Applied Energy 336 (2023) 120832

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

An Incentive-based robust flexibility market for congestion management of an active distribution system to use the free capacity of Microgrids

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HIGHLIGHTS

- Design an incentive-based LFM to integrate the flexibility services of MGs.
- Demand side energy management and rescheduling to use the free capacity of MGs.
- Use a modified ADMM method for LFM based on a request and response structure.
- Provide a RO model to consider the real-time price uncertainty in LFM.
- A two-stage model for LEM and LFM for congestion management of distribution system.

ARTICLE INFO

Keywords:
Flexibility
Local market
Congestion management
Microgrids
Robust optimization
Fairness

ABSTRACT

Microgrids (MG) formation has changed the passive structure of the distribution system. MGs participate in local energy markets as separate decision-making units to optimize their economic profit by energy trading with the distribution system operator. However, in the transition-duration from passive to active configuration, the lack of sufficient infrastructure may define new challenges for distribution system security. This paper proposes a robust model of a local flexibility market to incentivize the MGs to provide flexibility services to relieve line congestion. The proposed market model is, based on a request and response structure by adopting a modified ADMM method for flexibility services negotiations. The proposed flexibility market is considered a complementary market for bilateral energy trading of MGs and a distribution system for a fairer environment. The distributed market frameworks keep data privacy and a low computational burden for the market clearing process. The IEEE 33 bus test system with four connected MGs is considered to simulate the proposed model. For results validation, the social welfare function result is compared with the centralized problem structure, and the effects of flexibility market separation are analyzed with a comparison with a security constraints-based market design.

1. Introduction

1.1. Background and significance

Under the development of Microgrids and the possibility of bilateral energy trading with the upstream network, Distribution Systems (DS) have gradually changed from passive to active ones. Stakeholders who own their properties would change the supply and absorption of power in the network buses, which poses further challenges to a Distribution System Operator (DSO) to maintain the reliability of the power system. One of the main challenges of a system operation refers to line congestion, which occurs for various reasons, such as the emergence of new structures for Local Energy Markets (LEM) [1]. Generally, congestion management approaches are classified into three categories: direct control, market-based, and price-based methods [2–3]. Direct control methods are not practical approaches in attention to the data privacy requirements of independent operation. Also, priced-based strategies include preventive approaches, which impose congestion costs on energy transactions, which would be paid by market participants [4–6]. According to the essential need for energy for all prosumers, by changing the provision to the local market formation, a big question is related to the effects of the proposed model on data privacy, jurisdictions, financial profits, and, also aspects of fairness in cost allocations to energy transactions. Priced-based strategies adversely affect the users' profits in a grid-constrained transactive market [4,5]. On other hand,

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https://doi.org/10.1016/j.apenergy.2023.120832
Received 22 August 2022; Received in revised form 11 January 2023; Accepted 7 February 2023
Available online 24 February 2023
0306-2619/

Nomenclature

Indices

i	Indices of MGs
t	Indices of time, hour
$m/n/j$	Indices of buses
Ω_n	Sets of connections for MGs and buses
Ω_l	Sets of lines for distribution system
$\alpha_c, \beta_c, \delta_c$	Sets of coefficients for the linearized constraints of lines loading

Scalars

ρ	Penalty coefficient
Γ	Budget of uncertainty
M	Big number
k	Number of iterations
N_{MG}	Number of MGs
n_{Ref}	Reference bus (point of common coupling with TS)

Parameter

P^l/Q^l	Active/Reactive power of load (kW/kVar)
P^{PV}/P^{WT}	Output power of PV/WT units(kW)
v	Levelized costs of electricity (¢/kWh)
c	Operation & Maintenance cost coefficient (¢/kWh)
η	Efficiency (%)
P^{max}/P^{min}	Maximum/Minimum power output (kW)
E^{log}	Price elasticity of demand (kWh/¢)
λ	Price (¢/kWh)
r/x	Resistance/Reactance of network lines (ohm)
$y^{UF/DF}$	A parameter for MGs to provide UP/DN flexibility for DS in LFM according to the received request (0/1)

Positive Variables

P^{Ch}/P^{dCh}	Charge/disCharge power of ES (kW)
SOC	State of Charge of ES (kWh)
P^{MT}	Output power of MT (kW)
$\widehat{P}^S/\widehat{P}^B$	DSO schedule to Sell/ Buy energy to/of MGOs(kW)
P^S/P^B	MGO schedule to Sell/Buy energy to/of DSO (kW)
$P^{S,TS}/P^{B,TS}$	DSO schedule to Sell/ Buy energy to/of TSO (kW)
P^{UF}/P^{DF}	MGO schedule to Sell UP/DN flexibility to DSO (kW)
$\widehat{P}^{UF}/\widehat{P}^{DF}$	DSO schedule to Buy UP/DN flexibility services from MGOs(kW)
$P^{S,RT}/P^{B,RT}$	DSO schedule to Sell/ Buy flexibility services to/of RT-market(kW)
C	Cost of energy generation (¢)
V	Voltage of buses(kV)
ΔP	Rescheduling of active power for units(kW)
ξ, β	Dual variables for RO

Free Variables

RE/CE	Revenue/Cost of energy trading (¢)
P^{line}/Q^{line}	Active/Reactive power of line (kW/kVar)
P^{Shft}	Shiftable load (kW)

Binary Variables

y^E	Binary variable for MGs to sell/Buy energy to/of DS in LEM
$y^{UF/DF}$	Binary variable for MGs to sell UP/DN flexibility services in LFM
y^{ES}	Binary variable for ES to determine Charge/Discharge state
x^E	Binary variable for DS to sell/Buy energy to/of MGs in LEM
x^{TS}	Binary variable for DS to sell/Buy energy to/of TS in LEM
$x^{UF/DF}$	Binary variable for DS to buy UP/DN flexibility of MGs in LFM
x^{RT}	Binary variable for DS to Sell/ Buy flexibility to/of RT-market

Abbreviation

ADMM	Alternating Direction Method of Multipliers
DLMP	Distribution Locational Marginal Pricing
DS/DSO	Distribution System/ Distribution System Operator
ES	Energy Storage
LCOE	Levelized Costs of Electricity
LEM	Local Energy Market
LFM	Local Flexibility Market
MG/MGO	Microgrid/ Microgrid Operator
MT	Micro Turbine
NG	Natural Gas
PV	Photovoltaic
RO	Robust Optimization
RT	Real-Time
Sch	Scheduled
Shft	Shiftable
TS/TSO	Transmission System/ Transmission System Operator
UF/DF	Up Flexibility / Down Flexibility
WT	Wind Turbine
0	Denotes to the initial state

incentive-based strategies can be adopted to incentivize prosumers to provide flexibility services to meet the network security requirements instead of imposing corresponding expenses on LEM transactions. The Local Flexibility Market (LFM) also makes an opportunity for DSO to integrate flexibility services of prosumers to trade the extra services in real-time flexibility markets. In this regard, this paper proposes a complementary LFM to relieve the line congestion of DS under a day-ahead two-stage local market framework. Based on a distributed market design, the data privacy requirements are met for different market participants, and the computational burden of the market-clearing process would be restricted under the modified Alternating Direction Method of Multipliers (ADMM).

1.2. Related works

Flexibility is defined by Euro electric as the ability to adapt the generation or consumption pattern in response to an external signal, which would be a price signal or any other incentive or inhibitory parameter[6]. Ref. [7], has divided local markets into two categories of LEM and LFM and has devoted some services, such as congestion management, voltage support, and uncertainty support to the LFMs framework. Regarding the scope of the current paper to design a new LFM as a complementary market for congestion management of the DS, recent LFM designs have been reviewed in this section. The concept of designing appropriate frameworks for LFMs has been considered by many researchers, each of which has designed an LFM concerning specific services. The markets would protect data privacy, pay attention to the computational burden of market settlement, and keep fairness for market participants [8].In this regard, Ref. [9] proposes a direct load control model for consumers to use the home appliance flexibility services. The service's pricing is done through the aggregator as an intermediary for the energy trading of consumers and the DSO. However, the proposed market framework ignored the ownership jurisdictions under the direct control strategies. Ref. [10] based on the decision-making authorities, assumes two different buyers for flexibility services as DSO and balance responsibility party, and assigned the load aggregators to reply to the flexibility requests. Ref. [11] considers MGs as a source of flexibility to eliminate the congestion of the DS at a specific time. Under the ignorance of MG's capabilities to participate in LEMs, the rescheduling process to estimate the required free capacity is ignored in this article. To make a more practical model, Ref. [12], proposed an LFM considering the LEM results. LEM design is not addressed by this study, and the model is based on a centralized market-clearing structure. Ref. [13], has proposed an LFM model to balance the generation and consumption using the free capacity of batteries of customers. Developing the market structures and peer-to-peer energy trading imposes new challenges for the current power system to keep the security margin of the system while operating. In Ref. [14] a two-part congestion management model to satisfy the security constraints of the system is proposed. Although the proposed model assigned financial benefits to the end user via participating in the LFM, it doesn't design a new LFM framework. In Ref. [15], a centralized model for using the flexibility of load, generators, and storage of prosumers in providing services to DSO is proposed. The request includes the increase or decrease of generation at a specific time duration. In Ref. [16], the flexibility of multi-energy systems for frequency control services is studied. The structure of the proposed model also is based on the centralized problem structure. A centralized solution approach guarantees the achievement of a unique and optimal global solution to a feasible problem. However, according to data privacy concepts, the confidentiality of data will be compromised under a centralized problem structure. So, the models would be replaced by distributed and decentralized ones in new market designs. Ref. [17], proposes an LFM as a complementary market to manage the grid constraints by a distributed price-directed market clearing mechanism. But the market price uncertainty is ignored under a deterministic market model. Ref. [18], proposes a decentralized LFM at the distribution level, operating at the day ahead for mitigating expected congestions and real-time periods. Although a two-framework of market design is introduced, the flexibility services are traded at fixed prices. Ref. [19] has used the reserve capacity of prosumers for efficient flexibility securing mechanism to support DS stability. The proposed mechanism operates in a decentralized environment between utility, peer-to-peer community operator, and prosumer. However, implementing appropriate incentives and penalty strategies to promote the participation of prosumers is pointed out as future work. As the problem structure for MGs and DSO usually forms a bi-level problem under the independency of prosumers[20–21], the problem-solving approach plays a prominent role in evaluating the effectiveness of the proposed model. Ref. [21] presents a two-stage model for trading energy and flexibility in the LEM based on a hierarchical approach. In the first stage, prosumers trade energy in a peer-to-peer market, and in the second stage, the DS constraints have been addressed under optimal power flow calculations through flexibility provided by prosumers. In this study, the strategic bidding of prosumers and the decentralization of the market clearing process are assumed for future work. In Ref. [22], using a bi-level model, the flexibility services required by DSO are provided through MGs with renewable generation resources. A direct mathematical technique has been utilized to convert the proposed bi-level programming into the single-level one to provide ramping flexibility services. Similarly, Ref. [23] proposes a two-level model for congestion management of a DS with electric vehicles based on Distribution Locational Marginal Pricing (DLMP) and Karush–Kuhn–Tucker (KKT) conditions. The KKT conditions change the bi-level models into a one-level problem to be solved in a centralized manner which finally makes challenges for data privacy requirements. The other solutions based on decomposition methods increase the computational burden by adding cutting planes or new variables in each iteration. Distributed solution approaches are good alternatives to resolve the mentioned challenges. The ADMM is a decomposition algorithm for distributed convex optimization, which nowadays is widely adopted for distributed computing environments of power systems. It is also a good solution for problems with a large amount of data such as fully distributed optimal power flow problems [24]. In Ref.[25], the ADMM is implemented to coordinate the operational scheduling of the agents in a distributed manner. Moreover, a robust optimization technique is employed to consider the worst-case uncertainties for each agent. In Ref.[26], to prevent a high communication overhead for data transferring to the central controller, the ADMM is implemented for scheduling distributed energy resources and Energy Storage (ES) units integrated with the electrical power system. This method completely avoids centralized data processing and can reduce the required communications by sharing the minimum data[27]. In Ref. [28], using the ADMM method, end-users help to mitigate the congestion under an incentive-based strategy. The proposed LFM uses the flexibility services provided by the aggregators for congestion management of DS. The uncertainty of LFM is not considered in this article, and the mechanism of setting bidding prices for flexibility services is ignored. Ref.[5] proposes a security-constrained-based LEM to resolve the congestion by devoting the congestion costs to energy transactions. Although the proposed model keeps the confidentiality of data and clears the market with the operating constraints of the system, the results show that it is not a fair strategy by imposing the cost of line congestion on the market participants' payments. Table 1 reports a comparison table of recent studies regarding local market designs and related considerations of the proposed models.

1.3. Motivations and contributions

As can be deduced from the recent studies, an incentive-based design of a local flexibility market for congestion management of an active distribution system is not considered in any previous work. The proposed model with the distributed market framework keeps the confidentiality of data, achieves a global optimal solution for a feasible problem, keeps the operating jurisdictions for independent prosumers, and also makes a free environment for energy trading of prosumers without line loading restrictions. According to the effects of local energy market results on the free capacity of MGs, the LEM for energy trading of MGOs and DSO is also modeled. The design of LEM is not the concern of the current work, although the proposed model is a distributed complete market. Scheduling the remaining capacity of MGs requires the payment of incentive parameters, which will emphasize the need to define a new local market framework as an LFM. Several papers studied LFM design, although most models are designed based on a centralized structure regardless of data privacy issues and LEMs' results. So, the proposed LFM is a rescheduling model to complete the LEM. The DSO as an aggregator can integrate the extra flexibility services for the real-time flexibility market. The effects of real-time flexibility service prices are also considered under a robust optimization model to provide a practical market framework with uncertain parameters.

The following highlights the most important contributions of this paper:

- Design an incentive-based LFM to integrate the flexibility services of MGs
- Demand-side energy management and rescheduling process to use the free capacity of MGs to provide up-and-down flexibility services
- Use a modified ADMM method for LFM based on a request and response structure
- Provide a RO model to consider the real-time price uncertainty in a local flexibility market
- A two-stage model for LEM and LFM to enhance fairness for market participants in energy trading scheduling of LEM under congestion management strategies

The remainder of the paper is organized as follows: After a brief description of the problem statement for LEM and LFM in Section 2, Section 3 includes the problem formulation for two proposed markets in a deterministic and robust optimization structure. The performance of the proposed model is evaluated in Section 4 on an IEEE 33-bus test

Table 1
Comparison of conducted studies regarding local market design under security constraints of DS.

Ref.	Participants	LFM Structure	LEM Structure	Stochastic Market Model	Data Privacy	Timeframe	Services
[12]	DS, Prosumers	Centralized	–	–	–	Day-ahead	Congestion management
[17]	DS, Market Operator, Prosumers	Distributed	Peer-to-Peer	–	✓	Day-ahead	Manage grid constraints
[18]	DS, Prosumers	Decentralized	Centralized	–	–	Day-ahead Intra-day Real-time	Management for expected and sudden congestion occurrence
[19]	DS, Market Operator, Prosumers	Peer-to-Peer	Peer-to-Peer	–	✓	Day-ahead	Manage grid constraints
[21]	DS, Prosumers	Centralized	Peer-to-Peer	–	–	Day-ahead	Manage grid constraints
[22]	DS, MGs	Bi-level	–	–	–	15 min	Ramping product
[23 29]	DS, Electric Vehicles	–	Distributed	–	–	Day-ahead	Congestion management
[25]	Multi-agent DS	–	Distributed	✓	✓	Day-ahead	Manage grid constraints
[28]	DS, Aggregators	Distributed	–	–	✓	Day-ahead	Congestion management
[5]	DS, MGs	–	Distributed	–	✓	Day-ahead	Energy trading scheduling and Congestion management
C.P	DS, MGs	Distributed	Distributed	✓	✓	Day-ahead	Congestion management

system with four connected MGs. Then, the authors discuss the effectiveness of the proposed model on congestion management of DS, analyze the rescheduling procedure to provide flexibility services, and report the market clearing prices for the LEM and LFM. According to the major role of flexibility service price uncertainty on DS scheduling for flexibility requests, the robust analysis is reported in the following. The results validation for LEM and LFM are executed under comparison with a centralized market structure and analysis for an integrated LEM and LFM or a two-stage model is provided. The article's conclusion provides key findings of current works with an outlook for future work in Section 5.

2. Problem statement

In this paper, an MG is considered a small-scale power system with distributed energy resources and programmable loads that connects to the distribution system, participates in LEMs with DSO, and provides flexibility services on condition of receiving incentive payments. At the upstream level, the DSO as an aggregator with the responsibility of providing infrastructure for energy trading can trade the aggregated extra energy with Transmission System Operator (TSO) to gain financial profits. The third layer of the market for energy negotiation possibility for DSO and TSO is out of the scope of the current study because several distribution system companies would be connected to a TS which defines new requirements for the problem. So, energy trading of DSO with TSO is considered under fixed prices. Fig. 1 illustrates the data exchanges for market players. DSO as an upper-level player can sell/buy energy to/of MGs. Similarly, the MGOs can send their offers for energy trading as a lower player in the LEM. So, LEM generally includes a two-directional request structure for buyers and sellers to execute the market. In LEM, both MGO and DSO can play the role of buyers and sellers for energy trading. According to the current DS with not sufficient infrastructure for bilateral energy trading, the thermal capacity of lines for the DS must not be considered in LEM to make a free environment for energy trading negotiations. In this regard, this paper proposes a LEM framework, regardless of the thermal capacity of lines. After the LEM settlement and determination of the energy trading scheduling for DSO and MGOs, the results of LEM need to be considered by DSO under a security-constrained based optimization model to provide the operating requirements of congestion management. So, the requests for flexibility services are sent to MGs in the second stage. Fig. 2 illustrates the day-ahead trading interaction between players for LEM and LFM. MGs with free capacity for more power-providing and demand-side management capabilities can respond to the received requests to provide flexibility services to gain financial profits. LFM will function as a complementary local market for flexibility services trading. As the LFM is considered a complementary market under the DSO request, the MGs' response for flexibility services is conditional upon receiving the request signal from the DSO. Therefore, the LFM is based on a request-response structure. The extra flexibility services can be traded in the real-time flexibility market by DSO as an aggregator and an intermediate party.

3. Problem formulation

3.1. Local energy market

The LEM is proposed based on a distributed solution approach for energy trading of MGs and DS. In this regard, the negotiations of market

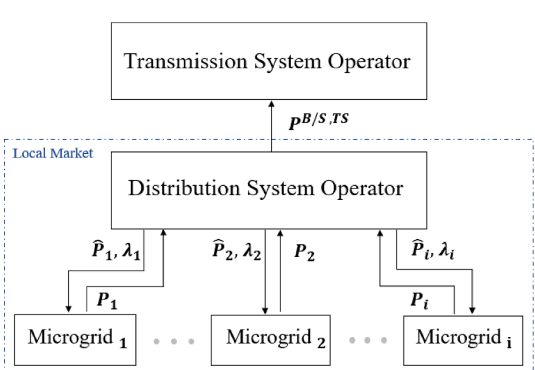

Fig. 1. Market participants.

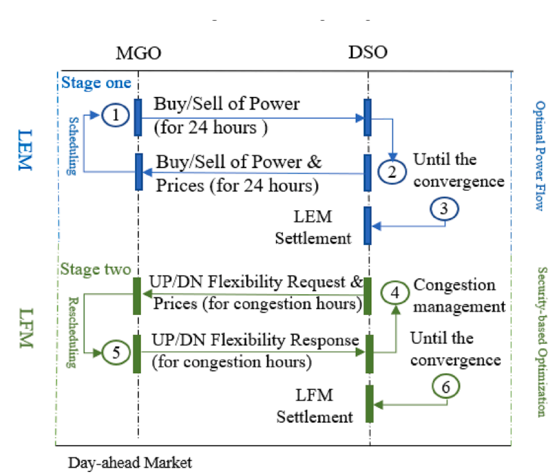

Fig. 2. Day-ahead trading inteactions between players for LEM and LFM.

participants are modeled under the ADMM method with a global parameter of λ[30]. The price of energy trading would be updated in each iteration according to the received bids and offers of buyers and sellers. Table 2 describes the communications of DSO and MGOs in the proposed LEM framework.

3.1.1. Microgrid

Equation (1) denotes the objective function of an MGO by considering the ability to participate in the LEM. Maximizing the profit of energy trading, minimizing the operation cost of energy generation, and penalty function form the main parts of an MG optimization model. Although renewable-based resources such as Wind Turbine (WT) and Photovoltaic (PV) units are considered zero costs resources with constant output power, due to the effect of the objective function on the energy trading schedule, the energy-providing cost needs to be considered in the model[31].

$$max\varphi_i \tag{1}$$

$$\varphi_i = \sum_{t=1}^{T} RE_{t,i}^{MG} - C_{t,i}^{ES} - C_{t,i}^{MT} - C_{t,i}^{WT} - C_{t,i}^{PV}$$

$$-\rho\Big/2\left\|\widehat{P}_{t,i}^{S} - P_{t,i}^{B} + \widehat{P}_{t,i}^{B} - P_{t,i}^{S}\right\|_2^2$$

s.t.
(2–14).

3.1.1.1. Photovoltaics. Given the assumption of separate ownership for MGs and DS, there is a need to estimate the cost of energy provided for MGs to generate rational energy-selling offers to the distribution system. According to the Levelized Cost Of Electricity (LCOE) definition as the price at which the generated electricity should be sold for the system to break even at the end of its lifetime[32], this concept is adopted in this paper to estimate the cost of energy-providing for renewable-based energy resources. LCOE is used as the lowest price at which electricity can be sold to another party to cover the energy-providing costs. Equation (2) denotes the energy-providing cost for the PV units. The output power of PV units within 24 h is assumed unprogrammable with deterministic power outputs.

$$C_{t,i}^{PV} = P_{t,i}^{PV} v_i^{PV} \qquad \forall t, \forall i \tag{2}$$

3.1.1.2. Wind Turbine. Similar to Equation (2), the LCOE is used for the cost estimation of WT units. Equation (3) denotes the energy-providing cost for the WT units. The output power is considered unprogrammable, and the distributed output power of WT is used for 24 h of the scheduling horizon.

$$C_{t,i}^{WT} = P_{t,i}^{WT} v_i^{WT} \qquad \forall t, \forall i \tag{3}$$

3.1.1.3. Micro Turbine. Equation (4) describes the operation cost of a Micro Turbine (MT) as the summation of the fuel costs and maintenance costs. Equation (5) denotes the limits for the output power of an MT unit.

$$C_{t,i}^{MT} = P_{t,i}^{MT} c_i^{MT} + P_{t,i}^{MT} \lambda_t^{NG} \Big/ \eta_i^{MT} \qquad \forall t, \forall i \tag{4}$$

$$P_{t,i}^{MT} \le P_i^{MT,max} \qquad \forall t, \forall i \tag{5}$$

3.1.1.4. Energy storage. Equation (6) denotes the operation cost for an ES. Equations (7) and (8) refer to the minimum and maximum values of power for charges and discharges. Equation (9) refers to the minimum and maximum values of the state of charge, and Equation (10) denotes the energy stored in an ES due to the charges and discharges.

$$C_{t,i}^{ES} = \left(P_{t,i}^{Ch} \eta_i^{Ch} + P_{t,i}^{dCh} \Big/ \eta_i^{dCh}\right) c_i^{ES} \qquad \forall t, \forall i \tag{6}$$

$$P_{t,i}^{Ch} \le P_i^{Ch,max} y_{t,i}^{ES} \qquad \forall t, \forall i \tag{7}$$

$$P_{t,i}^{dCh} \le P_i^{dCh,max} \left(1 - y_{t,i}^{ES}\right) \qquad \forall t, \forall i \tag{8}$$

$$SOC_i^{min} \le SOC_{t,i} \le SOC_i^{max} \qquad \forall t, \forall i \tag{9}$$

$$SOC_{t,i} = SOC_{t-1,i} + P_{t,i}^{Ch} \eta_i^{Ch} - P_{t,i}^{dCh} \Big/ \eta_i^{dCh} \qquad \forall t, \forall i \tag{10}$$

3.1.1.5. Local energy market. Equation (11) refers to the cost of energy trading for each MG in LEM. Equation (12) and Equation (13) used a binary variable to prevent a simultaneous bid for buying or selling the energy.

$$RE_{t,i}^{MG} = \left(P_{t,i}^{S} - P_{t,i}^{B}\right)\lambda_{t,i} \qquad \forall t, \forall i \tag{11}$$

$$P_{t,i}^{S} \le M.\left(y_{t,i}^{E}\right) \qquad \forall t, \forall i \tag{12}$$

$$P_{t,i}^{B} \le M.\left(1 - y_{t,i}^{E}\right) \qquad \forall t, \forall i \tag{13}$$

3.1.1.6. Power equality. Equation (14) refers to the power balance constraint at each hour for each MG.

$$P_{t,i}^{PV} + P_{t,i}^{WT} + P_{t,i}^{MT} + P_{t,i}^{dCh} + P_{t,i}^{B} = P_{t,i}^{l} + P_{t,i}^{Ch} + P_{t,i}^{S} \qquad \forall t, \forall i \tag{14}$$

3.1.2. Dso

Energy trading with MGs has necessitated making changes to the load flow models of DS based on the effect of power injections considering MGs connections. The load flow of a radial DS is formulated through a Dist. flow model[3334]. Fig. 3 shows a typical radial DS. Equation (15) refers to the DSO objective function in the LEM market. The objective function includes the cost of energy trading with TSO as Equation (16), and the revenue of energy trading with MGs as Equation (17). Equations (18) and (19) denote the DSO's decisions to trade energy with MGs. Equations (20) and (21) indicate the DSO's decision to trade energy with TSO. Equations (22) and (23) represent the active and reactive power balance constraints. Equation (24) determines the voltages of buses. Equation (25) refers to the permitted values of bus voltage deviations.

Table 2
LEM structure for energy trading of DSO and MGOs.

Start k = 0, $\widehat{P}_{i,t} = \widehat{P}_{i,t}^{0}$, $\lambda_{i,t} = \lambda_{i,t}^{0}$
Repeat
At each individual MG
Repeat
Wait
Until receive update $\widehat{P}_{i,t}, \lambda_{i,t}$ from DSO
(1) solve local problem in (1) for optimal solution $P_{i,t}$
(2) send $P_{i,t}$ to the DS
At the DSO
Repeat
Wait
Until receive update $P_{i,t}$ from all MGs
solve problem (15) for optimal solution $\widehat{P}_{i,t}$
ii) update dual variables (26): $\lambda_{i,t}^{k+1} = max\left(0, \lambda_{i,t}^{k} + \rho\left(\widehat{P}_{t,i}^{B} + P_{t,i}^{B} - \widehat{P}_{t,i}^{S} - P_{t,i}^{S}\right)\right)$
send $\widehat{P}_{i,t}, \lambda_{i,t}$ to all MGs
$k \leftarrow k+1$
Until a stopping criterion is met Equation (27)

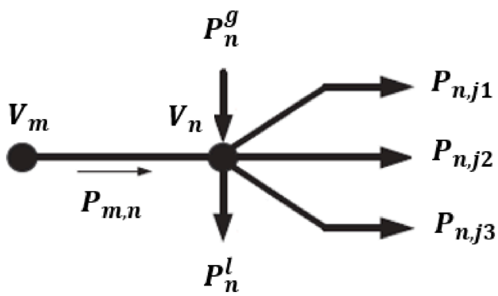

Fig. 3. A typical distribution system.

$$\min \quad \phi$$

$$\phi = \sum_{t=1}^{T} CE_t^{DS} - RE_t^{DS} + \rho/2\left\| \widehat{P}_{t,i}^{S} - P_{t,i}^{B} + \widehat{P}_{t,i}^{B} - P_{t,i}^{S} \right\|_2^2 \tag{15}$$

$s.t.$

$$CE_t^{DS} = P_t^{B,TS}\lambda_t^{B,TS} - P_t^{S,TS}\lambda_t^{S,TS} \qquad \forall t \tag{16}$$

$$RE_t^{DS} = \sum_{i=1}^{N_{MG}} \left(\widehat{P}_{t,i}^{S} - \widehat{P}_{t,i}^{B}\right)\lambda_{t,i} \qquad \forall t, \forall i \tag{17}$$

$$\widehat{P}_{t,i}^{S} \le x_{t,i}^{E}.M \qquad \forall t, \forall i \tag{18}$$

$$\widehat{P}_{t,i}^{B} \le \left(1 - x_{t,i}^{E}\right).M \qquad \forall t, \forall i \tag{19}$$

$$\widehat{P}_{t,i}^{S,TS} \le x_{t,i}^{TS}.M \qquad \forall t, \forall i \tag{20}$$

$$\widehat{P}_{t,i}^{B,TS} \le \left(1 - x_{t,i}^{TS}\right).M \qquad \forall t, \forall i \tag{21}$$

$$P_{m,n,t}^{line} + P^{B,TS}_{\substack{t,n \\ (n=n_{Ref})}} + \widehat{P}^{B}_{\substack{t,i \\ i\in\Omega_n}} = \sum_{\forall(n,j)\in\Omega_l} P_{n,k,t}^{line} + P_{n,t}^{l} + P^{S,TS}_{\substack{t,n \\ (n=n_{Ref})}} + \widehat{P}^{S}_{\substack{t,i \\ i\in\Omega_n}} \qquad \forall t, \forall n \tag{22}$$

$$Q_{m,n,t}^{line} + Q^{TS}_{\substack{t,n \\ (n=n_{Ref})}} = \sum_{\forall(n,j)\in\Omega_l} Q_{n,j,t}^{line} + Q_{n,t}^{l} \qquad \forall t, \forall n \tag{23}$$

$$V_{n,t} = V_{m,t} - \frac{r_{m,n}P_{n,t}^{l} + x_{m,n}Q_{n,t}^{l}}{V_{ref}} \qquad \forall t, \forall n \in \Omega_l \tag{24}$$

$$V^{min} \le V_{n,t} \le V^{max} \qquad \forall t, \forall n \tag{25}$$

As mentioned in the LEM algorithm, after solving the DSO problem, the price signal is updated according to the powers announced by MGO. The planned energy trading $\widehat{P}_{t,i}$ and prices are sent to the MGs afterward. According to Equation (26), the price signal needs to be updated.

$$\lambda_{i,t}^{k+1} = \max\left(0, \lambda_{i,t}^{k} + \rho\left(\widehat{P}_{t,i}^{B} + P_{t,i}^{B} - \widehat{P}_{t,i}^{S} - P_{t,i}^{S}\right)\right) \qquad \forall i, \forall t \tag{26}$$

This process will continue until both DSO and MGO reach an agreement on the amount of energy trading. Equation (27) refers to the stop condition of the algorithm.

$$\widehat{P}_{t,i}^{\,k+1} - P_{t,i}^{\,k+1} \le \varepsilon \qquad \forall i \in \Omega_n, \forall t \tag{27}$$

3.2. Local flexibility market

The MGO seeks to respond to the flexibility requests of DSO for gaining economic profits. Each response to decrease or increase power at a specific time needs a rescheduling process for operation planning of programmable energy generation units and demand side management at the MG side. Due to the participation of MGs in LEM, the majority of the energy generation capacity of MGs for energy trading would be allocated to the energy transactions in LEM. So, according to the impossibility of providing flexibility services by PV and WT units with the inherent characteristic of being unprogrammable, and according to the selling of the significant capacity of MG resources in the LEM, each MG would provide flexibility services by demand side management and rescheduling of MT units. Fig. 4 illustrates the two-stage market framework coordination. Equation (28) denotes the objective function of each MG regarding participation in the LFM. Maximizing profits from flexibility services, minimizing the cost of MT operation planning, and minimizing the ADMM penalty function part, includes the MG objective function for participating in an LFM. Table 3 describes the LFM structure for flexibility service trading of DSO and MGs.

3.2.1. MG

$$\max \quad \varphi_i^{'} \tag{28}$$

$$\varphi_i^{'} = \sum_{t=1}^{T} P_{t,i}^{UF}\lambda_{t,i}^{UF} + P_{t,i}^{DF}\lambda_{t,i}^{DF}$$

$$-\sum_{t=1}^{T}\left(\Delta P_{t,i}^{MT}c_i^{MT} + \Delta P_{t,i}^{MT}\lambda_t^{NG}\Big/\eta_i^{MT}\right)$$

$$-\rho\Big/2\left\| P_{t,i}^{UF} - \widehat{P}_{t,i}^{UF} + P_{t,i}^{DF} - \widehat{P}_{t,i}^{DF} \right\|_2^2 \qquad \forall i$$

$s.t.$

$(31-42)$

3.2.1.1. Flexibility request type.

Equations (29) and (30) denote the times that the request for flexibility is determined in each MG. Equations (31) and (32) make the provision of flexibility services conditional on receiving a request signal from the DSO. Equation (33) refers to the profitability of participation to LFM for MGO. Thus, if the MG does not gain economic benefits, it will prevent participating in the LFM.

$$y_{t,i}^{DF} = \begin{cases} 1 & \widehat{P}_{t,i}^{DF} \neq 0 \\ 0 & \widehat{P}_{t,i}^{DF} = 0 \end{cases} \qquad \forall i, \forall t \tag{29}$$

$$y_{t,i}^{UF} = \begin{cases} 1 & \widehat{P}_{t,i}^{UF} \neq 0 \\ 0 & \widehat{P}_{t,i}^{UF} = 0 \end{cases} \qquad \forall i, \forall t \tag{30}$$

$$P_{t,i}^{DF} \le M.y_{t,i}^{DF} \qquad \forall i, \forall t \tag{31}$$

$$P_{t,i}^{UF} \le M.y_{t,i}^{UF} \qquad \forall i, \forall t \tag{32}$$

$$\varphi_i^{'} \ge 0 \qquad \forall i \tag{33}$$

3.2.1.2. MT rescheduling.

Equation (35) denotes the possibility of providing excess power for MTs under the maximum and minimum generation capacity.

$$P_i^{MT,min} \le P_{t,i}^{MT,Sch} + \Delta P_{t,i}^{MT} \le P_i^{MT,max} \qquad \forall t, \forall i \tag{34}$$

$$\Delta P_{t,i}^{MT} \ge 0 \qquad \forall t, \forall i \tag{35}$$

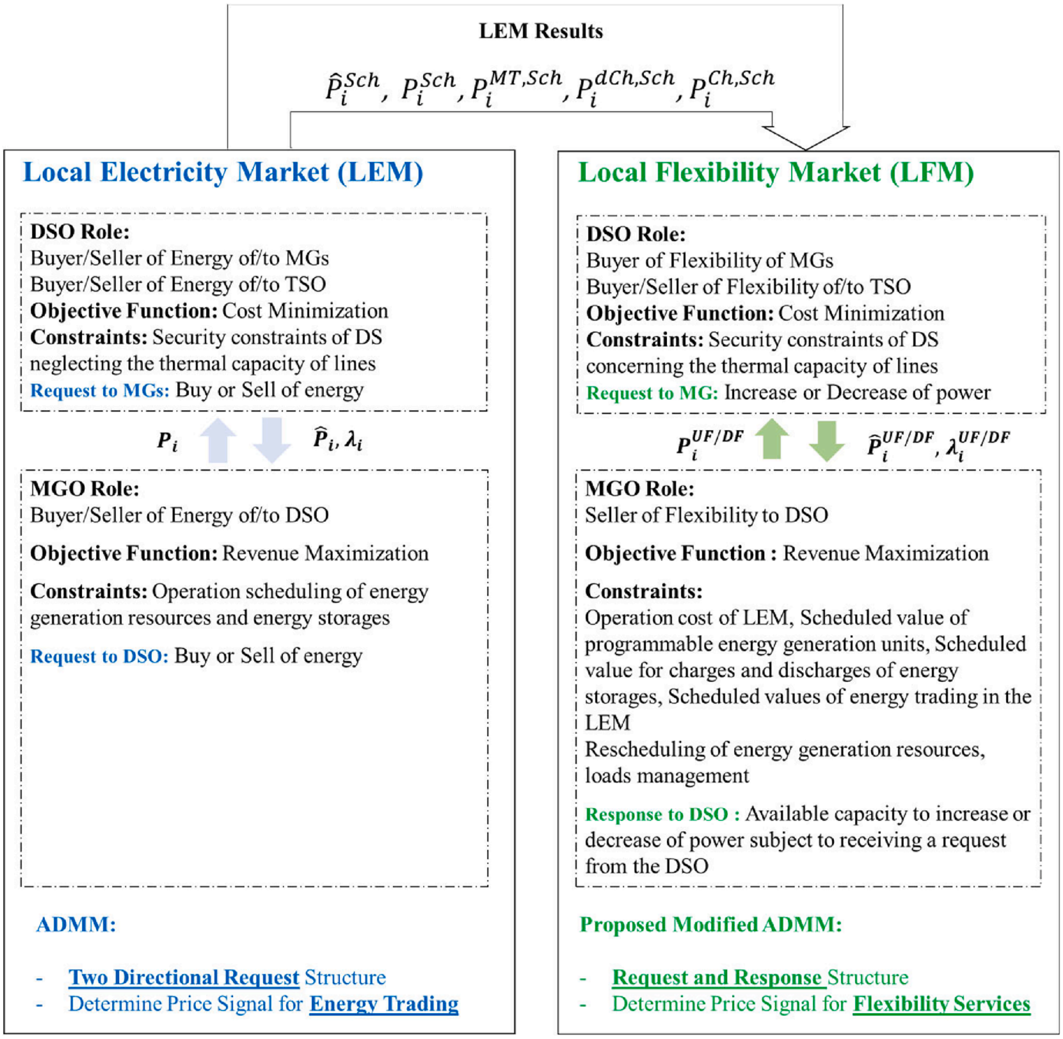

Fig. 4. LEM and LFM design for DS and MGs.

Table 3
LFM structure for energy trading of DSO and MGs.

1	Start K = 0, $\hat{P}_{t,i}^{DF/UF} = \hat{P}_{t,i}^{DF,0/UF,0}$, $\lambda_{i,t}^{UF/DF} = \lambda_{i,t}^{UF,0/DF,0}$ $\forall t, \forall i$
2	Repeat
3	**At each individual MG**
4	Repeat
5	Wait
6	**Until** receive request of $\hat{P}_{t,i}^{DF/UF}$, $\lambda_{t,i}^{UF/DN}$ for flexibility services from DSO
7	i) solve local rescheduling problem of MG in (28) for optimal solution
8	ii) update $\Delta P_{t,i}^{PR,UF/DF}$
9	iii)send $P_{t,i}^{UF/DF}$ to the DS
10	**At the DSO**
11	Repeat
12	Wait
13	**Until** receive update $P_{t,i}^{UF/DF}$ from all MGs
14	i) solve problem (44) for optimal solution $\hat{P}_{t,i}^{DF/UF}$
15	ii) update dual variables: $\left(\lambda_{t,i}^{UF}\right)^{k+1} = \max\left(\varepsilon, \left(\lambda_{t,i}^{UF}\right)^{k} + \rho\left(\hat{P}_{t,i}^{UF^{k+1}} - P_{t,i}^{UF^{k+1}}\right)\right)$
16	$\left(\lambda_{t,i}^{DF}\right)^{k+1} = \max\left(\varepsilon, \left(\lambda_{t,i}^{DF}\right)^{k} + \rho\left(\hat{P}_{t,i}^{DF^{k+1}} - P_{t,i}^{DF^{k+1}}\right)\right)$
17	iii) send $\hat{P}_{t,i}^{DF/UF}$, $\lambda_{t,i}^{DF/UF}$ to all MGs
18	$k \leftarrow k+1$
19	**Until** a stopping criterion is met (52)

3.2.1.3. Price-based demand response. Equations (36) determine the amount of load reduction in each MG to provide up-flexibility services. Also, Equations (36) refers to the amount of incremental load to respond to down flexibility[35]. To avoid synchronization of load increase and decrease programs, two Equations (38) and (39) have been used with binary variables to decide on a load management strategy. Two Equations (40) and (41) model the MG shiftable load for a 24-time period schedule.

$$\Delta P_{t,i}^{UF} = E_{t,i}^{log} log_{10}\left(\lambda_{t,i}^{UF}\right) \quad \forall t, \forall i \tag{36}$$

$$\Delta P_{t,i}^{FD} = E_{t,i}^{log} log_{10}\left(\lambda_{t,i}^{DF}\right) \quad \forall t, \forall i \tag{37}$$

$$\Delta P_{t,i}^{UF} \le M.y_{t,i}^{L} \quad \forall t, \forall i \tag{38}$$

$$\Delta P_{t,i}^{DF} \le M.\left(1 - y_{t,i}^{L}\right) \quad \forall t, \forall i \tag{39}$$

$$\sum_{t=1}^{T} P_{t,i}^{Shft} = 0 \quad \forall i \tag{40}$$

$$-P_{i}^{Shft,max} \le P_{t,i}^{Shft} \le P_{i}^{Shft,max} \quad \forall t, \forall i \tag{41}$$

3.2.1.4. Power equality constraint. Considering the impact of the LEM market on the LFM market, the power balance equation is represented as Equation (42). The request for up flexibility services denotes increasing the energy generation to be able to sell $P^{UF}_{t,i}$, and down flexibility services are about decreasing energy generation on the MG side to consume $P^{DF}_{t,i}$ as an incoming power to the MG.

$$P^{PV}_{t,i} + P^{WT}_{t,i} + P^{MT,Sch}_{t,i} + \Delta P^{MT}_{t,i} + P^{dCh,Sch}_{t,i} + P^{B,Sch}_{t,i} + P^{DF}_{t,i} + P^{Shft}_{t,i}$$
$$= \left(P^{l}_{t,i} - \Delta P^{UF}_{t,i} + \Delta P^{DF}_{t,i}\right) + P^{Ch,Sch}_{t,i} + P^{S,Sch}_{t,i} + P^{UF}_{t,i} \qquad \forall t, \forall i \qquad (42)$$

3.2.2. DSO

After the market clearing of LEM, to satisfy the thermal capacity constraints of the lines and prevent the occurrence of congestion in the network, DSO sends the request for up and down flexibility services to the MGs. The objective function of DSO includes minimizing the cost of purchasing flexibility services, optimizing trading of extra flexibility services in the real-time market, and minimizing the penalty function under the ADMM method. Equation (43) refers to the DSO objective function for LFM. Equations (44) and (45) refer to the active and reactive power balance constraints. Equations (46–47) denote the network voltage constraints. Equation (48) restricts the line's power flow to the thermal capacity of the lines.

$$\min$$
$$\sum_{t=1}^{T}\sum_{i=1}^{N_{MG}}\left(\widehat{P}^{UF}_{t,i}\lambda^{UF}_{t,i} + \widehat{P}^{DF}_{t,i}\lambda^{DF}_{t,i}\right) + \left(P^{B,RT}_{t}\lambda^{B,RT}_{t} - P^{S,RT}_{t}\lambda^{S,RT}_{t}\right)$$
$$+\rho/2\left\|P^{UF}_{t,i} - \widehat{P}^{UF}_{t,i} + P^{DF}_{t,i} - \widehat{P}^{DF}_{t,i}\right\|^2_2 \qquad (43)$$

$$s.t.$$

$$(44-47),(49)$$

$$P^{line}_{m,n,t} + P^{B,RT}_{t,n} + \underset{(n=n_{Ref})}{P^{B,TS,Sch}_{t,n}} + \underset{(i\in\Omega_n)}{\widehat{P}^{UF}_{t,i}}$$
$$= \sum_{\forall(n,j)\in\Omega_l} P^{line}_{n,j,t} + P^{l}_{n,t} + \underset{(n=n_{Ref})}{P^{S,TS,Sch}_{t,n}} + P^{S,in,RT}_{t,n} + \underset{(i\in\Omega_n)}{\widehat{P}^{DF}_{t,i}} \qquad \forall t, \forall n \qquad (44)$$

$$Q^{line}_{m,n,t} + \underset{(n=n_{Ref})}{Q^{TS}_{t,n}} = \sum_{\forall(n,j)\in\Omega_l} Q^{line}_{n,j,t} + Q^{l}_{n,t} \qquad \forall t, \forall n \qquad (45)$$

$$V_{n,t} = V_{m,t} - \frac{r_{m,n}P^{l}_{n,t} + x_{m,n}Q^{l}_{n,t}}{V_{ref}} \qquad \forall t, \forall n \qquad (46)$$

$$V^{min} \le V_{n,t} \le V^{max} \qquad \forall t, \forall n \qquad (47)$$

$$\left(P^{line}_{m,n,t}\right)^2 + \left(Q^{line}_{m,n,t}\right)^2 \le \left(S^{max}_{m,n}\right)^2 \qquad \forall t, \forall(m,n)\in\Omega_l \qquad (48)$$

Since the feasible region restricted in Equation (48) comprises the interior space of a circle (depicted in Fig. 5), using the polygonal inner-approximation method, the nonlinear constraints in Equation (48) can be changed to the linear model as Equation(49)[36]:

$$\alpha_c P_{m,n,t} + \beta_c Q_{m,n,t} + \delta_c S^{max}_{m,n} \le 0$$
$$\forall t, \forall c \in \{1,2,..,12\}, \forall(m,n)\in\Omega_l \qquad (49)$$

After performing the calculations and determining the required flexibility, the price signal is updated. Equation (50–51) shows how the price signal is updated.

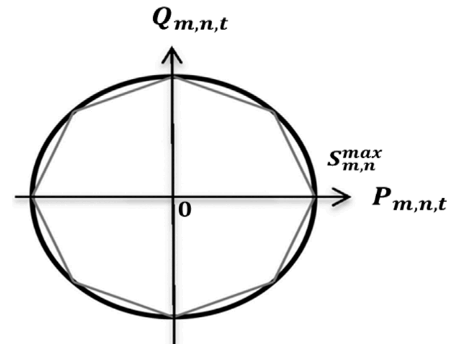

Fig. 5. Diagram of a polygonal inner-approximation method.

$$\left(\lambda^{UF}_{t,i}\right)^{k+1} = \max\left(\varepsilon, \left(\lambda^{UF}_{t,i}\right)^{k} + \rho\left(\widehat{P}^{UF^{k+1}}_{t,i} - P^{UF^{k+1}}_{t,i}\right)\right) \qquad \forall t, \forall i \qquad (50)$$

$$\left(\lambda^{DF}_{t,i}\right)^{k+1} = \max\left(\varepsilon, \left(\lambda^{DF}_{t,i}\right)^{k} + \rho\left(\widehat{P}^{DF^{k+1}}_{t,i} - P^{DF^{k+1}}_{t,i}\right)\right) \qquad \forall t, \forall i \qquad (51)$$

This algorithm will continue until the stop condition is met. Equation (52) denotes the stopping condition for the LFM algorithm.

$$\widehat{P}^{UF/DF}_{t,i} - P^{UF/DF}_{t,i} \le \varepsilon \qquad \forall t, \forall i \qquad (52)$$

In the following, considering the uncertainty of the RT-market price parameter, the deterministic model would change to a RO problem.

3.3. Robust model of LFM problem

LFM design is a new concept and there is not a powerful database to make a stochastic analysis for this market results now. Due to the impossibility of scenario generation for unknown parameters and increasing the computational burden of problem-solving by assuming different scenarios, the RO method is an effective solution to model the uncertainty of the RT market price uncertainty for flexibility services trading. RO ensures the feasibility of the results for all cases of uncertain parameters and determines the optimal solution of the problem for the worst case of the uncertain parameter. Assuming the range of $\left[\lambda^{B}_{t}{}_{-}, \overline{\lambda^{B}_{t}}\right]$ and $\left[\lambda^{S}_{t}{}_{-}, \overline{\lambda^{S}_{t}}\right]$ for real-time market prices and the budget of uncertainty to control the degree of risk ($\overline{\Gamma_\lambda}$ and $\Gamma_{\lambda\,-}$), the RT-price uncertainty can be modeled with Equations (53–54) [37]:

$$U_{\lambda^{B,RT}} = \left\{\begin{array}{ll} \lambda^{B,RT,u}_{t} \in R^{+}: & \Gamma_{\lambda\,-} \le \dfrac{\sum \lambda^{B,RT,u}_{t}}{\sum \lambda^{B,RT}_{t}} \le \overline{\Gamma_\lambda} \\ \lambda^{B,RT,u}_{t} \in \left[\lambda^{B,RT}_{t}{}_{-}, \overline{\lambda^{B,RT}_{t}}\right] & \end{array} \quad \forall t \right\} \qquad (53)$$

$$U_{\lambda^{S,RT}} = \left\{\begin{array}{l} \lambda^{S,RT,u}_{t} \in R^{+}: \Gamma_{\lambda\,-} \le \dfrac{\sum \lambda^{S,RT,u}_{t}}{\sum \lambda^{S,RT}_{t}} \le \overline{\Gamma_\lambda} \\ \lambda^{S,RT,u}_{t} \in \left[\lambda^{S,RT}_{t}{}_{-}, \overline{\lambda^{S,RT}_{t}}\right] \end{array} \quad \forall t \right\} \qquad (54)$$

For a more conservative solution, a wider range of uncertainty deviation and a bigger value for a budget of uncertainty must be considered. Equation (55) refers to the robust model of the deterministic model of the problem (43).

$$\min$$

$$\sum_{t=1}^{T}\sum_{i=1}^{N_{MG}}\left(\widehat{P}_{t,i}^{UF}\lambda_{t,i}^{UF}+\widehat{P}_{t,i}^{DF}\lambda_{t,i}^{DF}\right)+\rho/2\left\|P_{t,i}^{UF}-\widehat{P}_{t,i}^{UF}+P_{t,i}^{DF}-\widehat{P}_{t,i}^{DF}\right\|_2^2$$

$$+\boldsymbol{minmax}\sum_{t=1}^{T}\left(P_t^{B,RT}\lambda_t^{B,RT}-P_t^{S,RT}\lambda_t^{S,RT}\right) \quad (55)$$

The min–max structure for RO is based on problem optimization for the worst-case price that leads to the lowest trading income. The worst-case scenario in the proposed robust model depends on two parts. The first part refers to the lowest revenue from the sale of energy in the RT market, and the second part refers to the highest cost from the flexibility purchases. Variable z indicates the probable deviation for the uncertain parameter. Considering that buying with the highest price and selling with the lowest price constitute the worst cases of uncertainty, by replacing the worst prices in Equation (55), the uncertain part of the robust model will be rewritten as follows.

$$\boldsymbol{max} \quad (56)$$

$$\sum_{t=1}^{T}P_t^{B,RT}\left(\lambda_t^{B,RT}+z_t^B\widehat{\lambda}_t^{B,RT}\right)-P_t^{S,RT}\left(\lambda_t^{S,RT}-z_t^S\widehat{\lambda}_t^{S,RT}\right)$$

$$z_t^B\le 1 \quad : \quad \xi_t^B\ ,\ \forall t$$

$$z_t^S\le 1 \quad : \quad \xi_t^S\ ,\ \forall t$$

$$\sum_{t=1}^{T}z_t^B+z_t^S\le\Gamma:\beta$$

$$z_t^B\ge 0$$

$$z_t^S\ge 0$$

The variables ξ_t^B, ξ_t^S, β are dual variables of the first problem. Using the Lagrangian method of multipliers and generalizing the basis of the technique to the problems with inequality constraints, the dual problem is rewritten using the KKT conditions as Equation (57):

$$\boldsymbol{min} \quad \Gamma\beta+\sum_{t=1}^{T}\xi_t^B+\xi_t^S \quad (57)$$

S.t.

$$\xi_t^B+\beta\ge\widehat{\lambda}_t^{B,RT}P_t^{B,RT}$$

$$\xi_t^S+\beta\ge\widehat{\lambda}_t^{S,RT}P_t^{S,RT}$$

$$\xi_t^B\ge 0$$

$$\xi_t^S\ge 0$$

$$\beta\ge 0$$

By replacing the dual model of the min–max problem in Equation (58), the robust optimization model of an LFM is formulated as follows:

$$\boldsymbol{min} \quad (58)$$

$$\Gamma\beta+\sum_{t=1}^{T}\xi_t^B+\xi_t^S+\sum_{t=1}^{T}\sum_{i=1}^{N_{MG}}\left(\widehat{P}_{t,i}^{UF}\lambda_{t,i}^{UF}+\widehat{P}_{t,i}^{DF}\lambda_{t,i}^{DF}\right)$$
$$+\rho\Big/2\left(\left\|P_{t,i}^{UF}-\widehat{P}_{t,i}^{UF}+P_{t,i}^{DF}-\widehat{P}_{t,i}^{DF}\right\|_2^2\right)$$

s.t.

$$\xi_t^B+\beta\ge\widehat{\lambda}_t^{B,RT}P_t^{B,RT}$$

$$\xi_t^S+\beta\ge\widehat{\lambda}_t^{S,RT}P_t^{S,RT}$$

$$\xi_t^B\ge 0$$

$$\xi_t^S\ge 0$$

$$\beta\ge 0$$

(44–47), (49–52).

4. Results

4.1. Input data

For evaluation of the proposed model, the IEEE 33-bus test system with four connected MGs (buses 8, 13, 16, 33) with the lines' power flow capacity of 1500kVA, 800 kVA, and 500 kVA has been studied [17]. Fig. 6 illustrates the schematic of the casestudy. Table 4 reports the components and resources of each MG. The technical parameter and specifications of MTs and ES are reported in Table 5, and Table 6, respectively. Fig. 7 refers to the 24-hour load profile, and Fig. 8 shows the distributed output power of PVs and WTs. Fig. 9 shows the distribution system's load profile for active and reactive demand. LCOE for PV units and WTs are assumed to be 5.1 and 5.2 ¢ / kWh [33]. Operation & Maintenance costs of MTs and ES are assumed to be 1.7 and 0.6 ¢ / kWh [34]. The NG-gas price and RT-market prices are taken from Ref. [35]. The load elasticity for the priced-based load models is assumed to be −13.397 according to Ref. [29] with the maximum shiftable load of 25 %. Fig. 6 reports the 24-hour load values of each MG.

4.2. Congestion management analysis

After the market clearing process for LEM and determination of the energy trading for MGs, power flow calculation reports the over loadings values for distribution system lines to determine the flexibility services requirements. Table 7 reports the overloading values and related congestion times after the LEM clearing process. According to the calculation results, ignorance of the line's capacity will create congestion for four hours of operation, especially in line No.1, close to the Point of Common Coupling (PCC) of the system. In hours 22, 20, 18, and 16 with maximum overloading of 6.92 %, 5.02 %, 2.44 %, and 1.04 %, the flexibility requests must be sent for MGs to prevent the violation of the system security constraints. The results of the system status after LFM clearing are reported in Table 8. According to the analysis of the result, the overloaded system with an average of 3.19 % line congestion, and 262 kVA net flexibility requirements, lead to buy of 435 kVA flexibility services to increase the security margins of the system up to 7.72 % with an average of 95.47 % lines loading. A fact, which is related to the inherent impact of the point of power injection effect to relieve line congestion. So as the flexibility services providing units are not exactly located in the best optimal location to relieve congestion, the actual flexibility services would take more value in comparison to the net flexibility requirements. The negotiation process would also influence the convergence procedure to an optimal global solution, which is the best point for all distributed systems coordination. Table 9 reports the results of the LFM settlement. Generally, the flexibility requests are generated for congested times with one more request for hour 15, which is related to the attractiveness of the LFM in obtaining economic profits. Also, hour 15 is a good option for flexibility trading according to the suitable security margin of line loading. The maximum, minimum, and average values of free capacity for system lines are 95.49 %, 9.68 %, and 68.19 % at this hour, respectively. The solution to respond to the flexibility request on MGs side is reviewed under section 4.3 for operation planning and rescheduling analysis. Table 10 reports the average and maximum values for system line loading after the LFM. The results are

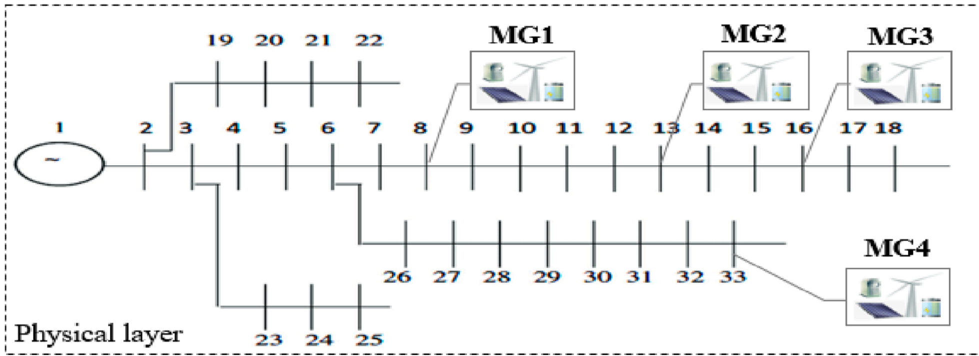

Fig. 6. IEEE 33 Bus with Four Microgrid.

Table 4
Microgrid Component information.

No.	Equipment configuration
MG1	PV: 200 kW, EES:150 kWh, MT:90 kW
MG2	PV: 300 kW, Wind:300 kW, EES:150 kWh, MT:90 kW
MG3	PV: 350 kW, Wind:200 kW, EES:150 kWh, MT:90 kW
MG4	PV: 250 kW, EES:150 kWh, MT:90 kW

Table 5
Micro turbine parameters.

Parameter	Value
$P^{MT,min}/P^{MT,max}$	0/90 (kW)
$c^{OP,MT}$	1.7(¢/kWh)
η^{MT}	0.9 (%)

Table 6
Electrical energy storage parameters.

Parameter	Value
$P^{Ch,min}/P^{Ch,max}$	0/50 (kW)
η^{Ch}/η^{dCh}	0.9/0.8 (%)
SOC^{min}/SOC^{max}	0/150 (kWh)
c^{ES}	0.6 (¢/kWh)

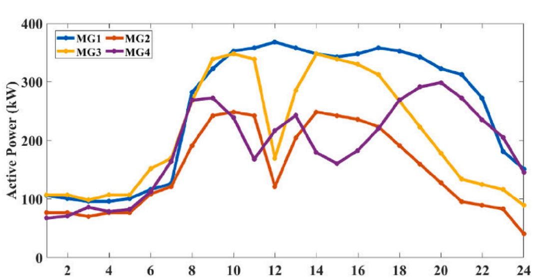

Fig. 7. Typical load curves of different MGs.

reported under both deterministic and robust optimization analyses. Applying the RO model by reducing the DSO's intendancy for economic risk, increased the average percent of overloading for the system under a lower integration of flexibility services for exchange in the real-time market.

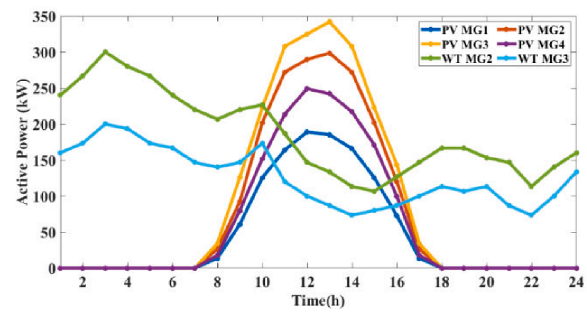

Fig. 8. Distributed power output of PVs and WTs.

4.3. Operation planning and rescheduling

Due to the unprogrammable output power of renewable energy resources, the free capacity of MT units and demand side management capabilities are employed to provide flexibility services in an LFM framework. Fig. 10 shows operation planning for LEM and the rescheduling process of each MG to make responses to the received requests.

As the MG1 has a high energy demand, this MG has bought energy in general periods and provided its required power deficit in the LEM. Due to the higher energy prices during peak hours, the ES in hours (12–14) and (21) has discharged to supply energy, and the charging process is shifted to the hours with lower prices, such as (4–6). The MT of MG1 is scheduled with total capacity except at hours 8 and 18 with the lower price of energy (6 ¢ / kWh), which the energy purchases strategy became a more practical solution. After clearing the LEM, MG1 has provided the flexibility request by using the free capacity of MT and demand-side management capabilities. Table 11 reports the rescheduling results of MG1 for LFM. According to the rescheduling results, MG 1 has provided 122.5 kWh flexibility services in response to a 1067 ¢ payment of the LFM.

MG 2 has generally played the role of an energy seller in the LEM except for hour 18, which purchased 74.6kWh of energy. Due to the lower energy demand for MG2, the MT was turned off for more hours in comparison to the MG1 (8, 18, 23, 6). This free capacity is used for flexibility services in LFM. Table 12 reports the rescheduling results of MG2 for LFM. MG 2 has provided 114.36 kWh of flexibility services to gain 856 ¢ payment from the LFM participation. Table 12 reports the rescheduling results of MG2 for LFM.

MG3 has power deficiency and surplus energy at different hours, so it plays the role of a seller and a buyer of energy. In most periods, MG3 has purchased energy and has not used the discharge capability of ES except at hour 18. This schedule is according to the lower energy price of this period (6–9 ¢ / kWh) compared to the period of 12–14 when the energy

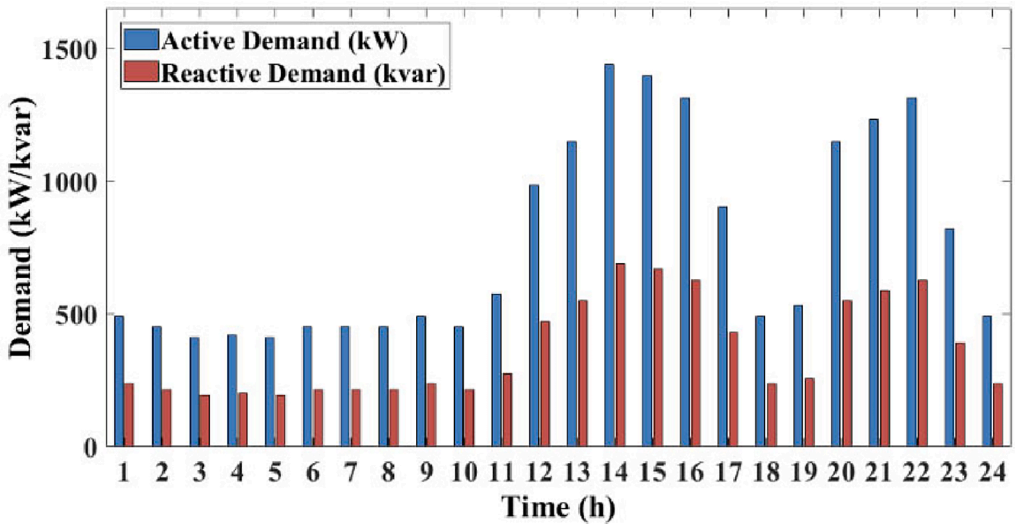

Fig. 9. Active and Reactive power demand of DS.

Table 7
LEM results for lines loadings.

Time (hour)	Line Number	From bus	To bus	Line Loading (kVA)	Line Capacity (kVA)	Over Loading (kVA)
22	1	b1	b2	1603.755	1500	103.754
20	1	b1	b2	1562.43	1500	62.430
18	1	b1	b2	1536.664	1500	36.663
20	25	b6	b26	525.097	500	25.097
16	1	b1	b2	1515.624	1500	15.623
18	6	b6	b7	813.191	800	13.191
20	26	b26	b27	505.354	500	5.354

Table 8
LFM results for lines loadings.

Time (hour)	Line Number	From bus	To bus	Line Loading (kVA)	Line Capacity (kVA)	Congestion Relief (kVA)
22	1	b1	b2	1468.717	1500	135.037
20	1	b1	b2	1457.918	1500	104.512
18	1	b1	b2	1456.904	1500	79.759
20	25	b6	b26	474.7214	500	50.375
16	1	b1	b2	1468.717	1500	46.906
18	6	b6	b7	737.7197	800	75.471
20	26	b26	b27	454.8659	500	50.488

Table 9
Flexibility services.

Time (hour)	MG1	MG2	MG3	MG4	Total flexibility request
22	52.46	33.34	39.81	21.43	147.04
20	8.03	27.99	23.56	52.08	111.66
18	10.05	31.84	33.8	5	80.69
16	7.12	21.19	17.19	5.85	51.35
15	44.87	0	0	0	44.87

Table 10
Line loading comparison for LEM & LFM.

	Maximum Line Loading	Average Line Loading
LEM	106.92 %	29.32 %
LFM (Deterministic)	97.91 %	28.16 %
LFM (Robust)	97.91 %	28.77 %

trading price is about 12–13 ¢ / kWh. Similarly, MG3 has provided 114.3 kWh of flexibility services for a profit gain of 856.7 ¢. Table 13 reports the rescheduling results of MG3 for LFM.

MG4 without a WT unit needs more energy to buy from the LEM. Because of higher energy prices in periods (10–16), the energy is sold during this duration, and energy purchases have been made in periods with lower energy prices. MG4 and MG1 with lower energy generation of MT and a more suitable situation in the system, have gained an average of 7.96 ¢ / kWh and 8.70 ¢/kWh for flexibility services, which reports a more average payment in comparison to the income of MG2 and MG3 with 7.49 ¢ /kWh. MG4 has received 672.18 ¢ for the delivery of 84.36 kWh of flexibility services. Table 14 reports the rescheduling results of MG4 for LFM.

4.4. Market clearing prices of LEM and LFM

Fig. 11 reports market-clearing prices for LEM. According to the execution of the day-ahead energy market, the results of the market settlement are determined 24 h a day under bilateral energy trading negotiations. Congestion management on the LEM framework, would increase the price of energy for prosumers. The price comparisons the for integrated market model are reported in Table 15. The obtained results indicate that the security-constrained based market design would control the energy trading of prosumers regarding their situation in the power system. After negotiations, providing the flexibility services is cleared for all MGs with 10.35 ¢ / kWh except for hour 15 for MG2 to MG4. Fig. 12 shows the negotiation process for flexibility trading of MG1 and DSO for congested durations and hour15.

4.5. Results validation

As can be seen in Table 16, the values of the social welfare function for the proposed LEM are equal to the results of the centralized market structure with 251622.8 ¢ cost, which guarantees the achievement of the optimal global solutions for the proposed LEM. Regarding the paper's points of view to propose a complementary LFM for the LEM to provide a proper congestion costs allocation for market participants, two different models are executed to show the effectiveness of the proposed model. At first, a result analysis is done for an integrated LEM under the security constraints of the system (Base model), and then the effects of an incentivized-based LFM as a complementary market for the LEM are considered (Proposed model). The proposed market structure would decrease the total cost of the entire system by 2910.2 ¢ and increase the social welfare value by 1.15 %. The result indicates the efficiency of the

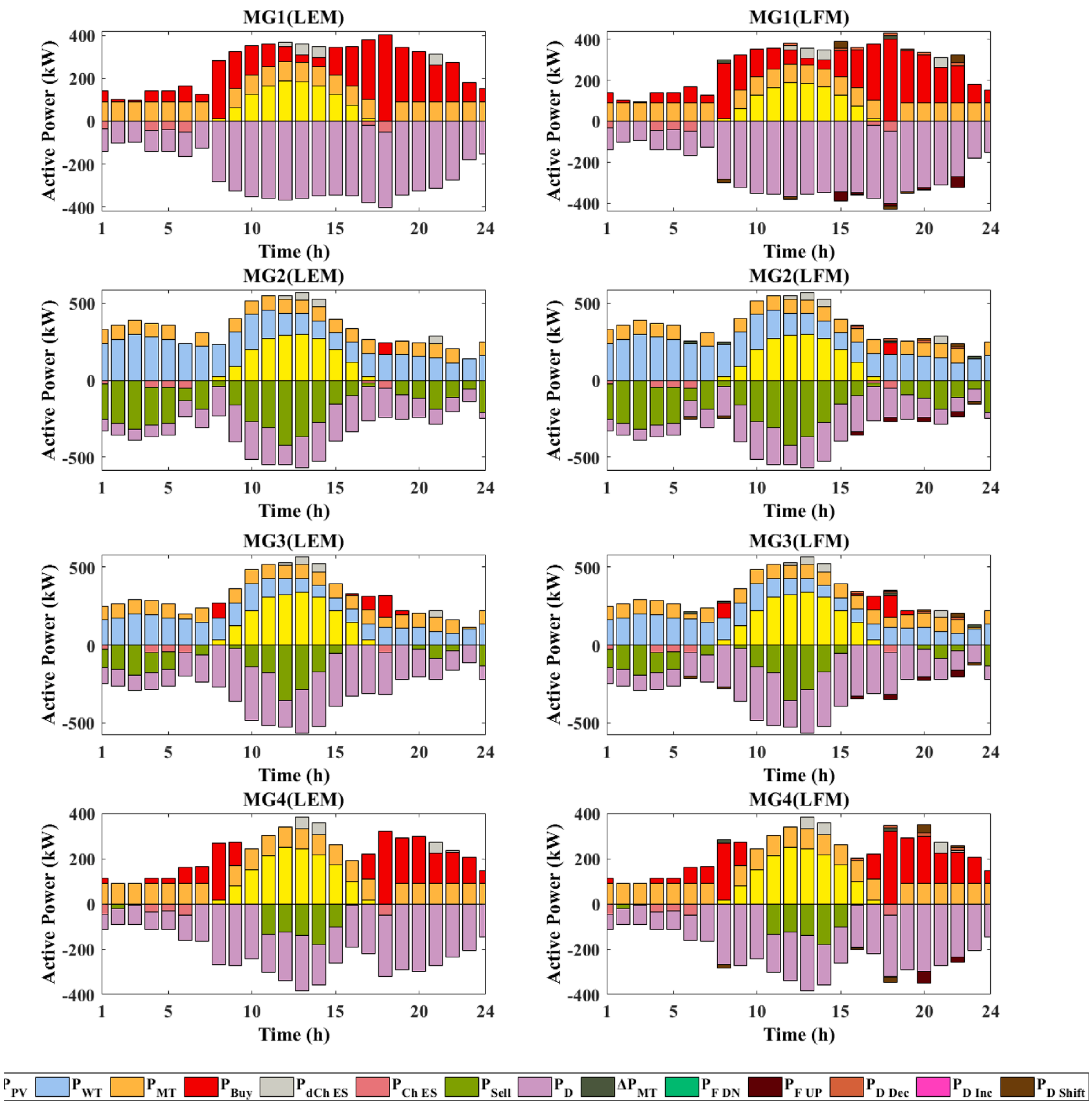

Fig. 10. Operation planning of Microgrids after LEM & LFM.

Table 11
Rescheduling of MG1 for LFM.

Time	MT Generation	Shiftable Load	Decreased Load	Flexibility Services
8	+15.00	−15.00	–	–
12	–	−13.26	+13.26	–
15	–	+31.28	+13.59	+44.87
16	–	−6.47	+13.59	+7.12
18	+15.00	−18.54	+13.59	+10.05
19	–	−11.32	+11.32	–
20	–	−5.57	+13.59	+8.03
22	–	+38.87	+13.59	+52.46

Table 12
Rescheduling of MG2 for LFM.

Time	MT Generation	Shiftable Load	Decreased Load	Flexibility Services
6	+15.00	−15.00	–	–
8	+15.00	−15.00	–	–
16	–	+7.60	+13.59	+21.19
18	+15.00	+3.25	+13.59	+31.84
20	–	+14.40	+13.59	+27.99
22	–	+19.75	+13.59	+33.34
23	+15.00	−15.00	–	–

proposed model to meet the security constraints of the system while improving social welfare. The security constraint-based LEM generally increases the operating costs for most MGs under congestion cost allocations and decreases the total costs for DSO. MG1 and MG4 have experienced the most changes in operating costs with 6.96 % and 5.98 % cost reductions under the proposed model. In this model, the location of MGs does not provide an obstacle for their energy trading in the LEM. The line congestion of the DS by changing the nodal prices affects the energy trading in the LEM, causing some transactions to intensify and others to be prevented due to the location of the prosumers. According to Table 17, just MG2 has experienced a cost increment under the new proposed model. The reason is referred to the low energy demand of MG2, which made it capable to sell more amounts of energy in the congested state under higher energy trading prices. The proposed market framework provides fairer situations for the participation of MGs in the LEM by eliminating the cost of congestion parameters of energy trading prices. On the other hand, by imposing a cost on the DSO side to

Table 13
Rescheduling of MG3 for LFM.

Time	MT Generation	Shiftable Load	Decreased Load	Flexibility Services
6	15.00	−15.00	–	–
8	15.00	−15.00	–	–
16	–	+3.60	+13.59	+17.19
18	15.00	+5.21	+13.59	+33.80
20	–	+9.97	+13.59	+23.56
22	–	+26.22	+13.59	+39.81
23	15.00	−15.00	–	–

Table 14
Rescheduling of MG4 for LFM.

Time	MT Generation	Shiftable Load	Decreased Load	Flexibility Services
8	15.00	−15.00	–	–
16	–	−7.74	+13.59	+5.85
18	15.00	–23.59	+13.59	+5.00
20	–	+38.49	+13.59	+52.08
22	–	+7.84	+13.59	+21.43

cover the inefficiency of the current distribution system for energy trading, it uses the available capacities of MGs instead of incentivizing payments for participating in LFM. Lack of LFM leads to higher prices during congestion hours to control energy trading and affects the fairness of MGOs by paying the cost of congestion.

4.6. Scalability

To verify the effectiveness of the proposed model in practical deployment, three different cases are studied to consider the effect of the number of prosumers on the computation time and the number of iterations required for ADMM convergence. According to the IEEE 33 bus test system elasticity, the current study is executed for MG1 with half the demand for 4, 8, and 12 connections to different system buses. The stop condition is defined based on energy transaction agreements for an ε less than 0.01 with an accuracy error of approximated zero. The results indicate that increasing the number of prosumers would increase both the computation time and the number of iterations under a more number of problem variables. However, as the market is performed for a day-ahead market framework the results are still acceptable and verify that the proposed two-stage market is implementable for local markets with a large number of MGs. Also, according to the proposed modified ADMM, which is based on the request and response structure, the negotiation procedure would be just limited to the request time of DS. This modification also enhanced the convergence time by eliminating the none required suggestions of MGs for providing flexibility services. Although this study is performed for an identical MG structure (MG1) to verify the effects of the number of MGs, this characteristic is related to several parameters such as prosumers scheduling coherence, computation systems capabilities, and defined problem accuracy that would increase or decrease the convergence time. General Algebraic Modeling System (GAMS) is used to model and analyze mixed-integer programming. Case studies were run on a home computer with an Intel core i7, 2.60 GHz, and 16 GB RAM. Table 18 reports the effects of the increment in the number of MGs on iteration number, computation time, and problem variables.

4.7. Robust analysis and uncertainty

The effects of market price uncertainty of the LFM for flexibility service trading of DSO are considered for three different deviations of 10 %, 20 %, and 30 %, and different budgets of uncertainty from $\Gamma = 0$ to $\Gamma = 5$. As expected, the value of the cost function for DSO has increased with increasing price deviation and budget of uncertainty value[38]. Fig. 13 shows the DSO cost parameter under robust optimization. The results show the impact of real-time market price uncertainty on the flexibility trading of DSO for financial purposes. The amount of flexibility services requested by the DSO on congestion hours is identical for all different values of Γ parameter and price deviation because, in this condition, the DSO is forced to buy services with any

Table 15
Market clearing price increments in security constrained-based LEM (¢).

Time	MG1	MG2	MG3	MG4
16	3.89	3.50	2.50	3.50
17	1.19	1.07	1.19	1.19
18	0.02	0.01	0.00	0.03
20	2.78	2.50	2.50	2.78
21	0.56	0.50	0.50	0.56

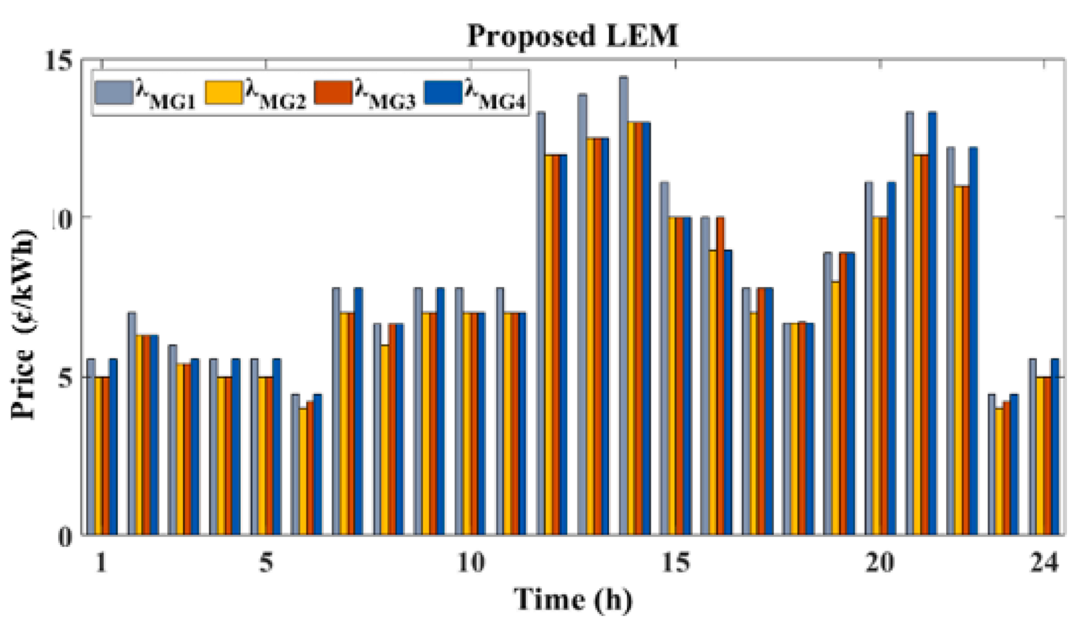

Fig. 11. LEM prices for energy trading of MG.

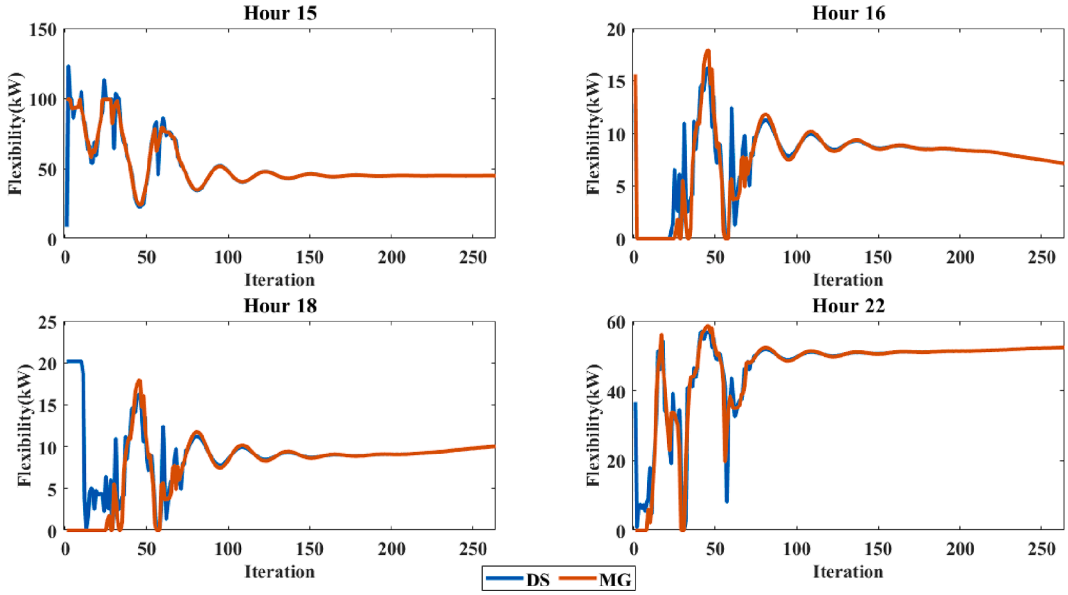

Fig. 12. Negotiation process for MG1in LFM.

Table 16
Results comparison for centralized and distributed LEM.

	Distributed Model	Centralized Model
Social Welfare	251622.8636	251622.8636
Iteration number	1521	–
Convergence time	02:35:20	00:00:05

budget of uncertainty in LFM. But sending the flexibility request for other hours depends on the level of LFM robustness, which emphasizes the main purpose of designing a LFM to purchase services to relieve line congestion. Fig. 14 shows the effects of robust optimization on flexibility services trading for different MGs. According to the results of the LFM for the MGs, it was deduced that implementing the robust model of the LFM influenced the values of the flexibility services for each of the MGs, especially for non-congested durations of time schedules.

5. Conclusion

In this study, a two-stage model of the local market for energy and flexibility services trading is proposed according to the data privacy considerations. The proposed model enhances the social welfare value by 1.15 % in comparison to the conventional security constraint-based LEMs. It also improves the fairness aspects for market participants by eliminating the costs of unprovided infrastructure from energy trading payments. To investigate the uncertainty of real-time LFM, the robust model is executed. The results show that the deterministic model of LFM would enhance the flexibility request of DSO to trade flexibility in real-time LFM. The proposed model would increase the cost of DSO operation compared to the conventional LEM. However, if LFM is eliminated, the extra cost would be imposed on MGs, to prevent congestion. To investigate the effects of voltage stability on energy trading of LEM, it's recommended that the model be developed with reactive power analysis and a complementary market be proposed to support voltage stability. Also, the effects of uncertainty for renewable-based energy resources of MGs can be considered, for more accurate results in a practical situation.

CRediT authorship contribution statement

Mahsa Babagheibi: Conceptualization, Methodology, Writing – original draft, Writing – review & editing. **Shahram Jadid:**

Table 17
Operation cost for market participants with and without LFM.

	Base model	Proposed model			Cost Comparison (¢)	Cost Reduction (%)
	LEM	LEM	LFM	LEM & LFM		
MG1	45309.7	43225.5	−1067.2	42158.3	−3151.4	6.96 %
MG2	5288.3	6229.9	−856.7	5373.19	84.8	−1.61 %
MG3	19906.4	19947.4	−856.7	19090.6	−815.7	4.10 %
MG4	26637.9	25716.0	−672.1	25043.8	−1594.0	5.98 %
DSO	154988.9	156503.9	1051.0	157555.9	2566.0	−1.66 %
System Cost	252131.1	251622.8	−2401.7	249221.0	2910.2	1.15 %

Table 18
The effect of increased MG's number on iteration number, computation time and problem variables.

	LEM			LFM		
MG No.	Iteration	Time	Variable No.	Iteration	Time	Variable No.
4MG	23	00:00:50	6725	25	00:03:55	57,150
8MG	548	00:38:52	7881	423	01:22:34	57,922
12MG	1129	02:06:45	9037	989	04:15:22	58,694

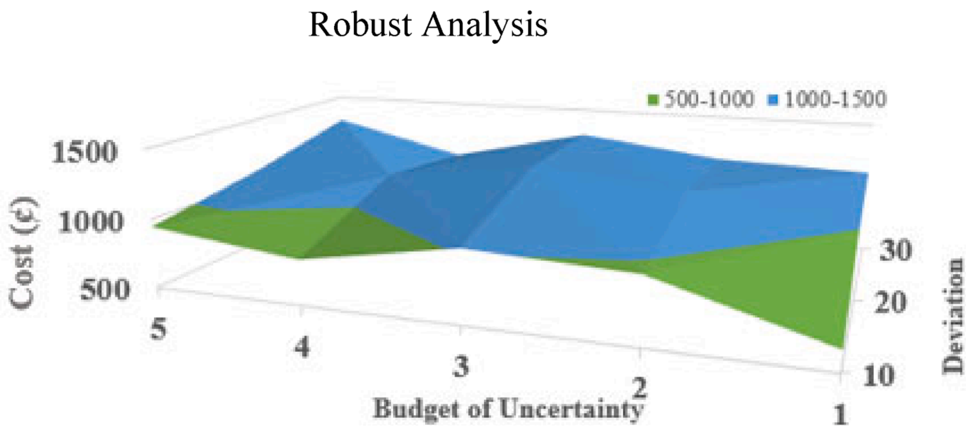

Fig. 13. Robust optimization of DSO cost for flexibility services.

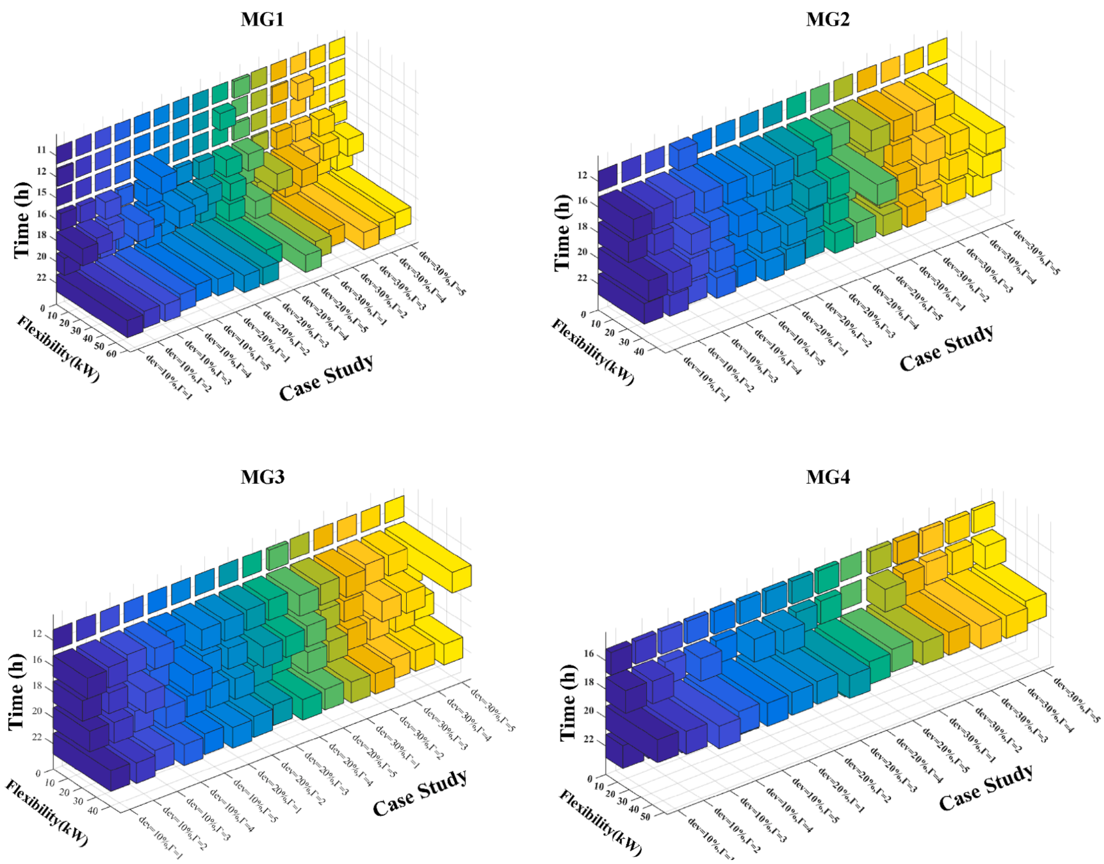

Fig. 14. Flexibility trading of DSO in LFM under robust optimization.

Methodology, Project administration, Supervision, Writing – review & editing. **Ahad Kazemi:** Methodology, Project administration, Supervision, Writing – review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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