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Abstract: This paper considers a microgrid connected with a medium-voltage (MV) distribution network. It is assumed that the microgrid, which is managed by a prosumer, operates in a competitive environment and participates in the day-ahead market. Then, as the first step of the short-term management problem, the prosumer must determine the bids to be submitted to the market. The offer strategy is based on the application of an optimization model, which is solved for different hourly price profiles of energy exchanged with the main grid. The proposed procedure is applied to a microgrid and four different its configurations were analyzed. The configurations consider the presence of thermoelectric units that only produce electricity, a boiler or/and cogeneration power plants for the thermal loads, and an electric storage system. The numerical results confirmed the numerous theoretical considerations that have been made.

Keywords: microgrids, spot price, prosumer, energy management

1 Introduction

A microgrid is defined as a cluster of distributed generation units, storage systems, and loads that are linked through an internal, low-voltage (LV) electric network. Such a system may operate in connection with a medium-voltage (MV) distribution network (grid-connected mode), independently (island mode), or in both modes [1, 2].

Grid connected mode is considered in this paper, so it is a small-scale replica of a national power system. For example, the interconnection with the distribution network is analogous to the set of interconnections with foreign countries, and the electric energy that is stored directly in small storage units is analogous to the energy stored indirectly in the large volumes of water in the basins of hydroelectric plants.

From the management perspective, the short-term management criteria can differ from one microgrid to another, according to the characteristics of the subject who manages the microgrid [3].

In this paper, it was assumed that the microgrid was managed by a prosumer, i.e., an entity that simultaneously manages both electric and thermal distributed plants, storage units, ICT (Information and Communication Technology) elements, and aggregate loads [3–7]. Therefore, the prosumer is both an energy producer and a final consumer, i.e., an independent power producer that can exchange energy with the main grid [8]. Moreover, he represents the microgrid into the market.

The prosumer, in order to perform the short term management, must know the status of the microgrid hour-by-hour during the day, i.e., the interchange with the distribution network, the production of each dispatchable unit, the amount of energy charged to/discharged from the storage units and the profiles of the controllable loads. Closely linked to these determinations is the choice of the thermoelectric units that must be in operation on an hourly base. That all must be made to optimize a given objective subject to a set of technical constraints, including the constraints on the operation of the internal electrical network. In general, the economic objective is optimized, while the other objectives (environmental and safety) are treated as constraints.

The exchange of energy with the main grid can occur under the tariff regime or in accordance with the rules of the liberalized market. In the first case, the unit cost of energy is an input data management problem, while the energy exchanged with the main grid is unknown. In the second case, both the market price[1] and the energy exchanged with the main grid are known a priori; the values obtained by market outcomes become input data for the general management problem.

In this work, we suppose that it is allowed to the prosumer to participate in the day-ahead market[2],

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1 The hourly market price is determined by the intersection of the curve of aggregate buying offers and the curve of aggregate selling offers. The price is unique if there is no network congestion.

2 In the paper, it is not expected that the microgrid would participate in the ancillary services market. Yet, in fact, there are minimum power requirements for participation that microgrids currently cannot meet [9]. However, the manager of the microgrid must ensure

offering, hour by hour, not the single production and consumption units, but the amount of power resulting from the difference between the aggregate load and the aggregate internal production [10].

Depending on the rules of the market, each offer may consist of a generic curve or, as often occurs (e.g., as in the Italian market), of a price-quantity pair [11].

It is worth noting that, when a price-quantity pair is bid, offers to sell are interpreted by the market operator as expressing the availability of the supplier to sell power not exceeding that indicated in the offer and at a price not less than that indicated; also, offers to buy are interpreted as expressing the willingness of the consumer to buy power not exceeding that indicated in the offer and at a price not exceeding that indicated. Therefore, in this case, the offers also can be represented as curves, and these are, in particular, step curves.

Moreover, it is worth noting that the bids may be unique (only a certain quantity at a certain price) or multiple (more price-quantity pairs). Therefore, multiple bids are characterized by a series of steps that identify a bidding curve that is piecewise constant, and monotone non-decreasing or non-increasing depending on whether the offers are to buy or to sell, respectively (Figure 1). The maximum number of offer couples is defined by the rules of the market[3].

The purpose of our work is to show in which way the prosumer submits bidding curves in the day-ahead market consistent with the results obtained by the optimal management. That is, curves able to guarantee that the hourly power exchanged, which will be derived from the market's outcomes, has the closest possible value to that obtained by solving the optimal management problem for its respective market price.

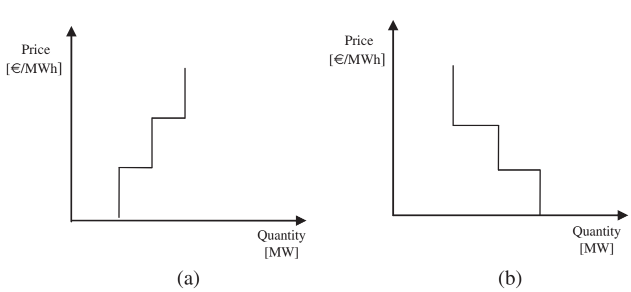


Figure 1: Selling multiple bids (a), buying multiple bids (b).

that internal power is available as necessary for ancillary services (resolution of congestions; primary, secondary, and tertiary reserve; balancing service) when the microgrid operates in island mode.

3 For example, in Spain, 25 pairs can be offered, whereas only four can be offered in Italy.

The paper is organized as follows. Section II provides the results of our literature review and the formulation of the offer strategy. Section III provides the optimization model that it was used to solve the problem. An application to a case study is reported in Section IV, and our conclusions and research perspectives are presented in Section V.

2 The offer strategy and relative literature

Optimal bidding strategies for participants in power markets have been extensively studied in literature. The majority of existing works has focused on GENCOs and VPPs [12–14]. The issue has been considered, then, also for microgrids, that, in contrasts with GENCOs and VPPs[4], must satisfy their own internal balance [16, 17].

Usually, the bidding strategy is limited to the submission of the optimal hourly exchanged power obtained in correspondence to the most probable hourly market price profile. In our work, indeed, we offer, for each hour, a bidding curve in function of the price. Each point of the curve represents a pair possible price-quantity, being the quantity the optimal power obtained in correspondence of possible market price.

The prices, ranging from a minimum to a maximum value, are determined by the analysis of the time series. They are considered in correspondence of the same hour, the same day of the week and the same month. This choice allows to reduce the risk for the prosumer to not offer the optimal power. Moreover, it allows the prosumer to offer an elastic demand with important implications: in fact, if more microgrids have this possibility, the elasticity of the aggregate demand curve increases, leading to an evident benefit, i.e., the reduction of the market price for all customers, even those that are not able to express a price-sensitive demand.

Our work is different for another reason too: the optimization model structure used is the simplest possible way. In fact, in deriving the bidding curves, in our opinions it is not useful to solve a scheduling problem, such as the one that was just defined in Section 1, using a unique optimization model.

It should be noted that, as in the case of a national power system, the optimal management problem could

4 Similar to a GENCO, also a VPP tends to deny local consumption as it is a virtual generator [15].

be solved by dividing it into three sequential, interrelated sub-problems [18–20].

In the first sub-problem, the internal electric network is represented by a "single bus" network[5]; if a thermal network exists, it is represented in the same way. Furthermore, it is assumed that forecasting techniques are used to determine the electric and thermal loads and the power produced by the non-dispatchable generating units of the microgrid [21]. Assuming that only the price is known, the prosumer aims to determine, on an hourly basis, the interchange with the MV distribution network, the production of each dispatchable unit, the amount of energy charged to/discharged from the storage units, and the profiles of the controllable loads[6]. The economic objective is related directly to the difference between the microgrid's revenue (from the energy it sells) and the expenses it incurs in purchasing and operating costs. The sub-problem can be solved using a non-linear, static mathematical programming algorithm.

Since the maximum amount of thermoelectric production is known now, the second sub-problem, still considering the "single bus" network, aims to identify the generating units that must be in operation on an hourly basis; this is referred to as the unit commitment (UC) problem [22–24].The input data are the results of the first sub-problem. In the economic objective are included, now, also the startup and shutdown costs of the units. The environmental aspects are taken into account by imposing a limit on emissions, and the security aspects are addressed by requiring that each unit have a margin of power reserve according to its characteristics. The sub-problem can be solved using a mixed-integer, programming algorithm.

Because the internal network is considered to be a busbar in the first and second sub-problems, the actual solution is not physically admissible. It is a solution, in fact, that does not consider losses and that does not provide any indication of the reactive power required. Furthermore, the solution does not guarantee that there will be no congestion. Therefore, it is necessary to start from the hour-by-hour knowledge of the in-service thermoelectric units and solve the third sub-problem, which is the hourly determination of the state of the internal electric network (in terms of amplitudes and phase angles of nodal voltages) in order to minimize of the production cost of the different thermoelectric plants. This is the optimal power flow (OPF) problem [25–30]. The security is taken into account by meeting the thermal limits of the electrical lines and the stability limits, which are represented by the margins on the phase shifts between the nodal voltages of the adjacent nodes. The sub-problem can be solved using a non-linear, static mathematical programming algorithm.

Not all follow this approach of the sequential resolution of the three sub-problems. Most papers neglect the network with its constraints, limiting the analysis only to the first sub-problem [31, 32] or dealing with the first and the second sub-problems in an integrated manner [33–35]. In refs [36, 37] indeed, the first sub-problem is resolved, but the second and third were treated together by formulating a unique model.

The considerations made above are applied to the resolution of the general optimal management problem in presence of tariff regime. If, instead, the resolution of the management problem is finalized to the submission of the bidding curves, as in this work, it is believed to implement only the first sub-problem for each price value: in fact, the power exchanged derived from the first sub-problem, does not change in the other two.

Obviously, the general problem is resolved by considering the outcomes of the market as the input of the first sub-problem; following the resolution of the second and the third sub-problem Figure 2.

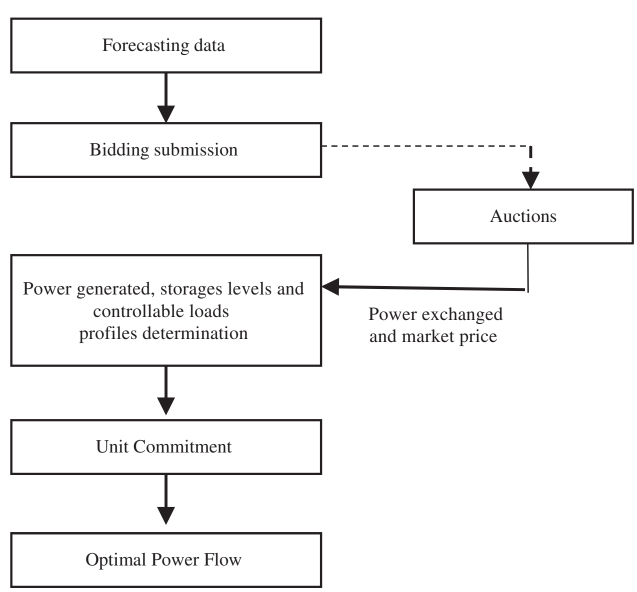


Figure 2: The management process.

5 It is assumed that the production system of the microgrid directly provides the total load, thereby reducing the structure of the internal distribution network to a busbar to which all of the generating units and loads are connected in parallel.

6 In monopolistic management of the nation's power system, the first sub-problem is the scheduling of mixed hydrothermal generation.

3 The model

Let us consider a microgrid in which both thermal and electrical loads must be satisfied. Also, let us consider that, in the microgrid, only electricity power plants, Combined Heat and Power (CHP) plants, and heat production plants (boilers) are already installed. The presence of thermal and electrical storage systems also is accounted for.

Let Ω_C be the set of CHP plants, Ω_B be the set of heat production plants, and Ω_G be the set of power plants that only produce electricity. Then, let Ω_{ST} and Ω_{SE} be the sets of thermal and electrical storage units, respectively. Finally, let $\Omega_{D_{th}}$ and Ω_{D_e} be the sets of total thermal and electrical loads, respectively.

Let us assume that all of the variables of interest are constant during the hourly intervals and that they are equal to the end value of each interval.

Let us assume that the j^{th} dispatched cogeneration power is the electric power at the t^{th} hour, $P_{Ce_{t,j}}$, therefore the corresponding thermal power, $P_{C_{tht,j}}$, is calculated by the following equation:

$$P_{C_{tht,j}} = \frac{P_{C_{et,j}}}{\eta_j} \quad (t = 1, \ldots, 24)$$

where η_j is the cogeneration efficiency of the j^{th} unit, given by the ratio of electrical efficiency to thermal efficiency.

Let $P_{G_{t,j}}$ be the power of the j^{th} unit of only electricity production at the t^{th} hour; $P_{B_{t,j}}$ be the thermal power of the j^{th} heat production at the t^{th} hour. Then, let P_{grid_t} be the power interchange with the MV distribution network at t^{th} hour; P_{grid_t} is assumed to be positive if the microgrid buys from the utility grid and it is assumed to be negative, if the microgrid sells energy to the utility grid.

Then, let ρ_t^e be the price of energy at the t^{th} hour, which is assumed to be equal when buying or selling.

Then, the optimization problem consists of minimizing the following function subject to a set of technical and operational constraints:

$$\sum_{t=1}^{24} \left[\sum_{j \in \Omega_C} C_{C_j}\left(P_{Ce_{t,j}}\right) + \sum_{j \in \Omega_B} C_{B_j}\left(P_{B_{t,j}}\right) + \sum_{j \in \Omega_G} C_{G_j}\left(P_{G_{t,j}}\right) + \rho_t^e P_{grid_t} \right] \tag{1}$$

In eq. (1), the hourly production costs can be expressed by the following functional relationships:

$$C_{C_j}\left(P_{Ce_{t,j}}\right) = \alpha_{C_j} P_{Ce_{t,j}}^2 + \beta_{C_j} P_{Ce_{t,j}} + y_{C_j}$$
$$C_{B_j}\left(P_{B_{t,j}}\right) = \alpha_{B_j} P_{B_{t,j}}^2 + \beta_{B_j} P_{B_{t,j}} + y_{B_j}$$
$$C_{G_j}\left(P_{G_{t,j}}\right) = \alpha_{G_j} P_{G_{t,j}}^2 + \beta_{G_j} P_{G_{t,j}} + y_{G_j}$$

with α_{C_j}, β_{C_j}, y_{C_j}, α_{B_j}, β_{B_j}, y_{B_j}, α_{G_j}, β_{G_j}, y_{G_j} depending on the particular technologies used.

First, the equality constraints are the thermal and electric balance constraints.

Let $P_{SE_{t,j}}$ and $P_{ST_{t,j}}$ be the electrical and thermal power, respectively, of the j^{th} storage system at the t^{th} hour with positive values during the discharge and negative values during the charge.

Given the assumption that all of the loads are not controllable, let $P_{D_{tht,j}}$ and $P_{D_{et,j}}$ be the values of the thermal and electric j^{th} load, respectively, at the t^{th} hour.

Thus, the energy balance constraints can be expressed, for $t = 1,\ldots,24$, as:

$$\sum_{j \in \Omega_C} \frac{P_{Ce_{t,j}}}{\eta_j} + \sum_{j \in \Omega_B} P_{B_{t,j}} = \sum_{j \in \Omega_{D_{th}}} P_{D_{tht,j}} + \sum_{j \in \Omega_{ST}} P_{ST_{t,j}} \tag{2a}$$

$$\sum_{j \in \Omega_C} P_{Ce_{t,j}} + \sum_{j \in \Omega_G} P_{G_{t,j}} + P_{grid_t} = \sum_{j \in \Omega_{D_e}} P_{D_{et,j}} + \sum_{j \in \Omega_{SE}} P_{SE_{t,j}} \tag{2b}$$

where the loads are reduced by the forecasted amount of renewable energy, both thermal and electrical, excluding biomass.

Then, additional equality constraints can be derived from modeling the storage units. In fact, it is necessary to express:

a) the variation of the storage levels:

$$W_{SE_{t,j}} = W_{SE_{(t-1),j}} + P_{SE_{t,j}} \; (j \in \Omega_{SE};\; t = 1, \ldots, 24) \tag{3}$$

$$W_{ST_{t,j}} = W_{ST_{(t-1),j}} - k_{s_j} P_{ST_{t,j}} \; (j \in \Omega_{ST};\; t = 1, \ldots, 24) \tag{4}$$

where k_{s_j} is the coefficient of the efficiency of charge and discharge;

b) the restoration of the initial levels:

$$\sum_{t=1}^{24} P_{SE_{t,j}} = 0 \; (j \in \Omega_{SE}) \tag{5}$$

$$\sum_{t=1}^{24} P_{ST_{t,j}} = 0 \; (j \in \Omega_{ST}) \tag{6}$$

Finally, the following inequality constraints must be considered:

$$P_{C_{ej}}^m \le P_{Ce_{t,j}} \le P_{C_{ej}}^M \; (j \in \Omega_C;\; t = 1, \ldots, 24) \tag{7}$$

$$P_{B_j}^m \le P_{B_{t,j}} \le P_{B_j}^M \; (j \in \Omega_B;\; t = 1, \ldots, 24) \tag{8}$$

$$P_{G_j}^m \le P_{G_{t,j}} \le P_{G_j}^M \; (j \in \Omega_G;\; t = 1, \ldots, 24) \tag{9}$$

$$-P_{grid}^M \le P_{grid_t} \le P_{grid}^M \; (t = 1, \ldots, 24) \tag{10}$$

$$0 \le W_{ST_{t,j}} \le W_{ST_j}^M \; (j \in \Omega_{ST};\; t = 1, \ldots, 24) \tag{11}$$

$$0 \le W_{SE_{t,j}} \le W_{SE_j}^M \; (j \in \Omega_{SE};\; t = 1, \ldots, 24) \tag{12}$$

$$-P_{ST_j}^M \le P_{ST_{t,j}} \le P_{ST_j}^M \; (j \in \Omega_{ST};\; t=1,\ldots,24) \tag{13}$$

$$-P_{SE_j}^M \le P_{SE_{t,j}} \le P_{SE_j}^M \; (j \in \Omega_{SE};\; t=1,\ldots,24) \tag{14}$$

That said, the problem of determining the optimal bids require, as input data, the energy price profiles and, for each of them, the resolution of the optimization problem (1–14). Note that piecewise continuous curves are obtained when the optimal offer points, provided by the subsequent resolution of the sub-problem, are linked. Of course, these curves can be used to derive the curves that effectively will be offered in the market, i.e., generic continuous curves or step curves with multiple offers.

Figure 3 provides a flowchart to better explain the procedure used to implement the strategy for determining the optimal offer.

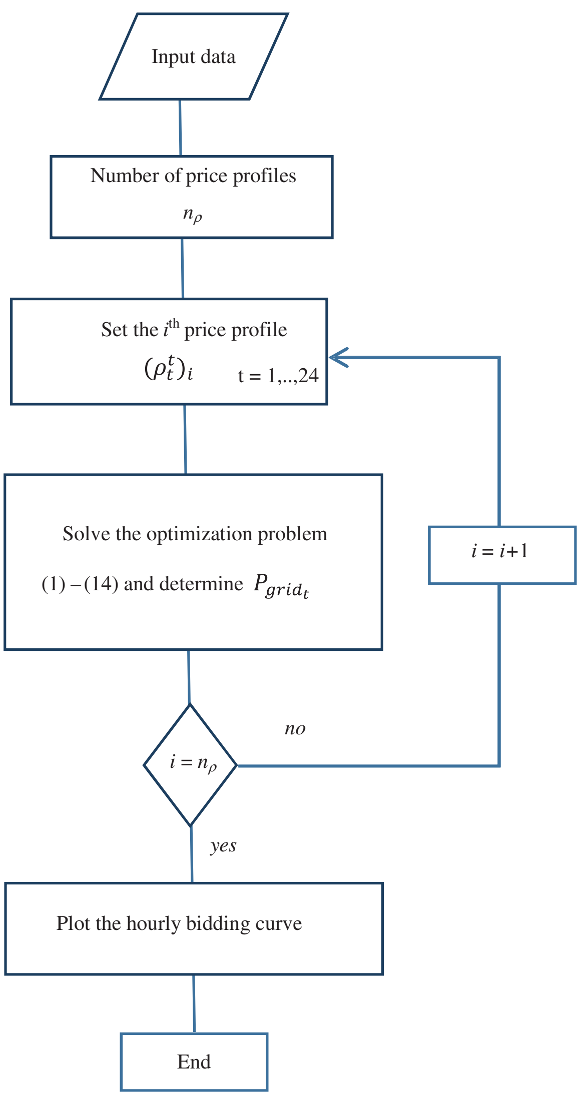


Figure 3: Determination of the optimal bid.

4 Case Study

The procedure proposed in Section II was applied to a microgrid containing the loads of six different entities, i.e., a hotel, a sports center, a hospital, a manufacturing plant, a supermarket, and several offices [38]. With reference to a summer day, the electrical and thermal loads are the ones reported in Table 1.

Four different configurations of the system were analyzed.

In the first configuration (case 1), there were six thermoelectric units producing only electricity, whose technical and economic characteristics are reported in Table 2, and an independent boiler for the generation

Table 1: Hourly electrical and thermal loads.

Hour *t*	$P_{D_{et}}$ [kWe]	P_{Dth_t} [kWt]
1	440	320
2	440	295
3	440	275
4	440	275
5	440	495
6	740	605
7	1,200	1,350
8	1,905	3,560
9	2,345	3,570
10	2,405	3,690
11	2,420	3,625
12	2,440	4,095
13	2,470	4,125
14	2,465	4,300
15	2,450	4,255
16	2,395	3,950
17	2,360	3,905
18	2,335	2,605
19	1,695	1,695
20	1,425	1,680
21	1,295	1,425
22	955	1,020
23	530	520
24	425	390

Table 2: Technical and economic characteristics of the thermoelectric units – Case 1.

j	$P_{G_j}^m$ [kW]	$P_{G_j}^M$ [kW]	γ_{G_j} [m€/h]	β_{G_j} [m€/kWh]	α_{G_j} [m€/kWh^2]
1	80	400	1,054	21.63	0.0005
2	80	400	1,054	9.87	0.0025
3	10	60	800	45.81	0.2222
4	10	60	461	51.60	0.1000
5	36	180	892	34.40	0.0021
6	36	180	892	25.78	0.0420

of thermal energy, whose maximum power is 4,500 kW and the cost coefficient is α_B = 63.0 m€/kWh. In the second configuration (case 2), four cogeneration power plants were considered in addition to the boiler to satisfy the thermal loads. Two 180 kW plants produced only electricity. The technical and economic characteristics of the CHP plants are presented in Table 3.

Table 3: Technical and economic characteristics of the CHP units – Case 2.

j	$P^m_{C_{ej}}$ [kW]	$P^M_{C_{ej}}$ [kW]	γ_{C_j} [m€/h]	β_{C_j} [m€/kWh]	α_{C_j} [m€/kWh^2]
1	80	400	1,107	22.71	0.0005
2	80	400	1,107	10.36	0.0026
3	10	60	840	48.10	0.2333
4	10	60	484	54.18	0.1050

In the third configuration (case 3), in addition to the same six thermoelectric power plants and the boiler of case 1, there also was an electric storage system with a power rating of 500 kW and a maximum stored energy of 4,500 kWh [38, 39].

In the fourth configuration (case 4), there were the same units of production as in case 2 and the electric storage system of case 3.

For all of the configurations, there also was a 100 kW PV plant, the energy production of which was assumed to be deterministic and calculable through time series analysis (Figure 4) [11].

In the first two cases, the model was solved hourly (i.e., 24 daily, independent, optimization problems); in the other two cases, the presence of the storage system, which introduced inter-temporal constraints, meant that only one resolution was required in a 24-hour period.

Table 4: Minimum and maximum profiles of the spot price.

Hour t	ρ^e_t [€/MWh] "minimum profile"	ρ^e_t [€/MWh] "maximum profile"
1	30.7	102.6
2	25.7	96.6
3	21.4	92.0
4	17.3	87.0
5	14.9	85.7
6	16.6	86.8
7	16.1	85.5
8	16.6	145.1
9	26.4	188.8
10	32.7	207.0
11	32.2	207.1
12	29.5	206.5
13	27.2	143.9
14	15.2	121.9
15	12.1	144.5
16	12.8	163.7
17	20.2	186.6
18	36.5	196.6
19	56.9	222.3
20	69.9	211.9
21	64.1	324.2
22	60.0	156.3
23	52.0	144.4
24	39.1	101.7

The profiles of the spot prices (minimum and maximum) were obtained through the analysis of the time series [11], and the results are shown in Table 4.

The optimization problems of the solving procedure were solved using MATLAB (more specifically, each

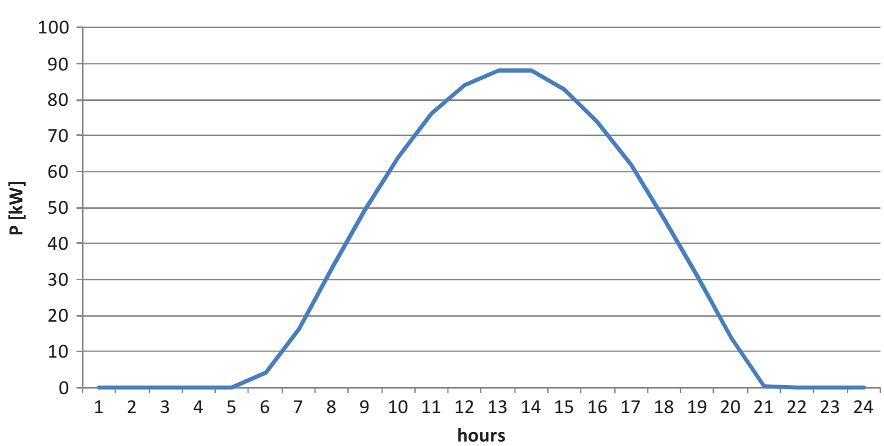


Figure 4: Power production curve of the photovoltaic plant.

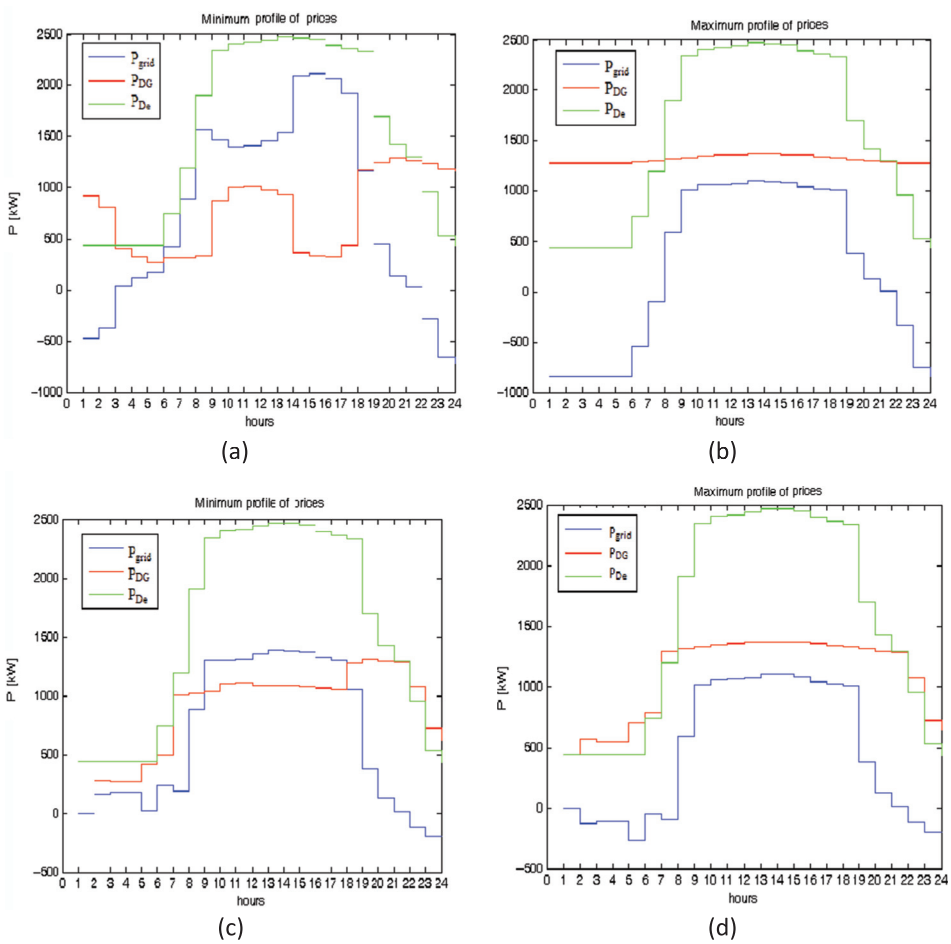


Figure 5: Hourly electric powers: (a) case 1 for the minimum profile of spot prices; (b) case 1 for the maximum profile of spot prices; (c) case 2 for the minimum profile of spot prices; (d) case 2 for the maximum profile of spot prices.

optimization problem was solved by using the function *quadprog*).

Before presenting the results in terms of bidding curves, it is appropriate to comment the results corresponding to the minimum and maximum price profiles.

Figures 5 and 6 show the power exchanged with the network, P_{grid_t}, and the total power produced by the cogenerators and generators, P_{DG_t}, in comparison with the load, $P_{D_{et}}$, for cases 1 and 2 (Figure 5) and cases 3 and 4 (Figure 6), respectively. In particular, in Figure 7, the profile of the electrical power of the storage system is also shown.

Figure 7 shows the daily profile of the thermal power produced by boilers P_{B_t} and by the cogeneration plants $P_{C_{tht}}$ compared with the thermal load, $P_{D_{tht}}$.

Since the marginal cost of the boiler was greater than the marginal costs of the CHP, thermal power production did not vary with the price, and it was not influenced by the presence of the storage.

Figure 8 shows the power and the energy charged into and discharged from the storage unit compared to the minimum and the maximum price profile.

The storage operation was always the same, regardless of the presence of cogeneration units.

It should be noted that, for example, in the presence of the maximum price profile, the internal generation is almost always maximum, while in the case of the minimum price profile, the generation is almost always minimum. In both situations, the microgrid sells in the intervals in which the generation exceeds the load to be met, otherwise it buys.

Table 5 reports the values of the daily management costs of the microgrid in all of the cases that were considered. Table 5 also reports the percentage variations of the total costs for cases 2, 3, and 4 with respect to case 1.

The presence of storage, the operation costs of which have been neglected in the analysis, leads to lower costs

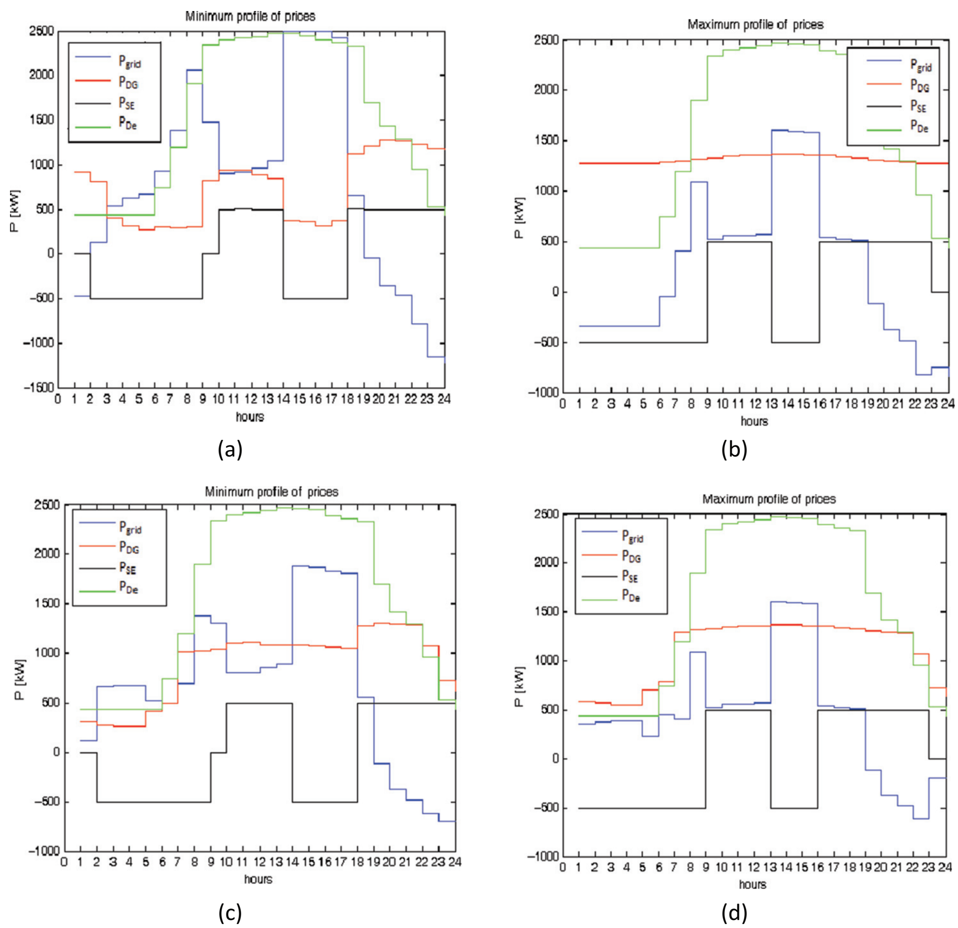


Figure 6: Hourly electric powers: (a) case 3 for the minimum profile of spot prices; (b) case 3 for the maximum profile of spot prices; (c) case 4 for the minimum profile of spot prices; (d) case 4 for the maximum profile of spot prices.

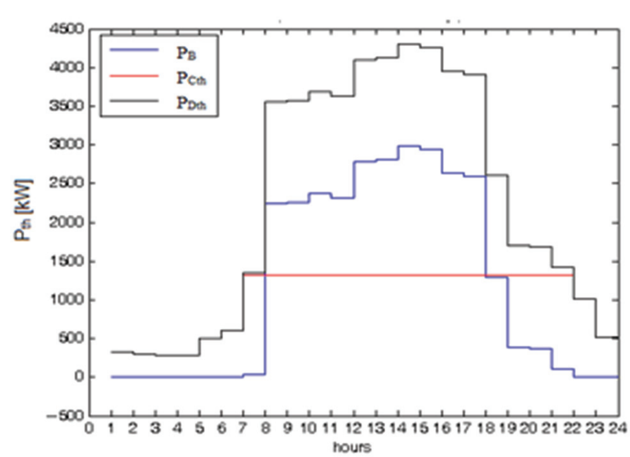


Figure 7: Hourly thermal power.

by bringing more flexibility to the model. The same applies for cogeneration plants.

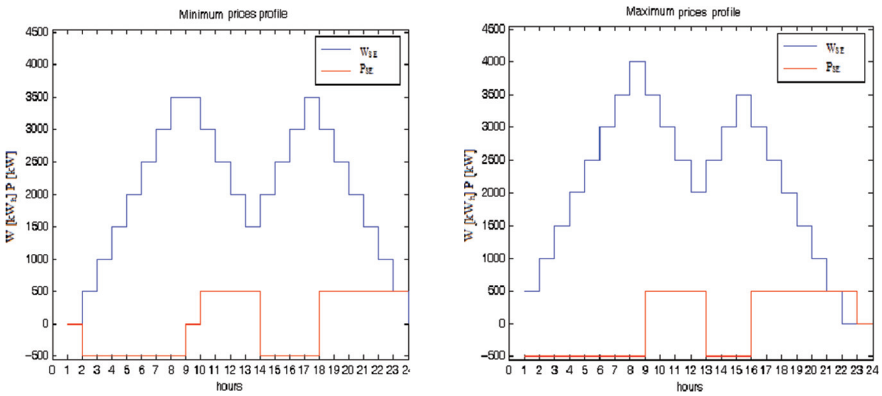
We can note that the *value* of cogeneration decreased as the market price increased, while the *value* of storage increased.

Let us present the bidding curve.

Figure 9 shows the bidding curves for all four cases considered at the second and eighth hours of the day. The analysis of Figure 9 shows that, while at the eighth hour the prosumer will present a buyer curve no matter which case is considered, at the second hour he will offer a buyer curve (case 4), a seller curve (case 1), and seller and buyer curves (cases 2 and 3).

The presence of storage involves the shift of curves 1 and 3 by an amount equal to the power stored, which, in the example, is the maximum value.

It is interesting to observe that the power corresponding to the vertical segment of the bidding curve is the difference between the load and the maximum production of the generating units compatible with the thermal constraints, including the energy produced by the photovoltaic system for the specific hour. Usually, there is another vertical segment of the bidding curve that corresponds to the difference between the load and the minimum production of the generating units (also including the energy produced by the photovoltaic



(a) (b)

Figure 8: Power and energy of the storage system: (a) with reference to the minimum profile of prices; (b) with reference to the maximum profile of prices.

Table 5: management costs for the four cases that were considered.

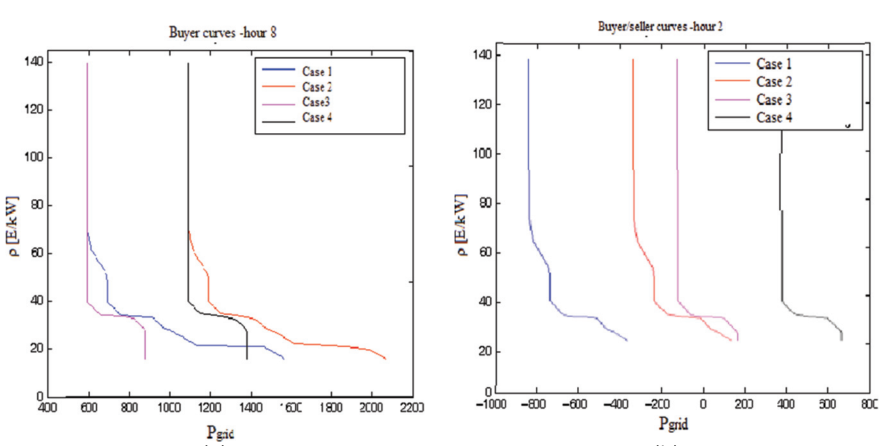
	Price profile	Objective Function [€]	Boiler costs [€]	Total costs [€]	Percentage variation
Case 1	Min	918	3,277	4,195	–
	Max	2,360	3,277	5,637	–
Case 2	Min	2,820	*	2,820	−32.8%
	Max	4,552	*	4,552	−19.3%
Case 3	Min	763	3,277	4,040	−3.7%
	Max	1,820	3,277	5,097	−9.6%
Case 4	Min	2,663	*	2,663	−36.5%
	Max	4,003	*	4,003	−29.0%

Note: *The objective function already contains the boiler costs.

system). This latter vertical segment appears, of course, at low energy prices but, in our application, this segment corresponds to prices that are outside the range of prices we considered and, therefore, it does not appear in the Figure 10.

Figure 10 shows that, with reference to the eight hour and to case 1, fixed the range of prices, the demand curve (Figure 10(a)) is symmetrical with, respect to the *y*-axis, of the equivalent marginal cost of production (Figure 10(b)); in turn, at the same price, this is the sum of the marginal costs of production which are shown in Figure 10(c). Note that the lower variability of the curves in cases 2 and 4 was due to the fact that the model forces the co-generators to work at their maximum output because the marginal cost of the boiler was greater than that of the co-generators. Therefore, there is less variability in the curves because they represent the equivalent marginal cost curves of only the two 180-kW plants.

Starting from the piecewise continuous offer curves obtained so far (see Figure 10), it's possible to derive the offers that will be effectively presented in the day ahead market, i.e., the step curves with multiple offers. For example, the curve of Figure 10(a) can be approximated by the step curve shown in Figure 11.



(a) (b)

Figure 9: Bidding curve for all four cases (a) at the eighth hour of the day; (b) at the second hour of the day.

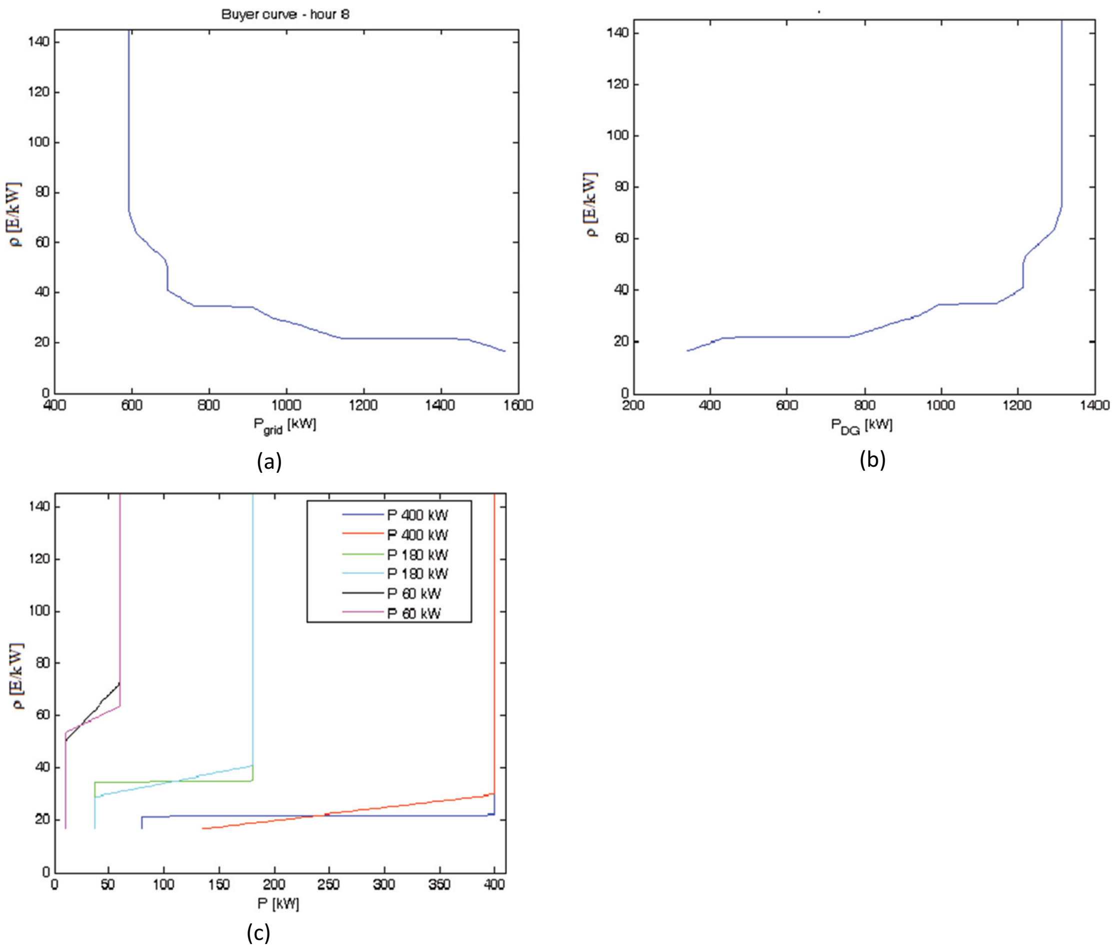


Figure 10: (a) Buyer curve; (b) equivalent marginal cost; (c) marginal costs of generators – Case 1.

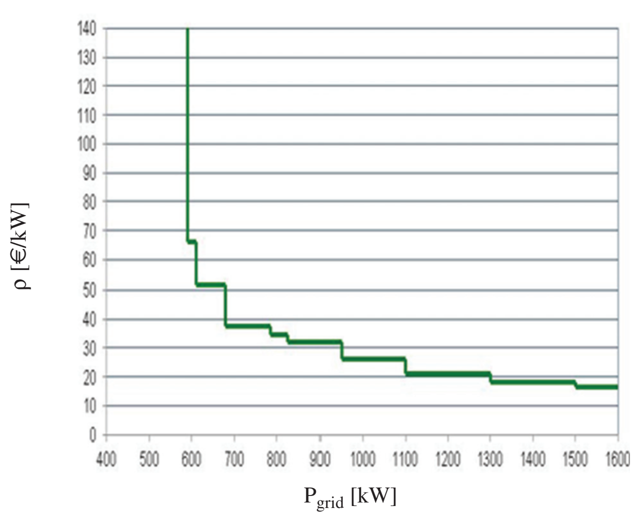


Figure 11: Buyer step curve of Figure 10(a).

5 Conclusions and further work

The problem of the short-term scheduling of a microgrid managed by a prosumer was presented.

It was shown that, if the prosumer participates in the spot electricity market, the determination of the bids must be considered as the first step of the short-term management problem. In particular, proposing a strategy for determining the optimal offer was the objective of this work.

The strategy is based on the application of an optimization model, which is solved for different hourly price profiles of energy exchanged with the main grid.

A case study was conducted in which four possible microgrid configurations were analyzed. In the first case, only electricity power plants and an independent boiler for the generation of thermal energy were considered; in the second case, cogeneration power plants were considered in addition to the boiler; in the third case, in addition to the independent boiler, only electrical generation units and an electrical storage plant were considered; in the fourth case, the presence of electrical generation units, a boiler for generating heat, cogeneration power plants, and electrical storage were considered.

In the paper, the participation of the microgrid in the ancillary services market was not accounted for. Yet, in fact, there are requirements of minimum power for participation, currently not owned by microgrids.

However, when there are more microgrid aggregations, and then, consequently, more prosumer aggregations, the participation in this market must be considered.

Our future research will focus on the optimal offers to be presented to the ancillary services market, coupled with the energy market issues, since it is already clear that the energy market and the auxiliary services market cannot be considered separately.

This means that, regardless of the market structure, the prosumer must consider the power to be offered in the day-ahead market and the power to offer in the ancillary services market as variables of the problem. In addition, in maximizing the difference between revenue and costs, the prosumer also must take into account the expected value of the revenue obtained in the ancillary services market. In this framework, the controllable loads will assume great importance, and their presence must be considered.

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