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Iranian Journal of Electrical and Electronic Engineering

Journal Homepage: ijeee.iust.ac.ir

Research Paper

Multiple Electricity Markets Competitiveness Undergoing Symmetric and Asymmetric Renewables Development Policies

S. A. Mozdawar*, A. Akbari Foroud*(C.A.), and M. Amirahmadi**

Abstract: This paper scrutinizes the impact of different renewable energy sources (RES) development policies on competitiveness within multiple electricity markets (MEMs). Also, the variation in market power indices by increasing the integration of the markets undergoing symmetric and asymmetric RES development policies is investigated. To do so, several stochastic mixed-integer non-linear programming objective functions are used in the agent-based simulation framework to model the power plants' behavior and markets. The case study shows in the low RES penetrated markets, one can say the more integration level of the markets, the lower potential of exercising market power. The reciprocal judgment is true for a high RES penetrated market. Also, large asymmetry in RES development between markets within MEMs may bring about market power problem for a high RES penetrated market. Unlike the asymmetric RES development policies, adopting homogeneous policies in RES development within MEMs reduces the market power potential in all markets and this potential decreases with the increase in the integration of the markets.

Keywords: Integration of the Markets, Market Power, Multiple Electricity Markets, Symmetric and Asymmetric Renewable Resource Development.

Nomenclature

Sets and Indices:

$t \in T$	Set of time
$se \in S$	Set of renewable generation scenarios
$b \in buses$	Set of buses
i	Index of power plants
l	Index of transmission lines in the whole network
le	Index of tie-lines
k	Index of iteration
N, M, R	Set of power plants in markets 1,2, and 3
Buses 1,2,3	Set of buses in markets 1, 2, and 3
bml, bnl	Starting/ending bus of line l
$bmle, bnle$	Starting/ending bus of tie-lines between markets
$f_{t,se,l}$	Line flow
L	Set of lines in the whole network
$L1/l2/L3$	Set of lines in markets 1, 2, and 3
$L12$, $L13$, $L23$	Set of tie lines between markets 1 and 2, 1 and 3, and 2 and 3
φ_{bi}	Set of generators which are connected to bus b
φ_{bl}	Set of lines which are connected to bus b

Decision Variables:

$s^{+}_{t,se,i}, s^{-}_{t,se,i}$	Positive variable for balancing power
$I_{t,se,i} \in \{0, 1\}$	Commitment variable
$P_{t,se,i}$	Power plants generation for energy [MW]
$P1_{t,i}$, $P2_{t,i}$, $P3_{t,i}$	Declared capacity of power plant i in markets 1, 2, and 3, respectively [MW]

Parameters:

$Cvar_{t,i}$	Variable cost for power plant i [$/MWh]
$f_l^{\max}$	Maximum capacity of line l [MW]
IR_i, DR_i	Incremental/ decrement ramp rate [MW/h]

Iranian Journal of Electrical and Electronic Engineering, 2022.
Paper first received 20 October 2020, revised 27 April 2021, and accepted 28 May 2021.
* The authors are with the Electrical and Computer Engineering Faculty, Semnan University, Semnan, Iran.
E-mails: a.mozdavar@semnan.ac.ir and aakbari@semnan.ac.ir.
** The author is with the Islamic Azad University-Semnan Branch, Semnan, Iran.
E-mail: m.amirahmadi@semnaniau.ac.ir.
Corresponding Author: A. Akbari Foroud.
https://doi.org/10.22068/IJEEE.18.1.2014

$LMP1_t$, $LMP2_t$, $LMP3_t$	Locational marginal price in markets 1, 2, and 3
$LS_{t,se,b}$	Load shedding [MWh]
MUT_i	Minimum uptime [hour]
MDT_i	Minimum downtime [hour]
$Prb_{t,se}$	Probability of scenario *se*
$P_i^{\max}$, $P_i^{\min}$	Maximum/minimum capacity of power plant *i* [MW]
$P^{\max\ trca\ i}$	Maximum capacity that each power plant is allowed to declare in other markets
$RD_{t,se,b}$	Residual demand [MWh]
$xP_{t,se,i}$	Power output balancing parameter for power plants in the markets [MW]
x_l	Reactance of line *l*
x_{le}	Reactance of tie-line
$\theta_{t,se,bl}$	Voltage angle
$\theta_{t,se,bml}$, $\theta_{t,se,bnl}$	Voltage angle of the tie-line buses
$\pi_{t,i}$	General form of the offer price of each power plant in each market

1 Introduction

DUE to the specific features of the power system such as transmission network constraints, market power is one of the most important concerns in the electricity markets [1, 2]. Generally, market dominance, supply scarcity, collusion, and transmission congestion have been introduced as the main reasons for the market power potential in the electricity markets [3, 4]. References [5] reviewed the market power issues in congested transmission systems and analyzed the role of transmission system companies on market power. The purpose of [6] was to analyze the strategic behavior of generating firms and optimized the electricity market structure under a generation constraint and transmission congestion. Reference [7] proposed specific methods and rules to prevent collusion. The goal of that reference was to disturb and stop the redistribution of profits among collusive generators.

In recent years, by increasing the renewable energy sources (RES), the market power problems are more complicated than ever [8, 9]. In the presence of high levels of RES, there is more uncertainty in the supply, which induces volatility in energy prices. This can create incentives for the generators to exercise market power by traditional means: withholding the output, bidding not the true marginal costs, or using locational market power. In addition, a new type of market power has been recently observed: the exercise of market power on ramp-rate [10]. The impact of wind power on market power potential on the Finnish electricity market was studied in [11]. According to that reference, the impact of wind power could be seen as a weak trend towards less market power potential with more wind power production. The authors in [12] investigated the impact of RES on market power in electricity markets with forward contracts. An important consequence of that reference was that allowing market power profit margins as a support mechanism for generation capacity investment was not a technologically neutral policy. The authors in [13] analyzed the impact of generation technologies on the potential of market power in a short-term period in the presence of wind power. To evaluate the potential of the market power, two market concentration boundary problems were solved. These two problems seek to find the minimum and maximum values of a market concentration measure, while considered operational constraints of a day-ahead market clearing problem. The impact of RES on market competition was studied in [14]. According to that paper, when thermal generators had a diverse energy portfolio, meaning that they also control some or all of the RES, they offset the price declined due to the merit order effect because they strategically reduced their conventional energy supplies when RES was high. According to [15], when a non-renewable generator was a dominant firm and a renewable generator was a competitive fringe, the non-renewable firm had a strong incentive to lower the RES certificate/credit price, even to zero for avoiding renewable energy certificate/credit costs. In [16], the market power exercise on ramp-rate was investigated in wind integrated power systems. According to the result of that reference, it was observed that, in the presence of network constraints, fast-ramping generating units were prone to act strategically and exercise market power by withholding their ramp rates.

Alongside the RES development, the tendency for the energy exchange between markets has been increased due to the benefits of energy exchange such as the maximization of social welfare [17, 18]. The interconnected markets alongside the RES expansion make the market power problem more complex than ever. The authors in [19] investigated the impact of RES on prices in Germany and mitigate market power in the French electricity market. That reference highlighted the importance of coordinating energy policies via joint renewable energy support schemes among interconnected European electricity markets. Reference [20] had a similar study between French and Germany. According to that study, during periods of low demand in Germany, and high demand in France, high RES output in Germany may depress French spot prices. France did not directly import electricity from German RES operators but RES integration causes German prices to fall, and traders in neighboring countries began to import, which resulted in lower prices for importing countries as well. The cross-border merit-order effect had also been estimated for other interconnected markets, for example, Germany–Austria [21, 22]. Those references showed that the merit-order effect varies depending on the region and the assessment method chosen. Also, the size of this effect was less dispersed throughout different markets than previously suggested by the literature. According to [23], inappropriate cross-border exchange design could lead to market power by some power plants, which reduces competition in the market.

According to [24, 25], it is observed in practice that, in the presence of network constraints, fast-ramping generating units are prone to act strategically and exercise market power by withholding their ramp rates. Reference [26] answered this question; if barriers between two power markets are eliminated, what might happen to competition and prices? References [27, 28] addressed the impact of cross-border energy exchanges on the electricity markets. According to those papers, small investments in transmission could surprisingly yield large payoffs in terms of increased competition. According to [29] inappropriate cross-border exchange design can reduce competition in the market.

In recent years, a new model for energy exchange between markets is introduced that the power plants can participate and sell energy in the other markets regardless of the power plant location that is known as multiple electricity markets (MEMs) [30, 31]. In this market model, each electricity market has its own expansion and reliability policies and market rules. Therefore, we have a wide range of differences in policies and rules between the electricity markets. According to the best of our knowledge, the impact of various RES development policies on the competition within MEMs has not yet been investigated. Therefore, this paper focuses on analyzing the effect of symmetric and asymmetric RES development policies on the competition by increasing the integration of the markets. In symmetric RES expansion policy, the RES penetration level in all markets is close together while in asymmetric RES development policy, the penetration level of renewables in the markets is different.

Accordingly, the main contributions of this paper can be summarized as follows:

- The impact of symmetric and asymmetric RES development policies on the potential of exercising market power within MEMs is investigated. Something that to the best of our knowledge has not been investigated in previous studies.
- The effect of increasing the integration of the markets on market competitiveness in the presence of different policies on RES penetration within MEMs is analyzed.
- A stochastic multi-objective decomposition method is used in the agent-based simulation framework to analyze the power plants' behavior and markets. The use of a multi-master problem in the agent-based simulation has not yet been performed in the power system.

The rest of the paper is organized as follows. Section 2 describes the model formulation. In Section 3, the framework of the analysis is expressed. The results are analyzed in Section 4, and the conclusion is presented in the final part.

2 Model Formulation

In the MEMs, each market acts independently with its own day-ahead energy market and settlement rules, while the power plants in the adjacent markets can declare in the other electricity markets regardless of the power plant location. That means the generation schedule and line flows in each market are affected by the generation schedule of the other markets. This mechanism causes the security constraint in some lines may violate. To obviate this concern, a coordinating entity is considered. Also, the coordinator provides the external power plants and network model for each market by the network reduction methods. In this paper, the Ward method is used on modelling the external power plants and networks as depicted in Fig. 1 [32].

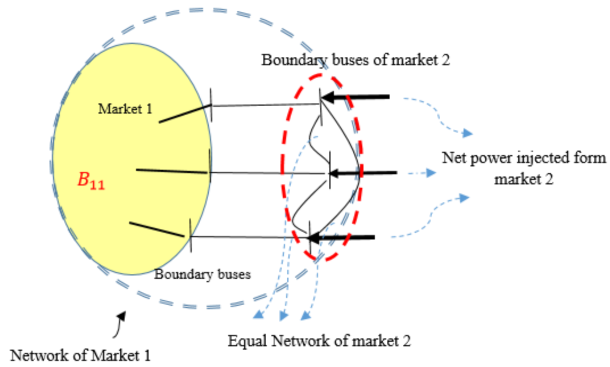

Fig. 1 External network model.

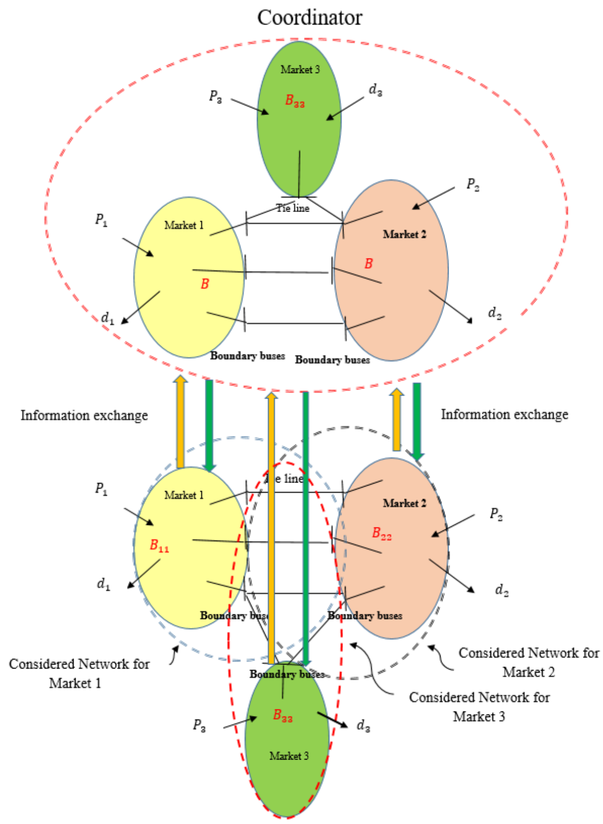

Fig. 2 MEMs model.

According to the MEM model, each GenCo decides about the declared capacity and offered price in its market and the adjacent markets and offer its bid to the markets. The agent-based simulation is used to model the power plants' behavior. The ISOs aggregate all these offers and runs its market to minimize sum of the energy purchase costs and sends the generation and load information to the coordinator. The coordinator runs a network-checking program by aggregating all this information. If some lines are overloaded, the coordinator sends a signal to each market. The markets should change the generation schedule according to this signal. Therefore, the coordinator objective function is defined as minimum generation adjustment for congestion alleviation of the overloaded lines. This process is repeated until all the network constraints are satisfied. Fig. 2 shows the considered model for MEMs.

To investigate the impact of RES on the competitiveness within MEMs, two main scenarios are considered for RES development between markets: adapting and not adapting coordinated policies on RES development between markets. The renewable resources do not participate in the markets directly and their generation is deducted from the corresponding bus load. That means the load is initially provided by the RES in each market. The RES generation uncertainty is modeled in three scenarios.

The model is applied to analyze market competitiveness over the course of one year. To reduce the computational calculation, the year is modeled as five weeks. Also, three scenarios are considered for the integration of the markets: the markets are independent, the power plants can declare 20% and 40% of their capacity in the other markets.

According to the above-mentioned descriptions, the independency of the markets is a prominent feature of the MEMs. Therefore, the optimization problem in this mechanism has a decomposed structure. In this structure, we have some separated objective functions that each objective function is influenced by the objective functions of the other markets and by the objective function of the coordinator. In this formulation, the markets objective function is modeled as the master-problems and the coordinator objective function is modeled as the subproblem. Consequently, there are many separated objective functions in the master-problem that each objective function aims to maximize social welfare and usage of the tie-line by two separate inner iterative processes between the markets. Also, the social welfare of each market is affected by an outer iterative process between markets and coordinator. Consequently, despite common decomposition methods such as Benders decomposition in which one optimization problem is decomposed into a master-problem and several subproblems, in MEMs optimization problem, several optimization problems are decomposed to several master-problems (the markets optimization problems) and one subproblem (the coordinator objective function). Therefore, unlike the common decomposition methods in which the cuts are only applied to one master-problem, in MEMs, the cuts are applied to several master-problems.

2.1 Power Plants Behavior

As mentioned in section 2, the power plants in each market can declare in the other markets regardless of the power plants' location. The maximum capacity that each power plant can declare in the adjacent market is determined by the ISOs in advance. That means the ISO has already taken into account all the reliability constraints. Therefore, the power plant can declare in the adjacent market at each time of the generation scheduling time, up to the specified maximum capacity by the ISO. Although this amount can vary between power plants depending on the network conditions, in this paper, it is similar for all power plants. This amount expresses the degree of integration of the markets. Consequently, the GenCos in MEMs should decide about the declared capacity in the other markets. Therefore, the GenCo's objective function and constraints are defined as follows.

$$\text{Maximize}\,Profit=\sum_{t}\left\{Revenue_t-Cost_t\right\}$$
$$=\left\{\sum_{t=1}^{T}P1_{t,i}.LMP1_{t,i}+P2_{t,i}.LMP2_{t,i}+P3_{t,i}.LMP3_{t,i}\right.$$
$$\left.-\left(P1_{t,i}+P2_{t,i}+P3_{t,i}\right)Cvar_{t,i}\right\} \tag{1}$$

S.t.

$$P_i^{\min}\le P1_{t,i}+P2_{t,i}+P3_{t,i}\le P_i^{\max} \tag{2}$$
$$P2_{t,i}\le P_{\max trca\,i} \tag{3}$$
$$P3_{t,i}\le P_{\max trca\,i} \tag{4}$$
$$P1_{t+1,i}-P1_{t,i}\le IR_i \tag{5}$$
$$P2_{t+1,i}-P2_{t,i}\le IR_i \tag{6}$$
$$P3_{t+1,i}-P3_{t,i}\le IR_i \tag{7}$$
$$P1_{t,i}-P1_{t+1,i}\le DR_i \tag{8}$$
$$P2_{t,i}-P2_{t+1,i}\le DR_i \tag{9}$$
$$P3_{t,i}-P3_{t+1,i}\le DR_i \tag{10}$$
$$\begin{cases}I_{t,i}-I_{t-1,i}\le MUT_i\\ I_{t-1,i}-I_{t,i}\le MDT_i\\ I_{t,i}-I_{t-1,i}\le MUT_i-MDT_i\end{cases} \tag{11}$$

where the first, second, and third parts in (1) are the power plant's revenue from markets 1, 2, and 3 and the fourth part is the generation variable cost at each time and each RES scenario. Equation (2) shows the maximum and minimum power constraint of each power plant. Also, (3) and (4) are the maximum capacity that each power plant can declare in the adjacent markets. We assume that the maximum declared capacity is a discrete variable, and it can be either 0%, 20%, or 40% of the maximum capacity of the power plants. Equations (5) to (10) show the ramp rate constraints, and (11) presents the minimum up/downtime constraints.

The power plants do not know what price or quantity to choose to maximize their benefit. For this purpose, the agent-based method is used to model the power plants' behavior. The power plants can learn from their past experienced strategies which can be computationally implemented by using a Q-Learning algorithm. The pseudo-code of the Q-learning-based method of declaring in the markets is presented in Fig. 3.

2.2 Markets Model

The objective function of each market is to minimize the energy purchase cost based on (12).

$$\text{Objective Function}(market) = \text{Min}\sum_{t\in T}\sum_{se\in S}\left(\sum_{i\in N}\left(P_{t,se,i}.\pi_{t,se,i}\right).Prb_{t,se} + \sum_{b\in buses1}(Voll.LS_{t,se,b}.Prb_{t,se})\right) \tag{12}$$

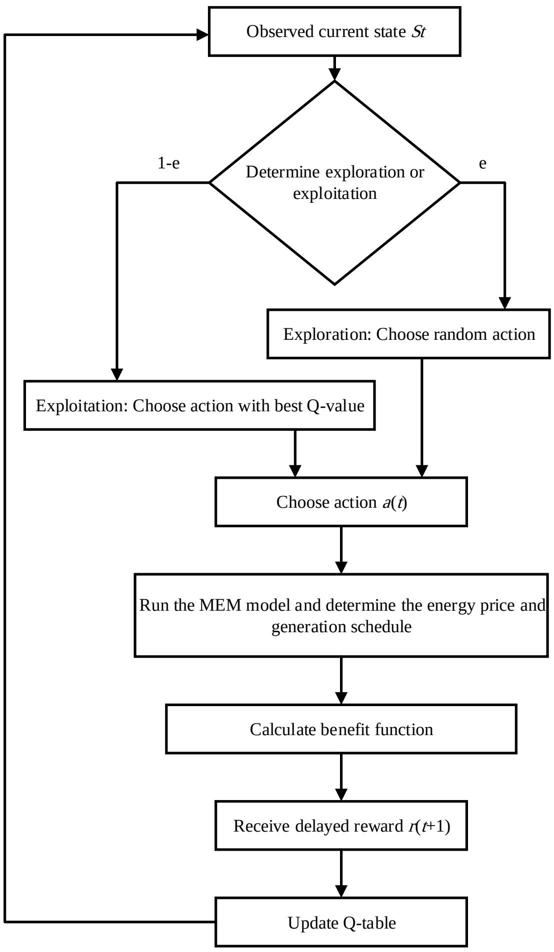

Fig. 3 Flow chart of the Q-learning based method for declaring in the markets.

In the above-mentioned objective function, the first term is the energy purchase cost of the power plants in each market, and the second part is the load shedding cost in the market at each time for each RES generation scenario.

Maximum and minimum power, load balance, unit ramp rates, minimum up/downtime, and transmission constraints are used as the optimization constraints, which are considered as equal and unequal constraints according to (13).

$$g(x) \le A \tag{13}$$

As the external power plants can create tie-line flows in the opposite direction of each market, the tie-lines capacity is determined by an iterative process between markets. This fact is reflected by (16).

$$f^{k}_{t,se,le} = \frac{\theta^{k}_{t,se,bmle} - \theta^{k}_{t,se,bnle}}{x_{le}} \quad \forall t \in T,\ le \in \{L12, L13, L23\},\ \forall se \in S \tag{14}$$

$$-f^{\max}_{le} - f^{'(k-1)}_{t,se,le} \le f^{(k)}_{t,se,le} \le f^{\max}_{le} + f^{'(k-1)}_{t,se,le} \quad \forall t \in T,\ le \in \{L12, L13, L23\},\ \forall k,\ \forall se \in S \tag{15}$$

where $f^{'(k-1)}_{t,se,le}$ is the tie-line flows obtained in the previous iteration from the adjacent markets.

When the generation schedule is determined in all markets, the markets send the generation and bus load information to the coordinator. The coordinator checks the network constraint based on the following method a_t.

2.2 Coordinator's Objective Function

Within IEMs, since the power plants in different markets can participate in the other markets, congestion management is the major problem with this framework. Two main approaches can be considered for the coordinator's objective function. The first approach is the system-wide clearing (perfect coupling) that observes all constraints associated with the considered areas and minimizes the total cost of the system. With this approach, the cost of some markets may increase as compared to independent inter-area market clearing. In the other approach, the coordinator only assesses the system security. To do so, each market only considers the generation, the load, and the branch flows, geographically located within its own area.

Although the first approach leads to the optimization of the participants' total social welfare within the interconnected system, a market operator could argue that it would have better market opportunities (higher social welfare for the market that it clears), if it was not incorporated into the system-wide optimization. Based on the above discussion, and the necessity for the confidentiality and the independency of the markets, the coordinator functions as the system security manager.

For this purpose, the coordinator receives the generation and load information in each bus of the whole system from the markets. Then it runs a DC network-checking program by aggregating all this information. If some lines are overloaded, the coordinator sends a signal to each market. The markets should change the generation schedule according to this signal. Therefore, the Coordinator's objective function is to minimize the power plant generation adjustment to satisfy the network constraint. For this purpose, two positive variables s_i^+ and s_i^- are defined that indicate the needed generation adjustment in each bus. Accordingly, the coordinator's objective function that is written for three markets is shown (16).

$$\text{Objective Function} = \min \sum_{t\in T}\sum_{se\in S}\Bigg(\sum_{i\in M}\left(s^+_{t,se,i}+s^-_{t,se,i}\right)+\sum_{i\in N}\left(s^+_{t,se,i}+s^-_{t,se,i}\right) + \sum_{i\in R}\left(s^+_{t,se,i}+s^-_{t,se,i}\right)\Bigg) \quad (16)$$

where the first, second, and third parts in (16) are the power plant generation adjustment in markets 1, 2, and 3, respectively.

The coordinator constraints are as follows:

- **Load Balance**

According to the above-mentioned description, the load balance equation is as follows:

$$\sum_{i\in\varphi_{bi}} xP_{t,se,i} + \sum_{l\in L_{bl}} F_{t,se} + LS_{t,se,b} = RD_{t,se,b}$$
$$\forall b\in\{buses1, buses2, buses3\},\ \forall t\in T,\ \forall i\in\{N,M,R\},\ \forall se\in S \quad (17)$$

$$xP_{t,se,i} = s^+_{t,se,i} - s^-_{t,se,i} + P_{t,se,i} \ :\ \mu_{t,i} \quad (18)$$

Equation (17) shows the load balance equation where the power plants generation plus the summation of connected line flows to that bus must be equal to the residual demand in each bus at each time for each RES generation scenario. Also, (18) represents the power plants generation adjustment to satisfy the power balance constraint on each bus.

If (19) is bounded, the duality of this constraint is applied to the corresponding market according to (19)-(21). This process carries on until all network constraints are satisfied.

$$\sum_{t\in T}\sum_{se\in S}\left(\sum_{i\in N}\mu_{t,se,i}.(xP_{t,se,i}-P_{t,se,i})\right)=0 \ :\ \gamma_{t,i} \quad (19)$$

$$\sum_{t\in T}\sum_{se\in S}\left(\sum_{i\in M}\mu_{t,se,i}.(xP_{t,se,i}-P_{t,se,i})\right)=0 \ :\ \gamma_{t,i} \quad (20)$$

$$\sum_{t\in T}\sum_{se\in S}\left(\sum_{i\in R}\mu_{t,se,i}.(xP_{t,se,i}-P_{t,se,i})\right)=0 \ :\ \gamma_{t,i} \quad (21)$$

where (19)-(21) show the power plant generation adjustment in each market, at each time for each RES generation scenario.

- **Line Flow**

The line flow in the whole network is calculated based on (22) and (23).

$$f_{t,se,l} = \frac{\theta_{t,se,ml}-\theta_{t,se,nl}}{x_l} \quad \forall t\in T,\ \forall l\in\{L1, L2, L3\},\ \forall se\in S \quad (22)$$

$$-f_l^{\max} \le f_{t,se,la} \le f_l^{\max} \quad \forall t\in T,\ \forall l\in\{L1, L2, L3, L12, L13\},\ \forall se\in S \quad (23)$$

2.3 Solution Procedure

At the beginning of each decision period, the markets publish the latest information on the demand and the price of energy. Based on this information, each power plant offers price and quantity to the energy market for each time and each wholesale electricity market based on (1)-(11) according to the algorithm that is presented in Fig.3. Then, each market maximizes its social welfare according to (12) and constraints (13)-(15) in coordination with the other markets sequentially and updated tie-lines capacity.

When the generation schedule finalizes in all markets, the coordinator checks the line flows in the whole network according to (16)-(18) and (22) and (23). If some lines are overloaded, the dualities of these constraints are applied to the corresponding market based on (19)-(21). This process is repeated until all network constraints are satisfied. The overall structure of this process in MEMs is illustrated in Fig. 4.

When all the network constraints are satisfied, each ISO calculates the LMPs in its market according to (24) and publishes the generation schedule and LPMs for the day-ahead energy market [33].

$$EXP(LMP_{t,i}) = (lmp_{t,se,i} - \mu_{t,se,i}\cdot\gamma_{t,se,i}).prb_{t,se} \quad (24)$$

Where $EXP(LMP_{t,i})$ is the expected value of the final marginal price in each bus. lmp_i is the marginal price obtained from the load balance equation. $\mu_{t,i}$ and $\gamma_{t,i}$ are the dualities of equations (18) and (19), or (20), or (21) respectively in each time for each scenario.

3 Framework of the Analysis

3.1 Network Modeling

Three modified 118-bus test systems that are connected through the 150 MW transmission line in buses 106 and 117 are used in the MEM model. Generation technologies are similar in three markets. Also in this paper, the value of lost load (VOLL) is considered 500$/MWh.

3.2 Load and RES Modeling

The simulation time interval is considered for one

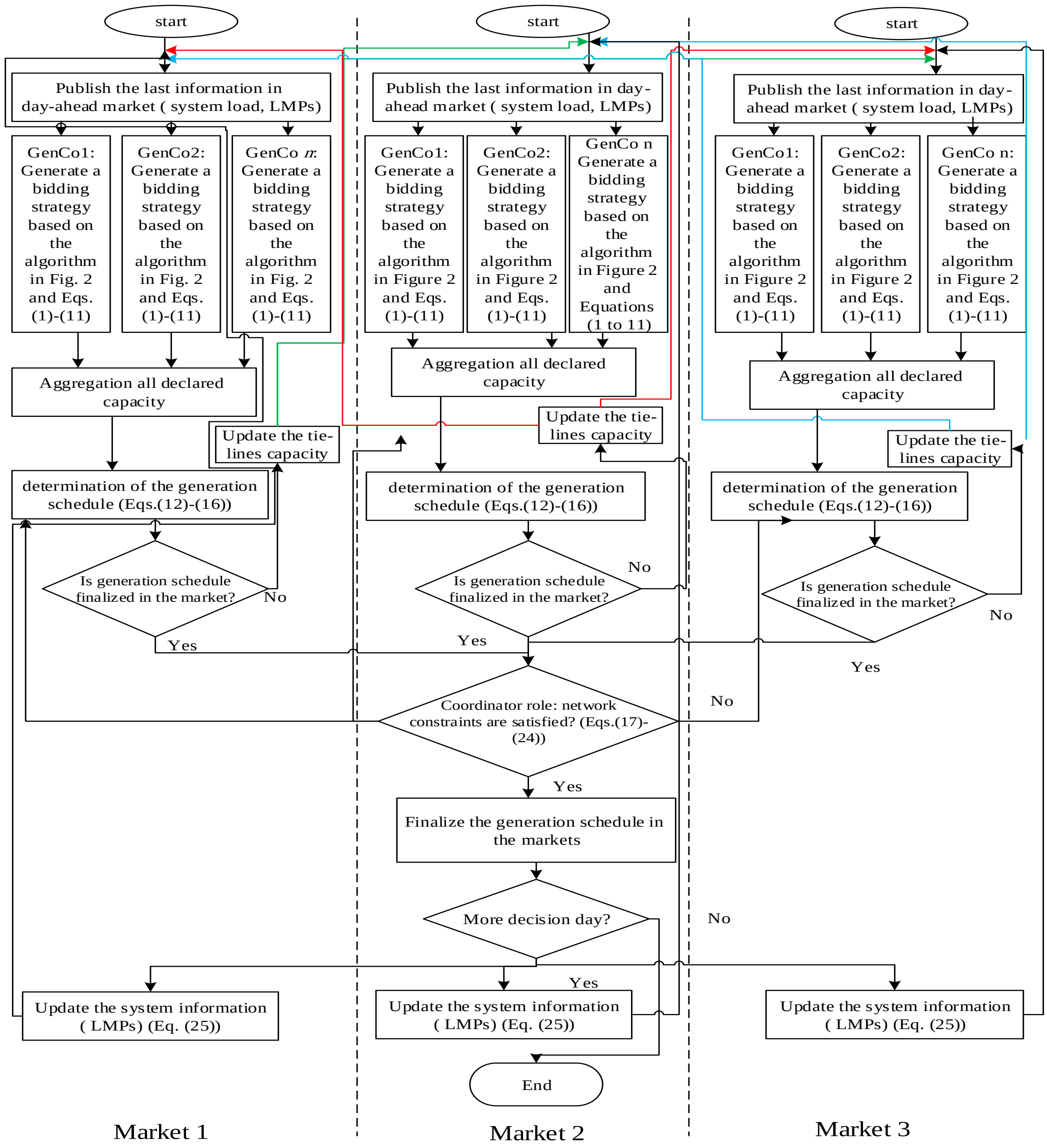

Fig. 4 Overall structure of determination of generation scheduling in MEMs.

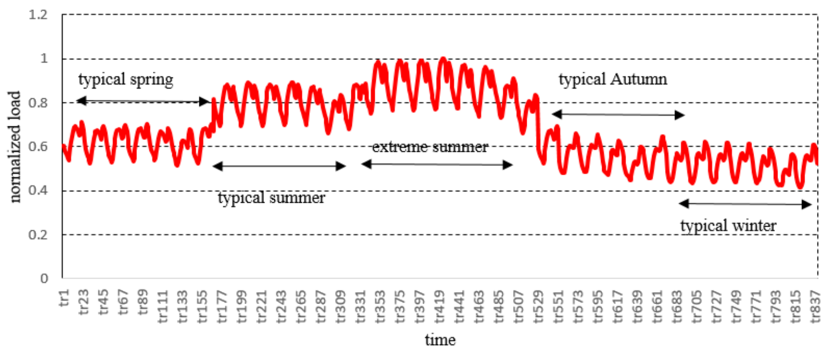

Fig. 5 Load profile with four seasonal representative weeks and one extreme summer week.

year. This time interval is selected based on the UK electricity market for market power assessment [5]. To reduce the computational calculation, the year is modeled as five weeks [34]. Since the load profile in the similar days in each season is almost the same, the average load in similar hours of similar days in every season are considered as the hourly load in each day of the weekly load profile. Therefore the load is modeled in 4 weeks. Furthermore, to analyze market power under extreme conditions, a week with extremely high demand and no wind (extreme summer, see Fig. 5) is also considered. Then this load profile is normalized based

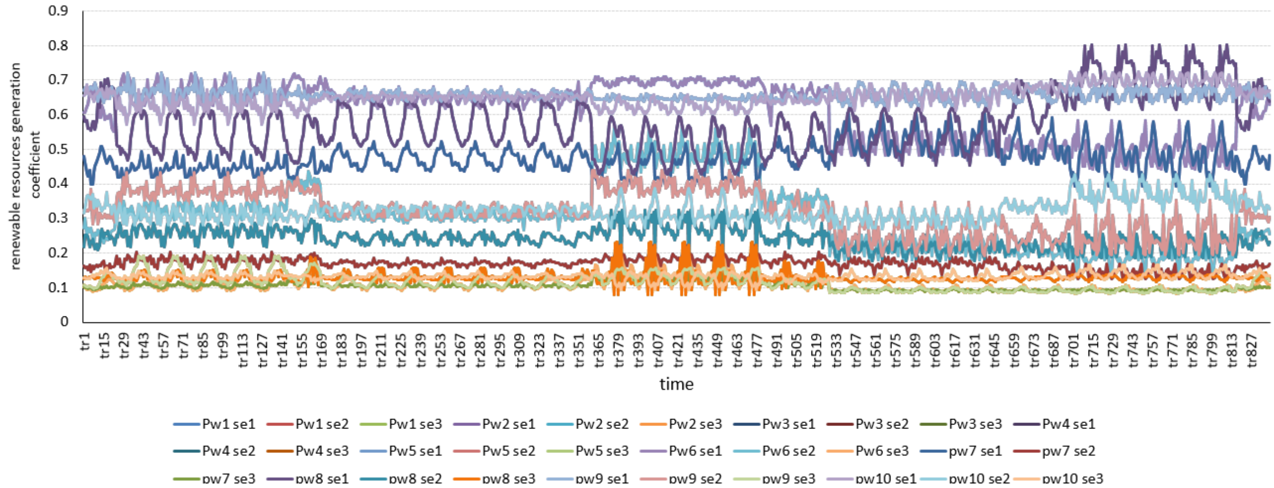

Fig. 6 Normalized renewable resource generation in 3 scenarios and 10 buses.

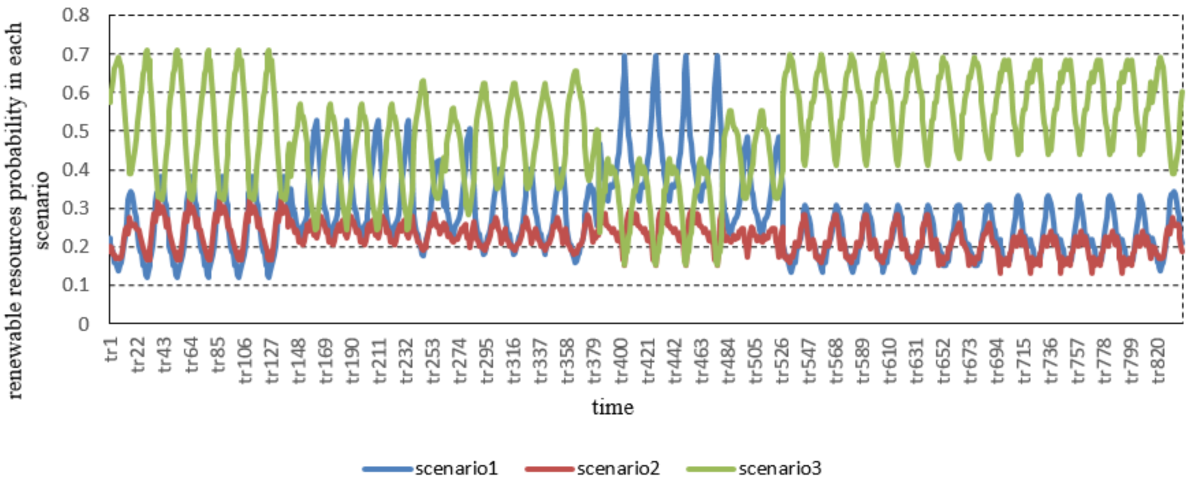

Fig. 7 Renewable resource generation probability in 3 scenarios.

on the maximum load. Thus, the hourly normalized load profile is obtained for each hour of the simulation period. Fig. 5 shows the normalized load profile in each market. Then these coefficients are applied to the 118-bus network load. The 118-bus network load profile for the simulation period is obtained by multiplying the peak load by the normalized load profile. The load profiles in all markets are the same.

The method which is used for load modeling is implemented for generating RES data. That means the RES generation is modeled in five weeks. To simulate the RES generation profile, the generation of ten wind sites of Iran's electricity market data in 2012-2015 is used. This data is taken from the Iran Grid Management Company which is available to researchers upon request. So, there are 48 data for each site of the RES in each hour (four years, three months in each year, four weeks in each month). The data in each hour are classified into 3 categories according to the standard deviation. The average of the data in each category is considered as RES generation. Then, the RES generation is normalized based on the maximum renewable unit's capacity in each site. Fig.6 shows the RES generation normalized coefficient in 10 buses for one year (5 weeks).

The RES generating probability in each scenario is calculated by dividing the number of data in each category into the total number of data in each hour. So, there are 30 RES generating probability (10 wind sites and 3 scenarios) for each hour. To reduce the complexity of the problem, the average probability of RES generation in similar scenarios in 10 sites is considered as a probability of that scenario in the whole network. The RES generating probability is shown in Fig. 7. The RES generation in the 118-bus network is obtained by multiplying the coefficients in Fig. 6 and renewable resources capacity in each bus.

Renewable resources expansion is applied linearly in both markets. The coefficients in Table 1 (obtained from the capacity ratio of 10 wind sites in the Iran electricity market) are used to distribute the renewable resource capacity in 14th, 15th, 23rd, 24th, 62nd, 76th, 49th, 98th, 84th, and 101st of the 118-Bus network. Renewable sources do not participate directly in the market and their generation is deducted from the bus load which is connected.

Table 1 Renewable energy distribution coefficient in 118-bus network.

Unit code	Bus number	Distributed coefficient
PW1	14	6
PW2	15	10
PW3	23	21
PW4	24	18
PW5	62	12
PW6	76	3
PW7	49	11
PW8	98	10
PW9	84	4
PW10	101	5

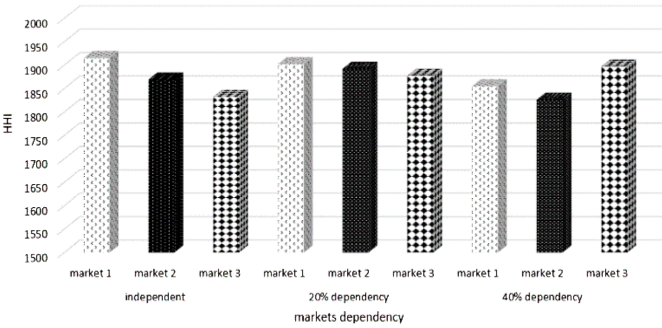

Fig. 8 HHI index in asymmetric expansion policies in three markets.

Table 2 Market share of each power plant type in three markets when the markets act independently.

	Power plant type	Market 1	Market 2	Market 3
Market 1	Coal	62.7%	0	0
	oil	23.4%	0	0
	Gas	13.9%	0	0
Market 2	Coal	0	54.2%	0
	oil	0	21.8%	0
	Gas	0	24%	0
Market 3	Coal	0	0	49.1%
	oil	0	0	22.6%
	Gas	0	0	28.3%

Table 3 Market share of each power plant type in three markets when the integration of the markets is 20%.

	Power plant type	Market 1	Market 2	Market 3
Market 1	Coal	53.8%	3%	1.7%
	oil	18.4%	1%	0.8%
	Gas	12.2%	0	5.5%
Market 2	Coal	4.3%	39.5%	6.5%
	oil	0	14.1%	0
	Gas	0	20%	4%
Market 3	Coal	9.2%	7.4%	32.2%
	oil	2.1%	5%	20.8%
	Gas	0	2%	28.5%

3.3 Renewable Resource Expansion Model

Symmetric and asymmetric RES development policies are two considered scenarios for RES expansion in three markets. In the asymmetric RES development, the RES capacity in markets 1, 2, and 3 is 1%, 2%, and 5% of the total load in the first hour, respectively, and these amounts are increased to 2%, 20%, and 40% of the initial value by the end of the year. In the symmetric scenario, the RES capacity in markets 1, 2, and 3 is 3%, 4%, and 5% of the total load in the first hour, respectively, and these amounts are increased to 30%, 35%, and 40% of the initial value by the end of the year. The RES increases linearly in two RES development scenarios in all markets.

3.4 Assessment of Market Power

The Herfindahl-Hirschman Index (HHI) is a common measure of market concentration and is used to determine market competitiveness. The HHI is calculated based on (26).

$$HHI = \sum_{i=1}^{n} (market\ share)_i^2 \tag{25}$$

A market with an HHI of less than 1,500 is considered to be a competitive marketplace, an HHI of 1,500 to 2,500 to be a moderately concentrated marketplace, and an HHI of 2,500 or greater to be a highly concentrated marketplace.

3.5 Modeling the Integration of the Markets

Market power is analyzed in three scenarios of the integration of the markets. In the first scenario, the markets act independently. In the second and third scenarios, the power plants can declare 20% and 40% of their capacity in the other markets, respectively.

4 Results Analysis

4.1 Asymmetric Expansion Analysis

Fig. 8 shows the average of HHI during the simulation interval in three electricity markets and three scenarios of the integration of the markets. As Fig. 8 shows, when the markets act independently, the HHI in the high RES penetrated market (market 3) is less than the other markets. With the increase in the integration of the markets, the HHI increases in this market (market 3). Meanwhile, the HHI decreases in markets 1 and 2 (the low RES penetrated markets). Also, as Fig. 8 shows, when the integration of the markets is 40%, the HHI in the market with more RES development is more than low RES penetrated markets. That means the heterogeneous expansion of RES in different markets within MEMs may bring about market power problem for some markets, even if these markets do not have market power problem when they act independently. But why does the HHI increase in the market with more RES with the increase in the integration of the markets?

To explain the HHI variation with the increase in the integration of the markets, the market share of each power plant type in different scenarios of the integration of the markets is shown in Tables 2-4.

Since the penetration of RES in market 3 is more than the other markets, the residual demand in this market is less than market 1 and market 2. Also, the variation in the load between two hours in market 3 is more than

Table 4 Market share of each power plant type in three markets when the integration of the markets is 40%.

	Power plant type	Market 1	Market 2	Market 3
Market 1	Coal	44%	4.5%	2.2%
	oil	15.4%	2.5%	1.2%
	Gas	9.1%	3	8%
Market 2	Coal	5.6%	34.5%	7.2%
	oil	5.6%	12.1%	1%
	Gas	1%	17%	5%
Market 3	Coal	10.5%	13.4%	25.2%
	oil	8.8%	7%	16.9%
	Gas	0	6%	33.3%

Table 5 Declared capacity of each power plant type in the other markets in 20% integration of the markets.

	Power plant type	Market 1	Market 2	Market 3
Market 1	Coal	97%	3%	0%
	Oil	94%	5%	1%
	Gas	89%	4%	7%
Market 2	Coal	8%	89%	3%
	Oil	7%	85%	8%
	Gas	4%	89%	7%
Market 3	Coal	13%	4%	83%
	Oil	12%	8%	80%
	Gas	0%	7%	93%

markets 1 and 2 due to high RES penetration. Therefore the base-load power plants (coal and oil power plants) in markets 1 and 2 do not declare in market 3. Also, according to the Ward method, as the external power plants are modeled by the coefficients less than one in the other markets, the generation levels of the external power plants are less than their maximum capacity in the adjacent markets. Therefore, the $P_{\max}$ of the external power plants reduces, which limits the ramp rate range of the external power plants in each market. So, most of the needed flexibility in market 3 is provided by the internal gas power plants.

Also, the penetration of RES in market 2 is more than market 1. So, market 1 has more residual demand and low load variation in comparison with market 2. Therefore, in general, the base-load power plants in market 3 prefer to declare in market 1, and gas power plants in market 3 declare their capacity in market 2. Tables 5 and 6 show the percentage of the declared capacity of each power plant type in the adjacent markets when the integration of the markets is 20% and 40%, respectively.

As Table 5 shows, when the integration of the markets is 40%, 25% (17% declares in market 1, and 8% declares in market 2) of the coal power plants and 33% (18% declares in market 1, and 15% declares in market 2) of the oil power plants in market 3 declare their capacity in the adjacent markets while only 8% of the gas power plants in this market declare in the neighbors' market. Meanwhile, only 5% (0% from market 1 and 5% from market 2) of the coal power plants capacity in markets 1 and 2 and 14% (3% from market 1 and 11% from market 2) of the oil power plants capacity in markets 1 and 2 declare in market 3.

In other words, when the integration of the markets is 40%, the capacity of the coal and oil power plants in market 3 reduces by 39% in comparison with the independent scenario. Furthermore, the ramp rate range of the coal and oil power plants in market 3 reduces in comparison with the independent situation. As a result, the internal gas power plants in market 3 catch 33.3% of the market share (see Table 4) that consequently, the HHI increases in market 3.

As Table 5 shows, unlike market 3, the base-load power plants in markets 1 and 2 prefer to declare in their markets. For example, only 6% of the coal power plants in market 1 and 13% of this type of power plants

Table 6 Declared capacity of each power plant type in the other markets in 40% integration of the markets.

	Power plant type	Market 1	Market 2	Market 3
Market 1	Coal	94%	6%	0%
	Oil	91%	6%	3%
	Gas	78%	10%	14%
Market 2	Coal	8%	87%	5%
	Oil	12%	77%	11%
	Gas	5%	86%	9%
Market 3	Coal	17%	8%	75%
	Oil	18%	15%	67%
	Gas	0%	8%	92%

in market 2 (8% and 5% of coal power plants from market 2 declare to market 1 and market 3, respectively) declare their capacity in the other markets. While the capacity of the coal power plants which is declared in markets 1 and 2 is 25% (17% from market 3 and 8% from market 2 declares in market 1) and 14% (6% from market 1 and 8% from market 3 declares in market 2), respectively. This means that the market share of coal power plants increases in market 1 and market 2, and consequently, the market power decreases in these markets.

When the integration of the markets is 20%, the declared capacity of the coal and oil power plants from market 3 in markets 1 and 2 is 17% and 20%, respectively. Meanwhile, the coal and oil power plants in markets 1 and 2 declare 3% and 9% (1% from market 1 and 8% from market 2) of their capacity in market 1. That means the coal and oil power plants catch more market share in 20% market integration in comparison with 40% integration of the markets (compare Table 3 and Table 4). Consequently, when the integration of the markets is 20%, the HHI in market 3 decreases in comparison with 40% integration of the market. Also, the declared capacity of the coal and oil power plants from markets 1 and 2 in market 3 in 20% market integration causes the HHI increases in markets 1 and 2.

4.2 Symmetric Expansion Analysis

Fig. 9 shows the average HHI during the simulation interval in three electricity markets and three scenarios of the integration of the markets. As Fig. 9 shows, the HHI in each scenario of the integration of the markets in all markets is near together. Tables 7-9 show the percentage of the market share of each power plant type in all market integration scenarios in three markets.

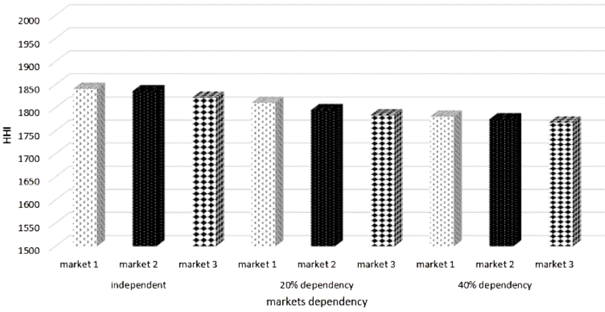

Fig. 9 HHI index in symmetric RES expansion policies in three markets.

Table 7 Market share of each power plant type in three markets when the markets act independently.

	Power plant type	Market 1	Market 2	Market 3
Market 1	Coal	53.4%	0	0
	Oil	24.6%	0	0
	Gas	22%	0	0
Market 2	Coal	0	51.2%	0
	Oil	0	23.5%	0
	Gas	0	25.3%	0
Market 3	Coal	0	0	49%
	Oil	0	0	23%
	Gas	0	0	28%

Table 8 Market share of each power plant type in three markets when the integration of the markets is 20%.

	Power plant type	Market 1	Market 2	Market 3
Market 1	Coal	48%	2%	1.5%
	oil	18%	1.1%	1%
	Gas	23%	1%	3%
Market 2	Coal	2.3%	45.4%	4%
	oil	1%	19.1%	0.5%
	Gas	1%	23%	2%
Market 3	Coal	4.5%	4.1%	42%
	oil	1.2%	3%	19%
	Gas	1%	1.3%	27%

Table 9 Market share of each power plant type in three markets when the integration of the markets is 40%.

	Power plant type	Market 1	Market 2	Market 3
Market 1	Coal	44.5%	2.1%	1.8%
	Oil	17.5%	1.4%	1.2%
	Gas	23.5%	1..2%	5.5%
Market 2	Coal	2.1%	41%	0.5%
	Oil	1.1%	18%	1%
	Gas	1 %	24.6%	4%
Market 3	Coal	5.1%	5%	40%
	Oil	3.1%	4.2%	18%
	Gas	2.1%	2.5%	28%

According to these tables, as the RES in three markets develop homogeneously, the residual demand in all markets in similar together. Since the power plants type in all markets is the same, the power plants prefer to declare in their markets. Therefore unlike the asymmetric RES expansion, the HHI in this situation in three markets is near together.

As Tables 7-9 show, with the increase in the integration of the markets, the external coal and oil power plants catch more market share in each market. As the characteristic of the power plants in the 118-bus test system shows, the maximum capacity of the coal and oil power plants reduces more than the gas power plants with the increase in the integration of the markets. For example, when the integration of the markets is 40%, the maximum capacity of 130 MW coal power plants decreases to 78 MW, while the maximum capacity of the 30 MW gas power plant decreases to 18 MW. Since the external power plants cannot catch the market share as much as their declared capacity in the other market, the market share of the internal gas power plant in each market increases. Therefore the potential of market power exercise decreases in all markets with the increase in the integration of the markets.

5 Conclusion

In this paper, the impact of different RES development policies on market power within multiple electricity markets was investigated. Also, the variation in HHI by increasing the integration of the markets undergoing symmetric and asymmetric RES development policies was analyzed. For this purpose, a stochastic multi-objective mixed-integer non-linear programming decomposition method was used in the agent-based simulation framework to model the power plants' behavior and markets. The case study shows in the low RES penetrated markets, one could say: the more integration level of the markets, the lower potential of exercising market power. The reciprocal judgment was true for a high RES penetrated market. Also, large asymmetry in RES development between markets within MEMs might bring about market power problem for a high RES penetrated market. Unlike the asymmetric RES development policies, adopting homogeneous policies in RES development within MEMs reduced the market power potential in all markets, and this potential decreased with the increase in the integration of the markets. That means adopting symmetric RES development policies within MEMs, will reduce the market power potential, so that all ISOs can benefit from the advantage of establishing the MEMs.

Intellectual Property

The authors confirm that they have given due consideration to the protection of intellectual property associated with this work and that there are no impediments to publication, including the timing of publication, with respect to intellectual property.

Funding

No funding was received for this work.

CRediT Authorship Contribution Statement

S. A. Mozdawar: Conceptualization, Methodology, Software, Formal analysis, Writing - Original draft. **A. Akbari Foroud:** Supervision and editing. **M. Amirahmadi:** Data.

Declaration of Competing Interest

The authors hereby confirm that the submitted manuscript is an original work and has not been published so far, is not under consideration for publication by any other journal and will not be submitted to any other journal until the decision will be made by this journal. All authors have approved the manuscript and agree with its submission to "Iranian Journal of Electrical and Electronic Engineering".

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S. A. Mozdawar was born in Khorasan province, Iran, on Aug. 31, 1980. He received the B.Sc. degree in System Engineering from Ferdowsi University, Mashhad, Iran, the M.Sc. degree from Amirkabir University of Technology, Tehran, Iran, and the Ph.D. degree in Electrical Engineering from Semnan University, in 2002, 2005, and 2021, respectively. His research interest includes power system economy and optimization. He is currently Power Market Executive Director of the Iran electricity market.

A Akbari Foroud received B.Sc. degree from Tehran University and M.Sc. and Ph.D degrees from Tarbiat Modares University, Tehran, Iran. He is currently a Professor with the Electrical & Computer Engineering Faculty, Semnan University. His research interests include restructuring, distribution systems and power quality.

M. Amirahmadi received the B.Sc. degree in Electrical Engineering from Guilan University, Rasht, Iran, in 2006 and M.Sc. and Ph.D. degrees in Electrical Engineering from Semnan University, Semnan, Iran, in 2009 and 2014, respectively. He is currently an Assistant Professor with the Department of Electrical and Electronic Engineering, Semnan Branch, Islamic Azad University, Semnan, Iran. His research interests include power system planning and operation, electricity markets and smart grids.