Tri-level optimization of industrial microgrids considering renewable energy sources, combined heat and power units, thermal and electrical storage systems

M.S. Misaghian [1], M. Saffari[1], M. Kia [2], A. Heidari [3*], M. Shafie-khah [4], J.P.S. Catalão [4,5,6*]

[1] *Faculty of Electrical Engineering, Shahid Beheshti University, A.C, Tehran, Iran*
[2] *Faculty of engineering, Pardis branch, Islamic Azad University, Pardis, Iran*
[3] *School of Electrical Engineering and Telecommunications, University of New South Wales, Sydney, Australia*
[4] *C-MAST, University of Beira Interior, 6201-001 Covilhã, Portugal*
[5] *INESC TEC and the Faculty of Engineering of the University of Porto, 4200-465 Porto, Portugal*
[6] *INESC-ID, Instituto Superior Técnico, University of Lisbon, 1049-001 Lisbon, Portugal*

[*] *alireza.heidari@unsw.edu.au (A. Heidari) and catalao@ubi.pt (J.P.S. Catalão)*

Abstract:

This paper presents a new framework for optimizing the operation of Industrial MicroGrids (IMG). The proposed framework consists of three levels. At the first level, a Profit Based Security Constrained Unit Commitment (PB-SCUC) is solved in order to minimize the total expected cost of IMG via maximizing the IMG revenue by transacting in the day-ahead power market and optimizing the scheduling of the units. In this paper, the tendency of IMG for participating in the day-ahead power market is modelled as a quadric function. At the second level, a Security Constrained Unit Commitment is solved at the upper grid for minimizing the upper grid operation and guaranteeing its security. At this level, the accepted IMG bids in the day-ahead power market would be determined. Finally, at the third level, the IMG operator must settle its units on the basis of its accepted bids. Therefore, a rescheduling problem is solved in the third level. Notably, Renewable Energy Sources (RESs), Combined Heat and Power (CHP) units, thermal and electrical storage systems are considered in the IMG. As the RESs and day-ahead market price have stochastic behaviours, their uncertainty is taken into account by implementing stochastic programming. Further, different cases for grid-connected and island modes of IMG are discussed, and the advantages of utilizing RES and storage systems are given. The simulation results are provided based on the IEEE 18-bus test system for IMG and IEEE 30-bus test system for the upper grid.

Keywords: industrial microgrid; day-ahead market; scheduling; renewable energy sources; uncertainty; stochastic programming.

Indices

b	Index of auxiliary boilers
ESS	Index of electrical storage systems
i	Index of CHP units
i_{cu}	Index of CU regarding upper grid
k	Index of day-ahead market price scenario
n, m	Index of buses
s	Index of RESs scenario
t	Index of time periods
th	Index of thermal group
TSS	Index of thermal storage systems

Binary Variables

$u_{i,t,ks}$	On/Off state of unit i at time t and scenario ks
$\kappa_{i,t,ks}$	1 if unit i starts at time t and scenario ks
$\kappa''_{i,t,ks}$	1 if unit i is shut down at time t and scenario ks

Continuous Variables

D_t^{IMG}	Electrical demand of IMG at time t
$D_{(th),t}^{thermal}$	Thermal demand of group thermal group th at time t
$Flow_{nm,t,ks}$	Active power flow from bus n to bus m at time t and scenario ks
$H_{b,t,ks}$	Generated heat by boiler b at time t and scenario ks
$H_{TSS,t,ks}^{D}$ / $H_{TSS,t,ks}^{C}$	Generate/Absorb power of TSS at time t and scenario ks
$Hcap_{TSS,t,ks}$	State of charge of storage TSS at time t and scenario ks
$P_{mg,t,k}$	Transacting value of upper grid with the IMG at time t and scenario k
$P\_buy_{tk}^{IMG}$	IMG Bidding for buying power at time t and scenario k
$P\_sell_{tk}^{IMG}$	IMG Bidding for selling power at time t and scenario k
P_{tk}^{DA}	Buying /selling active power from/to the day-ahead market at time t and scenario k
$P_{ESS,t,ks}^{D}, P_{ESS,t,ks}^{C}$	Discharge/Charge power of ESS at time t and scenario ks
$P_{t,ks}^{pv}$	Output of PV unit at time t and scenario ks
$P_{t,ks}^{wind}$	Output of wind unit at time t and scenario ks

$S_{ESS,t,ks}$	State of the charge of storage ESS at time t and scenarios ks
$SU_{i,t,ks}$	Start-up cost of unit i at time t and scenario ks
$SD_{i,t,ks}$	Shutdown cost of unit i at time t and scenario ks

Constants

C_i^{SU}	Start-up offer cost of unit i
C_i^{SD}	Shutdown offer cost of unit i
$Flow_{nm}^{Max}$	Maximum flow between buses n and m
$\overline{H}_b$ / $\underline{H}_b$	Maximum/Minimum power of boiler b
$\overline{H}_{TSS}^{C}$ / $\overline{H}_{TSS}^{D}$	Maximum of absorbing/generating heat by storage TSS
$Hcap_{TSS}^{max}$ / $Hcap_{TSS}^{min}$	Maximum/Minimum capacity of storage TSS
$P\_buy_{t,k}^{MG\text{-}acc}$	Accepted value of IMG bid for buying power at time t and scenario k
$P\_sell_{t,k}^{MG\text{-}acc}$	Accepted value of IMG bid for selling power at time t and scenario k
$\overline{P}_{ESS}^{C}$ / $\overline{P}_{ESS}^{D}$	Maximum of charging/discharging power by storage ESS
$\overline{P}_{mg,t,k}$	Maximum allowable transacting power of upper grid with IMG at time t and scenario ks
RU_i / RD_i	Ramp up/down of unit i
$\overline{S}_{ESS}$ / $\underline{S}_{ESS}$	Maximum/Minimum capacity of storage ESS
T_i^{on} / T_i^{off}	Minimum on/off time of unit i
x_{nm}	Reactance of line between buses n and m
α_i, β_i, λ_i	Cost coefficients of ST units
$\alpha_{mg,t}$, $\beta_{mg,t}$, $\lambda_{mg,t}$	Cost coefficients of IMG bidding quadric function at the second level of optimization process at time t
ρ_{tk}	Price of day-ahead active power market at time t and scenario k
$\rho_{ESS}^{degradation}$	Degradation cost of ESS
$\rho_{TSS}^{degradation}$	Degradation cost of TSS
ρ^{gas}	Gas price
ρ_i^{OM}	Operation and maintenance price of unit i
η_b^{boiler}	Efficiency factor of boiler b

η_i^{CHP}	Efficiency factor of unit i
$\eta_{ESS}^{C}, \eta_{ESS}^{D}$	Efficiency factors of storage ESS in charging and discharging modes, respectively.
$\eta_{TSS}^{C}, \eta_{TSS}^{D}$	Efficiency factors of storage TSS in absorbing and generating modes, respectively.
υ_i	Waste heat factor of CHP unit i
Abbreviation	
CFTOOL	MATLAB Curve Fitting Tool Box
CHP	Combined Heat and Power
CU	Conventional Units
DER	Distributed Energy Resources
ESS	Electricity Storage System
GT	Gas Turbine
IMG	Industrial MicroGrid
IMGO	Industrial MicroGrid Operator
LHS	Latin Hyper Cube Sampling
MG	MicroGrid
MILP	Mix-Integer Linear Programming
MINLP	Mix-Integer Non Linear Programming
MT	Micro Turbine
NG	Natural Gas engine
PB-SCUC	Price Based- Security Constrained Unit Commitment
PV	Photovoltaic
RES	Renewable Energy Source
SCUC	Security Constrained Unit Commitment
SMILP	Stochastic Mix-Integer Linear Programming
ST	Steam Turbine
TSS	Thermal Storage System
UGO	Upper Grid Operator

Noted, Set $\bullet$ runs from 1 to $N_{\bullet}$

1. Introduction

MicroGrid (MG) is an electrical network structure, which leads to use Distributed Energy Resources (DERs) in a secure and reliable way. In addition, it can connect to or disconnect from the grid to enable it to operate in both grid-connected or island modes[1]. The local loads of an MG must be supplied in islanded mode. However, the presence of intermittent Renewable Energy Sources (RESs) put challenges ahead of secure operation of MG. Consequently, dispatchable energy resources like Combined Heat and Power (CHP) units become more popular among MG developers. On the other side, integration of renewable energy becomes a salient issue as they assist in reducing greenhouse gas emissions, environmental concerns and lead to guarantee energy security and sustainability of various energy sources[2].

The utilization of CHP systems is on the rise, which conducts to the grow of the interdependencies of electricity and heat systems[3]. Efficient CHP units lead to a reduction in energy costs and also diminution in emissions in comparison to power-only and boilers units[4]. According to the United States Department of Energy (DOE), employing CHP units has significant advantages, including the intensification of the energy security, improvement in resiliency of the energy infrastructure, enhancement in energy efficiency, and proceed the climate change and environmental targets by reducing emission[5]. The scheduling of CHP units takes the attention of many researches ([6-23]]). In[6], a new formulation of unit commitment for minimizing the Industrial MG (IMG) operational cost is given, while CHP and boilers are considered for supplying the thermal demand. However, the presence of RESs and the advantages of storage systems are not discussed. In [7], an innovation method on the basis of information gap theory for CHP units scheduling from the perspective of a generation company is presented, where the uncertainty of electricity market prices is considered. However, RESs and energy storage systems are not included in their work. Energy storage systems are foremost components of a system especially when intermittent RESs exist [8]. In [9], the role of energy storage systems in boosting the flexibility of CHP units and consequently decreasing the curtailments of wind power units is discussed. However, the uncertainties of wind power and the network constraints are ignored in that paper. A cooperatively and independently operation of CHP and wind units for participating in electricity market is presented in [10], where shows that a joint operation of CHP and wind units can decrease the overall net imbalance of the producers and result in growing their profits, nevertheless, stochastic behaviour of market prices and wind units are not considered in their work. In [11], a decentralized approach for CHP dispatch is presented on the basis of benders decomposition method, where the operational flexibility of power system is assessed by taking the advantages of heat storage systems. Although wind power is considered in their work, its uncertainty is ignored. Moreover, transactions in the power market are not considered in their model. In [12], a reliability assessment for specifying the number and size of CHP units, boilers, and heat storage systems for a large residential campus is done, however, no RES is contemplated. In [13], an innovative structure for sizing strategy of an MG is presented, where CHP and RESs are considered, and three different types of ESSs are modelled. However, their model lacks the presence of TSS and also the power flow constraints of MG. In [14], optimal scheduling of CHP units problem by considering thermal and electrical storage systems is presented, while the contingency security constraints of the system are considered, but the presence of RESs is not scrutinized. In [15], short-term scheduling of CHP units is presented, in which auxiliary boilers, Thermal Storage System (TSS), and conventional power units are taken into account. In [16], a CHP scheduling problem is discussed, while the stochastic behaviour of pool market price and load are taken into account, however, the configuration of the IMG and the existence of RES are considered neither in [15] nor [16]. Reference [17] presents an approach for generation scheduling of electricity and heat in an IMG. Although Photovoltaic (PV) units and electrical storages are considered in [17], the uncertainty of PV and market price and the presence of TSS are not discussed. In [18] and [19] the advantages of using CHP units in the active distribution systems are presented. In [18], linearization techniques are utilized for linearizing the problem of scheduling CHP units, further, the contingency of the system is considered that makes the model a two-stage stochastic problem. Further, in [19], the optimal scheduling of CHP units in the active distribution system is presented, while the inter-zonal power exchange of the system is discussed. Both in [18] and [19], the Electricity Storage Systems (ESSs), TSS and technical constraints of network are taken into account, however, the uncertainty of RES and market price are not considered. In [20], a novel model for optimal scheduling of CHP units of an MG is presented, while industrial customers are contemplated. Their novelty centres on introducing a formulation that takes into account inter-zonal power exchanges of industrial customers and also considers dynamic dependency of heat and electric systems. However, their model lacks RESs and their relevant uncertainties. In [21], a stochastic programming method is introduced for short-term scheduling of CHP-based MGs in order to maximize the profit. In their proposed framework, the uncertainty of wind and market price are considered, but the technical constraints of MG network are not included, further, the presence of PV units is neglected. A multi-objective optimization, including the minimization of cost and emission for the optimal energy management of an MG is presented in [22], where the CHP, boilers, ESS, and TSS and the uncertainty of load and price are contemplated, however, the network configuration, wind, and PV units are neglected. In [23], a multi-objective optimization approach for an MG comprised of CHP, wind and PV units, and hydrogen storages is presented for concurrent consideration of various objectives, including profit, emission, and reliability indices. However, its main study is concentrated on efficacious impact of using multi-objective technique and also their MG is devoid of TSS. In [24], an innovative formulation for scheduling and bidding of an MG is presented, where the thermal dynamics features of the buildings are considered. In their proposed framework, heating, ventilation, and air-conditioning system, uncertain wind and PV units, and the batteries are taken into account and the MG can participates in the market by bidding, however, the network configuration, CHP units, and TSSs are not captured in their work. In [25] the MG bidding in the power market is scrutinized. Indeed, a hybrid stochastic/robust optimization method is proposed for MG biding in the active power market. In their proposed model, the uncertainty of wind and PV units is considered, however, the network configuration, thermal demand, and CHP units are neglected. In [26], an optimization method is presented for specifying the MG biddings in the day-ahead power market and scheduling of its generation units, while in addition to market price uncertainty, RESs along with their uncertainties are considered. Nonetheless, CHP units, TSS, and thermal demands are not taken into account. In [27], a two-stage stochastic optimal scheduling of MG with the aim of minimizing the expected operational cost and power losses is presented, while the intermittent nature of renewable energies is considered, but the thermal demand and CHP units are not contemplated. In [28], a novel optimization framework is presented for scheduling of an MG that consists of uncertain RESs, dispatchable DGs, and ESS. However, its authors mainly concentrate on MG operation under unfolding islanding mode. Besides, they do not take into account power flow constraints and their considered MG is without CHP and TSS units.

It is worth noting that, in addition to electrical loads, thermal demands are considered in the current paper. There are multiple sources for providing heat in a system. Some papers ([29-31])

investigate units like ground-coupled heat pump for supplying thermal loads and some articles ([6, 14, 17-20]) consider CHP units, boilers, and TSS units to provide heat. In this context, in this current paper, CHP, axillary boilers, and TSS are taken into account for supplying thermal loads.

In the present research, RESs, including wind units and PV units are modelled, while their uncertainties are contemplated. The network configuration and its technical constraints are considered. In addition, the IMG can participate in the day-ahead market via bidding, while the uncertainty of market price is considered. For showing the advantages of grid-connected mode over island mode, a cost comparison is given. For optimal scheduling of IMG units and determining the values of its transaction in the day-ahead market, a stochastic Price Based-Security Constrained Unit Commitment (PB-SCUC) problem is solved in the IMG.

Overall, for solving a unit commitment problem, various methods exist. For instance, genetic algorithm and harmony search algorithm are respectively utilized in [32] and [33]. Further, the particle swarm optimization is employed by [34] and [35]. On the other hand, both classical optimization approach and decomposition methods such as Lagrangian relaxation [36] and Benders decomposition [37] are used. In addition, mathematical programming algorithm such as Mix-Integer Linear Programming (MILP) [38] and Mix-Integer Non Linear Programming (MINLP) [39] approaches are applied in various literature. Taking everything into account, mathematically optimization techniques, like MILP method, lead to the global optimum solution, however, the heuristic methods such as particle swarm optimization or genetic algorithm may reach to a local optimum solution as they consider a limited area of search space [18].

Generally, some of the aforementioned reviewed articles consider upstream network, and they take attention to the possibility of MGs to participate in the power markets and transacting with their upper grid, however, some of them ignore the uncertainty of market price. The comparison study for this concept is given in Table 1. In the current research, in addition to uncertain RESs, the uncertainty of day-ahead market price is captured by Latin Hyper Cube Sampling (LHS) method, which can completely cover the range of random variable variations [40]. Notably, neither of the references [6-28] consider the configuration of the upper grid and also the results of the IMG biddings are not discussed in them. As a novelty, the upper grid structure is considered in this paper. For showing the novelty and advantages of the current article over the existing literature, a survey has been conducted for comparing the current work with others. Table 1 illustrates this comparison.

Table 1.

Comparison of This Paper with Other Articles

References		[17]	[33]	[32]	[38]	[34]	[35]	[37]	[39]	[24]	[21]	22]	[14]	[18]	[19]	**[26]**	**[23]**	**[28]**	**[20]**	**This paper**
Method	MILP	×	×	×	✓	×	×	×	×	×	×	×	✓	✓	✓	✓	×	✓	✓	✓
	MINLP	✓	×	×	×	×	×	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×
	Heuristic	×	✓	✓	×	✓	✓	×	×	×	×	×	×	×	×	×	✓	×	×	×
Optimization Framework	Single level	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	×
	Multi-level	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓
CHP units		✓	✓	✓	✓	✓	✓	✓	✓	×	✓	✓	✓	✓	✓	×	✓	×	✓	✓
RES	Wind	×	×	×	✓	×	✓	×	×	✓	✓	×	×	×	×	✓	✓	✓	×	✓
	PV	✓	×	×	×	×	×	×	×	✓	×	×	×	×	×	✓	✓	✓	×	✓
Storage System	ESS	✓	×	×	✓	×	×	×	×	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	TSS	×	×	×	✓	×	×	×	×	×	✓	✓	✓	✓	✓	×	×	×	✓	✓
IMG Network Constraints		✓	×	✓	✓	✓	✓	×	×	×	×	×	✓	✓	✓	×	✓	×	✓	✓
Upper Grid Network Constraints		×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓
Grid Connected		✓	×	×	✓	×	×	×	×	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Model	deterministic	✓	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×
	stochastic	×	×	×	✓	✓	✓	×	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Stochastic Parameters	Wind	×	×	×	✓	×	✓	×	×	✓	✓	×	×	×	×	✓	✓	✓	×	✓
	PV	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	✓	✓	✓	×	✓
	Market Price	×	×	×	✓	×	×	×	✓	✓	✓	✓	×	×	×	✓	✓	×	✓	✓

Finally, a tri-level optimization framework is presented, in which a Stochastic MILP (SMILP) problem is solved. In the first level, a stochastic PB-SCUC problem is solved in order to schedule the CHP units, boilers and so forth. In addition, bided power of IMG in the day-ahead power market is released. After determination of the IMG biddings in the day-ahead market, the IMG bids are transferred into the MATLAB environment [41], and the tendency of IMG for participating in the day-ahead market would be estimated as a quadric function at each hour. Next, the quadric functions of all 24-hour are transferred into the GAMS software for optimizing the second level of the problem, where Upper Grid Operator (UGO) runs a Security Constrained Unit Commitment (SCUC) for optimizing the upper grid operation and analyzing the received bids. It is worth mentioning that, the upper grid configuration and its security constraints are well considered. Once the accepted bids have been determined by the UGO, the IMG Operator (IMGO) must then settle its units on the basis of the accepted bids. As a result, a rescheduling problem is done as a third level. Briefly, the main contribution of this paper can be highlighted as follow:

1. A tri-level optimization framework for IMG optimization is presented, in which the transaction of the IMG in the day-ahead market is contemplated, and the uncertainty of market price is considered. Further, the tendency of the IMG in the day-ahead market is modelled as a quadric function.
2. Optimal scheduling of an IMG is done, while the CHP units, uncertain RESs, TSSs, and ESSs are taken into account and as a contribution, the technical constraints of IMG and upper grid networks are considered.
3. The rescheduling problem is solved at the third level, while the acceptance of the IMG bids in the day-ahead market is considered. Furthermore, several scenarios, including grid-connected modes with the full bids acceptance, grid-connected with the impact of the upper grid configuration, and island modes are discussed.

The rest of paper is organized as follows. Section 2 represents the proposed model along with its mathematical formulations. Solution algorithm is given in Section 3. Numerical results and discussions are elaborated in Section 4. At last, the conclusion is drawn in Section 5.

2. Modelling and Formulating the Problem

In this section, the market framework is firstly described. Afterward, the structure of IMG and its transaction with the upper grid is discussed. Next, a brief description of optimization framework is elaborated. Finally, the mathematical formulations are represented.

1. Market Framework

Active day-ahead power market is considered in the current research. Fig. 1 depicts its framework. Observe that, IMG can submit bids in this market in order to purchase or sell active power. Afterward, the submitted bids are assessed by the upper grid operator, and the accepted ones would be declared.

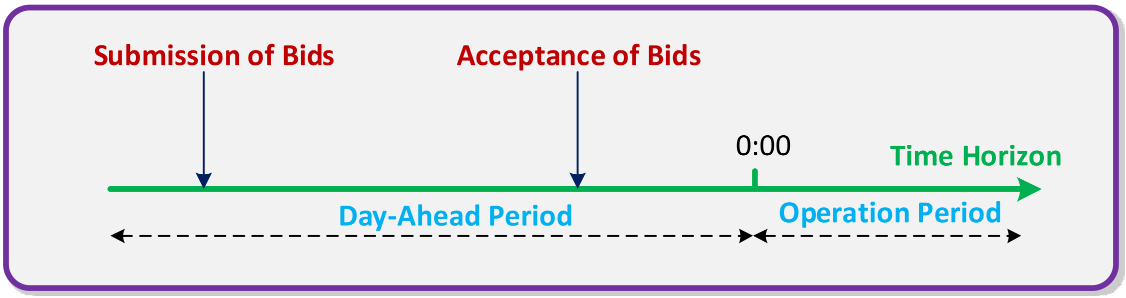

Fig. 1. Day-Ahead Power Market Framework

2. IMG and Upper Grid Structure

An IMG is considered in this current article, where comprises various units and also electrical and thermal loads. Besides, it is connected to one bus of its upper grid and can transact with it within the day-ahead power market. For clarifying, Fig. 2 illustrates the IMG and its upper grid and also shows how the IMG is connected to its upper network.

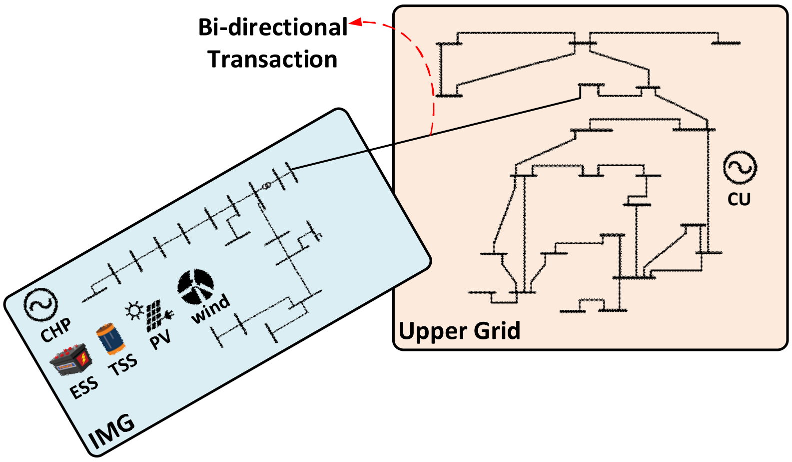

Fig. 2. IMG and Upper Grid Structure

3. Optimization Framework

A tri-level optimization problem is presented in this paper, where the first and third levels are regarding the IMG and the second level is concerning the upper grid. The object of establishing such a tri-level framework is motivated by encountering with challenges ahead of IMG for bidding in the day-ahead power market and transacting with its upper grid. The IMG is optimized on the basis of optimal scheduling of its units and its transaction with its upper grid. In other words, IMG biddings play an important role in the scheduling of its units and on the total expected cost of IMG. Hence, the final result of the IMG biddings would determine the final scheduling of units. A simple structure of the proposed algorithm is given in Fig. 3. As can be seen, at the first level of the optimization problem, a PB-SCUC problem is solved in the IMG, in which the scheduling of its units are determined. Furthermore, its optimal bids for participating in the day-ahead power market with the aim of transacting with its upper grid are specified, which are the outputs of this layer. Afterward, the optimal bids of IMG are entered as inputs in the second level of optimization, where a SCUC problem is solved in the upper grid and the receiving IMG bids (inputs of the second level) are considered. Once the second level of optimization has been finished, the accepted bids of IMG are then announced to the IMGO. Follows, the accepted bids of IMG are entered as inputs to the third level of optimization, where a redispatch is taken place in IMG. In the third level of optimization, IMGO must settle its units on the basis of its accepted bids in order to maintain the balance between generation and consumption. Section 3 delves into more details on this proposed framework.

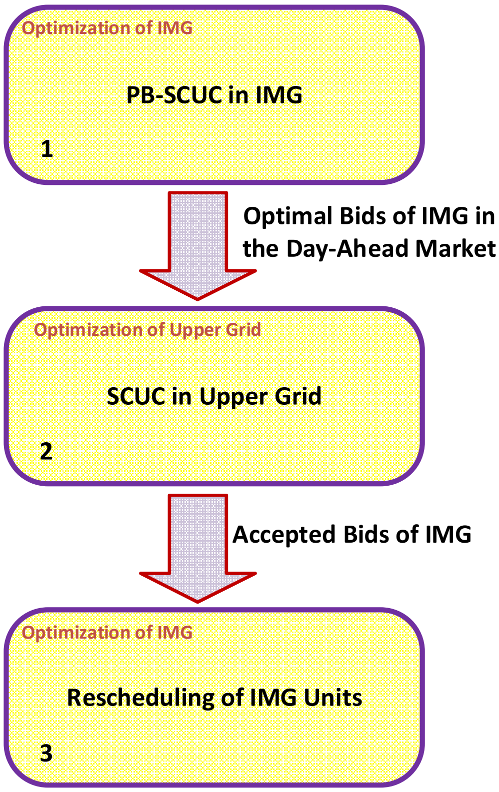

Fig. 3. Schematic of the Proposed Tri-level Framework

4. Mathematical Formulation

In what follows, the mathematical formulations for the proposed model are presented in the sequence of optimization levels.

A. First Level

The main goal of this paper is optimizing the IMG by settling its units and transacting with its upper network. At the first level of the optimization process, the IMG tries to optimize its operational procedure and submits its bids to the upper grid. As stated, a PB-SCUC problem is solved in this level. The objective function and the corresponded constraints are given as follow:

Objective function of the first level:

The objective function is given at (1), where $C(IMG)_k$ shows the cost of transaction of IMG with its upper grid (2), $C(CHP)_{i,ks}$ illustrates the cost of using CHP unit i (3) and (4), $C(Boiler)_{ks}$ presents the cost of using auxiliary boilers (5), and $C(ESS)_{ks}$, and $C(TSS)_{ks}$ stand for degradation cost of utilizing ESS (6) and TSS (7). It is assumed that no cost is considered for using wind and PV units.

$$Obj^{IMG} = min \sum_{k=1}^{N_k} \pi_k \left(C(IMG)_k + \sum_{s=1}^{N_s} \pi_s \begin{pmatrix} \sum_{i=1}^{N_i} C(CHP)_{i,ks} \\ +C(Boiler)_{ks} \\ +C(ESS)_{ks} \\ +C(TSS)_{ks} \end{pmatrix} \right) \tag{1}$$

$$C(IMG)_k = \sum_{t=1}^{N_t} \rho_{tk} \left(P\_buy_{tk}^{IMG} - P\_sell_{tk}^{IMG} \right) \tag{2}$$

$$C(CHP)_{i,ks} = \sum_{t=1}^{N_t} \left(\left(\frac{P_{i,t,ks}^{CHP}}{\eta_i^{CHP}} \times \rho^{gas} \right) + P_{i,t,ks}^{CHP} \times \rho_i^{OM} \right) \quad \forall i \in \{GT, NG, MT\} \tag{3}$$

$$C(CHP)_{i,ks} = \sum_{t=1}^{N_t} \alpha_i \left(P_{i,t,ks}^{CHP} \right)^2 + \beta_i P_{i,t,ks}^{CHP} + \lambda_i + \left(SU_{i,t,ks} + SD_{i,t,ks} \right) \;\; \forall i \in \{ST\} \tag{4}$$

$$C(\,Boiler\,)_{ks} = \sum_{b=1}^{N_b}\sum_{t=1}^{N_t}\frac{H_{b,t,ks}}{\eta_b^{boiler}} \times \rho^{gas} \tag{5}$$

$$C(ESS)_{ks} = \sum_{t=1}^{N_t}\sum_{ESS=1}^{N_{ESS}} \rho_{ESS}^{degradation}(P_{ESS,t,ks}^{D} + P_{ESS,t,ks}^{C}) \tag{6}$$

$$C(TSS)_{k,s} = \sum_{t=1}^{N_t}\sum_{TSS=1}^{N_{TSS}} \rho_{TSS}^{degradation}(H_{TSS,t,ks}^{D} + H_{TSS,t,ks}^{C}) \tag{7}$$

Subject to:

The technical constraints of CHP units, auxiliary boilers, ESS, TSS, wind and PV units are all considered. Moreover, as the configuration of the IMG is contemplated, the electrical and thermal constraints of IMG network must be taken into account as well. Notably, several types of CHP units are considered, including Gas Turbine (GT), Natural Gas engine (NG), Micro Turbine (MT), and Steam Turbine (ST), where their constraints are all given as follow.

- GT, NG, and MT units:

$$\underline{P}_i^{CHP} \le P_{i,t,ks}^{CHP} \le \overline{P}_i^{CHP} \tag{8}$$

- ST units:

$$\underline{P}_i^{CHP} u_{i,t,ks} \le P_{i,t,ks}^{CHP} \le \overline{P}_i^{CHP} u_{i,t,ks} \tag{9}$$

$$\kappa_{i,t,ks} - \kappa''_{i,t,ks} = u_{i,t,ks} - u_{i,(t-1),ks}$$

(10)

$$\begin{aligned} &P_{i,t,ks}^{unit} - P_{i,(t-1),ks}^{unit} \le RU_i \\ &P_{i,(t-1),ks}^{unit} - P_{i,t,ks}^{unit} \le RD_i \end{aligned}$$

(11)

$$\sum_{t}^{t-T_i^{on}+1} u_{i,t,ks} \geq \kappa_{i,t,ks} T_i^{on} \qquad (t=1,\dots,N_t - T_i^{on}+1)$$
$$\sum_{t}^{N_t} u_{i,t,ks} \geq \kappa_{i,t,ks} (N_t - t + 1) \qquad (t = N_t - T_i^{on} + 2,\dots,N_t) \tag{12}$$

$$\sum_{t}^{t-T_i^{off}+1} 1 - u_{i,t,ks} \geq \kappa''_{i,t,ks} T_i^{off} \qquad (t=1,\dots,N_t - T_i^{off}+1)$$
$$\sum_{t}^{N_t} 1 - u_{i,t,ks} \geq \kappa''_{i,t,ks} (N_t - t + 1) \qquad (t = N_t - T_i^{off} + 2,\dots,N_t) \tag{13}$$

$$SU_{i,t,ks} \geq C_i^{SU} \left(u_{i,t,ks} - u_{i,(t-1),ks}\right) \tag{14}$$

$$SD_{i,t,ks} \geq C_i^{SD} \left(u_{i,(t-1),ks} - u_{i,t,ks}\right) \tag{15}$$

- Axillary boilers:

$$\underline{H}_b \leq H_{b,t,ks} \leq \overline{H}_b \tag{16}$$

- ESS and TSS units:

$$0 \leq P_{ESS,t,ks}^{C} \leq \overline{P}_{ESS}^{C}$$
$$0 \leq P_{ESS,t,ks}^{D} \leq \overline{P}_{ESS}^{D} \tag{17}$$

$$S_{ESS,t,ks} = S_{ESS,(t-1),ks} + \eta_{ESS}^{C} P_{ESS,t,ks}^{C} - \frac{1}{\eta_{ESS}^{D}} P_{ESS,t,ks}^{D}$$
$$\underline{S}_{ESS} \leq S_{ESS,t,ks} \leq \overline{S}_{ESS} \tag{18}$$

$$0 \leq H_{TSS,t,ks}^{C} \leq \overline{H}_{TSS}^{C}$$
$$0 \leq H_{TSS,t,ks}^{D} \leq \overline{H}_{TSS}^{D} \tag{19}$$

$$Hcap_{TSS,t,ks} = Hcap_{TSS,(t-1),ks} + \eta_{TSS}^{C} H_{TSS,t,ks}^{C} - \frac{1}{\eta_{TSS}^{D}} H_{TSS,t,ks}^{D}$$
$$Hcap_{TSS}^{min} \le Hcap_{TSS,t,ks} \le Hcap_{TSS}^{max} \tag{20}$$

- Wind and PV units

The output power of wind generator, at time t and scenario s, can be written as:

$$P_{t,s}^{wind} = \begin{cases} 0 & if \ v_{t,s}^{wind} \le v_{ci}^{wind} \ or \ v_{t,s} \ge v_{co}^{wind} \\ P_r^{wind} \cdot \frac{(v_{t,s} - v_{ci}^{wind})}{(v_r^{wind} - v_{ci}^{wind})} & if \ v_{ci}^{wind} \le v_{t,s} \le v_r^{wind} \\ P_r^{wind} & otherwise \end{cases} \tag{21}$$

Where, P_r^{wind} is nominal power of wind turbines and $v_{t,ks}$, v_{ci}^{wind}, v_r^{wind},and v_{co}^{wind} are the actual speed of wind, cut-in speed of wind, nominal speed of wind, and cut-out speed of wind, respectively.

The available output power of PV unit at time t and scenario s, according to sunlight direction and ambient temperature can be achieved as:

$$P_{t,s}^{PV} = \eta^{PV} S^{PV} \Phi_{t,s} \left(1 - 0.005 \left(T_t^{amb} - 25\right)\right)$$

(22)

Where, η^{PV} is the efficiency of solar panel conversion, S^{PV} is the area of solar panel, T_t^{amb} is the ambient temperature, and $\Phi_{t,s}$ is the energy of solar radiation.

- Power Flow Constraints

$$\sum_{i=1}^{N_i} P_{n,i,t,ks}^{CHP} + P_{n,t,ks}^{wind} + P_{n,t,ks}^{pv} + P\_buy_{n,t,k}^{IMG} - P\_sell_{n,t,k}^{IMG} + \sum_{ESS=1}^{N_{ESS}} (P_{n,ESS,t,ks}^{D} - P_{n,ESS,t,ks}^{C}) - D_{n,t}^{IMG} = \sum_{\substack{m=1 \\ m \neq n}}^{N_m} Flow_{nm,t,ks} \tag{23}$$

$$Flow_{nm,t,ks} = \left(\frac{\delta_{n,t,ks} - \delta_{m,t,ks}}{x_{nm}} \right) \tag{24}$$

$$\left| Flow_{nm,t,ks} \right| < Flow_{nm}^{Max} \tag{25}$$

- Thermal Demand Constraints

CHP units, auxiliary boilers, and TSS can participate in supplying thermal loads. However, only the ones can supply thermal loads, where are in the vicinity of each other. The generated heat in each thermal group is presented in (26).

$$\sum_{i,b,TSS \in th} \left(\upsilon_i \times P_{i,t,ks}^{CHP} + H_{b,t,ks} + H_{TSS,t,ks}^{D} - H_{TSS,t,ks}^{C} \right) \geq D_{(th),t}^{thermal} \tag{26}$$

B. Second Level

At the second level of optimization, the UGO receives the bids of IMG. In this level, the operator's goal is to optimize its operation, while transacting with its lower IMG. In this level, a SCUC problem is executed by UGO in order to minimize total expected cost and maintain the security of the network. Therefore, the objective function and its concerning constraints are as follows:

Objective function of the upper grid:

$$Obj^{grid} = min \sum_{k=1}^{N_k} \pi_k \left(\sum_{i_{cu}=1}^{N_{i_{cu}}} C(CU)_{i_{cu},k} + C(IMG)_k \right) \tag{27}$$

The upper grid consists of Conventional Units (CU), their incorporation cost in (27) consists of a quadratic function and start/shutdown costs (analogous to (4) and (14)-(15) [24], [42]), which the piece-wise linear form of their quadratic function is implemented [18]. Here, the term $C(IMG)_k$, stands for the revenue/cost of selling/buying power to/from IMG, where the equation (28) shows the quadric form of it. $C(IMG)_k$ is positive when the UGO buys power from IMG through the day-ahead market and it is negative when the UGO sells power to the IMG via the day-ahead market. The positive/negative of $C(IMG)_k$ depends on the cost coefficients of (28). Notably, the linearization techniques are used for linearizing equation (28). Worth mentioning that, the variable $P_{mg,tk}$ in (28) is the amount of power that can be sold/bought in the day-ahead market by the UGO. If the UGO sells power to the IMG through the market, the variable $P_{mg,tk}$ would be a negative variable in (30), and also the term $C(IMG)_k$ would be negative, which shows the revenue of UGO by transacting in the market. On the contrast, $P_{mg,tk}$ would be a positive variable if the UGO buys power from IMG through the day-ahead market and also $C(IMG)_k$ would be positive, which shows the cost of buying power.

$$C(IMG)_k = \sum_{t=1}^{N_t} \left(\alpha_{mg,t} \left| P_{mg,tk} \right|^2 + \beta_{mg,t} \left| P_{mg,tk} \right| + \lambda_{mg,t} \right) \tag{28}$$

Subject to:

$$\left| P_{mg,t,k} \right| \le \overline{P}_{mg,t,k} \tag{29}$$

$$\sum_{i_{cu}=1}^{N_{i_{cu}}} P_{n,i_{cu},t,k} + P_{n,mg,t,k} - D_{n,t}^{grid} = \sum_{\substack{m=1 \\ m \ne n}}^{N_m} Flow_{nm,t,k}^{grid} \tag{30}$$

Similar to (24) and (25), the power flow constraints are considered in this level. As CU units are implemented in the upper grid network, the technical constraints of them are taken into account. Hence, ramp up/down, minimum up/down time, and start up and shut down constraints are well contemplated similar to constraints (9)-(13).

C. Third level

By realizing the values of accepted bids, IMG must settle its units. Therefore, a redispatch must be run in the IMG. The problem formulation of this level is given as follow:

Objective function of IMG:

$$Obj^{IMG} = min\sum_{k=1}^{N_k}\left(C_{Rescheduling}(IMG)_k + \sum_{s=1}^{N_s}\pi_s \begin{pmatrix} \sum_{i=1}^{N_i} C(CHP)_{i,ks} \\ +C(\,Boiler\,)_{ks} \\ +C(ESS)_{ks} \\ +C(TSS)_{ks} \end{pmatrix}\right) \tag{31}$$

According to (31), in this level, IMGO tries to utilize the most optimal units. The term $C_{Rescheduling}(IMG)_k$ is a parameter and is given in (32). $P\_buy_{n,t,k}^{MG\text{-}acc}$ and $P\_sell_{n,t,k}^{MG\text{-}acc}$ are parameters, and they stand for the accepted values of IMG bids for buying and selling, respectively. The term $C_{Rescheduling}(IMG)_k$ is constant, and it merely added to illustrate the final cost of IMG operation.

$$C_{Rescheduling}(IMG)_k = \sum_{t=1}^{N_t}\rho_{tk}\,(\,P\_buy_{n,t,k}^{IMG\text{-}acc} - P\_sell_{n,t,k}^{IMG\text{-}acc}\,) \tag{32}$$

Subject to:

Equations (8)-(22) are all considered in this level. In addition, the power balance constraint is altered and is given in (33). Further, equations (24) and (25) are taken into account. In addition, any changes in CHP outputs leads to alteration in supplying thermal loads. As a result, the equation (26) is considered with the new outputs of units in this level again. Because, any change in IMG bids may cause alternation in CHP outputs (33) and it directly affects the generated heat by CHP units. Consequently, the thermal balance must be considered again to guarantee that the thermal demand is supplied.

$$\begin{aligned} &\sum_{i=1}^{N_i} P_{n,i,t,ks}^{CHP} + P_{n,t,ks}^{wind} + P_{n,t,ks}^{pv} + P\_buy_{n,t,k}^{IMG\text{-}acc} - P\_sell_{n,t,k}^{IMG\text{-}acc} \\ &+ \sum_{ESS=1}^{N_{ESS}} (P_{n,ESS,t,ks}^{D} - P_{n,ESS,t,ks}^{C}) - D_{n,t}^{IMG} = \sum_{\substack{m=1 \\ m \neq n}}^{N_m} Flow_{nm,t,ks}^{IMG} \end{aligned} \tag{33}$$

3. Solution Algorithm

The outputs of wind and PV units are dependent on wind velocity and solar irradiance, which both have stochastic natures. On the other hand, because of the existing situation of the day-ahead market, it has stochastic behavior as well. Therefore, probability distribution function is utilized for considering the stochastic nature of aforementioned parameters.

For considering the stochastic behaviour of parameters, uncertainty simulation should be done that composes of two sections, including scenario generation and scenario reduction. Latin Hypercube Sampling (LHS) method is used for generating scenarios, and it is a technique for full covering the variations range of a random variable and it is more precisely in comparison with Monte Carlo random sampling [40]. Therefore, the LHS technique is exploited for generating scenarios for the output of wind, PV, and market prices. A huge number of scenarios is required for a precise discretionary estimate of the continuous random process. However, this may cause run-time increment of the problem and also occurring infeasibility in some cases. As a result, efficacious approaches are required to decrease the initial number of scenarios in such that the remaining scenarios have the best estimate of the initial set and contain the data of the initial scenario set. For reducing the scenarios, Kantorovich distance method is utilized. The concept of scenario reduction is on the basis of selecting a reference scenario, compare the selected one with other scenarios and eliminate the nearest scenario. As a result, the Kantorovich distance is utilized for finding the minimum distance between the initial scenario and the reduced one. Afterward, the scenario with the minimum Kantorovich distance would be deleted. Notably, the probability of the deleted scenario must be added to the reference scenario. Finally, the final scenarios with their probability would be achieved. More details on the Kantorovich distance method is available at [43].

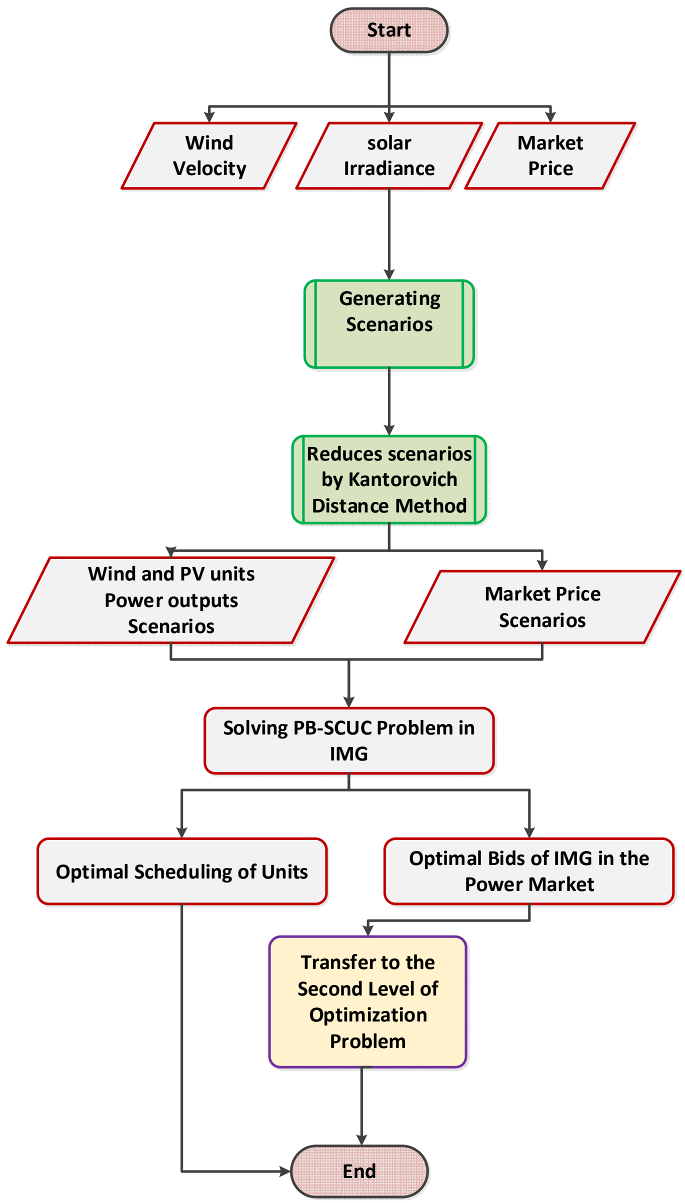

Fig. 4. Solution Algorithm of First Level of Optimization

By realizing the scenarios, the optimization process of IMG is started. According to Section 2.4.A, a PB-SCUC problem should be solved. As a result, the objective function of the first level and its corresponded constraints would be considered. Consequently, the optimal scheduling of units and optimal biddings of IMGO in the power market are realized. Fig. 4 depicts the solution algorithm of the first level.

As stated, distinct scenarios are taken into account for the day-ahead market price. So, the IMGO determines different bids on the basis of different market price scenarios at each hour for transacting with its upper grid. As a novelty, the determined bids of IMG at each hour are estimated as a quadric function. Then, these quadric functions are linearized by piece-wised method. For clearing the problem, the process is discussed as follows:

Once the values of IMG biddings in the power market have been determined for each scenario, and at each hour, they then should transfer to the second level in order to be analysed by the upper grid operator. Indeed, IMGO submits price-quantity pairs of bids in order to buy/sell power from/to the market. These pairs are depicted in orange circles in Fig. 5, where the circles on the vertical axis represent market price scenarios at each hour and the horizontal axis shows the IMG biddings in the day-ahead market at each hour and for each relevant market price scenario. They are discrete values; however, in the proposed framework, the discrete values are transferred into the MATLAB environment by linking GAMS and MATLAB. Afterward, by exploiting the MATLAB Curve Fitting Tool Box (CFTool)[41], they would be estimated as a quadric function at each hour. In other words, the IMGO would present a quadric function at each hour to the market. Fig. 6 shows the process of generating IMG biddings at each hour as a quadric function. As it is obvious in Fig. 6, at each hour, the bidding values and the day-ahead market price values for all scenarios are considered and by relying on the powerful features of CFTOOL, the quadric functions of IMG for participating in the day-ahead market would be achieved for each separate hour. Finally, it is expected to have quadric functions for each hour analogous to blue curves in Fig. 5.

As it demonstrates, the IMGO can bid for either buying or selling at each hour. Notably, the IMG cannot bid for buying and selling, simultaneously. According to Fig. 5, the bids for selling power to the market would be increased by rising in the market price. Nonetheless, the bids for buying power from the market would be decreased by increasing in the market price.

After being discerned the bidding curves of IMG, they are then transferred into the second level of optimization, where a SCUC problem is executed and the upper grid operator analyses the received bids from technical and economic points of view. As the quadric function makes the problem non-linear, the piecewise linearization method [18] is utilized for linearizing the problem. Hence, the linearized form of (28) is used in the second level of optimization. In the second level of optimization, the goal of operator is optimizing the operation of the grid by using its local units and transacting with its lower IMG. Once the optimization of the second level has been done, the scheduling of the upper grid and the accepted values of receiving bids of IMG are then determined.

Now, the IMGO must reschedule its units. In other words, as some of IMG bids are not accepted by the UGO, IMGO must maintain the balance between generation and consumption by making some changes to its local units. This rescheduling problem is done at the third level of the optimization process. Fig. 7 illustrates the optimization procedure, from the first level to the third one.

The solution algorithm of the problem is delineated in Fig. 8, where represents each level along with its corresponding objective function and constraints. In a nutshell, 1- “Scenario Generation and Reduction” block demonstrates the steps of achieving scenarios regarding wind, PV, and market prices. 2- “First Level of Optimization” block shows the PB-SCUC problem objective function and its constraints, which are regarding IMG. 3-“GAMS & MATLAB Interface” block illustrates transferring of IMG bids from the first level of optimization to the second level of optimization in the form of quadric functions via GAMS and MATLAB CFTOOL. 4-“Second

Level of Optimization" block presents the SCUC problem objective function and its constraints concerning upper grid. And finally, 5- "Third Level of Optimization" block represents the rescheduling of IMG units with its objective function and its relevant constraints.

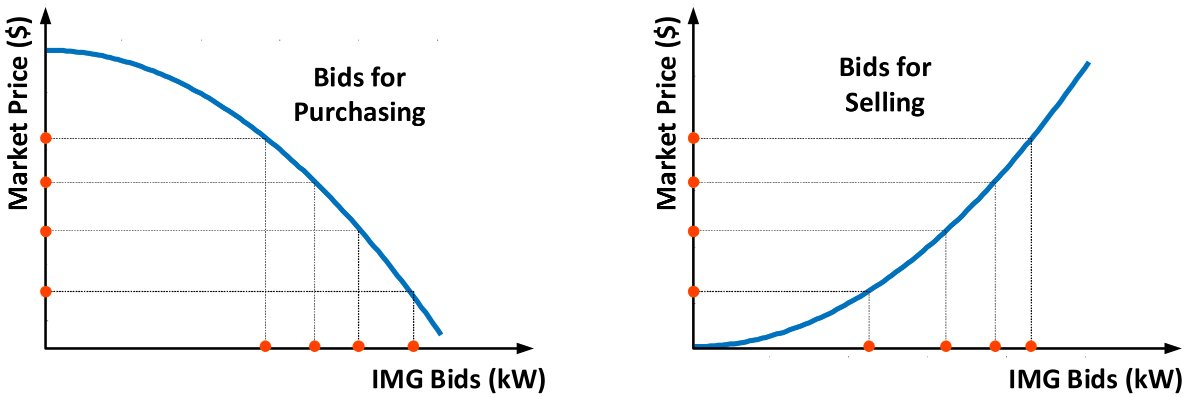

Fig. 5. The Expected Curves Concerning IMG Biddings at Each Hour

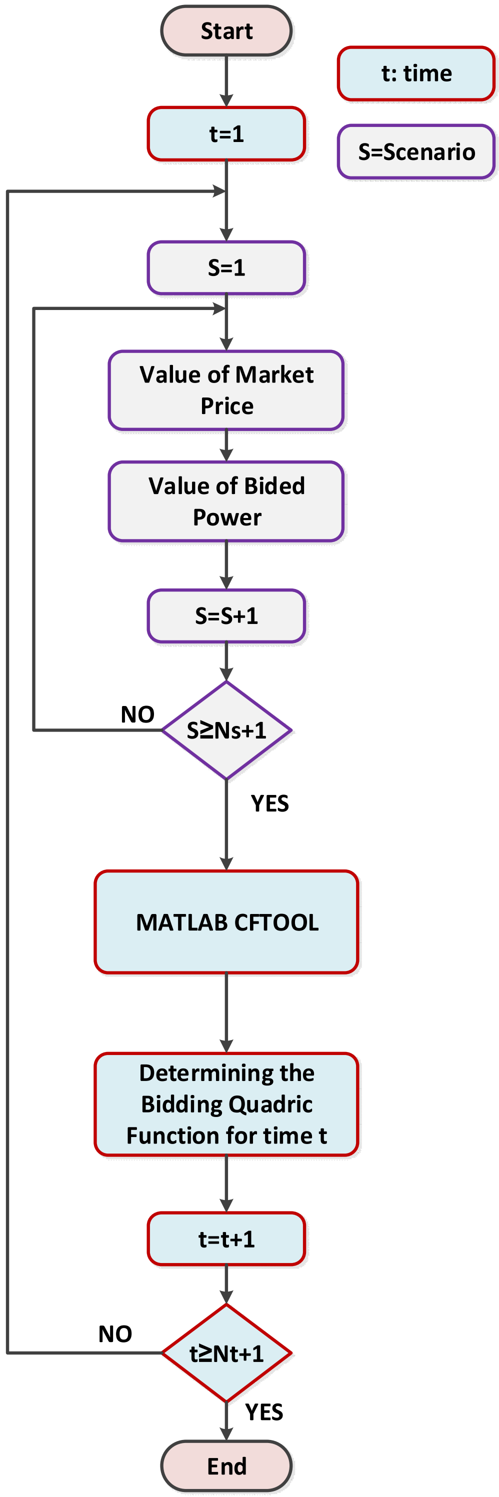

Fig. 6. Flowchart of Generating Biddings of IMG at Each Hour as a Quadric Function

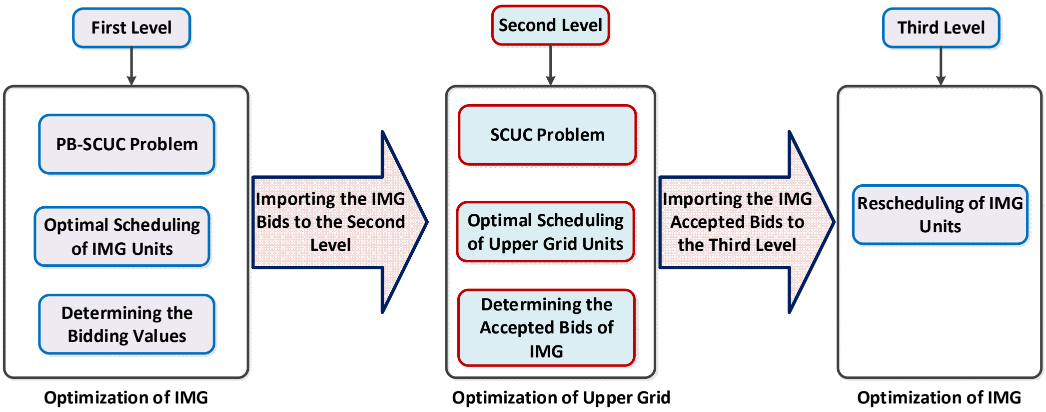

Fig. 7. Tri-level Optimization Structure

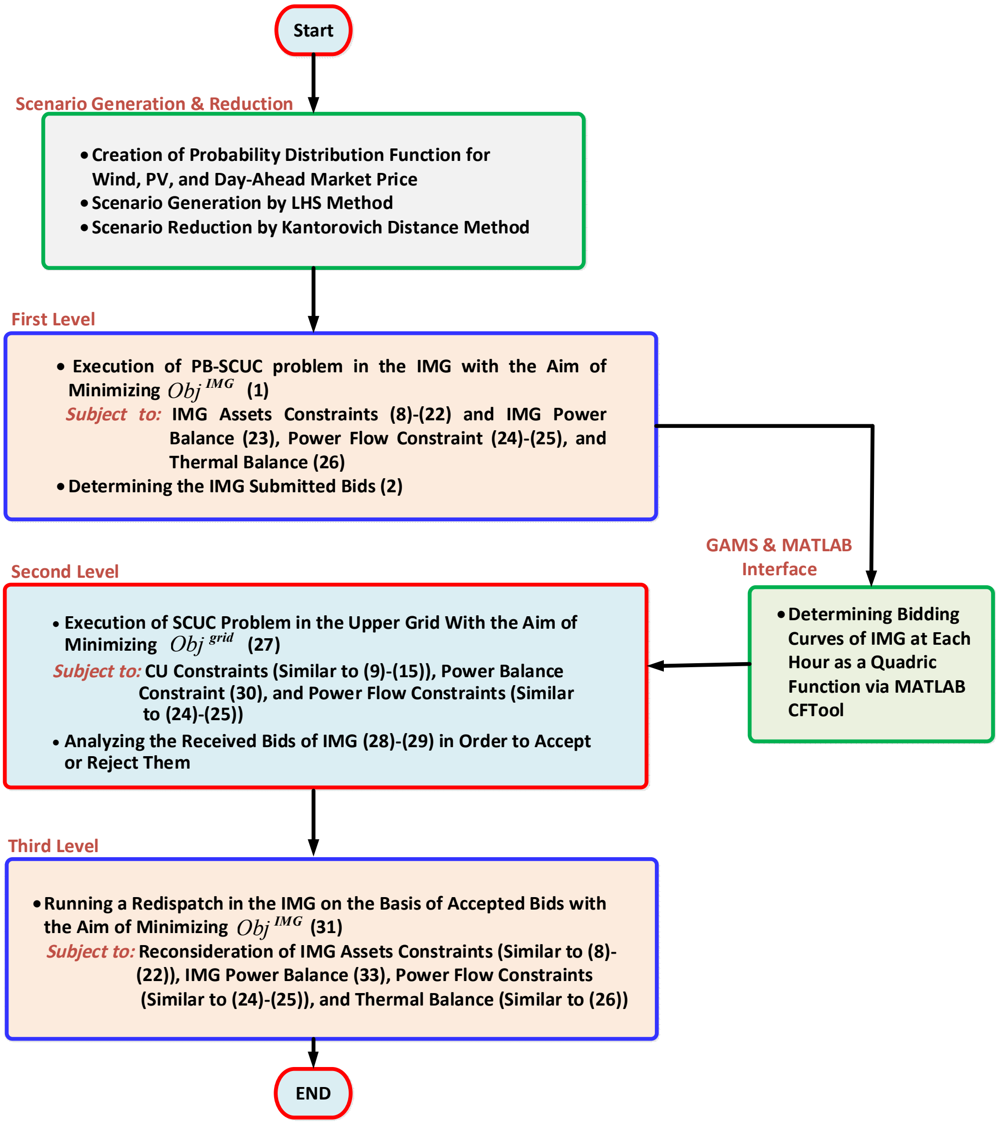

Fig. 8. Tri-level Optimization Flowchart on the Basis of Equations

4. Numerical Results and Discussion

1. Case Study

In order to show the advantages of the proposed model, a modified 18-bus IEEE test system [17] is considered, which consists of 12 factories, including 12 CHP units and 9 auxiliary boilers. Further, three ESSs, two TSSs, four wind units, and three PV units are added to the system. Noted, as the novelty of the current paper centers at bidding process of IMG in the market and its results on optimal operation of IMG, and in addition for simplicity, mechanical features of the turbines and generators such as steam quality and temperatures are ignored. Fig. 9 shows the modified 18-bus IEEE test system. Worth mentioning that, all factories can participate in supplying electrical demand. However, only the factories in the vicinity of the same thermal group can participate in supplying the thermal demand. In fact, factories 5, 10, and 12 have no thermal demand, and they merely generate electrical power. More details on technical features of units, ESSs, and TSSs are given in [14]. Additionally, 30-bus IEEE test case is utilized for the upper grid network[44]. Furthermore, it should be mentioned that, the only market that is considered in this paper is a day-ahead active power market. Fig. 10 shows its price and it is taken from reference [25]. In addition, the electrical and thermal loads of IMG are given in Fig. 11. In order to simulate the problem, GAMS software [45], which is one of the most powerful optimization software is utilized. As the problem is a stochastic mix-integer linear programming(SMILP), the CPLEX 11.2.0 linear solver from ILOG solver [46] is exploited for solving the problem.

2. Results Analysis

First and foremost, it should be noted that, this work is the developed model of our previous works ([14, 18-20]) and our initial results at the first level of optimization are verified on their basis. In what follows, the results of this current work are discussed.

As stated in Section 3, the outputs of the first level are in line with IMG. In this level, the scheduling of units in addition to its bids in the day-ahead market would be realized. The total output of CHP units is given in Fig. 12. Additionally, their values are illustrated in Table 2. As can be seen, CHP units average generation is approximately 8819 kW during 24-hour scheduling horizon. The outputs of auxiliary boilers are depicted in Fig. 13. It can be seen that auxiliary boilers generate heat in peak thermal hours, that is to say, the hours 9-19. Indeed, the IMGO prefers to utilize the cheaper units than the expensive ones and as CHP units are cheaper than boilers, the IMGO operator prefers CHP units. Hence, it is logical to turn on boilers merely in hours, in which the thermal demands are high, and CHP units cannot satisfy them alone.

Fig. 14 presents the behaviour of two considered TSSs for one selected scenario. It can be seen that in the hours 1-7 that the thermal demand is low, the TSSs absorb heat. In fact, the TSSs are empty in initial hours, and they must be charged before using. The CHP units are supplying electrical and thermal demands in hours 1-7, and indeed their surplus heat can be absorbed by TSSs. On the contrary, during the hours 9-19 that the thermal demand is high, the TSSs generate heat. Notably, TSSs are the cheapest heat providers as their operation costs are merely restricted to their degradation costs. Hence, it is logical to apply TSSs for supplying a fraction of thermal demand, when they are charged instead of increasing the outputs of boilers or CHP units.

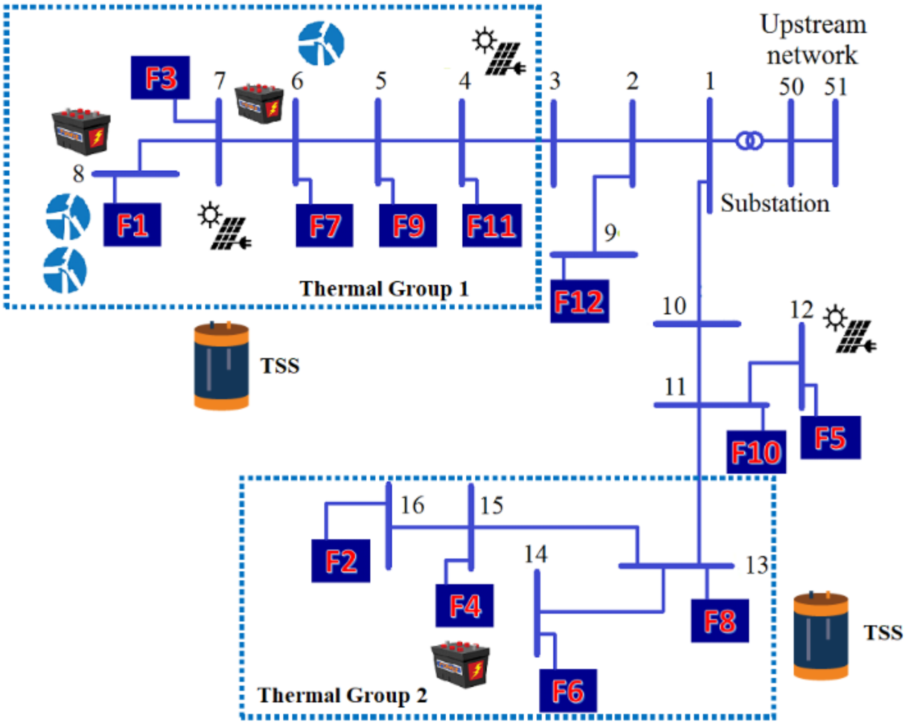

Fig. 9. Single-line Diagram of the Modified 18-bus IEEE Test System

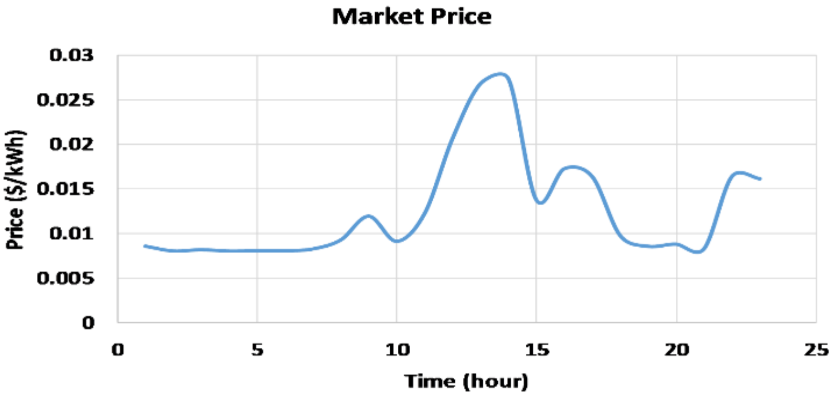

Fig. 10. Day-Ahead Market Price [6]

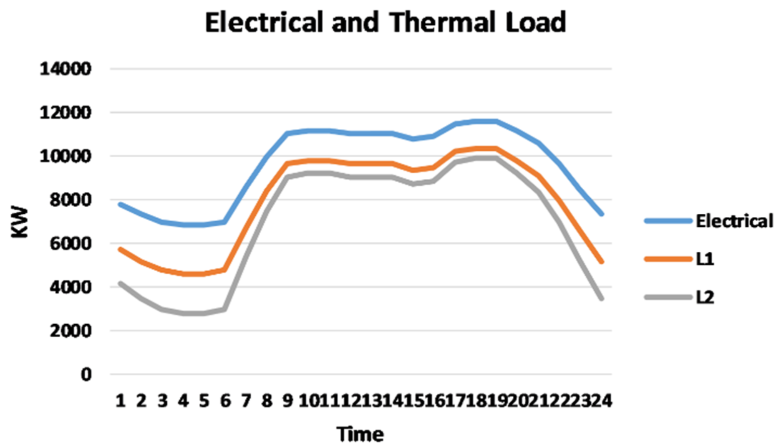

Fig. 11. Electrical and Thermal Load Profile

Similar to TSSs, ESSs operational costs are limited to their degradation costs, and this is a logical reason for IMGO to exploit ESSs to the full as they are cheaper than CHP units. An interesting behaviour of ESSs is depicted in Fig. 15. Notwithstanding the peak electrical load periods during hours 9-19, ESSs are charged. For discussing the reason for this behaviour, some points must be contemplated. Firstly, ESSs are charged by various units such as CHP units, wind and PV units. Further, thermal loads are at their peak periods during hours 9-19, and according to the previous discussion, it is economical to utilize CHP and TSS units for supplying thermal loads instead of using boilers. Hence, during hours 9-19, when thermal loads reach their peak, CHP units and TSSs are deployed by IMGO to provide heat. However, TSSs generate heat to their maximum allowable limit during this period, and they cannot generate more heat. In this way, it would be efficient to increase the output of CHP units for supplying thermal loads, which leads to a rise in the electrical and thermal generation of CHP units. Consequently, some fraction of generated electrical power by CHP units are utilized for supplying electrical loads and the surplus production of them must be employed for selling in the day-ahead power market and/or charging

ESSs. In this context, the submitted bids of IMG in the day-ahead power market is delineated in Fig. 16 and it is obvious that IMG submits its selling bids with the maximum allowable limit in the day-ahead market during hours 9-19. As the IMG bidding in the day-ahead market is restricted because of the line capacity, the remaining generated electrical power of CHP units would be stored in ESSs. On the other hand, during hours 20-24, which the market price has undergone a small increase and also the thermal demand has been decreased, ESSs are started to discharge in order to supply a fraction of the electrical load.

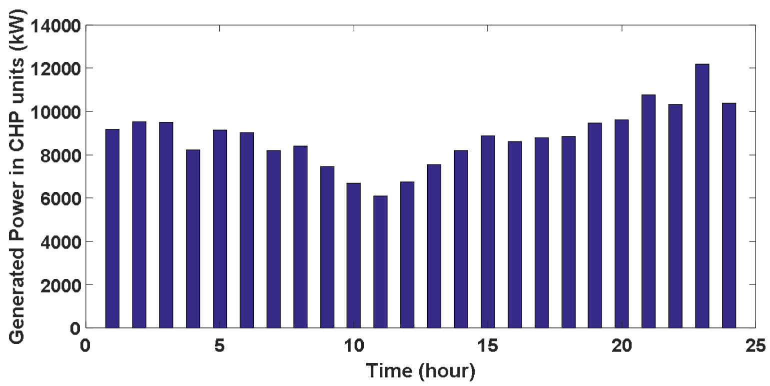

Fig. 12. Output Power of CHP Units in 24-hour

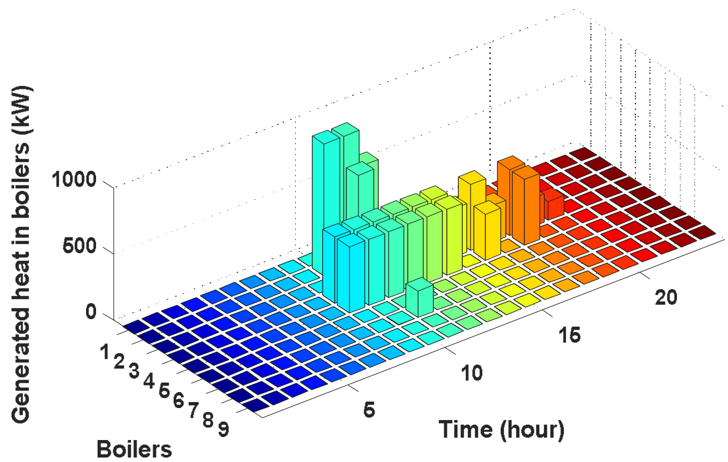

Fig. 13. Generated Heat of Auxiliary Boilers

Another significant feature of IMG is its biddings in the day-ahead market. It should be noted that the market price plays a prominent role in the tendency of IMG to participate in the day-ahead market. In fact, in order to earn revenue by selling power in the day-ahead power market or reduce operational costs by purchasing power from day-ahead power market, IMGO must consider the day-ahead market price. In other words, the IMGO's decision for transaction in the power market is dependent on the market price. The IMG biddings for one selected scenario are presented in Fig. 16. According to Fig. 10, the market price is low in the initial hours and because of that, the IMGO tends to buy power from the market to supply a fraction of its electrical demands instead of supplying them by its local units. Afterward, the market price increases steadily, which leads to reduction in the IMG bids for buying power from the market and this depletion in buying bids is continued to the point where the market price has changed so much that the IMGO prefers to submit selling bids in the day-ahead market (hours 9-19), and this selling process continues to the point that the market price falls again and as a result, the tendency for selling power reduces until the IMGO prefers to buy power from the market (hours 20-24).

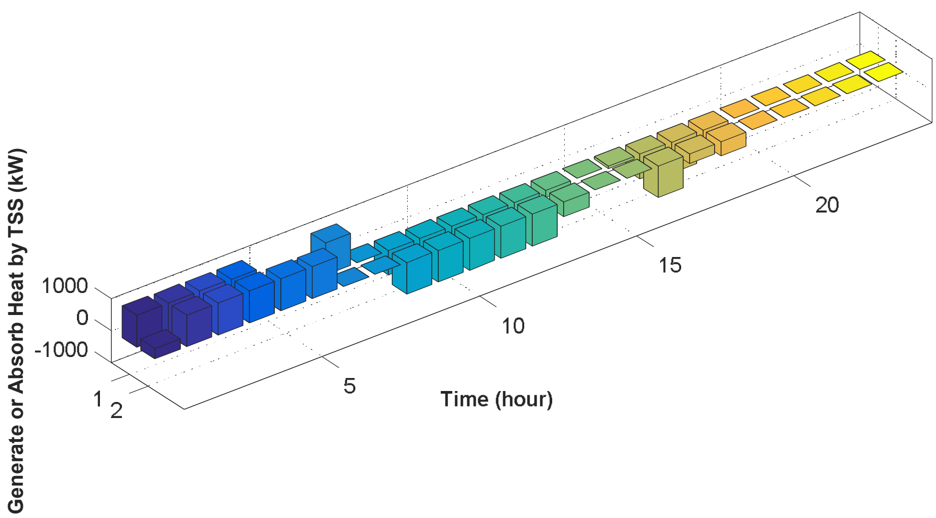

Fig. 14. Generate or Absorb Heat by TSSs

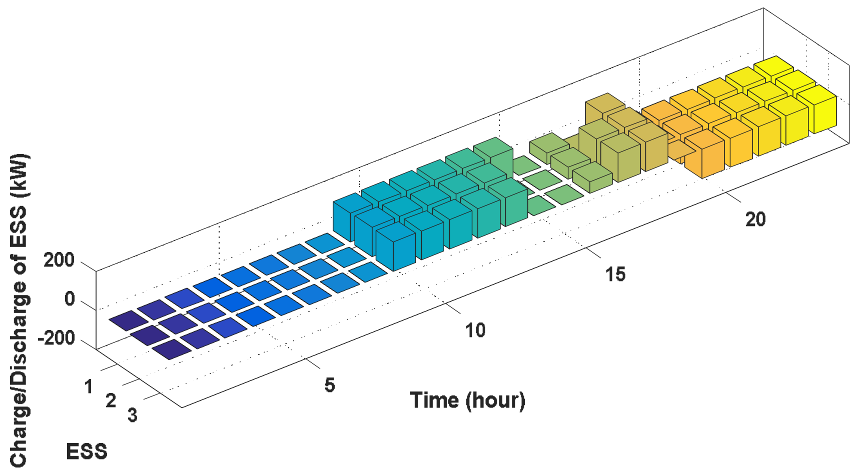

Fig. 15. Charge or Discharge of ESSs

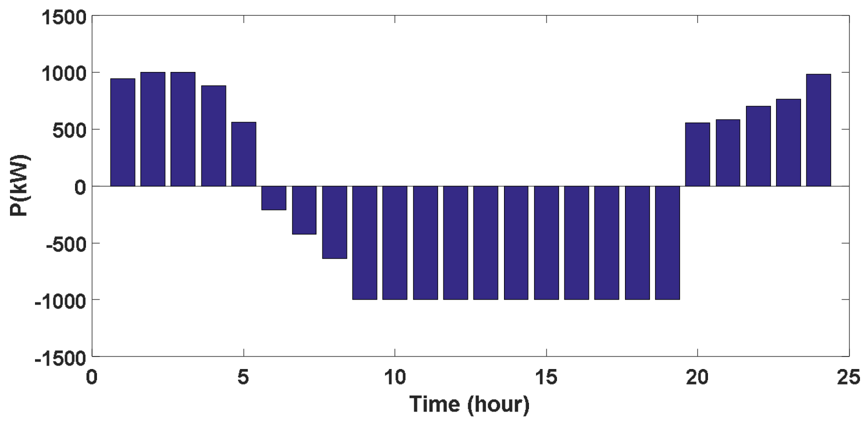

Fig. 16. IMG Biddings in the Day-Ahead Market

As discussed in Section 2.B and Section 3, the IMG bids in the day-ahead market are scrutinized by the UGO. Indeed, UGO wants to optimize its operation, and because of that, various sources such as its local units and its transaction with the day-ahead market must be analysed, and finally, the accepted bids of IMG would be realized. Fig. 17 illustrates the bids and accepted bids of IMG for one selected scenario. Overall, around 77% of the IMG bids in the day-ahead market is accepted. Notably, the presence of IMG has positive effects on the optimal operation of the upper grid. In this context, two distinct cases are considered for showing the virtues of the transaction with the IMG from the upper grid perspective. Case1 is the condition in which upper grid does not have any transaction with the IMG, and on the contrary, the transaction of upper gird with IMG is considered as Case2. Fig. 18 presents a comparison of the total expected cost of the upper grid operation for two considered cases. As can be seen, the total expected cost of the upper grid goes down from 115754 \$ to 115291 \$ that represents around 0.4% reduction in the operational costs of upper grid, which is reasonable by considering the scale of the IMG and the upper grid.

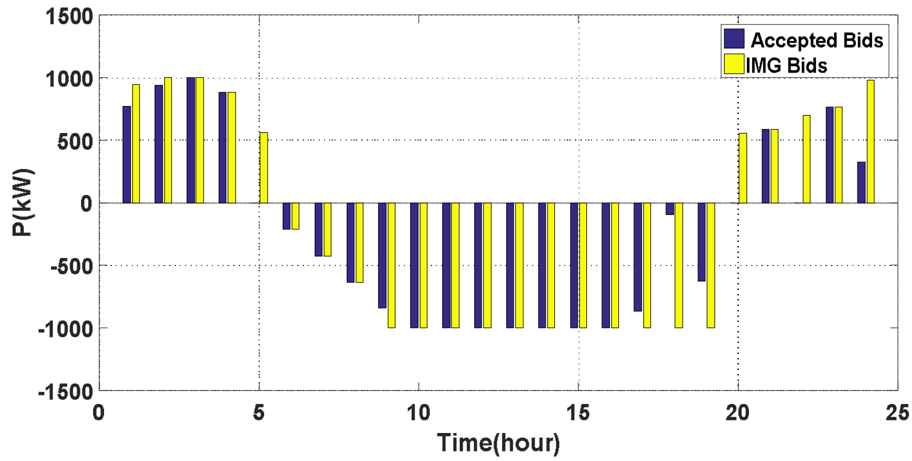

Fig. 17. Accepted Bids of IMG

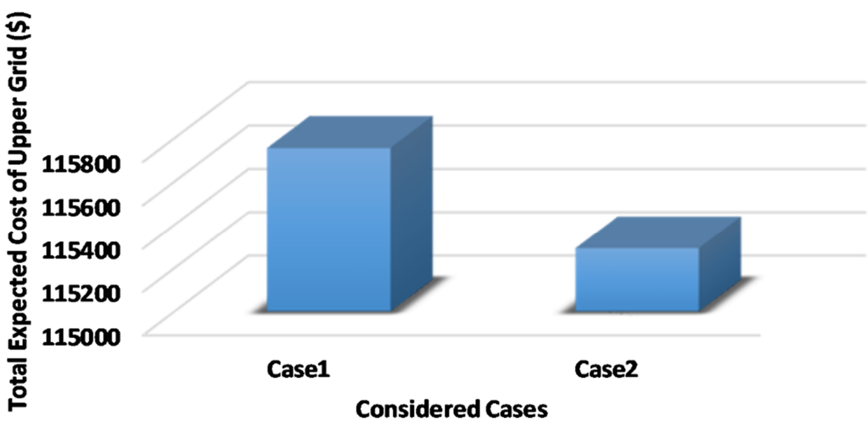

Fig. 18. Total Expected Cost of Upper Grid for Considered Cases

After the realization of the accepted bids, IMGO must reschedule its units. For showing this process, Fig. 19 presents the generated power in CHP units for first scheduling and rescheduling steps, namely the first and third levels, respectively. Additionally, Table 2 represents the output power of CHP units for 24-hour concerning the scheduling and rescheduling levels. As can be seen, CHP units' outputs remain the status quo at hours 2-4, 8-13, and 21-23. However, they rise at hours 1, 5, 6, 14, 15, and 24 and also decreases in hours 7 and 16-20. By way of illustration, outputs of CHP units rises by about 333 kW at the first hour. However, they go down by around 185 kW at hour 7. Fig. 20 illustrates the reduction or increase in CHP units' outputs in comparison with their first-level schedule. Similarly, the diminution or rise in boilers output in comparison with their first-level schedule is depicted in Fig. 21. Furthermore, for a better showing of falling and increasing trends in boilers' outputs, Fig. 22 represents this trend for some selected boilers, which their outputs altered more than others. Take the fourth boiler as an example; its output decreases 144 kW and 312 kW at hours 15 and 16, respectively. Nevertheless, it increases in order by about 223 kW and 286 kW at hours 17 and 19. By considering everything into account, it is obvious that in some hours the first-scheduled units increase or decrease their output powers. However, the justification of this process depends on the many existing stochastic variables and it is beyond the scope of this paper as the behaviour of many variables should be analysed.

Table 2

Output Power of CHP Units During 24-hour

Time (hour)	Total CHP Outputs (kW)		Time (hour)	Total CHP Outputs (kW)	
	Scheduling	Rescheduling		Scheduling	Rescheduling
1	9163.11	9496.44	13	7551.29	7551.29
2	9533.05	9533.05	14	8198.38	8348.38
3	9478.96	9478.96	15	8867.38	8987.38
4	8216.90	8216.90	16	8599.99	8419.99
5	9140.26	10140.26	17	8775.20	8625.20
6	9024.63	10024.63	18	8830.45	8624.20
7	8185.08	8000.00	19	9470.98	9112.50
8	8387.77	8387.77	20	9604.43	9593.62
9	7466.10	7466.10	21	10760.82	10760.82
10	6680.94	6680.94	22	10330.05	10330.05
11	6092.90	6092.90	23	12183.00	12183.00
12	6731.14	6731.14	24	10381.40	11381.40

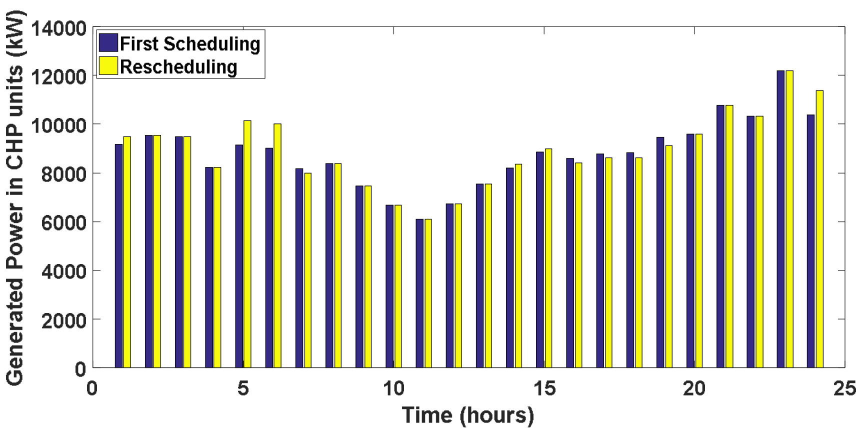

Fig. 19. Comparison of Rescheduling with First Scheduling of CHP Units

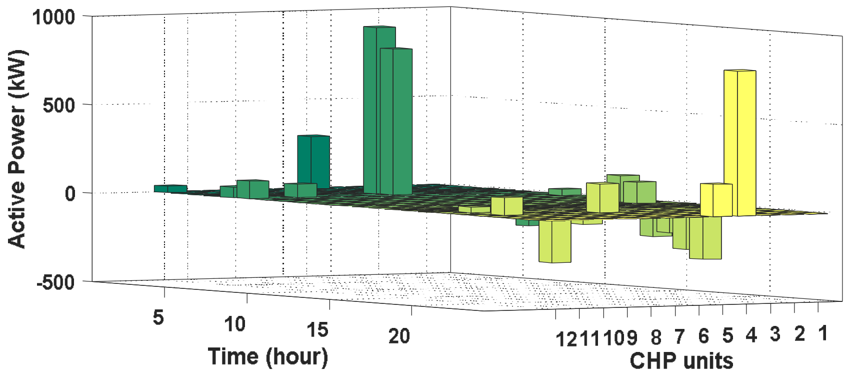

Fig. 20. Reduction or Increase in CHP Units' Outputs after Realization of Accepted Bids

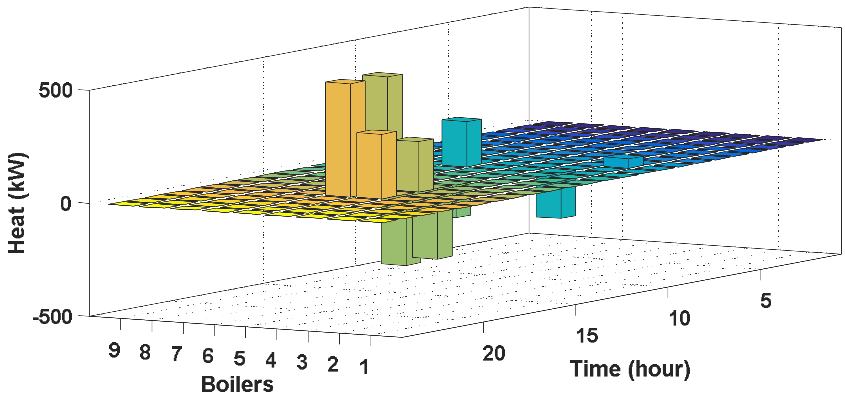

Fig. 21. Reduction or Increase in Boilers' Outputs after Realization of Accepted Bids

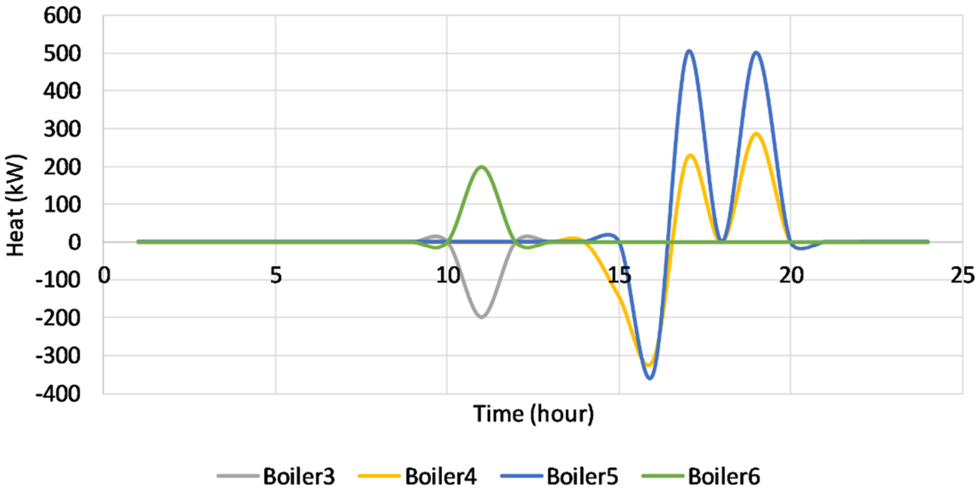

Fig. 22. Falling and Increasing Trends of Boilers' Outputs after Realization of Accepted Bids

In order to show the advantages of using renewable energy units, ESSs, TSSs, and presenting the merits of transaction in the power market, five distinct cases are considered. The first case is the normal condition, and it is assumed that all the IMG bids in the power market are accepted. In the second case, it is assumed that there is no renewable energy in the IMG. The third case is without ESSs and TSSs. In the fourth case, the IMG is in the island mode, in other words, there is no connection between IMG and its upper grid. Finally, the fifth case is the real and final case, which the accepted bids of IMG in the power market are realized and IMG must schedule its units based on the accepted bids. In other words, the fifth case is regarding the redispatch (third level) in the IMG. Total expected costs of mentioned cases are delineated in Table 3. According to it, in the absence of renewable units, the operational cost of IMG rises by 56.35% in comparison with the first case, and it is logical as the operational costs of renewable units are assumed to be zero. Therefore, the absence of them leads to an increase in the operational cost. Additionally, the operational cost of IMG grows from 18670$ to 26911$, when the storage units are ignored. In the fourth case, which the IMG is in the island mode, the operational cost of IMG jumps from 18670$ to 32118 $ and it is reasonable as the IMGO must supply its electrical and thermal loads by its local units. At last, the fifth case is the case of interest in this paper, and as it shows, the IMG has undergone 7.14% increase in its operational costs in comparison with the first case. This rise in the costs of the fifth case in comparison with the first one is because of the rescheduling and increasing the output of some IMG local units. For clarification the cost comparison of mentioned cases, the total expected cost of IMG for five considered cases are depicted in Fig. 23. According to it, the worst case is the fifth one and the best goes to Case1.

Hence, considering the full acceptance of all the IMG bids may lead to some mistakes in the calculation of IMG operational costs in addition to some problems in the scheduling of the units.

Based on the proposed model in this paper, the transaction of IMG in the power market is taken into account, while the upper grid technical and economic constraints are contemplated.

Table 3

Total Expected Costs of Different Cases

	Case 1	Case 2	Case 3	Case 4	Case 5
Total Expected Cost ($)	18670	29191	26911	32118	20003

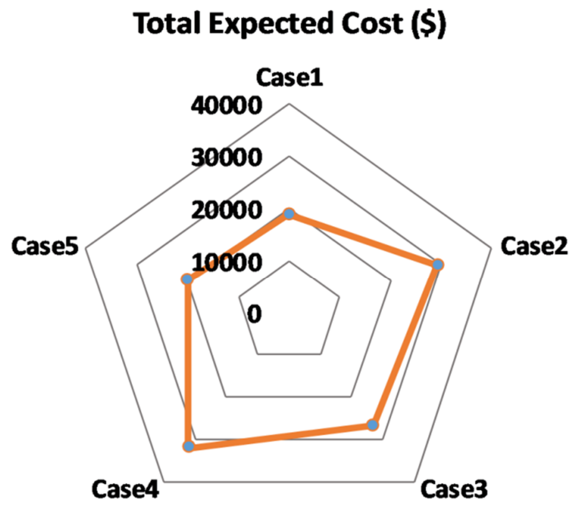

Fig. 23. Cost Comparison of Different Considered Cases

5. Conclusion

In this paper, a new framework for the optimal operation of IMG is presented, which consists of three levels. In the proposed model, an IMG is considered that comprises of CHP units, auxiliary boilers, wind units, PV units, ESSs and TSSs. The stochastic behaviour of wind and PV units is well considered by the LHS method. In the first level, the optimization of IMG is the main goal that is achieved by running a PB-SCUC problem by IMGO. The transaction of IMG with its upper grid is well considered by bidding in the day-ahead power market. Indeed, the IMGO can bid for buying or selling power in the day-ahead market. Meanwhile, the stochastic behaviour of day-ahead market price is taken into account. By determining the bids of IMG in the power market for each scenario and at each hour, a method is introduced for estimating the tendency of IMGO to participate in the day-ahead market. In fact, the biddings of IMG at each hour are estimated as a quadric function, and these quadric functions will be transferred to the next level. In the second level, the upper grid operator must optimize its grid by executing a SCUC problem. Therefore, there is a challenge ahead of the upper grid operator for supplying its loads by local units or by buying from the IMG through the day-ahead market and also get benefits by selling power to the IMG through the day-ahead market. At the second level, the accepted bids of IMG would be determined. Next, by realization of the accepted bids, the IMGO must settle its local units. Indeed, a rescheduling problem would be solved at the third level. At last, the simulation results are presented, and the behaviour of different components of IMG is discussed. Furthermore, the IMG bidding in the day-ahead market is scrutinized. In addition, it shows that the transaction of IMG with the upper grid is not only economic for IMG but also for the upper grid. At the end, different cases are taken into account for showing the advantages of using renewable energy units, storage units, and transaction in the power market. It is noteworthy that, the presence of Plug-in Electric Vehicles (PEVs) is neglected in the current work. Besides, only day-ahead active power market is considered, while the model can be developed to capture real-time active power market as well. Moreover, it is assumed that only one microgrid is connected to the upper grid, while there may exist more than one. It is worth mentioning that, as future work, authors are working on the concept of multiple MGs, where in addition to CHP, boilers, wind, and PV units, the presence of PEVs are analyzed, and the MGs can participate in the day-ahead and real-time power markets.

Acknowledgment

J.P.S. Catalão acknowledges the support by FEDER funds through COMPETE 2020 and by Portuguese funds through FCT, under Projects SAICT-PAC/0004/2015 - POCI-01-0145-FEDER-016434, POCI-01-0145-FEDER-006961, UID/EEA/50014/2013, UID/CEC/50021/2013, UID/EMS/00151/2013, and 02/SAICT/2017 - POCI-01-0145-FEDER-029803, and also funding from the EU 7th Framework Programme FP7/2007-2013 under GA no. 309048.

References

[1] Babazadeh M, Nobakhti A. Robust Decomposition and Structured Control of an Islanded Multi-DG microgrid. IEEE Transactions on Smart Grid. 2018:1-.

[2] Khodaei A. Provisional Microgrid Planning. IEEE Transactions on Smart Grid. 2017;8:1096-104.

[3] Martinez S, Michaux G, Salagnac P, Bouvier J-L. Micro-combined heat and power systems (micro-CHP) based on renewable energy sources. Energy Conversion and Management. 2017;154:262-85.

[4] Davoodi E, Zare K, Babaei E. A GSO-based algorithm for combined heat and power dispatch problem with modified scrounger and ranger operators. Applied Thermal Engineering. 2017;120:36-48.

[5] Combined Heat and Power (CHP). United States Department of Energy, Office of Energy Efficiency & Renewable Energy. [online]. Available: https://www.energy.gov/eere/amo/combined-heat-and-power-chp

[6] Derakhshandeh SY, Golshan MEH, Masoum MAS. Profit-based unit commitment with security constraints and fair allocation of cost saving in industrial microgrids. IET Science, Measurement & Technology. 2013;7:315-25.

[7] Aghaei J, Agelidis VG, Charwand M, Raeisi F, Ahmadi A, Nezhad AE, et al. Optimal Robust Unit Commitment of CHP Plants in Electricity Markets Using Information Gap Decision Theory. IEEE Transactions on Smart Grid. 2017;8:2296-304.

[8] Esen M. Thermal performance of a solar-aided latent heat store used for space heating by heat pump. Solar Energy. 2000;69:15-25.

[9] Chen X, Kang C, Malley MO, Xia Q, Bai J, Liu C, et al. Increasing the Flexibility of Combined Heat and Power for Wind Power Integration in China: Modeling and Implications. IEEE Transactions on Power Systems. 2015;30:1848-57.

[10] Hellmers A, Zugno M, Skajaa A, Morales JM. Operational Strategies for a Portfolio of Wind Farms and CHP Plants in a Two-Price Balancing Market. IEEE Transactions on Power Systems. 2016;31:2182-91.

[11] Lin C, Wu W, Zhang B, Sun Y. Decentralized Solution for Combined Heat and Power Dispatch Through Benders Decomposition. IEEE Transactions on Sustainable Energy. 2017;8:1361-72.

[12] Benam MR, Madani SS, Alavi SM, Ehsan M. Optimal Configuration of the CHP System Using Stochastic Programming. IEEE Transactions on Power Delivery. 2015;30:1048-56.

[13] Liu Z, Chen Y, Zhuo R, Jia H. Energy storage capacity optimization for autonomy microgrid considering CHP and EV scheduling. Applied Energy. 2018;210:1113-25.

[14] Kia M, Nazar MS, Sepasian MS, Heidari A, Siano P. Optimal day ahead scheduling of combined heat and power units with electrical and thermal storage considering security constraint of power system. Energy. 2017;120:241-52.

[15] Alipour M, Zare K, Mohammadi-Ivatloo B. Short-term scheduling of combined heat and power generation units in the presence of demand response programs. Energy. 2014;71:289-301.

[16] Alipour M, Mohammadi-Ivatloo B, Zare K. Stochastic risk-constrained short-term scheduling of industrial cogeneration systems in the presence of demand response programs. Applied Energy. 2014;136:393-404.

[17] Derakhshandeh SY, Masoum AS, Deilami S, Masoum MAS, Golshan MEH. Coordination of Generation Scheduling with PEVs Charging in Industrial Microgrids. IEEE Transactions on Power Systems. 2013;28:3451-61.

[18] Kia M, Setayesh Nazar M, Sepasian MS, Heidari A, Siano P. An efficient linear model for optimal day ahead scheduling of CHP units in active distribution networks considering load commitment programs. Energy. 2017;139:798-817.

[19] Kia M, Setayesh Nazar M, Sepasian MS, Heidari A, Catalão JPS. New framework for optimal scheduling of combined heat and power with electric and thermal storage systems considering industrial customers inter-zonal power exchanges. Energy. 2017;138:1006-15.

[20] Kia M, Setayesh Nazar M, Sepasian MS, Heidari A, Sharaf AM. Coordination of heat and power scheduling in micro-grid considering inter-zonal power exchanges. Energy. 2017;141:519-36.

[21] Alipour M, Mohammadi-Ivatloo B, Zare K. Stochastic Scheduling of Renewable and CHP-Based Microgrids. IEEE Transactions on Industrial Informatics. 2015;11:1049-58.

[22] Nazari-Heris M, Abapour S, Mohammadi-Ivatloo B. Optimal economic dispatch of FC-CHP based heat and power micro-grids. Applied Thermal Engineering. 2017;114:756-69.

[23] Bornapour M, Hooshmand R-A, Khodabakhshian A, Parastegari M. Optimal stochastic scheduling of CHP-PEMFC, WT, PV units and hydrogen storage in reconfigurable micro grids considering reliability enhancement. Energy Conversion and Management. 2017;150:725-41.

[24] Nguyen DT, Le LB. Optimal Bidding Strategy for Microgrids Considering Renewable Energy and Building Thermal Dynamics. IEEE Transactions on Smart Grid. 2014;5:1608-20.

[25] Liu G, Xu Y, Tomsovic K. Bidding Strategy for Microgrid in Day-Ahead Market Based on Hybrid Stochastic/Robust Optimization. IEEE Transactions on Smart Grid. 2016;7:227-37.

[26] Mehdizadeh A, Taghizadegan N. Robust optimisation approach for bidding strategy of renewable generation-based microgrid under demand side management. IET Renewable Power Generation. 2017;11:1446-55.

[27] Su W, Wang J, Roh J. Stochastic Energy Scheduling in Microgrids With Intermittent Renewable Energy Resources. IEEE Transactions on Smart Grid. 2014;5:1876-83.

[28] Liu G, Starke M, Xiao B, Tomsovic K. Robust optimisation-based microgrid scheduling with islanding constraints. IET Generation, Transmission & Distribution. 2017;11:1820-8.

[29] Esen H, Inalli M, Esen M. A techno-economic comparison of ground-coupled and air-coupled heat pump system for space cooling. Building and Environment. 2007;42:1955-65.

[30] Esen H, Inalli M, Esen M. Technoeconomic appraisal of a ground source heat pump system for a heating season in eastern Turkey. Energy Conversion and Management. 2006;47:1281-97.

[31] Esen M, Yuksel T. Experimental evaluation of using various renewable energy sources for heating a greenhouse. Energy and Buildings. 2013;65:340-51.

[32] Basu M. Combined heat and power economic emission dispatch using nondominated sorting genetic algorithm-II. International Journal of Electrical Power & Energy Systems. 2013;53:135-41.

[33] Vasebi A, Fesanghary M, Bathaee SMT. Combined heat and power economic dispatch by harmony search algorithm. International Journal of Electrical Power & Energy Systems. 2007;29:713-9.

[34] Lingfeng W, Chanan S. Stochastic combined heat and power dispatch based on multi-objective particle swarm optimization. 2006 IEEE Power Engineering Society General Meeting2006. p. 8 pp.

[35] Piperagkas GS, Anastasiadis AG, Hatziargyriou ND. Stochastic PSO-based heat and power dispatch under environmental constraints incorporating CHP and wind power units. Electric Power Systems Research. 2011;81:209-18.

[36] Rooijers FJ, Amerongen RAMv. Static economic dispatch for co-generation systems. IEEE Transactions on Power Systems. 1994;9:1392-8.

[37] Abdolmohammadi HR, Kazemi A. A Benders decomposition approach for a combined heat and power economic dispatch. Energy Conversion and Management. 2013;71:21-31.

[38] Pazouki S, Haghifam M-R. Optimal planning and scheduling of energy hub in presence of wind, storage and demand response under uncertainty. International Journal of Electrical Power & Energy Systems. 2016;80:219-39.

[39] Alipour M, Zare K, Mohammadi-Ivatloo B. Optimal risk-constrained participation of industrial cogeneration systems in the day-ahead energy markets. Renewable and Sustainable Energy Reviews. 2016;60:421-32.

[40] Shi L, Luo Y, Tu GY. Bidding strategy of microgrid with consideration of uncertainty for participating in power market. International Journal of Electrical Power & Energy Systems. 2014;59:1-13.

[41] MATLAB Release 2012b, The MathWorks, Inc., Natick, Massachusetts, United States.

[42] Aghaei J, Nikoobakht A, Siano P, Nayeripour M, Heidari A, Mardaneh M. Exploring the reliability effects on the short term AC security-constrained unit commitment: A stochastic evaluation. Energy. 2016;114:1016-32.

[43] Gazijahani FS, Salehi J. Optimal Bi-level Model for Stochastic Risk-based Planning of Microgrids Under Uncertainty. IEEE Transactions on Industrial Informatics. 2017;PP:1-.

[44] Sgouras KI, Bouhouras AS, Gkaidatzis PA, Doukas DI, Labridis DP. Impact of reverse power flow on the optimal distributed generation placement problem. IET Generation, Transmission & Distribution. 2017;11:4626-32.

[45] GAMS user guide [online]. Available: At Https://www.GAMS.com. [Accessed 22 February 2016]

[46] How to run a model with GAMS/CPLEX. GAMS development corporation, Washington D.C. [online]. Available: http://www.gams.com/solvers/[Accessed 22 February 2016]