Paper accepted for presentation at 2009 IEEE Bucharest Power Tech Conference, June 28th - July 2nd, Bucharest, Romania

PV Systems Penetration and Allocation to an Urban Distribution Network: A Power Loss Reduction Approach

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Abstract**-- This paper examines the impact of Distributed Generation to loss reduction in power distribution networks. In specific, the way that penetration level and allocation of PV units in a distribution Medium Voltage feeder affects power losses is investigated. Different approaches, regarding PV units placement across the feeder and their capacity, are analyzed and useful conclusions regarding the penetration level of PV units and their optimal placement across distribution feeders for loss reduction are derived.**

Index Terms**-- Distributed generation, loss reduction, photovoltaic power systems, power distribution.**

I. Introduction

DISTRIBUTED Generation (DG) has become an important issue for researchers, since the traditional form of power systems is evolving to a more decentralized layout. This is due to the increasing penetration of small generating units in the power grid aiming to locally satisfy consumers' energy demands. Various technologies of DG such as fuel cells and micro-turbines are utilized in order to fulfill the above requirement. At the same time, environmental pollution renders the need for covering energy demands by Renewable Energy Sources (RES), such as solar or wind power, more imperative than ever. The above developments constitute a new reality for the power systems, since the majority of these generating units are expected to be connected directly to distribution networks. Moreover, implementation of DG alters the traditional operating and planning practices of distribution operators. This is based on the consideration that, distributed power injection has an important impact on power losses, reliability, protection, voltage profiles, short circuit levels and peak load demand.

Considerable research has been accomplished so far regarding the optimal placement of DG in order to obtain maximum potential loss reduction [1]-[3]. Most of these approaches quantify the benefit resulting by DG for loss reduction, considering simple test cases with concentrated constant loads and distributed generators [4]. In [5] a novel methodology for the development of penetration scenarios for DG sources is presented in order to ensure the validity of modeling and of simulations. Several papers address the use of artificial intelligence algorithms to optimize DG placement [6]-[8] based on minimizing power loss. These aforementioned approaches utilize exhaustive algorithms, Tabu search method and genetic algorithms to solve the problem. In [9] a technique based on a genetic algorithm and an ε-constrained method is implemented for the sizing and siting of DG, while in [10] a technique named "reverse load-ability" performs negative load shedding and effectively maximizes the installed capacity of DG in power systems.

In the present analysis only PV power systems are considered. This choice was made due to a recent Greek Law [11] that foresees the installation of 590 MW of PV units in the Interconnected Greek Transmission System by 2010. Furthermore, the above law provides a categorization of PV units according to their rated power and more specific it determines that 210 MW of the total 590 MW will concern small PV units with nominal power up to 150 MW which are expected to be connected to Low Voltage (LV) and Medium Voltage (MV) distribution network.

The aim of this paper is to investigate the impact on power losses of a distribution feeder after the installation of PV units. The analysis is based on software simulations of various test cases, concerning the allocation and the penetration level of PV units, for a time period of one year. It is mentioned that the distribution feeder utilized in this paper is a part of the urban distribution network of the city of Thessaloniki. Real data were used regarding the length of the feeder, the resistance and reactance of the underground cable and the nominal power of the distribution transformers. Furthermore, the implementation of the power flow analysis was based on real loading data for the feeder that were provided by the PPC for the year 2007. Finally, simulations of PV units production was implemented by the utilization of two software packages. For the computation and formulation of the meteorological data METEONORM©, a comprehensive climatological database for solar energy applications, has been used [12]. Moreover, PVSYST©, a PC 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 the power outputs [13]. The power flow simulations were implemented in NEPLAN© [14].

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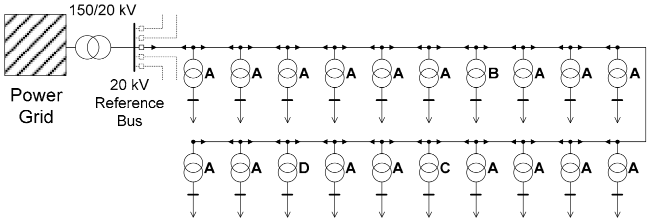

Fig. 1. General layout of the test feeder.

II. Description Of Distribution Feeder

In this section the configuration of the distribution feeder, which will be used further in the analysis, is described. The chosen area is located in the eastern part of Thessaloniki, in northern Greece, and has a high load density with a lot of low voltage residential and commercial customers. This purely urban area is supplied by a distribution feeder consisted of underground cables. The general layout of the feeder along with the loads served is illustrated in Fig. 1.

A. Feeder

The distribution feeder is connected to the transmission system through a substation containing a 150/20 kV transformer. In this work the LV terminals of the above transformer are considered as an infinite bus with a constant 20 kV voltage, as shown in Fig. 1. It has to be noted that, even though five feeders are connected to the LV side of the transformer, only one has been taken into consideration in the present work. This feeder has a total length of 6.23 km, twenty distribution transformers 20/0.4 kV to feed the various loads of about 12 MVA in total, and consists of underground cables with various lengths. The type of the cables is 3x240mm^2 NAEKBA, with $R' = 0.15\ \Omega$/km, $X' = 0.108\ \Omega$/km and maximum thermal current I_{max} = 310 A. The rated values of the four different type of transformers, such as the rated power S_r, the short-circuit voltage u_k, the p.u. resistance r, the open-circuit current I_0, and the iron-core losses P_{Fe}, can be seen in Table I.

B. Loads

The various residential and commercial customers supplied from the feeder are modeled as aggregated loads connected to the LV side of the distribution transformers. Since the analysis aims at examining the power losses during one year, these loads will be simulated continuously using load profiles for one year. These load profiles come from data measurements from the Greek PPC concerning the year 2007, after the process described in the following paragraph.

At first, measured hourly values of the total current of the feeder were provided for one year. In order to determine each distribution transformer current, the feeder total current was divided among them, according to their rated power. This assumption is based on the consideration that each transformer feeds a number of consumers according to its nominal power. Any statistical deviation of the loading profiles of different consumers located in a common urban area was assumed insignificant, considering the number of customers supplied by each transformer. The steps of the above procedure are the following:

- At first, the total loading capacity of the feeder, S_{tot}, is calculated as the sum of the rated power of all the MV/LV transformers.
- Subsequently, the ratio S_i / S_{tot} is calculated for every transformer, where S_i is the rated power of the transformer i.
- This ratio is used along with the total current of the feeder I_{tot}, in order to calculate the current I_i of transformer i as follows:

$$I_i = \frac{S_i}{S_{tot}} \cdot I_{tot} \tag{1}$$

Finally, from the above current profiles the corresponding load profiles are obtained, assuming nominal voltage 20 kV. After calculating values for the active power of the loads, values for the reactive power are also obtained assuming a constant power factor of 0.9.

TABLE I
Distribution Transformers Characteristics

Type (see Fig.1)	S_r (kVA)	u_k (%)	r (%)	I_0 (%)	P_{Fe} (kW)
A	630	5.24	1.12	2	1.3
B	1000	6	1.13	2	1.65
C	250	5	1.11	2	0.65
D	500	5.2	1.12	2	1.1

C. PV Units

The power production of the PV units has been calculated using two software packages. METEONORM© database has been used to acquire meteorological data for the specific area in Thessaloniki. Hourly values for the air temperature and mean irradiance of global horizontal radiation for the whole year have been calculated. The following step was to import the data acquired to PVSYST© software, in order to simulate the PV units and generate their power output. The software uses meteorological data along with commercial available PV panel and dc-ac inverter models and calculates the power production of each PV unit.

The PV units are assumed to be connected to the LV bus of the distribution transformers in parallel with the loads. This implies that each PV unit cannot exceed the limit of 100 kW installed capacity, according to the directive of the Greek PPC concerning the interconnection of DG. However, more than one PV units can be connected simultaneously to the same transformer as long as their total nominal power does not exceed the transformer rated power. Thus, the PV units are modeled in the simulation software as aggregated negative loads with a unity power factor, a common practice for many researchers.

III. Scenarios Examined

The methodology regarding the allocation of PV units was based on four different scenarios. Each scenario constitutes a different approach concerning the siting of the PV units, where candidate installation points are the Low Voltage (LV) buses of the Distribution Transformers (DT). Scenario A considers uniformly distributed PV units in all the DTs across the feeder. Scenario B assumes three installation points for the PV units in the beginning, the middle and the end of the feeder. For scenario C it was assumed that the first installation point was DT no.10 (in the middle of the feeder) and additional capacity of PV units was installed to adjacent DTs symmetrically. Finally, Scenario D was structured as follows: the first installation point was the DT at the end of the feeder and additional PV units were installed to adjacent DTs towards the beginning of the feeder. Each of the above mentioned scenarios was simulated for different penetration levels of PV units. The penetration level was defined as the ratio of the total capacity of PV units to the total loading capacity of the feeder:

$$\text{Penetration level (\%)} = \frac{\sum_i S_{PV}^i}{S_{tot}}\% = \frac{\sum_i P_{PV}^i}{S_{tot}}\% \tag{2}$$

where the installed apparent power of PV units equals the active power, since PV units are assumed to operate with a unity power factor.

In total five different penetration levels were assumed, namely 10% (level 1), 20% (level 2), 30% (level 3), 40% (level 4), and 50% (level 5). The combination of the four scenarios regarding the allocation of the PV units along with the five different penetration levels provided the 20 cases (A1-D5) that were finally examined. The above mentioned scenarios are presented in Table II. For all these scenarios various sets of simulations, which will be described in the following paragraphs, were performed.

Before analyzing the different sets of simulations, it has to be noted that for each power flow simulation the voltage limits for all nodes were kept in mind. In specific, the worst time intervals were found, where for the highest total penetration, PV production was high and load was at the lowest point. Even for these moments the overvoltages observed in the connection points of the PV units were at maximum about 1%, much lower than the limits set by the standards.

TABLE II
FORMULATION OF SCENARIOS

PV units allocation	Penetration Level				
	10%	*20%*	*30%*	*40%*	*50%*
Uniform distribution in all nodes	A1	A2	A3	A4	A5
First, middle, last node	B1	B2	B3	B4	B5
Middle node of feeder	C1	C2	C3	C4	C5
Last node of feeder	D1	D2	D3	D4	D5

A. *First set of simulations*

In order to get some preliminary results, the first series of simulations regarded only two months, instead of a whole year, in particular January and June of 2007. This selection was made on one hand to illustrate the difference between winter and summer periods and on the other hand because these months were the most indicative as far as both load curves and PV units' production is concerned.

More specific, based on the measurements data, a power flow for a whole year was performed using NEPLAN©. Afterwards, a yearlong simulation of the PV units operation was performed in PVSyst©, according to data from METEONORM©, as mentioned in Section II. The monthly energy losses of the feeder, along with the monthly energy production from PV units of 200 kW installed capacity are shown in Fig. 2.

It was found that January presented the largest amount of energy losses, due to the fact that at that month the total energy consumption was also the highest (excluding December which contains a lot of "abnormal" days during Christmas time and therefore was not selected). This is easily explained by checking the load curves. January was the coldest month of the year and in the area investigated a high penetration of thermal accumulators exists. These accumulators absorb high amounts of electric energy during the night and contribute in a peak demand during these hours, even higher than the midday peak, as their operation is totally simultaneous. During the same month the total energy production from PV units was the lowest, as one would have expected in the middle of winter. On the other hand, as far as June is concerned, high energy production of PV units was observed, almost as high as July or August. At the same time energy consumption was quite low, despite great use of air-conditioning units. As mentioned before, this is because peak demand hours for this feeder are mostly determined by the presence of thermal accumulators. As a conclusion January and June were chosen, as at these months the greatest deviation between consumption and production was observed.

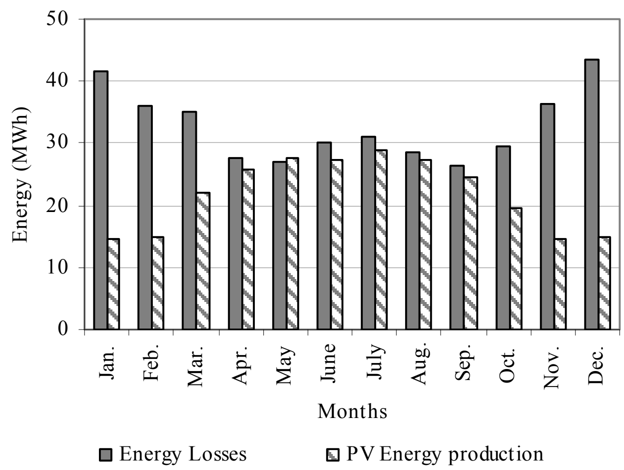

Fig. 2. Energy consumption of the feeder and Energy production from PV units of total installed capacity 200 kW.

It is noted that for all scenarios the total installed capacity of PV units in each DT was equal to DT's rated power. The remaining PV units, until the total installed capacity of PV in the whole feeder was reached, were connected to adjacent DTs in a symmetrical way under the above requirement. The results of these simulations regarding energy loss reduction were compared to the base scenario without any PV units installed.

B. *Second set of simulations*

After conducting the first set of simulations for January and June, some first conclusions were derived. It was decided that the above scenarios should be simulated once more for these two months, but following a different approach concerning the amount of installed capacity connected to each DT. More specific, the practice of connecting PV units in a DT with total installed capacity equal to its rated power was considered somewhat non-realistic. For a better approximation of real conditions, in this second set of simulations the total installed capacity of PV units connected to a DT was at maximum equal to 50% of its rated power. The soundness of this choice was strengthened by the fact that the maximum loading observed from the measured load profiles didn't exceed 55% of the total loading capacity of the feeder. With the above practice, for large penetration scenarios the PV units were allocated in more DTs than before (almost double the number) and this could be clearly seen for 50% penetration level, where the distribution was almost uniform in all nodes. As a result, for this last penetration level all five scenarios tend to degenerate in one.

In this set of simulations, the comparison of energy loss reduction results was not anymore in proportion to the case without any PV penetration. Rather than that, the best case scenario regarding energy loss reduction was used as the base scenario and all the others were compared with it. The above mentioned best case scenario was found to be scenario A for all cases. However, the uniform installation of PV units across the feeder is an ideal scenario and in reality almost impossible to occur.

C. *Third set of simulations*

Finally, in order to have a complete analysis, the exact same simulations with the second set were performed, but for a whole year instead for only two months. The results regarding energy loss reduction were once again presented in proportion to the best case scenario, whose performance is taken as the upper limit.

IV. Results and Discussion

In Table III the results derived from the first set of simulations, for both months January and June, are illustrated. The percentages designate the reduction in energy losses in respect to the base scenario, i.e. the case without any PV units installed. These results verify the aforementioned observation regarding scenario A, i.e. the maximum loss reduction is achieved when PV units are uniformly distributed across the feeder. Furthermore, an important ascertainment arising from these results is that, for scenario D the optimal upper limit for penetration level is 30% for month June. When penetration level reaches 50%, loss reduction is even less than the corresponding one for penetration level of 10%. This is due to the allocation approach of PV units for this scenario across the feeder. Since the first installation point of PV units is the last DT of the feeder, such high penetration level would result converse load flow and thus contribute in increasing losses. This occurs on summer months due to the low load demand joint to high energy production by the PV units. For a better illustration the results of Table III are also presented in Fig. 3 and 4, using bar charts.

TABLE III
RESULTS FOR JANUARY AND JUNE – 1ST SET OF SIMULATIONS

Scenario	Penetration Level									
	10%		*20%*		*30%*		*40%*		*50%*	
	Jan.	June	Jan.	June	Jan.	June	Jan.	June	Jan.	June
A	2.74	5.75	5.00	10.11	6.77	13.10	8.05	14.72	8.84	15.22
B	2.08	3.92	2.51	3.22	4.11	5.78	4.08	3.76	5.19	4.89
C	1.90	3.27	3.23	4.92	4.00	5.08	4.24	3.76	5.14	4.25
D	1.99	3.33	3.22	4.49	4.00	4.44	4.41	3.39	4.68	2.02

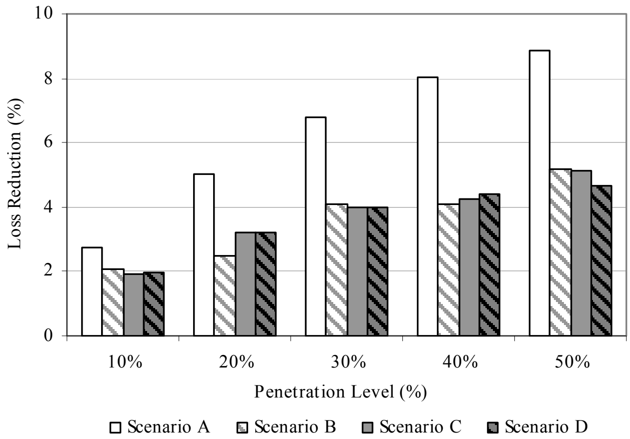

Fig. 3. Loss reduction in comparison to base scenario without PV units. First set of simulations for January 2007.

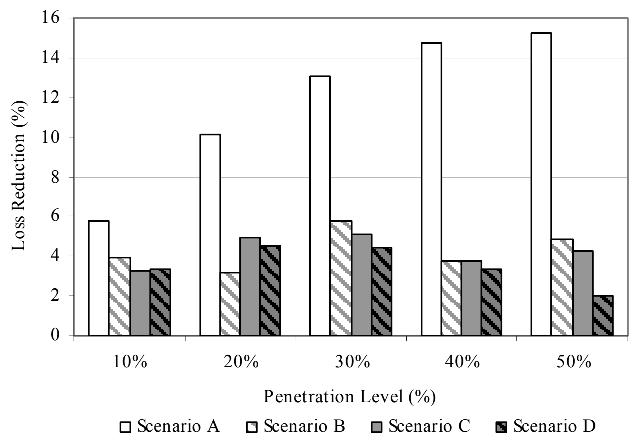

Fig. 4. Loss reduction in comparison to base scenario without PV units. First set of simulations for June 2007.

For the second set of simulations the obtained results are illustrated in Table IV. As mentioned above this set of simulations adopts a different approach regarding the nominal power of PV units that were considered to be installed on every DT. More specific, for a predefined penetration level of PV units across the whole feeder the allocation of these units was implemented in a way that in every DT the installed capacity of PV units never exceeded 50% of its nominal power. As a result, for every penetration level more PV units were considered installed across the feeder. Following this approach, the higher the penetration level, the more uniformly distributed the PV units, and accordingly the larger the loss reduction. Results in Table IV confirm this last expectation when compared to the respective ones in Table III. Especially for scenarios B, C and D the improvement is very significant from penetration level 20% and up. Of course as observed in Table IV when the penetration level reaches 50%, loss reduction is the same for all scenarios. This is justified by the distribution of the PV units to the feeder's DT. For this high penetration level (i.e. almost 6 MW of PV units) regardless the allocation approach of each scenario, PV units are uniformly distributed exactly like scenario A.

In Fig. 5 and 6 scenarios B, C and D are compared to the ideal scenario A for both months. The chart is structured in such way that the nearer a scenario is to ideal scenario A, the larger the percentage would be. Thus, a percentage of 100% would mean that the respective scenario should perform almost identical efficiency, in loss reduction, with scenario A.

As illustrated in these charts, scenario D was found to be the best one after the ideal scenario A. Furthermore, for 50% penetration level, as shown in both figures, all scenarios coincide with scenario A, due to reasons explained in the previous paragraph.

Finally, the analysis was expanded for a period of one year. It has to be mentioned that for this set of simulations the methodology concerning the installation of PV units was similar to the previous one, i.e. the installed capacity of PV units on every DT never exceeded 50% of its nominal capacity. As shown in Table V, the difference loss reduction for scenario A between penetration levels 30% and 50% is almost equal to 1.5%. In turn, this has the meaning that an additional installation of almost 1.5 MW of PV units, in regard to penetration level of 30%, would result in a reduction of merely 5.9 MWh in yearly energy losses. Counting in the increased installation cost for PV units it is becoming obvious that for the specific feeder penetration level above 30% presents disproportional benefits in regard to investment cost. Finally, for penetration level of 50% loss reduction for all the examined scenarios is similar, as explained previously for this high penetration level. Fig. 7 presents a comparison of scenarios B, C, and D to the ideal scenario A.

TABLE IV
RESULTS FOR JANUARY AND JUNE – 2ND SET OF SIMULATIONS

Scenario	Penetration Level									
	10%		*20%*		*30%*		*40%*		*50%*	
	Jan.	June	Jan.	June	Jan.	June	Jan.	June	Jan.	June
A	2.74	5.75	5.00	10.11	6.75	13.18	8.04	14.89	8.89	15.32
B	2.43	4.91	4.41	8.49	6.08	11.24	7.56	13.42	8.89	15.32
C	2.41	4.74	4.50	8.58	6.20	11.41	7.70	13.65	8.89	15.32
D	2.60	5.08	4.71	8.90	6.37	11.57	7.76	13.64	8.89	15.32

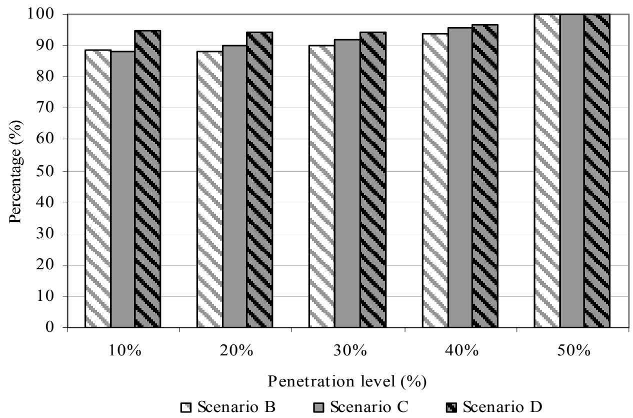

Fig. 5. Percentage of loss reduction in comparison to loss reduction from ideal scenario A. Second set of simulations for January 2007.

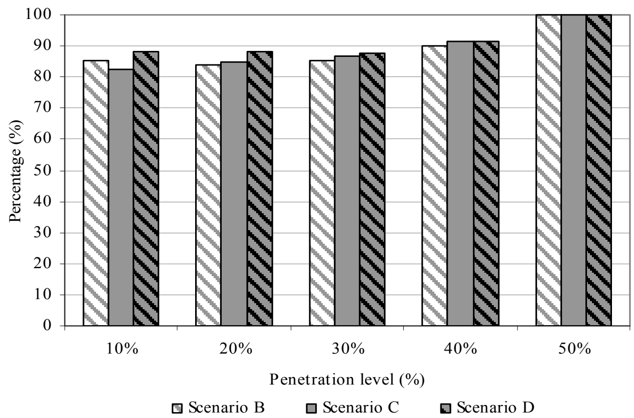

Fig. 6. Percentage of loss reduction in comparison to loss reduction from ideal scenario A. Second set of simulations for June 2007.

V. CONCLUSION

In the present work the impact of DG penetration in power networks regarding loss reduction was investigated. Amongst the available technologies for DG units, the one used in this paper was PV. Optimal placement of PV units is becoming a very complex issue, due to the nature of their operation status. Power output of such units fully depends on weather conditions and in turn lack of constant power production modifies the traditional approaches for optimal placement of such DG units in distribution feeders. Therefore, in this work various scenarios regarding the allocation of PV units and the penetration level in a distribution feeder were fully examined. The analysis was based on software simulations, using real data concerning loading conditions of the feeder for a period of one year. On the other hand estimation for PV power production was also based on real data regarding air temperature and sun irradiance.

TABLE V
RESULTS FOR ONE YEAR – 3RD SET OF SIMULATIONS

	Penetration Level				
Scenario	*10%*	*20%*	*30%*	*40%*	*50%*
A	4.12	7.24	9.44	10.65	10.95
B	3.51	6.08	8.04	9.60	10.95
C	3.38	6.13	8.16	9.75	10.95
D	3.64	6.37	8.28	9.75	10.95

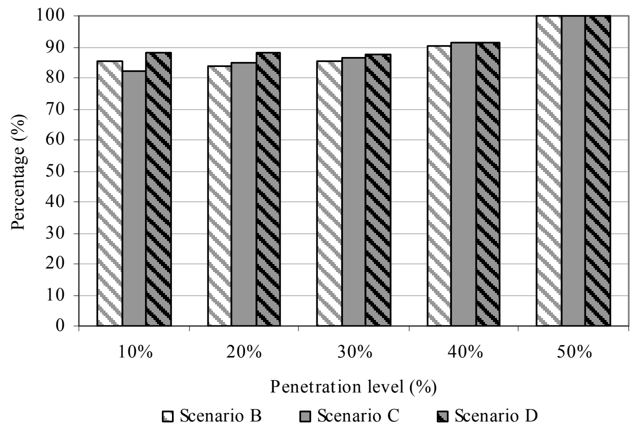

Fig. 7. Percentage of loss reduction in comparison to loss reduction from ideal scenario A. Third set of simulations for a whole year.

The obtained results showed that, even with a low penetration level of PV units, i.e. 10% of feeder's capacity, loss reduction as high as 3.4% can be achieved, regardless the allocation approach. Moreover, when penetration level reaches 20%, loss reduction can even be doubled. Finally, the analysis showed that, for the specific examined feeder a realistic and efficient upper limit for penetration could be considered the one of 30%, since higher penetration levels present disproportional improvement on loss reduction to the increase of the installed capacity of PV units.

Although PV technology, as means of DG, is not the best solution to deal with loss reduction problem on distribution networks, installation of PV units is becoming a reality due to environmental issues, and in near future a large number of such units is expected to penetrate the EPS. This work estimates the benefits, concerning loss reduction, that would arise after the installation of PV units in distribution feeders and could constitute a guideline for the way engineers decide the siting and sizing of PV units.

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VII. BIOGRAPHIES

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