Large Scale Integration of

Micro-Generation to Low Voltage Grids

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Contents

1. Abstract

Existing transmission and distribution networks were originally designed and sized having in mind the existing loading situation and the expected load growth over a given time horizon.

The connection of an increasing amount of Distributed Energy Resources (DER) into these networks will provoke the modification of the usual direction of the power flows. This effect will be beneficial in some cases and detrimental in others. Large local levels of DER relatively far away from the load will make line loadings and voltage values exceed their safety limits. In contrast, small amounts of DER close to the load will reduce the loading and the losses of the distribution system. This could affect the system operation and planning with economic implications.

But the impact of introducing DER on distribution networks is not only technical but environmental as well. That is, the amount of gaseous pollutants released into the atmosphere for production of power is significantly reduced when using DER instead of traditional plants. This is particularly important because electricity power generation emissions represent a significant contribution to overall emissions that cause the global warming and the greenhouse effect.

Another characteristic of DER is that it can be used as backup generation in case a utility service interruption occurs. This way, reliability of supply is improved and interruption costs are minimised.

And finally, depending on the type of DER connected, the system efficiency is improved. This is the case of Combined Heat and Power Plants (CHP) that are able to recover and use the waste heat.

2. Case Study: Spanish Medium Voltage Network

2.1. Introduction

This study is focused on the analysis of the economic impact of DER penetration.

The modification of operation and maintenance costs due to the DER connection are related to the ohmic losses modification. For this purpose a stochastic methodology based on Monte Carlo simulations that obtains the variation of the losses has been developed. In each simulation the power flow for a determined operating condition of the system is calculated.

A similar analysis for line loading and voltage profile was carried out for the subtasks I3 (Construction of an analytical models with existing or foreseen levels of RES and micro sources penetration forming MicroGrids) and I4 (Steady State and Dynamic Analysis of Study Case networks) of this project. This contribution supposes a complement of the mentioned work.

In addition to the study of local losses, an estimation of the CO_2 emission reduction, installation efficiency improvement and reduction of the supply interruption costs are provided.

Different scenarios characterised by the number and location of the distributed generators are taken into account in order to evaluate the previous issues. The type of technology considered in all of them is CHP.

The results will demonstrate that DER penetration can help to defer network investment because of the reduction of the ohmic losses and to reduce other type of costs associated with supply interruptions and CO_2 emissions.

2.2. Modelling

2.2.1. Monte Carlo Simulations

The objective consists in analyzing the influence of a determined amount of DER connected to the network on local losses, CO_2 emissions, efficiency and interruption costs.

In the study, different kinds of variables are involved. Some of them are deterministic because they take predictable values. This is the case of the number and type of the distributed generators connected to the system and the location of each of them. However, other variables such as load demand or DER output are uncertain and they take random values given by probability distributions. If we wanted to do a deterministic analysis of all possible states of the system, it would be practically impossible and it would require an enormous computational effort.

To simplify the problem, Monte Carlo Simulations have been employed [1], [2], [3] and [4]. The Monte Carlo Simulations are a repeated process using randomness that obtains deterministic solutions to a given problem. The main issue is to define the number of simulations required to obtain accurate results. In order to adjust the value of this parameter, some test with different number of simulations were carried out. After the analysis it was concluded that 100 simulations are enough to obtain a good solution.

Each simulation consists in calculating a power flow on a fixed operating condition of the system characterised by different sets of values of the following parameters:

- Load demand.
- Generation output.

2.2.2. Study network

In order to carry out the analysis, a real Spanish Medium Voltage Network of 30 kV has been chosen as a test system. It is a meshed network exploited in a radial configuration containing 23 buses and 18 loads. The customers connected are mainly commercial although there is an industrial load placed on bus 23. The one-line diagram is given in Figure 2-1:

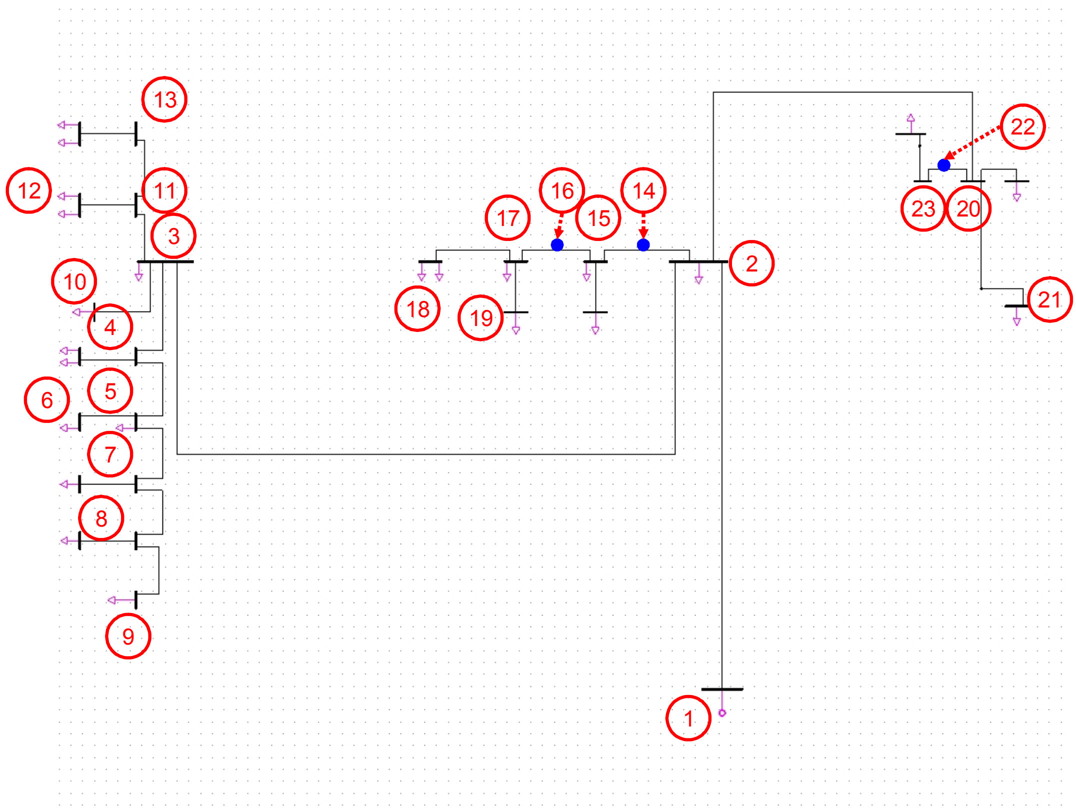

Figure 2-1 Spanish Medium Voltage Network

The following tables show the power flow results of the base case corresponding to the peak load demand.

BUS DATA						
Bus	**Voltage**		**Generation**		**Load**	
#	Mag (pu)	Ang (deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)

1	1,0000	0,000	11,67	5,62	-	-
2	0,9961	-0,056	-	-	0,096	0,046
3	0,9948	-0,076	-	-	0,018	0,009
4	0,9947	-0,077	-	-	0,783	0,376
5	0,9946	-0,077	-	-	0,121	0,058
6	0,9946	-0,077	-	-	0,078	0,038
7	0,9946	-0,078	-	-	0,181	0,087
8	0,9946	-0,079	-	-	0,844	0,405
9	0,9946	-0,079	-	-	0,119	0,057
10	0,9947	-0,076	-	-	0,734	0,352
11	0,9947	-0,077	-	-	-	-
12	0,9947	-0,077	-	-	0,874	0,420
13	0,9946	-0,078	-	-	0,874	0,420
14	0,9959	-0,059	-	-	-	-
15	0,9959	-0,060	-	-	0,280	0,135
16	0,9957	-0,062	-	-	-	-
17	0,9957	-0,063	-	-	0,594	0,285
18	0,9957	-0,063	-	-	0,970	0,465
19	0,9957	-0,063	-	-	0,495	0,237
20	0,9960	-0,058	-	-	0,130	0,062
21	0,9960	-0,058	-	-	0,031	0,015
22	0,9956	-0,063	-	-	-	-
23	0,9956	-0,064	-	-	4,399	2,111

Table 2-1 Base case PF results under peak conditions - Node data

BRANCH DATA							
From	**To**	**From bus injection**		**To bus injection**		**Losses**	
Bus	Bus	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
1	2	11,67	5,62	-11,63	-5,58	0,040	0,033
2	3	4,63	2,23	-4,63	-2,22	0,005	0,005
3	4	2,13	1,02	-2,13	-1,02	0,000	0,000
4	5	1,34	0,64	-1,34	-0,64	0,000	0,000
5	6	0,08	0,04	-0,08	-0,04	0,000	0,000
5	7	1,14	0,55	-1,14	-0,55	0,000	0,000
7	8	0,96	0,46	-0,96	-0,46	0,000	0,000
8	9	0,12	0,06	-0,12	-0,06	0,000	0,000
3	10	0,73	0,35	-0,73	-0,35	0,000	0,000
3	11	1,75	0,84	-1,75	-0,84	0,000	0,000
11	12	0,87	0,42	-0,87	-0,42	0,000	0,000
11	13	0,87	0,42	-0,87	-0,42	0,000	0,000
2	14	2,34	1,12	-2,34	-1,12	0,000	0,000
14	15	2,34	1,12	-2,34	-1,12	0,000	0,000
15	16	2,06	0,99	-2,06	-0,99	0,000	0,000
16	17	2,06	0,99	-2,06	-0,99	0,000	0,000
17	18	0,97	0,47	-0,97	-0,47	0,000	0,000
17	19	0,49	0,24	-0,49	-0,24	0,000	0,000
2	20	4,56	2,19	-4,56	-2,19	0,001	0,000
20	21	0,03	0,01	-0,03	-0,01	0,000	0,000
20	22	4,40	2,11	-4,40	-2,11	0,001	0,001
22	23	4,40	2,11	-4,40	-2,11	0,000	0,000

Table 2-2 Base case PF under peak conditions - Branch data

Table 2-1 shows the voltage magnitude obtained at each bus of the network. The calculation has been done taking the bus 1 as reference and giving it a voltage equal to 1.

Looking at the results it can be observed that the maximum voltage drops are approximately 0.5 % and they occur at feeder end nodes. The voltage profile has been graphically represented in Figure 2-2.

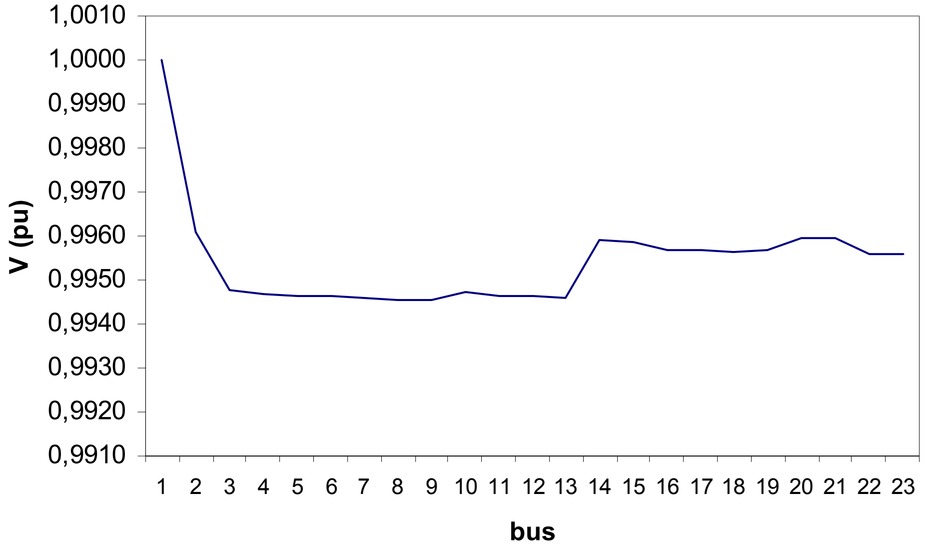

Figure 2-2 Base case voltage profile

2.2.3. Load demand curves

Load demand curves provide the forecasted power consumption at each load bus for each time interval of the day and they have been obtained from real historical data of a weekday of May 2004. Figure 2-3 shows the profile of the aggregated load demand curve employed in this study.

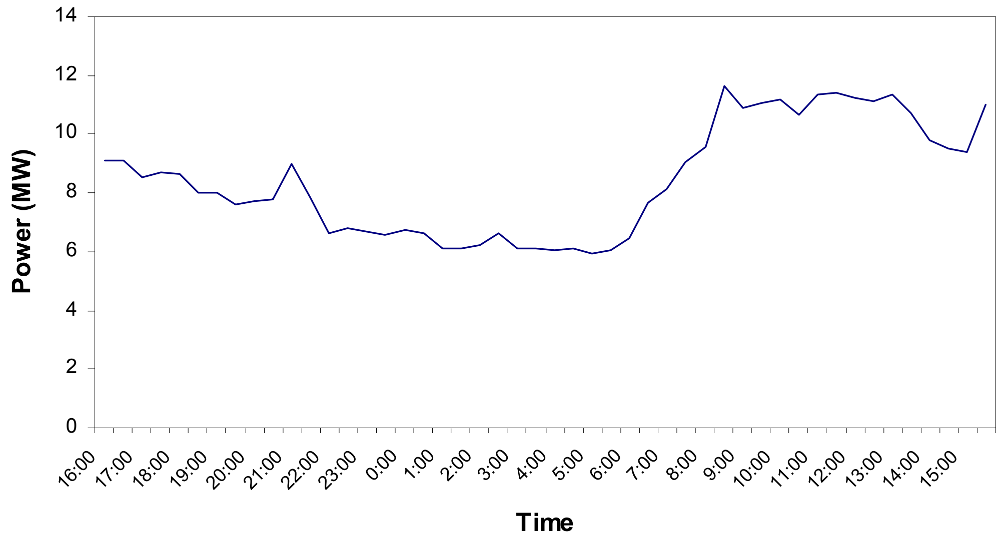

Figure 2-3 Load demand curve

2.2.4. Uncertainty modelling

Some of the parameters of the system, such as forecasted load demand and DER outputs are uncertain, that is, they take random values that can be modelled using probability distributions. The most frequently used probability distributions are the following:

- Normal distribution.
- Triangular distribution.

A detailed description of each of them is given below.

2.2.4.1. Normal distribution

The normal distribution is appropriated when values are expected to cluster disproportionately near the most probable value. This distribution requires to provide an estimation of the most probable value (the mean) and the standard deviation [4].

The probability density function is:

$$f(x) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{\frac{-(x-\mu)^2}{2\sigma^2}}$$

Where:

μ: mean

σ: Standard deviation

The graphical representation [6] is given in Figure 2-4:

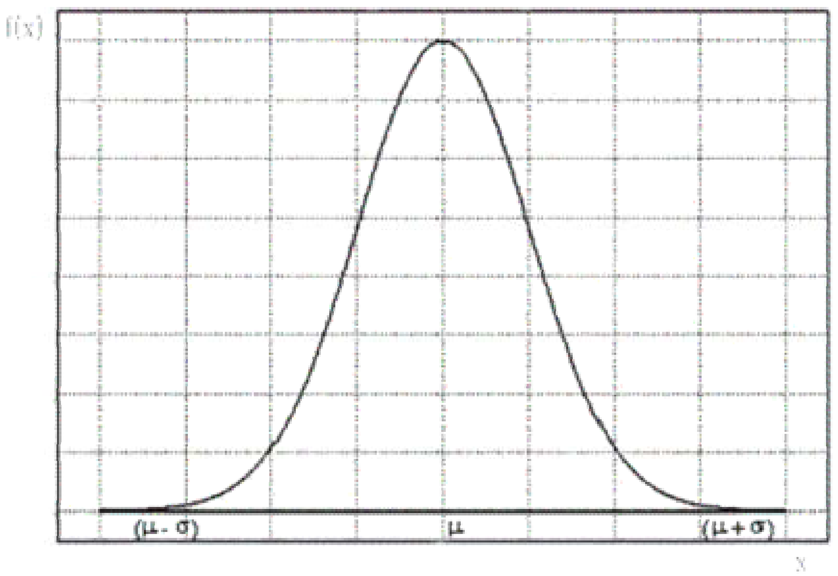

Figure 2-4 Normal distribution

By definition during 68% of the time the values are between (μ-σ) and (μ+σ). But if the range (μ-3σ) and (μ+3σ) is considered, this percentage reaches the 99.73%.

For a given value of accuracy, the standard deviation can be calculated as follows:

$$3\sigma = \mu \frac{accuracy}{100} \rightarrow \sigma = \mu \frac{accuracy}{300}$$

This distribution has been used to model the uncertainties in forecasted commercial power demand and the output of CHP units.

2.2.4.2. Triangular distribution

The triangular distribution is similar to the normal distribution but it requires only the range (a & c) and the most probable value (b) as parameters [4].

The probability density function is:

$$f(x) = \begin{cases} \dfrac{2(x-a)}{(c-a)(b-a)} & a \le x \le b \\ \dfrac{2}{(c-a)(c-b)} & b \le x \le c \end{cases}$$

Figure 2-5 shows a graphical representation of the probability density function [6]:

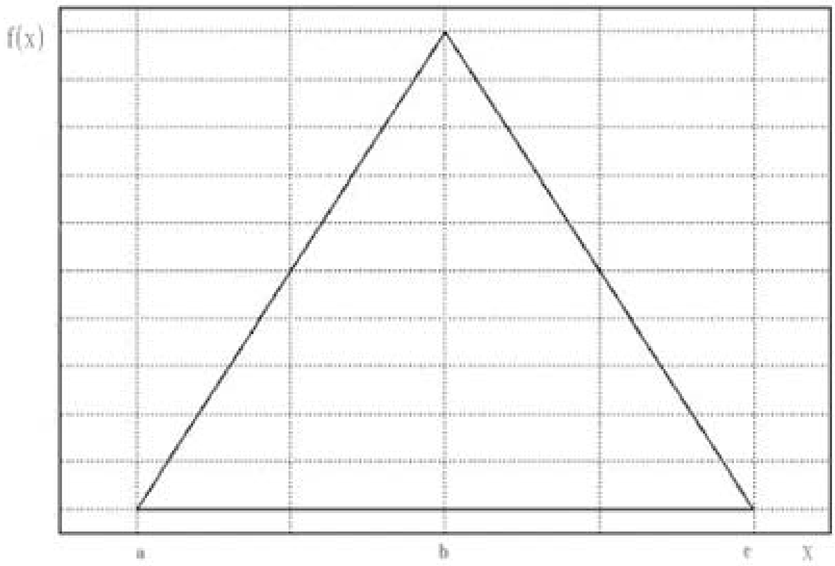

Figure 2-5 Triangular distribution

This distribution has been employed to take into account the randomness of the industrial load.

2.3. General approach

2.3.1. Introduction

Distributed generation connected to the distribution network causes an impact on it that can affect to the network operation, planning and produce economic losses because the network was not designed taking into consideration this kind of generation.

However, if DER unit are connected to the system at the right location and they are of the convenient size, they can contribute to reduce line loadings and therefore local losses.

Besides, this kind of generation provides very important advantages such as, backup generation, CO_2 emission reduction and improvement of the system efficiency.

In order to obtain the influence of DER penetration on the previous parameters, two scenarios characterised by different number and location of DER are studied. The type of DER considered in both scenarios is CHP due to the big increment of the installed capacity that this kind of generation is suffering nowadays. This is because of the environmental benefits and the possibility of recovering and using the waste heat that allows a higher efficiency.

The study has been performed for a whole day supposing that it is divided in 48 time intervals, that is, one for each half an hour.

For each time interval, one hundred Monte Carlo Simulations have been carried out. In each simulation, the power flow for a determined operating condition of the system is calculated. These conditions are characterised by different values of load demand and DER outputs that are generated randomly.

Modelling of these variables is presented in the following section.

2.3.2. Load and DER modelling

2.3.2.1. Load modelling

Load demand curves have been obtained from real historical data of a weekday of May 2004.

Randomness for the commercial and the industrial load demands has been modelled with normal and triangular probability distributions respectively. It has been assumed that the accuracy in both cases is equal to 100%, so the necessary parameters for each distribution are the following:

Normal distribution:

$$\mu = \text{load demand}$$
$$\sigma = \mu \frac{\text{accuracy}}{300} = \mu \frac{100}{300} = \frac{\mu}{3} = \frac{\text{load demand}}{3}$$

Triangular distribution:

$$a = b - \frac{\text{accuracy}}{100} b = b - \frac{100}{100} b = 0$$
$$b = \text{load demand}$$
$$c = b + \frac{\text{accuracy}}{100} b = b + \frac{100}{100} b = 2b$$

2.3.2.2. DER modelling

The power output curves for combined heat and power plants (CHP) have been calculated following a market driven approach where the production of each CHP unit is obtained as a function of the energy price curve. This way, generators produce their maximum when the price reaches the higher value and the remaining outputs are calculated proportionally. This is an evolutionary methodology because nowadays the CHP production is in relation to the heat demand but it is supposed that in the future it will follow this profile.

For this purpose, historical hourly data have been chosen. Data corresponding to this curve has been taken from the "Operador del mercado ibérico de energía – Polo Español, S.A." [9] and they are given in Table 2-3. It should be noted that higher prices are found in the evening due to be a winter day.

Date	Time	Price (cent/kWh)
11/05/2004	16:00	2,700
11/05/2004	17:00	2,700
11/05/2004	18:00	2,700
11/05/2004	19:00	2,330
11/05/2004	20:00	2,330
11/05/2004	21:00	2,012
11/05/2004	22:00	3,000
11/05/2004	23:00	2,300
11/05/2004	0:00	1,617
12/05/2004	1:00	2,207
12/05/2004	2:00	2,000
12/05/2004	3:00	1,804
12/05/2004	4:00	1,773
12/05/2004	5:00	1,705
12/05/2004	6:00	1,803
12/05/2004	7:00	2,007
12/05/2004	8:00	2,217
12/05/2004	9:00	2,183
12/05/2004	10:00	2,357
12/05/2004	11:00	2,467
12/05/2004	12:00	2,357
12/05/2004	13:00	2,357
12/05/2004	14:00	2,147
12/05/2004	15:00	1,468

Table 2-3 Energy price curve

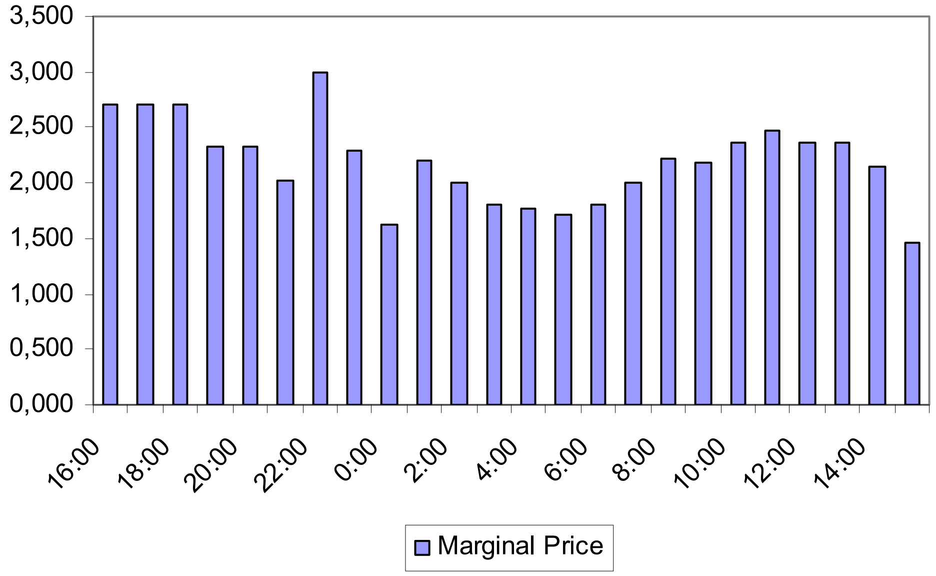

Figure 2-6 Energy price curve

The installed capacity represents the maximum output of each individual CHP and it has been obtained as a function of the "Generation level" that is defined as follows:

$$\text{Generation level}\,(\%) = \frac{\text{DER installed capacity}}{P_{\text{load peak}}} \cdot 100 \rightarrow$$

$$\text{DER installed capacity} = \frac{\text{Generation level} \cdot P_{\text{load peak}}}{100}$$

Where the $P_{\text{load peak}}$ represents the peak load demand of the bus where the CHP is connected.

The power calculated with the formula represents the maximum power of the CHP, so the real value of generation will be a bit smaller. Besides, the required generation depends on the heat demand that is uncertain. For this reason, there is also an uncertainty on the generation outputs that has been simulated modifying the values of the generation curve with a normal distribution of 30% of accuracy.

This power output corresponds to the generation at the time of the day of maximum energy price. The remaining values of the generation curve are obtained following the energy price curve profile in a similar manner.

2.3.3. Analysed scenarios

Two scenarios characterised by different number and location of CHP are considered:

- Scenario 1: one DER is placed on bus 23 because it is the only industrial load of the network and therefore its energy consumption is the biggest of the system.
- Scenario 2: one DER is located in all buses whose peak load demand is bigger than 500 KW. Following this criteria nine CHP are connected on buses 23, 18, 12, 13, 8, 4, 10, 17 and 19. In this situation the half load buses of the network have a DER.

For each scenario, six generation levels that vary from 0% to 133% are considered (0%, 16%, 33%, 66%, 100% and 133%). The 0% represents the base case where there is no DER connection and the 100% corresponds approximately to the situation given by the "Real Decreto 436/2004 of the 12 of March for Special Regime" that says that a Combined Heat and Power Plant with less than 25 MW of installed capacity must auto-consume the 30% of the energy produced if it wants to be considered as a Special Regime and so receive the corresponding bonus.

Table 2-4 shows the installed capacities of the CHP connected in the first scenario (bus 23) for the different generation levels considered:

Generation Level (%)	CHP installed capacity (MW)
16	2,20
33	4,40
66	8,80
100	13,20
133	17,59

Table 2-4 Installed capacities (scenario 1)

It can be seen that the installed capacity given by the Spanish legislation is 13.2 MW and if we take into account that the rating of the lines of the network is 20.78 MVA, this value do not suppose problems in relation to overloads. For this reason, a higher generation level has been considered.

The 16%, 33% and 66% represent the situations where the installed capacities of the CHP are smaller than the reference value given by the regulation. In these cases, the investment pay-backs are negatively affected because the bonuses corresponding to the Special Regime are not received. However, it has the advantage of increasing the global possibility of CHP integration, that is, the number of CHP units that can be connected to the network before requiring system reinforcements.

2.3.4. Solving process

This section presents an overview of the general procedure used in this work to carry out the mentioned study. A description of the required input data, the processing and the output data obtained is given.

2.3.4.1. Input data

The necessary inputs are the following:

- Number of Monte Carlo Simulations: one hundred simulations are performed.
- Network topology: it is defined by the bus and line data. A real Spanish Medium Voltage Network has been chosen as a test system.
- Demand curves: they provide the forecasted hourly load demand for each bus of the network.

- Energy price curve: it represents the hourly price of the energy at the market. This data is necessary to obtain the power output curves of the CHP because they follow a market driven approach.

2.3.4.2. Processing

The computational algorithm is the following:

- Step 1: Read input data.
- Step 2: Take the first time interval of the day.
- Step 3: Run the Monte Carlo Simulations that consist in defining load and distributed generators data that are generated randomly and solve the power flows.
- Step 4: Take the next time interval and return to the step 5. This process is repeated for every time interval of the day.
- Step 5: Process the results.

Figure 2-7 summarises this method:

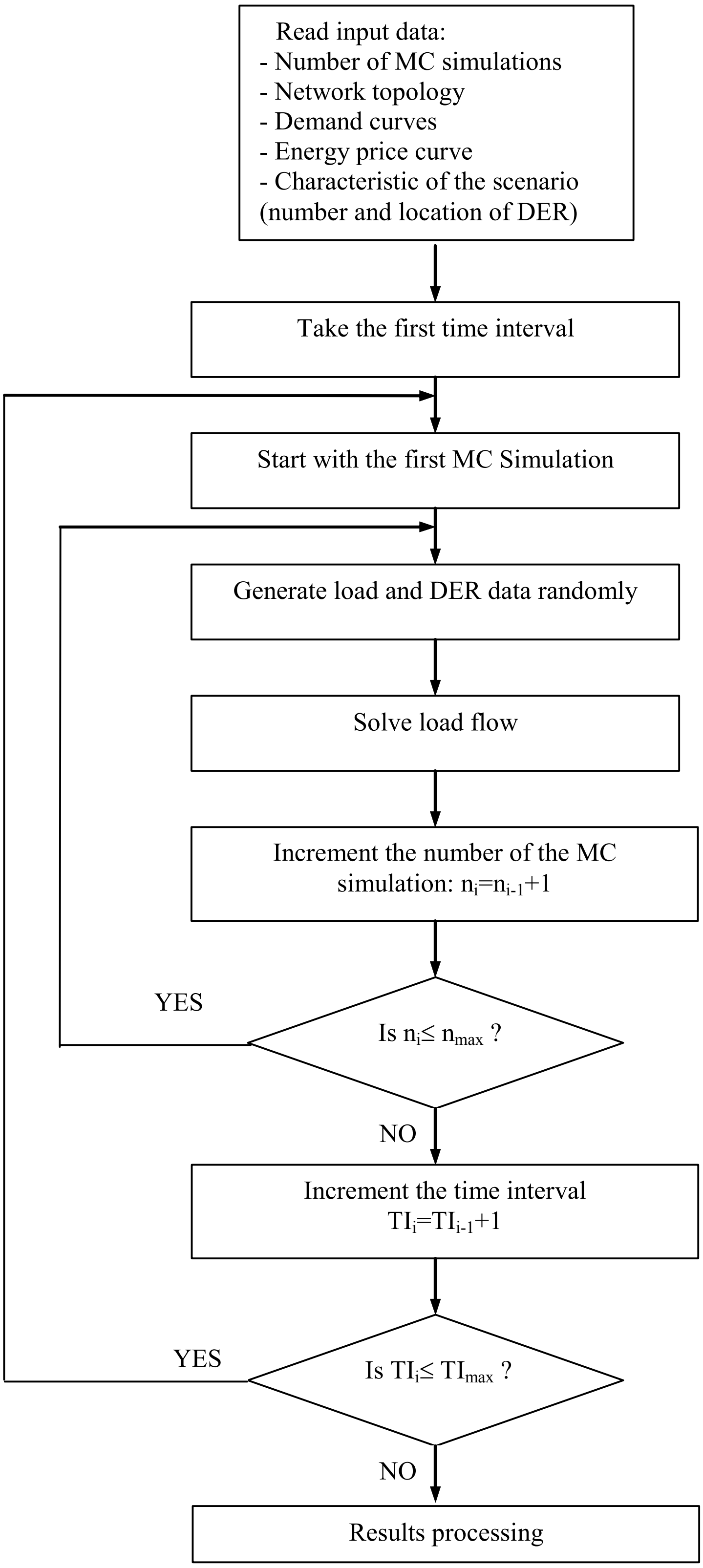

Figure 2-7 Flowchart of the resolution process

Where:

TI_i = time interval.

n_i = number of the Monte Carlo simulation that is being run.

n_{max} = the maximum number of Monte Carlo Simulations (100).

TI_{max} = the maximum number of time intervals (48).

2.3.4.3. Output data

For each scenario and generation level, a graphic that represents the value of the losses for each time interval of the day is obtained. This value represents the average of all the values obtained for the 100 Monte Carlo Simulations.

In order to have a reference of the increment or decrement of this variable, the losses of the base case are represented in the same chart.

2.3.5. Other results

2.3.5.1. Introduction

In addition to system losses, some conclusions regarding CO_2 emissions, system efficiency and interruption costs are obtained.

These parameters depend on multiple variables such as the technology employed, the type of fuel, the load demand curves, the size of the CHP, the heat demand…

Therefore, if we wanted to obtain the value of the mentioned parameters it would be required the specification of all the technical characteristics of the installation. However, the objective of this work is not defining the best type of CHP to be connected to the system under study but obtaining an estimation of the possible improvement if traditional generation plants were substituted by CHP. For this reason, a real CHP installation has been taken as reference and some conclusions about the previous variables have been obtained.

The technical information of the installation that has been used as model (type of equipments, installed capacity, efficiency…) is given in the next section.

2.3.5.2. Real CHP installation

In a CHP there is an energy conversion process where electrical power and useful heat are generated in a single, integrated system. The CHP produces both forms of energy from a single fuel at a facility near the consumer.

Typical CHP system consists of the following individual components:

- Prime mover or heat engine.
- Generator.
- Heat recovery system.
- Electrical interconnection.

The CHP considered as reference owns to an industrial plant whose steam demand is very high. Before the installation of the CHP this steam was generated in two boilers of fuel-oil that had an efficiency of the 85%.

The solution adopted consists in a CHP of 5.5 MW of installed capacity that is composed of a simple cycle plant with two engine-generator devices whose capacity is 2734 KW and a mixed boiler for heat recovery with ancillary burner.

The objectives that are expected to get with the installation of this CHP are the following:

- Diminish the energetic costs due to the high efficiency of the CHP system because of the heat and electricity produced simultaneously.
- Improve the actual situation in relation to the energy supply interruptions.
- Employ natural gas instead of fuel oil because it is more economical and ecological.
- Have a flexible generation plant able to provide energy in case a future load demand growth occurs.
- Contribute to maximize the auto-generation level of the country with the corresponding reduction of the primary energy consumption.

This plant is designed to have an availability of 95% to include maintenance and therefore it works 6840 hours/year.

The energy given to the Transmission and Distribution (T&D) System is the difference between the CHP production and the load demand. The maximum value of the previous parameter occurs when there is no load consumption at the industrial plant and the minimum when the load demand is maximum. These are 5.24 MW and 3.24 MW respectively.

A study of the economic reliability of the installation concludes that the investment pay back is 6 years.

In case a utility service interruption occurs, the two engine-generators will operate in islanding mode. But these generators cannot have a part load operation indefinitely because of refrigeration, mechanical and environmental problems. For this reason, after a short period of time, one of the engine-generators is disconnected in order to let the other operate at a load closer to the nominal.

And finally, the amount of CO_2 emissions that is avoided releasing into the atmosphere due to the generation of energy with this plant is 13300 t/year.

It has been taken into account that the Combined Heat and Power Plants constitute a special case regarding the CO_2 emissions because they increment the local emissions but they reduce the global emissions due to the industrial activity:

- The industrial plant diminishes the CO_2 emissions due to the heat received from the CHP that previously it had to produce.
- The power plant CO_2 emissions are reduced because it has to generate less electricity than before.
- The CHP emits more CO_2 that the industrial plant but less that the industrial and the power plants together.

2.4. Results

2.4.1. Losses

The obtained results for the different scenarios are presented bellow.

2.4.1.1. Scenario 1

Figure 2-8 shows the value of the losses along the day obtained for the different generation levels. The losses of the base case are also plotted.

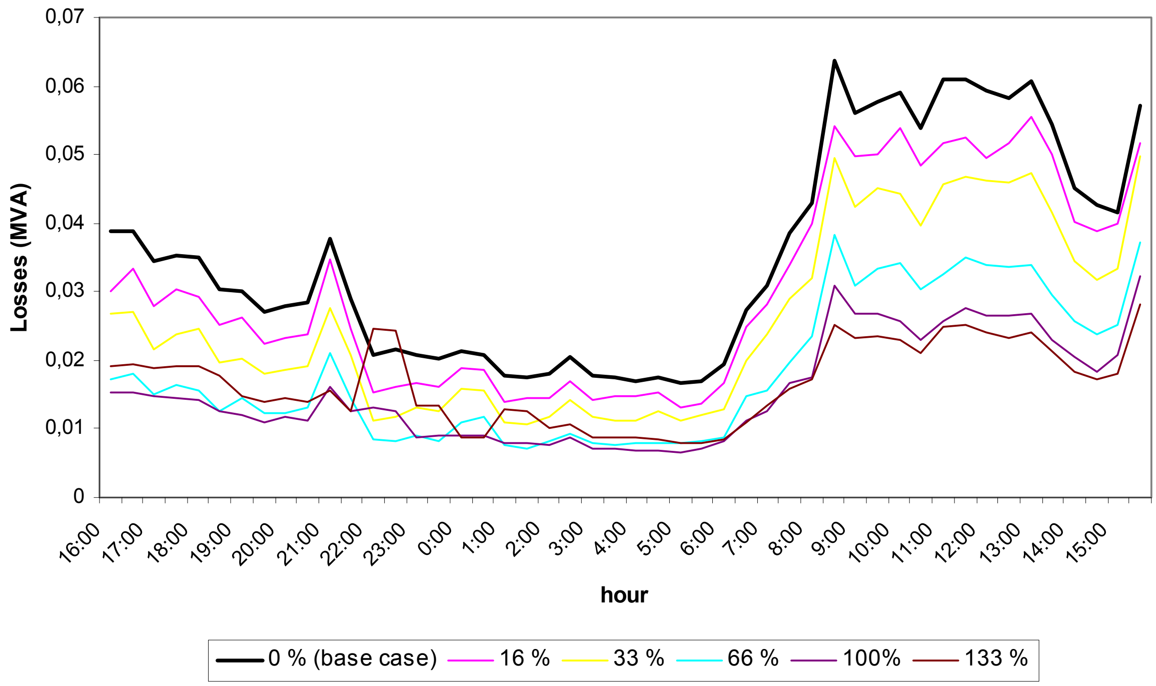

Figure 2-8 Losses variation (Scenario 1)

Results show that the losses of the system vary as a function of the generation level. The higher the generation level is, the smaller the losses are. Besides, these values are always smaller than the corresponding to the base case where there is no DER connected.

As the CHP feeds the load locally, the loading of the T&D lines (from the central station power plant to the customer site) decreases. As a result, the system losses are reduced.

It can be seen too, that the maximum reduction appears between the 66% and the 100% of generation and after it, the losses start to rise again. This occurs because the amount of energy generated locally is high enough to reverse line flows and so increase system losses.

It has to be noted that the CHP is placed on bus 23 which is the extreme node of a feeder that is composed of four lines (1-2, 2-20, 20-22 and 22-23). In this situation the losses variations only occur in such lines because the remaining ones are not affected by the CHP generation.

And finally it can be seen too that the losses reduction is different for each time interval of the day because the outputs of the CHP follow a market driven approach.

2.4.1.2. Scenario 2

Figure 2-9 shows the value of the losses obtained for the second scenario:

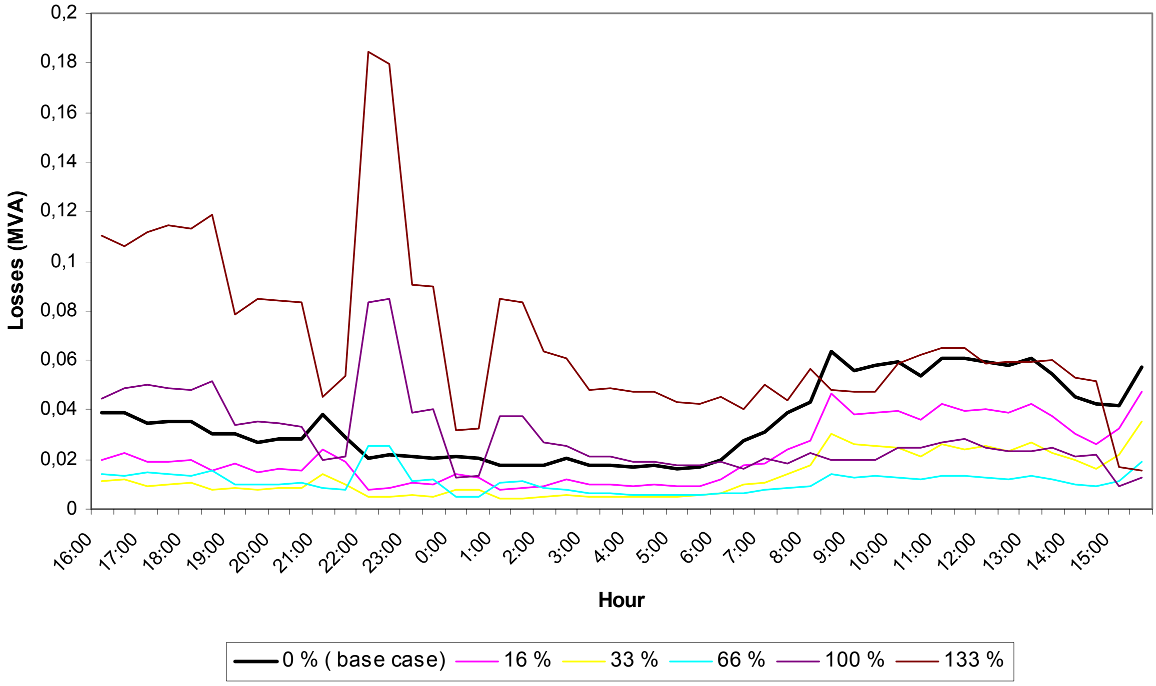

Figure 2-9 Losses variation (Scenario 2)

The results show that the value of the losses decreases for low generation levels (<66%). However, if the generation level is increased, the losses begin to rise and they can exceed the values of the base case.

In this scenario there are nine CHP that inject power in nine load buses. For high generation levels, the total energy production of the CHP exceeds the total load demand of the system reversing line flows and making them bigger than in the base case. Consequently, the losses become bigger than the base case too.

This situation did not occur in the first scenario because there was only one CHP connected instead of nine and therefore the total power output due to the distributed generation was less relevant in relation to the total generation of the system. Besides, in this case the generators are uniformly distributed along the buses and as a result, most of the lines of the network are influenced by the local generation.

The maximum reduction occurs for a generation level between the 33% and the 66%.

The same as in the previous scenario, the losses variation is different for each time of the day because the outputs of the CHP units follow a market driven approach. In Figure 2-9 it can be seen that there is a peak at 22:00 o'clock. This point corresponds to the time of the day where the energy price is the highest and consequently the CHP units have the maximum generation.

2.4.1.3. Conclusion

Looking at both scenarios it can be concluded that the introduction of DER contributes to reduce local losses due to the generation located near the demand that makes lines reduce their loading. However, after a determined generation level, the losses values are incremented.

Depending on the number of CHP connected and the generation level, the losses improvement that can be obtained is different.

If the average of the losses of all day for each scenario is calculated, the following chart is obtained:

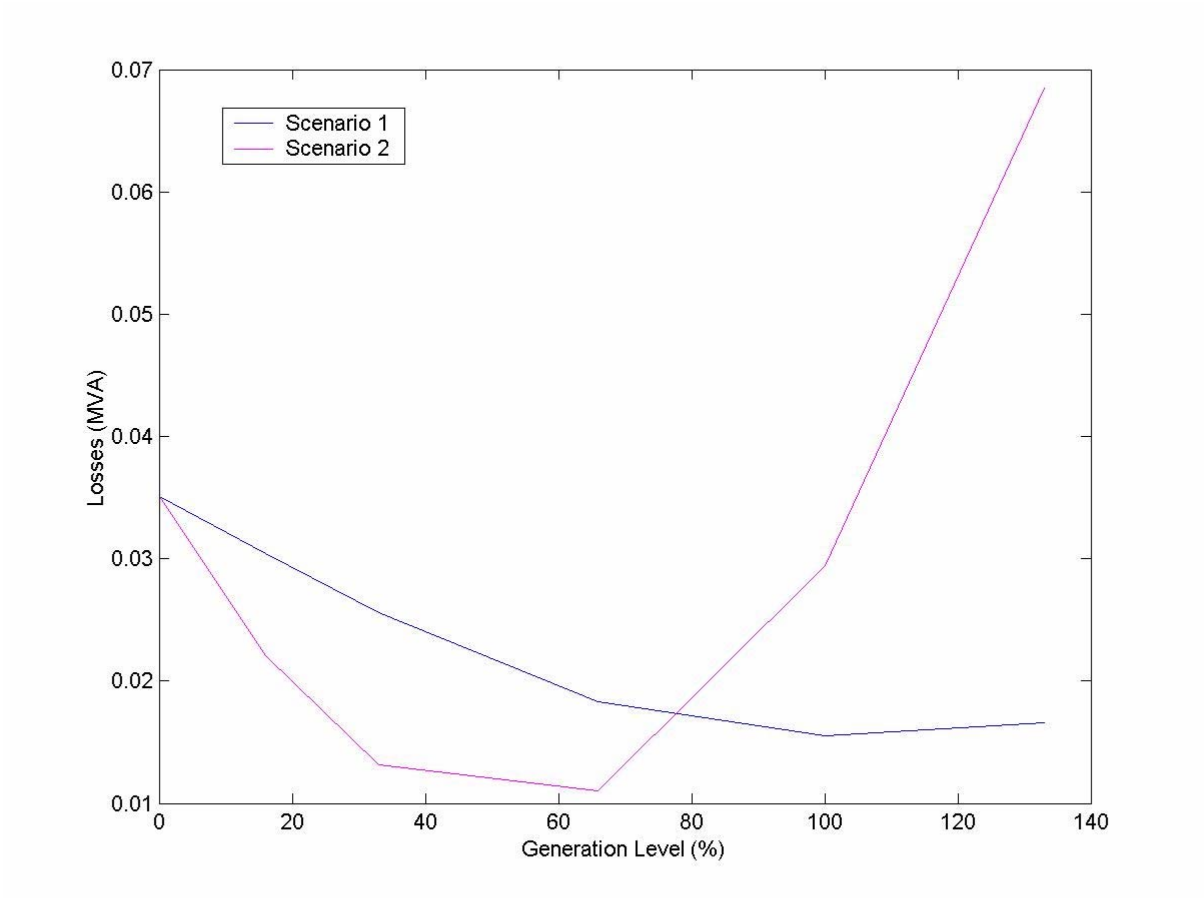

Figure 2-10 Comparison between the local losses of the two scenarios

It can be seen that the more number of DER are connected, the higher losses reduction is obtained. In contrast, the generation level for which the losses start to increase their value is smaller.

2.4.2. Efficiency

The local efficiency of the CHP depends on multiple variables such as the technology employed, the type of fuel, the load demand curves, the size of the CHP, the heat demand, etc. Consequently, the calculation of the efficiency requires the specification of all the previous parameters.

As it has been mentioned, the objective of this work is not defining all the technical characteristics of the CHP connected to the system, but demonstrating that distributed generation can help to improve some variables of the system such as the efficiency. For this reason, the real CHP described in section 2.3.5.2 has been taken as reference.

It is known that the economic reliability of the installation is in relation to the local efficiency. That is, the higher the efficiency is, the sooner the investment is recovered. In this case, the pay-back is six years. This means that the system is much more efficient than before installing the CHP because only six years are enough to recover the high cost of the installation.

Not only the local efficiency but also the T&D system efficiency is improved. That is, as now the network is able to generate locally for its own consumption, the energy demanded to the T&D system decreases and consequently the losses due to the transportation of electricity from traditional power generation plants to the network are reduced. In Spain, the value of the transmission and distribution losses is the 7.84% of the consumption.

In order to obtain this value, it is necessary to know all the consumptions of the system along the year but because of confidentiality reasons this information is not available. To cope with this, the calculation has been done based on one day data.

Table 2-5 shows for the first scenario considered and for each generation level, the following parameters:

- CHP generation: it is the average generation of the CHP along the day.
- Demand: it is defined as the difference between the average load demand of the network and the average CHP production and it represents the energy demanded to the T&D system.
- Losses: they are the transmission and distribution losses due to the transportation of energy from traditional power plants to the network. In Spain, their value is the 7.84% of the consumption.
- T&D System generation: it is obtained adding the losses to the demand.

Generation level (%)	**Average generation CHP (MW)**	**Demand (MW)**	**Losses (MW)**	**T&D System generation (MW)**
0	0	8,43	0,66	9,09
16	1,01	7,41	0,58	7,99
33	2,03	6,40	0,50	6,90
66	4,07	4,36	0,34	4.70
100	6,10	2,33	0,18	2,51
133	8,13	0,30	0,02	0,33

Table 2-5 Transmission and distribution losses (Scenario 1)

The demand and the T&D system generation have been represented in the following chart:

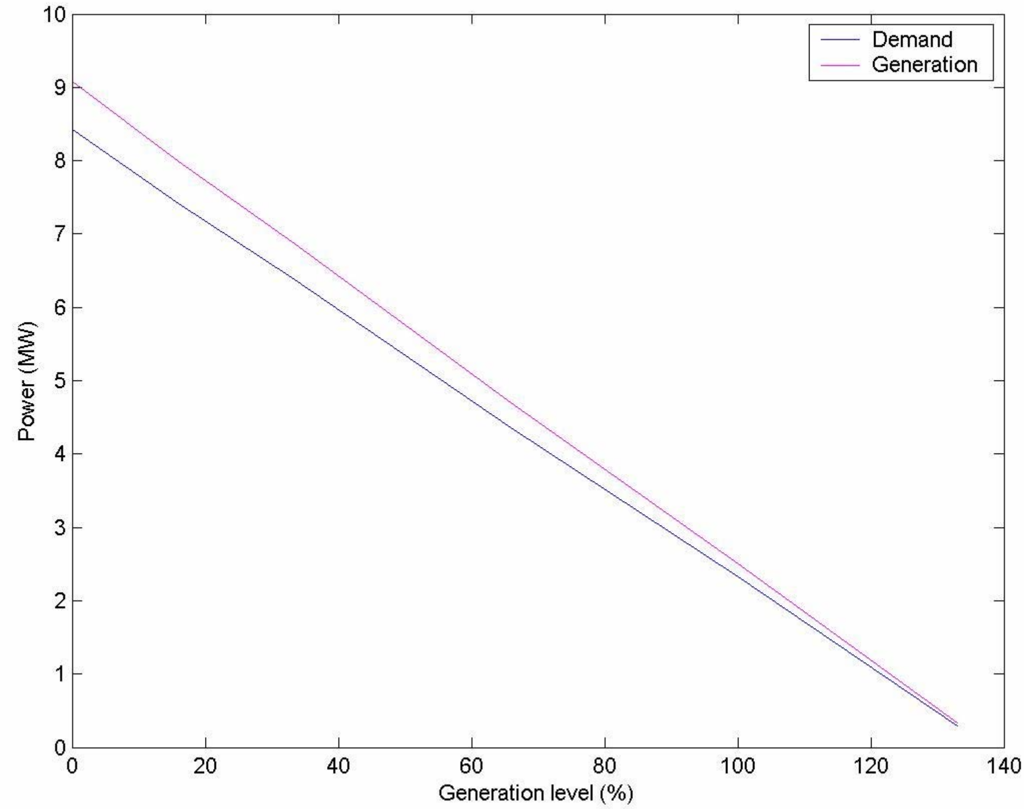

Figure 2-11 Transmission and distribution losses (Scenario 1)

It can be seen that the value of the losses decreases as the generation level increases. If we compare the value of the losses obtained for the generation level given by the legislation and the losses corresponding to the base case, we obtain a reduction of the 70%. For this reason, the system efficiency is improved.

2.4.3. CO_2 emissions

As for the efficiency, the overall CO_2 emissions depend on the characteristics of the CHP such as, the technology employed, the type of fuel, the load demand curves, the size of the CHP, the head demand, etc.

For this reason, the comparison with the real plant described in section 2.3.5.2 has been done in order to obtain some conclusions about the total CO_2 emission reduction that it could be obtained if an installation of the same type as the example was employed.

The amount of CO_2 emissions that is avoided releasing into the atmosphere due to the generation of energy with this plant is 13300 t/year.

If we extrapolate this figure linearly, we obtain the values presented in Table 2-6.

Generation Level (%)	P_{CHP} (MW)	CO_2 emissions (t\year)
50	2,20	5318
100	4,40	10637
200	8,80	21273
300	13,20	31910
400	17,59	42546

Table 2-6 CO_2 Emissions results (Scenario 1)

It is worth underlying that these estimates are obtained as approximation to the possible real case, varying the CHP unit and the driving heat demand could require changing unit type, size and performance.

The obtained results show the importance of using DER instead of other traditional plants, mainly thermal, for reducing the amount of CO2 emissions that contribute to the greenhouse effect and the global warming. This is very important due to the Kyoto Protocol requirements.

2.4.4. Interruption costs

DER can be used as backup generation when a utility service interruption occurs. This is particularly important because all the costs associated with the interruption of the industrial activity are avoided.

These costs can take both direct and indirect forms. Direct costs include lost production, damage to electronic data, damaged or spoiled product, damage to equipment or customer refunds. Residential customers may experience direct out-of-pocket expense for example alternative light sources, food spoilage or damage to electrical equipment. In addition to direct costs, there are several types of indirect costs (accidental injuries, legal costs, increases in insurance rates…) with monetary impacts that, in some cases, may exceed direct costs [10].

Interruption costs vary significantly based on the demand characteristics of the end-user. The customers connected to the network under study are mainly industrial or commercial. The costs for this kind of customers are 11.66 €/KW and 10.78 €/KW respectively for a 1-hour interruption.

If we consider an average cost of 11 €/KW, we can obtain the total economic losses for our system in case of a power supply interruption lasting for 1 hour.

This calculation has been done for the peak and the valley load demand:

Peak:

$$11.61\,\mathrm{MW}\cdot\frac{11€}{\mathrm{KW}}\cdot\frac{1000\mathrm{KW}}{1\mathrm{KW}}=127710\,€$$

Valley:

$$5.93\,\mathrm{MW}\cdot\frac{11€}{\mathrm{KW}}\cdot\frac{1000\mathrm{KW}}{1\mathrm{KW}}=65230\,€$$

These calculations demonstrate a very important advantage of having a distributed generator near the consumption. This kind of generation not only improves the technical characteristics of the system but the economic ones as well.

2.5. Conclusions

In this work a study of local losses from a stochastic point of view has been developed. In addition to this, an estimation of the CO_2 emission reduction, installation efficiency improvement and reduction of the interruption costs are provided.

For this purpose, two scenarios characterised by different number and location of DER are considered. In both scenarios, the penetration of the CHP technology has been analysed. The power outputs provided by the generators are obtained as a function of the energy price at the market and the “Generation level” that represents the relation between the peak load generation and the peak load demand.

From a technical point of view, results show that the integration of CHP contributes to reduce the line loadings and so the local losses. This fact has economic implications because it can defer investments in new infrastructures and existing network reinforcements. However, as the operating point of the Spanish Medium Voltage Network is very far from the exploitation limit under peak conditions, the contribution of CHP penetration on the investment deferral is not significantly.

It has been seen too that they can help to reduce the CO_2 and greenhouse gas emissions. Besides, the reliability of the system is improved because they can be used as backup generation reducing this way the interruption costs and finally the system efficiency is incremented too due to the possibility of recovering and using the waste heat.

Consequently, it can be concluded that integration of DER has not only technical but economic and environmental advantages as well.

2.6. References

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3. Case Study: Portuguese Networks

3.1. Introduction

Environmental resources are being more and more exploited from past years to present day and are in danger of becoming exhausted in a not very distant future. Furthermore, pollution, atmosphere and soil degradation and hydro resource's exhaustion is becoming more common.

Accordingly, urgent measures must be taken in order to allow the reduction of Green-House Gases (GHG) emissions and motivate the use of renewable power resources. These two factors are part of the objectives of the European Energy Policy.

An important contribution may be given by the connection of Microgeneration considering, for instance, the investment in wind parks, photovoltaic panels, small hydrous, microturbines powered by bio-diesel or natural gas and fuel cells, both of these intended for Combined Heat and Power (CHP) applications. These technologies allow local renewable resources to be explored and contribute to increase global efficiency when using fossil fuels. Moreover, Microgeneration may also contribute to a decrease in active power losses.

A re-regulation phenomenon has been changing power system operation paradigms in terms of management and control. The next years will testify new changes due to the advent of the connection of Microgeneration to the LV distribution network.

Different types of distribution networks (High Voltage, Rural Medium Voltage, Semi-Urban Medium Voltage and Urban Medium Voltage networks) were analysed and simulated under different operating scenarios (Summer, Winter, Valley, Peak and In Between Hours), considering different power factors. The impact of Microgeneration was evaluated through the changes experienced in voltage profiles, power losses and branch congestions in these networks, assuming that the equivalent load consumption was reduced due to the connection of Microgeneration units to the LV grids.

The analysis on the impact of Microgeneration was based on a methodology characterized by:

1. Simulation of Microgeneration connection to the network by reducing the value of active power at each node.
2. System evaluation, concerning voltage profiles, loss estimation and branch congestion analysis.

The work presented here focused on the analysis of the influence of Microgeneration in energy distribution networks.

The results obtained indicate that the Microgeneration penetration contributes favourably to improve network operating conditions.

3.2. Characterization of the Study-Case Networks

Several types of networks have been considered, and a general characterization of each network under analysis is performed next:

- A High Voltage (HV) network with an injector node (node 1); it is an aerial network of 63 kV with 5 buses and is explored in an open-ring. The opening of the ring is made between nodes 5 and 7 (Figure 3.2-1).
- A Rural Medium Voltage (RMV) network with an injector node (node 119); it is a network of 30 kV (Exit 1) that feeds 34 load nodes, one of them being a 30/15 kV substation. The substation has 3 exits to 15 kV (exits 2, 3, and 4) that feed 175 load nodes. This network has both airline and underground cables (Figure 3.2-2).
- A Semi-Urban Medium Voltage (SUMV) network with 372 load nodes and 3 injectors of 15 kV that feed 3 distinct networks. The network has both aerial and underground cables and the areas fed by the different injectors were named Area 1 (fed by node 332), Area 2 (fed by node 158) and Area 3 (fed by node 267). This network is shown in Figure 3.2-3.
- An Urban Medium Voltage (UMV) network with a single injector to 15 kV (node 095), that feeds 7 exits in underground cable (named Exit A to Exit G). The network has reconfiguration capability and a total of 153 load nodes (Figure 3.2-4).

The topologies of these networks are presented in the following figures:

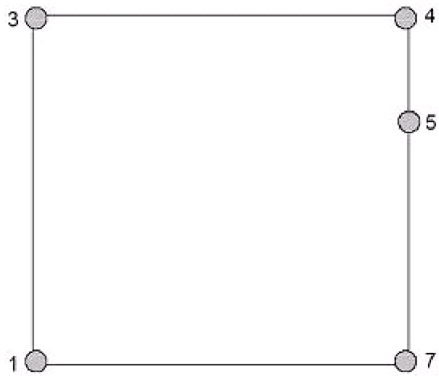


Figure 3.2-1 High Voltage Network

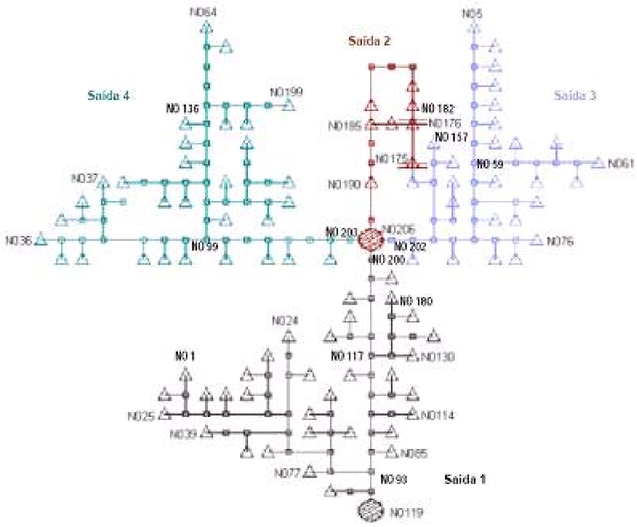


Figure 3.2-2 Rural Medium Voltage Network

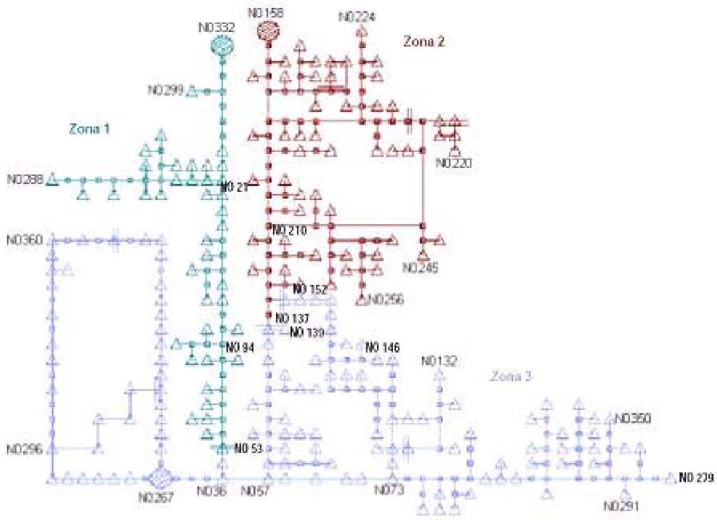


Figure 3.2-3 Semi-Urban Medium Voltage Network

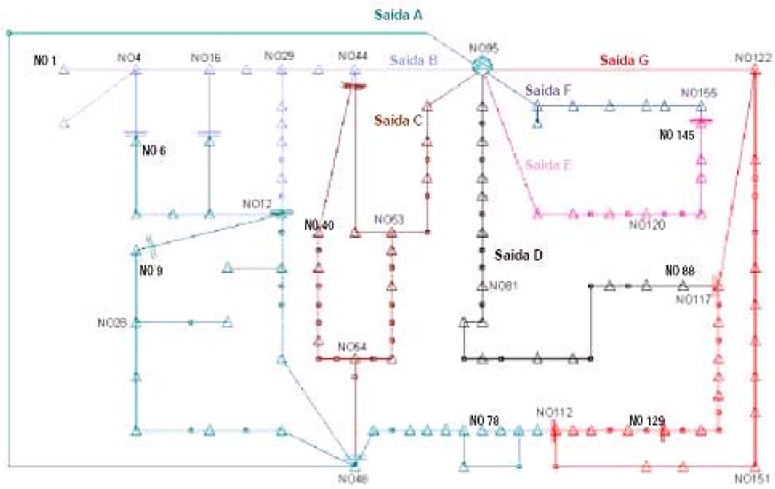


Figure 3.2-4 Urban Medium Voltage Network

3.2.1. Network Data

The network data used for this research corresponds to typical distribution networks in Portugal and are fully described in a technical report by INESC Porto [1].

The following operating scenarios were considered, associated to HV, RMV and SUMV distribution networks: Peak Hours of Winter (PHW), Peak Hours of Summer (PHS), In Between Values of Summer (BVS), In Between Values of Winter (BVW) and Valley Hours of

Summer (VHS). Also, the following operating scenarios were considered, associated to the UMV network: In Between Values (BV), Peak Hours (PH) and Valley Hours (VH).

For each operating situation, several scenarios have been considered, corresponding to different power factors (ranging from 0.0 to 0.6 in steps of 0.1 – values of tan(φ)).

3.2.2. Algorithm Used

For each situation described above, the following guideline was adopted:

◦ The impact of Microgeneration was evaluated by considering a percentage reduction in the amount of Active Power consumption in several load nodes.

◦ Network simulation and analysis was performed according to the following steps:

1. Run Newton – Raphson;
2. Calculate the voltage in each bus, the losses and the branches' load;
3. Quantify the total network load;
4. The network Microgeneration percentage (penetration of Microgeneration), which results of an active power decrease in the referred nodes, is given by the ratio between the network total load variation before and after the active power decrease and the initial network total load value.

3.3. Main Results

Although tests have been performed and results have been obtained using all four networks presented in Section 3.2, the results obtained with the HV network will not be presented in this report, considering that, in face of the characteristics and size of the network, this was the least interesting of the four study cases.

3.3.1. Impact on Active Power Losses

The contribution of Microgeneration penetration for reducing active power losses has been assessed during the work carried out.

The following figures show active power losses for the three MV networks, considering the operating conditions mentioned and a tan(φ) = 0.4 (for the loads), as a function of the percentage of penetration of Microgeneration.

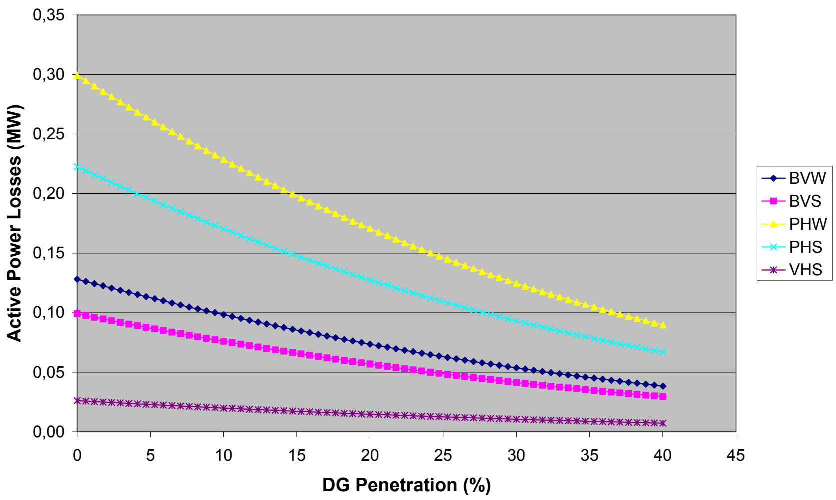


Figure 3.3.1-1 Rural Medium Voltage Network Active Power Losses

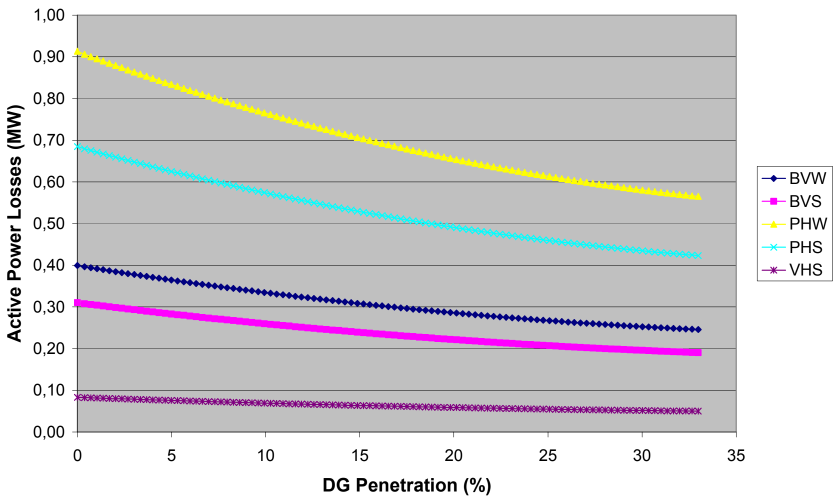


Figure 3.3.1-2 Semi-Urban Medium Voltage Network Active Power Losses

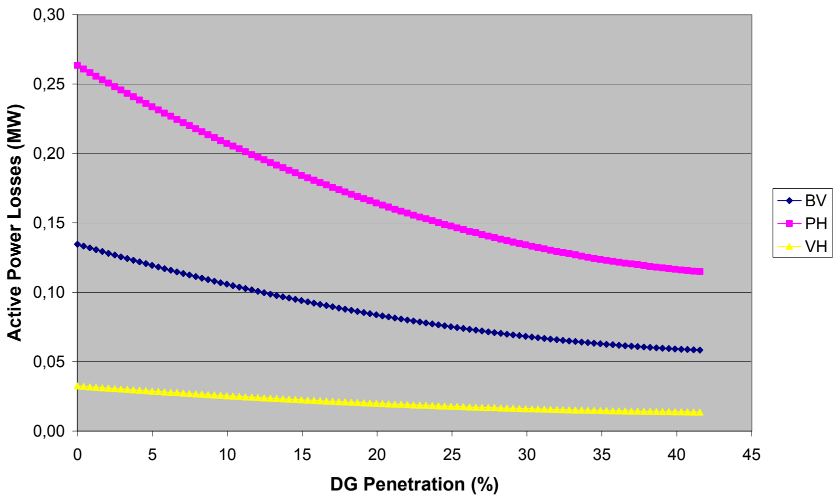


Figure 3.3.1-3 Urban Medium Voltage Network Active Power Losses

From the previous figures, it can be seen that active power losses decrease with an increasing percentage of Microgeneration penetration for all networks.

For the case of the UMV network for instance, and considering only peak hours, the total reduction in active power losses is around 46% for a Microgeneration penetration of 30%.

It is more interesting, however, to observe the cost of active power losses considering an increasing percentage of Microgeneration in the network.

In order to do so, for the cases of the RMV and SUMV networks, a single average price of 50 €/MWh was considered for the energy cost. For the case of the UMV network, an average price was given to the energy cost for in BV hours (50 €/MWh), for PH (60 €/MWh) and for VH (40 €/MWh).

For the cases of the RMV and SUMV networks, it was considered 4 hours for the PHW and PHS scenarios and 10 hours for the remaining scenarios and 4 months of winter and 8 months of summer. For the UMV network, it was considered 10 hours for BV and VH conditions and 4 hours for PH conditions.

The prices used here were derived from very recent data obtained from the Iberian Market Operator (OMEL) for typical days [2]

The following figures show the total cost of active power losses as a function of the percentage of Microgeneration for the three networks considered, for a 1 year period.

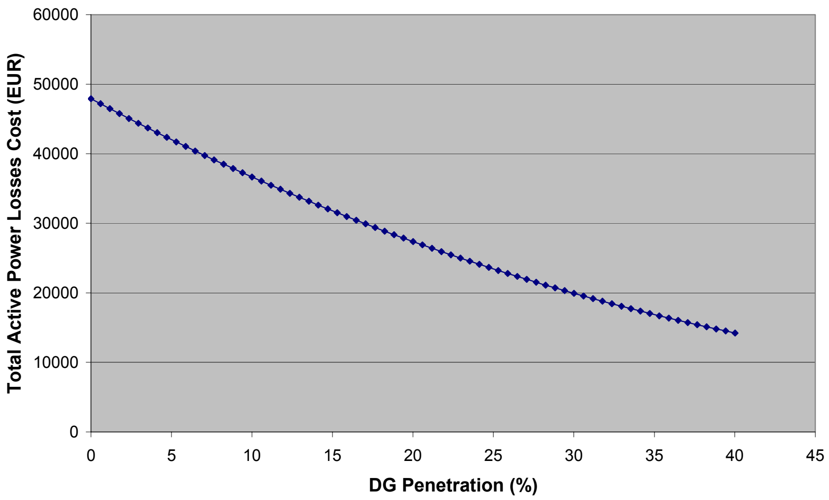


Figure 3.3.1-4 Rural Medium Voltage Network Total Active Power Losses Cost

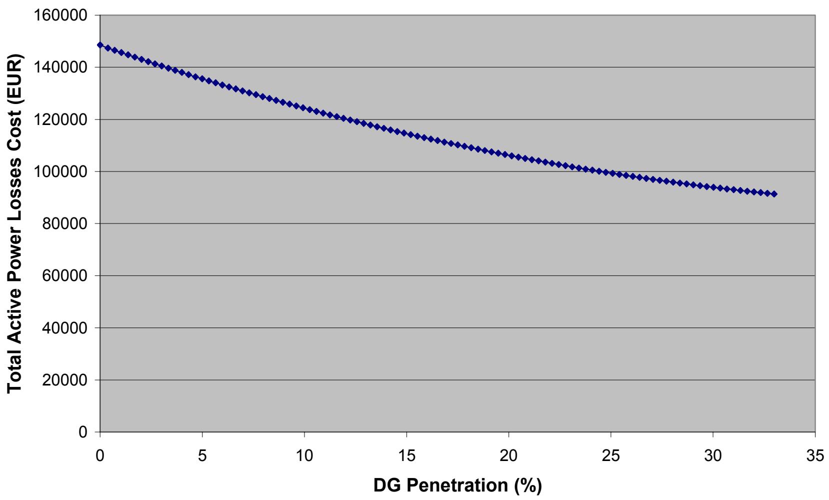


Figure 3.3.1-5 Semi-Urban Medium Voltage Network Total Active Power Losses Cost

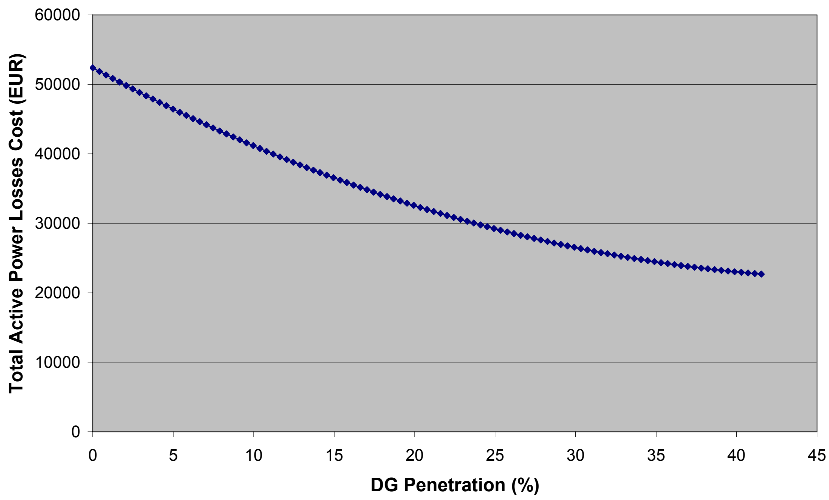


Figure 3.3.1-6 Urban Medium Voltage Network Total Active Power Losses Cost

It can be observed from the previous figures that the total cost decreases significantly with an increasing percentage of Microgeneration.

For the case of the UMV network for instance, a penetration of 30% of Microgeneration allows a save of approximately 25000 €, corresponding to a 50% reduction, approximately.

A summary of the saves in the cost of active power losses considering a situation with 0% of Microgeneration penetration (current base situation) and a situation with 20% of Microgeneration penetration is shown in Table 3-1.

Table 3-1 Comparison of Saved Active Power Losses Cost Considering 0% and 20% of Microgeneration penetration for 3 Typical Distribution Networks

	Saved Cost (€)
RMV	20543,88
SUMV	42533,54
UMV	19785,28
HV	103837,58

In order to provide a global estimate of the real economical benefits of a high percentage of Microgeneration penetration, the total energy losses that took place in the Portuguese distribution system for the year of 2002 (reference year) was spread for the different types of networks analysed. In Table 3-2, the division of the distribution system is presented.

Table 3-2 Energy Losses for each Type of Network for the Year of 2002

	Energy (GWh)	Percentage (%)
Losses Distribution System	**2989**	**100**
LV	1793,40	60,0
RMV	152,44	5,1
SUMV	508,13	17,0
UMV	355,69	11,9
HV	179,34	6,0

These percentages have been obtained considering the following values (for Portugal):

- A 60% of the Distribution System corresponds to LV networks and the remaining 40% corresponds to MV and HV networks;
- From the 40% of MV and HV networks, 85% correspond to MV and the remaining 15% to HV;
- From the percentage of MV networks, 15% correspond to Rural type networks, 50% to Semi-Urban and 35% to Urban networks.

Using these values it was possible to estimate the benefits raised by energy loss reductions in distribution networks. Table 3-3 summarizes the results obtained for a 1 year period. The two cases considered included a situation with 0% of Microgeneration penetration (current base situation) and a situation with 20% of Microgeneration penetration.

Table 3-3 Total Saved Active Power Losses Cost Considering 0% and 20% of Microgeneration penetration

Network Type	Energy Losses Reduction (%)	Energy Losses Reduction (GWh)	Avoided Cost (€)
LV	-	-	-
RMV	2,19	65,40	3.270.053,31
SUMV	4,85	145,11	7.255.467,00
UMV	4,50	134,46	6.722.821,18
HV	2,07	61,99	3.099.425,70
	Total	**406,96**	**20.347.767,19**

Concerning the LV networks, the correspondent data was included them in this study since an estimation of energy losses in this type of systems is not so linear. In fact, several more studies should be performed in order to obtain a more reliable estimate of this value, including studies considering import and export scenarios for the Microgeneration, etc. At this stage, it was not possible to fulfil this analysis.

From the results obtained it can be seen that a 13% reduction in energy losses, approximately, can be obtained. It can also be seen that a total of around 20300 M€ can be saved in a year, corresponding to energy losses.

3.3.2. Impact on Network Congestions

The impact of Microgeneration penetration on network congestions has also been assessed in this research.

In this section, the figures presented show the load variation in several network branches for a tan(φ) = 0.4 scenario, as a function of the percentage of penetration of Microgeneration.

Figure 3.3.2-1 illustrates the load reduction in the branch 118–119 for the RMV network for different Microgeneration penetration levels. This branch has been chosen because it has a higher load value before reducing the active power in each node of 15 kV.

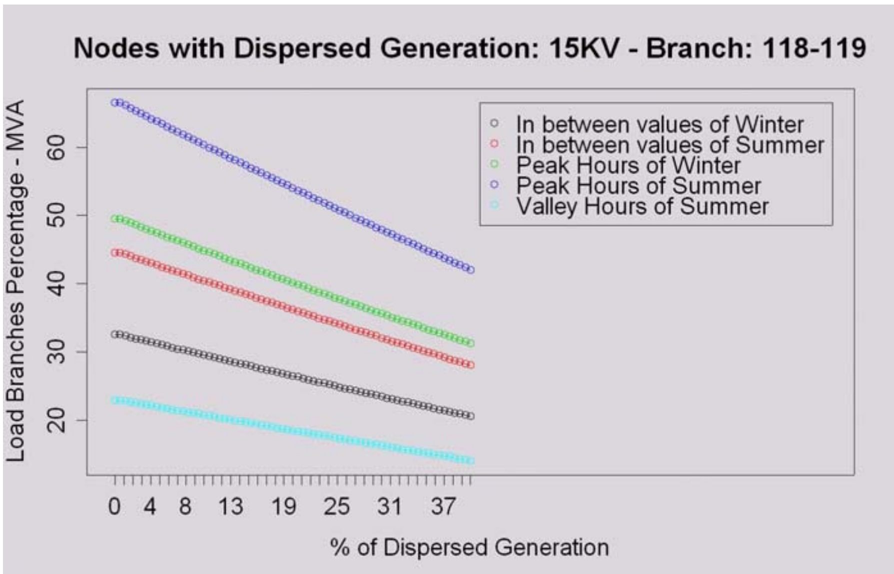


Figure 3.3.2-1 Rural Medium Voltage Network Load Branches

Figure 3.3.2-2 shows the load reduction in branch 7-12 for the SUMV network for different percentages of Microgeneration. This branch was chosen due to the fact of having a higher load value before active power reduction in each node from 1 to 120.

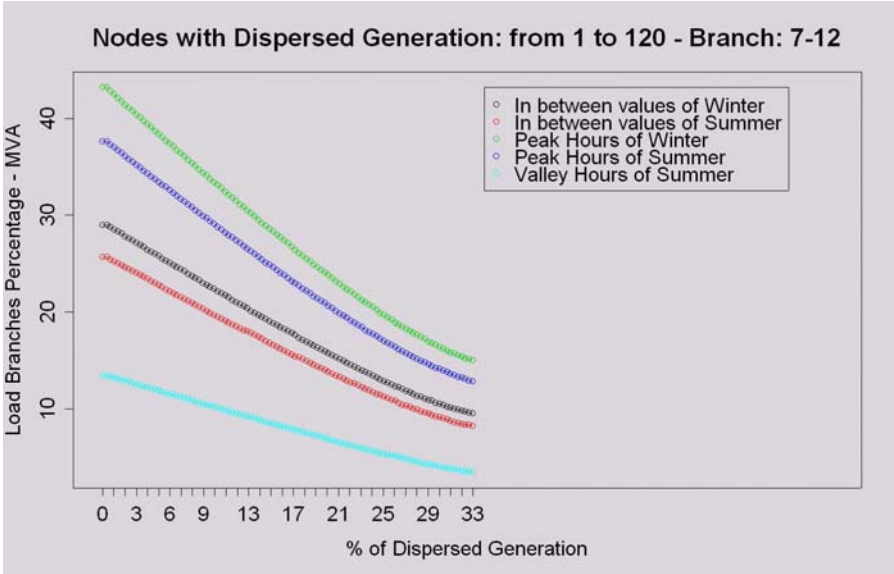


Figure 3.3.2-2 Semi-Urban Medium Voltage Network Load Branches

Figure 3.3.2-3 illustrates the network branches load reduction in the 94-95 branch for the UMV network as a function of the percentage of penetration of Microgeneration. This particular branch has been chosen because it has a higher load value prior to the active power reduction in each node from 1 to 50.

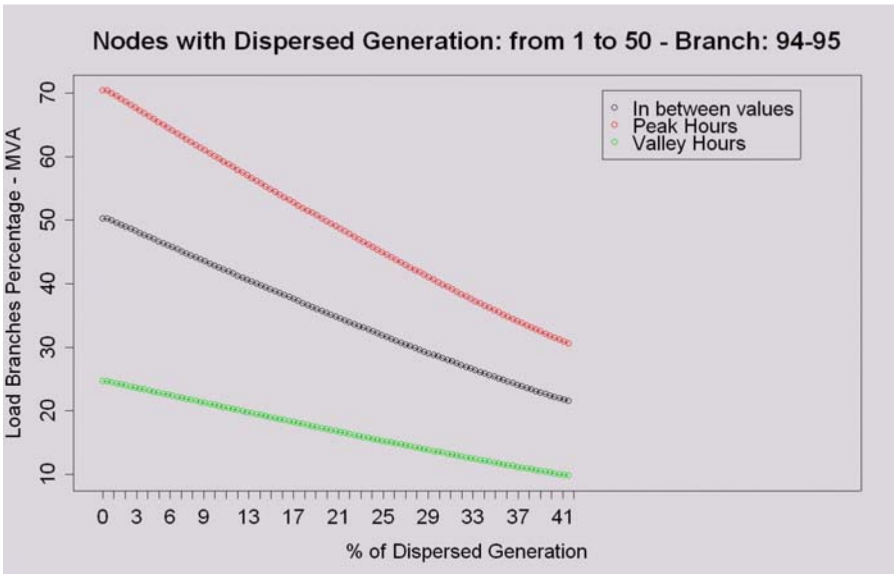


Figure 3.3.2-3 Urban Medium Voltage Network Load Branches

From the figures derived, it can be seen that the larger the Microgeneration percentage, the smaller the load percentage in the branch, for all three networks considered.

3.3.3. Impact on CO2 Emissions

In this section, an attempt at identifying the quantity of CO2 emissions avoided over a 1 year period as a function of the percentage of Microgeneration penetration was made.

For this section, the same assumptions regarding operating scenarios from Section 3.3.1 are made. A. The total active energy losses were computed and multiplied by a value of 0.29 kg/kWh for CO2 emissions (this value is a weighted value considering the current operation status in Portugal that includes already a considerable percentage of renewable generation in the general mix of generation). The main results obtained for the three networks considered are presented in the following figures.

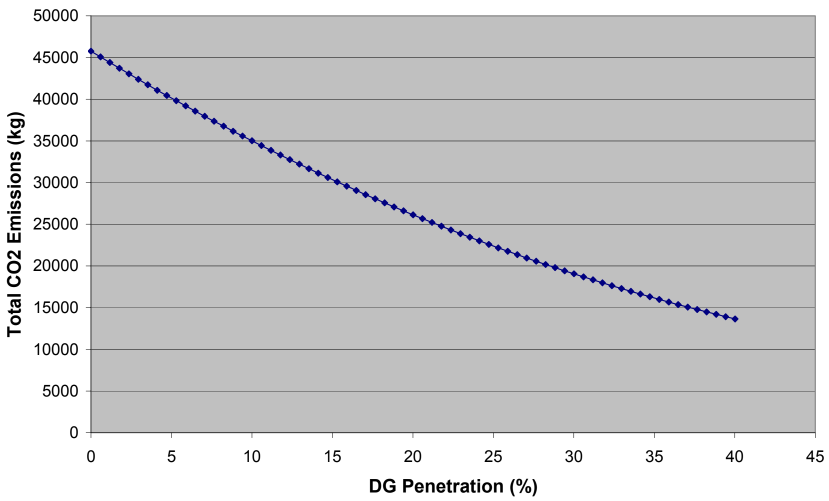


Figure 3.3.3-1 Rural Medium Voltage Total CO2 Emissions

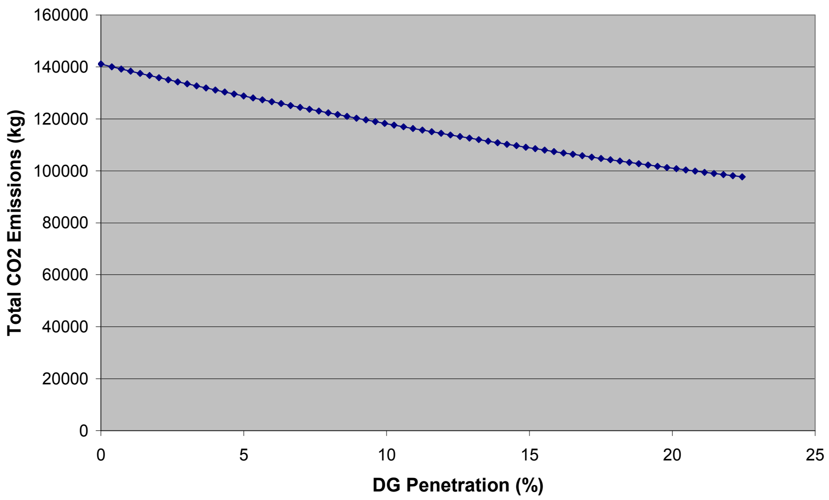


Figure 3.3.3-2 Semi-Urban Medium Voltage Total CO2 Emissions

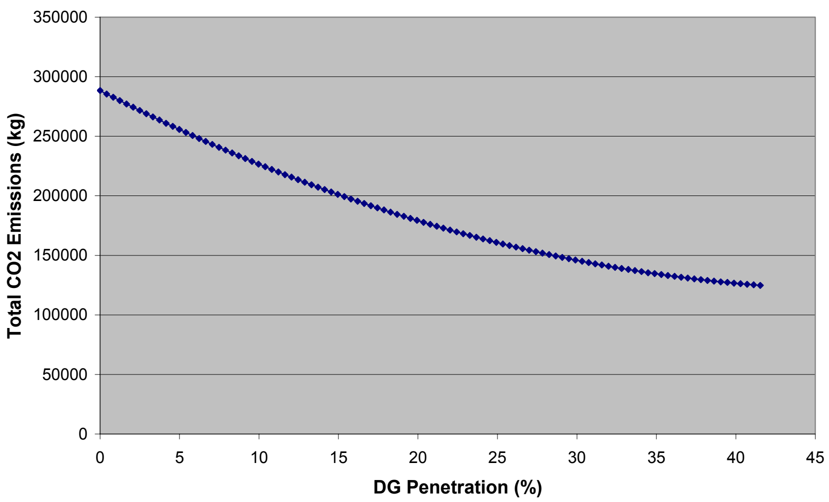


Figure 3.3.3-3 Urban Medium Voltage Total CO2 Emissions

It can be observed that a serious reduction in CO2 emissions can be obtained with an increasing penetration of Microgeneration.

For the case of the UMV network, for instance, a total reduction of around 50% of CO2 emissions can be achieved, considering a percentage of 30% of Microgeneration. With this percentage of Microgeneration, approximately 150 tons of CO2 emissions can be avoided.

A summary of the avoided CO2 emissions considering a situation with 0% of Microgeneration penetration (current base situation) and a situation with 20% of Microgeneration penetration is shown in Table 3-4.

Table 3-4 Comparison of Avoided CO2 Emissions Considering 0% and 20% of Microgeneration penetration for 3 Typical Distribution Networks

	CO_2 emissions avoided (kg)
RMV	19.634,54
SUMV	40.304,12
UMV	109.017,99
HV	104.564,40

Also, and considering the same percentages shown in Table 3-2, it was possible to estimate the benefits raised by CO2 emission reductions in distribution networks. Table 3-5 summarizes the results obtained for a 1 year period. Once again, the two cases considered included a situation with 0% of Microgeneration penetration (current base situation) and a situation with 20% of Microgeneration penetration.

Table 3-5 Total Avoided CO2 Emissions Considering 0% and 20% of Microgeneration penetration

Network Type	**CO_2 Emissions Reduction (%)**	**CO_2 Emissions Avoided (kg)**
LV	-	-
RMV	2,19	18.966.309,18
SUMV	4,85	42.081.708,61
UMV	4,50	38.992.362,85
HV	2,07	17.976.669,04
	Total	**118.017.049,68**

The LV networks were not included in this study for the same reasons previously mentioned.

It can be seen that a total of around 118.000 tons of CO2 emissions can be avoided in a year.

3.3.4. Impact on Reliability

The data collected for reliability analysis purposes for the Portuguese network has been scarce. In order to overcome this issue, the studies were based on the EDP Low Voltage network considered in some previous reports for Work Package I. The LV network is shown in Figure 3.3.4-1.

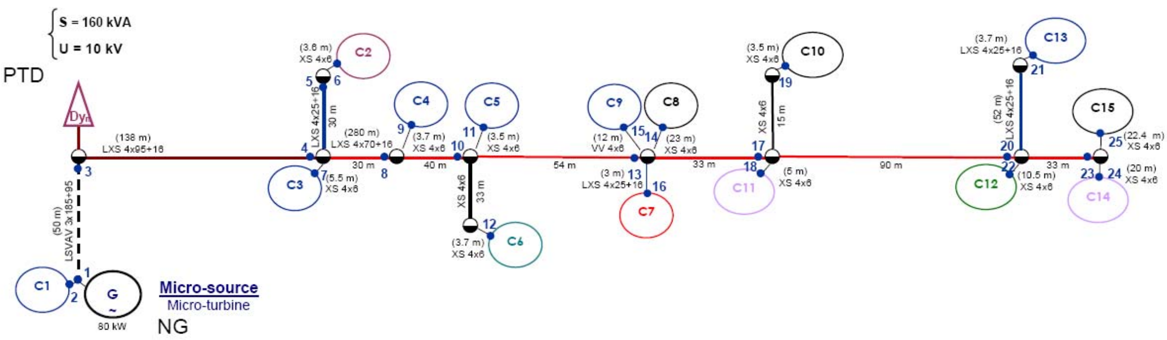


Figure 3.3.4-1 EDP LV Network

This LV network comprises a micro-cogeneration system based on a microturbine, which generates electric power and heat in a Natural Gas station. Details on the electrical data and consumers' characterisation can be found in [3]. A potential operation scheme is depicted in Figure 3.3.4-1, where is possible to observe the distribution transformer, the microturbine plant and an LV feeder with its electrical loads. The consumers are mainly of the industrial, residential and agricultural type [3]

the implementation of the microgrid shall bring great potential benefits. It is expected a global efficiency improvement associated to a reduction of T&D losses and costs. In fact, the T&D efficiency improvement and the heat recovery in the Natural Gas station shall support a reduction of the global energy bill to this industrial Customer and a better resources utilization.

The Figure 3.3.4-2 illustrates a situation of efficiency improvement achieved by a CHP generation system, based in a micro turbine, alternatively to generation of heat and power in centralized units.

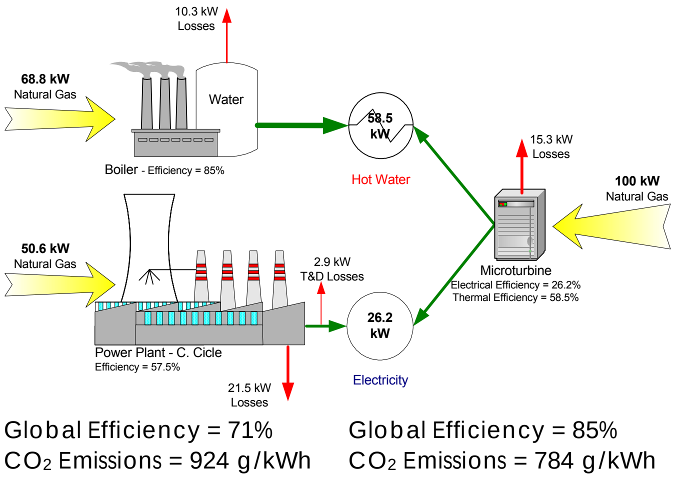


Figure 3.3.4-2: Power flow in centralized / distributed power and heat generation

This simplified scheme emphasises the efficiency achieved with the micro turbine (85%) compared to the efficiency achieved in centralized generation (71%).

As result of the efficiency improvement, the microgrid presents an effective potential to make a major contribution for reducing Green House Gas (GHG) emissions and the global pollution.

On the other hand, the microgrid shall improve the reliability of the LV grid, supplying the Customers during MV voltage interruptions. In fact, the main causes of voltage interruption are related with MV network.

Power quality is other important issue, which can be improved by microgrids. In steady state, the micro-sources can contribute to voltage control and frequency stability, reducing the severity of voltage dips, voltage droops and swells. Simultaneously, the microgrid would provide some ancillary services to the distribution operator, such as power factor control and harmonics mitigation.

The small-scale investments in micro-sources, closely matching the demand of the microgrid's loads, reduce the risk and capital exposure. In a distribution perspective, these micro-sources can prevent bulk investments on the reinforcement of the T&D systems.

In natural preserved areas, the microgrid and particularly the micro-sources can also contribute definitely to reduce the proliferation of MV and HV distribution infrastructures.

Table 3-6 presents a comparison between two possible scenarios – "Customers supplied by typical Distribution System" or "Customers supplied in MicroGrid", based on the data collected during the year of 2004. In order to analyse the two scenarios, it was considered that two MV interruptions and one LV interruption in the Distribution System that supplies these Customers occurred in 2004 [4].

Table 3-6 Analysis of Scenarios With and Without LV Microgeneration [4]

	Customers Supplied by Typical Distribution System	**Customers Supplied by the Possible Micro-Grid**
Yearly Number of Voltage Interruptions	3	1
Yearly Interruption Time (min)	153	60
Yearly ENS[1] (kWh)	33	13
Yearly ENS by LV Maintenance (kWh)	1,3	1,3
Yearly Energy Generation (kWh)	238.388	219.554
Yearly Losses (kWh)	21.455	5.446

The yearly losses in the scenario of "Customers supplied by typical Distribution System" (21.455 kWh) include the losses in the LV feeder (5.707 kWh) and the losses in the T&D systems, from the centralized power plant (15.748 kWh). In a MicroGrid scenario, the yearly losses are only referred to the reconfigured LV circuit, from the local micro-generation installation (NG station) to the local of consumption (Customers installations).

In this analysis it was assumed that the Microgeneration system is always available to supply the loads when a MV network interruption occurs. Consequently, the LV Customers are not disturbed by MV interruptions.

With the integration of the Microgeneration system in this LV grid the following potential improvements are expected:

- Reduction of the number of voltage interruptions from 3 to 1 interruption per year – Improvement of 66,6%;
- Reduction of the interruption time from 153 minutes to 60 minutes per year – Improvement of 61%;
- Reduction of the ENS from 64 kWh to 13 kWh per year – Improvement of 80%;

[1] ENS: Energy Not Served

- Reduction of the losses from 21455 kWh to 2621 kWh, due to the no-utilization of the T&D networks to supply the customers and reduction of losses in the LV feeder – Improvement of 88%.

In a global perspective, with the integration of the microturbine in this LV grid and the implementation of a real LV MicroGrid, it would be possible to save about 18834 kWh (about 1671 €, considering an average price of 0.0887 € per kWh) per year to supply 216933 kWh to these 15 customers. Additionally, the system reliability would be significantly improved, as well as the overall quality of service, reducing the ENS.

3.4. Conclusions

The results obtained indicate that Microgeneration brings some interesting socio-economical and technical advantages for distribution system operation.

It was seen that active power losses decrease significantly with the growth of Microgeneration penetration and consequently the corresponding cost is also strongly reduced. A reduction of around 13% in energy losses may be achieved, considering 20% of Microgeneration penetration in the distribution system. Concerning network congestion issues, it was observed that branch load can be significantly reduced considering a high percentage of Microgeneration penetration. In addition, a reduction in CO_2 emissions can be achieved with high Microgeneration percentages.

Concerning the EDP LV network, it was seen that it is expectable an improvement in reliability and in the overall quality of service as a result of the integration of the MicroGrid system.

3.5. Acknowledgement

The authors would like to thank the contribution made by António Amorim and Nuno Melo from EDP for this report.

3.6. References

[1] J. A Peças Lopes, J. L Pereira da Silva, R Ribeiro, A. Mendonça, “Análise do Impacto em Redes de Distribuição de Energia da Alteração do Valor Limite da Energia Reactiva

a Facturar nos Períodos Fora de Vazio” (in Portuguese), INESC Porto Report for EDP, 2002.

[2] Operador del Mercado Ibérico de Energía – Polo Español: http://www.omel.es/.

[3] J. Oyarzabal, et al., “DI1 – Electrical and RES Data Collection”, MicroGrids Project Deliverable, 2005.

[4] J. Oyarzábal, et al., “Progress Report for WPI”, MicroGrids Annex to Annual Report 2004, 2005.

4. Case study: Samothraki Island

4.1. Global overview

4.1.1. Geographical View

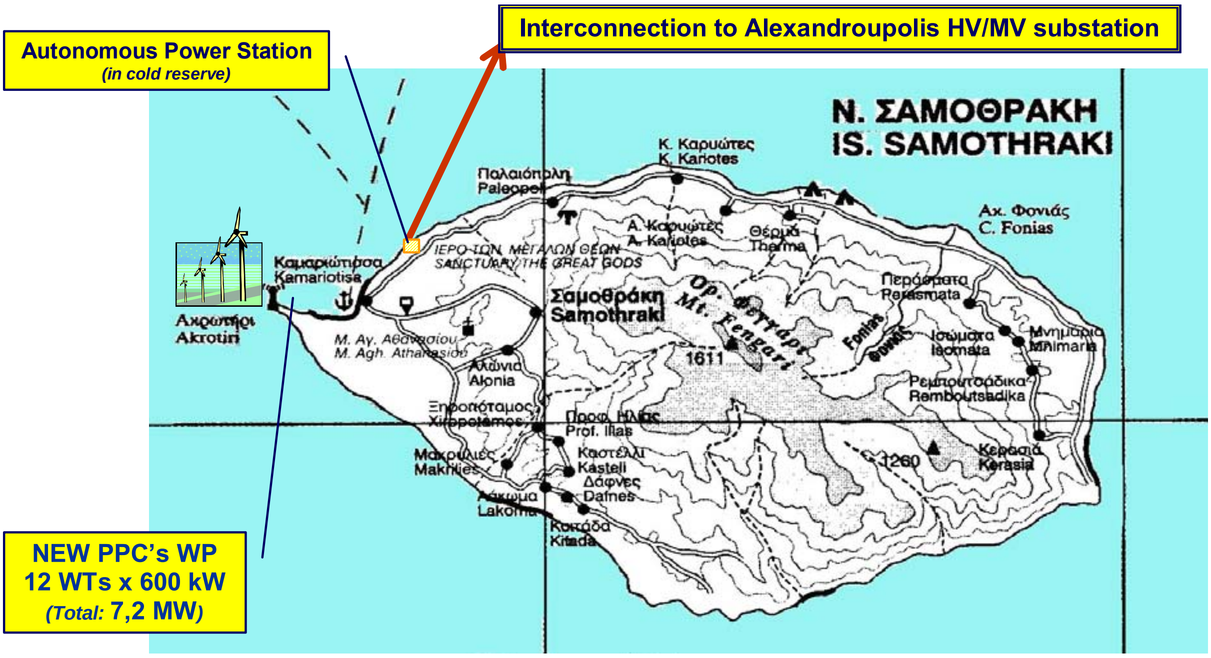
Samothraki is an island located in the north-eastern corner of the Aegean Archipelagos, in the midst of the Thracian sea, opposite of the Delta of the Evros River, the coast of Thrace and the city of Alexandroupolis.

It is one of most beautiful and picturesque islands in Greece. Its mountain Saos is the highest mountain in the Aegean. Its summit, Feggari, climbs up to 1664 metres. It is on this mountaintop that Homer imagined Poseidon, god of the sea, seated while watching the developments of the Trojan War.

The island is oval-shaped with an area of almost 180 km^2 and a coastline of 32 km.

4.1.2. Global description

Samothraki is a small island system with a peak demand of about 3000 kW. The network on the island is a 20 kV network consisting of overhead lines and cables.



Until mid 2000 Samothraki was powered by an Autonomous power station utilizing diesel generators. At that time the island was interconnected to the mainland power system of Greece (at Alexandroupolis substation), via two MV submarine cables and an overhead line.

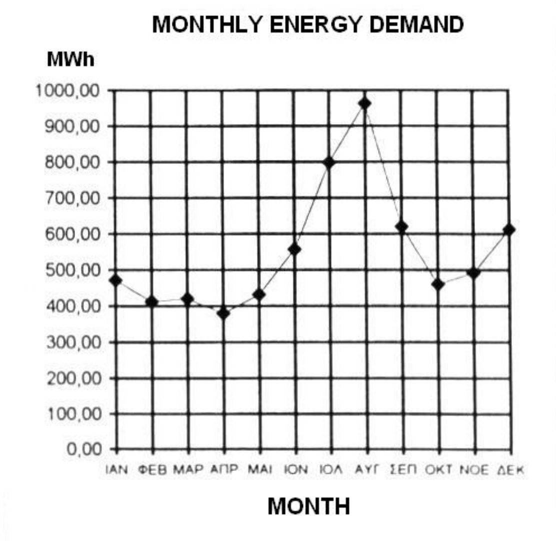
On Samothraki a small Wind Park (WP) with 4 W/Ts of 55 kW each is currently in operation. A new Wind Park consisting of 12 W/Ts of 600 kW each is planned to be installed in the future.

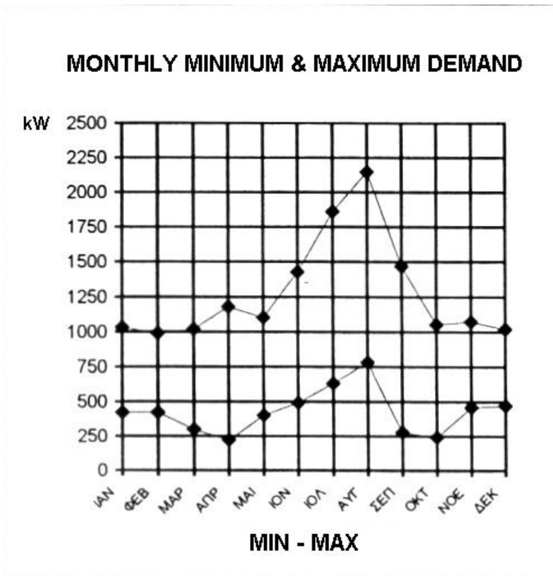
4.1.3. Context

The microgrid of Samothraki is connected to the Greek mainland power system. The global peak load of this system is on the order of 9000 MW.

The climate in Greece is typical of the Mediterranean climate: mild and rainy winters, relatively warm and dry summers and, generally, extended periods of sunshine throughout most of the year. The climate of Samothraki is this of northern Greece. It is mainly Mediterranean but slightly colder and wetter than this of central and southern Greece.

From the power system point of view, the seasonal variation of the load demand on Samothraki Island is given in the following figures:





4.1.4. Modelling

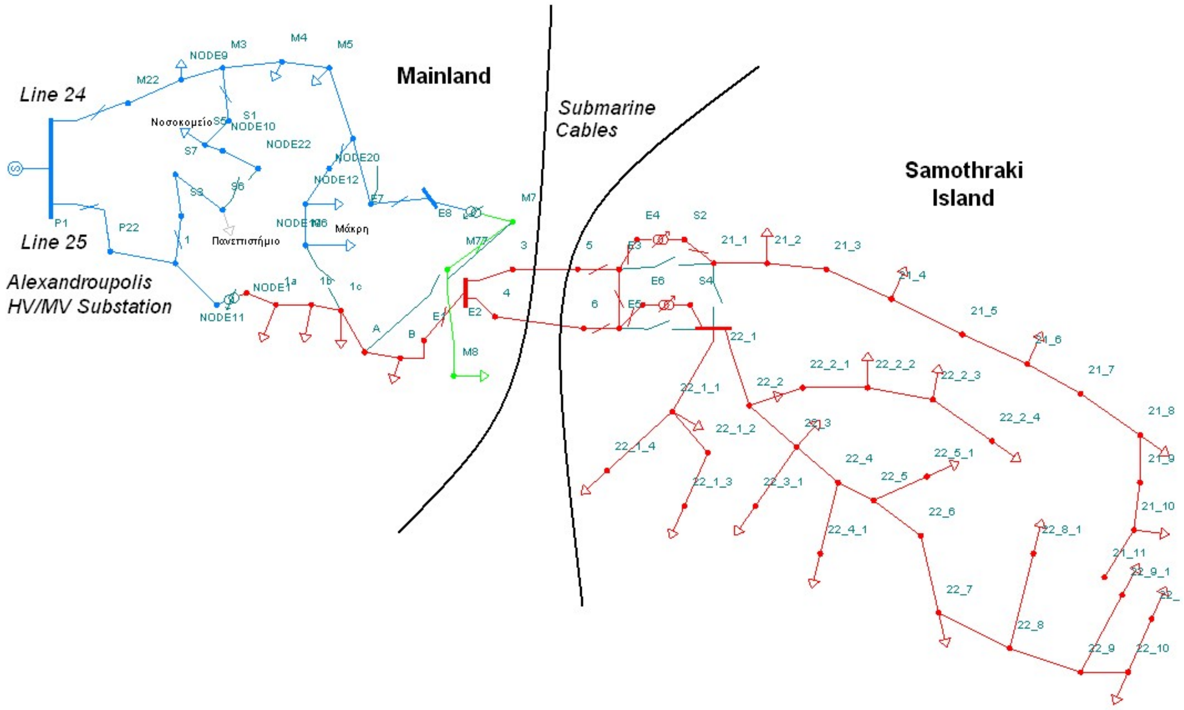
A great number of studies have been carried out on the Greek mainland power system where the microgrid of Samothraki is connected, but only few for the Samothraki power system. These concern mainly Power Flow Analysis for the evaluation of steady state load flow on the Samothraki network.

The software used for the simulations is PSS/Adept version 4.2.1. For the simulation of all power system elements the standard ADEPT libraries have been utilized

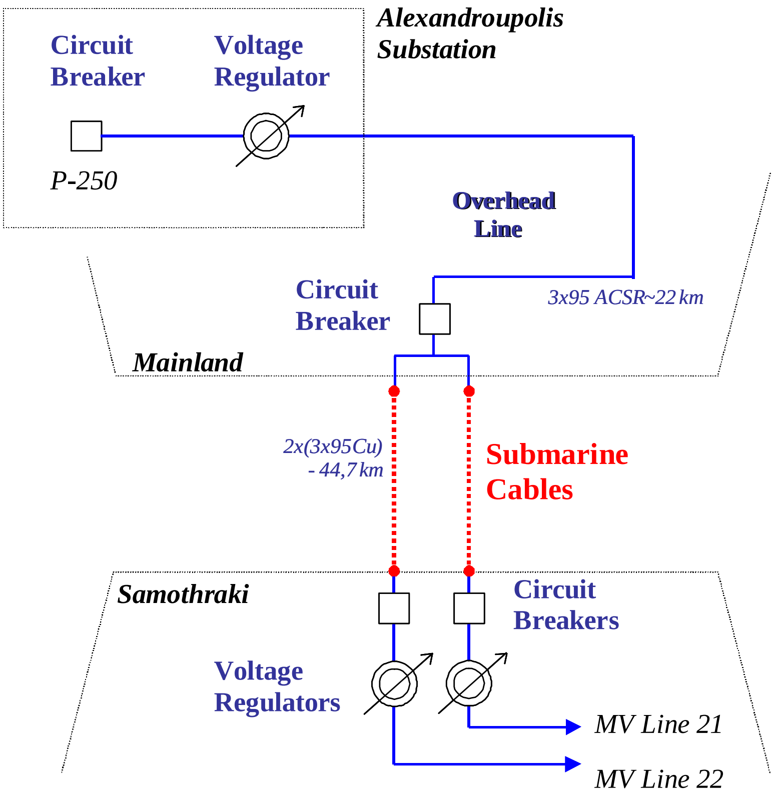
4.2. Topology

4.2.1. Schematic Diagram

The electrical layout of the study case network is presented.



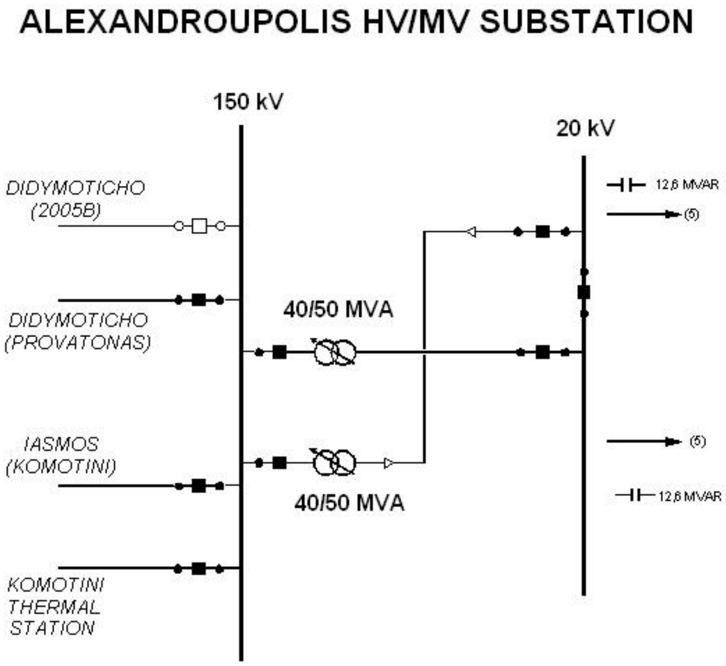
A simplified drawing of the Samothraki interconnection scheme to the mainland (present status) is given in the following figure



4.2.2. Components and characteristics

4.2.2.1. Alexandroupolis HV/MV substation

The island of Samothraki is interconnected to the mainland power system of Greece, via two MV submarine cables and an overhead 20 kV line, at Alexandroupolis 150/20 kV substation. The general layout of this substation is presented in the following figure:



4.2.2.2. 20 kV Nodes

The MV Line No 25 of Alexandroupolis substation supplies the network of Samothraki Island.

Table presents all nodes of this line and the corresponding peak/min/average loads for each node.

NODE	Peak Load		Minimum Load		Average Load	
	P [kW]	*Q [kVAr]*	*P [kW]*	*Q [kVAr]*	*P [kW]*	*Q [kVAr]*
Samothraki Island						
21_2	102	45	10,2	4,5	20,4	9
21_4	220	91	22	9,1	44	18,2
21_6	103	32	10,3	3,2	20,6	6,4
21_8	102	35	10,2	3,5	20,4	7
21_10	102	35	10,2	3,5	20,4	7

NODE	Peak Load		Minimum Load		Average Load	
	P *[kW]*	*Q* *[kVAr]*	*P* *[kW]*	*Q* *[kVAr]*	*P* *[kW]*	*Q* *[kVAr]*
22_1_1	104	45	10,4	4,5	20,8	9
22_1_3	104	45	10,4	4,5	20,8	9
22_1_4	104	45	10,4	4,5	20,8	9
22_10	35	15	3,5	1,5	7	3
22_11	70	30	7	3	14	6
22_2	180	75	180	75	180	75
22_2_2	34	15	3,4	1,5	6,8	3
22_2_3	102	45	10,2	4,5	20,4	9
22_2_4	140	60	14	6	28	12
22_3	34	15	34	15	34	15
22_3_1	180	75	18	7,5	36	15
22_4_1	70	30	7	3	14	6
22_5_1	34	15	3,4	1,5	6,8	3
22_7	140	60	14	6	28	12
22_8_1	68	30	6,8	3	13,6	6
22_9_1	34	15	3,4	1,5	6,8	3
Mainland						
1a	46,8	22,7	93,6	45,3	468	226,7
1b	9,4	4,5	65,8	31,5	94	45
1c	12,5	6	87,5	42	125	60
B	24,9	12,1	174,3	84,7	249	121
S6	1550,8	751,1	1550,8	751,1	1550,8	751,1

4.2.2.3. Lines and cables

Table presents all lines and cables along with their technical data.

From Node	To Node	Type	Section	Length [km]	R1 (Ω/km)	X1 (Ω/km)	R (Ω)	X (Ω)
Samothraki Island								
3	5	Submarine	3x95 Cu	46	0,248	0,125	11,41	5,75
4	6	Submarine	3x95 Cu	46	0,248	0,125	11,41	5,75
21_1	21_2	Overhead	70 AAAC	2,1	0,562	0,37	1,18	0,78
21_2	21_3	Overhead	70 AAAC	1	0,562	0,37	0,56	0,37
21_3	21_4	Overhead	70 AAAC	3,9	0,562	0,37	2,19	1,44
21_4	21_5	Overhead	70 AAAC	1,9	0,562	0,37	1,07	0,70
21_5	21_6	Overhead	70 AAAC	2,3	0,562	0,37	1,29	0,85
21_6	21_7	Overhead	70 AAAC	1,2	0,562	0,37	0,67	0,44
21_7	21_8	Overhead	70 AAAC	4,5	0,562	0,37	2,53	1,67
21_8	21_9	Overhead	70 AAAC	2,3	0,562	0,37	1,29	0,85
21_9	21_10	Overhead	16 ACSR	1,8	1,268	0,422	2,28	0,76
21_10	21_11	Overhead	16 ACSR	0,9	1,268	0,422	1,14	0,38
22_1	22_2	Overhead	50 ACSR	1,58	0,404	0,386	0,64	0,61
22_2	22_3	Overhead	50 ACSR	1,76	0,404	0,386	0,71	0,68
22_3	22_4	Overhead	50 ACSR	0,28	0,404	0,386	0,11	0,11
22_4	22_5	Overhead	50 ACSR	0,18	0,404	0,386	0,07	0,07
22_5	22_6	Overhead	50 ACSR	0,47	0,404	0,386	0,19	0,18
22_6	22_7	Overhead	70 AAAC	1	0,562	0,37	0,56	0,37
22_7	22_8	Overhead	70 AAAC	2,35	0,562	0,37	1,32	0,87
22_8	22_9	Overhead	70 AAAC	1,95	0,562	0,37	1,10	0,72
22_9	22_10	Overhead	70 AAAC	0,2	0,562	0,37	0,11	0,07
22_10	22_11	Overhead	16 ACSR	4,9	1,268	0,422	6,21	2,07
22_2	22_2_1	Overhead	16 ACSR	2,3	1,268	0,422	2,92	0,97
22_2_1	22_2_2	Overhead	50 ACSR	0,3	0,404	0,386	0,12	0,12
22_2_2	22_2_3	Overhead	50 ACSR	1,3	0,404	0,386	0,53	0,50
22_2_3	22_2_4	Overhead	16 ACSR	0,8	1,268	0,422	1,01	0,34
22_1	22_1_1	Overhead	50 ACSR	0,9	0,404	0,386	0,36	0,35
22_1_1	22_1_4	Overhead	16 ACSR	1,76	1,268	0,422	2,23	0,74
22_1_1	22_1_2	Overhead	16 ACSR	0,5	1,268	0,422	0,63	0,21
22_1_2	22_1_3	Overhead	16 ACSR	0,9	1,268	0,422	1,14	0,38
22_3	22_3_1	Overhead	16 ACSR	2,1	1,268	0,422	2,66	0,89
22_4	22_4_1	Overhead	16 ACSR	1	1,268	0,422	1,27	0,42
22_8	22_8_1	Overhead	16 ACSR	2,7	1,268	0,422	3,42	1,14
22_9	22_9_1	Overhead	16 ACSR	1,96	1,268	0,422	2,49	0,83
22_5	22_5_1	Overhead	16 ACSR	1,5	1,268	0,422	1,90	0,63
Mainland								
P22	1	Overhead	95 ACSR	6,5	0,215	0,334	1,40	2,17
1	NODE11	Overhead	95 ACSR	1	0,215	0,334	0,22	0,33
NODE1	1a	Overhead	95 ACSR	3,6	0,215	0,334	0,77	1,20
1a	1b	Overhead	95 ACSR	0,7	0,215	0,334	0,15	0,23
1b	1c	Overhead	95 ACSR	0,4	0,215	0,334	0,09	0,13
1c	A	Overhead	95 ACSR	0,7	0,215	0,334	0,15	0,23
A	B	Overhead	95 ACSR	9,3	0,215	0,334	2,00	3,11

From Node	To Node	Type	Section	Length [km]	R1 (Ω/km)	X1 (Ω/km)	R (Ω)	X (Ω)
B	E1	Overhead	95 ACSR	0,5	0,215	0,334	0,11	0,17

4.2.3. Evolution / Planning

The major network changes foreseen are related with the grid connection of the new wind park consisting of 12 W/Ts of 600 kW.

It is obvious that, since the total capacity of the new wind park (7200 kW) exceeds by far the island's current peak demand (~3000 kW), as well as the peak demand of the next 10 years, major network arrangements have to be planned

4.2.4. Main grid equivalent

Samothraki network is connected to the mainland by two submarine cables an overhead line and one HV/MV transformer in Alexandroupolis substation. The transformer has the following characteristics:

Nominal capacity	50 MVA
Nominal primary voltage	150 kV
Nominal secondary voltage	15.75/21 kV
No-load voltage set point	20.4 kV
Tap changer dead band voltage set point	+/- 2.5%
Number of taps	17
Tap changer voltage range	-12.5 ÷ +7.5 %
Capacitor bancs	12600 kVAR

The short circuit power at the HV side is considered equal to 181 MVA.

4.3. Generation

4.3.1. Static / steady state

Until mid 2000 Samothraki was powered by an Autonomous power station utilizing diesel generators. These units are currently considered as cold reserve and they have not been out of use until this time.

The only generation units operating on the island are 4 wind turbines of 55 kW each consisting a small Wind Park (220 kW installed capacity) at Kamariotissa, the port of Samothraki.

4.3.2. Planning / Evolution

A new wind park consisting of 12 wind turbines of 600 kW (total capacity 7200 kW) is planned to be installed on Samothraki, in the vicinity of the existing Wind Park. The exact type and the sizing of the wind turbines have not been decided yet.

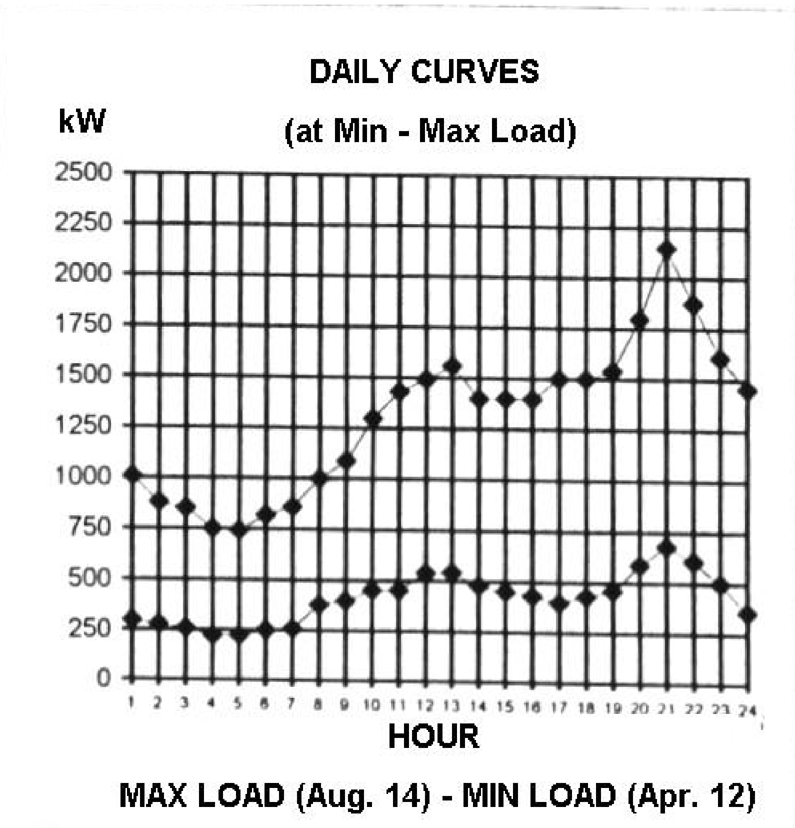
4.4. Load

4.4.1. Static / steady state

The loads are mainly residential and commercial.

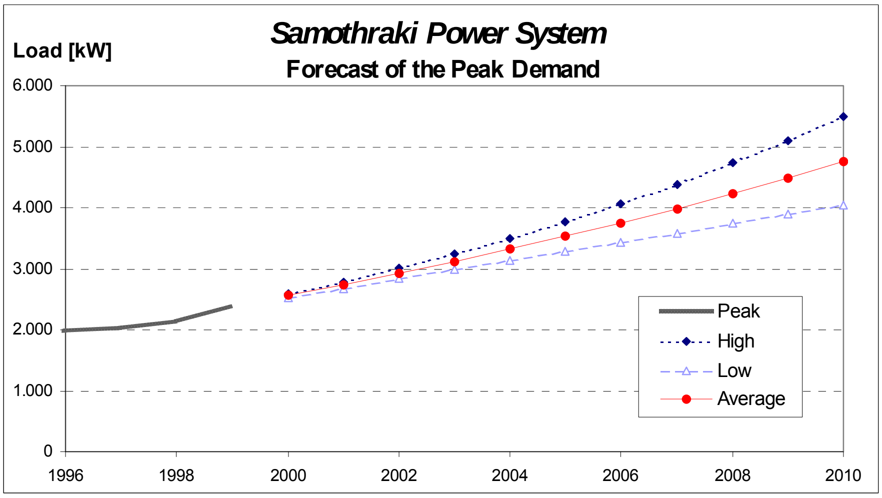
4.4.2. Profile

Examples of representative load curves are given in the following figure. This figure shows the daily variation of the load demand on Samothraki Island for two characteristic days corresponding to days of peak and minimum demand.



4.4.3. Planning / Evolution

The forecast of the peak demand of Samothraki Power System for the following years is given in the next figure:



4.5. Protection

4.5.1. Static / steady state

The protection scheme includes:

- Phase over-current
- Ground over-current
- Automatic reclosing
- Under frequency

The MV feeders are equipped with under frequency protection. On under-frequency conditions, the protection disconnects groups of MV feeders and not each feeder separately. So no partial load shedding exists on Samothraki Island.

At Alexandroupolis substation, there are no under/over voltage or over frequency relays.

4.5.2. Dynamics

In all MV overhead feeders there are three phase circuit breakers with operation circle:

O – 0.35 s – CO – 10 s – CO 10 s – CO

The protection scheme includes:

- Inverse time relay for phase-fault protection
- Single-phase extreme inverse time relay for phase-ground protection
- Relay with time setting 0.5 ÷ 3 s with two instant and two delaying contacts

4.5.3. Planning / Evolution

As concerns the protection scheme no major evolution is foreseen for the next years.

4.6. Operation procedures

4.6.1. Normal operation

The power system of Samothraki is interconnected to the mainland power system of Greece, via two MV submarine cables and an overhead line. At the time being, there is no special management system to control the power supply to the MV network of the island. It operates as a typical MV distribution network.

Currently, a new SCADA system is under development for the area of East Macedonia-Thrace. This system will supervise all MV feeders of the relative HV/MV substations (tele-monitoring) as well as network points of special interest, including the circuit breakers of the submarine cables. The measurement of voltage and power flow will be available in real time. In addition, tele-commands through a GSM communication system shall be possible.

4.6.2. Emergency operation

In case of fault on a MV overhead line, the protection system devices undertake to clear the fault. If this is possible in a specific time scale with no customer disconnection, no other action is required. Otherwise, a number of customers are disconnected and since the damaged part of the grid is located, the customers are fed by an alternative route.

If there is a damage of a submarine cable, the second cable has to carry the full load. In case of a simultaneous damage of both submarine cables, the island of Samothraki is disconnected from the mainland power system of Greece, a regional black out occurs and the local Autonomous power station, being in cold reserve, has to start up in order to feed the local loads. Till now, no damage of the specific submarine cables has occurred.

4.7. Quality of Service

4.7.1. General

The quality of service on the island of Samothraki is in accordance to the typical level realized in MV and LV distribution networks consisting of overhead lines in Greece. The quality is similar to this of the rest area of East Macedonia-Thrace. However it is expected to be improved even more, since a major program undergoes for the replacement of all stranded conductors (of both MV & LV lines) with bundled cables

4.7.2. Reliability

No reliability data are available exclusively for the Samothraki island network. As concerns the wider area of Alexandroupolis, where Samothraki belongs, it is estimated that the mean value of power outages for both MV and LV lines are 4-6 cases per 100 km and month. The mean time for the power cut is about 100 min for the MV and 70 min for the LV lines

4.8. Scenarios

4.8.1. Generation Mix

The current generation mix includes wind generation in parallel to the main distribution network. Since the local Autonomous power station remains in cold reserve, it should not be considered in the generation mix. No storage units are planned to be installed and no other micro-source is expected to be integrated in a near future.

4.8.2. Load level

The scenarios should consider both mean and extreme load levels (peak and minimum load demand) in combination with different wind power levels (from zero to full wind power output).

4.8.3. Isolated mode

The system may operate for a limited time scale in an isolated (islanding) mode if a sudden disconnection from the mainland happens and in the same time there is a near power balance between the energy demand and the power produced by the wind generators. The system has not been designed to operate in isolated mode and, although islanding is not considered probable to occur, it is a dangerous situation and measures have to be taken in order to be avoided.

Besides, as described previously, if there is a permanent disconnection from the mainland due to a simultaneous outage of both submarine cables or of the corresponding MV lines, a regional black out occurs and the local Autonomous power station has to start up.

4.8.4. Connected mode

According to the original planning for the wind park connection, the wind power generation should be injected to the network at Alexandroupolis HV/MV substation, through a dedicated MV distribution line and the corresponding submarine cable. The other line along with the other submarine cable should be used in order to supply the local demand.

In connected mode, the wind power generation shall be injected to the network through both MV distribution lines (L21 and L22) and the corresponding submarine cables. A switching scheme is proposed to be applied, so as the whole wind power or just a part of it shall feed the local loads. The surplus wind power shall be transferred directly to the mainland. The following figure gives the one-line equivalent diagram of the simplified Samothraki Island electrical network.

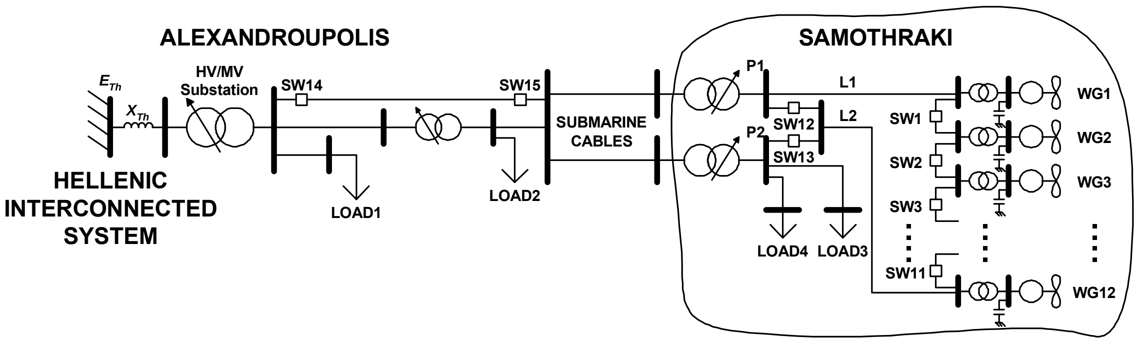


Figure 4.8.4-1: One-line equivalent diagram of simplified Samothraki Island electrical network

Depending on the status of the switches SW1 to SW13, the wind power generation can be divided in two groups, which are injected to the network through the distribution lines L1 and L2 at points P1 and P2 respectively. For example, if all switches from SW1 to SW12 are closed and the switch SW13 is open, the whole wind power will be connected to the submarine cable through point P1 and the two lines L1 and L2 will operate in parallel. In this case, the other cable (connected to P2) is feeding only the two local loads. In addition, if all switches except SW6 (intermediate switch in the terminal of wind generators) and SW12 are closed, then half of the wind farm generation will be injected to the network in point P1 through line L1 and the other half in point P2 through line L2. Thus, the local loads will be fed by the wind generators from WG6 to WG12.

4.8.5. Transition between the 2 modes

The transition from connected to isolated mode should not occur or it is expected to happen very rarely and only in case of a fault. No specific procedure exists to cope with that event. Then, there is a local blackout and subsequently the diesel unit feeds the loads.

The transition from isolated to connected mode is simple. The diesel units are stopped and the cables are reconnected to the mainland system.

4.8.6. Suggestion of simulation cases

The simulation should have the objective to determine the maximum number of wind generators that can be connected on a weak feeder supplying the local loads. The possibility of available network configuration that would allow switching a different number of wind generators on each feeder should be also investigated according to available wind power, local load, mainland network configuration, contingencies etc. Short and long-term voltage stability analysis has to be performed.

4.9. Socio-economic data & evaluation

The cost of energy at the MV side of a HV/MV transformer is about 0.30 € / kWh, without including fixed costs. This price is the marginal cost of energy production plus the cost of energy transmission.

The introduction of MicroGrids on Samotraki island is going to offer a positive socio-economic impact. The operation of the wind park according to the proposed scheme is more advantageous compared to the originally proposed scheme. The power and energy losses are significantly lower providing higher power efficiency and reduced emissions of particles, SO2, NOX, CO, HC and CO2. The annual energy losses have been calculated as follows:

Both network operation scenarios*, described in paragraph 4.8 were simulated with PSS/Adept 5.2 Software. The wind generators were modeled as induction machines and the load of the island was set at 1400 kVA with a power factor of 0,9.

The whole wind distribution curve for the area has been considered in combination with the wind turbine power curve. A separate load flow calculation has been performed for every different wind velocity, standing for different power output of the wind park. In all of load flow cases, the branch power losses have estimated. The results are as in the following table.

	Scenario A[1]	Scenario B[2]	Energy Gain
Annual Energy Losses (MWh)	3.703	1.845	1.858
Annual Energy Losses (% of yearly wind park production)	19,5%	9,7%	9,8%

It is clear that there is a considerable energy gain due to the losses reduction. This energy gain is equivalent to reduced emissions according to the next table:

	Total Emissions Avoided [tn]
CO_2	1579,44
SO_2	28,80
CO	0,33
NO_X	2,23
HC	0,09
Particles	1,49

Therefore the introduction of MicroGrids on Samotraki Island is also beneficial from the environmental point of view.

1 All 12 wind generators (7,2 MW) are connected to one submarine cable and the load of the island (1400kVA) is connected to the other submarine cable.

2 3 wind generators (1,8 MW) are connected to one submarine cable and 9 wind generators together with the load of the island (1400kVA) are connected to the other submarine cable