Electricity Market Scheduling Considering Active Distribution Networks and Microgrids

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***Abstract*—The increasing use of distributed energy resources in distribution networks and introduction of microgrids have activated distribution networks. The conventional procedures of power system operation in which transmission and active distribution grids are considered separately are not appropriate for future power systems. It is necessary to consider elements of active distribution networks and microgrids in power system operation optimization to have an economical use of the power system. However, this problem cannot be solved in a centralized manner due to computational and communication requirements. In this paper, day-ahead electricity market optimization with considering active distribution networks and microgrids is decomposed into three levels of transmission, distribution, and microgrid. In the obtained tri-level model, the coordination among operators is carried out through exchanging local marginal prices, distribution local marginal prices and boundary power of active distribution networks and microgrids. Each operator attempts to minimize the costs of the entity under its supervision. Convergence and optimality of the proposed method have been shown with its implementation on the modified IEEE RTS 24-bus. Moreover, Robustness of the proposed method to the change of different parameters has been shown through a sensitivity analysis.**

Keywords— active distribution grid, decentralized operation, microgrid

I. Nomenclature

A. Sets

τ	Set of scheduling horizon
N_{bus}^{trn}	Set of all transmission buses
N_{Bbus}^{trn}	Set of transmission boundary buses that connected to an active distribution grid (ADG)
N_{line}^{trn}	Set of all transmission lines
$\mathrm{N}_{bus}^{dis,k}$	Set of the nodes of ADG k
$\mathrm{N}_{Bbus}^{dis,k}$	Set of the boundary nodes of ADG k that connected to an microgrid (MG)
$\mathrm{N}_{line}^{dis,k}$	Set of all lines of ADG k
$S^{dis,k}$	Set of energy storage systems (ESSs) of ADG k
$I^{mg,e}$	Set of the distributed generations for I=G/ renewable generations for I=R/ ESSs for I=S/ curtailable loads for I=C/ deferrable loads for I=D/ uncontrollable loads for I=L of MG e

B. Parameters

$PL_{u,t}^{trn}$	Uncontrollable load of transmission bus u at hour t
GSF_{l-u}^{trn}	Generation shift factor for transmission bus u on transmission line l
$L_l^{\max}$	Transmission capacity of line l
$PL_{a,t}^{dis,k}$	Uncontrollable load of distribution node a of ADG k at hour t
$PR_{a,t}^{dis,k}$	Generation power of the renewable generation at distribution node a of ADG k at hour t
$GSF_{r-a}^{dis,k}$	Generation shift factor for distribution node a on distribution line r in ADG k
$E_{a,\max}^{dis,k}$	Energy upper bound of the deferrable load that is connected to node a of ADG k
$PL_{v,t}^{mg,e}$	Uncontrollable load v of MG e at hour t
$PR_{q,t}^{mg,e}$	Generation power of the renewable generation q of MG e at hour t
$E_{d,\max}^{mg,e}$	Energy upper bound of the deferrable load d of MG e
$a_{u,t}$	Bid function coefficient of the unit at transmission bus u at hour t
$b_{u,t}$	Bid function coefficient of the unit at transmission bus u at hour t

C. Variables

$PG_{u,t}^{trn}$	Generation power of the unit at transmission bus u at hour t
$PB_{k,t}^{dis}$	Boundary power that ADG k demand from transmission network at hour t
$PI_{a,t}^{dis,k}$	Generation power of the distributed generation for I=G/ charge or discharge power of the ESS for I=S/ curtailable load for I=C/ Deferrable load for I=D, at distribution node a of ADG k at hour t
$ES_{s,t}^{dis,k}$	Energy stored in ESS s of ADG k
$PB_{e,t}^{mg}$	Boundary power that MG e demand from related distribution grid at hour t
$PI_{i,t}^{mg,e}$	Generation power of the distributed generation for I=G/ charge or discharge power of the ESS for I=S/ curtailable load for I=C/ Deferrable load for I=D, element i of MG e at hour t
$ES_{s,t}^{mg,e}$	Energy stored in ESS s of MG e

II. Introduction

Economic, environmental and technical challenges have led to activation of distribution grids and introduction of microgrids (MGs). These changes resulting in numerous advantages for the power system performance in term of technical and economic issues [1,2]. Despite abovementioned benefits, these changes have resulted in some operational issues in power systems [3]. Ignoring active distribution grids (ADGs) and MGs generation resources in operation optimization of power system results in uneconomical operation. Additionally, generation and load balance issue due to an error in ADGs and MGs load forecast are some of operational issues. To cope with these issues, traditional separate scheduling of transmission and distribution grid must be changed and a cooperation is

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required between operators of transmission system, ADGs and MGs.

One major problem of power system operation is day-ahead electricity market scheduling [5]. In the conventional day-ahead electricity market optimization, distribution networks are assumed as a forecasted load that is contradicted by the active nature of ADGs. In order to have maximized economic efficiency and to solve technical issues regarding MGs and activation of distribution grids, cost functions and constraints related to elements of ADGs and MGs should be considered in day-ahead electricity market optimization. Considering elements of ADGs and MGs result in maximum distributed energy resources (DERs) utilization. Due to following reasons, solving this problem in a centralized manner is not possible: i) the computational burden of the problem because of numerous components of the system [6]; ii) centralized operation demands expensive communication infrastructures, connecting all components in a wide geographical region to a control center; iii) distribution and transmission systems are controlled by different operators and have limited data exchange for privacy reasons. Furthermore, there may exist several private MGs within a distribution network which have no desire to share their data with distribution/transmission system operators. Thus, it is mandatory to operate power system in a decentralized manner.

In [7, 8], a scheduling is employed for a distribution network and the connected MGs. In these papers, once electricity market closes and local marginal prices (LMPs) appear, scheduling process initiates for distribution system and connected MGs. Having no cooperation between distribtion system operator (DSO) and independent system operator (ISO) leads to a difference between the forecasted power of each distribution system by ISO and the required power of each distribution system from transmission system after completed scheduling process [9]. References [10-13] address coordinated operation of the transmission and distribution systems. However, these papers do not consider independence of microgrid operators (MGOs) in scheduling their own resources. In [11], a method is proposed to solve economic dispatch problem in two transmission and distribution level based on optimality condition decomposition (OCD) method. This approach that was proposed first in [14] is based upon similar data exchange between different computational units with similar nature. Therefore, in [11], this approach is referred to as homogenous decomposition method. Transmission system considers a distribution system as a load; while, each distribution system sees transmission system as a power supply source with a given price. Thus, since the way these two systems interact with each other is different, they have access to heterogeneous information of each other. Considering this issue, the heterogeneous decomposition method suggested in [11] is considered as a suitable method for power system scheduling along with integrated constraints and details of ADGs. Moreover, the method is asynchronous, which is suitable for practical implementation with lower information exchange, resulting in a reduced cost of telecommunication equipment compared to most of the reported methods. Furthermore, in [15], the overall convergence of this method is validated based on calculating the estimation of LMPs.

The need for separate electricity market on distribution level is discussed in [16]. In [17], conventional price-based scheduling and market-based scheduling are compared and the advantages of the latter are mentioned. One of the reasons suggested for market-based scheduling is that the active participation of price-sensitive loads in the price-based market leads to uncertainty in load profile [17]. Load profile uncertainty has increased the need for ancillary services, imposing added costs to the power system. In addition, increased distributed generation (DG) penetration and MGs endanger reliability of the distribution systems [18]. The market-based approach allows MGOs to schedule their own resources. However, they oblige to consume power based on their bid otherwise they will be panelized. Therefore, this approach leads to uneconomical power system operation.

In this paper, first day-ahead electricity market scheduling considering all power generation resources in transmission network, ADGs and MGs is modeled as a single optimization problem. Then day-ahead electricity market scheduling is decomposed into three sets of optimization problems using heterogeneous OCD method. The first level set consists of optimization problem of ISO, the second level set consists of optimization problems of DSOs, and the third level set consists of optimization problems of MGOs. The optimization problems are solved by an iterative method. In each iteration, limited information is exchanged between operators of consecutive levels. In this approach operators are independent in terms of decision-making and the confidential data of each grid is also preserved. Additionally, the components of ADGs and MGs such as deferrable loads, curtailable loads, and ESSs are included in this model. The simulations show that scheduling results of the above-mentioned tri-level optimization are consistent with those of the centralized approach with high accuracy.

The scheduling of MGs is carried out through estimating DLMPs using sensitivity factors [15]. In the proposed method, it is assumed that power system operator is a minimum ISO, i.e., each generation company (GENCO) participates in the market as a single unit and after market-clearing it dispatches its units based on market result considering constraints of all its generating units such as ramp rate and minimum up/down time limits.

The rest of the paper is organized as follows: In Section III, the model is described. Optimization problem of each operator is described in section IV. The proposed algorithm for solving the distributed optimization is presented in Section V. Section VI presents simulations and discussions. Finally, Section VII summarizes conclusions of the paper.

III. MODEL OVERVIEW

In conventional electricity market model, retailers and DSOs are the main interfaces between GENCOs and consumers by purchasing electricity from the wholesale market and selling it to consumers. With the emergence of DERs, introduction of MGs and consequently the activation of distribution networks, it is necessary to have a model that consider these changes to improve the economic performance of the power system. Operating the entire network considering the elements of MGs and ADGs by ISO is a complex process because of a large number of them and consequently large dimensions of the problem. In this paper, a tri-level model is proposed for day-ahead electricity market scheduling as presented in Fig. 1. In this model, the first level operates the generations installed in the transmission network, while the second level operates the generators and loads installed in ADGs and the third level operates the generators and loads installed in MGs. ISO, DSOs, and MGOs are responsible for operating the generation and consumption of their corresponding network. To achieve a comprehensive and optimal scheduling, it is necessary to have a coordination between every two related operators in consecutive levels.

To solve this problem, first, the whole network scheduling problem is decomposed into three categories of optimizations. For this purpose, the heterogeneous decomposition method is used [11]. Coordination between every two related operators is carried out through the interrelating variables. Power exchange between each two grid, LMPs and DLMPs are used as the interrelating variables, as shown in Fig. 1. It is necessary to exchange interrelating variables to obtain an agreement at the end of the scheduling process on the value of the interrelating variables. To improve the convergence of the process, MGOs scheduling is performed based on estimation of DLMPs [15]. In the proposed model, ISO calculates LMPs based on sales offers from GENCOs and forecasting the power of each distribution network. Then, MGOs and DSOs will schedule their networks based on LMPs and inform ISO about their power exchange. This process is carried out repeatedly until an agreement is reached on the boundary power between ISO and DSOs as well as between DSOs and related MGOs.

IV. Mathematical Formulations

Optimization of day-ahead electricity market considering MGs and ADGs is an optimization with objective to minimize total cost of ISO, DSOs, and MGOs subject to technical constraints of all three levels. In order to solve mentioned optimization in decentralized manner it is decomposed in two levels. First, it is decomposed to optimizations of ISO and distribution networks. Then, optimizations of distribution networks are decomposed to optimizations of DSOs and MGOs. Heterogeneous OCD method is used for optimization decomposition. In this section, optimization of each level of scheduling is presented. Central optimization and decomposition process are not presented here due to room shortage.

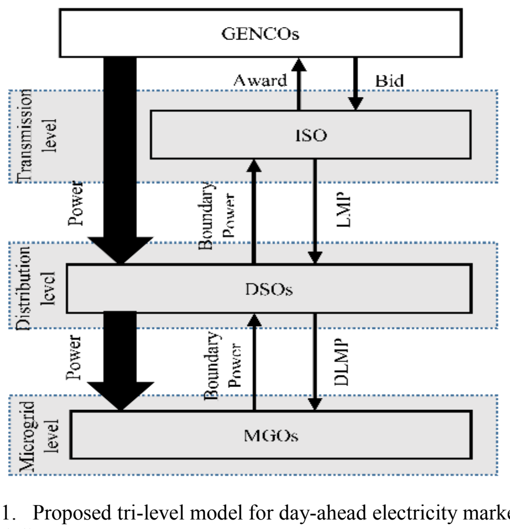

Fig. 1. Proposed tri-level model for day-ahead electricity market scheduling.

A. Level 1: Optimization of ISO

It is assumed that GENCOs present their supply functions to ISO, while DSOs inform ISO about their requested power for different hours of the next day. It is assumed that the *ith* GENCO presents its offer to ISO as an affine supply function in form of $a_{u,t} + b_{u,t} PG_{u,t}^{tm}$. Then, ISO schedules GENCOs by maximizing the social welfare (minimizing the cost of purchasing electricity from GENCOs [20]). The optimization of ISO is formulated as follows:

$$\min \sum_{t\in\tau} \sum_{u\in N_{bus}^{tm}} \left(\frac{1}{2} b_{u,t} (PG_{u,t}^{tm})^2 + a_{u,t} PG_{u,t}^{tm}\right) \tag{1}$$

s.t.

$$\sum_{u\in N_{bus}^{tm}} (PG_{u,t}^{tm} - PL_{u,t}^{tm}) = \sum_{k\in N_{Bbus}^{tm}} PB_{k,t}^{dis},\ \forall t\in\tau \tag{2}$$

$$\begin{gathered} -L_l^{\max} \le \sum_{u\in N_{bus}^{tm}} GSF_{l-u}^{tm} \times (PG_{u,t}^{tm} - PL_{u,t}^{tm}) - \\ \sum_{k\in N_{Bbus}^{tm}} GSF_{l-k}^{tm} \times PB_{k,t}^{dis} \le L_l^{\max},\ \forall l\in N_{line}^{tm}, \forall t\in\tau \end{gathered} \tag{3}$$

$$PG_{u,\min}^{tm} \le PG_{u,t}^{tm} \le PG_{u,\max}^{tm},\ \forall u\in N_{bus}^{tm}, \forall t\in\tau \tag{4}$$

Objective function (1) represents the cost of purchasing electricity from GENCOs. Constraint (2) represents power balance at each transmission node. Constraint (3) ensures function of transmission lines within the allowable limits. Constraint (4) shows the generation limits of each GENCO.

ISO calculates LMPs of hour t for ADG k after the optimization shown in (1) - (4) is solved using the following equation:

$$\begin{gathered} LMP_{k,t} = \pi_t^{tm} + \sum_{l\in N_{line}^{tran}} GSF_{l-k}^{tm} \times (\mu_{l,1,t}^{tm} - \mu_{l,2,t}^{tm}), \\ \forall k\in N_{Bbus}^{tm}, \forall t\in\tau \end{gathered} \tag{5}$$

In the equation (5) π_t^{tm}, $\mu_{l,1,t}^{tm}$ and $\mu_{l,2,t}^{tm}$ represent lagrange multipliers of (2) and (3), respectively.

B. Level 2: Optimizations of DSOs

Each DSO aims to minimize its costs in order to determine the amount of requested power from the transmission network. This paper considers renewable generations and conventional generations in ADG. The generation cost of renewable units is considered zero, while the cost of conventional generators is modeled by a quadratic function. It is assumed that renewable generation is forecasted. Each ADG can own a number of ESSs. The cost of ESS at node a of ADG k is considered as follows [21]:

$$\begin{gathered} C_{bat,a}^{dis,k} (PS_{a,t}^{dis,k}) = \alpha_{s,a} \sum_{t\in\tau} (PS_{a,t}^{dis,k})^2 + \\ \beta_{s,a} \sum_{t=0}^{T-1} PS_{a,t}^{dis,k} \times PS_{a,t+1}^{dis,k},\ \forall a\in N_{bus}^{dis,k} \end{gathered} \tag{6}$$

The first item of the cost function (6) indicates the degradation cost due to the amount of charge and discharge. The second item relates to switches between charging and discharging states. Coefficients $\alpha_{s,a}$ and $\beta_{s,a}$ are positive constants.

Each ADG may have uncontrollable and controllable loads. Controllable loads are divided into two categories: 1) Deferrable loads; and 2) Curtailable loads. Curtailable loads can be shedded to a permissible level. The cost function of curtailable load depends on the amount of the shedded load and for the curtailable load at node *a* of ADG *k* is defined as [22]:

$$C_{cur,a}^{dis,k}(PC_{a,t}^{dis,k}) = \alpha_{c,a} \sum_{t\in\tau} (PC_{a,\max}^{dis,k} - PC_{a,t}^{dis,k})^2, \quad \forall a \in N_{bus}^{dis,k} \tag{7}$$

In the formula (7), $\alpha_{c,a}$ is a positive constant. The power consumption of the deferrable load can be shifted in time. It also needs to consume a certain amount of energy over a given time period. The cost function of deferrable load depends on unfulfilled energy and for the deferrable load at node a of ADG *k* is defined as [22]:

$$C_{def,a}^{dis,k}(PD_{a,t}^{dis,k}) = \alpha_{d,a}(E_{a,\max}^{dis,k} - \sum_{t\in\tau} PD_{a,t}^{dis,k}), \quad \forall a \in N_{bus}^{dis,k} \tag{8}$$

In the formula (8), $\alpha_{d,a}$ is a positive constant. The optimization of the *kth* DSO is as follows:

$$\min \sum_{t\in\tau} \sum_{a\in N_{bus}^{dis,k}} (C_{gen,a,t}^{dis,k}(PG_{a,t}^{dis,k})) + \sum_{a\in N_{bus}^{dist,k}} (C_{cur,a}^{dis,k}(PC_{a,t}^{dis,k}) + C_{def,a}^{dis,k}(PD_{a,t}^{dis,k}) + C_{bat,a}^{dis,k}(PS_{a,t}^{dis,k})) + \sum_{t\in\tau}(LMP_{k,t} \times PB_{k,t}^{dis}) \tag{9}$$

s.t.

$$\sum_{a\in N_{bus}^{dis,k}} (PG_{a,t}^{dis,k} + PR_{a,t}^{dis,k}) + PB_{k,t}^{dis} = \sum_{e\in N_{Bbus}^{dist,k}} PB_{e,t}^{mg} + \sum_{a\in N_{bus}^{dis,k}} (PS_{a,t}^{dis,k} + PC_{a,t}^{dis,k} + PD_{a,t}^{dis,k} + PL_{a,t}^{dis,k}), \ \forall t \in \tau \tag{10}$$

$$-L_r^{\max} \le \sum_{a\in N_{bus}^{dist,k}} GSF_{r-a}^{dis,k} \times (PG_{a,t}^{dis,k} + PR_{a,t}^{dis,k} - PC_{a,t}^{dis,k} - PS_{a,t}^{dis,k} - PD_{a,t}^{dis,k} - PL_{a,t}^{dis,k}) - \sum_{e\in N_{Bbus}^{dis,k}} (GSF_{r-e}^{dis,k} \times PB_{e,t}^{mg}) \le L_r^{\max}, \quad \forall r \in N_{line}^{dis,k}, \forall t \in \tau \tag{11}$$

$$PI_{a,t,\min}^{dis,k} \le PI_{n,t}^{dis,k} \le PI_{a,t,\max}^{dis,k}, \ \forall a \in N_{bus}^{dis,k}, \forall t \in \tau \tag{12}$$

$$0 \le PB_{k,t}^{dis} \le PB_{k,\max}^{dis}, \ \forall t \in \tau \tag{13}$$

$$PS_{a,\min}^{dis,k} \le PS_{a,t}^{dis,k} \le PS_{a,\max}^{dis,k}, \ \forall a \in N_{bus}^{dis,k}, \forall t \in \tau \tag{14}$$

$$E_{a,\min}^{dis,k} \le \sum_{t\in\tau} PD_{a,t}^{dis,k} \le E_{a,\max}^{dis,k}, \ \forall a \in N_{bus}^{dis,k} \tag{15}$$

$$DOD_s \times ES_{s,\max}^{dis,k} \le ES_{s,t}^{dis,k} \le ES_{s,\max}^{dis,k}, \quad \forall s \in S^{dis,k}, \forall t \in \tau \tag{16}$$

$$ES_{s,t+1}^{dis,k} = ES_{s,t}^{dis,k} \times \eta_s + PS_{s,t}^{dis,k}, \ \forall s \in S^{dis,k}, \forall t \in \tau \tag{17}$$

$$ES_{s,\mathrm{T}}^{dis,k} \ge ES_{s,end}^{dis,k}, \ \forall s \in S^{dis,k} \tag{18}$$

Objective function (9) involves the costs of ADG *k*. The first fifth terms in the objective function represent the cost of DGs, curtailable loads, deferrable loads, ESSs, and purchasing power from the transmission network, respectively. Constraint (10) indicates the power balance in ADG *k*. Constraint (11) maintains the power passing through distribution lines within the allowable limits. Constraint (12) describes generation or consumption limits of conventional units and controllable loads respectively. Constraint (13) represents the permitted limits for the power exchange of ADG *k* with the transmission network. Constraint (14) specifies the limits for the power exchange of each ESS in which the positive values of $PS_{a,t}^{dis,k}$ are related to the charging state and the negative values are related to the discharging state of ESS. Constraint (15) specifies the limits of the energy required for each deferrable load. ESS capacity limit is given in constraint (16). The amount of discharge of ESS affects their useful life. For this purpose, the lower energy stored in ESS is equal to the fraction of ESS capacity that is shown by DOD_s .Constraint (17) models charge and discharge of energy in/from ESSs. Each ESS must have a minimum amount of stored energy at the end of the scheduling period which is considered in constraint (18)

After solving the optimization in (9) - (18) DLMP of MG *e* at hour *t* is calculated using the following equation by related DSO.

$$DLMP_{e,t} = \pi_t^{dis,k} + \sum_{r\in N_{line}^{dist,k}} GSF_{r-e}^{dis,k} \times (\mu_{r,1,t}^{dis,k} - \mu_{r,2,t}^{dis,k}), \forall e \in N_{Bbus}^{dis,k}, \forall t \in \tau \tag{19}$$

In the equation (19), $\pi_t^{dis,k}$, $\mu_{r,1,t}^{dis,k}$ and $\mu_{r,2,t}^{dis,k}$ represent lagrange multipliers of constraints (10) and (11), respectively.

C. Level 3: Optimizations of MGOs

The components of MGs are similar to ADGs with the exception that the constraints of power lines are ignored in this section to avoid complexity. Each MGO must specify the amount of requested power from the respective ADG. The optimization problem of MG *e* connected to ADG *k* is as follows:

$$\min \sum_{t\in\tau} (\sum_{g\in G^{mg,e}} C_{gen,g,t}^{mg,e}(PG_{g,t}^{mg,e}) + (DLMP_{e,t}(PB_{e,t}^{mg}) \times PB_{e,t}^{mg})) + \sum_{s\in S^{mg,e}} C_{bat,s}^{mg,e}(PS_{s,t}^{mg,e}) + \sum_{c\in C^{mg,e}} C_{cur,c}^{mg,e}(PC_{c,t}^{mg,e}) + \sum_{d\in D^{mg,e}} C_{def,d}^{mg,e}(PD_{d,t}^{mg,e}) \tag{20}$$

s.t.

$$\sum_{g\in G^{mg,e}} PG_{g,t}^{mg,e} + PB_{e,t}^{mg} + \sum_{q\in R^{mg,e}} PR_{q,t}^{mg,e} = \sum_{s\in S^{mg,e}} PS_{s,t}^{mg,e} + \sum_{c\in C^{mg,e}} PC_{c,t}^{mg,e} + \sum_{d\in D^{mg,e}} PD_{d,w,t}^{mg,e} + \sum_{v\in L^{mg,e}} PL_{v,t}^{mg,e}, \ \forall t \in \tau \tag{21}$$

$$PI_{i,t,\min}^{mg,e} \le PI_{i,t}^{mg,e} \le PI_{i,t,\max}^{mg,e}, \ \forall i \in I^{mg,e}, \forall t \in \tau \tag{22}$$

$$0 \le PB_{e,t}^{mg} \le PB_{\max}^{mg,e}, \ \forall t \in \tau \tag{23}$$

$$E_{d,\min}^{mg,e} \le \sum_{t\in\tau} PD_{d,t}^{mg,e} \le E_{d,\max}^{mg,e}, \ \forall d \in D^{mg,e} \tag{24}$$

$$DOD_s \times ES_{s,\max}^{mg,e} \le ES_{s,t}^{mg,e} \le ES_{s,\max}^{mg,e}, \forall s \in S^{mg,e}, \forall t \in \tau \tag{25}$$

$$ES_{s,t+1}^{mg,e} = ES_{s,t}^{mg,e} \times \eta_s + PS_{s,t}^{mg,e}, \ \forall s \in S^{mg,e}, \forall t \in \tau \tag{26}$$

$$ES_{s,\mathrm{T}}^{mg,e} \ge ES_{s,end}^{mg,e}, \ \forall s \in S^{mg,e} \tag{27}$$

Objective function (20) indicates the costs of MG *e*. The second term in the objective function (20) indicates the cost of the requested power from the relevant ADG. According to DLMP, each MGO informs relevant DSO about the amount of boundary power.

V. ALGORITHM

The algorithm of the proposed tri-level method for day-ahead electricity market scheduling is as follows:

Step 1: Initialization (z=1, y=1). First, ISO receives sales offers from GENCOs. Each MGO estimates the required power from the connected ADG and informs the connected DSO of this information. Then, each DSO computes the total required power of its grid and informs ISO of its total required power.

Step 2: ISO solves its optimization using equations (1) - (4). Then, LMPs are obtained according to equation (5) for each ADG for each hour of the next day.

Step 3: Each DSO executes its optimization according to equations (9) - (18). By solving optimization problem of each DSO, the requested power of each ADG from the transmission network is determined. DLMPs are calculated using equation (19). Then, each DSO delivers obtained DLMPs to its connected MGOs.

Step 4: Each MGO calculates the sensitivity of DLMP to its boundary power and estimates DLMP in the subsequent iteration using its recorded DLMPs and boundary powers at the previous iterations [15].

Step 5: Each MGO solves its optimization using equations (20) - (27). By solving optimization problem of each MGO, the amount of its demanded power from the connected ADG is achieved. Then, it is informed to the relevant DSO.

Step 6: Each DSO checks the following conditions to control the agreement between DSO and its MGOs:

$$\left| PB_{e,t}^{(y)} - PB_{e,t}^{(y-1)} \right| \le \varepsilon \ , \ \forall e \in N_{Bbus}^{dist,k}, \forall t \in \tau \tag{28}$$

If conditions (28) are not satisfied, the algorithm returns to step 3 for next iteration *y=y+1*, otherwise, it goes to step 7.

Step 7: ISO controls the following convergence conditions for checking the achievement of an agreement between ISO and DSOs:

$$\left| PB_{k,t}^{dis,(z)} - PB_{k,t}^{dis,(z-1)} \right| \le \varepsilon \ , \forall k \in N_{Bbus}^{tran}, t \in \tau \tag{29}$$

If conditions (29) are not satisfied, the algorithm returns to step 2 for next iteration *z=z+1*, otherwise, the algorithm has converged and the algorithm finishes.

VI. RESULTS AND DISCUSSION

A. Simulation Settings

In order to evaluate the performance of the proposed tri-level day-ahead electricity market scheduling, this algorithm is tested on the modified IEEE RTS 24-bus test system [23]. Distribution networks of 24-bus system are modified to have distribution systems with multiple MGs, controllable loads, and ESSs. The other related data is the same as [23]. Fig. 2 and Fig. 3 show the configuration of the two modified ADGs and the connected MGs. Index of MGs is defined as $e \in MG(k, x)$ which means *xth* MG of ADG *k*. The 24-bus test system has 9 ADGs. The five first ADGs are similar to ADG *1*, shown in Fig. 2 and are connected to buses 1, 2, 3, 5, and 6 of 24-bus test system. The rest of them are like ADG *2*, shown in Fig. 3 and are connected to buses 7, 10, 13 and 19 of 24-bus test system. As shown in Fig. 2 and Fig. 3, ADGs *1* and *2* have DERs, constant loads, curtailable loads, deferrable loads, ESSs, and MGs on their nodes. The scheduling time period is 8 hours and the scheduling time interval is 1 hour. Hourly load of 24-bus system is shown in table I. The share of each ADG load to the total load of ADG is shown in Figs 2 and 3 in percentages. Data of DGs, ESSs, and controllable loads for each ADG and MG are provided in tables II to IV. The forecast of renewable energy production for each ADG and MG is about 20% of the total network load. The weighting coefficients of ESS cost function are $\alpha_{s,a} = 0.05$ and $\beta_{s,a} = 0$ Weighting coefficients $\alpha_{c,a}$ and $\alpha_{d,a}$ are set to 1.

First, results of implementing the proposed method on the modified 24-bus system are analyzed and results are compared with those of centralized method. Then, the sensitivity of runtime and error of scheduling to the change of various parameters are assessed.

All simulations were implemented using GAMS on a laptop with an Intel Core i7, 2.50 GHz processor, and an 8-GB RAM. The solver used in the simulations is PATHNLP.

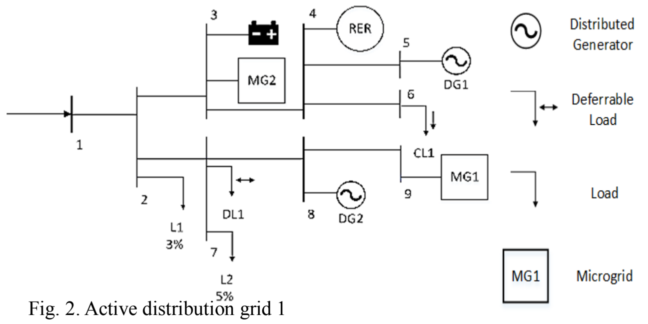

Fig. 2. Active distribution grid 1

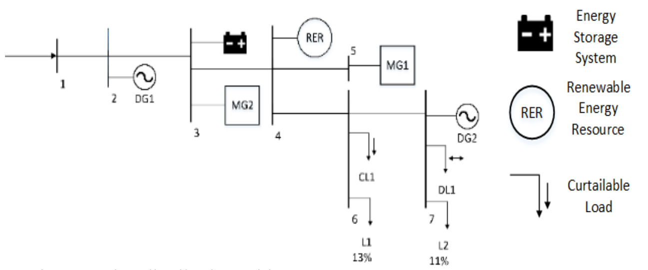

Fig. 3. Active distribution grid 2

TABLE I. . HOURLY LOAD OVER 8-H HORIZON

Hour	Demand (MW)	Hour	Demand (MW)	Hour	Demand (MW)
1	1600	4	2000	7	1980
2	1430	5	2200	8	1700
3	1760	6	2300		

TABLE II. DISTRIBUTED GENERATOR DATA

Entity	DG	P_{min} (MW)	P_{max} (MW)	a (MBtu)	b (MBtu/MWh)	c (MBtu/MW²h)
ADG1	1	0	10	100	7	0.08
	2	0	16	65	3	0.03
ADG2	1	5	22	140	5	0.04
	2	0	15	50	25	0.00
MG(1,1)	1	0	4	100	7	0.03
MG(1,2)	1	0	4	80	6	0.05
	2	0	6	100	7	0.03
MG(2,1)	1	0	7	80	6	0.05
MG(2,2)	1	0	8	65	3	0.03
	2	0	5	110	6	0.07

TABLE III. ENERGY STORAGE SYSTEM DATA

Entity	DOD_s	P_{min} (MW)	P_{max} (MW)	η_s	E_{max} (MWh)
ADG1	0.2	-1	1	0.95	3
ADG2	0.2	-1.3	1.3	0.95	4
MG(1,1)	0.2	-0.25	0.25	0.95	1
MG(1,2)	0.2	-0.25	0.25	0.95	1
MG(2,1)	0.2	-0.7	0.7	0.95	2
MG(2,2)	0.2	-1	1	0.95	3

TABLE IV. CONTROLLABLE LOAD DATA

	Deferrable Load				Curtailable Load	
Entity	P_{min} (MW)	P_{max} (MW)	E_{min} (MWh)	E_{max} (MWh)	P_{min} (MW)	P_{max} (MW)
ADG1	0	4	8	16	5.32	7.6
ADG2	0	8	16	32	5.6	8
MG(1.1)	0	0.8	1.6	3.2	1	1.6
MG(1.2)	0	1	2	4	1.5	3
MG(2.1)	0	1.6	3.2	6.4	1.5	3
MG(2.2)	0	2	4	8	6	10

B. Simulation Results

Implementation of the tri-level scheduling on the modified IEEE RTS 24-bus test system shows that scheduling results are consistent with those of the centralized approach up to three decimal points. The error, of course, depends upon values of different parameters of the problem. In the next section, the error sensitivity to the change of parameters is assessed.

Consider ADG *5*, scheduling of generators, loads and ESSs of ADG *5* are shown in Fig. 4. The exchanged power of ADG 5 with the transmission network and MGs connected to this ADG, i.e. *MG (5,1)* and *MG (5,2)*, and LMP of the transmission bus that this ADG is connected to are shown in Fig 5. As Figs. 4 and 5 shows, the required power of ADG *5* and the connected MGs is mainly provided by its local power sources. ADG *5* purchases power from the transmission system only at hours 2 to 4, as total load of ADG is at its highest value in this time period. *MG (5,1)* is more dependent on the external power supply than *MG (5,2)*. However, ADG *5* is the main supplier because of the cheaper power resources in distribution level compared to those of transmission level. DG *2* in ADG *5*, which is located on distribution node *8*, is always operated at its maximum value due to its lower incremental cost than LMP of ADG *5*. On the other hand, DG *1*, which is located on distribution node *5*, is only operated at its maximum capacity when LMP of ADG *5* increases and the load is high, i.e. at hours 2 to 4, as shown in Fig. 4. The deferrable load also shifts its consumption toward hours 7 and 8 when LMP of ADG *5* and uncontrollable load are low, as shown in Fig. 4 and Fig. 5. ESS of this ADG starts saving energy in the early hours of the scheduling when LMP is low as shown in Fig. 5. ESS of this ADG will discharge its energy to compensate power shortages when ADG load increases and its renewable energy source production decreases, i.e. at hours 3 and 4, as shown in Fig. 4.

Consider first MG of ADG *7*, which is shown by MG *(7,1)*. The amount of provided power for MG *(7,1)* from ADG *7* and the transmission network during the scheduling time period are shown in Fig. 6. Further, Fig. 6 illustrates LMP of ADG *7* and DLMP of MG *(7,1)*. It should be noted that DLMP of MG *(7,1)*, is equal to LMP of ADG *7* at the entire scheduling period, and therefore all of requested power of MG (7,1) provides from the transmission network. However, requested power of *MG (3,1)* provides from ADG *3* because at most hours of the scheduling period its DLMP is less than LMP of ADG *3*. This is illustrated in the Fig. 7.

At hours 2 to 4, DGs of ADG *3* are operating at their highest levels. And, because distribution lines are not congested, its DLMP and LMP of ADG *3* are equal.

C. Sensitivity Analysis

The modified 24-bus network in this paper has 9 ADGs and 18 MGs. To determine the dependency of the runtime of tri-level scheduling method on the number of ADGs and MGs and its error relative to the centralized method, all ADGs and MGs are first eliminated, and then they are added again, step by step respectively. The program runtime versus number of ADGs and MGs are shown in Fig. 8. It should be noted that scheduling error of the tri-level method in comparison to the centralized method is zero up to three decimal points by changing the number of ADGs and MGs.

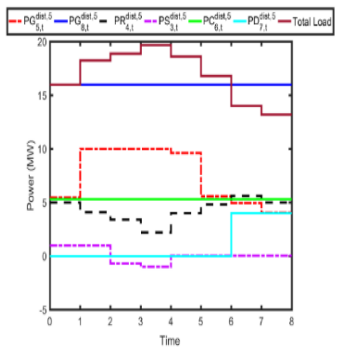

Fig. 4. Output schedules of ADG *5*

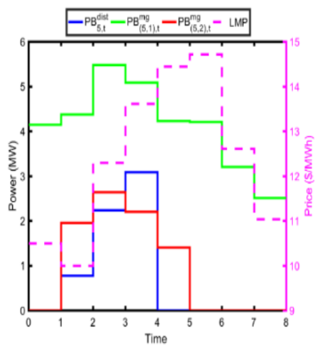

Fig. 5. Exchange power and LMP of ADG *5*

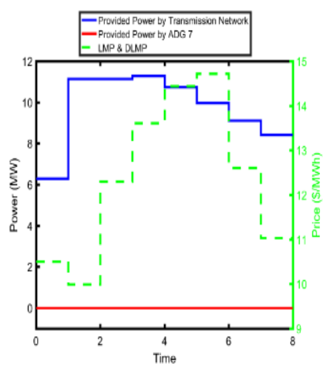

Fig. 6. Boundary power of MG (7,1) and its associated LMP and DLMP

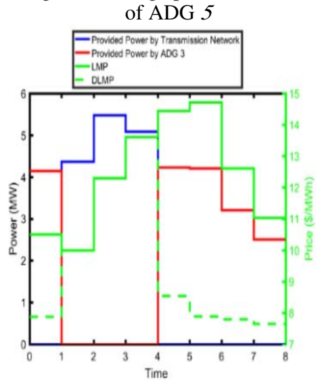

Fig. 7. Boundary power of MG (3,1) and its associated LMP and DLMP

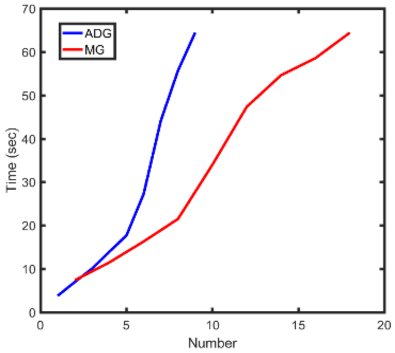

Fig 8. Sensitivity of tri-level method runtime to number of ADGs and MGs

As seen in Fig. 8, after increasing the number of ADGs more than 5, increasing rate of run time of tri-level scheduling increases, since ADGs 6 to 9 are more dependent on the transmission network, requiring more time for convergence along with their MGs. Fig. 8 also shows that as the number of MGs increases, the tri-level scheduling run-time increases linearly approximately.

The number of outer iterations, i.e. iterations between ISO and DSOs, when only ADGs *1-5* are connected to transmission network is five. However, the number of outer iterations increases to eight with more than five ADGs. This indicates that the number of iterations depends on the degree of dependency of each ADG in transmission networks for supplying its load. The number of inner iterations, i.e. iterations between a DSO and its MGOs, does not change with the number of ADGs, and the number of these iterations depends on the structure of ADG and MG as well as dependency of MGs load to generation of related ADGs.

VII. Conclusion

In this paper, day-ahead electricity market scheduling problem is decomposed into three sets of optimizations using heterogeneous OCD method. These three sets which are transmission grid, ADGs, and MGs optimizations are solved iteratively to find optimal solution. The coordination between DSOs and MGOs is done through the exchange of DLMP and requested power of MGs in each iteration. The results achieved from testing the proposed method on the modified IEEE RTS 24-bus shows that the schedule obtained from the tri-level method is consistent with the schedule obtained from the centralized method up to three decimal point. The sensitivity analysis shows that runtime and the schedule error remain within acceptable range as number of MGs and ADGs increase.

Future studies will concentrate on use more accurate power flow for power system scheduling. Meanwhile, future studies will consider uncertainty in renewable generations and load profiles.

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