.61	18.1	40.98	12.93
300	37.50	62.57	17.5	39.8	12.53

- Power capacity in Greece has been increased from 11,739 MW in 2002 to 12,695 MW in 2007, based on extrapolation of available data.

All the above data, except the last one, concern estimations by HTSO in order to structure the examined scenarios. The annual energy production for 2007 was 56.132 TWh.

3.2. Distribution system indices

As far as the reliability in the distribution system is concerned, indices SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) are used, as defined in [6]. Definitions for these indices are given in the following equations and were chosen among others because of their straightforwardness on describing the reliability of a given part of a distribution network:

$$\mathrm{SAIDI} = \frac{\sum \text{Customer interruption duration}}{\text{Total number of customers served}} \tag{1}$$

$$\mathrm{SAIFI} = \frac{\sum \text{Total number of customers interrupted}}{\text{Total number of customers served}} \tag{2}$$

$$\mathrm{CAIDI} = \frac{\sum \text{Customer interruption duration}}{\text{Total number of customers interrupted}} = \frac{\mathrm{SAIDI}}{\mathrm{SAIFI}} \tag{3}$$

The above indices vary significantly for different periods of time and number of total customers to which they are referred. Especially in this paper, the time period examined is 1 year and the customer total is the number of customers in a single Medium Voltage (MV) feeder of 10 MW, as it will be later analysed. A factor affecting the value of these indices is the possible inclusion of the so-called Major Event Days (MEDs), which are the days in which the daily system SAIDI exceeds a threshold value [6]. For the case studied later an initial value of 287.35 min was chosen for SAIDI, even though actual data for its present value in the IGTS were not available. The corresponding value with MEDs removed was 49.86 min. The above assumed values were chosen based on an example in [6] for a system similar to the IGTS. The improvement of the reliability is not evaluated by the exact values of SAIDI and CAIDI, but from the fact that, in case of a load shedding event, these indices do not increase as much as they would do without the PV.

4. Contribution of PV systems

In this section the contribution of PV systems to the reliability of both transmission and distribution systems will be evaluated. The methodology will be analysed along with the resulting improvements.

4.1. Contribution to transmission system reliability

4.1.1. LOLP and LOEP

In the present work indices LOLP and LOEP are based on periods of peak load demand conditions, which for the Greek system is the summer period. Within this time period, the IGTS may become unable to match generation to the excessive demand of energy, mainly due to air-conditioners. This situation was observed in the year 2007 during June, July and August, mostly during hours 11:00–15:00, and forced the Transmission System Operator (TSO) to proceed in load shedding, in order to ensure the stability of the IGTS and avoid a possible general blackout. Moreover, the HTSO's data regarding the daily power demand for the IGTS [7] also illustrate that the summer peak demand hours are 11:00–15:00. Therefore, indices LOLP and LOEP are estimated only for this time period of each summer day.

The following approach illustrates how LOLP and LOEP values could be reduced through the injection of power from PV units in the IGTS. First of all, the power production from PV within the summer period for each region and hour is defined as $P_j(t)$, where index $j = 1, \ldots, 11$ is the region and index $t = 1, \ldots, 2208$ is the hour starting from June 1st and finishing to August 31st. The total PV power production of the IGTS for the hour t, $P_T(t)$ is the sum of the production of each region, as shown in Eq. (4):

$$P_T(t) = \sum_{j=1}^{11} P_j(t) \tag{4}$$

For each day d, where $d = 1, \ldots, 92$ starting from June 1st and finishing to August 31st, the vector $\mathbf{P_{Td}}$ is defined. This vector consists of four values $P_T(t)$ for the hours 11:00–12:00, 12:00–13:00, 13:00–14:00, and 14:00–15:00, as shown in Eq. (5):

$$\begin{aligned}\mathbf{P_{Td}} = [&P_T(11 + (d-1) * 24), \quad P_T(12 + (d-1) * 24),\\ &P_T(13 + (d-1) * 24), \quad P_T(14 + (d-1) * 24)]\end{aligned} \tag{5}$$

For each vector $\mathbf{P_{Td}}$, meaning for each day d, the minimum of the produced power is defined as follows:

$$P_{d,\min} = \min \mathbf{P_{Td}} \tag{6}$$

As a result, 92 values of minimum power production from PV units for the examined summer period are provided, one for each summer day.

Furthermore, various levels of total power production P_a from PV units are assumed as follows:

$$P_a = 190 + 10a \tag{7}$$

where $a = 0, \ldots, 11$, thus 12 power production levels from 190 to 300 MW, by steps of 10 MW. The initial value of 190 MW was chosen because, as it will be shown later through the simulation results,

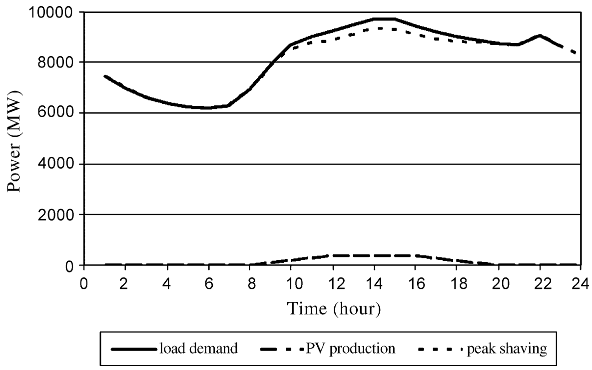

Fig. 2. Peak shaving by PV units in the IGTS for a sunny summer day (30th July 2007).

this power production is almost certainly available throughout summer for the examined hours.

Finally, the discrete variable p_{da} for $a = 0, \ldots, 11$ and $d = 1, \ldots, 92$, is defined as:

$$p_{da} = \begin{Bmatrix} 1, & \text{if } P_{d,\min} \geq P_a \\ 0, & \text{if } P_{d,\min} < P_a \end{Bmatrix} \tag{8}$$

The scope of the above analysis is to calculate the probability for each predefined production power level P_a that the power production from PV units will exceed this level. Thereby, the probability that $p_{da} = 1$ is given by the following equation:

$$P(p_{da} = 1) = \frac{\sum_{d=1}^{92} p_{da}}{92} \tag{9}$$

The results obtained by the above analysis are illustrated in Table 3 for all power levels P_a between 190 and 300 MW, along with the corresponding probability of having this minimum power ensured. This actually depicts the PV power availability in the IGTS for the hours 11:00–15:00. In this table the corresponding values for LOLP and LOEP for both scenarios for hydro production, as calculated from the HTSO's report for each of the above PV power production values P_a, are also shown.

4.1.2. Peak shaving

Another way to evaluate the contribution of PV power production to the transmission system is to show its beneficial effect on peak shaving, during high energy demand periods. Research in the field of peak shaving has already shown that, decentralized grid connected PV systems could improve the voltage level of a power system and contribute in peak load demand [8]. Data made available from HTSO [7] and regarding daily load demand in the IGTS have shown that the peak load period during a summer day occurs around noon time, due to increased utilization of air-conditioners and coolers during these hours of the day. On the other hand, during these hours of the day PV units are expected to provide their maximum power production, since high sun irradiation is also available around noon time.

In Fig. 2 the contribution of power production from PV units in all 11 regions to peak shaving is shown. As expected, maximum output of PV units occurs around midday, which is also the time period of peak load demand. Table 3 may be considered by the HTSO as a forecast for the expected PV power production during summer. Considering this power production, an estimation about the contribution of PV units in meeting energy demand in the IGTS could result in decreased load shedding by the HTSO, thus in lower values for LOLP and LOEP indices. From Fig. 2 it is concluded that, during a sunny day a significant amount of energy, approximately 3 GWh, could be covered by power production from PV units. Finally, it is also clearly shown that peak load between hours 13:00 and 15:00 could be reduced from 290 MW up to 370 MW.

4.2. Contribution to distribution system reliability

One of the basic reasons for reliability deterioration in the distribution system is the interruptions caused by load shedding, which are considered as sustained interruptions [6]. Load shedding is the process of cutting off the electric supply on certain feeders, in times when generation is unable to meet the excessive load demand. The LOLP index for 1 year, which is the time period examined in the present study, actually provides information about the duration of load shedding events, which occurred during this year. As mentioned in a previous paragraph, LOLP index is determined by peak load demand conditions, and the analysis will concern only the hours that these conditions occur, meaning 11:00–15:00 from June 1st to August 31st, 2007, which comprise all the load shedding events in 2007.

In each load shedding event, the TSO calls for the Distribution System Operator (DSO) to cut off specific MV feeders at 20 kV. These feeders serve a 10 MW nominal urban load, thus mostly residential and commercial customers. Based on the above analysis, the contribution of PV units may be easily evaluated. For example, if load demand exceeds load generation for 300 MW in a summer day between the hours 11:00 and 15:00, thirty MV feeders will be cut off during these hours. The selection of these feeders is performed by the DSO, considering among others overloading conditions. Assuming that the newly installed PV units inject additional power to the grid, some of the above feeders will potentially avoid this 4-h power outage, thus their SAIDI will also avoid an increase of 240 min. A remarkable economic benefit exists as well, but this will be analysed thoroughly in Section 5.

Following the previous analysis, various load shedding scenarios have been investigated. Feeders that are being cut off are assumed to be scattered around Greece according to loading and transmission constraints, while power production from PV units in a prefecture may be used to avoid the cutting off of some feeders in this or in adjacent prefectures.

4.2.1. Scenarios

Three different scenarios SC#1, SC#2, and SC#3 for total load shedding of 300, 400, and 500 MW respectively are investigated. The choice for these scenarios was based on a major load shedding of 500 MW, which occurred in July 24th, 2007 in Greece, following an excessive load demand. These scenarios concern the hours between 11:00 and 15:00 for each of the 92 summer days. According to the previous paragraph, thirty, forty, and fifty 10 MW feeders at MV have to be cut off, respectively. They are assumed to be located in six different load shedding areas, other than the 11 regions mentioned in [2]. These areas are shown in Fig. 3 and they have been chosen in a way that, in case load shedding is necessary in one prefecture, its adjacent prefectures in the same area can provide their PV power production without violating transmission system limits [9]. Cut off feeders have been distributed in the above areas, as shown in Table 4, according to the area load demand. It is noted that the need for load shedding comes from an excessive load demand, which the power generation from all other units except PV cannot meet.

The basic concept is that with the future installation of new PV units, according to Ref. [1], some feeders, which would otherwise be cut off during a load shedding event, may eventually be supplied by the accessed power generation of these PV units. For the hours 11:00–15:00 of each day during summer, PV power production is calculated in each of the 46 prefectures using PVSYST©. The minimum hourly power output $P_{\min}^{k,m}$ is considered for the kth prefecture of area m, where $m = 1$–6. It is assumed that every prefecture will

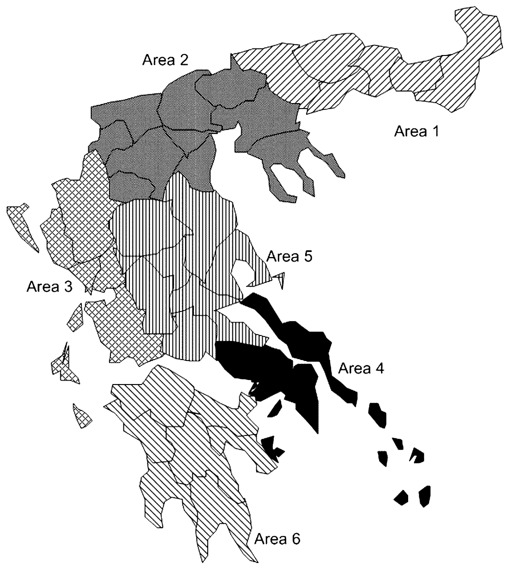

Fig. 3. IGTS divided into six load shedding areas, according to transmission system limits.

have this power output $P_{\min}^{k,m}$ guaranteed during the 4-h period of time, for the day in question. The total minimum power production $P_{\min}^{m}$ in the mth area is the sum of all $P_{\min}^{k,m}$ values for each prefecture of the area m. This power production is afterwards compared with the load shedding in this area and as a result a number of feeders avoid being cut off.

4.2.2. Results

Based on the procedure analysed in the previous paragraph, Table 5 presents the number of feeders that avoid being cut off, for the three load shedding scenarios. For each load shedding area m, as shown in Fig. 3, $P_{\min}^{m}$ has been calculated for the 92 summer days. This power is quantized into 10 MW steps, assuming to supply a corresponding number of feeders in the area, which would otherwise have to be cut off. Finally, for each different step, i.e. for a number of feeders eventually cut off, the percentage of the corresponding days has been calculated. This percentage can be also defined as the probability that for a specific scenario a number of feeders in an area would eventually avoid being cut off. Therefore, the number of eventually cut off feeders in the upper cell for each area and scenario, as seen in Table 5, is the maximum number of cut off feeders, if the contribution of PV units is considered. The above results can be explained better with a couple of examples.

Area 4 is considered as the first example, since it involves the prefecture of Attica, the largest urban area in Greece, with almost 40% of the country's population. For 1 day (1.09% of the total days considered) $P_{\min}^{4}$ was below 10 MW, thus there is a probability of 0.0109 that none of the feeders can avoid cutting off. For 11 days (11.96%) 10 MW $\leq P_{\min}^{4} <$ 20 MW, thus one feeder will avoid being cut off with a probability of 0.1196. Similarly, for 77 (83.69%) and 3 (3.26%) days $P_{\min}^{4}$ was enough to supply 2 and 3 feeders, respectively. As a result, at least 2 feeders in area 4 will eventually avoid being cut off with a probability greater than 85%, due to the accessed power production from the new installed PV units. This goes for all three scenarios and the only thing that changes is the final number of cut off feeders, leading to a different economic benefit, as it will be analysed in Section 5.

As a second example area 6 is chosen, since in the Peloponnese peninsula the greatest part of PV units is scheduled to be constructed. In total, more than 200 MWp power capacity will be available in area 6, including one large PV unit of 50 MWp to be installed by the Greek PPC. Seeing scenario SC#1 in Table 5, one can conclude that for all summer period the power produced by PV units can completely supply all 5 feeders, which the TSO would otherwise have to cut off in case of need of load shedding. This is also true with a probability of 0.9891 and 0.913 for scenarios SC#2 and SC#3, respectively.

4.2.3. Reliability indices improvement

In order to quantify the contribution of future installed PV units in the reliability of the distribution system, reliability indices mentioned in Section 3 are used. SAIDI is investigated only for one 10 MW feeder at MV and for a time period of 1 year, containing MEDs. The initial value of SAIDI for our study was assumed to be 287.35 min, as explained in Section 3.

The contribution of the PV units by means of SAIDI may now be easily evaluated. For example, if a single feeder eventually avoids a 4-h cut off, due to the accessed power production of PV, it will also avoid a SAIDI increase of 240 min, or a 83.52% increase. In the same way, for a known value of SAIFI the improvement would consist in avoiding its increase by 1. Finally, the CAIDI for all customers served by that feeder would also avoid a substantial increase, according to Eq. (3).

5. Economic assessment

The contribution of PV units in both transmission and distribution systems will also be expressed in financial terms. As far as the transmission system is concerned, LOEP index will be used and a comparison between PV and expensive peak units, which would cover the unsupplied energy, will be performed. The final economic benefit will be referred to the PPC, which is the dominant corporation in the field of electricity generation in Greece. On the other hand, for the distribution system the Expected Interruption Cost (ECOST) for different types of customers will be used and the potential economic benefit from the avoidance of cutting off a feeder will be calculated.

5.1. Transmission system

The values of LOEP index shown in Table 2, have the meaning that these two amounts of energy, for the two hydro production

Table 4
Cut off feeders distribution in the IGTS, due to load shedding.

Area	Proportion of total load shedding (%)	Cut off feeders (10 MW/feeder)		
		300 MW total load shedding	400 MW total load shedding	500 MW total load shedding
1	8.33	3	3	4
2	16.67	5	7	9
3	8.33	2	3	4
4	33.33	10	13	17
5	16.67	5	7	8
6	16.67	5	7	8
Sum	100.00	30	40	50

Table 5
Cut off feeders due to load shedding with and without PV contribution.

Load shedding area	SC#1			SC#2			SC#3		
	Number of cut off feeders *without* PV	Number of cut off feeders *with* PV	Percentage of days (%)	Number of cut off feeders *without* PV	Number of cut off feeders *with* PV	Percentage of days (%)	Number of cut off feeders *without* PV	Number of cut off feeders *with* PV	Percentage of days (%)
Area 1	3	2 1	1.09 98.91	3	2 1	1.09 98.91	4	3 2	1.09 98.91
Area 2	5	2 1 0	6.52 58.7 34.78	7	4 3 2	6.52 58.7 34.78	9	6 5 4	6.52 58.7 34.78
Area 3	2	1 0	33.7 66.3	3	2 1	33.7 66.3	4	3 2	33.7 66.3
Area 4	10	10 9 8 7	1.09 11.96 83.69 3.26	13	13 12 11 10	1.09 11.96 83.69 3.26	17	17 16 15 14	1.09 11.96 83.69 3.26
Area 5	5	3 2 1	30.43 68.48 1.09	7	5 4 3	30.43 68.48 1.09	8	6 5 4	30.43 68.48 1.09
Area 6	5	0	100	7	1 0	1.09 98.91	8	2 1 0	1.09 7.61 91.3

Table 6
LOEP and UCC.

LOEP (GWh)	UCC (€/kWh)
35.5	0.97
24.2	1.425

Table 7
Cost for OCGT units considering lower LOEP values due to PV units contribution.

Initial LOEP (GWh)	New LOEP after 200 MW PV power production (GWh)	Cost for OCGT units including O&M (M€)
35.5	23.5	24.79
24.2	16.42	24.89

scenarios, cannot be served by the IGTS over the examined period. In case the PPC of Greece needed to cover this energy, it should proceed in an increase of its installed capacity. The least expensive available solution, concerning units that could cover peak demand and are normally expensive ones, has found to be Open Cycle Gas Turbine (OCGT) units. It is estimated [10] that the annual Capital Cost (CC) for such a unit is approximately M€34.5. The Unitary Capital Cost (UCC) normalized by LOEP is calculated using the following equation:

$$UCC = \frac{CC}{LOEP} \quad (10)$$

where UCC is expressed in €/kWh, CC in M€ and LOEP in GWh. Table 6 illustrates the two values for LOEP index used in this analysis, along with the corresponding UCC calculated by Eq. (10).

The implementation of PV units, however, as defined in [1], constitutes a private investment activity, implying that a proportion of the capacity to be installed in the IGTS to cover the increased energy demand will not have to be installed by the PPC. According to Ref. [1], energy produced by PV units will be rated with 0.4 €/kWh and the PPC will be bound to purchase this produced energy with that cost.

For the present analysis, PV units are assumed to produce 200 MW. This value is chosen because the corresponding probability for this power level is 98.91% as shown in Table 3, therefore it is almost totally ensured. The corresponding values for LOEP index are 23.5 and 16.42 GWh for the two scenarios, as shown again in Table 3. As a result, the energy to be covered by the PPC OCGT units is now lower and so is the corresponding cost. This cost, for the two scenarios, is shown in Table 7, where the O&M cost has been included. The maintenance cost has been considered to be a default value of 1% of the CC, whereas the operational cost mostly comprises of the cost for fuel gas, which is 0.07 €/kWh.

In order to calculate the final cost for the PPC, the cost for the purchase of the energy produced by PV units, shown in Table 8, has to be added to the cost as shown in Table 7.

Table 8
Cost for the PPC to purchase energy by PV units.

Initial LOEP (GWh)	Energy produced by PV units (GWh)	Cost for purchasing this energy (M€)
35.5	12	4.8
24.2	7.78	3.11

The final cost for PPC in order to cover the non-supplied energy indicated by LOEP index is shown in Table 9, along with the profit of the PPC. This profit results from the comparison of the two possible options of the PPC. The first one, shown on the second column of Table 9 including O&M, is to cover the non-supplied energy with OCGT units only, whereas the second one, shown on the third column of Table 9, is to purchase energy from PV owners and cover the rest of the non-supplied energy again from PPC OCGT units.

5.2. *Distribution system*

The three reliability indices used in Sections 3 and 4 actually measure unreliability, since they increase as reliability deteriorates. An ideal measure of unreliability would be its cost according to each customer, i.e. the cost in Euros for a power outage. An interruption cost analysis, based on a customer survey approach, was conducted in Greece during 2001 [11]. In this survey three different types of customers were investigated: industrial, small and medium commercial (businesses), and large commercial (organizations), providing the average cost per interruption (€/interruption) and the cost normalized by customer annual peak demand (€/kW). The value for interruption cost normalized by annual peak demand for commercial customers was calculated at 5.4 €/kW for small and medium and at 14.5 €/kW for large ones. It has to be mentioned that the survey's values regarding the cost normalized by annual peak demand were readjusted to present values (2007). The inflation rate and the nominal discount rate were considered 3.5% and 8%, respectively. The same cost for residential customers was taken from another work [12], having a value of 1.5 €/kW.

In order to evaluate the contribution of PV units in financial terms, the Expected Interruption Cost (ECOST) for each customer type is considered. ECOST consists of the above mentioned costs and the corresponding aggregated load per customer type. Each feeder was assumed to serve various types of customers with the following composition: 60% residential, 15% small commercial, 15% medium commercial and 10% large commerical. Estimation for the simultaneous loading of each customer type is shown in Table 10, along with the resulting estimation for the number of each type of customers per feeder.

Based on the above, the ECOST for each customer type per feeder for a 4-h interruption is 6000 kW × 1.5 €/kW = €9000 for residential customers and €16,200 and €14,500 for small/medium and large commercial customers, respectively. Thus, the total ECOST

Table 9
Final cost for the PPC and corresponding profit.

Initial LOEP (GWh)	Cost with OCGT units only (M€)	Cost considering PV energy production (GWh)	Profit for PPC (M€)
35.5	37.33	29.59	7.74
24.2	36.54	28	8.54

Table 10
Customer composition of a 10 MW feeder at MV.

Type of customer	Total Power Demand (kW)	Simultaneous Loading (kW)	No of customers	ECOST (€/kW)
Residential	6000	2.5	2400	1.5
Small commercial	1500	10	150	5.4
Medium commercial	1500	20	75	5.4
Large commercial	1000	200	5	14.5

Table 11
Cost reduction at distribution level.

Load shedding area	Number of feeders avoiding cut off *with* PV	Total avoided cost (€)	Probability (%)
Area 1	1	39,700	1.09
	2	79,400	98.91
Area 2	3	119,100	6.52
	4	158,800	58.70
	5	198,500	34.78
Area 3	1	39,700	33.70
	2	79,400	66.30
Area 4	0	0	1.09
	1	39,700	11.96
	2	79,400	83.69
	3	119,100	3.26
Area 5	2	79,400	30.43
	3	119,100	68.48
	4	158,800	1.09
Area 6	6	238,200	1.09
	7	277,900	7.61
	8	317,600	91.30

per feeder for a 4-h interruption is estimated in €39,700. Finally, considering the load shedding events and the analysis in the previous section, Table 11 presents the total expected reduction in €, for each area.

6. Conclusion

In the present paper, the siting of PV systems in Greece has been systematically analysed and their contribution in the reliability of the transmission and distribution system is illustrated. Reliability improvement has been expressed firstly as a reduction of transmission system LOLP and LOEP indices, and secondly at the distribution system level, by examining the avoidance of feeder cut off when load shedding is bound to happen during peak demand days. Furthermore, useful conclusions regarding peak shaving during peak load demand periods are depicted. Finally, a brief economic analysis has been implemented resulting in a profit for the PPC as well as in a substantial amount of money being saved for the DSO.

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