Chapter 5

Allocation of Distributed Generation for Maximum Reduction of Energy Losses in Distribution Systems

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Additional information is available at the end of the chapter

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Abstract

The analysis of actual distribution systems with penetration of distributed generation requires powerful tools with capabilities that until very recently were not available in distribution software tools; for instance, probabilistic and time mode simulations. This chapter presents the application of parallel computing to the allocation of distributed generation for maximum reduction of energy losses in distribution system when the system is evaluated during a given period (e.g., the target is to minimize energy losses for periods equal or longer than 1 year). The simulations have been carried out using OpenDSS, a freely available software tool for distribution system studies, when it is driven as a COM DLL from MATLAB using a multicore installation. The chapter details a MATLAB–OpenDSS procedure for allocation of photovoltaic (PV) generation in distribution systems using a parallel Monte Carlo approach and assuming that loads are voltage-dependent. The main goals are to check the viability of a Monte Carlo method in some studies for which parallel computing can be advantageously applied and propose a simple procedure for minimization of energy losses in distribution systems.

Keywords: distribution system, distributed generation, long-term evaluation, loss minimization, Monte Carlo method, parallel computing

1. Introduction

Distributed generation (DG) can provide backup power, support voltage, reduce losses, improve local power quality and reliability, provide ancillary services, and defer distribution system upgrade [1–3]. Modeling of renewable generation raises several challenges, since capabilities for representing intermittent generators, voltage-control equipment, or multi-phase unbalanced systems are required. In addition, studies of systems with intermittent nondispatchable resources must be based on a probabilistic approach and calculations performed over time periods that may range from minutes to years. Voltage-dependent load models with random variation can also be needed. These issues complicate the study of power distribution systems since software tools have to combine new analysis capabilities with a high number of models for representing various generation technologies, besides the conventional distribution system components, and include capabilities for time mode calculations [4].

One potential application of a power flow simulator is the optimum allocation of distributed generation. This study can be seen from two different perspectives:

- From the independent producer's point of view, the goal is to optimize the benefit. Although the utility will usually impose some constraints to the generation units to be connected to its system (e.g., a maximum rated power), it can be assumed by default that the units can be connected to any node of the system. Therefore, the optimization approach will be in general a feasibility study whose main goal is to check the viability of the installation, select the most economical size (irrespective of the location), and in case of dispatchable units, the control strategy that will maximize the benefit; see for instance [5, 6].

- From the utility's point of view, the goal is to maximize the positive impact of distributed generation (e.g., voltage support, energy losses, investment deferring) and minimize or avoid those aspects that can negatively affect the system performance (e.g., miscoordination of protective devices, overvoltages during low load periods); see for instance [7].

This chapter presents a procedure for estimating the size and location of photovoltaic (PV) generators whose connection to the distribution system will minimize system losses.

The following aspects have to be accounted for:

- Given the intermittent and random nature of PV generation, the variable to be minimized is the energy loss, not the power loss. Since power demand and generation are not coincident, the optimum allocation of distributed generators with the goal of minimizing power losses is meaningless.

- The optimum allocation of distributed generators must be carried out taking into account some constraints, namely, thermal limits of distribution system components and the maximum voltage that can be accepted in the system under study.

- In a deregulated market in which independent producers connect their generation units to the distribution system without considering their impact on energy losses, the connection of generation units will usually be random and not be made with the target assumed in this chapter. In other words, assuming that either utilities or independent producers will select sizes and locations of generators with the maximum reduction of energy losses in mind is not realistic. Therefore, the goal of this study is the theoretical estimation of the maximum energy loss reduction that can be achieved with the connection of PV generators.

- Since the goal is to maximize energy loss reduction, two other aspects, in addition to sizes and locations of generators, have to be considered: the period during which energy losses must be minimized and the time at which every PV generator must be connected to the distribution system.

Several strategies have been proposed to optimally allocate DG; for instance, loss minimization [8], system update minimization [9], risk minimization [10], or DG capability minimization [11]. A significant activity has been dedicated to this purpose during the last decade; for a summary of the works related to optimum allocation of DG, see references [12] and [13].

Although some works have been made in this field using probabilistic methods [14, 15], not much has been done with a full model of the distribution system (e.g., a multiphase model including load and generation). A Monte Carlo method is a natural approach when uncertainties are involved and some variables are random/intermittent. However, the application of a pure Monte Carlo method can be time consuming if many DG units have to be allocated in large distribution systems. Multicore computers and software that take advantage of their capabilities can be used to significantly reduce the computation time.

This chapter presents a procedure based on a parallel Monte Carlo method for estimating the size and location of PV generators that can minimize distribution energy losses during a period of time, assuming voltage-dependent loads.

Two evaluations are considered in this chapter:

1. Short-term evaluation: The size and location of generators are estimated in order to minimize distribution energy losses during 1 year. If more than one generator is to be connected, then all generators are simultaneously connected at the beginning of the year.
2. Long-term evaluation: The size and location of generators are estimated in order to minimize distribution system losses during a period longer than 1 year. In this chapter, the evaluation period will be 10 years; up to six generators will be connected, and their connection will be sequential (i.e., one generator will be connected at the beginning of consecutive years during the first 6 years).

Section 2 presents the test system studied in this chapter. The procedure developed for short-term evaluation (i.e., minimization of energy losses during 1 year) is detailed in Section 3. The section includes a description of the Monte Carlo approach, its implementation for a multicore environment, and the results obtained when up to four PV generators are allocated. The section also proposes a refinement of the Monte Carlo method aimed at reducing the number of runs and therefore the computing time. Section 4 details the procedure developed for long-term evaluation (i.e., minimization of energy losses during 10 years) when up to six PV generators are to be sequentially connected. A simplified method for energy loss minimization will be presented in Section 5. Finally, a summary of the main conclusions derived from results presented in this chapter and other works by the authors is presented in Section 6.

2. Test system

Figure 1 shows the diagram of the test system. It is a three-phase 60-Hz single-feeder distribution system with a distributed load. The model includes the substation transformer and a simplified representation of the high-voltage system. The system tested is a 500-node radial configuration feeder with the following characteristics:

- Total feeder length: 30,000 ft.
- Number of nodes: 500 (i.e., section length = 60 ft).
- Node load = 9 kW, pf = 0.9 (lg) (i.e., total load = 4500 kW).

The phase conductors of the line are in a flat configuration, and the normal thermal limit is 400 A, with an emergency limit of 600 A.

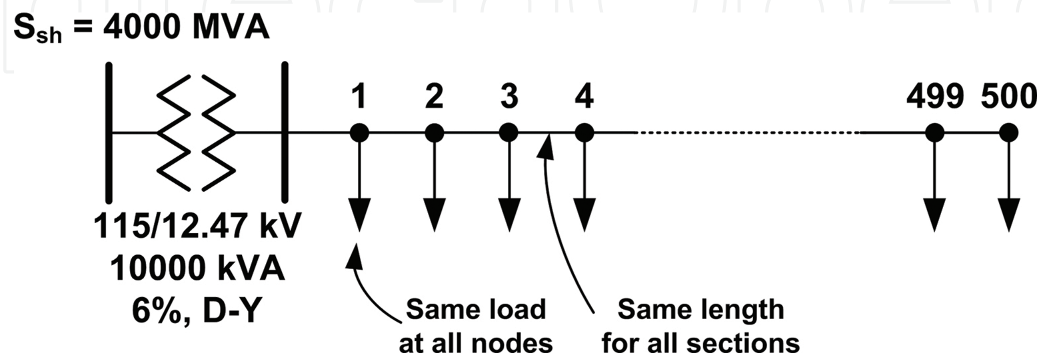

Figure 1. Test system configuration and data.

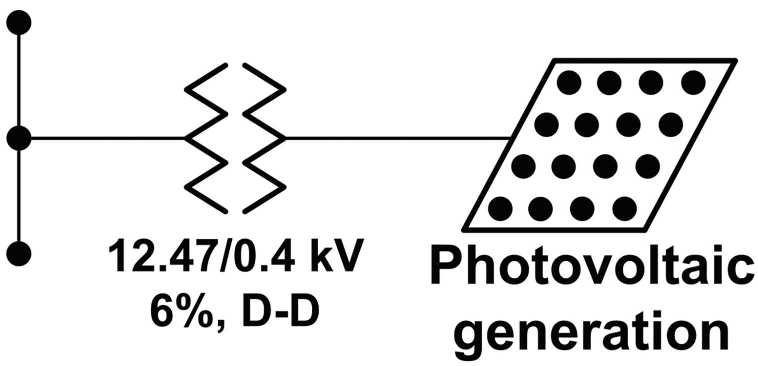

Figure 2. Configuration of a PV generator.

The studies have been carried out with the PV generator model presented in [16]. For the current study, a PV generator is connected to the system through a step-up interconnection transformer (see **Figure 2**). The rated power of the interconnection transformer is chosen once the rated power of the PV generator/plant has been selected; it is rounded in steps of 50 kVA, and, by default, the short-circuit impedance is 6%. The *X*/*R* ratio is 6.

Table 1 summarizes the information used to obtain PV generation curves. The implemented procedure will be used for obtaining the allocation of PV generators when considering that the shape of each node load is different (although the patterns will exhibit some similarities during the day hours and the week days), the generators only inject active power, and their generation patterns are the same. All node load profiles and PV generation curves have been created using the algorithms presented in [17].

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Average monthly clearness index	0.41, 0.43, 0.44, 0.47, 0.45, 0.5, 0.51, 0.5, 0.51, 0.5, 0.42, 0.4
Panel's slope angle	35°
Normal operating cell temperature	45°C
Average monthly daily minimum temperatures (°C)	-5.92, -3.9, -0.21, 5.09, 9.89, 14.9, 17.1, 16.6, 12.6, 6.95, 1.97, -3.76
Average monthly daily maximum temperatures (°C)	2.58, 5.5, 11.1, 18.9, 25.1, 29.9, 31.6, 30.7, 26.7, 19.8, 11.2, 4.13

Table 1. Summary of solar resources.

Figure 3 provides an example of curve shapes for representing load and PV generation derived from the procedures developed by the authors for a given period of the year. The two curves are depicted with a different scale for active power values.

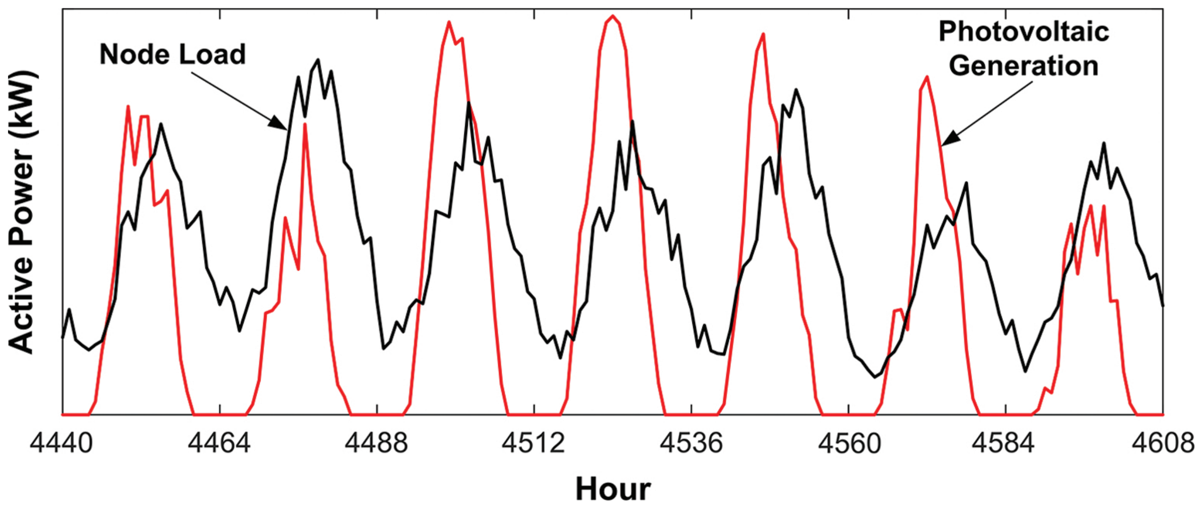

Figure 3. Curve shapes for node loads and PV generation.

The radial feeder configuration has been chosen because the solution to this problem is well known when the load is constant, voltage independent, and uniformly distributed. The optimum allocation of capacitor banks in a distribution feeder with uniformly distributed load has been thoroughly analyzed [18]. The analysis is similar when the goal is to minimize losses by installing generation units that only inject active power [8]. This system configuration can be useful for validating test cases whose results are obtained by means of a Monte Carlo method [19].

3. Maximum reduction of energy losses—short-term evaluation

3.1. Introduction

This section presents the application of a Monte Carlo method to the estimation of the size and location of the PV generators that will minimize energy losses in distribution systems during

1 year without including substation losses. The section details the method, its implementation in a MATLAB–OpenDSS environment, and its application to the test system presented above using single-core and multicore computations. Later, a refinement of the Monte Carlo for multicore computation aimed at decreasing the computing time is proposed.

3.2. Application of the Monte Carlo method

A 1-year evaluation period has been considered for short-term evaluation. The study is carried out assuming that generation units will be simultaneously connected at the beginning of the evaluation period, taking into account some operational constraints (e.g., there are a thermal limit for each system line section and a maximum voltage that should not be exceeded).

Input data for the present study includes system parameters and time variation of loads and generations. Random variables to be generated during the application of the Monte Carlo method are locations and sizes of the generation units. This latter aspect can be rigorously made by considering that the generation pattern depends on the area/node where the generator is located. In this chapter, generation units are PV arrays that only inject active power into the system. It is also assumed that the solar radiation is the same for each generator.

The procedure has been implemented taking into account certain rules when choosing locations and sizes for the generators. The rules as well as the general procedure used in this work for short-term (1 year) evaluations are detailed below [20]:

1. PV generators can be connected to any system node. The locations to which generators will be connected are determined by generating as many uniformly distributed random values as units to be allocated.
2. Once the locations are known, the rated power values are determined. Beforehand, the user has to fix the maximum generation power that can be connected to system nodes taking into account some constraints (e.g., the maximum thermal limit of feeder sections). Remember that all line sections are equal in the test system. This step is carried out as follows:
   - When only one generator is to be allocated, the maximum rated power is determined according to the following steps: (i) calculate the maximum noncoincident active power (i.e., the active power value that results from adding the active rated power of all load nodes); (ii) check the maximum power that can be carried by the feeder sections; (iii) compare the previous power values and choose the minimum one; this will be the maximum rated power a generation unit can be assigned during the Monte Carlo execution. Then generate a random number uniformly distributed between 0 and 1, and multiple it by the above value.
   - When two or more units are to be installed, the following changes are introduced in the procedure:
     - Generate an independent uniformly distributed random value for the initial rated power of each generation unit using the maximum rated power fixed for every node as the upper end point of each uniform distribution.

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- Compare the maximum rated powers for all the chosen locations and choose the maximum value, P_{DG_MAX}.
- Generate the penetration factor as a uniformly distributed random number between 0 and 1. Multiply the maximum value found in the previous step by this penetration factor; the result will be the overall rated power of distributed generators.

$$\sum_{i=1}^{NG} P_{DG\_i} = pf \cdot P_{DG\_MAX} \tag{1}$$

where NG is the number of generation units under evaluation, P_{DG_i} is the rated power of unit i, pf is the penetration factor, and P_{DG_MAX} is the maximum DG-rated power found in the previous step.

- Calculate the scale factor, sf, from the initial rated powers as follows:

$$sf = \frac{pf \cdot P_{DG\_MAX}}{\sum_{i=1}^{NG} P_{DGinit\_i}} \tag{2}$$

where P_{DGinit_i} is the initial rated power for unit i.

- Obtain generator-rated powers by scaling initial rated powers:

$$P_{DG\_i} = sf \cdot P_{DGI\_i} \tag{3}$$

Note that the order in which random values for locations and rated powers are generated matters: first, the location nodes; afterwards, the rated powers.

3. Perform the load flow calculation. Neglect a case if one of the following conditions is satisfied: (i) the voltage at one node exceeds the fixed maximum value; (ii) the current through one or more system sections is above the thermal limit.
4. Stop the procedure when the specified number of runs or samples (according to the terminology of the Monte Carlo method) is reached.

The combination of rated powers and locations that produces the minimum energy losses and meets the technical constraints will be selected as the solution. The number of executed runs must be large enough to ensure that the estimated solution is near enough to the global minimum. In this work, it is assumed the method has converged when the variations of the estimated minimum of system energy losses are within a margin of 1%.

3.3. Implementation of the procedure

The procedure has been implemented in OpenDSS, a simulation tool for electric utility distribution systems, which can be used as both a stand-alone executable program and a COM

DLL that can be driven from some software platforms [21]. In this study, the program is driven from MATLAB, which is used to calculate the random variables and control the execution of the procedure. The implementation of the procedure, when using parallel computing, is schematized in **Figure 4**, and is valid for any number of cores. MATLAB capabilities are used to distribute Monte Carlo runs between cores.

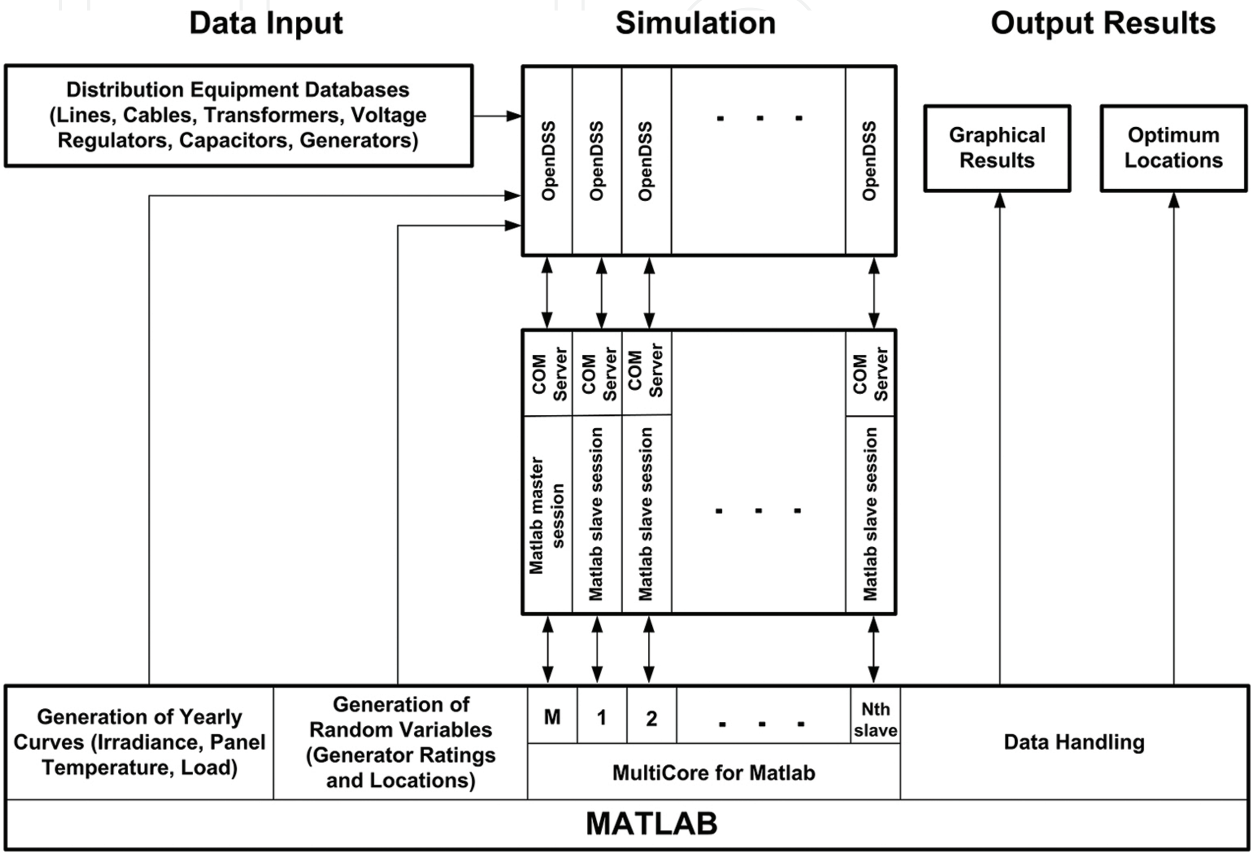

Figure 4. Block diagram of the implemented procedure.

The implementation of the procedure for any number of cores is based on the library of MATLAB modules developed by Buehren [22]. Load and intermittent solar generation curves were generated by means of the algorithms detailed in [17].

3.4. Simulation results using single-core computing

Table 2 summarizes the operating conditions in the system before any generation unit is connected. Three different models are used to represent loads (constant power model, constant impedance model, and ZIP model). The ZIP load model is defined as a combination of constant power, constant current, and constant impedance load models [23]. When this model is used, weighting factors are assigned to specify active and reactive powers for each of these three components, being the sum of the weighting factors equal to unity for both active and reactive powers. For the present study, each load component has been assigned a weighting factor equal to 1/3 for both active and reactive powers; this means that 1/3 of the load behaves respectively as a constant power, constant current, and constant impedance load. For more details about component fractions and power factors of common actual loads, see [23]. The minimum voltage value in this system during the year of study is 0.9561 p.u. and occurs with the constant power load model.

	Constant power load model	Constant impedance load model	ZIP load model
Energy from substation (kWh)	16,914,396.5	16,503,855.3	16,702,520.9
Energy losses (kWh)	161,732.4	151,198.0	156,245.2
Energy losses (%)	0.9561	0.9161	0.9354

Table 2. Short-term evaluation (1 year)—operating conditions without PV generation.

Table 3 summarizes the results obtained after applying the procedure with different number of runs when allocating one, two, and four PV generators. The results presented in **Table 3** were obtained by assuming a constant power load model. The maximum accepted voltage in the feeder for this and any other study presented here is 1.05 p.u. These results clearly prove that the number of runs has to be increased with the number of PV generators to be allocated. The results presented in **Table 3** show clear tendencies for one and two generation units; they indicate that the number of executed runs is enough for these two cases. However, the values obtained for four units present important variations from one execution to another; this is an indication that more runs are necessary to identify the correct values or tendencies for locations and rated powers, although energy losses are within the desired margin (i.e., 1%). **Figure 5** depicts the results corresponding to the allocation of one generation unit after 5040 runs. This figure illustrates the way in which minimum energy losses can be estimated.

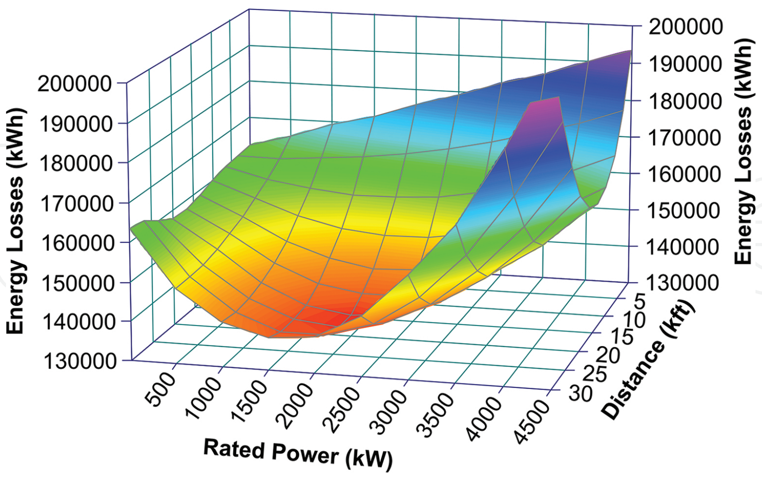

Figure 5. Optimum allocation of a single PV generator—5040 runs.

The complete results with the three load models are shown in **Table 4**. A behavior similar to that obtained with the previous study can be identified: the results for one and two generation units show clear tendencies, but when allocating four units, the results are not conclusive and might require a higher number of runs. These results prove again that the number of runs has to be increased with the number of generation units to be allocated. The differences between energy loss values obtained with different numbers of runs are very small in all studies (always within the 1% margin); therefore, it can be expected that the global minimum will not present a significant variation with respect to the values found here. It has been discussed that more runs are required to establish a well-defined tendency for more than two generation units; however, one must consider if the increment in computational time is justified when assessing the improvement in energy losses obtained with a larger number of runs.

One PV generator				
Runs		2520	5040	10,080
Unit 1	Node	381	376	383
	Power (kW)	1954.7	2005.2	1956.4
Energy losses (kWh)		134948.4	134995.5	134964.8
Energy losses (%)		0.7991	0.7994	0.7992
Two PV generators				
Runs		20,040	30,000	40,080
Unit 1	Node	279	284	290
	Power (kW)	1097.4	1192.8	970.7
Unit 2	Node	437	426	426
	Power (kW)	1093.3	1003.1	1186.7
Energy losses (kWh)		133532.0	133607.0	133571.8
Energy losses (%)		0.7908	0.7912	0.7910
Four PV generators				
Runs		40,080	60,000	80,040
Unit 1	Node	328	229	220
	Power (kW)	869.0	518.1	455.4
Unit 2	Node	329	353	307
	Power (kW)	186.1	548.7	796.8
Unit 3	Node	336	387	428
	Power (kW)	230.0	701.2	683.7
Unit 4	Node (kW)	449	490	448
	Power (kW)	823.3	414.0	411.7
Energy losses (kWh)		132991.7	132927.7	132873.3
Energy losses (%)		0.7876	0.7872	0.7869

Table 3. Short-term evaluation (1 year)—allocation of PV generators (constant power load model).

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Scenario		Constant power load model	Constant impedance load model	ZIP load model
One PV generator (5040 runs)	Node	376	376	385
	Rated power (kW)	2005.2	1868.8	1913.3
	Energy losses (kWh)	134995.5	127772.1	131247.9
Two PV generators (40080 runs)	Nodes	290–426	309–420	269–425
	Rated powers (kW)	970.7–1186.7	1230.7–828.5	915.0–1189.7
	Energy losses (kWh)	133571.8	126547.9	129919.6
Four PV generators (80040 runs)	Nodes	220–307 428–448	277–338 435–471	308–379 432–448
	Rated powers (kW)	455.4–796.8 683.7–411.7	422.6–957.3 339.2–418.5	645.6–548.8 376.0–369.9
	Energy losses (kWh)	132873.3	125827.0	129231.6

Table 4. Short-term evaluation (1 year)—comparison of simulation results.

Some interesting conclusions are derived from the comparison of these results with those obtained in Ref. [19]. Although the test system and load are the same in both studies, there are some differences in sizes and locations of the PV generators to be allocated; for instance, the difference between the sizes of the generators obtained in both studies when only one unit has to be allocated is about 25%.

There are several reasons for these differences:

- The target in [19] included the energy losses in the substation transformer, while the target in this chapter is to minimize energy losses in the feeder, without including substation losses. This is obviously an important reason to obtain smaller size values in the current study.
- The model used to represent PV generation is different in both studies. Reference [19] was based on a basic generator model represented only by the active and reactive powers it injects into the grid, while the current study is based on a more detailed custom-made PV generator model that is an expanded version on that available in OpenDSS [16]. Take into account that the new PV generator model includes the interconnection transformer, in which some losses are always caused.
- The results obtained in [19] were derived by means of curve shapes obtained from HOMER [5], while the results presented here are based on algorithms developed for OpenDSS application [17]. Although PV generation curves obtained with HOMER and with the MATLAB application developed by the authors are very similar, the solar resources (i.e., information like that in **Table 2**) are different in both studies. In addition, discrepancies are significant in the load curves. The load curve shapes obtained with the algorithm presented in [17] were derived from actual measurements that could be considered as representative of some types of loads (e.g., residential, commercial).

Somehow, this discussion supports important conclusions: the results are very much dependent on the component models, and the allocation of generation units must be based on the minimization of energy losses, not on power losses. The results can be different even when load ratings are equal and if the load shapes are different (e.g., same ratings but different time variation).

3.5. Simulation results using multi-core computing

A very important aspect to consider is the reduction of time that can be achieved when using a multicore installation. **Table 5** provides the computing times that are required for simulating the test system when only one unit has to be allocated, as well as the corresponding energy losses, using single-core and multicore computations. As expected, the achieved reduction of simulation time is significant and almost proportional to the number of cores.

Scenario	Load model	Single core	60 cores
One PV generator (5040 runs)	Constant power load model	134978.0 (kWh) 36.46 (h)	134995.5 (kWh) 0.92 (h)
	Constant impedance load model	127806.0 (kWh) 35.46 (h)	127772.1 (kWh) 0.86 (h)
	ZIP load model	131270.8 (kWh) 43.66 (h)	131247.9 (kWh) 1.00 (h)

Table 5. Simulation results using single-core and multicore computing.

3.6. Refinement of the Monte Carlo method

Figure 6 illustrates the way in which the Monte Carlo method can be applied to this particular study when only one generation unit has to be connected [19]. Every cross within the square is a combination of the two random numbers that are generated for each run: the distance with respect to the origin of the feeder at which the generation unit is to be connected, and the corresponding rated power. Remember that the result of concern for the present study is the energy loss obtained with each combination of values.

According to the results presented in **Figure 5** and **Table 4**, not much difference between energy loss values should be expected when the combination of the two random values gives a point that is closely located to a previously simulated point that is not far from the minimum. Therefore, during the generation of random values, these cases do not need to be simulated; so, the number of runs can be significantly reduced. The goal now is to check how much accuracy is lost and how much reduction of time is achieved by neglecting some runs. The approach is similar when more than one generation unit has to be connected. In such a case, all combinations located within a Euclidean distance equal or shorter than R are discarded.

Once some runs have been already computed and simulated, the combination of random values corresponding to run k is not simulated when the following condition is fulfilled:

$$\sqrt{x_{ij-ik}^2 + p_{ij-ik}^2} \leq R \tag{4}$$

where $x_{ij\text{-}ik}$ is the distance in percent between the location of the unit i corresponding to j runs (previously simulated) and unit k, and $p_{ij\text{-}ik}$ is the distance in percent between the rated powers of the unit i corresponding to j runs and unit k. R in this work will be 5%.

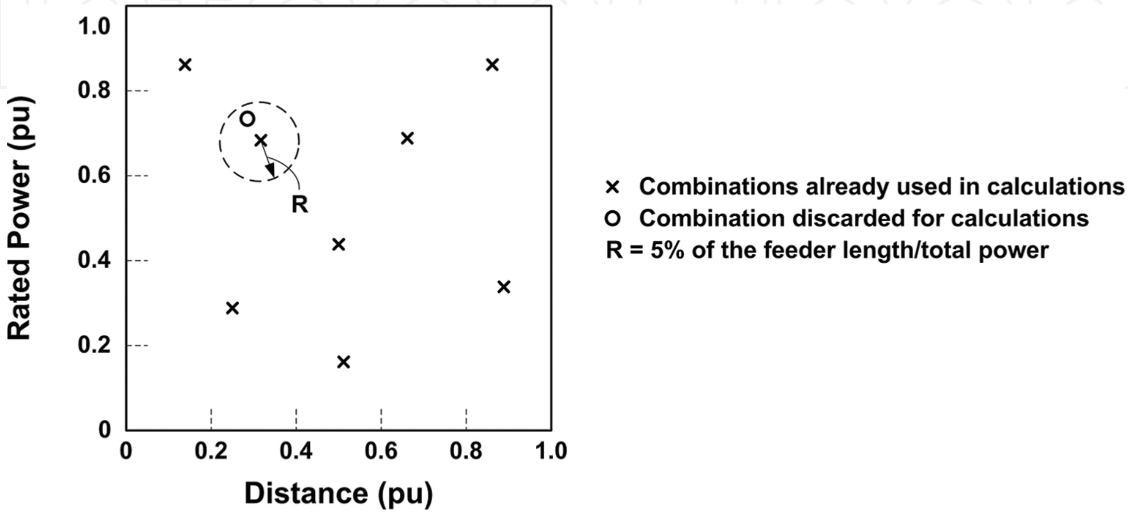

Figure 6. Generation of random values for energy loss minimization—one generation unit.

When more than one unit is being allocated, the calculation of the minimum Euclidean distance between the combinations of random values corresponding to two different runs is not obvious, since the order in which generation units are numbered does not have to be same when comparing two different runs. In addition, expression (4) has to be checked with respect to any previous combination, which can be time-consuming. A solution to this problem was proposed in [19].

Table 6 shows a summary of results obtained for the test system after applying the new approach. All the results shown in the table were obtained with a 60-core installation. The table compares results obtained by means of the conventional Monte Carlo method and the new approach. According to these results, a significant reduction in computing time can be achieved; as expected, the accuracy decreases as the number of generators increases.

Although some differences between location and power values between the two approaches are very significant, the energy losses obtained when applying the new method are basically the same as that were obtained with the original method. These differences can be justified by looking at the energy losses obtained when a single generation unit is to be allocated (see **Figure 5**). The surface shown in the figure is very smooth around the minimum, so the difference between energy losses even for nonsmall deviations with respect to the minimum will not be very significant. Note also that the ratio between simulation times with both methods is about 15 when one unit has to be allocated and about 2 when the number of units is four.

Number of generators	Scenario		Conventional method	Refined method
One PV generator (5040 runs)	Constant power load model	Node	376	375
		Rated powers (kW)	2005.2	1894.5
		Energy losses (kWh)	134995.5	135221.4
		Simulation time (h)	0.92	0.06
	Constant impedance load model	Node	376	376
		Rated powers (kW)	1868.8	1757.4
		Energy losses (kWh)	127772.1	128051.3
		Simulation time (h)	0.86	0.06
	ZIP load model	Node	385	385
		Rated powers (kW)	1913.3	1836.5
		Energy losses (kWh)	131247.9	131377.2
		Simulation time (h)	1.00	0.07
Two PV generators (40080 runs)	Constant power load model	Nodes	290/426	308/427
		Rated powers (kW)	970.7/1186.7	1187.2/959.1
		Energy losses (kWh)	133571.8	133515.0
		Simulation time (h)	7.21	1.80
	Constant impedance load model	Nodes	309/420	285/427
		Rated powers (kW)	1230.7/828.5	1110.2/1055.7
		Energy losses (kWh)	126547.9	126612.8
		Simulation time (h)	7.11	1.73
	ZIP load model	Nodes	269/425	302/447
		Rated powers (kW)	915.0/1189.7	961.6/956.5
		Energy losses (kWh)	129919.6	129958.8
		Simulation time (h)	8.09	2.00
Four PV generators (80040 runs)	Constant power load model	Nodes	220/307 428/448	279/353 390/466
		Rated powers (kW)	455.4/796.8 683.7/411.7	546.6/412.5 642.1/487.7
		Energy losses (kWh)	132873.3	132813.0
		Simulation time (h)	14.50	7.07
	Constant impedance load model	Nodes	277/338 435/471	271/337 369/474
		Rated powers (kW)	422.6/957.3 339.2/418.5	863.9/227.9 658.6/456.2

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Number of generators	Scenario		Conventional method	Refined method
		Energy losses (kWh)	125827.0	125773.2
		Simulation time (h)	14.03	6.84
	ZIP load model	Nodes	308/379 432/448	255/300 354/445
		Rated powers (kW)	645.6/548.8 376.0/369.9	426.4/819.4 91.7/835.5
		Energy losses (kWh)	129231.6	129339.1
		Simulation time (h)	16.15	7.91

Table 6. Simulation results using a refined Monte Carlo method.

4. Maximum reduction of energy losses—long-term evaluation

This section presents the results derived from a long-term study aimed at estimating the size and location of PV generators when the target is to minimize the energy losses and the generators are sequentially connected.

Figure 7 shows the variation assumed for the total load during the evaluation period. A different variation for each node load and even negative variations have been assumed. **Table 7** shows the year of connection for each PV generator.

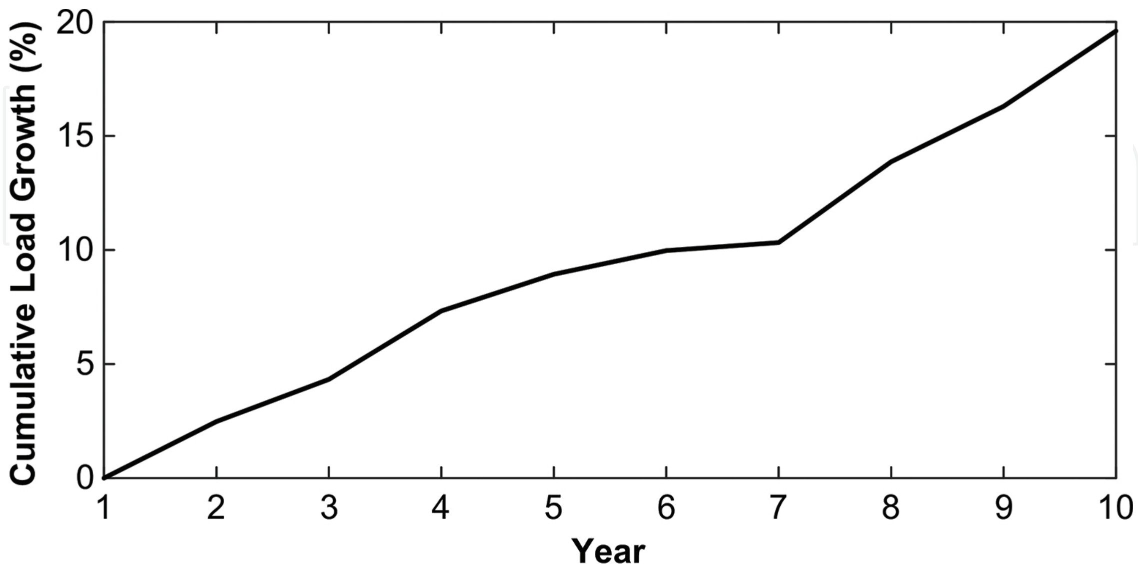

Figure 7. Long-term evaluation—load growth.

PV generator	Year									
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Unit 1	•	X	X	X	X	–	–	–	–	–
Unit 2		•	X	X	X	X	–	–	–	–
Unit 3			•	X	X	X	X	–	–	–
Unit 4				•	X	X	X	X	–	–
Unit 5					•	X	X	X	X	–
Unit 6						•	X	X	X	X

•, Year of connection; X, considered for optimization; -, not considered for optimization.

Table 7. Scenario for long-term evaluation.

The main aspects of the study are summarized below:

- Up to six PV generators will be connected to the test system.
- The optimization period every time a PV unit is added to the system is 5 years. That is, the target upon which the locations and rated powers of the units are selected is the minimization of energy losses during 10 years, taking into account that every unit is connected at the beginning of a year, and its size and location are selected to minimize energy losses during 5 years. According to this, if a unit is connected at the beginning of year 3, the energy losses to be accounted for are those caused from the beginning of year 3 till the end of year 7 (see **Table 7**).

The energy losses that correspond to the entire period of evaluation (i.e., 10 years) without PV generation and considering the three types of load models are as follows:

- Constant power load model: 1,950,262.8 kWh.
- Constant impedance load model: 1,803,067.9 kWh.
- ZIP load model: 1,873,210.8 kWh.

The minimum voltage value during this period is 0.9423 p.u., and occurs again when loads are represented by the constant power model.

Table 8 shows the results obtained upon the application of both the conventional Monte Carlo and the refined methods during the period of evaluation (e.g., 10 years). The number of runs to be used every year a PV generator is connected is based on the experience obtained with the previous study. As shown in **Table 6**, when one generator is to be connected, 5040 runs will usually suffice. **Table 9** summarizes the main results corresponding to each load model. The value of *R* when the refined method is applied is again 5%. Remember that substation losses are not included.

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PV generator		Constant power load model	Constant impedance load model	ZIP load model
		Conventional–Refined method	Conventional–Refined method	Conventional–Refined method
Unit 1	Node	384–367	368–383	378–381
	Rated power (kW)	2091.0–2183.6	2047.5–2116.1	2000.0–1937.6
Unit 2	Node	235–499	234–242	236–249
	Rated power (kW)	325.3–188.5	322.1–232.6	455.1–344.6
Unit 3	Node	217–256	499–178	488–229
	Rated power (kW)	137.5–189.5	94.8–50.9	97.7–138.4
Unit 4	Node	270–170	191–269	212–198
	Rated power (kW)	139.1–47.3	91.0–106.1	92.2–100.1
Unit 5	Node	262–234	494–349	197–480
	Rated power (kW)	92.3–51.4	92.4–49.0	92.5–50.7
Unit 6	Node	213–209	231–219	475–456
	Rated power (kW)	92.5–111.8	93.0–142.8	91.0–143.0
Energy losses (kWh)		1590646–1593987	1493209–1497960	1538789–1540441
Simulation time (h)		28.31–0.99	26.32–0.96	29.98–1.15

Table 8. Long-term evaluation—comparison of simulation results.

Load model	Total generation (kW) (Conventional–Refined)	Cumulative energy loss reduction (%) (Conventional–Refined)
Constant power	2878.0–2772.4	18.439–18.268
Constant impedance	2741.0–2697.8	17.185–16.921
ZIP	2828.8–2714.6	17.852–17.764

Table 9. Long-term evaluation—total generation and energy loss reduction.

The maximum coincident active power measured at the substation terminals for each load model during the period of study is as follows: (1) constant power model = 4021.5 kW, (2) constant impedance model = 3753.5 kW; (3) ZIP model = 3879.7 kW. After connecting six generation units, the total rated power of all PV generators is less than 75% of the maximum coincident power of the system at the end of the period.

From the results presented in **Table 8**, one can observe that the maximum rated power of a generation unit is below 2500 kW with all load models. This maximum can be accepted according to the interconnection policies adopted by many utilities. However, it can exceed the limit adopted by other utilities (see for instance [24]); in such a case, the procedure should be modified to include that limit in calculations.

To understand these results, it is important to keep in mind that once one unit has been allocated, the location and the rated power of the subsequent units are selected by discarding the nodes to which units previously allocated were connected and taking into account the maximum rated power that results after subtracting the rated power of the allocated generators from the total feeder power.

Figure 8 shows the rated power of the generation units to be connected every year and the cumulative reduction of energy losses, not the yearly reduction, derived from the conventional Monte Carlo method. As expected, the larger values of the rated powers correspond to the first units to be allocated, that is, the rated powers of the unit to be connected at the beginning of year 1 are larger than the rated powers of any unit to be connected in subsequent years, regardless of the load model. However, due to the yearly variation of loads, the rated power of the new PV generator will not be always smaller than any other PV generator in operation, because the energy losses to be compensated for a certain 5-year term could be larger than for a previous term.

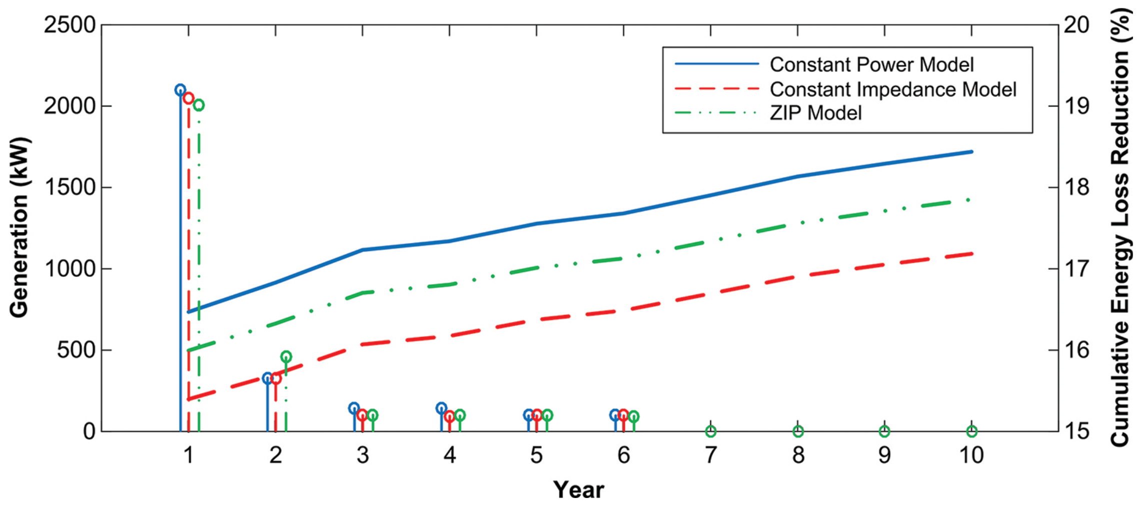

Figure 8. Sequential connection of optimum rated PV generators—conventional Monte Carlo method.

The total power to be allocated is similar for a given model when using either the conventional or the refined method: differences are below 4%. However, differences are larger when comparing the individual rated power values derived from the conventional and the refined methods. A reason for this is discussed in the next section.

As with the short-term evaluation, the highest reduction of energy losses corresponds again to the constant power load model, while the lowest generation is required when the load is represented as constant impedance. As for the reduction of energy losses, the resulting values are different for each load model, and although differences are not too large they cannot be neglected. In addition, the resulting energy losses are basically the same with the two approaches. This supports the conclusion that a quasi-optimum solution can be reached by considering different combinations of locations and rated powers, because the minimum of energy losses is not very sensitive with respect to rated powers and locations of generators.

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From the simulation times presented in **Table 8**, it is evident that a significant reduction in the CPU (central processing unit) time can be achieved by using the refined approach.

The behavior of the energy loss reduction factor deserves some special attention. **Figure 8** shows the energy loss reductions that are obtained at the end of a given year, considering the reduction caused from the beginning of the period. One can note that the total reduction at the end of the studied period is not too large—less than 20%. There are several causes that justify this quantity. Since PV generators inject only active power, energy losses caused by the reactive component of load currents are not compensated. On the other hand, the nature of the solar resource causes that the connected PV generators will not inject power during many hours of the day and the injected power during other hours will be below or far below the maximum value the PV generators can inject. Finally, since the minimization period is 5 years and the load will be higher at the end of this period, the selected rated power will be such that the unit will overcompensate active load during the first years and undercompensate during the last years.

One can also observe that the reduction of energy losses continues after the last PV generator has been connected. Remember that the last unit is connected at the beginning of the sixth year, and its rated power is selected to minimize losses until the end of the tenth year. However, one can also observe that the cumulative energy loss reduction factor continues increasing after the optimization period (i.e., after the year 10).

As proved in [20], the cumulative energy loss reduction factor one year after the optimization period will exceed the cumulative energy loss reduction factor at the end of the optimization period, if the energy loss reduction factor of that year exceeds the cumulative energy loss reduction factor at the end of the period. That is, the cumulative factor will continue increasing while the energy loss reduction factor corresponding to 1 year is larger than the cumulative factor at the end of the previous year. For the test system, the cumulative energy loss reduction factor with a constant power load model at the end of the optimization period is about 18.4% (see **Table 9** and **Figure 8**), while the energy loss reduction factor during the subsequent year (i.e., year 11) is above 18.4%; therefore, if no more generation units are connected, the trend will continue until the year at which the cumulative energy loss reduction factor exceeds the energy loss reduction factor corresponding to that year.

It can be assumed that the reduction of energy losses could be larger if the number of units to be connected was higher; however, the present study is not aimed at estimating the number of units that could achieve the maximum reduction of energy losses. In any case, it is worth mentioning that the reduction of energy losses that can be achieved with more than four units is very small with respect to that achieved with four units [20].

5. Maximum reduction of energy losses—a systematic approach

The application of the refined Monte Carlo method has significantly reduced the simulation time, and it has provided energy loss values that are very close to those obtained with the conventional Monte Carlo method. The values were obtained by using $R = 5\%$; see Section 3.6.

Consider the case when only one PV generation unit has to be allocated. If R = 5%, then the calculations could be carried out by following a systematic method instead of a statistical method, that is, only 20 values should be considered for both the rated power of the generator and the location node. In other words, 400 runs in which values are systematically calculated and combined would be enough to obtain results equal or very similar to those derived from the conventional and the refined methods (see Subsection 3.6).

Note, however, that if the systematic method is applied when two units have to be allocated, then 160,000 (i.e., 20 × 20 × 20 × 20) runs would be respectively required, since four variables must be estimated for each case. Obviously, the systematic method would not be a solution when two or more units are to be allocated. This is in accordance to what was concluded from the results shown in **Tables 3** and **4**: many more runs than those applied when four units had to be allocated were needed.

The systematic method can be a potential solution for long-term evaluation when PV generation units are sequentially allocated (see Section 4). **Tables 10** and **11** show the results obtained for an evaluation of 10 years when up to six units are sequentially connected.

PV generator		Constant power load model	Constant impedance load model	ZIP load model
Unit 1	Node	375	375	375
	Rated power (kW)	2025.0	2025.0	2025.0
Unit 2	Node	225	225	250
	Rated power (kW)	517.3	388.0	388.0
Unit 3	Node	500	250	200
	Rated power (kW)	107.6	114.1	228.2
Unit 4	Node	250	500	500
	Rated power (kW)	108.9	115.1	109.4
Unit 5	Node	200	200	225
	Rated power (kW)	107.1	112.9	107.5
Unit 6	Node	475	175	175
	Rated power (kW)	104.1	109.6	104.5
Energy losses (kWh)		1594536.3	1499115.9	1544531.8
Simulation time (h)		2.14	2.15	2.46

Table 10. Long-term evaluation—simplified method.

Some interesting conclusions can be derived from these results:

- Although a systematic procedure (i.e., without generation of random quantities) is applied, the simulation times shown in **Table 10** are longer than those shown in **Table 8** with the

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refined method. This is due to a simple reason: when using the refined method, together with a value or $R = 5\%$, the total number of runs is less than 400. For instance, when the load is modeled as a constant power, the number of runs needed to obtain the values shown in **Table 8** was respectively 257, 145, 137, 132, 135, and 128.

- The rated powers presented in **Table 11** are larger than those obtained with the refined method (see **Table 9**); the largest difference between values presented in both tables is more than 9%. However, the reduction in energy losses that is achieved after the 10-year period is basically the same with the refined method and the simplified systematic approach; the largest difference between the energy loss reduction values corresponding to each load is less than 1.5%.
- Although size and location values for the first unit are the same with the three load models, the results derived for the subsequent units exhibit some important discrepancies.
- As with any previous study, the highest reduction of energy losses corresponds to the constant power load model, while the lowest generation is required when the load is represented as constant impedance.

Load model	Total generation (kW)	Cumulative energy loss reduction (%)
Constant power	2970.2	18.239
Constant impedance	2864.9	16.857
ZIP	2962.7	17.546

Table 11. Long-term evaluation—total generation and energy loss reduction—simplified method.

A simple conclusion can be derived from this and the previous studies: a refined Monte Carlo method can be accurate enough if the goal is to estimate the minimum energy losses. If the goal includes also an accurate estimation of sizes and locations, then a conventional Monte Carlo method with a good convergence criterion should be applied. Obviously, a simple way to increase the accuracy with size and location values is to decrease the value of R; however, as discussed above this can be a too demanding approach if more than one unit is to be allocated.

Although the systematic method and the refined method have both been applied here by setting the Euclidean distance at 5% without any further justification, the fact is that some simple rules can be used to select a reasonable value and then decide whether any of these approaches is worth applying. Consider the operating conditions of the system studied in this chapter. The maximum power to be allocated cannot exceed the total load (i.e., 4500 kW). A 5% of 4500 is 225 kW, and a 5% of the power to be allocated after the first unit has been selected is about 125 kW (i.e., 5% of about 2475 kW). If the rated power of units to be selected is expected to vary in steps of 50 kW, then the 5% rule is not the adequate one; it should be reduced and the number of runs increased, at least for the first units. A similar reasoning could be followed with the location nodes. If line/cable lengths of the test system are too long, then it would be advisable to reduce the value of R. This basically means that the accuracy of the refined and the systematic methods can be predicted, and their application is limited by the topology and operating conditions of the test system.

6. Conclusions

This chapter has presented a procedure based on a Monte Carlo method for maximum reduction of energy losses using multicore computation. The procedure has been developed to cope with short-term and long-term evaluation periods (i.e., greater than 1 year). The method can be applied to any system regardless of its topology (see [20]). The present procedure is single-objective, but it can be expanded to include other objectives (e.g., minimization of the cost of energy or the cost of interruptions, and system upgrading) when optimizing the allocation of generation units.

Advantages and disadvantages of procedures based on the Monte Carlo method are well known: they are rather simple and can be usually based on advanced models; in turn, they usually require a high number of runs and consequently long CPU times. The application of parallel computing in this work has achieved a significant reduction of the simulation time. The application of multicore environments is becoming a usual practice, and it is foreseen that large multicore systems will be soon available at an affordable cost. In addition, a similar procedure could be implemented in a larger computer cluster (i.e., using grid computing); so, a not-too long simulation time could be achieved without significantly increasing the cost. However, it is evident from the obtained results that the application of a conventional Monte Carlo method to very large distribution systems (i.e., with several thousands of nodes) to which several dozens of DG units are to be connected might not be carried out in an affordable time even if a large multicore installation (i.e., with several hundreds of cores) was used. This can be very obvious when a long-term evaluation is carried out.

The results derived from short-term evaluation show that the energy loss surface is very smooth near the global optimum. The most interesting conclusion is that a quasi-optimum value can be obtained by means of several combinations (i.e., different combinations of node location and rated power of PV generators). That is, values very close to the global minimum (with differences below 1%) can be reached by considering several results; these findings are the foundation of the refined Monte Carlo approach. Through the application of the 5% criterion, the number of runs needed with the conventional Monte Carlo method can be significantly reduced without loss of accuracy. The differences between the values derived from different load models are not negligible. This can be seen as a proof of the importance that accurate load models have for this and other studies.

The systematic approach presented in Section 5 can also provide accurate-enough solutions if only minimum energy losses have to be estimated. If the size and locations of the PV generators must be estimated with some accuracy, then the conventional Monte Carlo method should be considered.

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The application of the approaches based on the Monte Carlo method can also be applied to multifeeder distribution systems. Reference [20] proposes a divide-and-conquer approach that can speed up the calculations in multifeeder systems by using also parallel computing.

Some important conclusions are obtained from the comparison between results obtained in this chapter and those presented in [19]. Although the test system was the same in both studies, the results are different. As discussed above, there are several reasons: the energy losses to be minimized in the current study did not include substation losses; the model used for representing PV generation was different in both studies; and there were significant differences between the yearly curves used to represent the time variation of node loads.

It is important to keep in mind that the allocation of distributed generators in actual deregulated systems is not made following a sequential connection of generation units whose sizes are selected to minimize energy losses; in addition, the time at which each unit is connected to the system does not follow any specific pattern (i.e., it can be assumed random). In fact, the procedure implemented for this work can cope with any pattern of DG connections. On the other hand, the long-term evaluation has shown that the maximum reduction of energy losses is achieved by connecting the largest generation unit at the beginning of the period with little room for more energy loss reduction in subsequent years. Remember that for a radial feeder with a uniformly distributed load and an active power demand of 9 kW at every node, the optimum size of the first unit to be allocated should be more than 2000 kW. The usefulness of this study is in the insight it provides about the impact that the connection of PV generation can have on the system energy losses, that is, utilities can obtain from this or similar studies important information about the maximum loss reduction they should expect.

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