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A Hierarchical Framework for Day-Ahead Optimal Operation Planning of Active Distribution Networks with Multi-Microgrids

Cyntia Cristinne Corrêa Baia de Aquino[1*]
https://orcid.org/0000-0002-5085-8086

Thaís Marzalek Blasi[1]
https://orcid.org/0000-0002-8933-1521

Clodomiro Unsihuay-Vila[1]
https://orcid.org/0000-0002-1639-7765

Thelma Solange Piazza Fernandes[1]
https://orcid.org/0000-0002-5167-1547

Rafael Silva Pinto[1]
https://orcid.org/0000-0002-0574-1444

Mauro Obladen de Lara Filho[1]
https://orcid.org/0000-0002-7306-4369

Alexandre Rasi Aoki[1]
https://orcid.org/0000-0001-9863-6610

Fabricio Henrique Tabarro[2]
https://orcid.org/0000-0002-0689-459X

Rodrigo Braun dos Santos[2]
https://orcid.org/0000-0001-6163-4558

[1]Universidade Federal do Paraná, Departamento de Engenharia Elétrica, Curitiba, Paraná, Brasil; [2]Companhia Paranaense de Energia – COPEL Distribuição, Curitiba, Paraná, Brasil.

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*Correspondence: cyntiacristinne@ufpr.br; Tel.: +55-96-988030303 (C.C.C.B.A).

HIGHLIGHTS

- Multi-microgrids and distributed energy resources in active distribution networks (ADNs).
- A coordinated hierarchical optimization model.
- Optimal day-ahead operation planning for ADNs with Multi-Microgrids.

Abstract: The insertion of new distributed energy resources, such as distributed generation (DG), energy storage systems (ESS), demand response (DR), and microgrids (MG), is emerging, bringing new challenges to the current distribution network. In this regard, the active distribution networks (ADN) with multi-microgrids concept appears. The present paper proposes a hierarchical (master-slave problem) computational model to achieve optimal coordinated operation of multi-microgrids connected to an ADN. Day-ahead operation planning of an ADN was formulated as a multiperiod non-linear optimal power flow model, resulting in a non-linear optimization problem, additionally, the day-ahead operation planning of MGs was formulated as a multiperiod linearized optimal power flow resulting in a mixed-integer linear optimization problem. Numerical results on four different test-system microgrids connected to a 359-nodes ADNs test-system belonging to a Brazilian distribution company show the effectiveness of the proposed model and solution strategy. Three cases have been tested: with a maximum load-shedding restriction, without this restriction, and considering insertion of DG. Besides, the hierarchical model can evaluate how much losses and load shedding take effect without integrated operation and expansion planning of emerging distributed networks. This study showed the importance of analyzing the systemic impact of integrating multi-MGs and ADN synergistic operation interactions, resulting in improvements in the voltage quality levels, operation costs, and power losses. The results showed that, including DG in the system, the costs were reduced by 13,48% compared to the case base.

Keywords: microgrids; active distribution network; multiperiod optimal power flow; hierarchical optimization framework.

INTRODUCTION

In the last years, distribution grids are facing transformations guided by the digitalization of the process, as well as the introduction of new elements as distributed energy resources (DER). Driven by concern about climate change and energy transition, the increase of renewable energy solutions is being encouraged worldwide, with new equipment, markets, and solutions, that can push for a more sustainable energy system. Part of this process is known as the 3Ds of energy transformation, corresponding to Decarbonization, Digitalization, and Decentralization. Moreover, some authors consider a fourth D, that corresponds to system Democratization, which means, changes in energy systems with consumers actuating more actively on it.

The Brazilian Energy Research Office (EPE) considers that DERs contemplate distributed generation; energy storage; electric vehicles and recharging infrastructure; and, demand-side management such as energy efficiency, demand response, etc. As reported in the EPE discussion note, DERs can pose several challenges for electric power distribution systems operation and planning, at the same time they can provide many benefits, such as reducing network costs, improving grid reliability, and others [1].

Another possibility is the development of microgrids or energy communities, based on the existence of energy generation systems simultaneous to storage systems and management devices. Microgrids can be defined as part of the power grid that can be disconnected from the main grid and operate autonomously. Thus, for a microgrid to be possible, it is necessary to have distributed energy resources such as distributed generation and storage systems that allow the load to be supplied in periods when it is disconnected from the main grid [2].

In this context, new concepts were defined, such as active distribution networks, distributed energy resources, and microgrids, creating a new scenario for a grid in a constant transformation. In the Technical Brochure 457 – Development and Operation of Active Distribution Networks, from [2], there are multiple ways to define an Active Distribution Network (ADN). However, in general, it is possible to define an ADN as a grid that enables the distribution system operator (DSO) to interact with the consumers, manage the power flow, coordinate, and control the distributed energy resources, and multi-microgrids integration and operation.

Microgrids have brought new paradigms, since several applications can be realized, e.g.: residential/commercial microgrids, with customers acting actively in the energy market; microgrids providing ancillary services to the distribution grid, acting together with the distributor, for example, for voltage support and load shifting; or the microgrids can be constituted to serve isolated localities, in places where there is no electrical grid.

Currently, in Brazil, there are already several microgrids for isolated systems, as is the case of the island of Fernando de Noronha, served by diesel and solar photovoltaic generation systems, with the recent installation of a storage system with lithium batteries. In addition, there are microgrid applications to serve communities in remote locations such as the islands of Lençóis and Ilha Grande, both in the state of Maranhão, as well as to serve the populations living in the Pantanal Sul-Matogrossense region.

For large scale implementations of multi-microgrids connected to a Brazilian distribution network, in September 2021, the Brazilian regulatory agency (ANEEL) approved the implementation of a pilot project for the Public Call of the *Companhia Paranaense de Energia (Copel)* for the acquisition of energy from distributed generation through the formation of a microgrid. The pilot project will last five years, since ANEEL's authorization is configured as a “regulatory sandbox” in which some rules can be relaxed and/or changed, with duration and conditions previously delimited so that the agents in the sector can carry out innovations [3,4].

With the integration of DERs and microgrids, the distribution system operator (DSO) starts to face new challenges and in this way, studies should be developed to allow the evaluation of grid integration and their main impacts on emerging distribution networks operations.

Among the main challenges faced by utilities are the voltage control, aiming to avoid the voltage limits; the reverse power flow at some points and equipment of the power grid that are not prepared for such behavior; the power factor control in the power system boundaries; as well as new technical configurations, new business models and system digitalization [5,6].

In this way multiple papers had proposed the usage of optimization techniques looking for new planning and operational systems, in the context of large DG penetration and an ADN behavior. The Optimum Power flow implementation is proposed by [7–11] in a similar approach considering multiple optimizations in the objective function, such as the minimization of costs, power losses, load shedding and voltage deviations, considering the behavior and the operational limits of the equipment modeled. In these cases, the authors considered the integration of DG, such as photovoltaic and wind generation, as well as storage systems, and the power grid itself is not modeled in detail.

In this context, a large-scale and complex distribution system increase the computational efforts of the day-ahead operation planning process of ADNs. Similarly, many microgrids connected to a traditional or an active distribution network increases the complexity of the day-ahead operation planning of an ADN with multi-MGs. The computational dimension and complexity can be reduced by decomposition or a hierarchical optimization model. Works, such as [12–16],have already analyzed the operation planning of single or multiple microgrids, in terms of cost, energy storage systems capacity, flexibility, stability and inclusion of distributed energy resources (DERs), which contributes to the MGs performance in many aspects that were also analyzed. The work developed by [17] consider the integration of a microgrid in a completed modeled distribution grid, with distribution transformers, capacitor banks and voltage regulators, as well consider the integration of DG, storage systems and a microgrid. In this case the authors also proposed a hierarchical approach between the optimization of the microgrid itself, consisting of optimization of its equipment, and the optimization of the entire ADN. It is important to highlight that [17] do not consider the integration of multiple microgrids simultaneously in the optimization problem, not even considering multiple and independent optimizations for each microgrid interacting with the power grid optimization, as proposed in the current paper.

In this way, the main objective of this paper is to develop a hierarchical optimization model considering as master problem the day-ahead optimal operation planning of ADN formulation and as slave problem the day-ahead optimal operation planning of each microgrid in a multi-microgrid system, resulting in a non-linear programming and mixed-integer linear programming. The day-ahead optimal operation planning of ADN formulation considers the completed ADN’s network system with the connection of distributed energy resources, such as distributed solar generation, battery energy storage systems, and demand response corresponding to the DSO point of view and it is solved using the interior-point algorithm. Similarly, the formulation of the day-ahead optimal operation planning of an MG considers the MG´s network connected to its distributed energy resources, such as distributed solar generation, battery energy storage systems, and demand response, the optimization of each microgrid was done using the Gurobi Optimizer solver, which optimizes the dispatch of DERs and its injection/consumption from the main grid.

Considering this approach, the proposed model was tested for different scenarios, considering the simultaneous connection of four different test-system microgrids to a 359-nodes DN test-system belonging to a Brazilian distribution company located in Curitiba, Brazil, and later is simulated in a scenario where it DN is considered as an active distribution grid. The challenge of the scenarios proposed consists in optimizing each microgrid connected independently, but at the same time optimizing the entire ADN and multi-MGs operation planning, considering their operational network and power quality constraints.

Thus, the main contribution of this paper is the proposes of a coordinated hierarchical optimization model for day-ahead optimal operation planning of ADNs with multi-microgrids, considering the ADN formulation as a large-scale full non-linear programming and the each MGs as a large scale mixed-integer linear programming. It is important to highlight that this paper is an extension from [17] in order to include multi-microgrids simultaneously instead of a single microgrid operation.

This paper is organized as follows: the material and methods section present the main mathematical formulation and data used in the proposed model, followed by the results section. The paper ends with the conclusion section.

MATERIAL AND METHODS

In this section, the concepts and data of the proposed hierarchical model are discussed. The model is formulated by the coordinated day-ahead optimal operation planning of active distribution networks (ADN) and multiple microgrids operating connected to an ADN. The final architecture considers a master-slave model, to find the optimal global performance of the full system. The master level corresponds to day-ahead operation planning optimization of an ADN, in this paper, it is named multiperiod optimal power flow (MOPF), and the slave level model contemplates to the day-ahead operation planning optimization of each microgrid, which is named as multiperiod optimization of a microgrid (MOuG).

The methodologies proposed in this section were chosen based on the literature review and the implementation of this methodology in previous researches developed by the authors, where parts of the problem were previous implemented and published in [17-19]. At this point is also important to highlight that the chosen methodology were based on several papers that already exists in the literature, proving the efficiency of these methods for the application on power grids and microgrids optimization. Additionally, this paper consists in a different approach where multiple microgrids were optimized independently and simultaneously, interacting with the main grid optimization in a master-slave approach.

Hierarchical Model

Multiperiod Optimal Power Flow to Active Distribution Networks Methodology (MOPF)

For the master level, it is necessary to optimize the day-ahead or daily operation of the active distribution network. The planning horizon for both master and slave levels is 24 hours, respectively. The detailed formulation of the master optimization problem (MOPF) is based on [17,18] and comprises the minimization of electrical losses ($flosses$), cost operation ($foper$), cost operation of the batteries ($fcost\_bat$) and load shed of the microgrids (*FPd*), cmicro:

$$fMOPF = flosses + foper + fcost_{bat} + \text{cmicro}\left(\sum_{t=1}^{np}\sum_{i=1}^{nb}(gamma_i^t - 1)^2\right), \quad (1)$$

Where *nb* is the number of buses, *np* is the number of periods, the factor ($gamma_i^t$) is applied at the load bus of microgrids (FPd_i^t).

From the power grid point of view, it is necessary to consider the integration of multiple microgrids. In this case it will receive the results of the optimizations of each microgrid as inputs to be inserted in the optimization problem, as proposed in [17].

Each microgrid behavior should be provided to the master in the same number of periods of the power grid optimization. The MGs will be considered as flexible loads, so that if any constraints are violated, the master optimization will propose changes in the operation of the microgrids, sending this information to the slave.

The corresponding values of the ideal percentage of $gamma_i^t$ of the power injection/consumption of microgrids (FPd_i^t) are sent to the slave problem, suggesting a new dispatch of the microgrids, when gamma is a value smaller than 1, it means that the power injection of microgrids must be reduced. If the gamma is equivalent to 1, it means that the injected power does not need to be changed, as it does not affect any technical operational aspect of the network.

Microgrids Optimization Model for Day-ahead Operation Planning (MOuG)

The slave problem considers the day-ahead operation planning problem for microgrids to perform the optimal microgrid elements dispatch. Notice that the microgrids could be connected to the ADN in different nodes, which are usually called points of common coupling (PCCs). In each iteration process of MOuG model, the power injection/consumption gamma values provided by the master problem are used as known input data. As the hierarchical model is solved iteratively, at each iteration, it is sought to recover the power required by the microgrids in the penultimate iteration and how much of this power needs to be adjusted for the new dispatch, as shown in (2):

$$Pd^{ideal^{t}}_{i,mg} = Pd^{realized^{t}}_{i-1,mg} * gamma^{t}_{i,mg}, \quad (2)$$

where the power injected from the main grid $Pd^{ideal^{t}}_{i,mg}$ in iteration *i* for microgrid mg during period t, $Pd^{realized^{t}}_{i-1,mg}$ is the power injected in the penultimate iteration *i-1* for microgrid *mg* during period *t*, and $gamma^{t}_{i,mg}$ sent by MOPF to MOuG is identified for each microgrid *mg* during period *t* for iteration *i*.

The day-ahead operation planning of a microgrid was modeled according to [19], that is, considering demand response, battery storage systems, photovoltaic generation, and thermal generation. However, due to the lack of space, the scope and contribution of this work are to present a hierarchical model for day-ahead operation planning of ADNs and microgrids, not considering the uncertainties related to parts of the energy resources used. Therefore, the formulation corresponds to the first level of the formulation of [19], and for the injected/consumption power deviations suggested by the master problem to be respected, then a penalty formulation was inserted in the objective function between what was requested by the network and what was carried out by microgrids:

$$min\ \left(TCost + \left(\left|Pd^{ideal^{t}}_{i,mg} - Pd^{realized^{t}}_{i,mg}\right|\right) * Hpen\right), \quad (3)$$

where *Hpen* is the penalty value for the non-adjustment of the ideal power injection in the hierarchical model and *Tcost* is the total cost, which depends on the cost of energy exchange with the main grid for each microgrid in each bus, the cost of batteries energy storage systems (BESS), the cost of thermal generation, and load shedding costs. The authors recommend checking [13] for more information about the cost terms and other details of the formulation. Differently than in [13], the demand response can only happen for controllable loads. However, the demand response program adopted in this work considers that part of the total load (maximum 15%) can be managed. So, if it is necessary to cut more loads than that percentage, there would be infeasibility problems caused by this restriction. That is why an adaptation from the original formulation is made, where the controllable load can be allocated along the 24-hours horizon, as in (4):

$$CL_b^t = \sum_{t=1}^{N} DR_b^t * (TL * 0.15), \tag{4}$$

where CL_b^t is the controllable load for bus *b* during period *t*, *DR* is an auxiliary variable that varies from 0 to 1 to represent the percentage of CL_b^t that will be allocated during the planning horizon, and *TL* is the total amount of loads, controllable and non-controllable. Besides, (5) presents that the maximum amount of controllable load that can be allocated in a period t is equal to the total amount of controllable load for the entire time horizon. The sum of the controllable load must be equal to 1, as seen in (6),

$$0 \leq DR_b^t \leq 1, \tag{5}$$

$$\sum_{t=1}^{N} DR_b^t = 1, \tag{6}$$

guaranteeing that all loads will be allocated during the time horizon. However, the load shedding is available for non-controllable loads and must respect this limit, as shown in (7),

$$0 \leq LS_b^t \leq NCL_b^t, \tag{7}$$

where LS_b^t is the load shedding and NCL_b^t is the non-controllable load for bus b during period *t*. With the adaptations made, the hierarchical model can be implemented. As the power grid and the microgrid equipment are modeled the first step it load all the grid model and the equipment behavior. At this point the microgrid optimization is realized individually for all the microgrids, considering only the internal restrictions of the microgrid itself (MOUG). The result of this first optimization is sent to the MFOP, for the power grid optimization considering all the equipment of the ADN. If no constraints are violated, the network optimization converges and you have optimal operation of the network and the microgrids. If at least one of the network's operational constraints is violated, the network optimization proposes a new dispatch for the micro-grids, so the MOUG optimization is redone considering the constraint imposed by the network. This new microgrid dispatch is then sent to the master optimization. This process is repeated until the optimization is able to converge without any constraints being violated, presenting as a result the joint optimization of the network and the microgrids. A detailed scheme can be seen in [17].

Data of Test-System

In this paper is used a 359-nodes ADN test system located in Curitiba city, Brazil. This distribution network test-system has an operating voltage of 1 pu, with 411 medium voltage (nominal 13.8 kV) lines and 489 low voltage (nominal 220/110 V) lines. It has 22 medium voltage consumer units and 1236 low voltage consumer units. As mentioned above, the proposed framework also considers photovoltaic distributed generation systems, batteries, and demand response considering that these systems can be added in the future. In this context, it is considered a scenario that of the 359 nodes in the system, 58 of these would have the installation of a photovoltaic system with different installed capacities. So, in this scenario, the total installed photovoltaic power distributed generation is 451.36 kWp. The microgrids test-system data used in this paper is adapted from [20], by replacing wind turbines for PV generation.

RESULTS

Intending to evaluate the behavior of the distribution network concerning the insertion of multiple microgrids connected to it at different points in the system, as well as evaluate the impacts of the insertion of PV distributed generation in the distribution network using the hierarchical model, this section presents the results of the computational model proposed.

To simulate cases with feedback from the hierarchical model, the results presented here refer to the insertion of four microgrids considering a substantial increase in the load presented in the materials and methods section for the cases:

• Case I: The four microgrids operating simultaneously located at different points of the feeder. In this case, there is a maximum load shedding constraint limited to 5%;
• Case II: Case I without constraints of the maximum load shedding;
• Case III: Case II with the insertion of photovoltaic distributed generation in several points of the feeder, that is, the network functioning as an active distribution network.

The solar generation was inserted in several nodes of the distribution network that present load. For the calculation of the insertion of DG, a penetration percentage of 30% was considered, which was calculated from the total installed power at the point, for example, if the bus has 10 kW of installed capacity, the input of 3 kW of distributed photovoltaic generation is considered. Therefore, in this case, this represents 30% of the 451,36 kWp which results in 135,41 kWp.

It is important to note that there were purposeful modifications to the test cases presented in the previous step:

• The load increases are 65 times greater for microgrids, since, through exhaustive computational tests, it was observed that for smaller values, it would not imply undervoltage, not bringing to light the computational capacity of the proposed model.
• Increase of 10 times greater for the other loads connected to the main network, because for smaller values there was also no undervoltage;

For a microgrid to act on or impact the ADN, it must be strategically placed on the feeder, because of that, the microgrids 1, 2, 3, and 4 were allocated in nodes 51, 319, 339, and 347, respectively. In the following subsections, the main results obtained from the simulations performed are presented.

Case I

Pre-processing

This process step is necessary for the initialization of the hierarchical model, informing what would be the ideal injected/consumed power from the point of view of the microgrid if no adjustment was necessary, such as load reallocation or even load shedding. With this, the dispatches of the microgrids are shown in Figure 1.

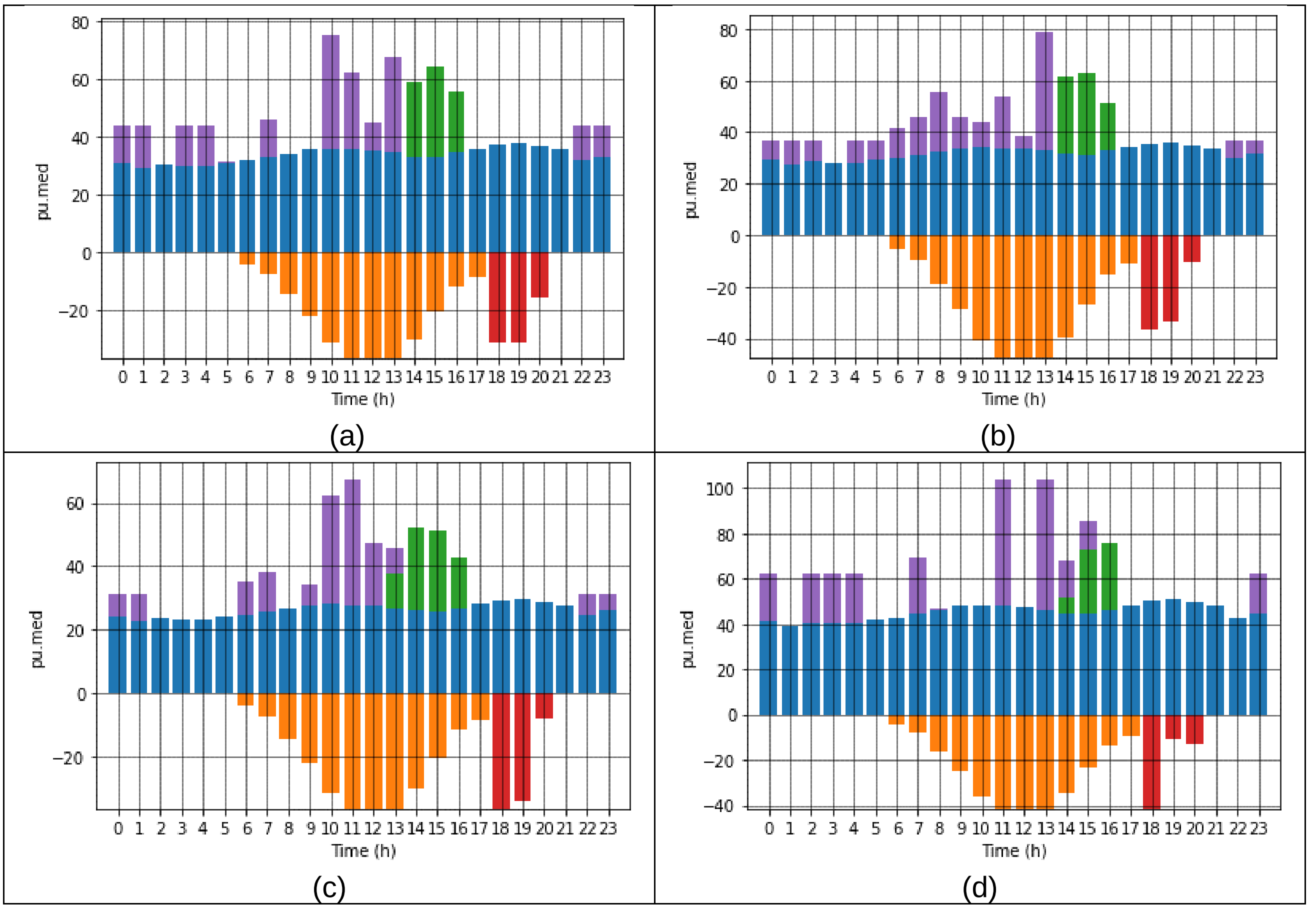


Figure 1. MOuG optimization dispatch during pre-processing for microgrids (a) 1, (b) 2, (c) 3, and (d) 4. NC-load in blue; C-load in purble, battery charge in green; battery discharge in red; PV-gen in red.

The results of pre-processing dispatches show that non-controllable loads (in blue), battery charging (in green), and controllable loads (in purple) are not allocated during peak hours, seeking to take advantage of PV generation (in orange) to reduce operating costs. In contrast, battery discharging (in red) is used during peak periods (from 5 pm to 9 pm), to reduce the use of energy from the distribution network, help in voltage levels, and supply loads from the point of view of microgrids. For this pre-processing, the resulting costs of microgrids are shown in Table 1.

Table 1. Pre-processing Operational Costs of the Microgrids.

Microgrid	Operational Costs
MG1	3,593.14 BRL
MG2	2,959.78 BRL
MG3	2,471.10 BRL
MG4	5,338.31 BRL
Total Cost	14,362.33 BRL

First Feedback

In this step, the master-level is run for the distribution network but considering the amount of injection/power consumption of the microgrids as a result of the pre-processing step. The MOPF results considering the original dispatch of the microgrid imply violations of minimum voltage magnitude constraint for the main grid. So then, there is a request from the master program so that there is a readjustment of this dispatch by the microgrids, being necessary to cut part of their original load. The convergence process takes 53 iterations. The numerical results related to the variation in the original load, losses, and operating costs are presented in Table 2:

Table 2. Numerical Results for case I in first feedback.

Total Costs	Losses	Total Consumed Energy	Readequation from Pdideal
148,763.98 BRL	9.43 MWh/day	269 MWh/day	-19.99% (MG1) -18.8% (MG2) -15.97% (MG3) -31.36% (MG4)

Table 2 shows that the ideal for the distribution network would be a reduction (in %) of consumption by microgrid loads, precisely because of violations of restrictions related to minimum voltages at the feeder nodes. Thus, the MOPF model indicates that undervoltage can be remedied from these suggested cuts. However, as can be seen in Table 3, the master level requires the slave level to cut percentages of its total load to eliminate undervoltage. Following these cut requirements, MOuG is executed, but it sends a new load shedding proposal to the master program, informing the impossibility of meeting the totality of the required cut since the microgrids can cut a maximum of 5% of their loads. Thus, at the end of the feedback, the new power suggestion demanded by the microgrids is sent to the master problem. In this case, even if the entire load change is not tolerated, the dispatch of the microgrids seeks to achieve part of the required change, suggesting a load shedding during peak hours, from 5 pm to 9 pm, mainly for microgrid 4.

In addition, the load shedding required by the master level is absorbed by the slave level so that it can perform a new dispatch that reallocates controllable loads and reduces battery charging so that the smallest amount of load is shed but seeking to adjust to the dispatch suggested by the main network. Therefore, it is possible to observe that, for microgrid 4, for example, a large part of the controllable load is allocated to the last period of the planning horizon, and that for this microgrid there is no dispatch of the batteries taking place because its financial benefit would not compensate for the load shedding required. The costs of microgrids for this case are shown in Table 3.

Table 3. Microgrids costs for case I in first feedback.

Microgrid	Load Shedding Costs	Hierarquical Penalty Costs	Total Costs
MG1	814.20 BRL	3,075.15 BRL	7,291.56 BRL
MG2	779.93 BRL	2,257.67 BRL	5,808.53 BRL
MG3	553.11 BRL	1,651.02 BRL	4,540.48 BRL
MG4	4,524.13 BRL	4,556.26 BRL	13,337.73 BRL

The costs are higher than those of the pre-processing because in this feedback process there is an increase in the load shedding of the microgrids due to the operational restrictions imposed by the distribution network as discussed above, in addition to the penalties for non-compliance with the proposed dispatch suggestion by the MOPF. These penalties result in the need of performing new feedback in the hierarchical model. This information exchange happens till the third feedback, which the results will be shown in the next subsection.

Third Feedback

In the hierarchical model, one of the input parameters is that the maximum number of the feedback process is up to three. Thus, this was the last feedback process performed, in which the MOPF algorithm was able to converge in 14 iterations. The numerical results of this feedback process are shown in Table 4:

Table 4. Numerical Results for case I in third feedback.

Total Costs	Losses	Total Consumed Energy	Readequation from Pdideal
147,397.88 BRL	9.253 MWh/day	267 MWh/day	-18.54% (MG1) -17.22% (MG2) -14.6% (MG3) -23.94% (MG4)

It is possible to verify through the data inferred from Table 4 that the total cost of the main grid was reduced compared to the cases of the first feedback, as well as the losses and the total energy consumed since the dispatches presented from the microgrids were able to contribute with an improvement of the technical characteristics of the main grid.

The load readaptation shown in Table 4 is necessary for the voltage profile to operate within the pre-established limits, which have some minimum voltage restrictions being activated. Therefore, it was still necessary for the microgrids to have part of their load shed so that these restrictions were not violated.

As it is the last feedback process, it is possible to observe that for the maximum number of iterations, the microgrids could not adapt to the dispatch suggested by the main grid. Therefore, the hierarchical model has a resource in the situation of non-adaptation between the two systems, which is the reduction of the minimum voltage. In this case, the minimum voltage was reset to 0.9 pu. The results of this feature will be presented in the next subsection.

Minimum Voltage Limit Reduction for 0.9 pu

As it was not possible to find a dispatch from the microgrids that would not violate the minimum voltage limit on the feeder buses and that the power injected by the distribution network was enough to supply the microgrid loads, the minimum voltage was reduced, and the pre-processing information is resumed to check the network with the new minimum voltage threshold.

By allowing it to operate with a minimum voltage below 0.93 pu, load shedding on microgrids is no longer necessary. Figure 2 presents the new voltage profile. It is observed that in some hours of the day, the network operates with voltage below 0.93 pu (ie, with undervoltage).

Thus, the network was able to accept all the power suggested by the microgrids already in the pre-processing, which was the first dispatch devised by the microgrids. However, this first dispatch, without any load shedding, implies a violation of the minimum voltage limits required by PRODIST, as they were relaxed.

Table 5 brings the numerical results for this case, demonstrating that there is an increase in costs, losses, and energy consumed since the network can meet all the necessary load power of the microgrids, not requiring any type of variation in its dispatch.

Table 5. Numerical results for case I after reducing the minimum voltage limit.

Total Costs	Losses	Total Consumed Energy	Readequation from Pdideal
152,559.06 BRL	9.987 MWh/day	276 MWh/day	0% (MG1) 0% (MG2) 0% (MG3) 0% (MG4)

The costs of the microgrids are the same as those of pre-processing, totaling 14,362.33 BRL. However, the total operating costs of the main grid (152,559.06 BRL) plus the costs of the microgrids result in 166,921.39 BRL. In this case, as there is no load shedding by the microgrids, some buses of the main grid showed undesirable undervoltage (<0.93), but higher than the newly established limit of 0.9).

Thus, the hierarchical model shows that for this case, a minimum voltage of 0.93, it would be necessary to make other investments, such as installing voltage regulators and capacitor banks, so that the voltage profile on the feeder bars could be adjusted without cut a large part of the loads from microgrids.

Thus, it is evident the importance of properly designing and sizing the loads, generation, and storage of microgrids aiming at the minimum impact on the active distribution networks where they will be connected. This is of great importance for the development of computational models for the integrated planning of the expansion of microgrids and active distribution networks, considering the optimal operation of distributed energy resources in both active and multi-microgrids.

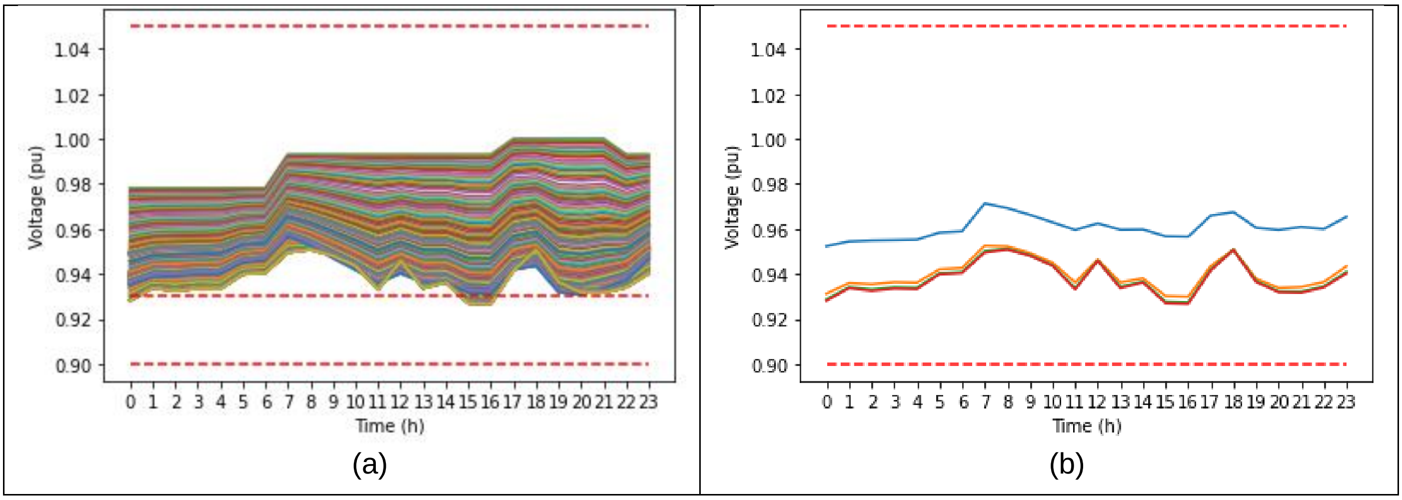


Figure 2. (a) Voltage for all buses; (b) Voltage for GLD buses.

Case II

As the results of Case I showed that the load shedding required by the network makes the convergence process of the hierarchical model impossible, it was decided to remove the maximum load shedding constraint from the MOUG model (which was around 5%), to re-evaluate the procedure of the hierarchical model.

In this case, after carrying out the ideal dispatch of the microgrids obtained by the pre-processing, which is identical to the one found for Case I, the main grid sends the suggestion of load shedding to MOuG. And, as in this case there is no restriction for load shedding in the microgrids, they adapt to the shed proposed by the first feedback of case I, and there are no penalty costs for not adjusting to the dispatch suggested by the main grid, as shown in Table 6.

Table 6. Microgrids costs for case II.

Microgrid	Load Shedding Costs	Hierarquical Penalty Costs	Operational Costs	Total Costs
MG1	4,504.38 BRL	0 BRL	2,835.11 BRL	7,339.52 BRL
MG2	3,489.14 BRL	0 BRL	2,348.07 BRL	5,837.21 BRL
MG3	2,534.33 BRL	0 BRL	2,029.30 BRL	4,563.63 BRL
MG4	9,991.64 BRL	0 BRL	3,458.76 BRL	13,450.40 BRL

However, it can be observed that the highest cost for the microgrids is the cost of load shedding, mainly for microgrid 4, in which the load shedding cost represents 74.29% of its total cost, with the biggest shedding occurring for all microgrids, 3,330.55 kW, that is, 24.53% of the total load shedding, plus adjustments to controllable loads and batteries, reaching a variation of 31.36% of the ideal dispatch presented in the first feedback section for Case I.

Figure 3 shows the behavior of microgrids when accepting the first dispatch suggestion given by the main grid. In this case, it is possible to observe that there is a greater load shedding for all cases (in pink) and that only microgrids 2 and 3 can dispatch a small part of the batteries, so that less energy is used for charging, mainly microgrid 3, since the amount of load shedding is the smallest of all microgrids, with an average of 844.77 kW, which represents 10.72% of load shedding for microgrid 3.

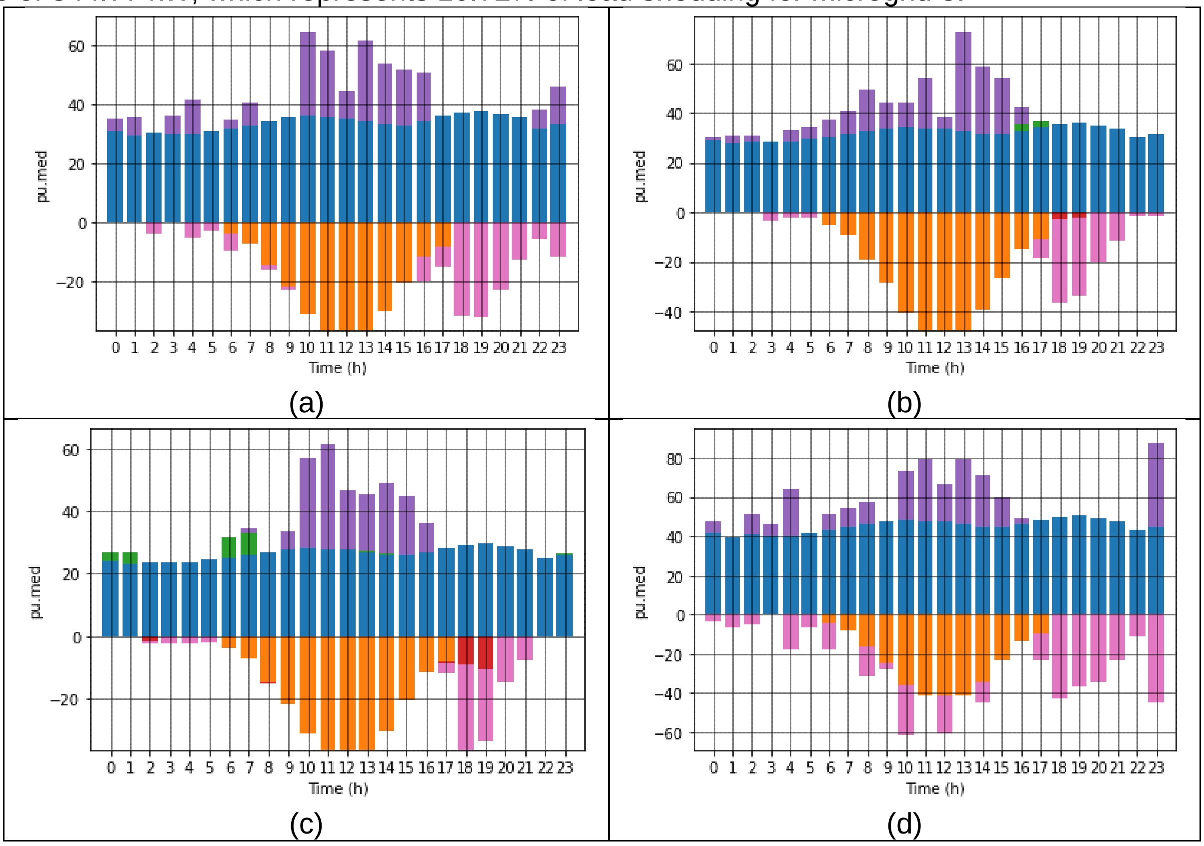


Figure 3. MOuG optimization dispatch in case II for microgrids (a) 1, (b) 2, (c) 3, and (d) 4. NC-load in blue; C-load in purble, battery charge in green; battery discharge in red; PV-gen in red.

The total costs of the microgrids for this case were 31,190.76 BRL. However, the total operating costs of the main grid (148,763.98 BRL) plus the costs of the microgrids result in 179,954.74 BRL. This cost is 8% higher than that presented in case I. This cost increase is due to the load shedding costs that occurred in the microgrids. It can be concluded that this 8% is the cost of having a better quality of voltage levels, that is, appropriate voltage levels in the main network, which is the cost to ensure the quality of energy referring to the voltage level of the network. main. This additional cost that is incurred by the microgrids could be paid to them through the appropriate allocation among all the agents of the distribution system and the microgrids. So then, these costs could be paid via regulatory mechanisms for ancillary services. Thus, it is possible to prove that the hierarchical model shows that with the correct adequacy and a refined parameterization, the results can both help in the dispatch of microgrids and the main grid.

Case III

The third and final scenario analyzed in this work considers the insertion of distributed photovoltaic generation systems. That is, considering a future scenario in which the distributions network-test system considered in this paper starts to present a massive insertion of distributed energy resources, the analysis was carried out considering the penetration of 30% of distributed generation in this feeder. The allocation of this penetration was carried out proportionally in the load bars, considering that part of the consumer units allocated in the equivalent low voltage may present the photovoltaic solar generation systems, as well as for the case referring to medium voltage consumers.

For this case, the results of the pre-processing of the microgrids are the same as presented in case I. And, as in case II, here it is considered that the modeling of the microgrids does not contemplate a maximum limit for load shedding, which implies say that, if no other microgrid constraint is violated from the main grid's dispatch suggestion, the microgrid is capable of accepting any load shedding level. Thus, as shown in Figure 4, the voltage profile shows that in the first period of the planning horizon, the feeder operates with minimum voltage limits activated for some buses, such as in one of the buses where there is a microgrid allocation, as observed in Figure 4-(b):

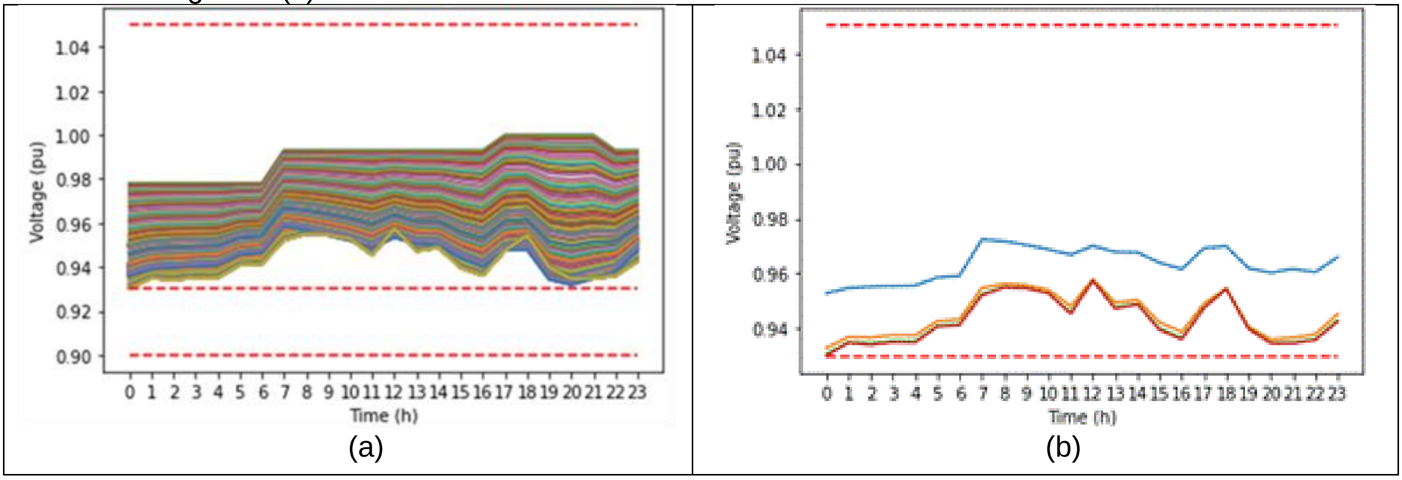


Figure 4. (a) Voltage for all buses; (b) Voltage for GLD buses.

The numerical results of the main grid are presented in Table 7, showing that the insertion of distributed generation reduces the feeder operating costs:

Table 7. Numerical Results for case III.

Total Costs	Losses	Total Consumed Energy	Readequation from Pdideal
133,742.08 BRL	7,778 MWh/day	273 MWh/day	-9,09% (MG1) -8,77% (MG2) -7,27% (MG3) -14,23% (MG4)

The results presented in Table 7 compared to case II show that the insertion of PV generation reduces the amount of load shedding suggested for microgrids to less than half. For case II, the readjustment (reduction or load shedding and re-dispatch of batteries of the microgrids, etc) for all the microgrids was 86.12%, while for this case, with the insertion of DG, this readjustment was reduced only to 39.36%. In case

III, there is greater total energy consumed when compared to the previous cases, since the PV generation contributes to supply part of the loads that were previously cut.

Figure 5 shows the total power injected by the substation into the main grid (in green) as well as the liquid power injection performed by the microgrids (in black), in addition to the total insertion of PV generation (in red). In this figure, the contribution of DG to the total supply of the feeder load is evident. It should be noted that in Figure 5, the portion of microgrids corresponds to the total net value, obtained from the algebraic sum of all of them for each period, that is, it reflects the behavior of all microgrids connected to the feeder from the grid point of view.

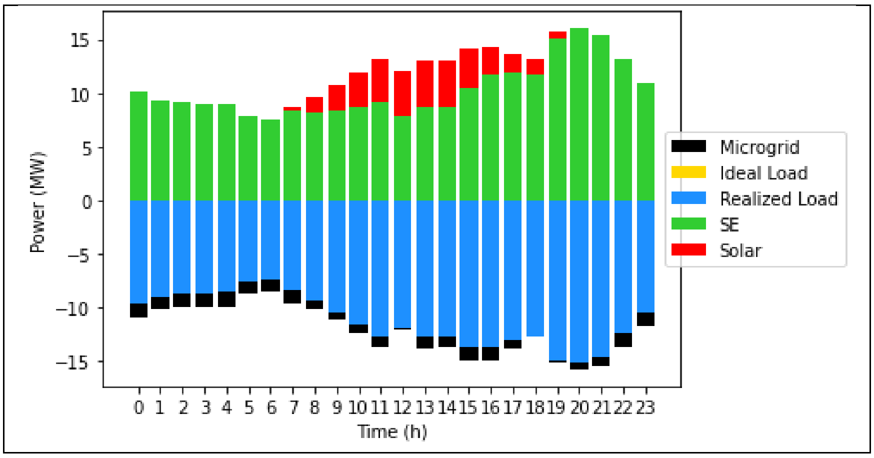


Figure 5. Power balance indexes of the feeder for the planning horizon with the distributed energy resources used.

In addition, the behavior of the normalized curve of the PV generation can be seen in Figure 6, verifying the typical behavior for injection of active power and a small injection of reactive power in the period of photovoltaic generation, since the inverters of the generation systems solar panels have a power factor of 0.92 pu.

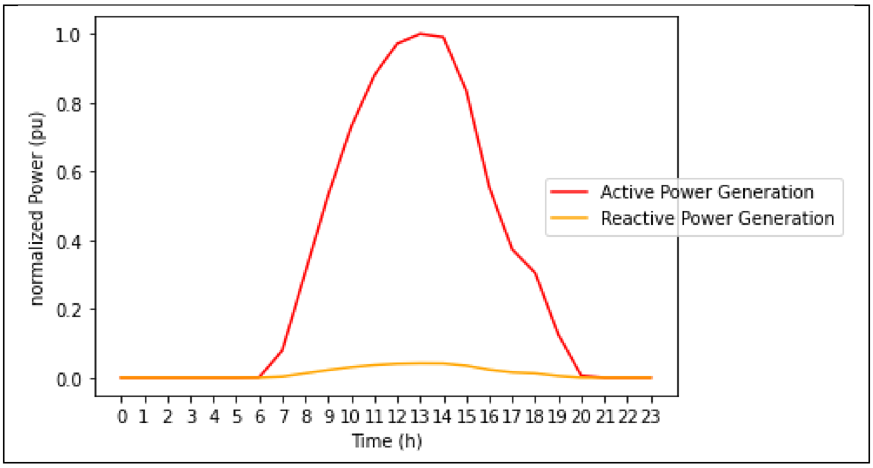


Figure 6. Active and reactive power for case III.

From the main grid point of view, the ideal power injection for microgrids is presented in Figure 7:

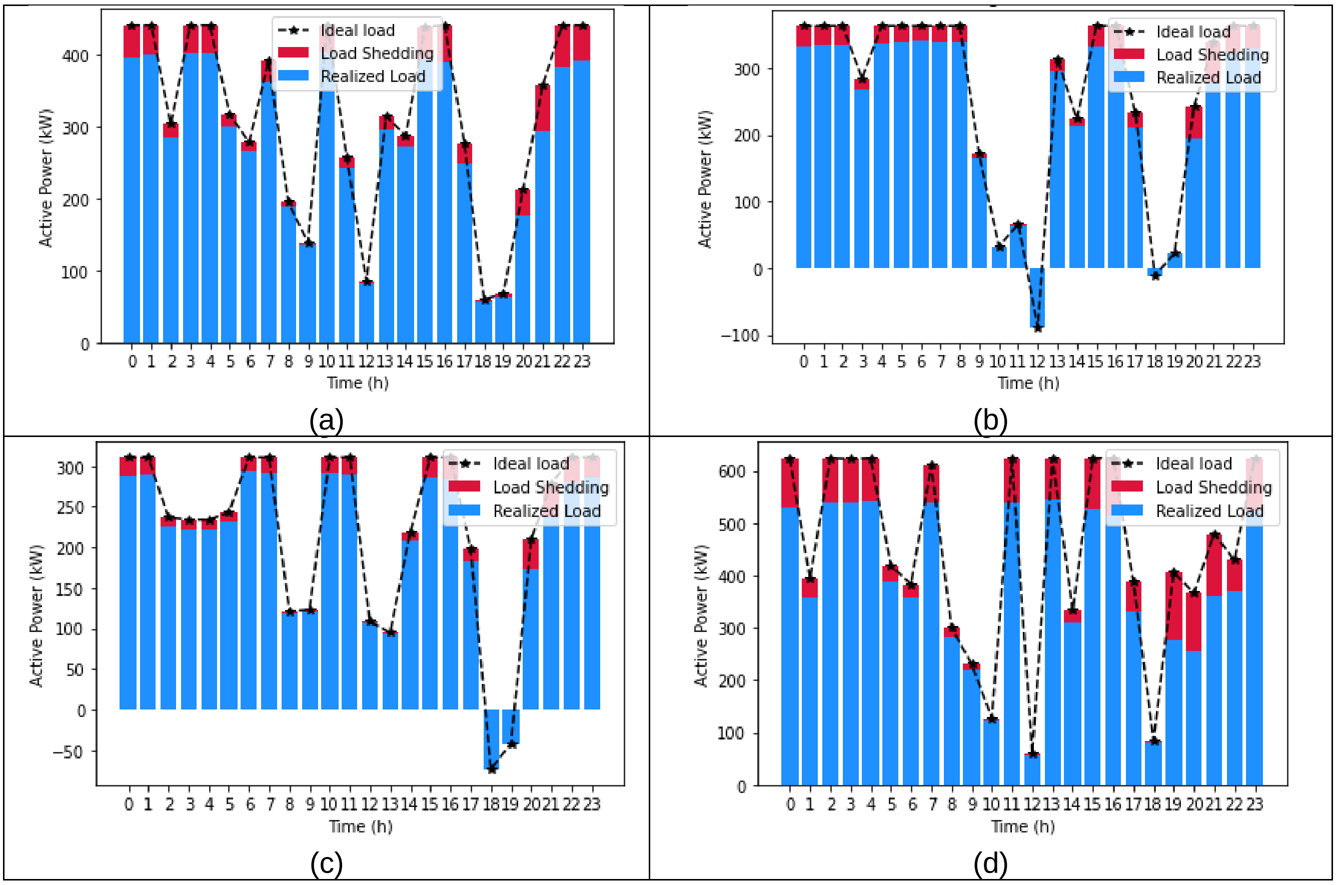
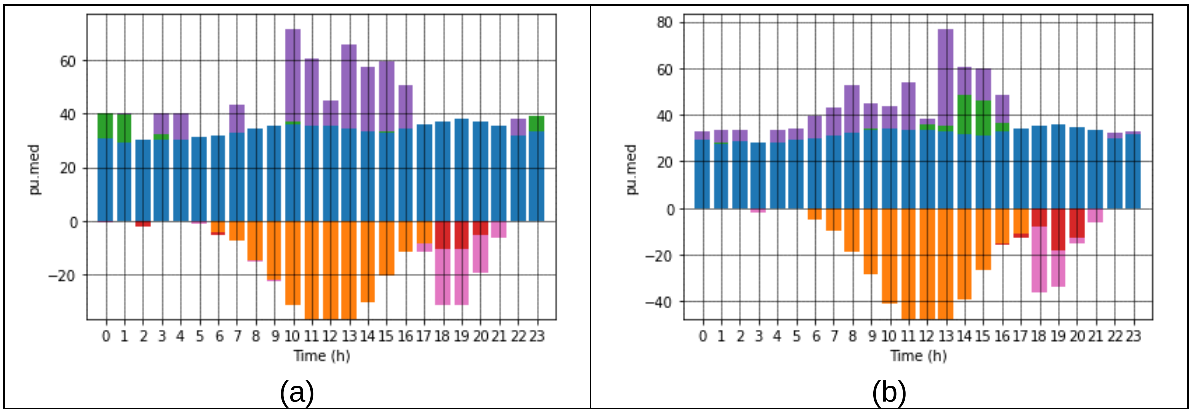


Figure 7. Ideal power injection from the main grid point of view for microgrids (a) 1; (b) 2; (c) 3; and (d) 4.

From Figure 7, it can be seen that the load shedding is greater for microgrid 4 in this case, as it is the microgrid with the highest installed power, both in terms of loads and energy resources. It is also observed that the required cuts are much smaller when compared to cases I and II. As there is no maximum load shedding restriction, this new dispatch suggested by the MOPF is accepted by the microgrids and the algorithm is finished. The new operating costs of microgrids are shown in Table 8, and their dispatches are shown in Figure 8.

Table 8. Microgrids costs for case III.

Microgrid	Load Shedding Costs	Hierarquical Penalty Costs	Operational Costs	Total Costs
MG1	2,048.29 BRL	0 BRL	3,239.89 BRL	5,288.29 BRL
MG2	1,628.09 BRL	0 BRL	2,670.32 BRL	4,298.41 BRL
MG3	1,153.03 BRL	0 BRL	2,268.56 BRL	3,421.59 BRL
MG4	4,533.38 BRL	0 BRL	4,409.53 BRL	8,942.91 BRL



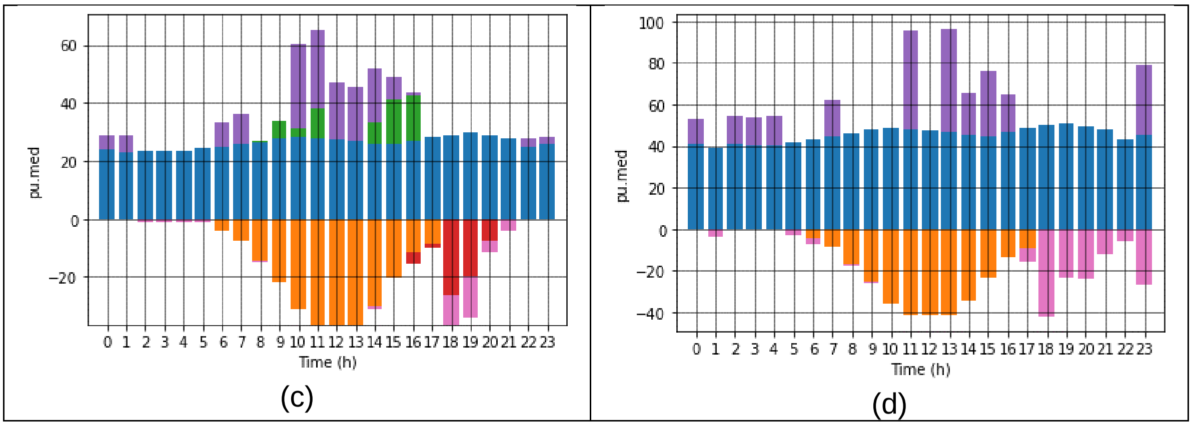


Figure 8. MOuG optimization dispatch in case III for microgrids (a) 1, (b) 2, (c) 3, and (d) 4. NC-load in blue; C-load in purple, battery charge in green; battery discharge in red; PV-gen in red.

Like what happens in other cases, the microgrid seeks to optimize the dispatch of all its resources to both reduce operating costs and meet the dispatch suggested by the grid, having the lowest possible load shedding, which is mainly during peak periods. In this case, it is possible to observe that there is a greater load shedding, as there is no restriction of maximum load shedding, and for microgrid 4, there is no dispatch of batteries taking place, as the aim is to reduce the use of energy from the feeder, which results in the batteries not charging, and consequently, not discharging.

In Table 9, a comparison of the costs and losses for each case is presented.

Table 9. Costs and losses comparison for each case.

	MGs Costs	Main grid Costs	Total Costs	Losses (MWh)
Case I	14,362.33 BRL	152,559.06 BRL	166,921.39 BRL	9.987
Case II	31,190.76 BRL	148,763.98 BRL	179,954,74 BRL	9.43
Case III	21,951.20 BRL	133,742.08 BRL	155,693,28 BRL	7.778

From Table 9, it can be seen that case I has an intermediate cost, but in this case, the quality of the voltage levels is compromised. While case II has a higher cost (179,954.74 BRL), however, the quality of the voltage levels is satisfactory. Finally, case III has the lowest cost (155,693.28 BRL) among all cases, due to the insertion of distributed generation in the distribution network, and the readjustment of the microgrids dispatch is smaller (when compared to the case II) in order to maintain adequate network voltage levels.

From the same Table 9, it is also possible to observe that the losses were considerably reduced compared to case I and case II. For example, comparing case III to case I, there was a reduction of 22.12%. These reductions in both cases are due to the insertion of DG in the network, which reduces the flows through the feeders. The losses in case I are greater than in case II because in case I it is observed that there is undervoltage, as discussed above.

In addition to the results presented in this technical report, other computational tests were carried out, such as the insertion of battery storage systems, which did not impact the reduction of load shedding, and therefore, were not presented in this work. In addition, the gradual insertion of microgrids was also evaluated, but as the objective was to show the behavior of the network given the insertion of multiple microgrids, the authors chose not to bring this theme, since the greater the number of microgrids, the more technical issues must be resolved and investigated, such as those evaluated here.

CONCLUSION

This paper aimed to develop a computational model with a coordinated operation of active distribution networks and multiple microgrids through a hierarchical framework. Three study cases were used, considering a maximum load shedding level, without it and adding PV distributed generation. The analyzes were carried out by observing the iterative feedback processes of the proposed model, verifying how the operation changes according to the suggested load cuts.

Case I was the scenario in which a maximum load shedding restriction is activated for the microgrids since load cuts do not bring financial advantages to the consumer. Therefore, a maximum load shedding rate of 5% has been inserted into the MOUG model. In this case, in three feedback processes, it was not possible to find a solution that would not violate the constraints of the grid and the microgrids simultaneously, since the ideal would be a load shedding greater than 14.6%. However, by relaxing the minimum voltage limit to

0.9 pu, it was not necessary to perform load cuts on the microgrids, and a dispatch was obtained for both systems (undervoltage being admitted). This result shows that an integrated planning of the expansion of active networks and microgrids would be necessary, however, considering the expansion and optimal operation of distributed energy resources and including other resources, such as voltage regulators or capacitor banks, present both in the active network and in the microgrids.

In case II, the results were presented with the four microgrids operating on the feeder without the load shedding restriction, which led to the convergence of the hierarchical process in the first feedback, requiring the adjustment and reduction of 19.99%, 18.8%, 15.97%, and 31.36% of loads of microgrids 1, 2, 3 and 4, respectively, compared to the initial proposition. This factor significantly increases the costs related to microgrids, with the largest increase occurring for microgrid 4. Initially, its operating cost, which was 5,338.31 BRL, became 13,450.40 BRL, that is, an increase of 251 .96%.

Finally, at several points of the feeder, distributed photovoltaic generation sources were inserted (case III), so that the network started to operate as an active distribution network. DG helps to reduce the variation of the ideal dispatch for microgrids to 9.09%, 8.77%, 7.27%, and 14.23% for microgrids 1, 2, 3, and 4, respectively, reducing operating costs that were previously from R$ 148,763.98 to R$ 133,742.08, as well as the electrical losses that went from 9.43 MWh per day to 7,778 MWh per day.

Thus, the great importance of optimal operation planning and integrated expansion of emerging distribution networks is highlighted. There is a need for new computational developments to carry out planning studies of the optimal expansion integrated into the optimal operation of microgrids and active distribution networks, aiming at the economy, energy quality, and reliability.

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