MORE MICROGRIDS – Advanced Architectures and Control Concepts for More Microgrids”

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1. Introduction

Microgrids are defined as low voltage (LV) or in some cases, e.g. Japan, as medium voltage (MV) networks with distributed generation (DG) sources, together with storage devices and controllable loads (e.g. water heaters, air conditioning) with a total installed capacity in the range of few kWs to couple of MWs. The unique feature of Microgrids is that although they operate mostly interconnected to the upper level voltage distribution network, they can be automatically transferred to islanded mode, in case of faults in the upstream network.

From the grid's point of view, a Microgrid can be regarded as a controlled entity within the power system that can be operated as a single aggregated load [1] and, given attractive remuneration, as a small source of power or ancillary services supporting the network. The installation of DG close to loads will reduce flows in transmission and distribution circuits with loss reduction as a consequence. Microgrids can provide additional benefits to the local utility by providing dispatchable power for use during peak power conditions and alleviating or postponing distribution system upgrades [2][3].

They can also provide network support in times of stress by relieving congestions and aiding restoration after faults. From a customer's point of view, Microgrids, similar to traditional LV distribution networks, provide their thermal and electricity needs, but moreover, enhance local reliability [4], and improve some power quality indices by supporting voltage and reducing voltage dips.

Power quality impact regarding harmonic distortion, voltage flickers or voltage unbalance have been and are being studied and proposed methodology for analysing, evaluating and proposing ways to combat them are inductively presented in References [5][6][7].

Development of environmental friendly and highly efficient power generation, like Combined Heat and Power (CHP) production and Renewable Energy Sources (RES) has attracted significant attention around the world. This is due to the increased awareness of the detrimental effects of the emissions from hydrocarbon based power stations on the environment, which has led to the commitment of many countries to comply with the Kyoto protocol [27] and reduce their Green House Gas (GHG) emissions. In line with the Kyoto protocol, emission trading has become a reality in several EU countries[28]. At the same time, the deregulated energy environment, among other effects, has favoured a gradual increase in Distributed Generation (DG) sources connected at the Medium Voltage (MV) or Low Voltage (LV) side of the Distribution Network [29]. DG sources like Micro Turbines (MT) and Fuel Cells (FC), either in CHP mode or purely for electricity production, are installed in the Distribution Network, even within consumer dwellings. RES, like Photovoltaics (PV), small Wind Turbines (WT) and small Hydro units, are also expected to increase their share in the coming years.

Co-ordinated operation and control of DER can help in obtaining full benefits from their operation. The technical challenges of controlling a multitude of small units with perhaps conflicting interests are huge, considerable research is however devoted in USA [29] and EU [1],[30] to develop centralised and decentralised control approaches of DER dominated MV and LV distribution networks. One possible future Distribution Network structure is the Microgrid, defined as a DER dominated network that operates mostly interconnected to the MV Distribution Network, but can be also operated in island mode, in case of faults in the upstream network [1]. Details of proposed control operation of Microgrids can be found in [31]. The installation of DER close to loads reduces flows in transmission and distribution circuits and thus losses. Moreover, the increased efficiency of DG sources, especially CHP, and the operation of RES reduces emissions. Preliminary studies [32] report that reduction of losses by 1% in the UK system reduces emissions by 2 million tonnes of CO_2 per year. Moreover, in the UK, reduction by 1 GWh from hydrocarbon can reduce emissions up to 400 thousand tonnes per year. In selected Portuguese networks of various types, ranging from rural LV networks to HV ones, 20% penetration of DG sources reduces CO_2 emissions by 2.07% -4.85% [33].

A significant impact of increased efficiency in the domestic utilization of gas and electricity on the reduction of CO_2 emissions is claimed in [34]. It is demonstrated that on European scale, 65 million tones of CO_2 per annum can be saved by 50 million installations of domestic CHP units. Next to the potential environmental benefits of DER, their economic evaluation is critically influenced by the developing CO_2 emissions trading markets [33], which also affect production costs of electricity generated by thermal (hydrocarbon) units [32].

In this part of the deliverable studies the environmental benefits of the co-ordinated operation of DER under two different optimisation objectives, namely minimising operating costs and minimising emissions. Moreover, the potential benefits from the participation of DER in the CO_2 emission trading markets are calculated. Section 6.1 presents the adopted methodology for the estimation of the environmental impact from the co-ordinated operation of DG sources. In section **3**, data for the typical LVs Microgrid and the multi-microgrid environment are presented. The results with regards to pollutants, $CO_{2,}$ $SO_{2,}$ NO_X and Particulate Matter (PM-10) are presented in section 6.2 for both LV and MV networks. In the same section under the two optimisation objectives and the surplus income obtained by the DER owners from their participation in the Emissions Trading markets.

This document describes the results from the simulation of Microgrid's operation under various combinations of realistic market prices and Renewable Energy Sources production. Two study cases have been derived from the Study Case LV Network, the first one considers all three feeders and the second one with the residential feeder only. The diagram for the whole Microgrid is presented in the Section 5 as well as data of the units used, cost functions and load curves for the network considered.

Section 3 briefly describes the Microgrid's operation and the Market policies applied.

The financial evaluation of the Renewable Energy Sources of the Microgrid, i.e. wind and solar power production using probabilistic analysis method is described in Section 4. In the study case results, the expected income for the Renewable Energy Sources owners is presented, according to the correlation with the market electricity prices. For the RES units feed-in tariff structures have been applied.

In the study cases of Section 5 results from the operation of the Microgrid are presented for different scenarios of market prices and level of RES production, for the two case studies examined and the two Market policies implemented. The calculations were executed at hourly basis for 12 months, while load and power exchange is presented only for August, as month with highest electricity prices, for different level of RES production.

2. Short description of the Microgrid operation and Market Policies

As a result of the deregulation of the energy environment and gradual transition to decentralized power production, integration of Distributed Generation sources has been widely applied.

MicroGrids are low voltage grids with modular generation connected into them which comprise distributed energy sources (micro-turbines, fuel cells, PV, etc.) together with storage devices (flywheels, energy capacitors and batteries) providing them operating either interconnected to the main grid or in an autonomous way, disconnected from the main grid.

The operation of the micro sources in the network can provide significant benefits to the overall system performance if managed and coordinated efficiently.

In achieving the complete benefits from the operation of MG, the integration of the micro sources into LV grids and their relation with the MV network upstream play important role, optimizing the general operation of the system. For this purpose a hierarchical system control architecture comprising three critical control levels has been adopted.

- Local Micro Source Controllers (MC) and Load Controllers (LC)
- MicroGrid System Central Controller (MGCC)
- Distribution Management System (DMS).

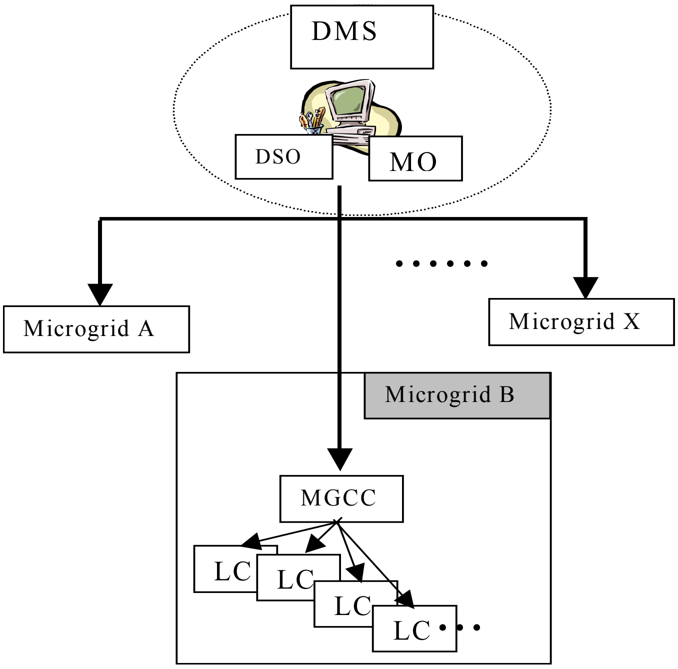

Figure 1 Microgrid control architecture

The Local Micro Source Controller (MC) is responsible for controlling the voltage and the frequency of the MG, following the demands from the MGCC, when connected to the power grid, or having autonomy in performing local optimization of the micro source power production in islanding mode.

Load Controllers (LC) provide load control capabilities following demands from the MGCC.

The MicroGrid Central Controller behaves as a traditional vertical integrated utility, having full information and knowledge of the managed network. It is responsible for the maximization of the

Microgrid's value and optimization of its operation, using market prices of electricity, costs and probably grid security concerns to determine the amount of power that the MG should draw from the distribution system, optimizing the local production capabilities. The defined optimized operating scenario is achieved by controlling the micro sources and controllable loads in the Microgrid by sending control signals to the MCs and LCs. In market terms, MGCC might represent the function of an Aggregator or Energy Service provider, which acts in the interest of one or more Microgrids.

Distribution Management system (DMS) deals with the management and control of distribution areas comprising several feeders including several MicroGrids.

From a grid's point of view, a Microgrid can be regarded as a controlled entity within the power system that can be operated as a single aggregated load and, given attractive remuneration, as a small source of power or ancillary services supporting the network. From a customer point of view, Microgrids similar to traditional LV distribution network provide their thermal and electricity needs, but in addition, enhance local reliability, reduce emissions, improve power quality and potentially lower costs of energy supply.

The scope of this document is studying the impact of integration of Microgrid on operating cost, production, i.e. energy exchange according to different policies under different input data.

Moreover, the results calculated under different scenarios could be subsequently used as inputs for the aggregation of many Microgrids.

The functions required for operation of the MGCC in interconnected mode are considered in this document, comprising two market policies.

2.1. Market Policies

2.1.1. Market Policy 1: The Microgrid serves only its own consumers requesting zero reactive power from the grid.

According to the prices of the market and the production cost, the MGCC tries to meet the active power demand of its own. When the prices are high, which usually means that there is peak demand at the whole grid, it is beneficial for the micro sources to produce energy in order to minimize the Microgrid cost of operation.

2.1.2. Market Policy 2: The Microgrid participates in the market by buying and selling active and reactive power from/to the grid.

It is assumed that the MG serves its own needs, but it also participates in the market offering bids via an aggregator that the MGCC has contracted with. The MGCC tries to maximize the value of the MG, maximizing the gains from the power exchange with the grid.

The information flow chart in both cases is shown in the following diagram (Figure 2).

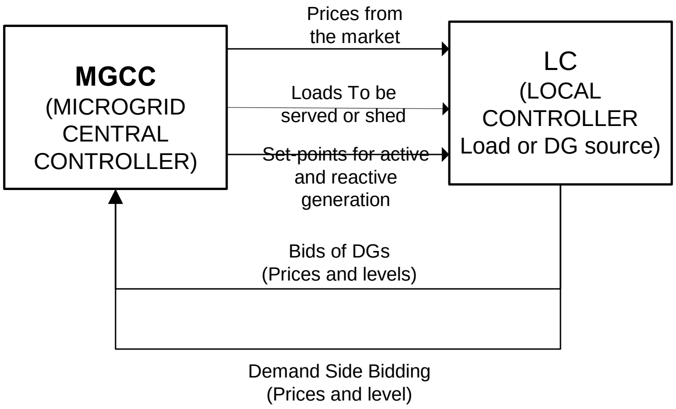

Figure 2 Information Exchange Diagram

3. Study case network

In this section, data about the study case network, the upstream network and the emissions are provided.

3.1. Description of the LV grid with DER

The typical LV network, shown in Figure 3 [21], is used in our study. The network comprises three feeders, one serving a primarily residential area, one industrial feeder serving a small workshop, and one commercial feeder. Typical daily load curves for each feeder and the whole Microgrid are shown in Figure 3. The total annual energy demand is 1160 MWh.

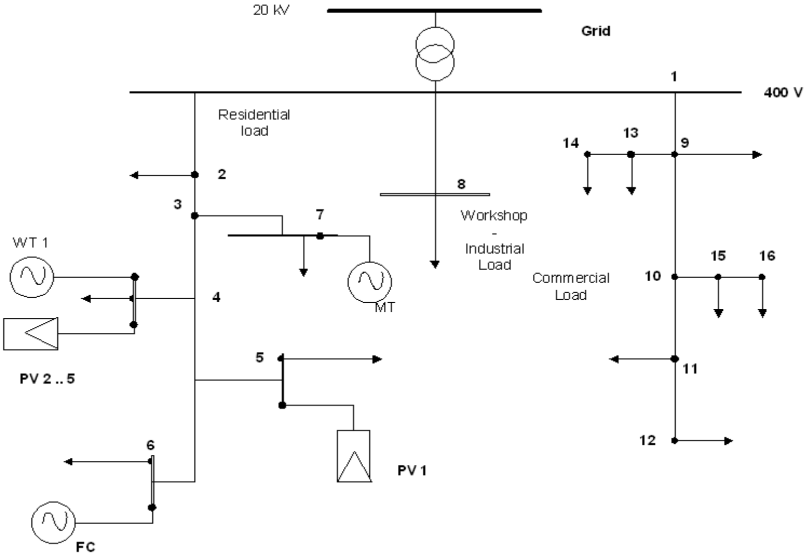

Figure 3 The study case LV Network

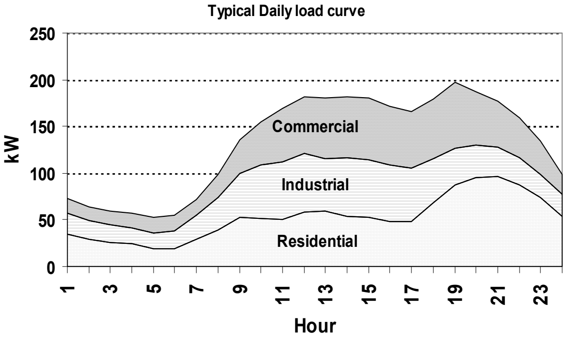

Figure 4 Typical load curve for each feeder of the study case network

A variety of DG sources, such as one Micro Turbine (MT), one Fuel Cell (FC), one directly coupled Wind Turbine (WT) and several PVs are installed in the residential feeder. It is assumed that all DG sources produce active power at unity power factor, i.e. neither requesting nor producing reactive power. Table 1 provides the capacity of the installed DG sources and their production costs. Both Micro-Turbine and Fuel Cell are assumed to run on natural gas, whose efficiency is 8.8 kWh/m^3 and price 10 c€/m^3 [22]. For the MT the efficiency is assumed 26%, while the efficiency of the Fuel Cell is assumed 40% [18]. Energy prices from the Amsterdam Power Exchange (ApX) for 2003 [48] have been assumed to represent realistically the open market in which the LV grid operates.

Table 1 Installed DG Sources

Unit ID	Unit Type	Max Power (kW)	Production Cost c€/kWh
1	MT	30	4.37
2	FC	30	2.84
3	WT	10	0
4	PV1	3	0
5	PV2	2.5	0
6	PV3	2.5	0
7	PV4	2.5	0
8	PV5	2.5	0

Wind Turbine and PV units are considered always committed and their output is, when available, always injected to the grid. The rest of the units are committed according to a)-c) operation modes. In our case MT and FC production depends on the operation mode followed and is the one that differentiates the emissions and economic savings.

In order to generalise the method used, instead of wind speed and solar radiation data time-series, probabilistic methods of deriving annual and monthly production of wind and PV have been utilised as described below.

For wind speed the Weibull parameters of the installation site and the wind turbine characteristic curve can be used to derive the expected annual wind power production using the methodology described in [15]. In our case study we have assumed Weibull parameters k=2.1 and c=8.1m/s and a 10kW Bergey wind turbine characteristic curve [49]. Under these assumptions the expected wind power production is 28.4 MWh [15].

In order to derive the expected savings from wind power production in a market environment, the wind power production is convoluted with the ApX market prices data for 2003, and the expected savings for the installed wind power as calculated in [15] are 1469.3 €.

In order to derive the monthly production of the wind turbine, monthly and annual wind power production data from a reference power system are used as equation (1) describes. Such data are usually available to the public either from the TSO reports [26]. In our case data from annual report of the Cretan Power system have been used [50].

$$Month\_WP\_tur = \frac{Annual\_WP\_tur}{Annual\_WP\_ref\_sys} \cdot Monthly\_WP\_ref\_sys \qquad (1)$$

where *Month_Wp_tur* is the monthly production of the wind turbine,
Annual_WP_tur the annual wind turbine production.
Annual_WP_ref_sys and *Monthly_WP_ref_sys* are the annual and monthly wind power production of the reference power system, respectively.

Solar radiation data for Athens have been used and the expected monthly solar power production has been calculated using the equations in [15] For the installed PV capacity the production is 15.2 MWh and using the convolution with ApX prices the savings due to PV operation are 1267.37 €.

For the monthly demand data, annual demand is distributed to each month according to the Reliability Test System weekly variation [23] and the typical demand curve of the Microgrid, as shown in Figure 4the monthly demand and production of RES sources of the studied LV network are given in Table 2.

Table 2 Monthly Demand and Production data in MWh

	Demand	Wind	PV
Jan	104.33	3.14	0.82
Feb	100.92	2.17	0.95
Mar	87.88	2.06	1.33
April	89.54	2.05	1.52
May	100.38	2.75	1.72
June	104.33	3.24	1.72
July	104.62	1.75	1.75
Aug	97.75	1.69	1.65
Sept	91.08	2.8	1.2
Oct	87.49	1.86	1.05
Nov	88.35	2.27	0.79
Dec	104.36	2.9	0.68

Wind and solar energy sources have zero direct emission during their operation. Fuel burning DER, like biogas units using tyres or agriculture residues, may even have higher emission levels than the ones of the central units [38]. Table 3 summarises the emissions of typical fuel consuming DG sources, assuming that they run on Natural Gas.

Table 3Typical emission data for various DG-sources (kg/MWh) [39]

Pollutants	**MT**	**FC**	**GT**	**ICE**
CO_2	724.6	489.4	678.2	650
NO_X	0.2	0.014	0.521	2.13
SO_2	0.004	0.003	0.004	0.206
PM-10	0.041	0.001	0.039	0.354

3.2. Data used for extended period simulation

The same assumptions for RES production are followed with Chapter 4.2. The average per season time-series as calculated by the Reliability Test System (RTS) and the typical demand curve of the Microgrid, (Figure 12) are combined to provide the daily demand per season of Table 4.

Prices from the Amsterdam Power Exchange (ApX (Figure 5) are used to simulate open market operation in which the LV grid operates. In this figure, each 24 steps correspond to one season, with the following sequence, Winter, Spring, Summer and Autumn at 3 levels: a)The highest per season and per hour, b) The average per hour and season and c) the lowest per season and hour.

The lowest demand bid corresponds to 6.9 €ct/kWh, which is the lowest energy tariff for LV networks in Greece during 2006 [25]. The high priority bids are considered at "infinitive" price. Each consumer is assumed to have low priority bids of 2kW, if his demand is higher than this value. For simplicity in the provided results, the power block and the bid price are considered constant throughout the period of study.

The analysis focuses on Market Policy 1 and shifting load as Demand Side Bid. Since production within Microgrid is usually lower than demand, policy 2 will not change results significantly.

Table 4 Daily demand for the various seasons

Season	Daily Demand (kWh)
Winter (W)	3571
Spring (Sp)	3096
Summer (Su)	3402
Autumn (A)	3009

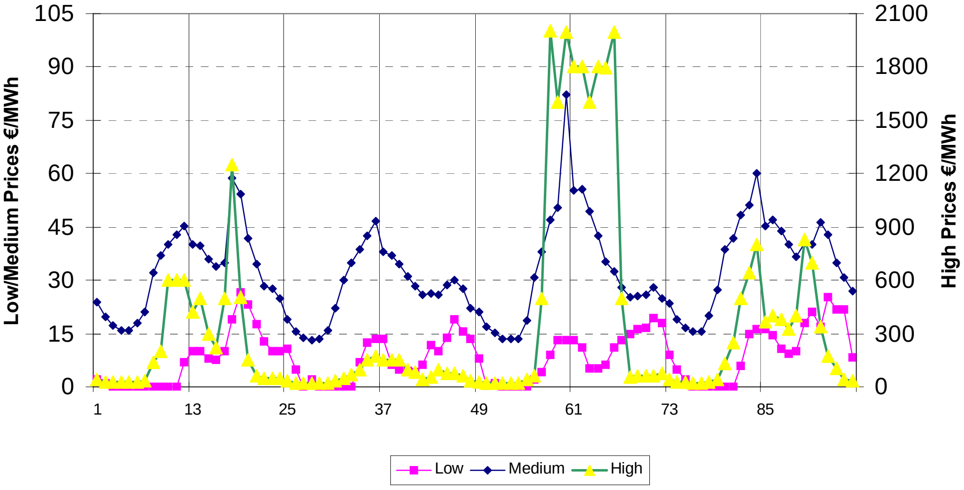

Figure 5 The market prices used. Season changes every 24 steps.

3.3. Typical MV network

A step forward is to consider many Microgrids operating in a typical radial MV (Medium Voltage) network, shown in Figure 6This network consists of two (2) parallel transformers of 25MVA, a typical size of many HV/MV substations in many semi-rural areas in Greece. The typical MV distribution network is derived from a physical MV network of Greece [40], which supplies a small town and the surrounding rural area at a rated voltage level of 20 kV supplied from a 150kV transformer station. The total number of LV Microgrids similar to Figure 4 is 64 in 8 feeders. The MV network structure consists of 130 nodes. The base voltage may be modified to study different voltage levels as long as the chosen values are realistic. The line length is 1km from bus to bus and they can be modified as long as the typical MV distribution network character is retained. Resistances and reactances of the MV network lines can be found in Table 5. On 20kV network and at buses the maximum capacity of dispersed generator is 6,5-10MVA [51].

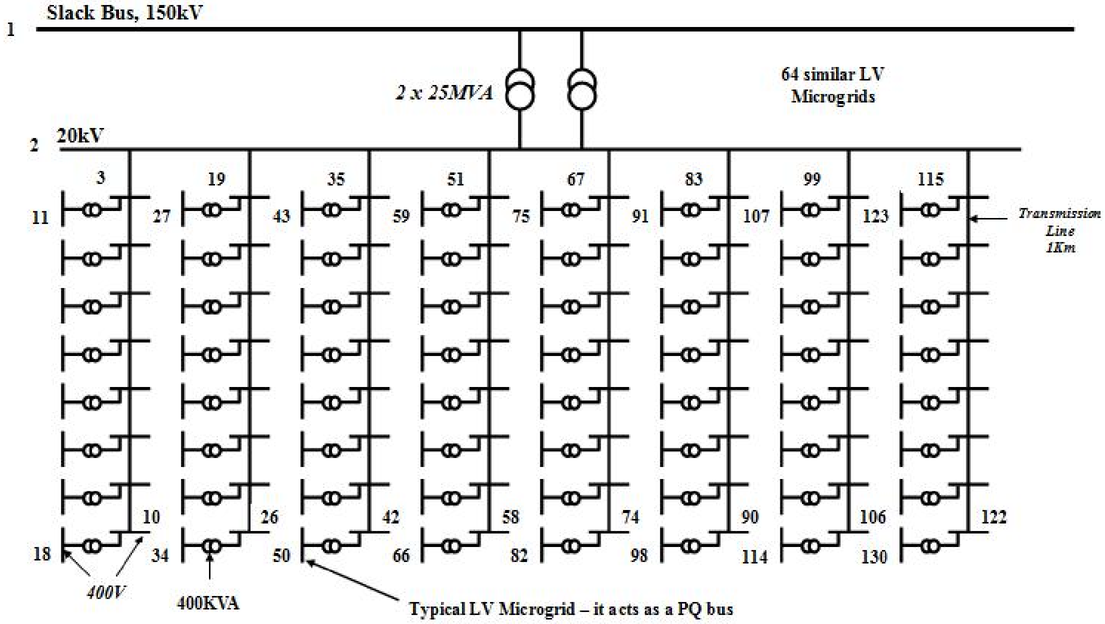

Figure 6 The MV network considered for multi-Microgrids environmen

Table 5 Electrical characteristics of MV transmission lines (20kV).

Conductors	3x50 Al+50 St (TC)
R (Ω/km)	0,823
X (Ω/km)	0,150
(jB) B (μS/km)	45,867
Imax (A)	123

3.4. Power System Connected

The LV network studied is assumed to operate connected to the power system of Crete. This is the largest island system in Greece with a variety of generating units, i.e. steam turbines, diesel units, gas turbines and one combined cycle unit using oil. For this system complete hourly time-series of load, production units and wind power production for year 2001 are available. From this, 24-hour emission curves can be derived for each month. Table 6, provides data about the average emissions of the power system of Crete in year 2001 and Table 7 summarises the monthly emissions. It is noted that during the summer months, when the gas turbines mostly operate consuming diesel oil with relatively low sulphur content, SO_2 emissions are reduced, but NO_X is increased [50].

Table 6 2001 Average annual Emissions of Crete (kg/MWh)

Pollutants	Annual Emissions
CO_2	809.4
SO_2	7.85
NO_X	2.25
Particulate Matter (PM-10)	0.501

Table 7 2001 Average Monthly Emissions of Crete Power System (kg/MWh)

	CO_2	SO_2	NO_X	PM-10
January	802.1	8.23	1.62	0.449
February	805.6	7.49	1.61	0.440
March	824.9	7.87	1.75	0.445
April	823.9	8.24	1.63	0.457
May	806.4	8.10	1.56	0.455

June	791.7	7.98	2.43	0.443
July	800.8	7.32	3.65	0.442
August	799.5	7.16	3.47	0.441
September	787.8	7.51	3.69	0.439
October	797.09	7.62	2.90	0.442
November	812.94	8.56	2.60	0.458
December	861.60	8.66	2.87	0.486

Table 8 provides the annual emissions for each type of unit operating in Crete. The peaking units are the old gas turbines, while in medium load conditions the new gas turbines are the marginal units. During low load conditions, e.g. spring nights, quick response units, gas turbines and diesels do not operate and only the must-run units steam and Combined Cycle unit operate. In such a case the marginal unit is the Combined Cycle (CC) unit.

Table 8 2001 Average Annual Emissions for Crete by type of unit (kg/MWh)

	CO_2	NO_X	SO_2	PM-10
Steam	964.7	1.09	17.50	0.59
Diesel	545	10.5	10.2	0.35
Combined Cycle	632.59	1.21	0.206	0.309
Old Gas turbines	1230	2.35	0.42	0.6
New Gas Turbines	861	1.65	0.28	0.42

The emission rate for each fuel type used and the specific consumption of each unit of the power system in kg/MWh or kg/GJ can be taken into account to estimate the avoided emissions. For the power system of Crete average fuel emissions per fuel are provided in Table 9. For other types of fuel, average emissions can be found in [36].

Comparing Table 1 and Table 8 it can be seen that the Fuel Cell has significantly lower emissions than all the types of units on Crete. On the other hand, the MT CO_2 emission level is higher than the corresponding emissions of both the Diesel and the Combined Cycle unit, but lower than the monthly or annual CO_2 emission levels.

Table 9 Emissions level for the two different types of fuels used in Crete

	Average Emissions (kg/Tn)	
	Heavy Oil	**Diesel**
Particles	1.86	1.19
SO_2	57.12	0.80
NO_X	11.4	4.67
CO_2	3200	2445

4. Economic Results

4.1. Impact analysis of Renewable Energy Sources using probabilistic analysis method

Probabilistic analysis techniques have been widely used for the estimation of the operating cost of a power system especially when intermittent power sources, such as Renewable Energy Sources (RES), are installed [8]. Moreover, probabilistic analysis techniques have been used in order to estimate the voltage profile and the active and reactive power flow in a distribution network when Wind Power penetration is significant [9].

In order to evaluate the financial impact of adding RES such as a wind turbine or a PV in a spot market environment, prices data from the Amsterdam Power eXchange (ApX) spot market [10] for 2003 have been used. The prices are sorted in bins in order to provide a discrete probability distribution function (pdf) of the hourly prices for the whole period examined.

Having calculated the distribution of the prices in the open market, the convolution with the power probability distribution function (pdf) of the RES production provides the expected revenues for the owner participating in such a spot market or the expected savings for the end users of the Microgrid.

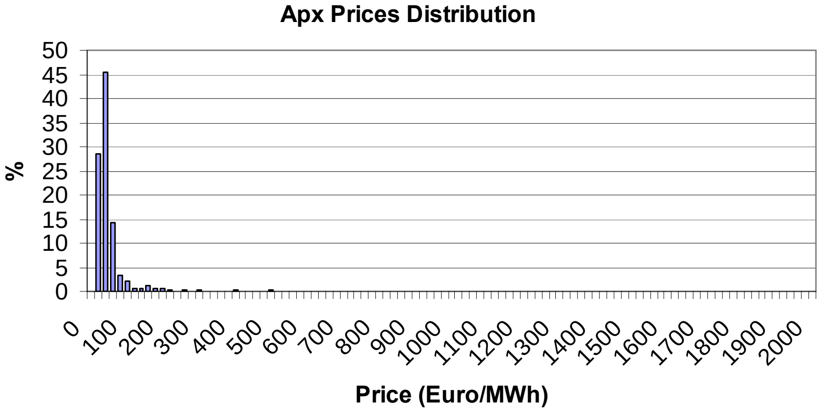

Figure 7 The ApX prices distribution for 2003

4.1.1. Wind Power

For wind power, the wind velocity is a random variable that usually follows a Weibull distribution as described by (2):

$$f(v) = \frac{k}{c} \cdot \left(\frac{v}{c}\right)^{k-1} \cdot \exp\left(-\left(\frac{v}{c}\right)^{k}\right) \qquad (2)$$

The wind velocity data are converted to wind velocity at the hub height of the wind turbine using equation (3)

$$\frac{U(Z)}{U(H)} = \left(\frac{Z}{H}\right)^{a} \qquad (3)$$

where Z is the hub height , H is the anemometer height and α is the Wind Shear Exponent describing the smoothness of the terrain. For smooth terrain α has values within 0.1 to 0.12.

The wind power production is calculated using the wind velocity to power characteristic equation (2). This production is a discrete pdf calculated at the following capacity points, at which the probabilities are calculated :

$$C_0 = 0 \qquad (4)$$
$$C_k = k \cdot \Delta P, k = 1..n$$

Where ΔP is considered equal to 5% of the nominal capacity therefore n in our case is equal to 20.
The possibilities of occurrence for each capacity point are given by the following set of equations :

$$\begin{aligned} p_0 &= 1 + \Phi(\mathrm{Vcut\_in}) - \Phi(\mathrm{Vcut\_off}) \\ p_k &= \Phi^{-1}((2k+1)\cdot\frac{\Delta P}{2}) - \Phi^{-1}((2k-1)\cdot\frac{\Delta P}{2}), k = 1.n-1 \\ p_n &= \Phi(\mathrm{Vnominal}) - \Phi^{-1}((2n-1)\cdot\frac{\Delta P}{2}) \end{aligned} \quad (5)$$

where Φ(x) is the cumulative distribution function of the wind speed –Weibull in this case, at the hub height. Vcut_in is the velocity above which the WT starts producing active power and vcut_off is the cut-off speed. $\Phi^{-1}(x)$ represents the wind velocity at which the x wind power production is calculated. Then, using convolution of wind production pdf and spot market prices pdf, the expected revenues for Wind Power can be evaluated.
In order to evaluate the WT production when prices and WT production are positively correlated (the production is high when the prices are high) or negatively correlated (high prices at periods of low production), the percentiles at steps of 5% for both pdfs can be calculated and then the expected revenues are calculated by multiplying the percentile points.

4.1.2. Solar Power

The maximum available power for a PV at a specific site is function of the time, the sun angle and the geographical coordinates of the installation site as described in [11], [12]. The maximum production of the PV at 9 am for instance is not equal to the installed capacity of the PV, if the PV is fixed e.g. on the roof of a building. The production of the PV depends also on the clearness index, the ratio of the beam radiation on a horizontal surface to the radiation of the same surface outside the atmosphere. Measurements of clearness index are made at various sites of the world and typical distribution of such measurements are presented in [12]. The clearness index is also associated with diffuse radiation measurements, as described in [13]. Therefore if measurements for diffuse radiation are available like in [14], then the probability distribution function for clearness index can be easily derived. Thus the probability distribution function of the PV production can be derived knowing the clearness index distribution, the maximum available radiation and data about the efficiency of the modules and their surface area.

The methodology followed for evaluating the PV production in a market environment consists of the following steps [15] :

- Specify the latitude of the place and the installation angle of the PV.
- Find representative days for each month and the time of sunrise and sunset.
- Neglecting cloudiness calculate the maximum solar radiation for the representative day for the specified geometry of the PV using equations (6)-(12).
- Taking into account the discrete probability of clearness index for the specified site calculate the distribution of the solar radiation for each hour of the representative days.
- The solar radiation is normalized using the maximum solar radiation result. The normalized result is the fraction of PV production.
- Convolute the prices probability distribution with the corresponding normalized production for the specific hour and month.

In order to calculate the solar radiation at the specific site for the representative day and hour the following equations are used :

$$H(A) = I_0 \cdot A^{\cos\sec h} \cdot \cos\boldsymbol{\theta} + \frac{I_0 \cdot \sinh \cdot (1 + \cos SL) \cdot (1 - A^{\cos\sec}}{4 \cdot (1 - 1.4 \cdot \ln A)} \qquad \textbf{(6)}$$

where A is the clearness index, SL is the inclination angle of the surface and

$$\sinh = \sin\phi \cdot \sin\delta + \cos\phi \cdot \cos\delta \cdot \cos\omega \qquad (7)$$

$$\cos\theta = \sinh \cdot \cos SL + \cosh \cdot \cos SL \cdot \cos(a - a') \qquad (8)$$

$$\cos a = \frac{\sinh \cdot \sin\phi - \sin\delta}{\cosh \cdot \cos\phi} \qquad (9)$$

Io the solar constant (1353 W/m^2),
φ is the geographical latitude of the site,
δ is the solar beam inclination angle given by the following equation as described in [24].

$$\delta = \sin(292 - 30 \cdot m - d) \qquad (10)$$

where m is the month and d is the number of the day of the month,
a’ is the direction of the surface compared to the south (for north hemisphere) or to the north for southern hemisphere,
h is the solar elevation angle and ω is the hour angle , that is given by the following equation:

$$\omega = 15 * (12\text{-hour}) \qquad (11)$$

This equation is modified for the daylight saving time (during April to October) as

$$\omega = 15 * (13\text{-hour}) \qquad (12)$$

All the angles used are in degrees.

The distribution of the spot market prices should be taken at each hour of the day time and for each month in order to take into account the seasonal and hourly variability of PV maximum production. Convolution of PV production and spot markets distribution for the specific hour and month will provides the expected income for the PV investor for each hour and month and thus for the whole year.

4.1.3. Case studies data

4.1.3.1. Wind Power

Data about the wind velocity distribution at an installation site near the North Sea coast in the Netherlands are used [16]. The Weibull distribution at the anemometer height is expressed using (1) and the parameters are k=2.1 and c=8.1m/s. Measurements are taken at 18.5 m whereas the hub height is 24m. The Wind Shear Exponent is considered equal to 0.11 due to the smooth terrain.

A typical Wind Turbine of 10 kW is used. The Wind Turbine power curve is represented by a 3rd order polynomial as presented in the following equation:

$$power(v) = \begin{cases} 0, \text{if } 0 \le v < 4 \text{ or } v > 54 \\ 0.0136 v^3 + 0.3776 \cdot v^2 - 2.176 \cdot v + 3.732, \text{if } 4 \le v \le 14.07 \\ -2.39 \cdot v + 43.63, \text{ if } 14.07 \le v \le 17 \\ 3, \text{ if } 17 \le v \le 54 \end{cases} \qquad (13)$$

where v is the wind velocity in m/s and power is the output in kW.

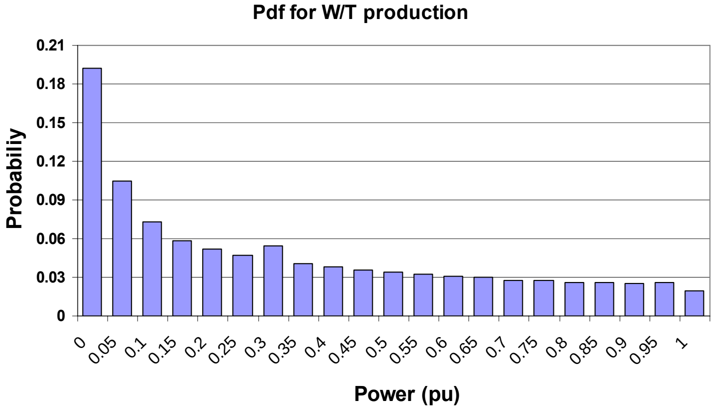

Figure 8 The probability distribution function of wind power production

4.1.3.2. Solar Power

It has been assumed that the PV installation site follows the solar radiation and clearness index data of the Solar Village in Athens [12], [17]. The latitude is 38°N and we have assumed that the PV faces south directly, therefore a'=0° and the installation angle is SL=38°,equal to the latitude of the installation place. The installed PV capacity is 1 kW. The representative days used for calculating the maximum production available according to the methodology described in section 2 are given in Table 10: The clearness index for the whole year is shown in Figure 9.

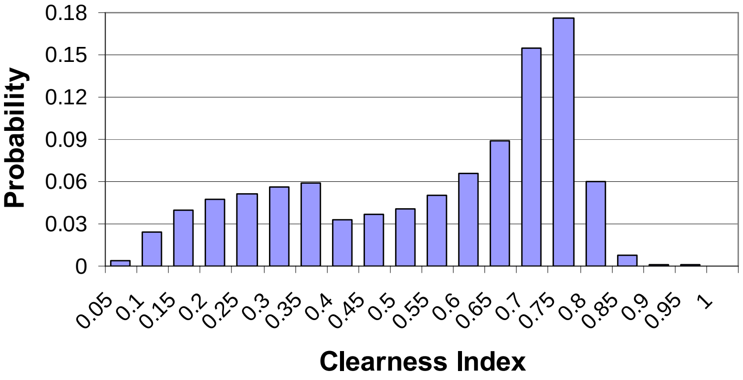

Figure 9 The clearness index probability distribution function

Table 10 Characteristic days for each month

Month	Day	Sunrise	Sunset
January	17	7.39	17.32
February	16	7.14	18.05
March	16	6.35	18.33
April	15	6.50	20.01
May	15	6.15	20.28
June	11	6.02	20.47
July	17	6.16	20.46
August	16	6.41	20.17
September	15	7.07	19.33
October	15	7.34	18.48
November	14	7.01	17.17
December	11	7.32	17.06

Using equation (6) and the clearness index pdf, the PV production pdf can be derived for each month and each hour. A typical example at 11:00 of the representative day of June is shown in Figure 10.

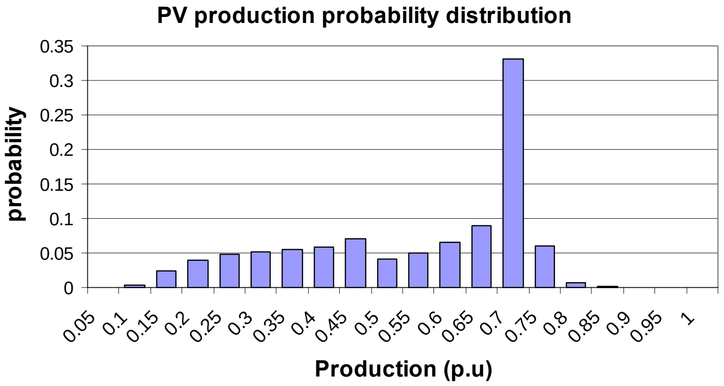

Figure 10 The probability distribution function of PV production at 11:00 am of the characteristic day of June

Convolution of spot market prices pdf and PV pdf for each hour and month provides with expected income for the whole year.

4.1.4. Case study results

4.1.4.1. Wind Power

The annual production of the WT at the installation site is expected to reach 28672 kWh and the expected income for the WT owner with uncorrelated prices and wind production 1469.3 € or 5.1 €ct/kWh. If the production is assumed positively correlated with the prices of the spot market, this means that the production is high when the prices are high, the expected income reaches 5248.43 €. On the contrary, when prices of the spot market and the wind power production are negatively correlated, which means that we have high prices at periods of low production, then the income is 527.85 €. In the former case the value of the kWh is 18 €ct/kWh, while in the latter only 1.8 €ct/kWh.

Using Greek tariff scheme for islands, the expected income would have been 2425.65 €.

4.1.4.2. Solar Power

Using the described methodology, the following results have been derived for each month of 2003.

Table 11 Monthly revenues and production for the PV installation

Month	Revenues (€)	Production (kWh)	Average Price (€ct/kWh)
January	5.4	63.34	8.52
February	3.3	72.72	4.54
March	4.14	102.68	4.03
April	4.36	116.88	3.73
May	5.7	132.51	4.3
June	15.48	132.68	11.66
July	9.88	134.91	7.33
August	24.62	127.09	19.37
September	6.57	92.41	7.11
October	9.41	80.83	11.65
November	5.82	60.92	9.55
December	2.81	52.56	5.34

The expected production is 1170 kWh while the expected income is 97.49 €. The average price for the whole year is 8.34 €ct/kWh. If the Greek feed-in tariff scheme is followed for island systems then the expected revenues would be 526.5 €. The following tables summarize the income for both wind and PV power.

Table 12 Expected income for wind power production

Prices and Wind production	**Income[€]**
Uncorrelated	1469,3
Positively corelated	5248.3
Negatively corelated	527.85
Greek tariff scheme	2425.65

Table 13 Expected income for PV power production

Prices and PV production	Income [€]
Market	97,49
Greek tariff scheme	526.5

4.1.5. Pay-back analysis

Having calculated the expected income for the RES installation the pay back period for the installation can be calculated using equation (14).

$$Ann\_Income = \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \cdot InsCost \qquad \textbf{(14)}$$

n is the depreciation time, i is the discount rate, InsCost is the installation cost and the Ann_Income is the expected income.

Typical Installation costs for a small wind turbine is 2500€/kW and for PV 7000€/kW [18]. Different subsidy systems can be examined, such as different percentages of subsidies in the capital investment. The one used in our study is 30% subsidy of the capital investment for Wind turbine installation and the 50% subsidy of the PV installation cost, as the Greek “Competitiveness” program [19] foresees for such installations.

The maximum interest rate given in (15) for paying back the investment is the ratio of annual income to the investment cost, that is the limit to infinitive for n of equation (14)

$$i^{MAX} = \frac{Ann\_Income}{InsCost} \qquad (15)$$

The results are summarized in Table 14 for wind power and in Table 9 for PV installations.

4.1.5.1. Wind power

In Table 15the years for paying back the investment cost with 7.5% interest rate are shown. If any number in Table 14is smaller than 7.5% then the respective case cannot be paid back. Such is the case with negatively correlated prices and the case of uncorrelated prices without any subsidy.

In Table 16 the interest rate for paying back within 12 years is summarized, while the necessary subsidy scheme for 10 years period and 7.5% interest rate is summarized in Table 17.

Table 14 Maximum interest rate for pay-back of the investment

	Not Correlated	Positively Correlated	Negatively Correlated	Greek tariff scheme

Without subsidy	5.87%	21%	2.11%	9.6 %
With subsidy	8.43%	30%	3.01%	13.79%

Table 15 Years for pay-back wind power and 7.5 % rate

	Not Correlated	Positively Correlated	Greek tariff scheme
Without subsidy	Not paid back	6.11	20.5%
With subsidy	30.94	4	10.77%

Table 16 Interest rate for pay-back period of 12 years

	Not Correlated	Positively Correlated	Greek tariff scheme
Without subsidy	Not paid back	18.1%	2.42%
With subsidy	0.1%	28.5%	8.85%

Table 17 Necessary subsidy scheme for 10 years pay-back period and interest rate, 7.5 %

Not Correlated	Positively Correlated	Negatively Correlated	Greek tariff scheme
58.92%	0%	85.51%	33.5%

4.1.5.2. Solar power

The results from payback analysis are summarized in the following tables.

Table 18 Maximum interest rate for pay-back of the investment

	Not Correlated	Greek tariff scheme
Without subsidy	1.39%	7.5%
With subsidy:	2.7%	15.02%

The necessary subsidy scheme for 20 years period and 7.5% interest rate is summarized in Table 19.

Table 19 Necessary subsidy scheme for 20 years period and interest rate, 7.5 %.

Not Correlated	Greek tariff scheme
85.71%	23.33%

4.1.6. Conclusion from the probabilistic analysis of RES

Probabilistic analysis helps in estimating the expected income for solar and wind installations in market environment. If Microgrids are expected to exchange power at open market prices then such analysis can help in evaluating the impact of operating RES during the whole year.

Timely pay-back for the installations would be performed if there is some kind of subsidy, either in the prices or in the installation cost. If the subsidy scheme is insufficient or no subsidy is available, the operating cost for the Microgrid is increased. The percentage increase will depend on the size of the Microgrid and the size of RES installed capacity. Indicatively, the required subsidy scheme if the market prices from ApX are used to pay back the investment in RES within their life time and 7.5% of interest, would be 85.71% for PVs and within 0%-85.51% for wind power. If the prices and wind power are positively correlated the subsidy is 0% while if these two variables are negatively correlated the necessary subsidy is 85.51%.

4.2. Study of Microgrid operation for various market prices combinations.

Typical, LV network, shown in Figure 11 is used in our study [21]. The network comprises three feeders, one serving a primarily residential area, one industrial feeder serving a small workshop, and one commercial feeder. A variety of DER, such as one Micro Turbine (MT), one Fuel Cell (FC), one directly coupled Wind Turbine (WT) and several PVs are installed in the residential feeder. It is assumed that all DER produce active power at unity power factor, i.e. neither requesting nor producing reactive power. Table 20 provides the capacity of the installed DG sources and their fuel costs. Both, Micro-Turbine and Fuel Cell are assumed to run on natural gas, whose efficiency is 8.8 kWh/m^3 and price 10 c€/m^3 [22]. For the MT the efficiency is assumed 26%, while the efficiency of the Fuel Cell is assumed 40% [18]. Energy prices from the Amsterdam Power Exchange (ApX) for 2003 [10] have been used to represent realistically the open market in which the LV grid operates.

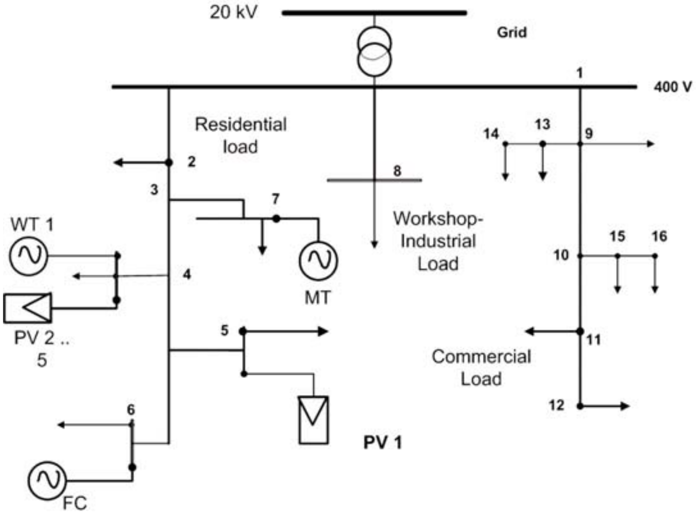

Figure 11 The study case LV Network

Table 20 Data for the Microgrid's units

UnitID	Unit_Name	Min_Capacity[kW]	MaxCapacity [kW]	Fuel_Coeff_A [Ect/kWh^2]	Fuel_Coeff_B [Ect/kWh]	Fuel_Coeff_C [Ect/h]
1	Microturbine	6	30	0,01	4,37	0,01
2	FuelCell	3	30	0,033	2,41	0,8415
3	Wind1	0,001	15	0	0	0
4	PV1	0,001	3	0	0	0
5	PV2	0,001	2,5	0	0	0
6	PV3	0,001	2,5	0	0	0
7	PV4	0,001	2,5	0	0	0
8	PV5	0,001	2,5	0	0	0

For the monthly demand data, annual demand is distributed to each month according to the Reliability Test System weekly variation [23] and the typical demand curve of the Microgrid, as shown in Figure 12.The monthly demand and production of RES of the studied LV network are given in Table 21.

Data about the wind velocity distribution of the island of Crete were used. A typical Wind Turbine of 15 kW is used. The Wind Turbine power curve is represented by a 3rd order polynomial as presented in (12).

For providing the time series for each of the PVs of the Microgrid, data for PVs from the campus of the National Technical University of Athens are used, with installed capacity of 1.1 kW [24].

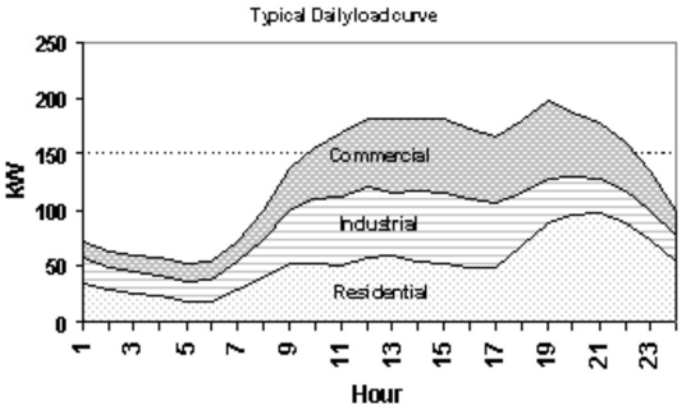

Figure 12 Typical load curve for each feeder of the study case network

Table 21 Monthly demand for the microgrid in MWh

Month	Demand
January	104.33
February	100.92
March	87.88
April	89.54
May	100.38
June	104.33
July	104.62
August	97.75
September	91.08
October	87.49
November	88.35
December	104.36

Several characteristic cases (months) are presented, i.e. APX prices for April as a month with lowest electricity prices and August as a month with highest electricity prices.

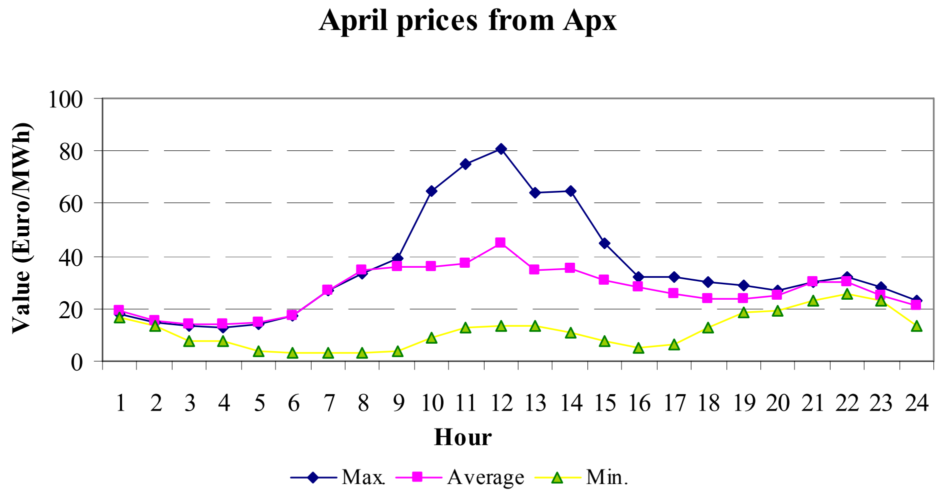

Figure 13 Electricity prices according to the APX prices for April

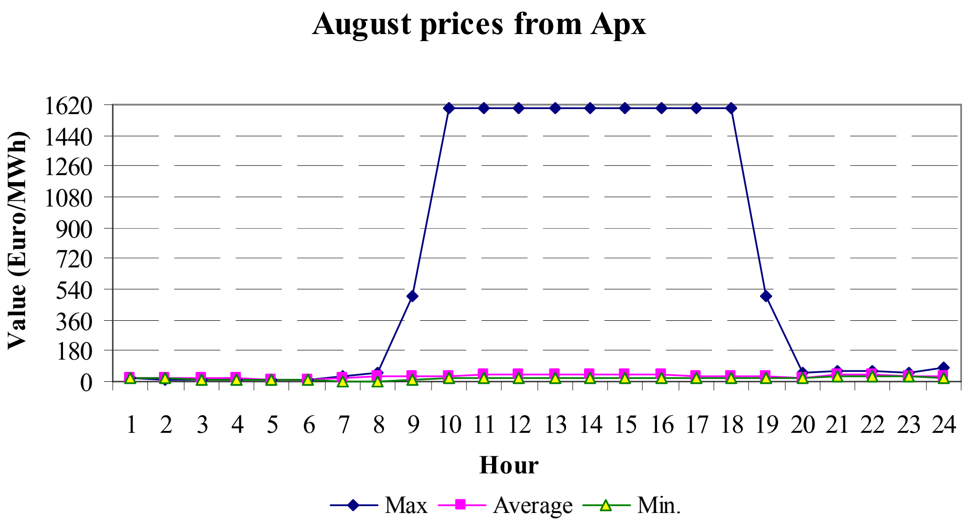

Figure 14 Electricity prices according to the APX prices for August

4.2.1. Case studies

Two case studies are examined in this document, including both Market Policies: Case study 1, comprising the 3 feeders and Case study 2, comprising the residential feeder only.

The following scenarios of operation have been examined regarding the results from the cases studies:

- No MG – sources are considered, i.e. all the demand has been met by the grid.
- Microgrid operation applying Market Policy 1.
- Microgrid operation applying Market Policy 2.

The calculations are made on hourly basis in a period of 12 months for nine characteristic cases for each of the operating scenarios above, according to the following combinations of market prices and RES production level:

- High RES production – low APX prices
- High RES production – average APX prices
- High RES production – high APX prices
- Average RES production – low APX prices
- Average RES production – average APX prices
- Average RES production – high APX prices
- Low RES production – low APX prices
- Low RES production – average APX prices
- Low RES production – high APX prices

indicating the days with highest, average and lowest wind and PV production and the days with highest, average and lowest electricity prices, according to ApX. The bids of the DG sources are as in Table 20. The scope was to calculate the maximum potential savings for the customers in Policy 1 and the maximum income for the Aggregator in Policy 2.

4.2.2. Results

4.2.2.1. Case study 1

Since 9 cases have been studied according to the level of RES production (lowest, average or highest) and the electricity prices according to Amsterdam Power eXchange prices, the final results are as follows. The cases of high APX prices have been highlighted in the tables 13-16.

Graphical presentation of the results is also shown in Figure 15-Fgiure Figure 17

Month	RES_production	APX_prices	MG_production [kWh]	MG_production [%]	Demand [kWh]	Output_costs with MG [euros]	Output_costs without MG [euros]	Cost_reduction [%]
January	high	low	244,93	7,1	3450,99	49,73	52,40	5,09
	high	average	484,93	3,71	3450,99	113,07	127,97	11,65
	high	high	1054,93	30,57	3450,99	645,72	967,13	**33,23**
	average	low	151,63	4,39	3450,99	50,35	52,40	3,90
	average	average	391,63	11,35	3450,99	115,52	127,97	9,73
	average	high	961,63	27,87	3450,99	671,92	967,13	**30,52**
	low	low	48,33	1,4	3450,99	52,09	52,4	0,58
	low	average	288,34	8,36	3450,99	119,34	127,97	6,75
	low	high	858,34	24,87	3450,99	698,32	967,13	**27,79**
February	high	low	247,31	6,69	3695,87	64,9	69,15	6,14
	high	average	817,31	22,114	3695,87	127,28	141,22	9,87
	high	high	1297,31	35,1	3695,87	183,76	222,07	**17,25**
	average	low	153,65	4,16	3695,87	66,6	69,15	3,68
	average	average	723,65	19,58	3695,87	131,17	141,22	7,12
	average	high	1203,65	32,57	3695,87	189,74	222,07	**14,56**
	low	low	4,51	0,12	3695,87	69,06	69,15	0,13
	low	average	574,51	15,54	3695,87	136,34	141,22	3,46
	low	high	1054,51	28,53	3695,87	197,87	222,07	**10,9**
March	high	low	255,88	8,8	2906,88	36,21	39,21	7,65
	high	average	582,99	20,06	2906,88	87,59	96,98	9,68
	high	high	972,99	33,47	2906,88	131,2	169,79	**22,73**
	average	low	146,76	5,05	2906,88	37,6	39,21	4,11
	average	average	452,095	15,55	2906,88	91,69	96,98	5,46
	average	high	842,095	28,97	2906,88	137,91	169,79	**18,78**
	low	low	30,58	1,05	2906,88	39,19	39,21	0,05
	low	average	330,7	11,38	2906,88	95,67	96,98	1,35
	low	high	720,7	24,79	2906,88	145,25	169,79	**14,45**

Table 22. Output results for Policy 1 and Policy 2 for the case with 3 feeders, 1st quarter of the results

Table 23 **Output results for Policy 1 and Policy 2 for the case with 3 feeders, 2nd quarter of the results**

Month	**RES_production**	**APX_prices**	**MG_production** [kWh]	**MG_production** [%]	**Demand** [kWh]	**Output_costs with MG** [euros]	**Output_costs without MG** [euros]	**Cost_reduction** [%]
April	high	low	266,85	8,72	3060,53	35,59	38,48	7,52
	high	average	476,85	15,58	3060,53	80,29	88,62	9,40
	high	high	626,85	20,48	3060,53	103,09	123,59	**16,59**
	average	low	133,11	4,35	3060,53	36,78	38,48	4,43
	average	average	343,11	11,21	3060,53	84,22	88,62	4,96
	average	high	493,11	16,11	3060,53	108,86	123,59	**11,92**
	low	low	3,28	0,11	3060,53	38,43	38,48	0,14
	low	average	213,28	6,97	3060,53	88	88,62	0,70
	low	high	363,28	11,87	3060,53	114,19	123,59	**7,61**
May	high	low	275,48	8,3	3320,35	39,46	42,65	7,49
	high	average	485,48	14,62	3320,35	85,49	94,57	9,6
	high	high	875,48	26,37	3320,35	177,8	240,42	**26,05**
	average	low	72,59	2,19	3320,35	41,66	42,65	2,33
	average	average	282,59	8,51	3320,35	90,94	94,57	3,84
	average	high	672,59	20,26	3320,35	191,72	240,42	**20,26**
	low	low	23,55	0,71	3320,35	42,4	42,65	0,6
	low	average	233,55	7,03	3320,35	92,35	94,57	2,35
	low	high	623,55	18,78	3320,35	195,28	240,42	**18,78**
June	high	low	284,07	7,97	3566,02	37,83	40,79	7,26
	high	average	824,07	23,11	3566,02	149,84	186,77	19,77
	high	high	914,07	25,63	3566,02	557,2	849,3	**34,39**
	average	low	225,6	6,33	3566,02	38,53	40,79	5,55
	average	average	765,6	21,47	3566,02	152,33	186,77	18,44
	average	high	855,6	23,99	3566,02	567,22	849,3	**33,21**
	low	low	29,28	0,82	3566,02	40,49	40,79	0,74
	low	average	569,28	15,96	3566,02	162,69	186,77	12,89
	low	high	659,28	18,49	3566,02	615,25	849,3	**27,56**

Table 24 **Output results for Policy 1 and Policy 2 for the case with 3 feeders, 3rd quarter of the results**

Month	**RES_production**	**APX_prices**	**MG_production** [kWh]	**MG_production** [%]	**Demand** [kWh]	**Output_costs with MG** [euros]	**Output_costs without MG** [euros]	**Cost_reduction** [%]
July	high	low	280,71	8,11	3460,61	63,26	68,3	7,38
	high	average	670,71	19,38	3460,61	108,11	123,24	12,28
	high	high	1120,71	32,38	3460,61	331,05	486,02	**31,89**
	average	low	232,05	6,71	3460,61	64,22	68,3	5,97
	average	average	622,05	17,98	3460,61	110,11	123,24	10,66
	average	high	1072,05	30,98	3460,61	340,12	486,02	**30,02**
	low	low	30,25	0,87	3460,61	67,6	68,3	1,02
	low	average	420,3	12,14	3460,61	116,85	123,24	5,19
	low	high	870,25	14,04	3460,61	365,45	486,02	**24,81**
August	high	low	281,9	8,72	3233,35	54,16	58,89	8,04
	high	average	611,9	18,92	3233,35	97,69	108,39	9,87
	high	high	1301,9	40,26	3233,35	1641,46	2776,02	**40,87**
	average	low	212,18	6,56	3233,35	55,23	58,89	6,22
	average	average	542,18	16,77	3233,35	100,01	108,39	7,73
	average	high	1232,18	38,11	3233,35	1706,28	2776,02	**38,54**
	low	low	44,44	1,37	3233,35	58,15	58,89	1,26
	low	average	374,44	11,58	3233,35	105,03	108,39	3,1
	low	high	1064,44	32,92	3233,35	1813,29	2776,02	**34,68**
September	high	low	322,59	10,36	3113,16	65,08	71,05	8,41
	high	average	562,59	18,07	3113,16	94,11	104,86	10,25
	high	high	1132,59	36,38	3113,16	369,84	590,97	**37,42**
	average	low	246,5	7,92	3113,16	66,61	71,05	6,25
	average	average	486,5	15,63	3113,16	96,71	104,86	7,77
	average	high	1056,5	33,94	3113,16	387,45	590,97	**34,44**
	low	low	100,37	3,22	3113,16	69,57	71,05	2,09
	low	average	340,37	10,93	3113,16	101,3	104,86	3,39
	low	high	910,37	29,24	3113,16	411,7	590,97	**30,33**

Month	RES_production	APX_prices	MG_production [kWh]	MG_production [%]	Demand [kWh]	Output_costs with MG [euros]	Output_costs without MG [euros]	Cost_reduction [%]
October	high	low	355,97	12,3	2893,96	45,74	50,46	9,35
	high	average	995,78	34,41	2893,96	125,29	159,9	21,65
	high	high	1175,78	40,63	2893,96	366,99	591,22	**37,93**
	average	low	250,1	8,64	2893,96	48,19	50,46	4,49
	average	average	891,38	30,8	2893,96	131,98	159,9	17,46
	average	high	1071,38	37,02	2893,96	392,09	591,22	**33,68**
	low	low	144,08	4,98	2893,96	48,9	50,46	3,08
	low	average	775,02	26,78	2893,96	137,86	159,9	13,78
	low	high	955,02	33	2893,96	406,28	591,22	**31,28**
November	high	low	214,22	6,73	3180,91	61,28	65,23	6,05
	high	average	514,22	16,17	3180,91	157,94	198,31	20,36
	high	high	1174,22	36,91	3180,91	563,83	874,85	**35,55**
	average	low	57,89	1,82	3180,91	64,42	65,23	1,24
	average	average	357,89	11,25	3180,91	164,68	198,31	16,96
	average	high	1017,89	32	3180,91	603,18	874,85	**31,05**
	low	low	1,78	0,06	3180,91	65,2	65,23	0,04
	low	average	301,78	9,49	3180,91	166,27	198,31	16,16
	low	high	961,78	30,24	3180,91	615,71	874,85	**29,62**
December	high	low	345,15	9,68	3567,08	76,87	82,23	6,52
	high	average	754,56	21,15	3567,08	125,36	138,06	9,2
	high	high	664,56	18,63	3567,08	377,01	517,35	**27,13**
	average	low	205,47	5,76	3567,08	79,86	82,23	2,88
	average	average	595,47	16,69	3567,08	130,97	138,06	5,14
	average	high	505,47	14,17	3567,08	389,75	517,35	**24,66**
	low	low	125,56	3,52	3567,08	81,39	82,23	1,02
	low	average	515,56	14,45	3567,08	133,87	138,06	3,04
	low	high	425,56	11,93	3567,08	398,06	517,35	**23,06**

Table 25 Output results for Policy 1 and Policy 2 for the case with 3 feeders

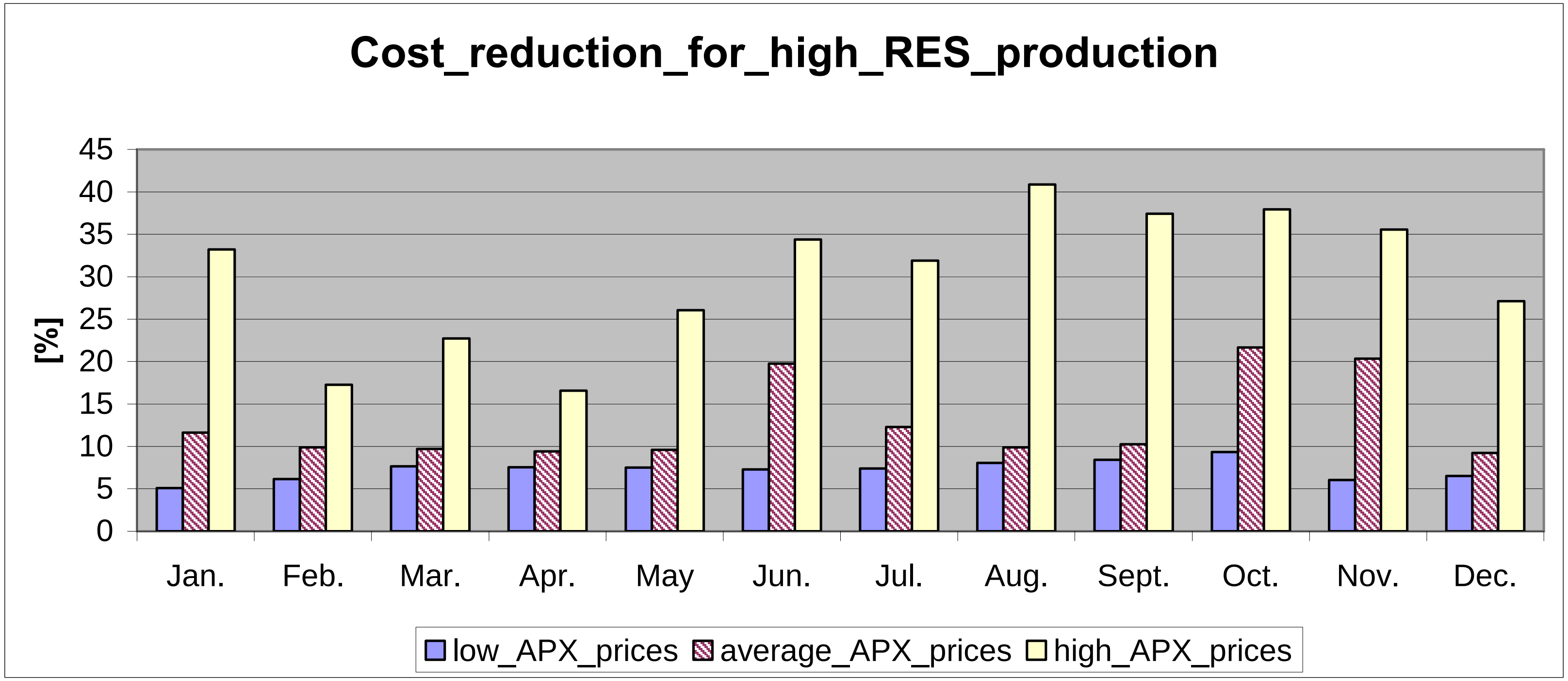

Figure 15 Cost reduction according to the APX prices for high RES production for the case study 1

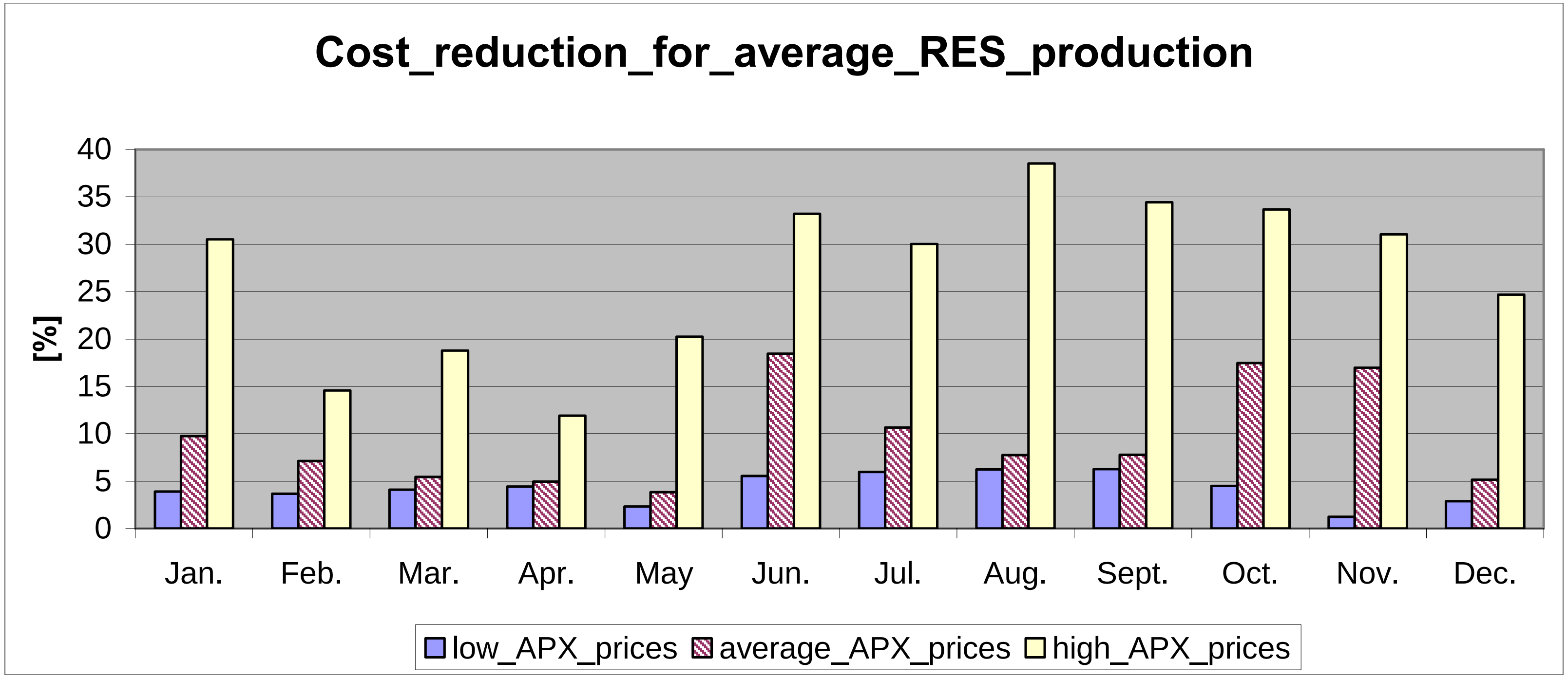

Figure 16 Cost reduction according to the APX prices for average RES

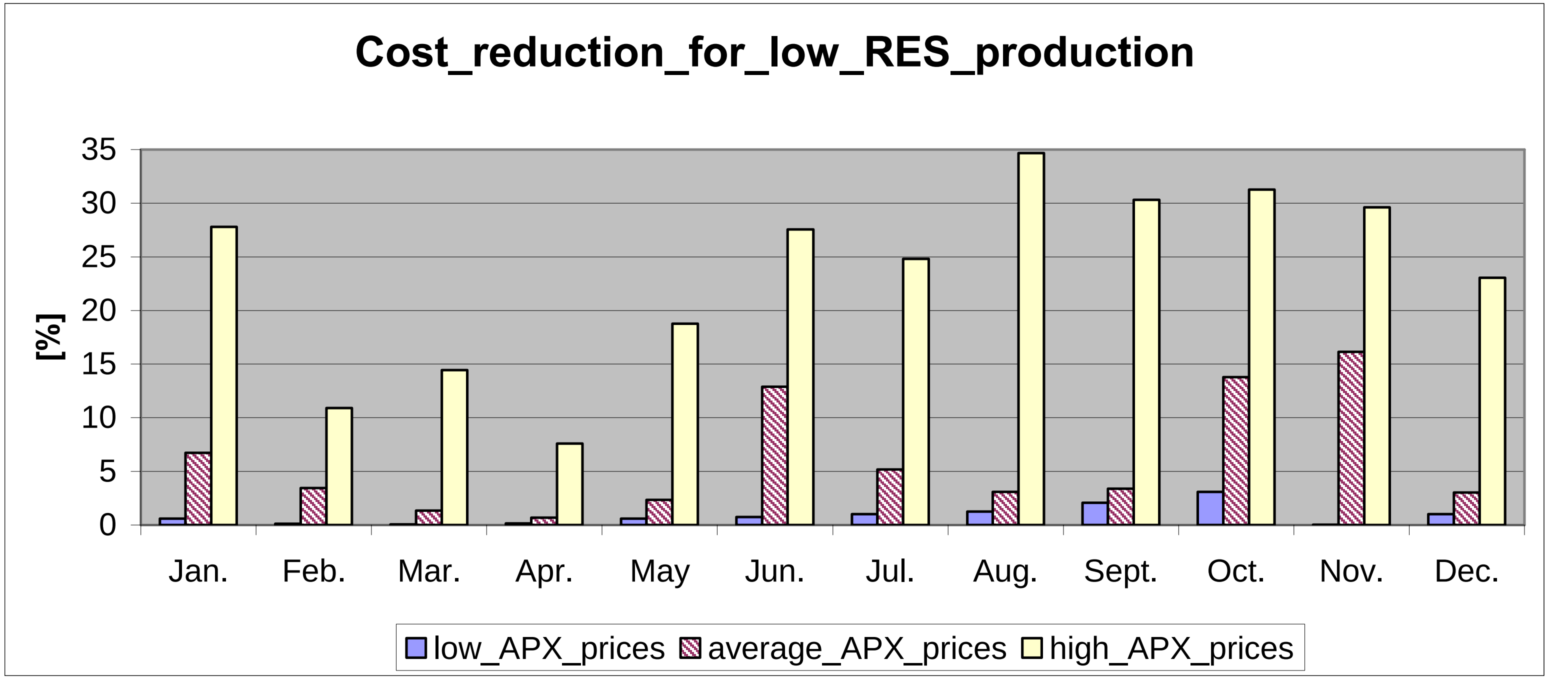

Figure 17. Cost reduction according to the APX prices for low RES production

The cost reduction is expressed in terms of percentages in comparison with the first scenario, where no MG sources are considered. The cost difference in terms of euros is the income of the Aggregator that the MICROGRID has contracted with.

The cost for the both Market policies is the same as a result of not having sufficient capacity of the MG sources to meet the whole demand and to benefit more selling power to the grid.

Significant cost reduction can be noted for the cases with highest electricity prices, especially for August as a month with highest electricity prices according to APX prices value (34.68 %– 40.87 % of cost reduction due to the case with no MG sources).

Since the cost reduction takes the biggest power effect in the cases with highest electricity prices, the load and power exchange are presented only for that cases.

The calculations are made for period of 12 months. August, as a month with highest electricity prices, i.e. highest cost reduction, is shown here.

Case: High electricity prices, high RES production

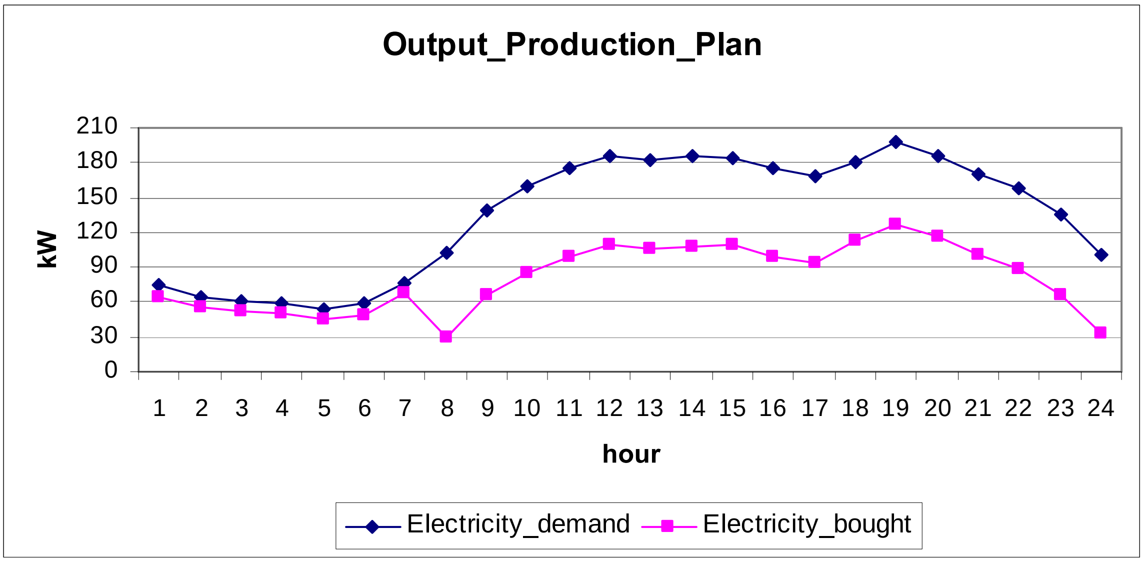

Figure 18. Electricity balance for August, case: high APX prices, high RES production

Case: High electricity prices, average RES production

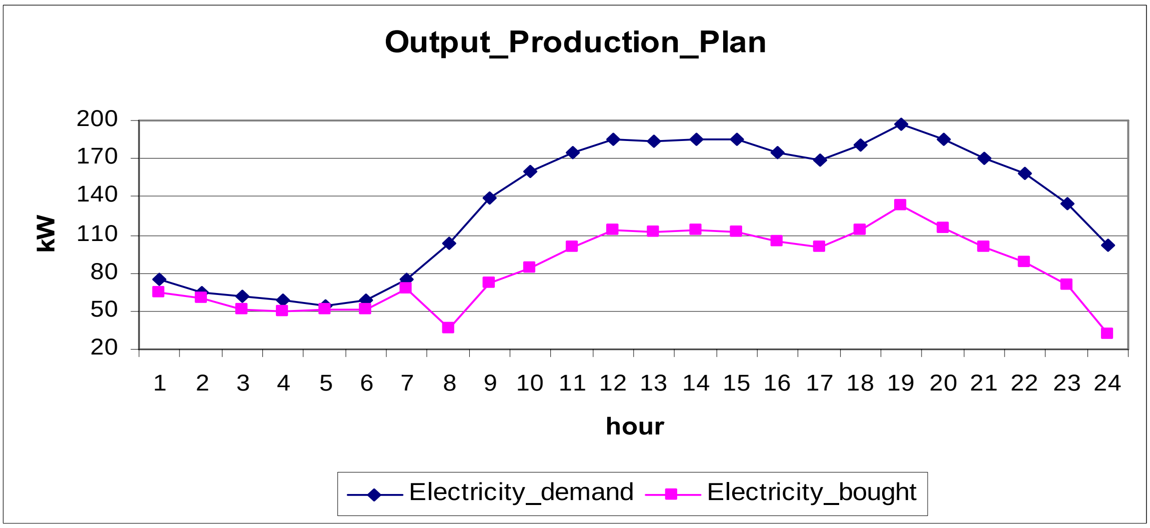

Figure 19. Electricity balance for August, case: high APX prices, average RES production

Case: High electricity prices, low RES production

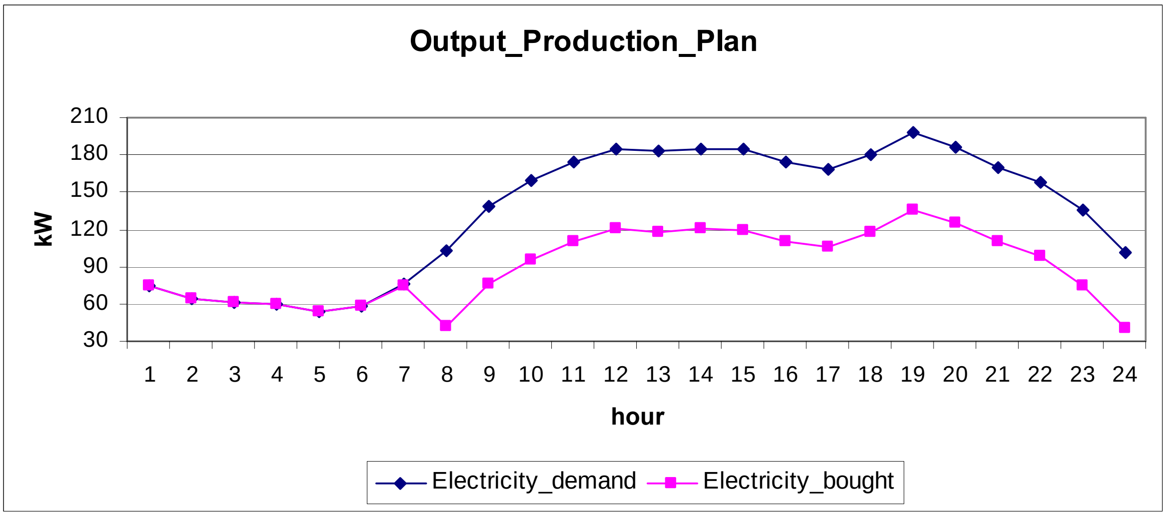

Figure 20. Electricity balance for August, case: high APX prices, low RES production

4.2.2.2. Case study 2

For the case study 2, when only one feeder is considered, there is a significant additional income for the Aggregator in Policy 2 due to the significantly lower demand for this case, contrary to the case study 1, that provides enough capacity to both meet the demand of the Microgrid and sell active power to the grid. This explains why the cost reduction for the both policies is the same, i.e. the cost reduction difference is zero.

The cases, with enough power to meet the demand of the MG and to sell energy to the grid are denoted in bold, presented in the tables bellow.

Since 9 cases have been studied according to the level of RES production (lowest, average or highest) and the electricity prices according to Amsterdam Power eXchange prices, the final results are comprised regarding the level of RES production as it follows.

Table 26 Output results for Policy 1 and Policy 2 for the case with 1 feeder when electricity is sold to the grid, 1st quarter of the results

					Policy 1			Policy 2			
Month	**APX_prices**	**RES_production**	**Demand**	**Cost_without_MG**	**Cost_reduction**	**Cost_reduction**	**DG_production**	**Profit**	**Profit**	**DG_production**	**Cost_reduction**
			[kWh]	[euro]	[euro]	[%]	[kWh]	[euro]	[%]	[kWh]	**difference** [%]
January	**high**	**low**	**1266,07**	**307,97**	**246,64**	**80,09**	**784,25**	**268,89**	**87,31**	**826,83**	**7,23**
	high	**average**	**1266,07**	**307,97**	**258,38**	**83,9**	**843,8**	**295,3**	**95,88**	**930,12**	**11,99**
	high	**high**	**1266,07**	**307,97**	**260,25**	**84,5**	**878,9**	**321,53**	**104,4**	**1023,41**	**19,90**
	average	low	1266,07	45,22	9,89	21,86	288,34	9,89	21,86	288,34	0,00
	average	**average**	**1266,07**	**45,22**	**12,39**	**27,39**	**330.68**	**12,7**	**28,09**	**331,33**	**0,70**
	average	**high**	**1266,07**	**45,22**	**14,74**	**32,59**	**423.06**	**15,15**	**33,5**	**424,62**	**0,91**
	low	low	1266,07	19,42	0,29	1,51	48,33	0,29	1,51	48,33	0,00
	low	average	1266,07	19,42	2,02	10,42	151,63	2,02	10,42	151,63	0,00
	low	high	1266,07	19,42	2,67	13,77	244,89	2,67	13,77	244,89	0,00
February	**high**	**low**	**1355,91**	**80,2**	**23,62**	**29,45**	**1003,54**	**24,31**	**30,31**	**995,35**	**0,86**
	high	**average**	**1355,91**	**80,2**	**30,39**	**37,89**	**1076,47**	**32,44**	**40,45**	**1168,58**	**2,56**
	high	**high**	**1355,91**	**80,2**	**35,23**	**43,93**	**1109,7**	**38,43**	**47,92**	**1262,24**	**3,99**
	average	**low**	**1355,91**	**49,98**	**4,88**	**9,77**	**506,36**	**5,03**	**10,07**	**506,97**	**0,29**
	average	**average**	**1355,91**	**49,98**	**10,06**	**20,14**	**640.76**	**10,2**	**20,41**	**655,5**	**0,28**
	average	**high**	**1355,91**	**49,98**	**13,87**	**27,76**	**702.41**	**14,06**	**28,12**	**749,15**	**0,37**
	low	low	1355,91	26,96	0,11	0,4	4,5	0,11	0,4	4,5	0,00
	low	average	1355,91	26,96	2,56	9,48	153,65	2,56	9,48	153,65	0,00
	low	high	1355,91	26,96	4,25	15,75	247,31	4,25	15,75	247,31	0,00
March	**high**	**low**	**1066,44**	**59,16**	**20,75**	**35,07**	**615,15**	**24,66**	**41,69**	**676,91**	**6,62**
	high	**average**	**1066,44**	**59,16**	**26,04**	**44,01**	**682,63**	**31,96**	**54,03**	**798,30**	**10,01**
	high	**high**	**1066,44**	**59,16**	**30,55**	**51,64**	**755,1**	**38,73**	**65,47**	**929,18**	**13,83**
	average	low	1066,44	34,96	1,31	3,76	330,7	1,31	3,76	330,7	0,00
	average	average	1066,44	34,96	5,28	15,11	452,1	5,28	15,11	452,1	0,00
	average	high	1066,44	34,96	9,45	27,04	571,32	9,45	27,04	571,32	0,00
	low	low	1066,44	15,66	0,04	0,28	30,58	0,04	0,28	30,58	0,00
	low	average	1066,44	15,66	1,63	10,43	146,76	1,63	10,43	146,76	0,00
	low	high	1066,44	15,66	3,01	19,24	255,88	3,01	19,24	255,88	0,00

Table 27 Output results for Policy 1 and Policy 2 for the case with 1 feeder when electricity is sold to the grid, 2^{nd} quarter of the results

					Policy 1			Policy 2			
Month	**APX_prices**	**RES_production**	**Demand** [kWh]	**Cost_without_MG** [euro]	**Cost_reduction** [euro]	**Cost_reduction** [%]	**DG_production** [kWh]	**Profit** [euro]	**Profit** [%]	**DG_production** [kWh]	**Cost_reduction difference** [%]
April	**high**	**low**	**1122,81**	**42,05**	**8,23**	**19,57**	**307,2**	**9,42**	**22,41**	**355,65**	**2,85**
	high	**average**	**1122,81**	**42,05**	**12,58**	**29,91**	**398,08**	**14,76**	**35,09**	**485,47**	**5,18**
	high	**high**	**1122,81**	**42,05**	**17,06**	**40,57**	**480,78**	**20,51**	**48,77**	**619,21**	**8,21**
	average	low	1122,81	31,57	0,61	1,94	213,28	0,61	1,94	213,28	0,00
	average	average	1122,81	31,57	4,38	13,88	343,11	4,38	13,88	343,11	0,00
	average	high	1122,81	31,57	8,36	26,49	468,81	8,36	26,49	468,81	0,00
	low	low	1122,81	15,31	0,07	0,47	3,28	0,07	0,47	3,28	0,00
	low	average	1122,81	15,31	1,69	11,05	133,11	1,69	11,05	133,11	0,00
	low	high	1122,81	15,31	2,89	18,89	266,85	2,89	18,89	266,85	0,00
May	**high**	**low**	**1218,14**	**74,91**	**38,45**	**51,33**	**523,52**	**45,18**	**60,31**	**612,81**	**8,98**
	high	**average**	**1218,14**	**74,91**	**40,29**	**53,79**	**553,06**	**48,75**	**65,08**	**661,83**	**11,29**
	high	**high**	**1218,14**	**74,91**	**47,16**	**62,96**	**655,11**	**62,64**	**83,61**	**864,73**	**20,66**
	average	**low**	**1218,14**	**33,03**	**2,11**	**6,4**	**158.85**	**2,52**	**7,62**	**165,01**	**1,23**
	average	**average**	**1218,14**	**33,03**	**3,53**	**10,7**	**205.69**	**3,95**	**11,97**	**214,03**	**1,27**
	average	**high**	**1218,14**	**33,03**	**8,76**	**26,53**	**396.07**	**9,38**	**28,39**	**416,92**	**1,86**
	low	low	1218,14	16,26	0,29	1,76	23,55	0,29	1,76	23,55	0,00
	low	average	1218,14	16,26	1,01	6,19	72,59	1,01	6,19	72,59	0,00
	low	high	1218,14	16,26	3,18	19,54	275,48	3,18	19,54	275,48	0,00
June	**high**	**low**	**1308,27**	**249,27**	**210,62**	**84,49**	**512,6**	**234,04**	**93,89**	**659,2**	**9,40**
	high	**average**	**1308,27**	**249,27**	**217,46**	**87,24**	**617,57**	**282,07**	**113,16**	**855,59**	**25,92**
	high	**high**	**1308,27**	**249,27**	**216,13**	**86,71**	**718,35**	**292,13**	**117,19**	**914,09**	**30,49**
	average	**low**	**1308,27**	**61,12**	**22,47**	**36,77**	**512,6**	**24,16**	**39,53**	**545,79**	**2,77**
	average	**average**	**1308,27**	**61,12**	**29,31**	**47,96**	**617,57**	**34,51**	**56,46**	**742,18**	**8,50**
	average	**high**	**1308,27**	**61,12**	**31,06**	**50,82**	**660,97**	**36,99**	**60,52**	**800,68**	**9,70**
	low	low	1308,27	15,99	0,3	1,89	29,19	0,3	1,89	29,19	0,00
	low	average	1308,27	15,99	2,3	14,4	225,6	2,3	14,4	225,6	0,00
	low	high	1308,27	15,99	2,95	18,46	284,07	2,95	18,46	284,07	0,00

Table 28 Output results for Policy 1 and Policy 2 for the case with 1 feeder when electricity is sold to the grid, 3rd quarter of the results

					Policy 1			**Policy 2**			
Month	**APX_prices**	**RES_production**	**Demand** [kWh]	**Cost_without_MG** [euro]	**Cost_reduction** [euro]	**Cost_reduction** [%]	**DG_production** [kWh]	**Profit** [euro]	**Profit** [%]	**DG_production** [kWh]	**Cost_r** **differe**
July	**high**	**low**	**1269,59**	**151,15**	**105,55**	**69,83**	**780,23**	**120,64**	**79,82**	**851,22**	**9**
	high	**average**	**1269,59**	**151,15**	**113,65**	**75,19**	**885,19**	**145,99**	**96,59**	**1053,04**	**21**
	high	**high**	**1269,59**	**151,15**	**115,64**	**76,51**	**902,45**	**155,05**	**102,58**	**1101,90**	**26**
	average	**low**	**1269,59**	**41,95**	**6,21**	**14,8**	**382,9**	**6,4**	**15,26**	**400,59**	**0**
	average	**average**	**1269,59**	**41,95**	**12,55**	**29,91**	**535,59**	**13,15**	**31,35**	**602,40**	**1**
	average	**high**	**1269,59**	**41,95**	**14,39**	**34,3**	**562,1**	**15,17**	**36,17**	**651,07**	**1**
	low	low	1269,59	25,21	0,66	2,61	30,25	0,66	2,61	30,25	0
	low	average	1269,59	25,21	4,07	16,14	232,05	4,07	16,14	232,05	0
	low	high	1269,59	25,21	5,07	20,11	280,92	5,07	20,11	280,92	0
August	**high**	**low**	**1186,22**	**822,79**	**772,82**	**93,93**	**903,81**	**962,72**	**117,01**	**1062,04**	**23**
	high	**average**	**1186,22**	**822,79**	**780,56**	**94,87**	**992,86**	**1069,75**	**130,02**	**1230,10**	**35**
	high	**high**	**1186,22**	**822,79**	**786,04**	**95,53**	**1014,08**	**1134,57**	**137,89**	**1299,49**	**42**
	average	low	1186,22	38,49	3,37	8,75	374,44	3,37	8,75	374,44	0
	average	average	1186,22	38,49	8,43	21,9	542,2	8,43	21,9	542,2	0
	average	high	1186,22	38,49	10,69	27,77	611,43	10,69	27,77	611,43	0
	low	low	1186,22	22,2	0,72	3,26	44,44	0,72	3,26	44,44	0
	low	average	1186,22	22,2	3,65	16,45	212,18	3,65	16,45	212,18	0
	low	high	1186,22	22,2	4,72	21,27	281,9	4,72	21,27	281,9	0
September	**high**	**low**	**1142,12**	**178,64**	**138,72**	**77,65**	**766,41**	**179,32**	**100,38**	**891,10**	**22**
	high	**average**	**1142,12**	**178,64**	**144,57**	**80,93**	**836,99**	**203,56**	**113,95**	**1037,23**	**33**
	high	**high**	**1142,12**	**178,64**	**147,62**	**82,64**	**863,56**	**221,17**	**123,81**	**1113,31**	**41**
	average	**low**	**1142,12**	**37,03**	**3,54**	**9,56**	**280.2**	**3,73**	**10,06**	**292,03**	**0**
	average	**average**	**1142,12**	**37,03**	**8,09**	**21,85**	**419.91**	**8,33**	**22,5**	**438,2**	**0**
	average	**high**	**1142,12**	**37,03**	**10,66**	**28,79**	**490.18**	**10,91**	**29,45**	**514,24**	**0**
	low	low	1142,12	27,25	1,46	5,35	100,37	1,46	5,35	100,37	0
	low	average	1142,12	27,25	4,41	16,17	244,76	4,41	16,17	244,76	0
	low	high	1142,12	27,25	6,00	22,01	319,99	6,00	22,01	319,99	0

Table 29 Output results for Policy 1 and Policy 2 for the case with 1 feeder when electricity is sold to the grid

						Policy 1			**Policy 2**		
Month	**APX_prices**	**RES_production**	**Demand**	**Cost_without_MG**	**Cost_reduction**	**Cost_reduction**	**DG_production**	**Profit**	**Profit**	**DG_production**	**Cost_re**
			[kWh]	[euro]	[euro]	[%]	[kWh]	[euro]	[%]	[kWh]	**differe**
	high	**low**	**1061,71**	**206,75**	**157,71**	**76,28**	**766,35**	**185,07**	**89,51**	**923,43**	**13**
	high	**average**	**1061,71**	**206,75**	**160,47**	**77,62**	**807,61**	**199,12**	**96,31**	**1009,78**	**18**
	high	**high**	**1061,71**	**206,75**	**173,82**	**84,07**	**851,35**	**215,05**	**104,01**	**1054,19**	**19**
	average	**low**	**1061,71**	**53,91**	**17,89**	**33,19**	**616,42**	**22,09**	**40,97**	**762,93**	**7,**
October	**average**	**average**	**1061,71**	**53,91**	**22,01**	**40,83**	**663,49**	**27,96**	**51,87**	**879,28**	**11**
	average	**high**	**1061,71**	**53,91**	**26,38**	**48,94**	**713,22**	**32,29**	**59,89**	**923,69**	**10**
	low	low	1061,71	20,4	1,57	7,71	144,08	1,57	7,71	144,08	0,
	low	average	1061,71	20,4	2,28	11,19	250,1	2,28	11,19	250,1	0,
	low	high	1061,71	20,4	4,71	23,1	355,97	4,71	23,1	355,97	0,
	high	**low**	**1112,5**	**273,48**	**219,23**	**80,16**	**812,07**	**259,22**	**94,78**	**934,35**	**14**
	high	**average**	**1112,5**	**273,48**	**221,48**	**80,99**	**828,16**	**271,75**	**99,37**	**990,46**	**18**
	high	**high**	**1112,5**	**273,48**	**231,2**	**84,54**	**898,75**	**315,04**	**115,2**	**1158,3**	**30**
	average	low	1112,5	73,49	32,02	43,57	299,61	32,02	43,57	299,61	0,
November	average	average	1112,5	73,49	33,6	45,72	355,71	33,6	45,72	355,71	0,
	average	**high**	**1112,5**	**73,49**	**40,26**	**54,78**	**504,81**	**40,83**	**55,56**	**507,75**	0,
	low	low	1112,5	22,74	0,05	0,23	1,78	0,05	0,23	1,78	0,
	low	average	1112,5	22,74	0,78	3,44	57,65	0,78	3,44	57,65	0,
	low	high	1112,5	22,74	4,13	18,17	225,72	4,13	18,17	225,72	0,
	high	**low**	**1308,65**	**185,38**	**118,04**	**63,68**	**407,92**	**119,28**	**64,34**	**425,56**	**0,**
	high	**average**	**1308,65**	**185,38**	**125,74**	**67,83**	**470,62**	**127,58**	**68,82**	**505,47**	**0,**
	high	**high**	**1308,65**	**185,38**	**137,28**	**74,05**	**597,14**	**140,35**	**102,23**	**664,56**	**28**
	average	low	1308,65	49,35	4,18	8,46	515,56	4,18	8,46	515,56	0,
December	average	average	1308,65	49,35	7,09	14,36	595,47	7,09	14,36	595,47	0,
	average	high	1308,65	49,35	12,69	25,71	754,56	12,69	25,71	754,56	0,
	low	low	1308,65	30,64	0,83	2,72	125,56	0,83	2,72	125,56	0,
	low	average	1308,65	30,64	2,38	7,78	205,47	2,38	7,78	205,47	0,
	low	high	1308,65	30,64	5,37	17,54	345,15	5,37	17,54	345,15	0,

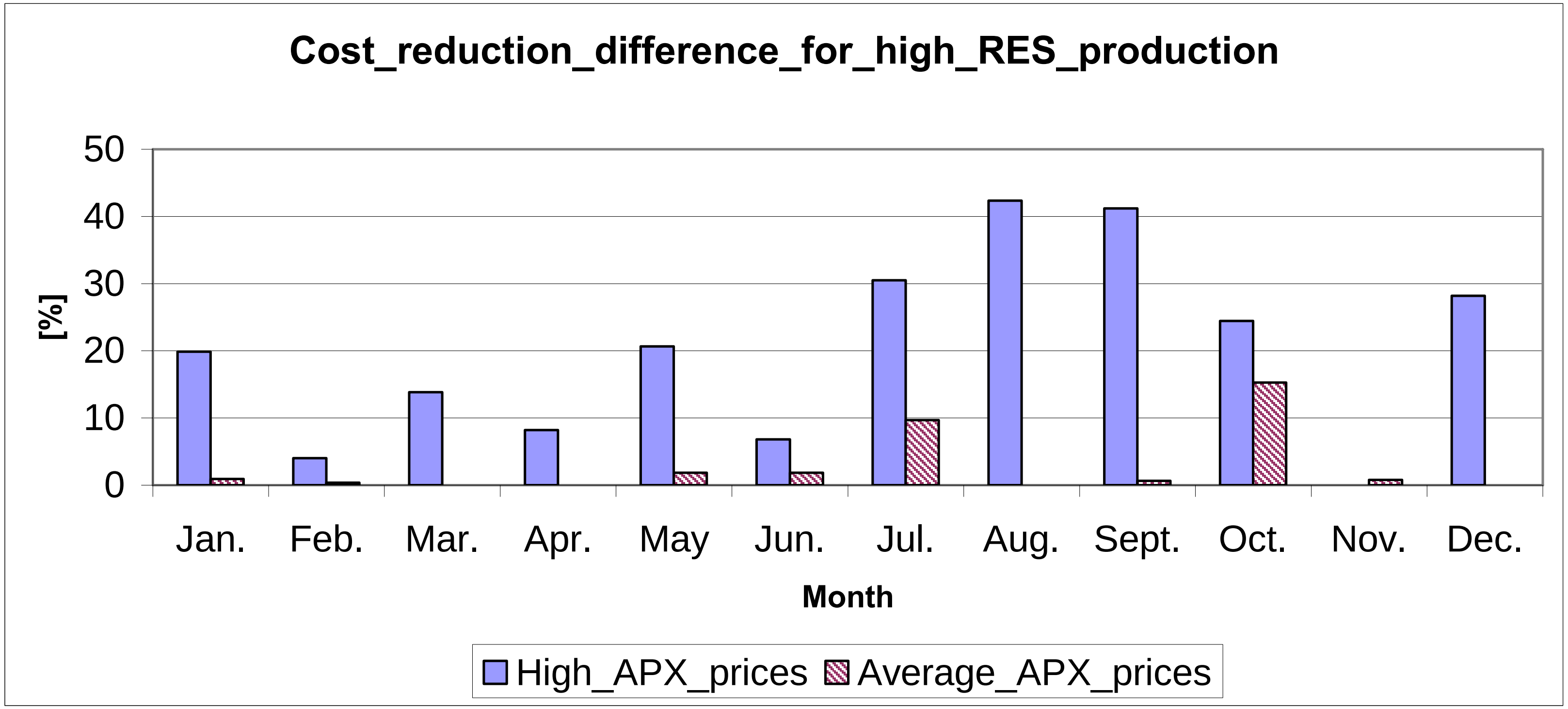

Figure 21. Cost reduction difference between Policy 1 and Policy 2 for the case with high RES production

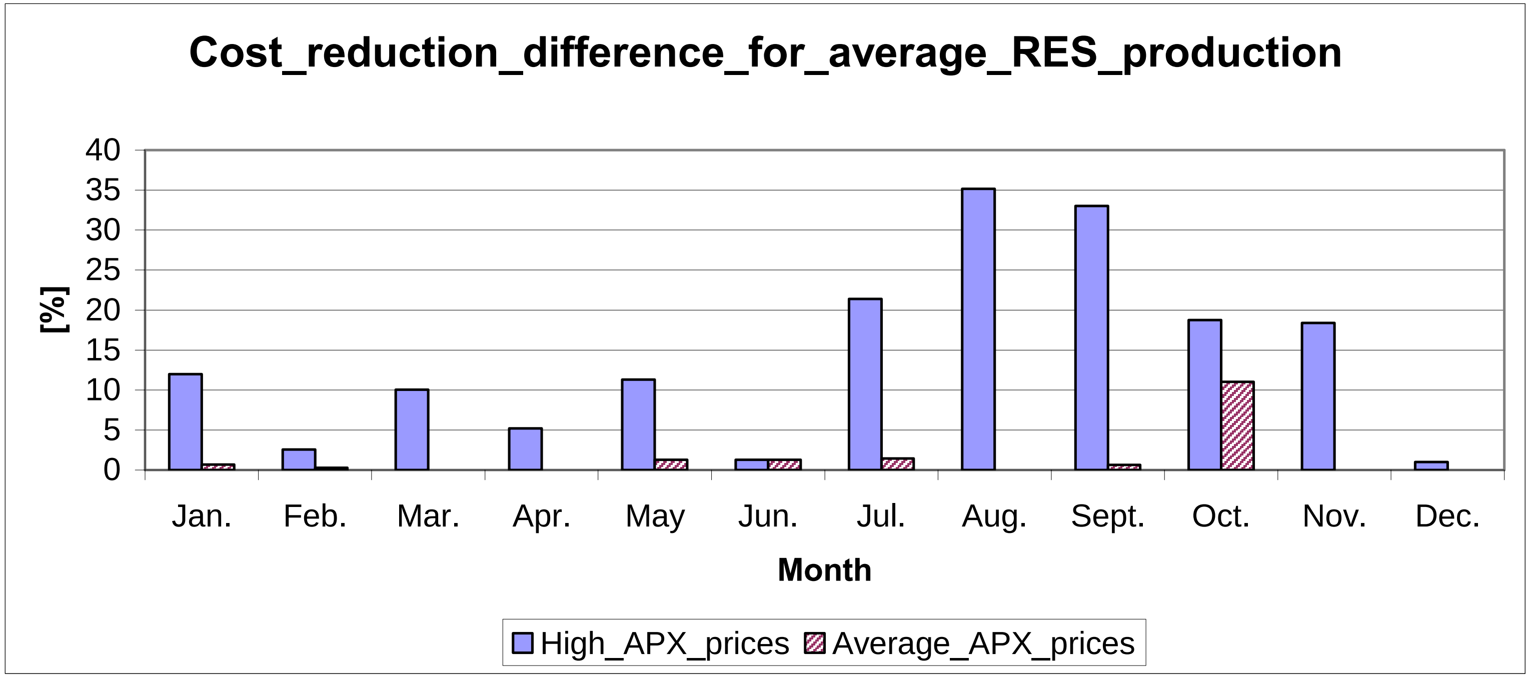

Figure 22. Cost reduction difference between Policy 1 and Policy 2 for the case with average RES production

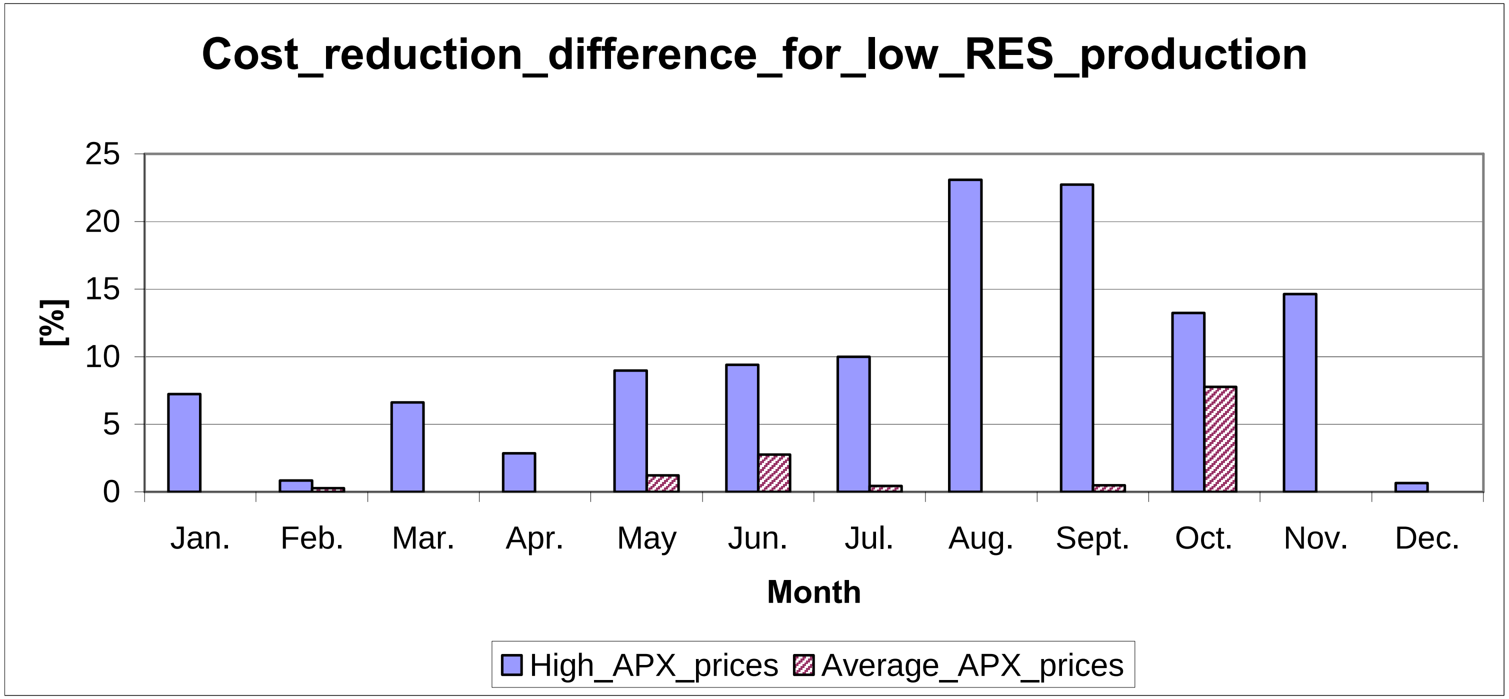

Figure 23. Cost reduction difference between Policy 1 and Policy 2 for the case with low RES production

It can be noticed that the cost reduction difference between the Policy 1 and Policy 2 is the most significant for high electricity prices, whereas, for low and in some cases for average prices there is no difference in the cost reduction, i.e. no energy is sold to the grid.

The calculations are made for period of 12 months. August, as a month with highest electricity prices, i.e. highest cost reduction, is taken as representative one. The negative values mean export to the grid. Selling active power for a few hours a day explains the greater cost reduction in the second market policy due to the first one.

Case: High electricity prices, high RES production

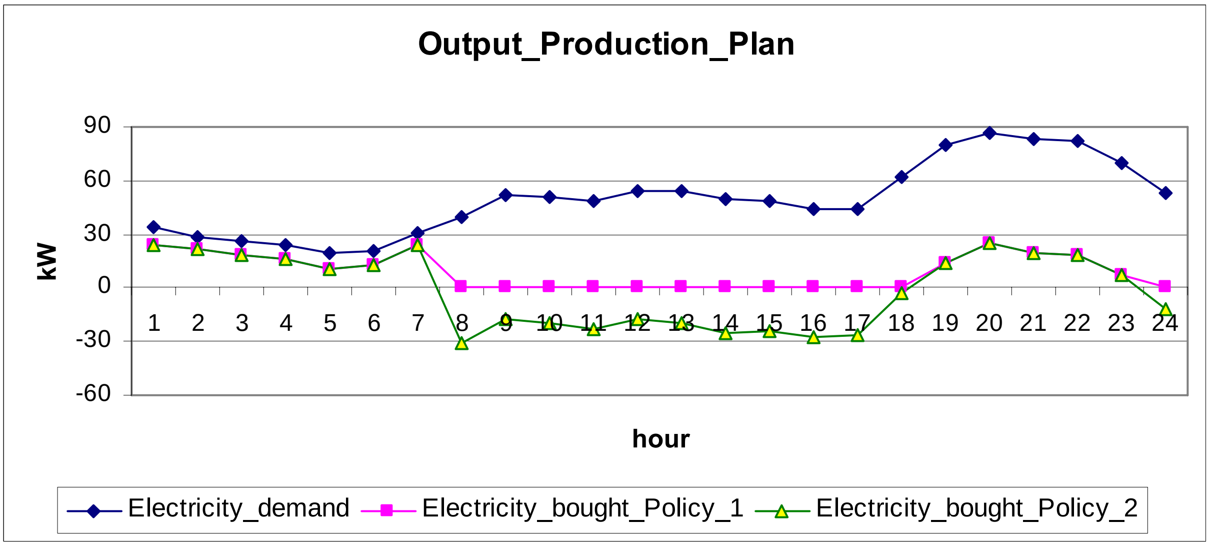

Figure 24. Electricity balance for August, case: high APX prices, high RES production when energy is sold to the grid

Case: High electricity prices, average RES production

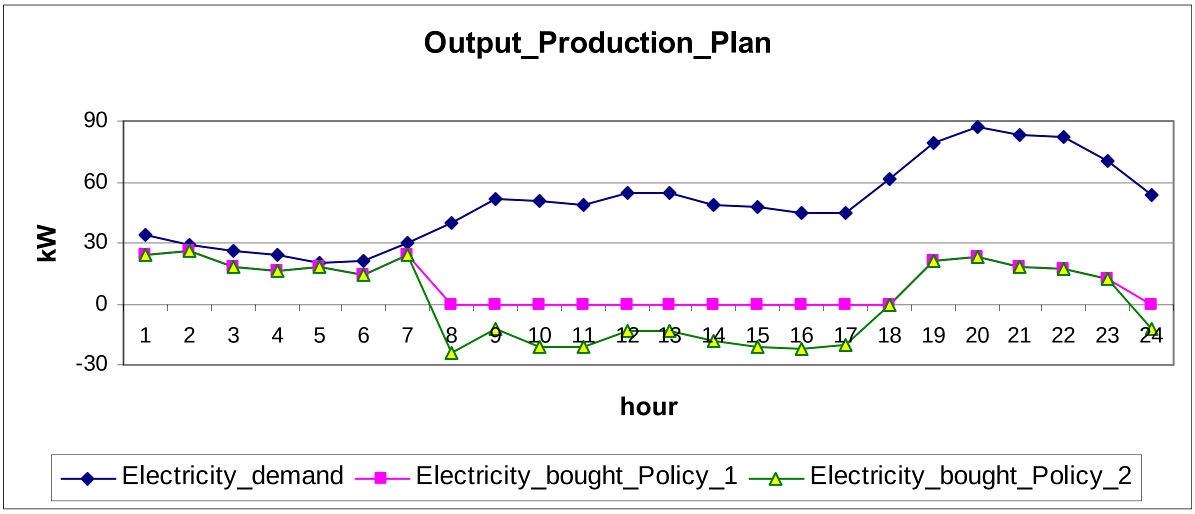

Figure 25. Electricity balance for August, case: high APX prices, average RES production when energy is sold to the grid

Case: High electricity prices, low RES production

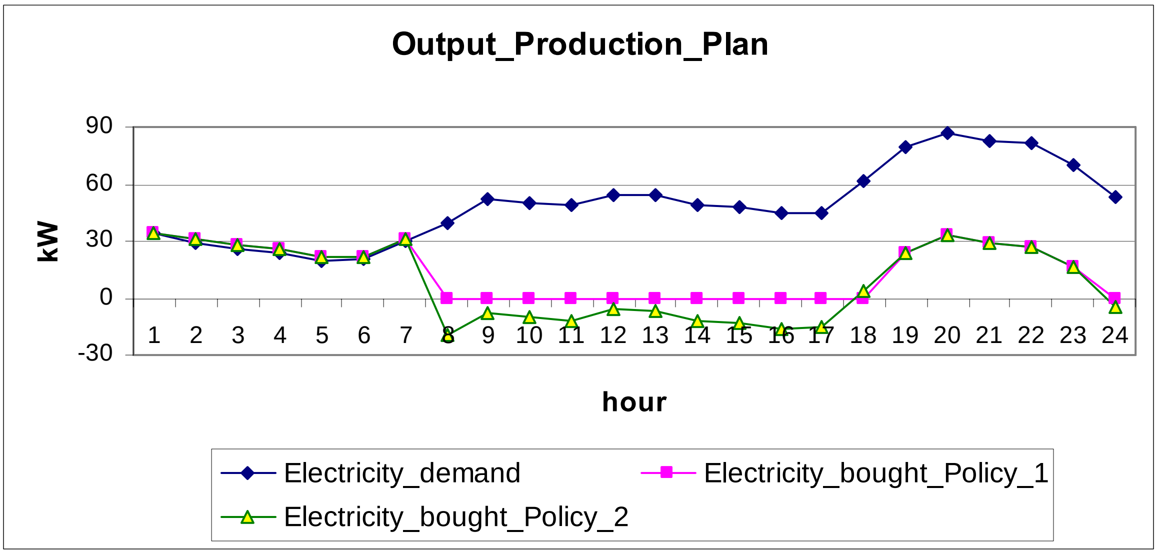

Figure 26. Electricity balance for August, case: high APX prices, low RES production when energy is sold to the grid

4.2.3. Summary of the results

Two study cases have been considered, with the all three feeders and the residential feeder only, by implementation of two Market policies. A great impact of the implementation of Microgrid on the cost reduction from the end-users point of view can been noticed in the cases with high market prices, like in August, the month with highest electricity market prices, when cost reduction for case study 1 and high production of RES reaches 40.87 %. For the same market and RES production conditions, cost reduction for case study 2 reaches 95.53 % for Market policy 1 while, for market policy 2, the Aggregator's income reaches 137.89 %. Table 30comprises the cases with high market prices, when the implementation of the Microgrid has the greatest impact, with the both Market policies considered.

For low market prices, however, the cost reduction is rather small, almost negligible for some months with very low market prices and very low RES penetration e.g. April. Furthermore, in low market prices our analysis has shown that there is no incentive for the aggregator of the Microgrid to sell active power to the upstream network in Market Policy 2. Thus, in such market environment, the Microgrid presents common behaviour to the upstream network when either Market Policy 1, or Market policy 2 is applied.

Table 30 Summarized results for the both case studies, applying the both market policies

		Case_study_1		**Case_study_2**			
				Policy_1		**Policy_2**	
APX prices	**RES production**	**Cost reduction [%]**		**Cost reduction[%]**		**Income[%]**	
		min	**max**	**min**	**max**	**min**	**max**
High	Low	7.61	34.68	19.57	93.93	47.9	137.9
High	Average	11.92	38.54	29.9	94.9	35.09	130.02
High	High	16.59	40.87	40.57	95.53	22.41	117.01
Average	Low	0.7	16.16	1.94	43.57	1.94	43.57
Average	Average	3.84	18.44	10.7	47.96	11.97	56.46
Average	High	9.2	21.65	25.71	54.78	25.71	64.2
Low	Low	0.04	3.08	0.23	7.71	0.23	7.71
Low	Average	1.24	6.22	3.44	16.45	3.44	16.45
Low	High	5.09	9.35	13.77	23.1	13.77	23.1

4.3. Taking into account Demand Side Bidding Strategies

Already in WPB, the potential Demand Side Bidding strategies approach have been described. Each consumer may place bids like the one described in Figure 27.

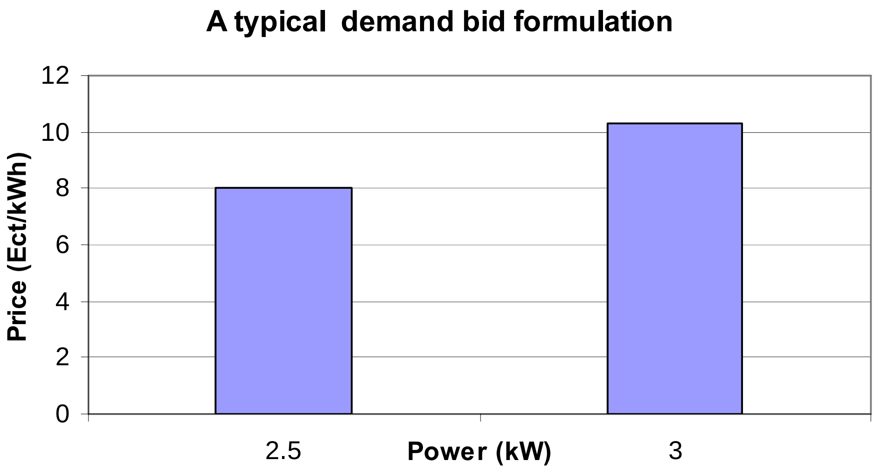

Figure 27 Typical Demand Side bid

Results from two options are also presented here from representative periods and combinations of RES production (High and low, market prices, (High(H), Medium(M), Low(L)) and different seasons (Spring (sp), Summer (Su), Winter(W), Autumn(A)). Theses periods correspond to the average periods of the seasons studied in chapter 4.2.

4.3.1. Results from Demand Side bidding strategies only.

Here 3 scenarios are considered for the extended periods and for the combinations stated above

- Scenario 1: Operation without DG
- Scenario 2: Operation with DG bids only, without adequacy constraints
- Scenario 3: Operation with DG bids and DSB, without adequacy constraints

Even though results from scenario 2 have been explicitly described in chapter 4.2, a comparison on the same basis is essential for making concrete conclusions.

For scenario 3, we can distinguish two cases, A, for option A (not remunerating loads) and B for option B (remunerating loads if DSB is accepted).

4.3.1.1. Case study 1

The results of DG penetration and cost change from scenario 2 compared to scenario 1 are presented in Table 31. For scenario 3, the load not served is in the order of 9-13% for high load, as shown in Table 32. In the same table the cost comparison with Scenario 1 is provided. When the prices are low, no bid is accepted, and the economics and DG penetration for scenario 3 are the same as with scenario 2.

DG penetration for Scenarios 2 and 3 and high prices is shown in Figure 28. The maximum difference in DG penetration for these cases is lower than 10% with High prices and the highest penetration reaches from 41.7% to 46% without DSB. The impact of DSB in the operation cost for these periods is significantly higher. As Figure 29 shows, the economic benefits are increased by about 15% compared to Scenario 2. Generally, for high prices and High RES, the operational cost can be significantly lower, i.e. up to 40%, and 56% for scenarios 2 and 3, respectively, compared to Scenario 1. Reducing RES production by 7-8% means lower benefits. In all cases with high prices however, the minimum benefit is 20% for scenario 2 and 33% for Scenario 3. For medium prices, demand side bids are accepted only during summer, resulting in a small cost additional reduction, lower than 2%.

Since energy bought from the upstream network during high prices periods is reduced, the Microgrid customers have significant economic benefits, as shown in Table 33, where the average cost of energy is shown. The maximum hourly cost reduction can reach 87.14 €ct/kWh, for the extreme ApX spot prices of 2000€/MWh, that appear for few hours per year. The maximum difference in cost between scenario 2 and 3 is 39.9€ct/kWh and the 24 hour average difference is 13.69 €ct/kWh.

Table 31 DG penetration and costs for Scenario 1 and 2

Prices	**RES Production**	**Season**	**DG penetration (%)**	**Cost Scenario 1 (€)**	**Cost Scenario 2 (€)**	**Cost Change**	
						€	**%**
High (H)	High(H)	Winter (W)	34.6	1217.24	819.26	397.98	32.7

		Spring(Sp)	39.52	274.235	195.46	78.78	28.73
		Summer(Su)	38.94	3318.72	2025.43	1293.3	38.97
		Autumn(A)	41.73	1063.21	635.04	428.17	40.27
	Low(L)	Winter (W)	29.11	1217.24	883.98	333.26	27.38
		Spring(Sp)	31.26	274.235	217.4	56.84	20.72
		Summer(Su)	38.94	3318.72	2244.2	1074.52	32.38
		Autumn(A)	41.73	1063.21	709.92	353.29	33.23
Medium (M)	High(H)	Winter (W)	15.49	130.74	119.82	10.92	8.36
		Spring(Sp)	13.5	94.01	84.92	9.09	9.67
		Summer(Su)	20.01	127.96	111.44	16.52	12.91
		Autumn(A)	25.72	117.75	102.85	14.9	12.66
	Low(L)	Winter (W)	10	130.74	126.73	4.01	3.07
		Spring(Sp)	5.23	94.01	92.51	1.5	1.6
		Summer(Su)	13.04	127.96	120.06	7.9	6.18
		Autumn(A)	17.25	117.75	113.32	4.43	3.77
Low(L)	High(H)	Winter (W)	5.41	33.44	31.76	1.68	5.28
		Spring(Sp)	6.55	25.99	24.07	1.92	7.99
		Summer(Su)	7.87	33.79	31.62	2.17	6.86
		Autumn(A)	7.26	25.26	23.55	1.71	7.26
	Low(L)	Winter (W)	0.22	33.44	33.36	0.08	0.23
		Spring(Sp)	0.25	25.99	25.91	0.08	0.32
		Summer(Su)	0.98	33.79	33.46	0.33	0.97
		Autumn(A)	0.63	25.26	25.07	0.19	0.75

Table 32 Demand bids accepted and cost change compared to Scenario 1

Prices	**RES Production**	**Season**	**Bids Accepted**		**Cost Change**	
			kWh	**%**	**€**	**%**
High (H)	**High(H)**	Winter (W)	362	10.14	565.21	46.43
		Spring(Sp)	296	9.56	113.79	41.49
		Summer(Su)	320	9.36	1759.3	53.01
		Autumn(A)	398	13.23	597.04	56.15
	Low(L)	Winter (W)	362	10.14	500.48	41.12
		Spring(Sp)	296	9.56	91.845	33.49
		Summer(Su)	320	9.36	1541.1	46.44
		Autumn(A)	398	13.23	522.55	49.15
Medium (M)	**High(H)**	Winter (W)	0	0	10.92	8.36
		Spring(Sp)	0	0	9.09	9.67
		Summer(Su)	28	0.82	18.55	14.5
		Autumn(A)	0	0	14.85	12.66
	Low(L)	Winter (W)	10	130.74	4.01	3.07
		Spring(Sp)	5.23	94.01	1.5	1.6
		Summer(Su)	13.04	127.96	7.9	6.18
		Autumn(A)	17.25	117.75	4.43	3.77

Table 33 Average 24-hour cost for the customers of the Microgrid

Prices	RES Production	Season	Scenario 1 (€ct/kWh)	Scenario 2 (€ct/kWh)	Scenario 3A (€ct/kWh)	Scenario 3B (€ct/kWh)
High (H)	High(H)	Winter (W)	34.08	22.94	20.32	21.08
		Spring(Sp)	8.86	6.31	5.73	6.29
		Summer(Su)	97.55	59.54	50.6	51.3
		Autumn(A)	35.33	21.1	17.85	18.89
	Low(L)	Winter (W)	34.08	24.75	22.33	23.1
		Spring(Sp)	8.86	7.02	6.51	7.01
		Summer(Su)	97.55	65.97	57.68	58.38
		Autumn(A)	35.33	23.59	20.71	21.74
Medium (M)	High(H)	Winter (W)	3.66	3.36	3.36	3.36
		Spring(Sp)	3.04	2.74	2.74	2.74
		Summer(Su)	3.76	3.28	3.24	3.28
		Autumn(A)	3.91	3.42	3.42	3.42
	Low(L)	Winter (W)	3.66	3.55	3.55	3.55
		Spring(Sp)	3.04	2.99	2.99	2.99
		Summer(Su)	3.76	3.53	3.49	3.53
		Autumn(A)	3.91	3.77	3.77	3.77

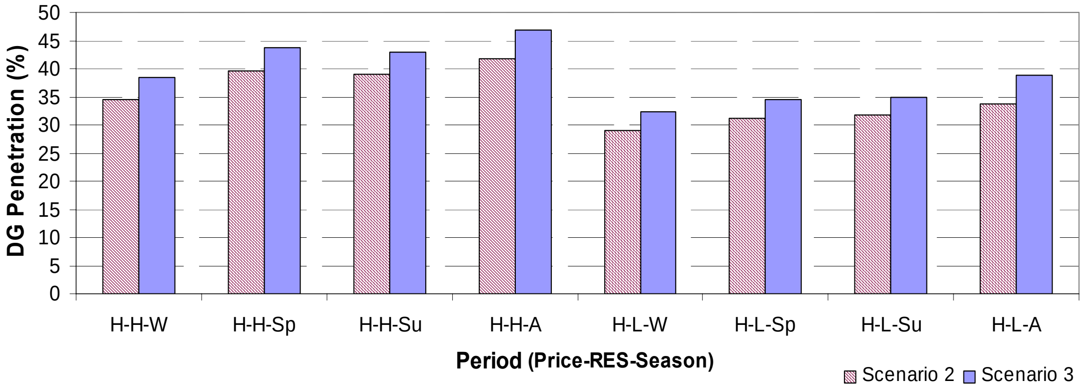

Figure 28 DG penetration comparison for High prices and case study 1., Scenario 2 vs Scenario 3

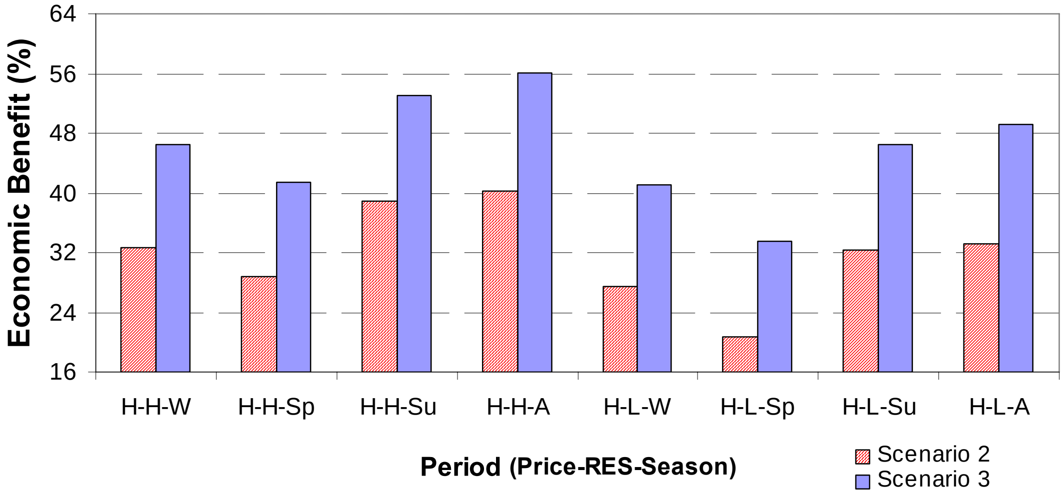

Figure 29 The benefits for Scenarios 2 and 3-High prices-Case study 1

The results for market policy 2 will be the same in terms of DG penetration and economics since the DG capacity is low enough to sell power to the upstream network.

4.3.1.2. Case Study 2

For the reduced microgrid, the impact on penetration and economics is shown in Table 34 when only DG production is considered. The DSB accepted for each case are provided in Table 35. The impact of DSB in both penetration and economics is provided in **Table 36** while the comparison of average cost for the customers is provided in Table 37. Without DG penetration, the average cost is lower due to the relatively low coincidence of market prices and production cost.

Table 34 DG penetration and costs applying Market policy 1 for Case study 2

Prices	RES Production	Season	DG penetration (%)	Cost Scenario 1 (€)	Cost Scenario 2 (€)	Cost Change	
						€	%
High (H)	High(H)	Winter (W)	81.37	395.53	58.72	336.81	85.15
		Spring(Sp)	83.58	92.41	33.03	59.38	64.26
		Summer(Su)	83.89	985.93	44.5	941.43	95.49
		Autumn(A)	86.3	351.8	38.3	313.5	89.11
	Low(L)	Winter (W)	73.93	395.53	83.11	312.51	78.99
		Spring(Sp)	73.05	92.41	44.21	48.2	52.16
		Summer(Su)	76.88	985.93	65.67	920.26	93.34
		Autumn(A)	76.78	351.8	58.2	293.6	83.46
Medium (M)	High(H)	Winter (W)	42.21	47.14	36.22	10.92	23.17
		Spring(Sp)	36.8	33.23	24.12	9.11	27.4
		Summer(Su)	43.57	43.46	28.39	15.07	34.68
		Autumn(A)	61.17	42.47	27.98	14.49	34.12
	Low(L)	Winter (W)	27.26	47.14	43.11	4.03	8.55
		Spring(Sp)	14.27	33.23	31.73	1.5	4.51
		Summer(Su)	31.81	43.46	35.9	7.56	17.4
		Autumn(A)	43.4	42.47	36.62	5.85	13.77
Low(L)	High(H)	Winter (W)	14.8	13.33	11.67	1.66	12.48
		Spring(Sp)	17.94	10.16	8.26	1.9	18.71
		Summer(Su)	20.42	13.11	10.84	2.27	17.34
		Autumn(A)	18.83	14.38	11.6	2.78	19.35
	Low(L)	Winter (W)	0.61	13.33	13.24	0.09	0.7
		Spring(Sp)	0.68	10.16	10.07	0.09	0.9
		Summer(Su)	2.68	13.11	12.77	0.34	2.63
		Autumn(A)	1.75	14.38	14.11	0.25	1.88

Table 35 Accepted bids for case study 2

Prices	RES Production	Season	Bids Accepted	
			kWh	%
High (H)	**High(H)**	Winter (W)	30	2.29
		Spring(Sp)	28	2.47
		Summer(Su)	10	0.8
		Autumn(A)	36	3.26
	Low(L)	Winter (W)	46	3.51
		Spring(Sp)	28	2.47
		Summer(Su)	18	1.43
		Autumn(A)	40	3.62
Medium (M)	**High(H)**	Winter (W)	0	0
		Spring(Sp)	0	0
		Summer(Su)	0	0

	Autumn(A)	0	0
Low(L)	Winter (W)	0	0
	Spring(Sp)	0	0
	Summer(Su)	2	0.16
	Autumn(A)	0	0

Table 36 DG penetration and costs applying Market policy 1 for Case study 2 with DSB acceptance

Prices	**RES Production**	**Season**	**DG penetration (%)**	**Cost Scenario 1 (€)**	**Cost Scenario 3(€)**	**Cost Change**	
						€	**%**
High (H)	**High(H)**	Winter (W)	82.64	395.53	49.49	346.04	87.51
		Spring(Sp)	85.67	92.41	30.75	61.66	66.72
		Summer(Su)	85.59	985.93	40.41	945.52	95.9
		Autumn(A)	87.42	351.8	30.11	321.69	91.44
	Low(L)	Winter (W)	75.47	395.53	62.8	332.73	84.12
		Spring(Sp)	74.9	92.41	41.92	50.49	54.63
		Summer(Su)	77.5	985.93	53.73	932.2	94.55
		Autumn(A)	79.29	351.8	46.92	304.88	86.66
Medium (M)	**High(H)**	Winter (W)	42.21	47.09	36.22	10.92	23.17
		Spring(Sp)	36.8	33.22	24.12	9.11	27.41
		Summer(Su)	43.57	43.46	28.39	15.07	34.68
		Autumn(A)	61.17	42.47	27.98	14.49	34.12
	Low(L)	Winter (W)	27.26	47.09	43.11	4.03	8.55
		Spring(Sp)	14.26	33.22	31.73	1.5	4.51
		Summer(Su)	31.9	43.46	35.8	7.66	17.63
		Autumn(A)	43.4	42.47	36.62	5.85	13.77

Table 37 Average costs for customers –Policy 1 and case study 2

Prices	**RES Production**	**Season**	**Scenario 1 (€ct/kWh)**	**Scenario 2 (€ct/kWh)**	**Scenario 3a (€ct/kWh)**	**Scenario 3b (€ct/kWh)**
High (H)	**High(H)**	Winter (W)	30.19	4.48	3.87	4.03
		Spring(Sp)	8.14	2.91	2.78	2.91
		Summer(Su)	78.58	3.55	3.25	3.3
		Autumn(A)	31.87	3.47	2.82	3.05
	Low(L)	Winter (W)	30.19	6.34	4.97	5.22
		Spring(Sp)	8.14	3.89	3.78	3.88
		Summer(Su)	78.58	5.23	4.34	4.45
		Autumn(A)	31.87	5.27	4.41	4.67
Medium (M)	**High(H)**	Winter (W)	3.6	2.76	2.76	2.76
		Spring(Sp)	2.93	2.12	2.12	2.12
		Summer(Su)	3.46	2.26	2.26	2.26
		Autumn(A)	3.85	2.53	2.53	2.53
	Low(L)	Winter (W)	3.6	3.29	3.29	3.29
		Spring(Sp)	2.93	2.79	2.79	2.79
		Summer(Su)	3.46	2.86	2.86	2.86
		Autumn(A)	3.85	3.32	3.32	3.32

Market policy 2

As examined in chapter 4.2, DG penetration is increased for the “reduced” microgrid since energy is sold to the upstream network. By accepting Demand Side Bids, the MGCC has the ability to sell power not to customers of the Microgrid but to the upstream network. Therefore no change in the economic results is foreseen. What will change is the DG penetration for the loads of the microgrid as described in Table 38. Option B for Demand Side Bidding is not considered because this would increase the cost for the aggregator.

Table 38 DG penetration - case study 2-market policy 2.

Prices	RES Production	Season	DG penetration with DSB(%)	DG penetration without DSB(%)
High (H)	**High(H)**	Winter (W)	110.19	99.25
		Spring(Sp)	119.31	109.02
		Summer(Su)	116.69	106.84
		Autumn(A)	129.08	113.65
	Low(L)	Winter (W)	93.59	81.64
		Spring(Sp)	94.66	85.5
		Summer(Su)	95.15	86.42
		Autumn(A)	106.25	92.03
Medium (M)	**High(H)**	Winter (W)	47.51	47.51
		Spring(Sp)	43.58	43.59
		Summer(Su)	59.66	59.19
		Autumn(A)	75.25	75.25
	Low(L)	Winter (W)	32.55	32.55
		Spring(Sp)	21.05	21.05
		Summer(Su)	39.79	39.47
		Autumn(A)	55.15	55.15

4.4. Results from Application of Adequacy Constraints

The economic impact of applying adequacy constraints, i.e. request specific part of the demand of the Microgrid to be supplied by local power production, in case of intentional islanding, is estimated. First, the methodology approach is presented. Results from considering the total load as critical are presented directly afterwards and then results from categorizing critical and non-critical loads via the statements of DSB are presented. A comparison between these two scenarios has been made. Additionally these results are compared with the cases without DSB constraints.

Two additional scenarios have been considered

- Scenario 4: Operation similar to scenario 3 with adequacy constraint on the whole load
- Scenario 5 : Operation similar to scenario 3 with adequacy constraint on critical loads

4.4.1.1. Methodology followed

In order to comply with adequacy constraints, it is essential that significant amount of running capacity exists in the Microgrid. In this case, the operating units can quickly increase their production to meet the pre-determined demand in case of an emergency. Thus, the required size of the storage device for facing such an incident is smaller.

The approach followed can take into account that customers, under circumstances reflected by their bids, would accept disconnection of their low priority loads in order to maintain supply to their high priority loads in case of upstream faults. Thus, by reducing their requirements, the total critical demand of the microgrid in such an event may be sufficiently met by the local units, rather than the total demand of the microgrid. The flow chart of Figure 30 summarizes this approach. The micro-sources are committed according to the priority list, until at least this predetermined demand is met. In this way, the necessary operating reserve to compensate grid disconnection is maintained, although this may not be clearly the most economical solution. During the hours the micro-sources and DSB are not sufficient to meet pre-determined demand, strict economic scheduling is followed and the pre-determined demand will not be met, unless sufficient storage capacity exists. It is suggested that the MGCC informs load controllers for this incident to more efficiently prepare their bids for the next periods, otherwise the Microgrid will not be adequate in case of an emergency.

In the Economic Dispatch procedure, active power is dispatched to the committed micro-sources and, if economical, active power is bought form the grid.

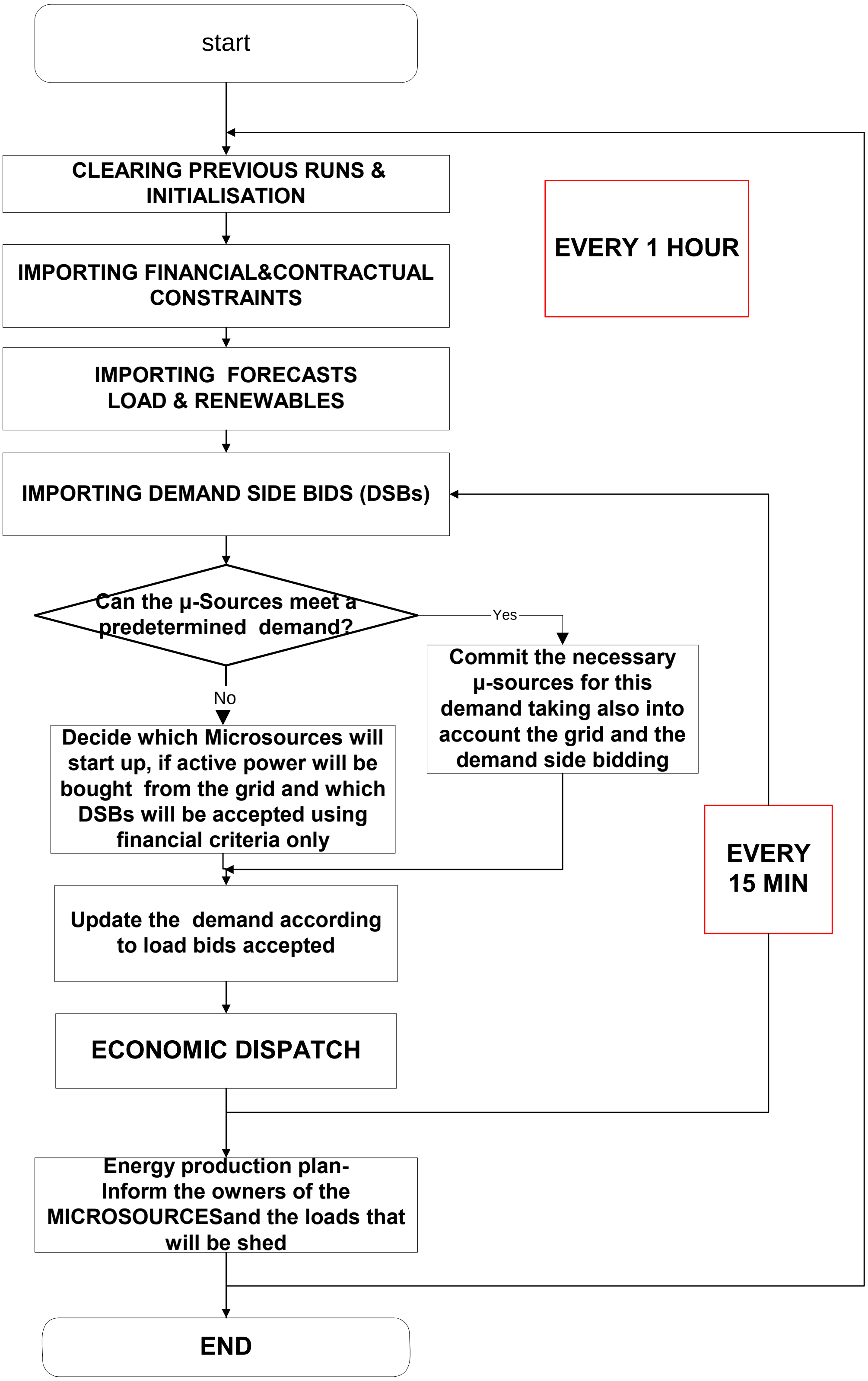

Figure 30 The flow chart of the proposed algorithm with adequacy constraints

4.4.1.2. Total load consideration

For Scenario 4, the increase in average DG penetration is shown in Figure 31. The economic impact may be low in actual values, but in percentage terms it is much higher for medium-low ApX prices, as shown in Figure 32. This is due to the fact that more local units operate purely to meet the adequacy constraints. This results in higher operating costs in the order of 5% for Scenario 4 compared to Scenario 1 for low prices, which represents a higher daily cost of 1.42€.

Table 41 presents the expected frequency of load disconnection in case of an upstream network fault, as a percentage of the periods when this may happen. Even if the capacity of the local DGs is sufficient to meet demand but it is not committed, then for a very short time there will be some load disconnection unless sufficient storage is available. Such a case is also counted in Table 41. As shown, inadequate operating cases are reduced by up to 20%, when comparing scenarios 2 and 4.

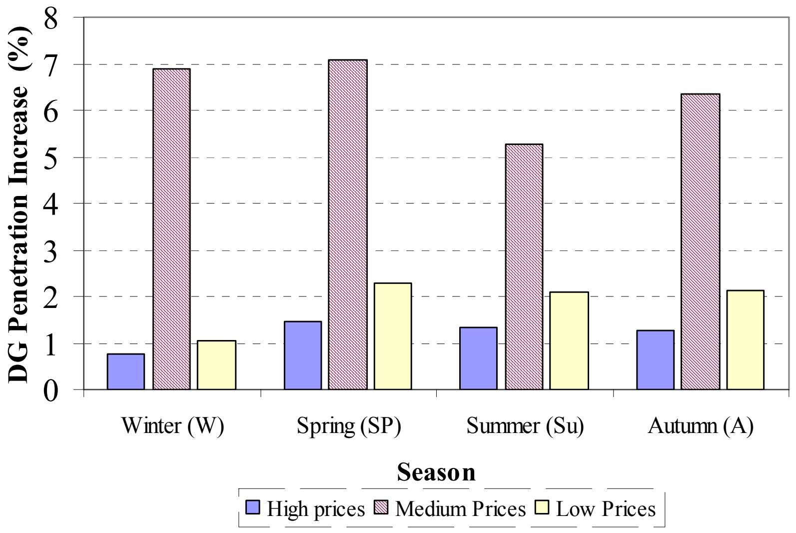

Figure 31 Average increase of DG penetration due to adequacy constraints. Scenario 4

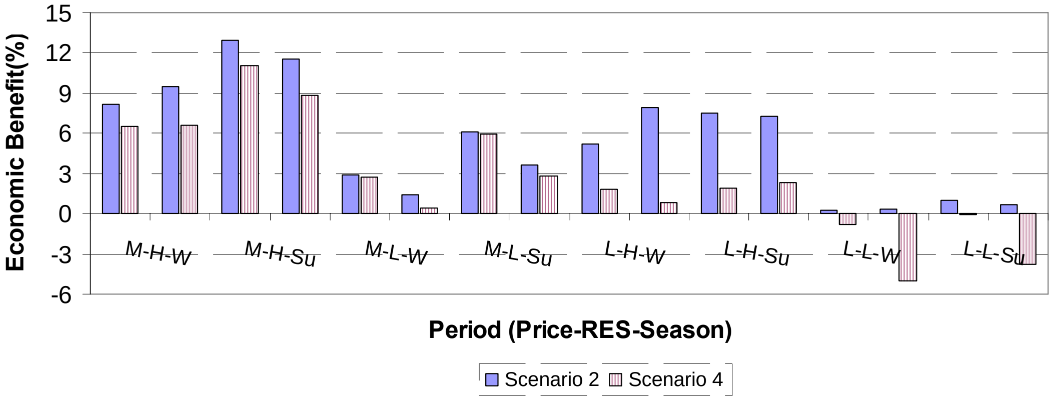

Figure 32 Impact of adequacy constraints on the economic operation without DSB

Case study 2

Since installed DG capacity and demand for case study 2 are comparable, the Microgrid will be more often adequate and this constraint will be more often activated than for the whole microgrid. The impact on both penetration and economics are presented in Table 39 and Table 40 respectively. The DG penetration is significantly increased for the cases of Medium -low prices by at least 10% as shown in Figure 33. This has adverse effect on the economics and when comparing cost without Microgrid and proposed operation the additional cost is up to 40% as shown in Figure 34. Due to low prices the additional cost is however low, 0.365**€ct/kWh.** The results in the diagrams focus on market policy 2 but similar are the results when market policy 1 is applied.

Table 42 presents the frequency of service for the critical loads of case study 2 in case of grid disconnection. Clearly adequacy constraint helps so that the majority of the critical loads is met.

Table 39 case study 2-Economic and Penetration resuts-Policy 1

Prices	RES Production	Season	DG penetration (%)	Cost Scenario 1 (€)	Cost Scenario 4 (€)	Cost Change	
						€	%
High (H)	High(H)	Winter (W)	84.88	395.53	58.72	336.81	85.14
		Spring(Sp)	89.28	92.41	33.15	59.26	64.13
		Summer(Su)	86.5	985.93	44.57	941.36	95.48
		Autumn(A)	88.85	351.8	38.39	313.41	89.09
	Low(L)	Winter (W)	79.42	395.53	83.29	312.33	78.95
		Spring(Sp)	80.69	92.41	44.6	47.81	51.74
		Summer(Su)	79.41	985.93	65.97	919.96	93.31
		Autumn(A)	81.07	351.8	58.32	293.48	83.42
Medium (M)	High(H)	Winter (W)	51.75	47.14	36.98	10.16	21.55
		Spring(Sp)	49.37	33.23	25.23	8	24.06
		Summer(Su)	54.04	43.46	28.57	14.89	34.27
		Autumn(A)	67.85	42.47	29.02	13.45	31.67
	Low(L)	Winter (W)	32.78	47.14	43.35	3.79	8.04
		Spring(Sp)	19.3	33.23	31.94	1.29	3.88
		Summer(Su)	34.17	43.46	35.98	7.48	17.21
		Autumn(A)	48.24	42.47	36.77	5.7	13.42
Low(L)	High(H)	Winter (W)	25.3	13.33	15.8	-2.47	-18.5
		Spring(Sp)	34.43	10.16	11.93	-1.77	-17.41
		Summer(Su)	32.29	13.11	14.25	-1.14	-8.66
		Autumn(A)	32.31	14.38	15.12	-0.74	-5.12
	Low(L)	Winter (W)	10.57	13.33	17.61	-4.28	-32.11
		Spring(Sp)	12.69	10.16	14.21	-4.05	-39.86
		Summer(Su)	13.76	13.11	17.02	-3.91	-29.82
		Autumn(A)	14.26	14.38	17.93	-3.55	-24.69

Table 40 DG penetration and costs for Scenario 1 and 2-Policy 2-Case study 2

Prices	RES Production	Season	DG penetration (%)	Cost Scenario 1 (€)	Cost Scenario 4 (€)	Cost Change	
						€	%
High (H)	High(H)	Winter (W)	99.71	395.53	-3.81	399.35	100.96
		Spring(Sp)	111.4	92.41	12.54	79.87	86.43
		Summer(Su)	108.5	985.93	-309.5	1295.4	131.39
		Autumn(A)	115.55	351.8	-76.15	427.95	121.64
	Low(L)	Winter (W)	85.67	395.53	61.01	334.52	84.58
		Spring(Sp)	90.45	92.41	34.73	57.67	62.41
		Summer(Su)	90.22	985.93	-89.52	1075.4	109.08
		Autumn(A)	95.99	351.8	-2.58	354.38	100.73
Medium (M)	High(H)	Winter (W)	54.38	47.09	36.62	10.47	22.23
		Spring(Sp)	51.77	33.22	24.94	8.28	24.93
		Summer(Su)	64.45	43.46	26.96	16.5	37.96
		Autumn(A)	82.04	42.47	27.92	14.56	34.27
	Low(L)	Winter (W)	39.88	47.09	43.81	3.28	6.97
		Spring(Sp)	30.83	33.22	33.01	0.22	0.65
		Summer(Su)	45.69	43.46	36.17	7.29	16.78
		Autumn(A)	62.49	42.47	36.62	5.85	13.78
Low(L)	High(H)	Winter (W)	25.3	13.33	15.8	-2.47	-18.5
		Spring(Sp)	34.43	10.16	11.93	-1.77	-17.41
		Summer(Su)	32.29	13.11	14.25	-1.14	-8.66
		Autumn(A)	32.31	14.38	15.12	-0.74	-5.12
	Low(L)	Winter (W)	10.57	13.33	17.61	-4.28	-32.11
		Spring(Sp)	12.69	10.16	14.21	-4.05	-39.86
		Summer(Su)	13.76	13.11	17.02	-3.91	-29.82
		Autumn(A)	14.26	14.38	17.93	-3.55	-24.69

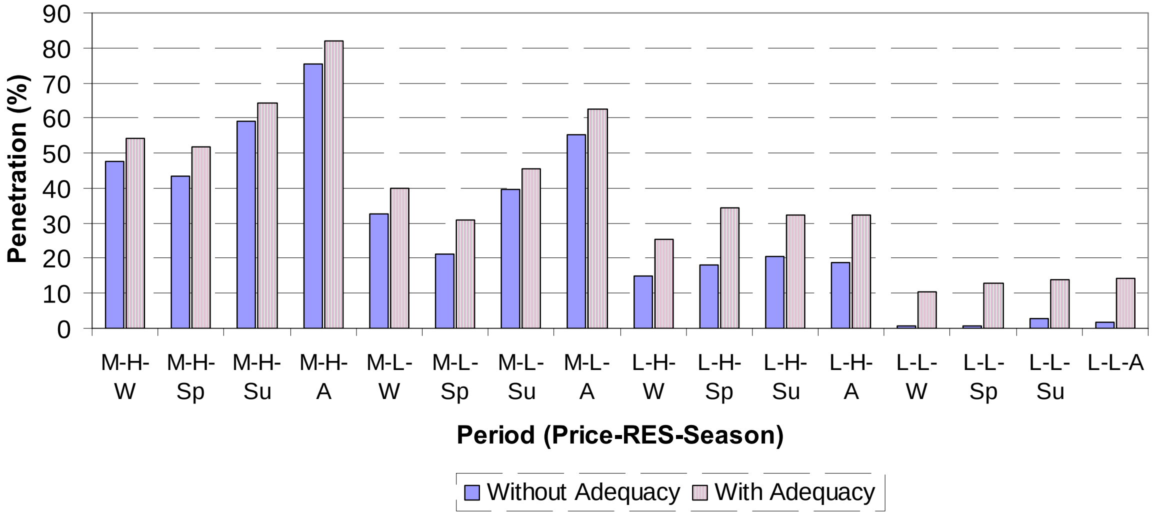

Figure 33 Impact of adequacy constraints on DG penetration without DSB for case study 2-market policy 2

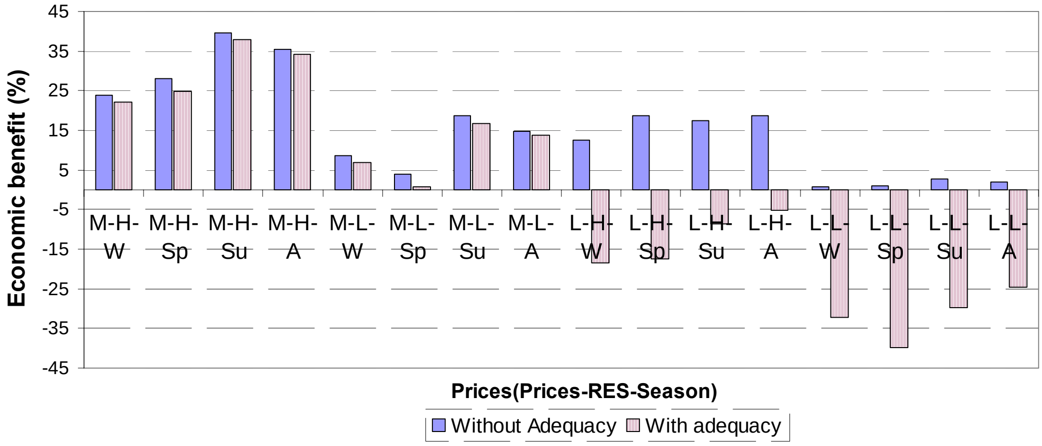

Figure 34 Impact of adequacy constraints on economics without DSB for case study 2-market policy 2

4.4.1.3. Applying it to "critical loads" only

The impact of classifying loads into critical and non-critical ones and the capability of disconnecting non-critical ones is studied next. The impact on DG penetration is shown in **Figure** 35. Increase in penetration during high market prices is mainly due to the acceptance of demand side bids (Table 32). When DSB takes place, local DGs are more often committed increasing DG penetration even for low prices.

For high prices, DSB helps in meeting the adequacy constraint at lower cost, mainly for the critical loads. The maximum benefit for scenario 4 compared to scenario 5 can reach 39.9 €ct/kWh, and on 24 hour average 13.69 €ct/kWh. When DSB is also accepted, adequacy constraint increases the cost by maximum 0.69 €ct/kWh, and on average 24 hour operation for 0.087 €ct/kWh. (scenario 3 vs scenario 5)

For low market prices, DG penetration increases up to 30% for high RES combination. This leads to cost increase compared to Scenario 1, even for high RES cases, as Figure 36 shows. The percentage increase is the highest among the studied cases. However, the absolute value is rather small and the additional cost is at maximum 0.562€ct/kWh, and on 24 hour average operation 0.059€ct/kWh.

The frequency of critical loads disconnection, in case of upstream network fault for all the cases studied is shown in Table 41. If 100% of the demand is taken as the criterion for adequacy, the percentages for both the critical loads and the total load are the same (Scenarios 2 and 4). If the adequacy constraint takes into account only critical loads, these are often even better served. Failure may happen for maximum 75% of the cases studied, which is lower than all previous cases with 100% demand adequacy constraint. Moreover, the frequency of not supplying non-critical loads due to the critical load adequacy constraint is slightly increased. An additional benefit of scenario 4 is that the critical loads are, in case of emergency, supplied more often and, especially for higher prices, at significantly lower cost.

Table 41 Frequency of not service for the critical loads for case study 1

Prices	RES Production	Season	Scenario 2	Scenario 4	Scenario 5
High (H)	High(H)	Winter (W)	100	87.5	70.8
		Spring(Sp)	100	79.2	70.8
		Summer(Su)	100	79.2	70.8
		Autumn(A)	100	79.2	70.8
	Low(L)	Winter (W)	100	95.8	70.8
		Spring(Sp)	100	83.3	70.8
		Summer(Su)	100	95.8	70.8
		Autumn(A)	100	79.2	75
Medium (M)	High(H)	Winter (W)	100	87.5	70.8
		Spring(Sp)	100	79.2	70.8
		Summer(Su)	100	79.2	70.8
		Autumn(A)	100	79.2	70.8
	Low(L)	Winter (W)	100	95.8	70.8
		Spring(Sp)	100	83.3	70.8
		Summer(Su)	100	95.8	70.8
		Autumn(A)	100	79.2	75
Low (L)	High(H)	Winter (W)	100	87.5	70.8
		Spring(Sp)	100	79.2	70.8
		Summer(Su)	100	79.2	70.8
		Autumn(A)	100	79.2	70.8
	Low(L)	Winter (W)	100	95.8	70.8
		Spring(Sp)	100	83.3	70.8
		Summer(Su)	100	95.8	70.8
		Autumn(A)	100	79.2	70.8

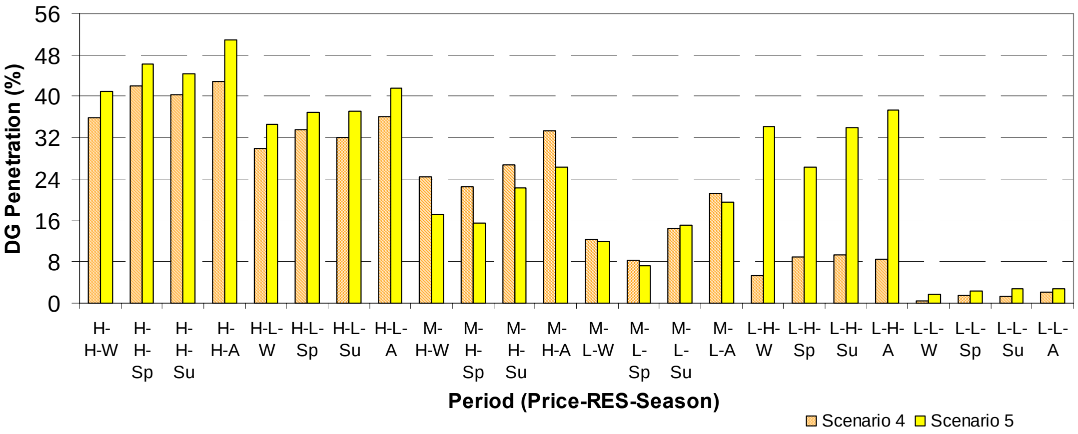

Figure 35 DG penetration with adequacy constraints. (Scenario 4 vs Scenario 5).

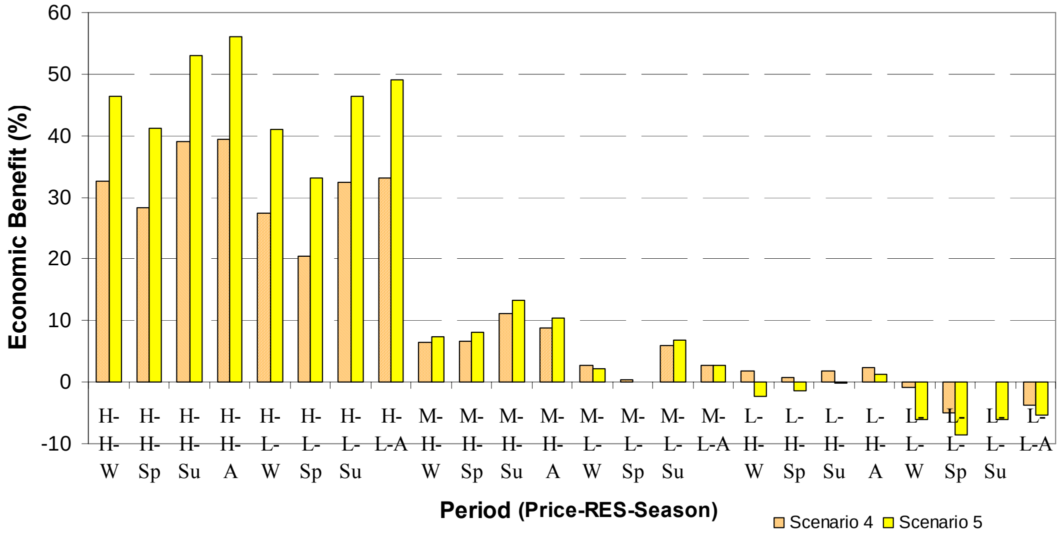

Figure 36 Economic impact of adequacy constraints compared to scenario 1

Case Study 2

A summary of frequency of service of the critical loads for case study 2 for scenarios 2 –DG production only, Scenario 4-adequacy constraint for the total load and Scenario 5-Adequacy constraint for the critical loads only6 is presented in Table 42. The results for applying adequacy constraints for market policy 1 are presented in Table 43, while results for Market Policy 2 are presented in Table 44. Figure 37 presents the change in penetration due to considering critical loads in the adequacy constraints for the medium-low prices combinations which are mostly affected. Figure 38 presents the economic results for the all the combinations studied. Clearly economic impact of adequacy constraint for low prices is significantly higher among all the scenarios studied in this report.

Table 42 Frequency of not service for the critical loads for case study 2

Prices	RES Production	Season	Scenario 2	Scenario 4	Scenario 5
High (H)	**High(H)**	Winter (W)	41.67	20.83	20.83
		Spring(Sp)	41.67	8.33	8.33
		Summer(Su)	45.83	16.67	16.67
		Autumn(A)	29.17	4.17	4.17
	Low(L)	Winter (W)	54.17	25	25
		Spring(Sp)	50	16.67	16.67
		Summer(Su)	45.83	20.83	20.83
		Autumn(A)	45.83	20.83	16.67
Medium (M)	**High(H)**	Winter (W)	91.67	20.83	20.83
		Spring(Sp)	70.83	16.67	8.33
		Summer(Su)	66.67	20.83	16.67
		Autumn(A)	58.33	16.67	4.17
	Low(L)	Winter (W)	100	29.17	25
		Spring(Sp)	100	20.83	16.67
		Summer(Su)	75	25	20.83
		Autumn(A)	79.17	20.83	16.67
Low (L)	**High(H)**	Winter (W)	100	20.83	20.83
		Spring(Sp)	100	16.67	8.33
		Summer(Su)	100	20.83	16.67
		Autumn(A)	100	16.67	4.17
	Low(L)	Winter (W)	100	29.17	25
		Spring(Sp)	100	20.83	16.67
		Summer(Su)	100	25	20.83
		Autumn(A)	100	20.83	16.67

Table 43 DG economics and penetration for case study 2 and market policy 1

Prices	RES Production	Season	DG penetration (%)	Cost Scenario 1 (€)	Cost Scenario 5 (€)	Cost Change	
						€	%
High (H)	**High(H)**	Winter (W)	86.76	395.53	49.5	346.03	87.49
		Spring(Sp)	89.12	92.41	30.87	61.54	66.59
		Summer(Su)	87.49	985.93	40.48	945.45	95.89
		Autumn(A)	90.95	351.8	30.2	321.6	91.42
	Low(L)	Winter (W)	80.59	395.53	62.9	332.63	84.1
		Spring(Sp)	78.89	92.41	42.11	50.3	54.43
		Summer(Su)	80.53	985.93	54.03	931.9	94.52
		Autumn(A)	83.34	351.8	47.01	304.79	86.64
Medium (M)	**High(H)**	Winter (W)	51.75	47.14	36.93	10.21	21.66
		Spring(Sp)	49.57	33.23	25.16	8.07	24.29
		Summer(Su)	50.85	43.46	29.06	14.4	33.13
		Autumn(A)	68.73	42.47	28.44	14.03	33.04
	Low(L)	Winter (W)	37.71	47.14	44.13	3.01	6.39
		Spring(Sp)	27.53	33.23	32.92	0.31	0.93
		Summer(Su)	39.86	43.46	36.78	6.68	15.37
		Autumn(A)	52.37	42.47	37.22	5.25	12.36
Low(L)	**High(H)**	Winter (W)	25.98	13.29	15.96	-2.67	-20.09
		Spring(Sp)	36.02	10.16	12.34	-2.18	-21.44
		Summer(Su)	31.5	13.11	14.76	-1.65	-12.55
		Autumn(A)	36.85	14.38	14.91	-0.53	-3.66
	Low(L)	Winter (W)	11.26	13.29	17.87	-4.58	-34.46
		Spring(Sp)	13.49	10.16	14.42	-4.26	-41.91
		Summer(Su)	14.48	13.11	17.27	-4.16	-31.69
		Autumn(A)	15.07	14.38	18.08	-3.7	-25.7

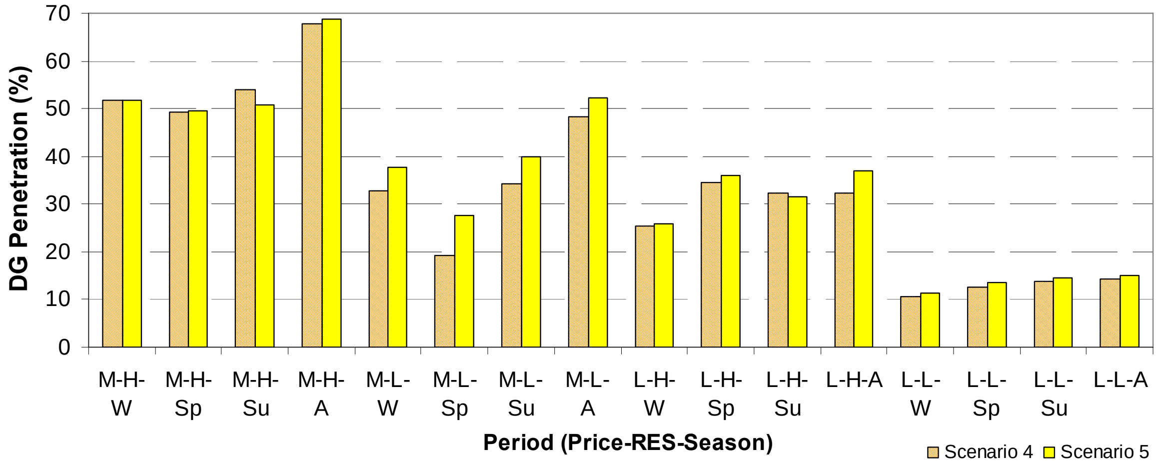

Figure 37 Comparing DG penetration for Case study 2 between scenario 4 and 5

The economic benefit for high prices periods is higher when the adequacy constraint is applied to the critical loads only compared to the total load. The average savings per day reach 1.56€ct/kWh, while the maximum hourly benefit can be 24.6€ct/kWh. For low prices however, the additional cost for meeting adequacy constraint is higher, since more often local units capacity is sufficient to meet the adequacy constraint. Thus they operate more often even though this is not clearly the most economic solution. The additional cost may be rather high in percentage terms but in absolute values is 0.365€ct/kWh on daily average and maximum hourly can reach 1.14€ct/kWh.

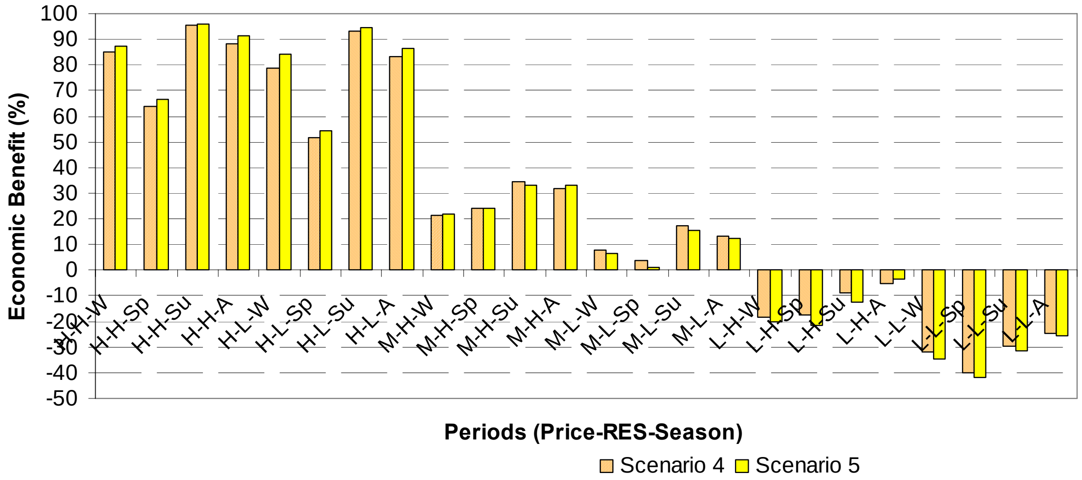

Figure 38 Comparing DG penetration for Case study 2 between scenario 4 and 5

Comparing fully economic operation and the suggested one for scenario 5, market policy 1 and case study 2 has as result increase of the cost by 0.383€ct/kWh on daily average and maximum hourly can reach 1.49€ct/kWh.

Case study 2-Market Policy 2

Table 44 presents the results regarding DG penetration and economics for case study 2 and market policy 2. The qualitive remarks are similar with the application of scenario 5 and market policy 2 but the DG penetration is higher due to the ability of selling active power to the upstream network. Since this market policy assumes the existence of an aggregator who is willing to maximize their own benefits, adequacy constraint for critical loads creates some income loss. To compensate for this income loss, the average daily values that the customers should be charged with are provided for various cases in Table 45. The additional charge is higher for case of low market prices and is much worse if one considers the percentage results. The maximum hourly charge to compensate between most economic operation (scenario 3 or 2-for low prices) compared to scenario 5 (maximum adequacy for critical loads) is for low RES low prices case 1.5€ct/kWh.

Table 44 DG economics and penetration for case study 2 and market policy 2

Prices	RES Production	Season	DG penetration (%)	Cost Scenario 1 (€)	Cost Scenario 5 (€)	Cost Change	
						€	%
High (H)	**High(H)**	Winter (W)	110.69	395.53	-3.55	399.09	100.9
		Spring(Sp)	121.92	92.41	12.59	79.82	86.38
		Summer(Su)	118.52	985.93	-309.5	1295.4	131.39
		Autumn(A)	131.24	351.8	-76.1	427.9	121.63
	Low(L)	Winter (W)	95.11	395.53	61.27	334.26	84.51
		Spring(Sp)	99	92.41	34.78	57.62	62.36
		Summer(Su)	98.55	985.93	-89.47	1075.4	109.07
		Autumn(A)	109.65	351.8	-2.51	354.32	100.71
Medium (M)	**High(H)**	Winter (W)	54.38	47.15	36.93	10.21	21.66
		Spring(Sp)	49.57	33.22	25.16	8.07	24.29
		Summer(Su)	65.45	43.46	27.32	16.14	37.14
		Autumn(A)	83.67	42.47	28.05	14.43	33.97
	Low(L)	Winter (W)	40.34	47.14	44.13	3.01	6.39
		Spring(Sp)	31.35	33.22	32.92	0.31	0.93
		Summer(Su)	46.54	43.46	36.5	6.96	16.02
		Autumn(A)	63.03	42.47	36.85	5.62	13.24
Low(L)	**High(H)**	Winter (W)	25.98	13.29	15.96	-2.67	-20.09
		Spring(Sp)	36.02	10.16	12.34	-2.18	-21.44
		Summer(Su)	31.5	13.11	14.76	-1.65	-12.55
		Autumn(A)	36.85	14.38	14.91	-0.53	-3.66
	Low(L)	Winter (W)	11.26	13.29	17.87	-4.58	-34.46
		Spring(Sp)	13.49	10.16	14.42	-4.26	-41.91
		Summer(Su)	14.48	13.11	17.27	-4.16	-31.69

	Autumn(A)	15.07	14.38	18.08	-3.7	-25.7

Table 45 Average daily additional charge for microgrids customers in Case study 2 and Market policy 2 when scenario 5 is applied

Price Level	Average price €ct/kWh	Maximum price €ct/kWh
High	0.03	0.05
Medium	0.096	0.13
Low	0.417	0.469

4.4.2. Discussion

Table 46 provides the maximum additional cost required to meet adequacy constraints compared to the purely economic operation with and without DSB. This is expressed in both hourly and average daily demand values, for high prices scenarios, where small economic percentage is translated to significant additional value. The daily average is higher for scenario 4. Thus, improved service for the critical loads of the microgrid is achieved at on average lower cost, when the adequacy criterion applies to the sum of the critical loads only. As the prices decrease, the additional percentage cost of the adequacy constraint is significant, as shown in Figure 32 and 27. For low prices, the cost may be higher even compared to operation without DG sources, especially for Low RES. The percentage cost increase may be high, but the actual value rather small. Table 47 compares the maximum additional cost for low prices at average and hourly level. In such conditions the consideration of critical loads only, increases the cost.

Table 46 Economic impact of adequacy constraints for case study 1

	SCENARIO 4 VS SCENARIO 2	SCENARIO 5 VS SCENARIO 3
Maximum additional cost €ct/kWh	0.473	0.69
Maximum average 24-hour cost €ct/kWh	0.278	0.087

Table 47 Comparison of maximum additional costs for low prices for case study 1

	Scenario 5-Scenario 4	Scenario 5-Scenario 1	Scenario 4-Scenario 1
Maximum additional hourly cost €ct/kWh	0.562	0.689	0.688
Maximum average 24-hour cost €ct/kWh	0.059	0.071	0.047

Regarding case study 2, the maximum additional cost is provided for Market policy 1 compared to the most economic scenarios in Table 48. the additional cost for low prices period is provided in Table 49. Clearly, the fact that the microgrid with high penetration of DG production can be more often adequate increases the periods when additional DG units are brought on –line even if this is not the most economic solution. This is the reason for higher additional charges required for case study 2. Nevertheless, the additional costs in absolute values are rather small.

Table 48 Economic impact of adequacy constraints for case study 2 compared to economics only

	SCENARIO 4 VS SCENARIO 2	SCENARIO 5 VS SCENARIO 3
Maximum additional cost €ct/kWh	1.15	1.16
Maximum average 24-hour cost €ct/kWh	0.134	0.141

Table 49 Comparison of maximum additional costs for low prices for case study 2

	Scenario 5-Scenario 4	Scenario 5-Scenario 1	Scenario 4-Scenario 1
Maximum additional hourly cost €ct/kWh	1.14	1.51	1.15
Maximum average 24-hour cost €ct/kWh	0.365	0.138	0.131

4.5. Hellenic Transmission System market prices considered

In order to evaluate another marker as well, the economic impact was evaluated for the Hellenic Transmission System prices. For this purpose the average per hour marginal system prices of the for 2008 were used [26] . These are higher on average but less volatile than ApX market prices and the typical time-series considered is shown in Figure 39. Moreover, the average per season production from RES was considered.

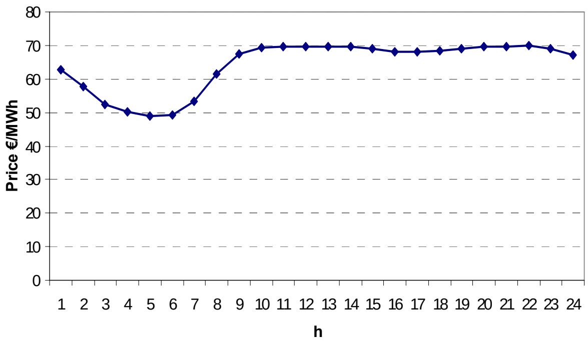

Figure 39 HTS prices considered

4.5.1. Case study 1

Figure 40 presents the cost reduction for the 4 days coming from various months (each one per season). Clearly the economic benefits are significant.

Table 50 DG penetration and costs for Scenario 1 and 2-HTS prices and Market Policy 1

Season	DG penetration (%)	Cost Scenario 1 (€)	Cost Scenario 2 (€)	Cost Change	
				€	%
Winter (W)	43.35	238.31	196.66	41.65	17.48
Spring(Sp)	49.73	206.47	163.68	42.79	20.73
Summer(Su)	46.33	228.09	183.88	44.21	19.38
Autumn(A)	51.05	200.67	157.74	42.93	21.4

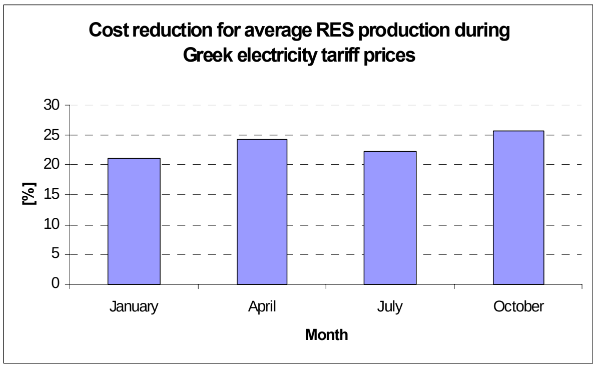

Figure 40 Cost reduction for representative months considered and HTS market prices

4.5.1.1. Results with DSB

In this case the accepted bids are described in Table 51. Clearly more bids are accepted than in case of ApX prices. However, slight in increase of the DSB bid price will lead to avoiding accepting bids. The impact on penetration and costs is described in Table 52. Figure 41 presents comparison between Scenario 3 and Scenario 2. The difference is not as high as in the case of ApX prices, due to already significant DG penetration and the constraint of not selling power to the upstream network.

Table 51 **Bids accepted-HTS prices and Market Policy 1-Case Study 2**

Season	**Bids Accepted**	
	kWh	**%**
Winter (W)	306	8.57
Spring(Sp)	296	9.56
Summer(Su)	300	8.77
Autumn(A)	296	9.84

Table 52 DG penetration and costs for Scenario 1 and 2-HTS prices and Market Policy 1

Season	**DG penetration (%)**	**Cost Scenario 1 (€)**	**Cost Scenario 3 (€)**	**Cost Change**	
				€	**%**
Winter (W)	47.42	238.31	175.4	62.91	26.4
Spring(Sp)	54.99	206.47	143.11	63.36	30.69
Summer(Su)	50.78	228.09	163.04	65.05	28.52
Autumn(A)	54.31	200.67	137.19	63.48	31.64

Table 53 Average customers charge. Case study 2-Market policy 2

Season	**Scenario 1 (€ct/kWh)**	**Scenario 2 (€ct/kWh)**	**Scenario 3a (€ct/kWh)**	**Scenario 3b (€ct/kWh)**
Winter (W)	6.67	5.51	5.37	5.5
Spring(Sp)	6.67	5.29	5.11	5.28
Summer(Su)	6.67	5.38	5.23	5.37
Autumn(A)	6.67	5.24	5.06	5.24

4.5.1.2. Results with Adequacy Cosntraints

Table 54 Results with adequacy cosntraints

Season	**Critical loads only**	**Whole Microgrid**	
Winter (W)	70.83	91.67	20.83
Spring(Sp)	70.83	91.67	8.33
Summer(Su)	70.83	87.5	16.67
Autumn(A)	70.83	83.33	4.17

4.5.2. *Case Study 2*

First the results from cases with simple operation of DG without taking into account security constraints are shown in Table 55. The penetration is rather high and significant are the cost savings as well.

Table 55 DG penetration and costs for Scenario 1 and 2-HTS prices and Market Policy 1

Season	**DG penetration (%)**	**Cost Scenario 1 (€)**	**Cost Scenario 2 (€)**	**Cost Change**	
				€	**%**
Winter (W)	88.87	87.38	50.24	37.14	42.5
Spring(Sp)	94.46	75.54	39.49	36.05	47.72
Summer(Su)	92.01	83.44	44.78	38.66	46.33
Autumn(A)	95.52	73.42	37.67	35.75	48.69

4.5.2.1. *Results with DSB (Scenario 3)*

In this case the accepted bids are described in Table 56. Clearly more bids are accepted than in case of ApX prices. However, slight in increase of the DSB bid price will lead to avoiding accepting bids. The impact on penetration and costs is described in Table 57. Figure 41 presents comparison between Scenario 3 and Scenario 2. The difference is not as high as in the case of ApX prices, due to already significant DG penetration and the constraint of not selling power to the upstream network.

Table 56 **Bids accepted-HTS prices and Market Policy 1-Case Study 2**

Season	**Bids Accepted**	
	kWh	**%**
Winter (W)	52	4.13
Spring(Sp)	46	4.22
Summer(Su)	48	3.98
Autumn(A)	46	4.35

Table 57 DG penetration and costs for Scenario 1 and 2-HTS prices and Market Policy 1

Season	**DG penetration (%)**	**Cost Scenario 1 (€)**	**Cost Scenario 3 (€)**	**Cost Change**	
				€	**%**
Winter (W)	92.38	87.38	46.66	40.72	46.6
Spring(Sp)	97.73	75.54	36.44	39.1	51.76
Summer(Su)	95.56	83.44	41.47	41.97	50.3
Autumn(A)	98.89	73.42	34.64	38.78	52.82

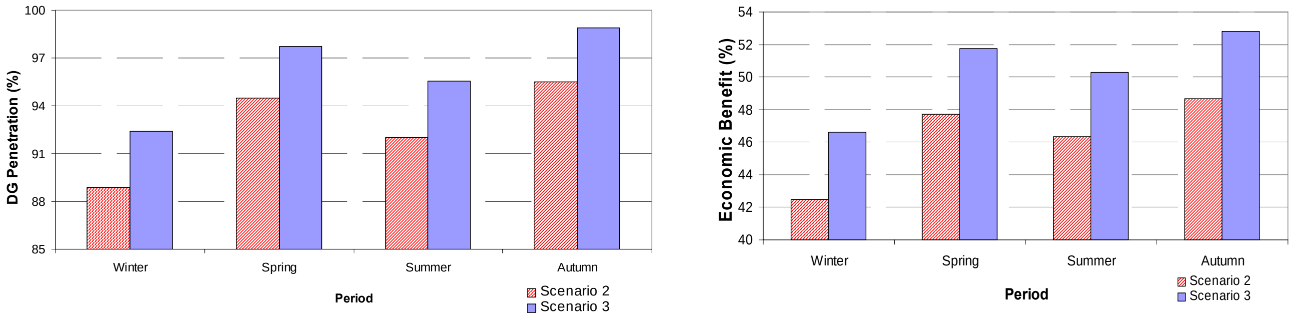

Figure 41 DG penetration (left) and savings (right) between scenario 2 and 3 for HTS market prices-Policy 1-Case study2

The average costs for customers finally served is provided in Table 58. Due to the comparable price of low load bids and the market prices, Scenario 3b-with remuneration of loads finally served presents significantly higher average prices than scenario 2. However, these prices are by around 1.3€ct/kWh lower than doing nothing scenario.

Table 58 Average customers charge. Case study 2-Market policy 2

Season	Scenario 1 (€ct/kWh)	Scenario 2 (€ct/kWh)	Scenario 3a (€ct/kWh)	Scenario 3b (€ct/kWh)
Winter (W)	6.67	3.83	3.708	5.387
Spring(Sp)	6.65	3.48	3.344	5.218
Summer(Su)	6.65	3.57	3.437	5.152
Autumn(A)	6.65	3.41	3.274	5.205

The maximum hourly savings for the customers of the microgrid can reach 4.56€ct/kWh while the maximum daily average is 3.48€ct/kWh.

4.5.2.2. Results with adequacy constraints

Table 59 presents the results from analysis of adequacy for case study 2. The results are common either the adequacy constraint is taken into account or not, either with or without DSB. The only categorization is the one between total microgrid demand and critical loads only. The economics and penetration levels will be the same with the ones presented in the above two paragraphs.

Table 59 Frequency of not service for the loads of the Microgrid. Case study 2-Market policy 2

Season	Whole Microgrid	Critical loads only
Winter (W)	25	20.83
Spring(Sp)	25	20.83
Summer(Su)	25	20.83
Autumn(A)	25	20.83

5. Calculation and impact on network losses

5.1. Introduction

Modern distribution systems were designed to accept bulk power at the Bulk Supply Transformers and to distribute it to customers. Thus, the flow of both real power (P) and reactive power (Q) was always from the higher to the lower voltage levels. However, with significant penetration of DG the power flows may become reversed and the distribution network is no longer a passive circuit supplying loads but an active system with power flows and voltages determined by the generation as well as the loads. The change in real and reactive power flows caused by Microgrids generation has important technical and economic implications for the power system [6]. So, Microgrid generation alters the power flows in the network and so will alter network losses.

If a small Microgrid generation is located close to a large load then the network losses will be reduced as both real and reactive power can be supplied to the load from the adjacent Microgrid generators. Conversely, if a large Microgrid generation is located far away from network loads then is likely to increase losses on the distribution system.

Generally, there are active power losses in the transmission network. These losses depend on the currents in the branches of this network which in turn depend on the voltages, and calculating these voltages is the object of the power flow calculation.

The avoided losses are often pointed out as an important value to be credited to microgeneration. Therefore, the quantification of the impact of microgeneration on losses of transmission and distribution networks is an important issue. Several studies have been made to evaluate the impact of DG on losses as well as to allocate the variations to generators and consumers. Most of those studies are devoted to find out how losses vary in a specific feeder and DG plant connection or when a predefined scenario of DG penetration is considered. Some of those studies propose algorithms to define the optimal location to DG [19][20][21].

The Microgrid generation will generally choose to operate at unity power factor to minimize their electrical losses and avoid any charges for reactive power consumption, irrespective of the needs of the distribution network. If a Microgrid generation produces some power at unity power factor the voltage profile is much more satisfactory [6] [21].The total injected complex power at bus i, denoted by Si, is given by: $S_i = P_i + jQ_i = V_i I_i^*$. The summation of powers over all buses gives the total system losses:

$$P_L + jQ_L = \sum_{i}^{n} V_i I_i^* = V_{bus}^T I_{bus}^*$$

where P_L and Q_L are the real and reactive power losses of the system, V_{bus} is the column vector of the nodal bus voltages, I_{bus} is the column vector of the injected bus currents and n is the number of buses.

5.2. LV losses results

Table 60 LV Active power losses (1st semester)

	Monthly active power losses (kWh)					
Scenario	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
All zero	1802,532	1873,049	1270,37	1229,39	1665,923	1865,286
All full production	1207,5	1235,501	918,4037	958,7442	1129,654	1239,174
Res Only	1702,345	1775,325	1187,751	1280,622	1569,981	1764,698
FC=>nom MT=>0	1452,224	1504,903	1045,734	1113,833	1345,992	1500,291
FC=>0 MT=>nom	1344,968	1315,84	855,0144	925,8225	1145,628	1300,741
All full production MT_bus=>8	920,7126	969,772	647,6177	692,3835	846,7677	958,2844

Table 61 LV Active power losses (2nd semester)

	Monthly active power losses (kWh)

Scenario	Jul	Aug	Sep	Oct	Nov	Dec	Yearly
All zero	1812,782	1578,072	1413,631	1258,922	1328,634	1928,595	19027,19
All full production	1213,426	1080,789	984,3426	912,665	939,5327	1281,15	13100,88
Res Only	1712,282	1484,949	1327,266	1176,715	1245,174	1824,62	18051,73
FC=>nom MT=>0	1460,239	1278,297	1150,387	1037,238	1086,17	1551,195	15526,5
FC=>0 MT=>nom	1256,551	1079,98	961,1901	846,816	899,0737	1344,968	13276,59
All full production MT_bus=>8	926,3503	800,4789	716,4938	642,2512	674,318	990,8658	9786,296

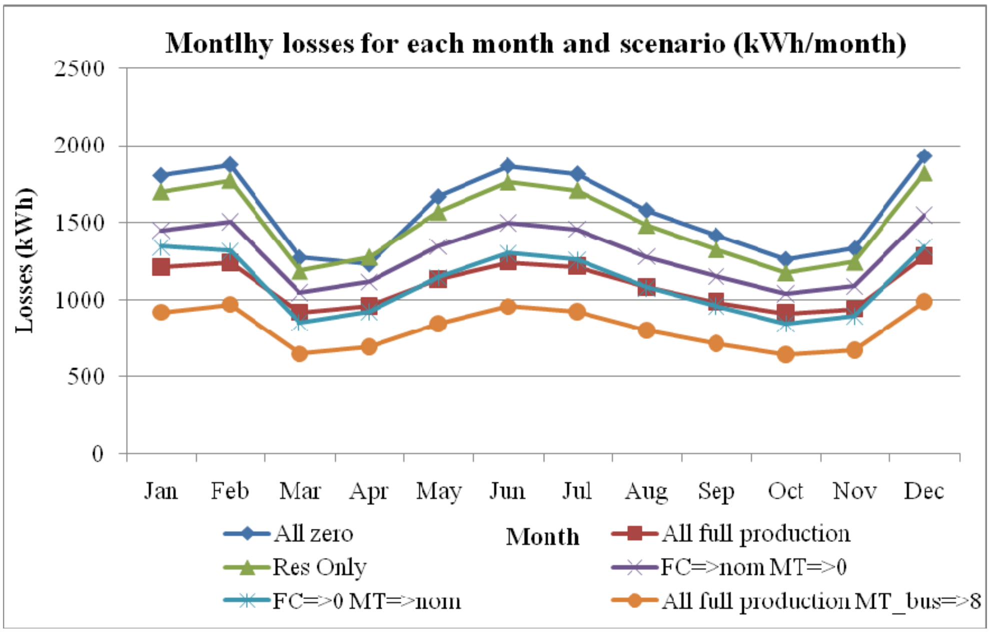

Figure 42 Monthly losses for each month and scenario

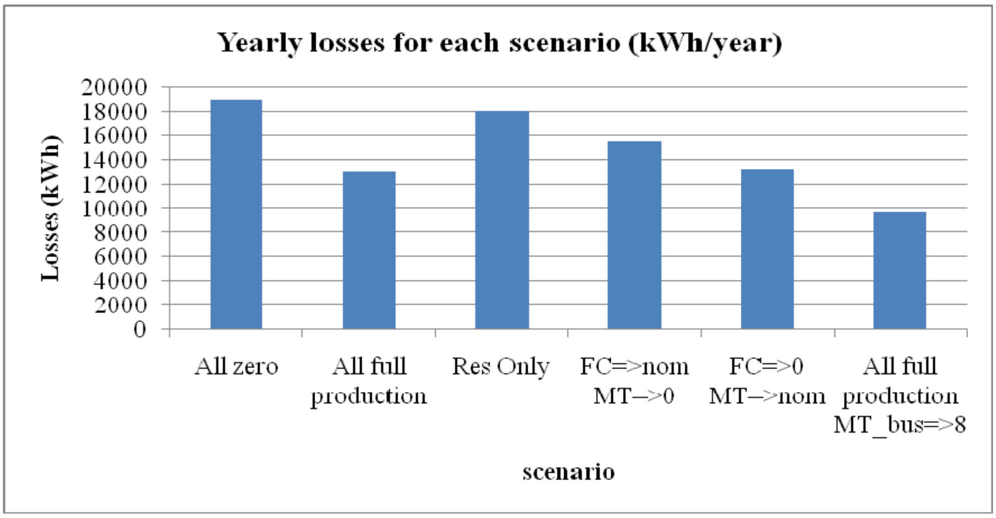

Figure 43 Yearly losses for each scenario

Table 62 Percentage decrease (%) of losses in comparizon with the absence of microproduction (1st semester)

	Month

Scenarios	Jan	Feb	Mar	Apr	May	Jun
All zero	0	0	0	0	0	0
All full production	-33,0109	-34,038	-27,7058	-22,0147	-32,1905	-33,5665
Res Only	-5,55817	-5,21738	-6,50358	4,167228	-5,75905	-5,39265
FC=>nom MT=>0	-19,4342	-19,6549	-17,6828	-9,39955	-19,2044	-19,5678
FC=>0 MT=>nom	-25,3845	-29,7488	-32,6956	-24,6926	-31,2316	-30,2659
All full production MT_bus=>8	-48,9212	-48,225	-49,0213	-43,6807	-49,1713	-48,6253

Table 63 Percentage decrease (%) of losses in comparizon with the absence of microproduction (2nd semester)

	Month						
Scenarios	Jul	Aug	Sep	Oct	Nov	Dec	Yearly
All zero	0	0	0	0	0	0	0
All full production	-33,0628	-31,5121	-30,3678	-27,5042	-29,2858	-33,5708	-31,1465
Res Only	-5,54397	-5,90111	-6,10943	-6,52993	-6,28162	-5,39121	-5,12666
FC=>nom MT=>0	-19,4476	-18,9963	-18,6218	-17,609	-18,2491	-19,5687	-18,3983
FC=>0 MT=>nom	-30,6838	-31,5633	-32,0056	-32,7348	-32,331	-30,2618	-30,223
All full production MT_bus=>8	-48,899	-49,2749	-49,3153	-48,984	-49,2473	-48,6224	-48,5668

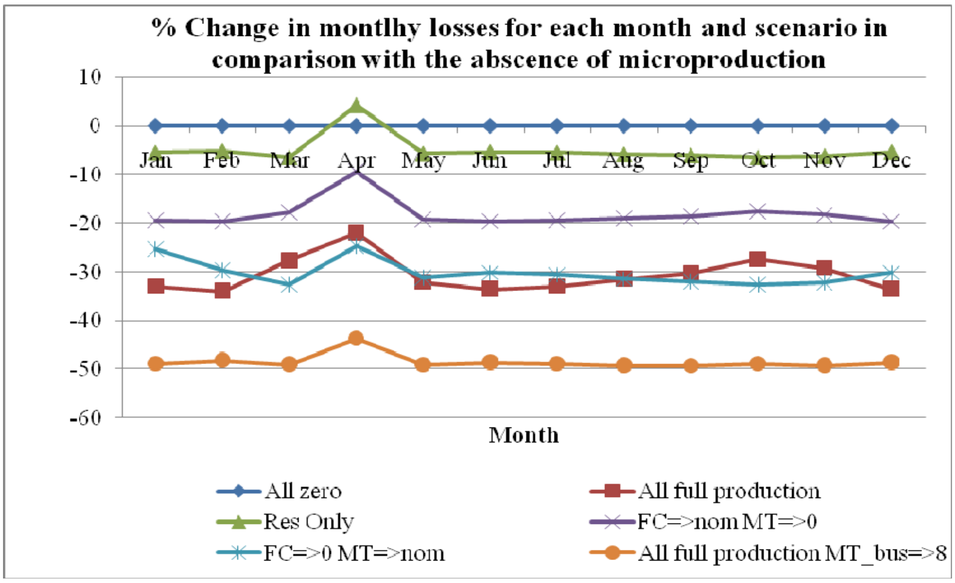

Figure 44 change in monthly losses for each month and scenario in comparison with the abscence of microproduction

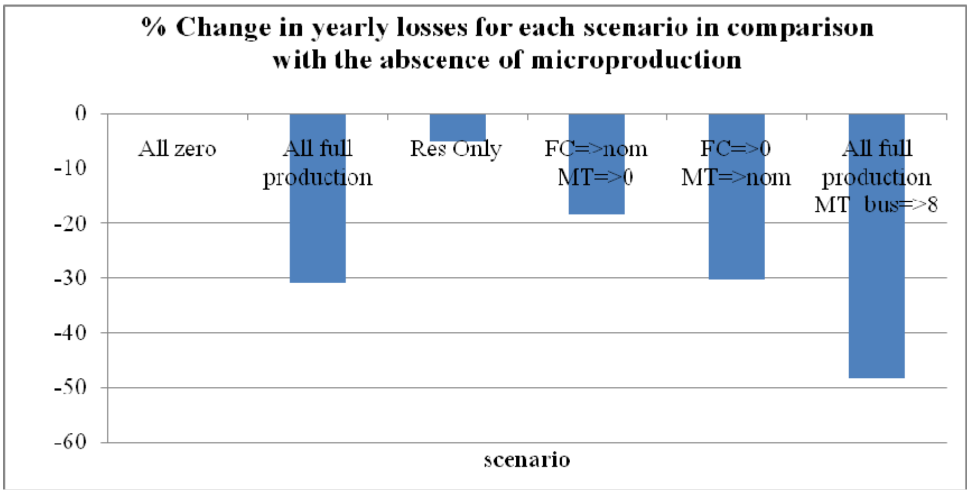

Figure 45 reduction in yearly losses for each scenario in comparison with the abscence of microproduction

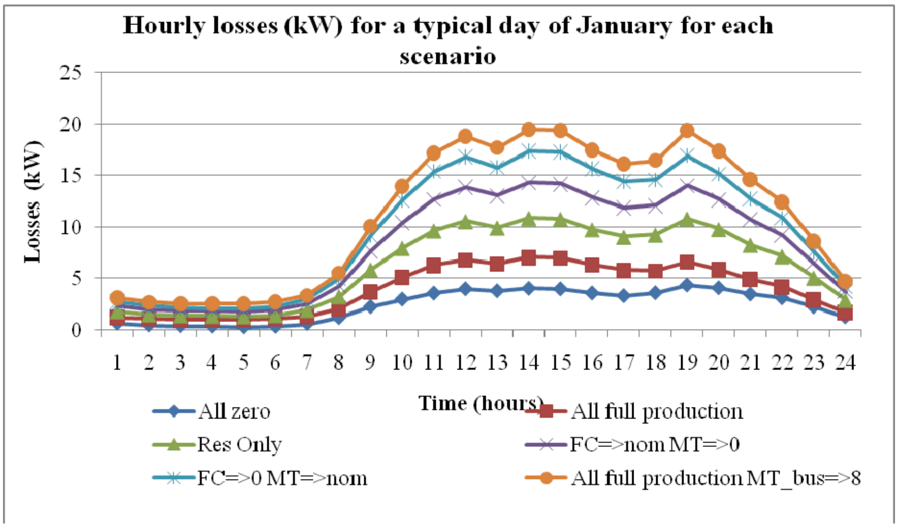

Figure 46 Hourly losses for a typical day of January for each scenario

5.3. MV losses results

Table 64 MV Active power losses (1st semester)

Losses (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
All zero	100,51	104,80	70,33	75,74	92,73	104,18
All full production	37,08	41,67	20,82	24,08	32,69	39,87
RES Only	93,34	97,79	64,44	69,69	85,87	96,97
FC=>nom MT=>0	61,11	65,98	38,65	43,00	55,21	64,43
FC=>0 MT=>nom	65,03	70,33	40,97	45,63	58,69	68,61
All full production MT_bus=>8	36,80	41,37	20,63	23,87	32,43	39,57

Table 65 Active power losses (2ndsemester)

Losses (MWh)	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Yearly (MW)**
All zero	101,10	87,74	78,47	69,68	73,66	107,71	1066,65
All full production	37,41	29,94	25,51	20,50	23,00	41,24	373,81
RES Only	93,91	81,09	72,31	63,82	67,71	100,27	987,20
FC=>nom MT=>0	61,56	51,46	45,01	46,52	41,48	42,86	617,26
FC=>0 MT=>nom	65,50	54,67	47,78	40,47	44,00	70,95	672,64
All full production MT_bus=>8	37,13	29,70	25,30	20,31	22,80	40,93	370,83

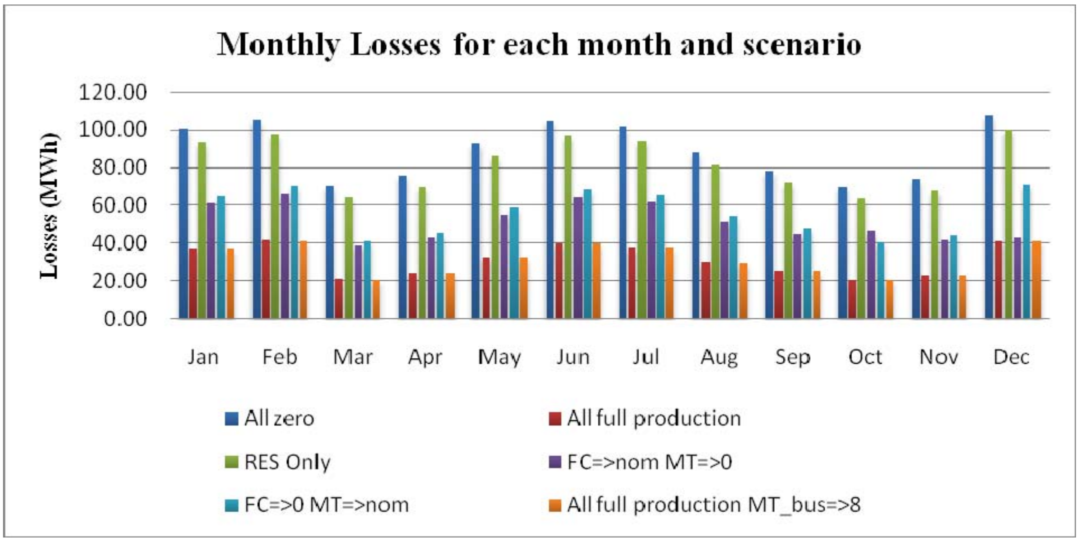

Figure 47 Monthly losses for each month and scenario

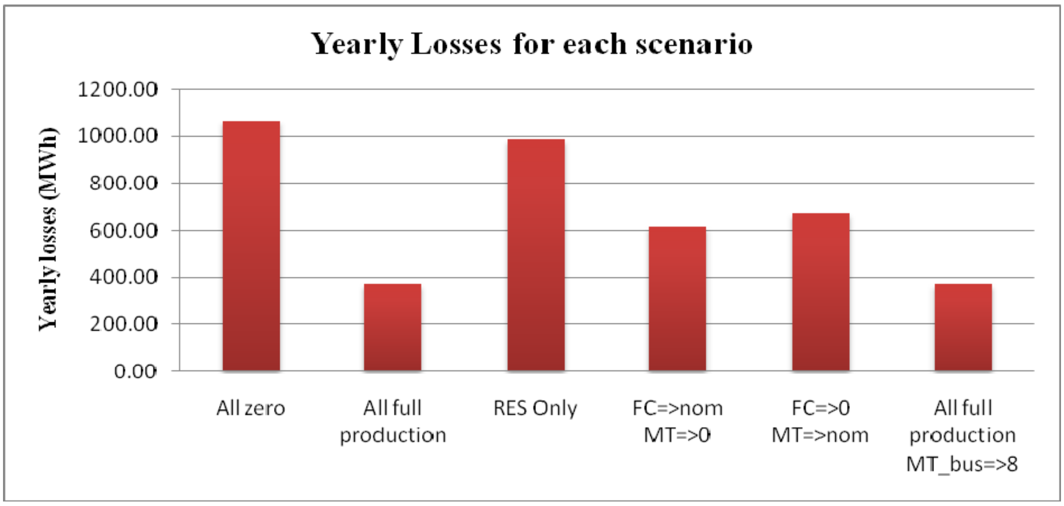

Figure 48 Yearly losses for each scenario

Table 66 Percentage decrease (%) of losses in comparizon with the absence of microproduction

Losses reduction from the All zero scenario	**All full production**	**RES Only**	**FC=>nom MT=>0**	**FC=>0 MT=>nom**	**All full production MT_bus=>8**
Jan	-63%	-7%	-39%	-35%	-63%
Feb	-60%	-7%	-37%	-33%	-61%
Mar	-70%	-8%	-45%	-42%	-71%
Apr	-68%	-8%	-43%	-40%	-68%
May	-65%	-7%	-40%	-37%	-65%
Jun	-62%	-7%	-38%	-34%	-62%
Jul	-63%	-7%	-39%	-35%	-63%
Aug	-66%	-8%	-41%	-38%	-66%
Sep	-67%	-8%	-43%	-39%	-68%
Oct	-71%	-8%	-33%	-42%	-71%
Nov	-69%	-8%	-44%	-40%	-69%
Dec	-62%	-7%	-60%	-34%	-62%
Yearly	**-65%**	**-7%**	**-42%**	**-37%**	**-65%**

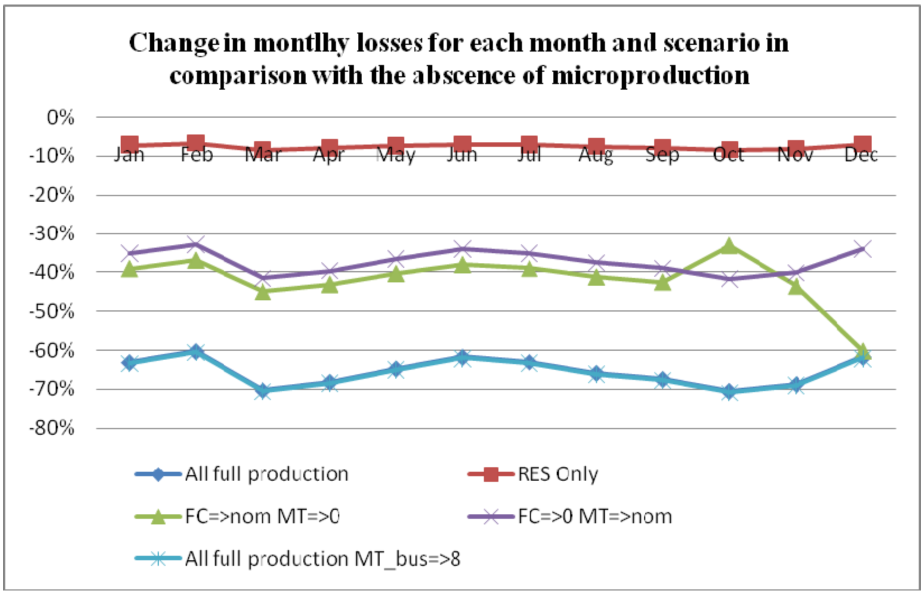

Figure 49 change in monthly losses for each month and scenario in comparison with the abscence of microproduction

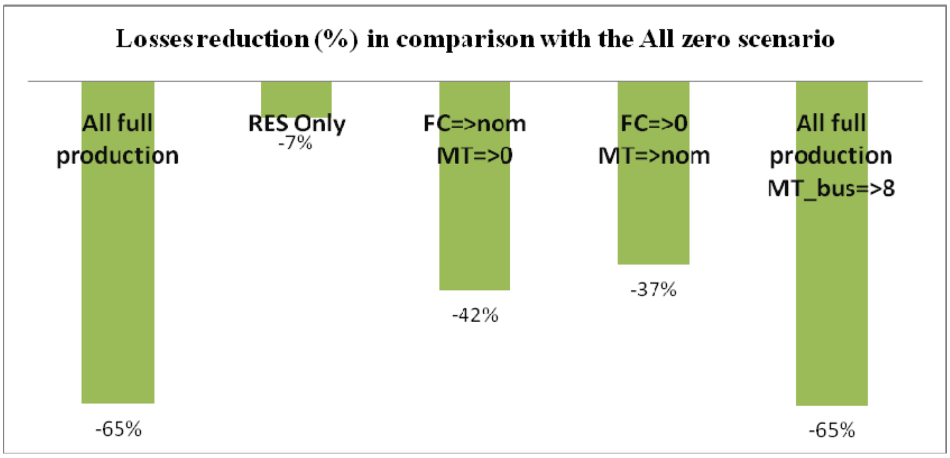

Figure 50 reduction in yearly losses for each scenario in comparison with the abscence of microproduction

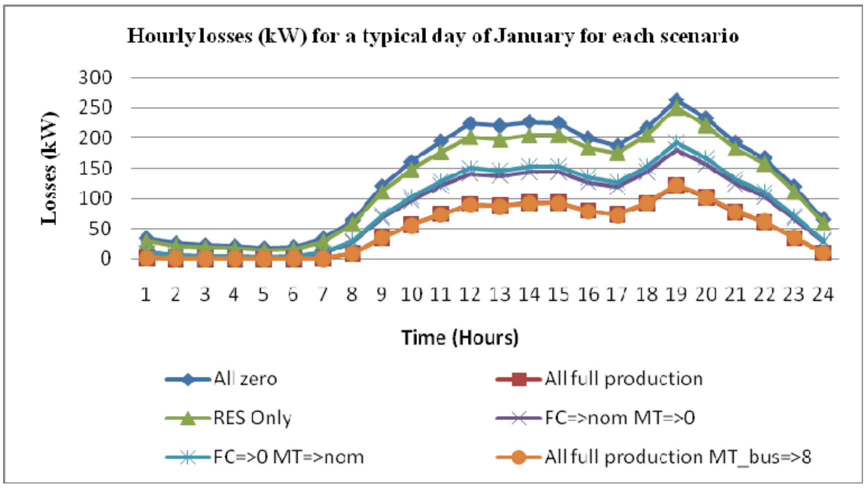

Figure 51 Hourly losses for a typical day of January for each scenario

6. Environmental Impact Assessment

6.1. Method For The Calculation Of DER Environmental Effects

Production from DG sources reduces injection from the upstream grid and thus the corresponding emissions from central units. DG output might produce of course its own emissions, which must be taken into account, in order to evaluate their environmental impact. Data about emissions of DG and central units for different fuels can be found in [36] and emission level in kg/GJ produced in [37].The USA Environmental Protection Agency has created a database with emissions from existing production units [38] and information on the DG sources in [39].

To calculate the environmental benefits of DER sources, an hourly analysis can be performed, if load and power production time-series are available. In this case, the operation of the system with DER penetration should be compared with operation based on central generation only, assuming optimal economic operation. This method was used to evaluate the economic and environmental benefits of both existing [40] and additional [41] wind power penetration on the island of Crete based on actual operating data. Alternatively, probabilistic methods can be used [42], to calculate the operating hours and production of both the central units and DER and the corresponding expected emissions with and without DER operation.

High penetration of DER in grid operation could affect central unit commitment, i.e. it is possible that central units might need to switch off, in order to accommodate increased DER production. In this paper, DER penetration is assumed relatively low, i.e. it does not affect scheduling of the units, but changes their hourly production. The most expensive units of the system are mainly affected, the so-called marginal units. Regarding emissions data, three possibilities exist in practice, which also determine the method used.

- Emissions Data Type 1 (ED1): Annual emissions available in gr/kWh
- Emissions Data Type 2 (ED2): Monthly emissions available
- Emissions Data Type 3 (ED3): Emissions by type of unit available and data on the type of marginal units

The simplest Type is ED1, frequently directly available by utilities [43] or obtained from the annual energy production by each type of unit available by Transmission System Operators (TSOs) **Fehler! Verweisquelle konnte nicht gefunden werden.**. In the latter case, the annual emissions for the power system can be estimated by the emission level of each unit using (16):

$$sys\_em\_lev = \frac{\sum_{i=1}^{N} emmision\_level_i \cdot energy_i}{\sum_{i=1}^{N} energy_i} \qquad (16)$$

Where

sys_em_lev	the emissions of the upstream network of the microgrid
i	the type of unit
$energy_i$	energy produced by unit type i for the studied period
$emission\_level_i$	is the emission unit type i
N	Different types of units

This analysis does not take into account the seasonality of production from both central and DG sources. This seasonality is important, in case different types of units are installed, e.g. peaking units, like gas turbines, do not operate during some months for many hours. Moreover, some DG sources, like PV and CHP units, might have significantly higher production during summer and winter, respectively, that should be taken into account in the analysis.

A more detailed analysis can be performed if the monthly production of each unit is known, usually made available by TSOs and utilities. Data about monthly emissions are also provided by some utilities on the web [43]. Monthly emissions data, either calculated by (16) or directly available, form the ED2 case.

Data case ED3 can be directly used, if it is assumed that the operation of DER does not change central unit commitment, but only the units' dispatch points. In fact, the production of marginal units only is altered, i.e. the most expensive production is substituted by DER. Therefore, only the emissions of these units should be taken into account, when evaluating the environmental impact of DG sources. The base units of the power system can be neglected in such analysis. The method applied requires knowledge of which type of marginal units operates at each hour of the month and the emissions of this type. Based on this, a monthly 24-hour emissions curve, *Emissions(hour,month)*, can be derived, as equation (17) describes. This method has been followed to evaluate the environmental impact of PVs in US utilities [44] and the marginal emissions in the California power system [45].

$$Emissions(hour,month) = \sum_{i=1}^{N} \frac{freq\_marg\_unit(hour,month)_i \cdot emission\_level_i}{30} \qquad \textbf{(17)}$$

where $freq\_marg\_unit(hour,month)_I$ is the frequency that unit type i is the marginal unit of the system.

The distinction between peaking and base units is especially important in the analysis of power systems with generation mix, significantly based on nuclear or hydro- units, like the systems of France and Norway, respectively [46]. In these networks the operation of the base units in fact reduces the overall CO_2 emissions, but the production of peaking units with significantly higher emissions is replaced by DER. Neglecting this fact and applying ED1 and ED2, significantly underestimates DER benefits. On the other hand, in power systems with thermal steam units operating as base units and oil- or gas-fired units covering load peaks, DER production reduces the output of units with lower CO_2 emissions. In this case, ED 1 and ED2 might overestimate DG benefits.

The more exact the estimation of the type of units whose production is replaced, the more accurate the estimation of the change in emissions due to the operation of DER. Such information is not easily available and requires simulation of the power system daily schedule normally based on a predefined priority list of the generation units of the power system and the system load curve.

For all data case availability, the following operating modes have been studied:

a) Minimisation of Operation cost
b) Minimisation of Pollutants, especially CO_2.
c) Profit maximisation by participation in the CO_2 emission trading market.

In all cases, the environmental benefits are calculated and are compared to the actual operation of the network studied without DER.

6.2. RESULTS

6.2.1. *Emissions without DER*

In this case, supply of the demand of the LV Microgrid without DER would produce the annual emissions shown in Table 67. In the next sub-sections the change in these emissions is calculated when the demand is met by the installed DER, so that the operating costs, the environmental effects or the profits obtained by participation in the CO_2 emissions market are optimized, respectively.

Table 67 Annual Emissions to satisfy centrally the Microgrid Demand

Pollutants	**Emissions (kg)**		
	ED1	***ED2***	***ED3***
CO_2	939,713	939,956	1,065,871
SO_2	9,109	9,167	351.9
NO_X	2,620	2,882	2,040
PM-10	523.5	522.5	520

6.2.2. *Minimization of Operating Costs*

It is assumed that RES are priority dispatched and the dispatch of the other DER is based on economic criteria. It is calculated that the MT operates for 22% of the year and the FC for 48.66%, when their operating costs (Table 1) are lower than the open market prices. The annual production of the DER is 231.48 MWh and the emissions avoided are presented in Table 68.

Table 68 Emissions avoided by DER when minimizing operating costs

Pollutants	Emissions Avoided (kg)		
	ED1	ED2	ED3
CO_2	81757.74	81416.77	114328.1
SO_2	1816.49	1814.95	71.75
NO_X	497.67	568.64	419
PM-10	109.2	100.92	116.79

It can be seen that the CO_2 emissions avoided are underestimated when we use the annual or monthly emissions data by 13.4% and 43.75%, respectively, while the SO_2 emissions avoided are significantly overestimated by 96% due to the fact that DER displace production from fuel with low sulfur content. NOx emission reductions are also overestimated by 22% and 20%, since DER do not displace diesel units, the units with highest NOx emissions. For PM-10 the difference is negligible summarises the percentage environmental benefits by the optimal economic operation of DER. Amongst the pollutants, the lowest reduction is achieved in CO_2.

Table 69. Percentage Emissions avoided

Pollutants	Emissions Avoided (%)		
	ED1	ED2	ED3
CO_2	8.70	9.15	11.03
SO_2	20.24	20.24	20.68
NO_X	19.73	20.15	20.21
PM-10	19.78	19.77	20.41

6.2.3. Minimization of Pollutants

In this section the DER operation is co-ordinated so that CO_2 emissions are minimised, this means that the emission of DER is compared to the grid emissions and DER units whose level is lower than the grid emissions are committed. As in 4.2, RES are always committed. In the first two cases (ED1 and ED2) the emissions from the DG sources are lower than the ones from the central units and, as a result, DER are always committed. Their total production reaches 571.4 MWh, with FC and MT operating 99.5% of the year. 0.5% is the assumed unavailability of DER (FOR-Forced Outage Rate) [52].

In ED3 case, DER consuming fuel are dispatched per hour and month, only if their emissions are lower than the average emissions of the central units, as calculated by (17). As a result, the FC is always committed, while the MT mostly does not operate during low demand periods, when the marginal unit is the Combined Cycle unit. The MT operates for less than 59 % of the year. The total production of DER is 447.8 MWh.

Table 70 provides results from the DER operation aiming to optimise environmental effects and Table 71 shows percentage reductions. Compared to the no DER operation, SO_2, NO_X and PM-10 emissions avoided are higher, when compared to the operation without DER. ED3 provides clearly the most accurate results regarding CO_2 emissions avoided, since it uses more detailed information about the emissions in the main grid.

Table 70 Emissions avoided when minimizing CO_2

Pollutants	Emissions Avoided (kg)		
	ED1	ED2	ED3
CO_2	144,560	144,675	186,777
SO_2	4,482	4,513	140.4
NO_X	1,234	1,363	796.9
PM-10	245.9	246.1	209.1

Table 71 Percentage Emissions avoided when minimizing CO_2

Pollutants	Emissions Avoided (%)		
	ED1	ED2	ED3
CO_2	15.38	15.39	17.52
SO_2	49.2	49.23	39.89
NO_X	47.1	47.3	39.06
PM-10	46.97	47.11	40.23

Environmental operation driven by CO_2 emission reduction obviously avoids more emissions than the economics driven operation. This comparison is shown in Table 72. In all pollutants there is significant change, for CO_2 is at least 59% and the rest above 90 %.

Table 72 Emissions avoided compared to economic operation at percentage level

Pollutants	Emissions Avoided (%)

	ED1	ED2	ED3
CO_2	76.82	68.20	58.96
SO_2	143.12	143.20	92.86
NO_X	138.67	134.80	93.29
PM-10	137.39	138.21	97.13

If the environmental operation is driven by any of the other pollutants, then the MT always operates in ED3 and the impact in the pollutants is presented at Table 73.

Table 73 Pollutants change if optimised operation for other pollutants is followed.

Pollutants	Change in Emissions Avoided (kg)-EV3
CO_2	-8176.73
SO_2	22.57
NO_X	113.4
PM-10	30.05

6.2.4. Economics resulting from the two operation objectives

In this Section the impact in the revenues of the DER owners by considering the operating objectives are compared. It should be noted that the difference between the two objectives affects operation of the FC and MT units. Table 74 compares the revenues between the economics driven and environmental driven operation of the Microgrid.

Table 74. DER revenues for different operating objectives.

Pollutants	Annual Revenues (€)
Economic	13549.13
Environmental-ED1 and 2	7715.9
Environmental ED3	9296.52

From the above table it can be concluded that environmental driven operation reduces annual earnings by 43% for ED1 and ED2 and by 31.39% for ED3. From the above calculations it can be concluded that, not only would environmental operation based only on average monthly or annual emission level actually increase the CO2 emissions compared to the operation implied by ED3, but would also increase the operating cost. Therefore, increased information on the emission level of the power system, does not only increase the calculations accuracy but also helps to avoid “optimal’ environmental operation that neither maximises the CO2 emissions nor increases the revenues of the Microgrid as described in Table 74. This fact is extremely important in view of the CO2 emissions trading, as discussed in section 4.5.

Table 75 summarises the minimum financial incentives that should be provided to DER owners for at least one pollutant per kg of avoided emissions, so that they could consider operating on optimal environmental operation without reducing their revenues.

Table 75. Financial incentives for avoided emissions

Pollutants	Emission Value (€/tn)		
	ED1	ED2	ED3
CO_2	92.88	99.44	61.41
SO_2	2210	2190	58410
NO_X	8140	7460	11060
PM-10	40980	40850	41290

6.2.5. Microgrid participating in CO_2 emissions market

A significant opportunity for DER to increase their operation and reduce their pay-back period is participation in the CO_2 emission trading market. DER can offer CO_2 reduction to the upstream grid and thus they can operate during periods that their operating cost is higher than the market cost, provided they are sufficiently remunerated for CO_2 emission reductions. The proposed operation is described in 6.2.6 and results from this analysis are given in 6.2.7.

6.2.6. Methodology followed

Assuming that DER participate in the CO2 emissions market, their marginal costs are accordingly modified to take into account fuel cost and the income due to CO2 emission savings, as follows:

$$marginal\_cost = operational\_cost - Emissions\_avoided \cdot Emission\_cost \qquad (18)$$

The operational cost is the bid of the unit, as provided in Table 1, and the *Emissions_avoided* is the difference between the emissions of the DER unit from the grid emissions in kg/MWh. The *emission_cost* is the financial incentive from the emissions trading market, mainly applied for CO_2 and usually expressed in €/tn.

Three cases are considered for the *Emissions_avoided,* depending on the available CO_2 emissions data for the upstream network.

- Case 1 (SCE 1): The annual emission level is considered constant for the whole year and the CO_2 remuneration is based on it.
- Case 2 (SCE2): Every month, the monthly CO_2 emission level is communicated to DER and the remuneration is based on the calculated emissions avoided.
- Case 3 (SCE3): The calculated 24-hour emission curve, as described in (2), is communicated to DER, every month. Thus DER are given an incentive to produce during hours with significant CO_2 emissions as described by the emission curve.

For instance for the FC, the marginal_cost is calculated for the different scenarios as:

28.4 €/MWh-(809.4-489.4)kg/MWh*x €/kg	SCE1
28.4 €/MWh-(802.1-489.4)kg/MWh*x €/kg	SCE2
28.4 €/MWh-(*Emissions(hour,month)*-489.4)kg/MWh*x €/kg	SCE3

x is the CO_2 emissions trading price.

Using the methodology described in section 2, the emissions avoided in the above cases (SCE1-SCE3) can be calculated, as well as the financial gains and can be compared to the revenues obtained by the economic operation and optimal environmental operation. Different values for CO_2 emissions trading prices have been considered ranging from 5 to 60 €/tn and the results are presented in the following sub-sections 6.2.7.

6.2.7. Change in operating hours and emissions

For our case study the difference in savings, DG production and emissions comes from the change in consumption of Fuel consuming units, in our case FC and MT.

The following tables summarize the operating hours and the production of the FC and MT in the 3 cases and for different prices for CO_2 avoided emissions in €/Tn.

SCE1

In this case, the remuneration for CO_2 avoidance is based on the calculations under ED1. The change in the operating hours and production for the FC and MT are presented at Table 76.

Table 76 Annual operating hours and Production of FC and MT - SCE1

CO_2 price (€/tn)	FC		MT		Total Microgrid Production (MWh)
	Operating Hours	Production (MWh)	Operating Hours	Production (MWh)	
0	4299	128.97	1955	58.65	231.49
5	4611	138.33	1957	58.71	240.91
10	4947	148.41	2008	60.24	252.52
15	5353	160.59	2045	61.35	265.81
20	5776	173.28	2076	62.28	279.43
30	6643	199.29	2163	64.89	308.05

50	8048	241.44	2399	71.97	357.28
60	8376	251.28	2497	74.91	370.06

FC operating hours are significantly increased, as the CO_2 trading value increases, and are almost doubled when the CO_2 trading price is 60 €/tn. On the other hand, MT operation is not much influenced due to its higher emission level. Its annual operating hours and production are increased by maximum 27.7%.

It is interesting to examine the impact on the avoided emissions not only for the assumption used for the remuneration, ED1, (Table 77) but also for the other two data cases, as shown in Table 78 and 20.

Table 77 Emissions change under ED1- SCE1

CO_2 price (€/tn)	CO_2 (kg)	NOx (kg)	SO_2 (kg)	PM-10 (kg)
0	81757.74	497.67	1816.49	109.2
5	84758.03	518.72	1890.41	113.54
10	88113.37	544.4	1981.51	118.94
15	92105.1	573.91	2085.8	125.1
20	96244.76	604.19	2192.67	131.4
30	104789.3	667.7	2417.25	144.67
50	118877.7	776.46	2803.55	167.6
60	122275.8	804.49	2903.83	173.59

Table 78 Emissions change under ED2 - SCE1

CO_2 price (€/tn)	CO_2 (kg)	NOx (kg)	SO_2 (kg)	PM-10 (kg)
0	81416.77	568.64	1814.95	100.92
5	84751.89	595.97	1900.29	105.76
10	88138.5	625.11	1993.73	110.99
15	92153.45	658.42	2098.68	116.93
20	96284.93	693.08	2205.72	123
30	104840.8	763.88	2431.56	135.76
50	118909.7	880.53	2819.28	157.53
60	122280.8	909.56	2920.74	163.15

Table 79 Emissions change under ED3- SCE1

CO_2 price (€/tn)	CO_2 (kg)	NOx (kg)	SO_2 (kg)	PM-10 (kg)
0	114328.06	419	71.75	116.79
5	118707.43	437.73	74.94	121.54
10	123159.25	458.01	78.38	126.63
15	128247.34	480.62	82.22	132.35
20	133184.91	503.19	86.05	138.06
30	142237.14	548.36	93.7	149.45
50	154308.55	620.46	105.87	167.53
60	157058.12	638.93	108.99	172.11

SCE2

In this case, the remuneration for avoided CO_2 is based on the calculations under ED2. The operating hours and production for both the FC and MT are presented at Table 80.

Table 80 Annual operating hours and Production of FC and MT – SCE2

CO_2 price (€/tn)	FC		MT		Total Microgrid Production (MWh)
	Operating Hours	Production (MWh)	Production (MWh)	Operating Hours	
0	4299	128.97	58.65	1955	231.49
5	4611	138.33	58.8	1960	241
10	4955	148.65	60	2000	252.52
15	5366	160.98	61.32	2044	266.17
20	5740	172.2	62.79	2093	278.86
30	6622	198.66	65.64	2188	308.17
50	8013	240.39	72.18	2406	356.44
60	8376	251.28	75.36	2512	370.51

The increase in operating hours and DER production is similar to SCE1. In this case the emission level is known at monthly level, therefore there is sufficient information allowing the use of monthly emission levels (ED2). The analysis based on annual emissions is not considered and only results for the analysis based on ED2 and ED3 are presented in Table 81 and Table 82, respectively.

Table 81 Emissions change under ED 2-SCE2

CO_2 price (€/tn)	CO_2 (kg)	NOx (kg)	SO_2 (kg)	PM-10 (kg)
0	81416.77	568.64	1814.95	100.92
5	84776.86	596.19	1901.25	105.81
10	88243.85	624.68	1994.47	111.03
15	92343.7	658.89	2102.56	117.14
20	96097.47	691.11	2203.09	122.8
30	104813	762.84	2434.21	135.84
50	118719.4	876.89	2814.36	157.22
60	122452.7	909.05	2926.14	163.4

Table 82 Emissions change under ED 3- SCE2

CO_2 price (€/tn)	CO_2 (kg)	NOx (kg)	SO_2 (kg)	PM-10 (kg)
0	114328.06	419	71.75	116.79
5	118678.25	437.82	74.95	121.56
10	123100.05	457.79	78.35	126.59
15	128230.45	480.91	82.27	132.42
20	132754.36	502.08	85.86	137.75
30	142097.68	548.59	93.74	149.48
50	153981.9	619.16	105.65	167.19
60	157099.5	639.64	109.12	172.28

Emissions savings in this case are similar to the ones of SCE1.

SCE3

This case can not be implemented as easily as the other two cases, since it requires information on a typical 24 hour emission curve for the main grid for the specific month to be transmitted to the DG sources as calculated by (17). This information however, helps in the reduction of CO_2 emissions, since it can increase remuneration during these hours, based on the marginal emissions of the upstream grid.

Table 83 Annual operating hours and Production of FC and MT – SCE3

CO_2 price (€/Tn)	FC		MT		Total Microgrid Production (MWh)
	Operating Hours	Production (MWh)	Operating Hours	Production (MWh)	
0	4299	128.97	1955	58.65	231.49
5	4679	140.37	2029	60.87	245.11
10	5148	154.44	2170	65.1	263.41
15	5537	166.11	2289	68.67	278.65
20	5843	175.29	2416	72.48	291.64
30	6317	189.51	2709	81.27	314.65
50	7138	214.14	3363	100.89	358.9
60	7455	223.65	3665	109.95	377.47

It can be noted that the operating hours for MT are significantly increased (almost doubled) compared to the previous 2 scenarios. This is due to the correlation of the hours with high emission rates with attractive market prices that makes MT participation in the open market beneficial. The decrease in Marginal cost of the MT, as calculated by (18), may even reach 30 €/MWh for 60 €/tn CO_2 prices when an old Gas turbine is the marginal unit of the system contrary to maximum reduction of 8.22 €/MWh obtained for December for SCE2. Thus, there is significantly higher possibility that the MT under SCE3 will have lower marginal cost than the open market prices compared to the previous two scenarios.

On the other hand, the operating hours of the FC are not so much increased, as in the previous 2 scenarios. The maximum decrease in marginal cost may be even more significant during high emission hours but, during these hours,FC will also probably operate for SCE 1 and 2. For SCE3, during some hours, the difference between FC emissions and main grid is lower compared to SCE1 and SCE2 leading to higher marginal cost compared to SCE1 and SCE2. Thus the operating hours at SCE 3 are not so much increased compared to economic operation as in the other two scenarios. However, the total production of the whole Microgrid is increased at all cases for SCE3 compared to SCE1 and SCE2.

Since 24-hour emission curve is available, avoided emissions can be calculated according to ED3 and results from this analysis are presented at Table 84.

Table 84 Emissions change under ED3 SCE3

CO_2 price (€/tn)	CO_2 (kg)	NOx (kg)	SO_2 (kg)	PM-10 (kg)
0	114328.1	419	71.75	116.79
5	121305.7	434.33	76.68	124.01
10	129090.4	467.21	82.47	132.47
15	135414.1	494.3	87.23	139.45
20	140147.1	516.32	91.12	145.12
30	147587.7	554.12	97.87	154.88
50	160468.1	624.66	110.58	173.11
60	165423.7	653.59	115.82	180.6

In the next subsection 6.2.8 the revenues and CO_2 emission savings are summarised and compared among the studied cases.

6.2.8. Income calculations- A comparative approach

Based on the results of subsection 6.2.7, total savings of the DER, shown in Table 85, are calculated.

Table 85 Revenues

CO_2 price (€/tn)	Revenues (€)		
	SCE 1	SCE 2	SCE 3
0	13549.14	13549.14	13549.14
5	13964.31	13964.52	14117.84
10	14396.25	14397.01	14724.13
15	14848.13	14849.74	15365.65
20	15317.96	15320.5	16034.62
30	16322.18	16326.11	17434.88
50	18565.43	18571.25	20227.2
60	19773.32	19778.89	21371.67

Remuneration for cases SCE1 and SCE2 is similar, with differences less than 10 €. More significant increase in earnings can be obtained in SCE3, reaching 58% of the savings compared to optimal economic operation or 7822.53 €/year for 60 €/tn emission trading prices. Percentage savings under different values and CO2 emission trading prices can be seen in Figure 52

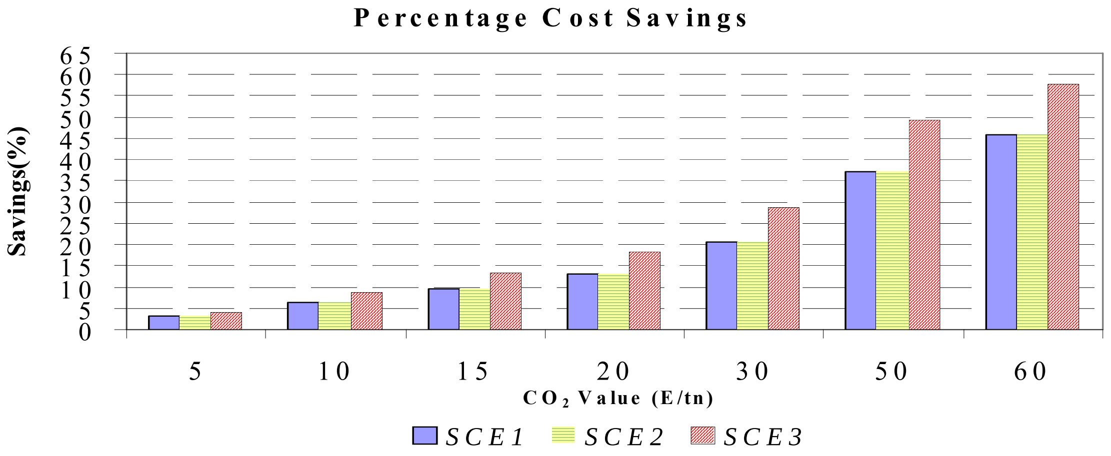

Figure 52 Changes in Savings of the Microgrid under different scenarios and different prices for CO_2 compared to no participation to the Emissions market.

Table 86 summarises the CO_2 emissions avoided in the three different scenarios evaluated by ED3 methodology, which more realistically represents the emissions from the upstream network.

Table 86 CO_2 reduction under different CO_2 emission prices and different scenarios.

CO_2 price (€/Tn)	CO_2 (Tn)		
	SCE 1	SCE 2	SCE 3
0	114.33	114.33	114.33
5	118.71	118.68	121.31
10	123.16	123.1	129.09
15	128.25	128.23	135.41
20	133.18	132.75	140.15
30	142.24	142.1	147.59
50	154.31	153.98	160.47
60	157.06	157.1	165.42

Figure 53 presents savings in CO_2 using the ED3 for the emission levels of the network. Differences between different scenarios are now smaller than in the revenue case. For SCE3 the maximum reduction in CO_2 emissions is 45%. Savings can be obtained for other kind of pollutants as well, reaching up to 56% for NOX, 55% for PM-10 and 10% for SO_2.

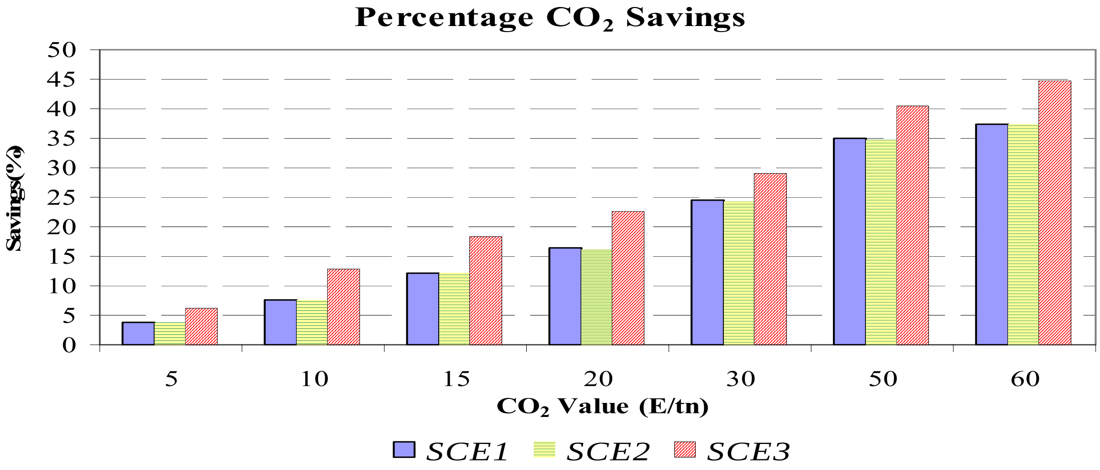

Figure 53 Savings in CO_2 under different scenarios and prices using EV3 for the emission levels compared to no participation to the Emission markets.

A typical value for CO_2 exchange market used in several studies is 20 €/tn [53]. Figure 54 summarises the 4 pollutants emissions avoided as calculated according to ED3 under the three operating scenarios, (SCE1-3) and optimal environmental and optimal economical operation. The emissions avoided are significantly higher for SO_2, NOx and PM-10 compared to the no-DER operation, ranging from 20% in the economic driven operation to 40% in the environmental driven operation. CO_2 avoided is lower ranging between 10.5% and 17%.

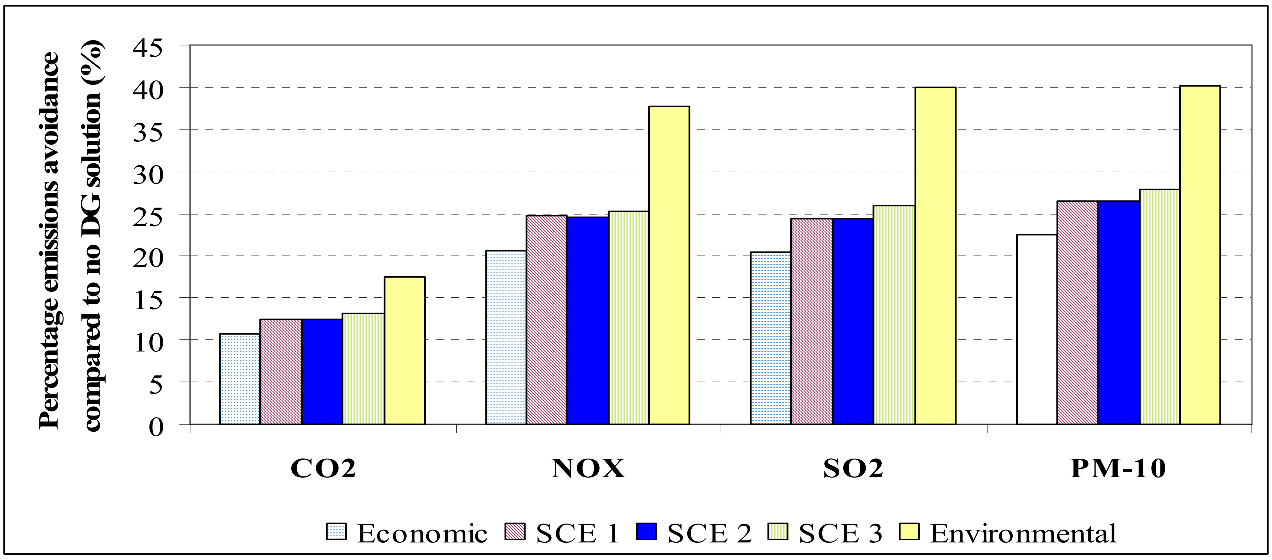

Figure 54 Comparison of Emission savings compared to no DG sources under the operating scenarios studied using CO_2 emissions value 20 €/Tn [53]

In order to compare the savings from adopting the scenario of sub-section 6.2.6, over the optimum environmental and "optimum" economic operation, the CO_2 compensation should be taken into account for both cases. To do so, the calculated CO_2 emissions corresponding to each case scenario should be taken into account. This means that, for instance, to compare SCE1 the emissions based on ED1 should be considered, because according to them, the Microgrid trades the CO_2 emission reduction, for the other scenarios the same approach is followed. compares the savings for this operation and Figure 55 focuses on the difference between optimum economic and SCE1-3 operation.

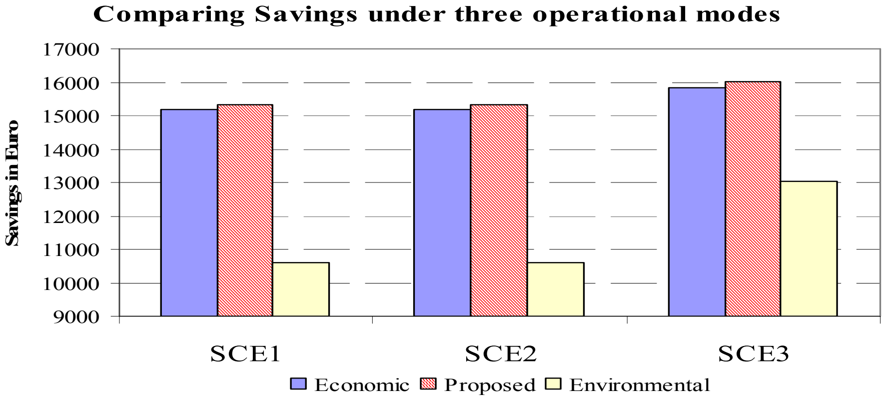

Figure 55 Comparison of cost savings compared to no DG sources under the operating scenarios studied assuming CO_2 emissions value 20 €/tn

It can be seen that in all cases operation under the proposed Scenarios SCE1-3 increases the savings for the Microgrid by up to 200 €, or about 1% compared to economic operation considering market prices only and the CO_2 remuneration as an additional income that is welcome but not an optimisation goal.

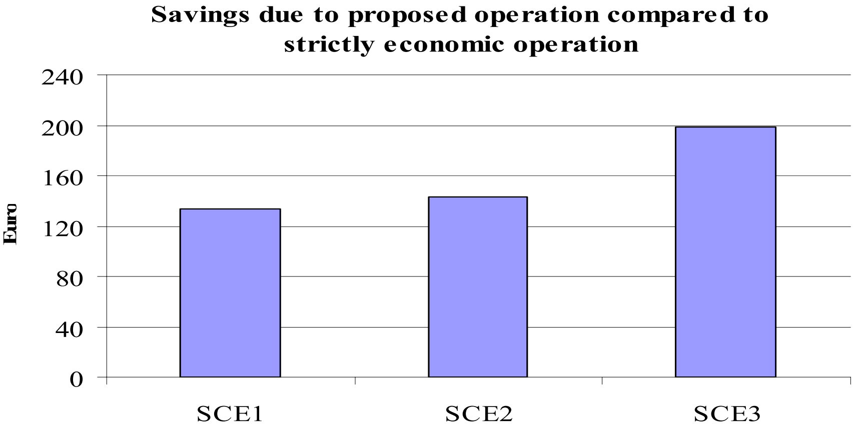

Figure 56 Comparison of cost savings between economic and proposed operation assuming CO2 emissions value 20 €/tn

6.2.9. Medium Voltage (MV) case stuudy

For the case study network of MV, Figure 57 presents the maximum emissions reduction percentage achieved for each month. Regarding CO_2 the maximum reduction can be achieved during January and max ApX-max RES combination while for the rest of pollutants this is achieved for the same combination during October.

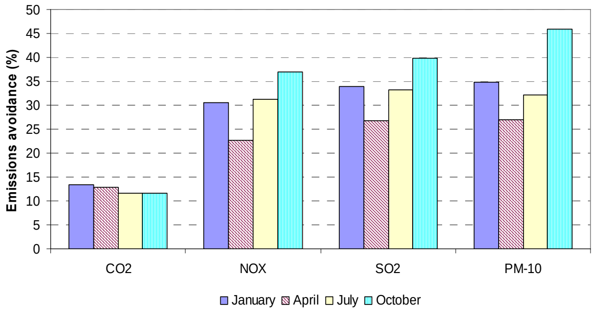

Figure 57 Maximum percentage avoidance for ApX prices per month studied.

Table 87 summarizes the results for the emissions reduction for the studied months for the scenarios of ApX and maximum (high) and minimum (low) penetration for this market. The minimum emissions reduction is achieved for combination of low ApX-low-RES during April for all the pollutants studied. The emissions reduction is sensitive to the DG penetration but is also very sensitive to the upstream network emissions curve, since DG penetration by itself is not sufficient to explain the difference in the month that maximum emission reduction occurs. For CO2 the emissions reduction is much sensitive to the RES penetration.

Table 87 Summary of emissions reduction for the studied period and Microgrid – MV Network for the typical days studied.

MONTHS	DG PENETRATION	CO_2 (tn)	NO_x (kg)	SO_2 (kg)	PM-10 (kg)
JANUARY	High	21.76	69.06	41.92	647.8
	Low	1.31	3.07	1.69	27.5
APRIL	High	15.65	41.69	21.32	400.1
	Low	0.140	0.200	0.100	1.500
JULY	High	16.76	66.26	31.12	432.7
	Low	1.360	2.000	0.900	12.60
OCTOBER	High	13.86	54.37	26.49	473.6
	Low	0.49	4.18	1.07	20.20

Figure 58 presents a comparison between the emissions avoided as a percentage compared to the emissions without Microgrid operation. The numbers refer to the summation of all the days studied.

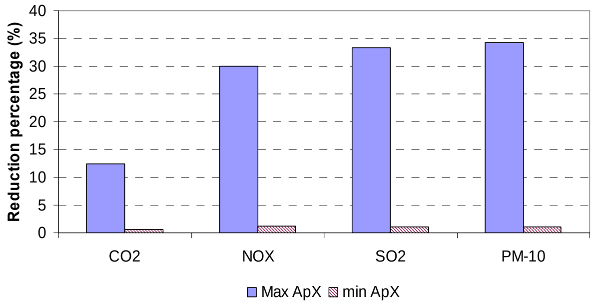

Figure 58 Emissions reduction percentage for all the studied days.

Another issue that has been studied is the impact of losses reduction in emissions reduction for the whole test network of Figure 6. Without DG, losses of the whole network account for about 3% of the pollutants for the days studied. With Microgrids, the percentage of emissions reduction due to losses reduction is significantly higher and is shown in Figure 59. Once again this figure refers to the total emissions reduction for all the days studied.

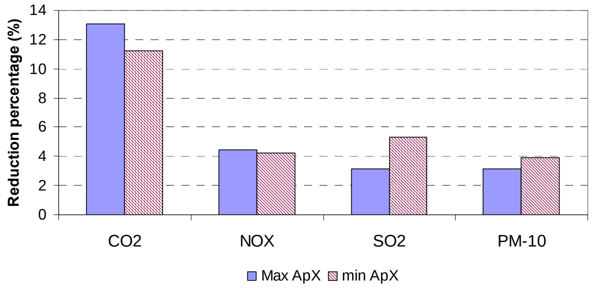

Figure 59 Percentage of emissions reduction due to losses reduction compared to the total losses avoided.

It is apparent that the reduction of emissions due to losses reduction constitutes a significant percentage of the total losses avoided for all the cases studies, especially for CO_2. For the ApX case and especially for October, reduction in CO_2 can reach 50%.

Moreover, the allocation of emissions avoided due to losses avoidance is studied for high and low DG penetration scenarios. Categories considered comprise of MV lines only, MV/LV transformers and LV lines only. Figure 60 and Figure 61 present the results for high and low DG penetration respectively.

Clearly for low DG penetration, the impact of MV line losses reduction is reduced increasing the impact of the LV losses reduction.

MV/LV transformers impact cannot be neglected since more than 14% of the emissions avoidance caused by the losses reduction is due to MV/LV transformer losses, reduction. Higher DG penetration means lower injected power to each microgrid hence significant decrease of the losses on the transformers. Taking into account the fact that some LV lines may have higher levels of power flow compared to no DG operation, justifies the comparable values of percentages in emissions avoidance.

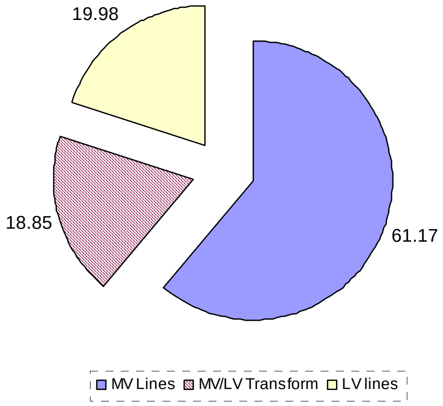

Figure 60 Allocation of emissions avoided due to losses avoidance for High DG penetration.

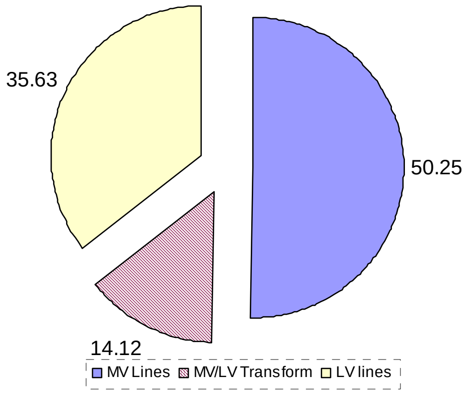

Figure 61 Allocation of emissions avoided due to losses avoidance for low DG penetration.

6.2.10. Sensitivity Analysis with Hellenic Transmission System Operator (HTSO) Prices

All the above results are based on ApX prices. Some sensitivity analysis on Greek market prices is also performed with the average yearly values shown in Figure 62 combined with the average monthly production of PV and wind. The emissions avoided are provided in Table 88.

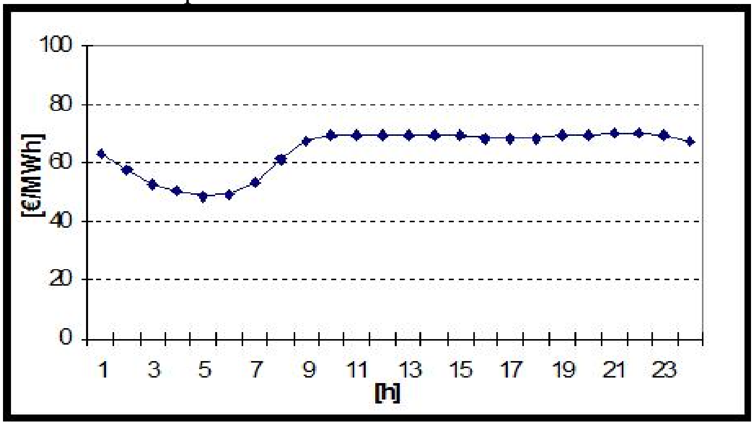

Figure 62 HTS prices

Table 88 Summary of daily emissions reduction for HTS prices and Microgrid – MV Network for the typical days studied.

MONTHS	CO_2 (tn)	NO_x (kg)	SO_2 (kg)	PM-10 (kg)
JANUARY	16.47	91.15	50.98	734.6
APRIL	4.400	80.00	33.29	608.7
JULY	10.01	86.30	39.28	513.1
OCTOBER	12.58	74.33	38.89	510.7

Another issue that has been studied is the impact of losses reduction in emissions reduction. Without DG, losses of both the LV and MV account for about 3% of the pollutants for the days studied. With Microgrids, the percentage of emissions reduction due to losses reduction is significantly higher and is shown in Figure 63: It is apparent that the reduction of emissions due to losses reduction constitutes a significant percentage of the total losses avoided for all the cases studies, especially for CO_2. Once again the figure refers to the total emissions reduction for all the days studied. It should be noted that for the Greek System, losses reduction accounts for the 39% of the avoided emissions during April. For the ApX case and especially for October, reduction in CO_2 can reach 50%.

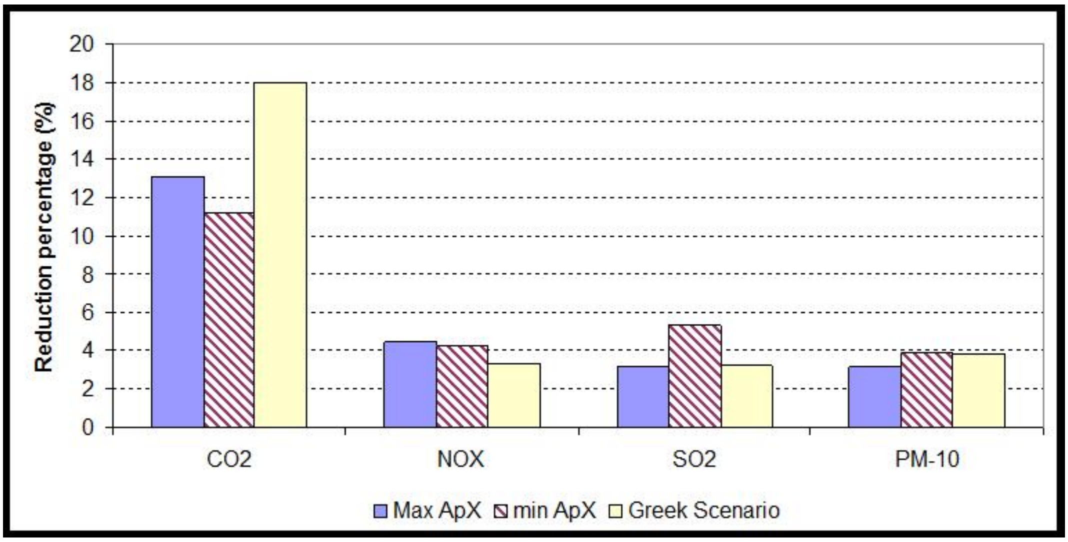

Figure 63 Comparison of Emissions avoided for the various scenarios studied.

For the Greek scenario, the impact of the topology was also studied on the emissions avoidance. If the Microturbine is moved to the industrial feeder, the losses reduction achieved has as impact further reductions in the emissions avoided as described in Table 89 while the percentage change is shown in Figure 64. Mainly CO_2 emissions are affected while for the rest of pollutants the change is similar. In that case the losses reduction accounts for the 20% of the avoided emissions.

Table 89 Additional Reduction of emissions due to change in the topology.

MONTHS	CO_2 (tn)	NO_x (kg)	SO_2 (kg)	PM-10 (kg)
JANUARY	0.49	0.6	0.4	5.4
APRIL	0.33	0.5	0.2	4.1
JULY	0.36	0.5	0.2	2.7
OCTOBER	0.34	0.4	0.2	3.0

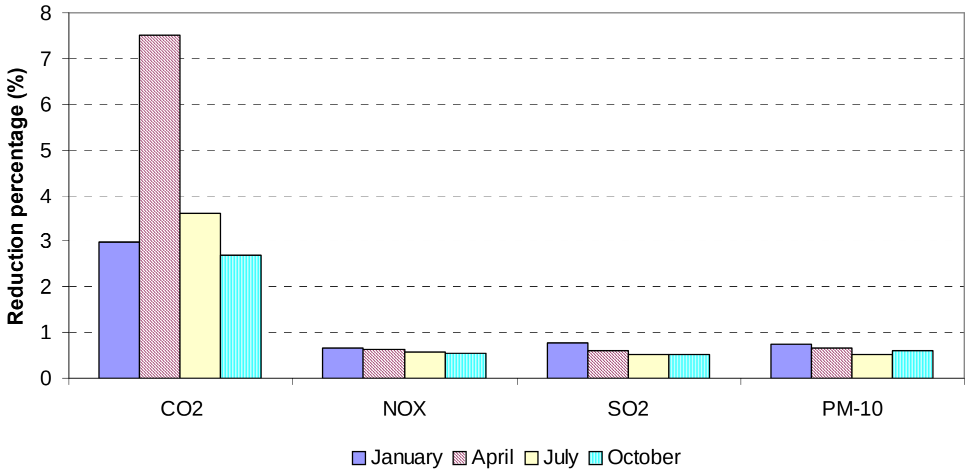

Figure 64 The additional emissions avoided per month due to change in Topology and greek scenario

7. Conclusion

From the above analyses it can be concluded that the cost for the end users is significantly reduced when the demand is met by the Microgrid's units especially for the cases when the electricity prices are very high.

Furthermore, operating cost of a Microgrid can be significantly decreased if MG bids are accepted, especially in networks with high DG penetration that allows selling power to the grid. In such cases network active power quantities can be sold to the main grid increasing the revenues of the aggregator when Market Policy 2 is applied. Implementation of Market Policy 1 involves constrictions of not selling active power to the grid and reducing the production of the MG sources that they can only meet the demand of the MG, although they can produce more and make profit by selling active power to the grid.

Additional value of the Microgrid operation is given to the total active power losses reduction due to reduction of the real power injected from the slack bus. The highest total active power losses reduction (%) was observed between scenarios with and without DGs production in the LV network (**Greek Scenario**, October, 49.02%) and MV network (**Greek Scenario**, October, 71%), respectively. The percentage of LV losses in the total network losses of the whole MV network is increased from **51 to 70%** as DG penetration increases. The more scattered the DG units within the Microgrid, the higher losses reduction is achieved if the DG penetration within the day is relatively high.

Both DG sources production, with lower emission level than the upstream network, and the losses reduction can provide significant emissions savings, especially as the RES penetration gets higher. The losses reduction can play significant role in emissions avoidance since they may lead up to **20%** of the CO2 emissions avoidance, if the DG sources are more scattered in the LV feeders.

It is also shown that, especially for high market prices, demand side bidding can help in reducing operating costs on top of the significant economic benefits achieved by the DG operation. Additionally, the customers can avoid high charges for low priority loads. Thus, even by simply denoting priority in their loads, the customers can help in further reducing costs for the whole microgrid.

Adequacy constraints increase the operational cost since for some periods, the DG sources operate even when they are not optimally dispatched, in order to ensure sufficient operating margin to cover critical loads in case of upstream network fault. The cost difference to satisfy this constraint can be rather high for high market prices. For low market prices, the cost may be even higher than the cost of no DG operation. However, this cost difference is rather small in absolute values.

When the adequacy constraint takes into account the bids of the loads, the customer accepts disconnection of part of his load in order to maintain supply to his high priority loads in case of upstream fault. By placing bids, he can increase service to his high priority loads in case of upstream faults compared to the case the total load is assumed critical. For the same service level of the critical loads, the cost without such an operation would be significantly higher, especially at high prices. For low prices, the additional cost is very low.

In this report, the capabilities of co-ordinated operation of DG sources to reduce the pollutant emissions of a power network are investigated. Optimal economic operation and optimal environmental operation are studied together with the effect of participation in CO_2 emissions trading, both with respect to emissions reduction and increase of earnings. Application of the developed method, depends on the available information regarding emissions of the operating units. The most accurate results are obtained when the emissions and operating intervals of the marginal units are available. Since this is not always the case, monthly or even yearly average emissions values can be used instead, producing however results of lower accuracy.

Although the goal of DER operation might be minimisation of CO_2, the error in the estimation of pollutants may not lead to achieving it, due to the fact that the average emission level leads to operation of DER during hours that are not actually environmentally better. Additionally, this error may lead to revenue reduction. Moreover, for power systems with low average CO_2 emission level, information on marginal units operation would lead to operation of DER during the hours that they can actually reduce emissions. Otherwise, it is possible that DER will not be committed at all.

Operation aiming at maximum emissions savings may reduce DER earnings and thus can be unattractive for DER, unless sufficient remuneration for the emissions avoided is provided. Participation of DER in the CO_2 emissions trading can offset the reduction of DER earnings while reducing CO_2 emissions. It is proven that aiming to maximise the earnings from combined participation in energy and CO_2 emissions market provides significantly higher environmental and economic benefits compared to maximising the earnings from participating only in energy market and considering the CO_2 remuneration as an additional income.

Finally, co-ordinated operation of DER helps in the application of economic and environmental policies, further improving DER benefits. The environmental benefits of such operation may be even higher if fuel consuming units operate in CHP mode, increasing energy efficiency and if the losses reduction is also taken into account.

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