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Optimal placement of distributed generator in competitive electricity markets based on mitigation of GENCOs' market power and congestion management

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Abstract

This paper presents an innovative two-level optimization framework for optimal placement of distributed generators (DGs) in competitive electricity markets, with a focus on mitigating market power and managing transmission congestion. The first level maximizes social welfare considering load flow, generator, and transmission constraints, while the second identifies strategic DG locations that reduce surplus gains of GENCOs exploiting congestion. The methodology is validated on the IEEE 118-bus system, demonstrating improved market fairness, reduced congestion, and enhanced system reliability. Comparative analysis with conventional methods shows that the proposed approach more effectively addresses

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individual GENCO behaviour, supporting a more efficient, equitable, and competitive electricity market environment.

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1. Introduction

The electricity markets have witnessed significant transformations all over the world as driven by many factors, which include deregulation, privatization, and technological innovations. The major aims of liberalization and reforms in structure and regulations of electricity sector are to increase competition and improve efficiency, but due to its inherent constraints along with high entry barriers and economies of scale, many electricity markets have resulted into the oligopolistic market structures [1]. In an oligopolistic electricity market with insufficient reserves and scarce power imports, there exists a high possibility that some firms could influence market prices by exercising their market power. It shifts entities from price takers to price makers, enabling them to control market prices above competitive levels for extended periods, which is highly detrimental to the competitive environment and market efficiency [2]. Moreover, during periods of congestion in electricity market, costly generators can take undue advantage of the situation and gain unfair surplus through their strategic behaviour [3]. Hence, identifying and mitigating market power has become increasingly crucial in the deregulation of the electric utility industry, to foster fair competition, maintain integrity, and improve efficiency and affordability of electricity markets [4, 5].

For mitigation of market power, regulatory bodies have to play important role by developing smart tools and greater understanding of electricity markets for producing sustainable and competitive outcomes [6, 7]. A demand shifting approach considering time-coupling operational constraints for market power mitigation in imperfect competitive electricity markets has been presented in [8]. However, it neglects the non-linear modelling of power system and complex operating constraints of generators. For mitigation of market power, researchers have also suggested methods such as reinforcement of transmission network [9, 10], transmission congestion management [11], market management measures [12], control of reactive power measures [13] and auxiliaries [14] and installing a renewable energy source based distributed generation unit [15].

The deregulated power market has witnessed a growing interest in distributed generations (DGs) due to both economic considerations and environmental concerns. Distributed generators, characterized as small plants strategically located at load centres, contribute incremental capacity to the power system. Additionally, the escalating demand for electrical power generation coupled with the constricted options for constructing new transmission lines for long-distance power transmission have spurred a heightened interest in distributed power generation. The advantages of distributed generators are location-specific, prompting their deliberate placement within the power system to optimize outcomes.

Numerous studies have examined various approaches to identify the optimal locations for DG placement, with goals such as maximizing societal welfare, increasing profits, and improving voltage regulation. In [16], a particle swarm optimization-based method for placing multiple DGs is presented to reduce power loss and enhance voltage profiles. In [17, 18], the authors introduce two ranking-based methodologies—LMP (Locational Marginal Price) and CP (Consumer Payment)—to optimize DG placement in electricity market, with a focus on maximizing social welfare. In [19], the author reviews existing research on DG allocation, analysing optimization techniques, objectives, decision variables, types of DG, constraints, and methods for addressing uncertainty. A nodal pricing-based methodology for optimal DG allocation is presented in [20] for distribution networks which considers profits, losses, and voltage regulation.

Gao, Alshehri and Birge presented in [21] that the strategic bidding of the generators leads to their higher margin and lower optimal social welfare as compared to the case when truthful bidding is considered. The negative impact on social welfare caused by strategic bidding of generators is reduced when distributed energy resource (DER) aggregation is implemented. The efficient integration of DERs of the prosumers results into higher optimal social welfare as compared to the case when prosumer participation is not considered. As per the present and upcoming trends, the rapidly growing solar, wind and other renewable energy based DGs can influence the market power [22, 23], hence it becomes utmost necessary to maximize their utilization for the well-being of competitive electricity markets and addressing the issue of their optimal placement for mitigation of existing market powers.

The present paper introduces a novel methodology for mitigating market power in competitive electricity markets through the strategic deployment of DGs. The central premise revolves around optimizing the placement of DGs to not only improve system performance but also to address the challenges posed by market power. In the proposed problem formulation, the surplus of the Generator Companies (GENCOs) serves as a crucial index for scrutinizing market power, and it has been determined by solving the proposed maximization of the competitive electricity market's social welfare problem using constrained non-linear programming. Based on the GENCOs' surplus, the optimal placement of DGs has been identified to maximize the reduction in surplus for those GENCOs that exploit market power.

The major contributions of this paper are:

- The surplus index has been utilized to identify GENCOs possessing market power and strategically placing DGs to mitigate the same.
- The proposed market power mitigation problem formulation incorporates and addresses the issue of transmission congestion management.

- A much-needed perspective of GENCOs' market power mitigation based optimal DG placement has been focused, which distinguishes this study from commonly available previous research on DG placements.

Through a detailed comparative analysis, the paper compares the optimal DG placement strategy for market power mitigation against various conventional strategies. These conventional approaches typically prioritize objectives such as minimizing losses, maximizing social welfare, or reducing fuel costs. In contrast to traditional approaches, which often focus solely on technical or economic optimization metrics, this study examines the implications of market power on system operation and fairness. By strategically locating DGs to counteract the effects of market power, the aim is to foster a more competitive and equitable marketplace. This work highlights the importance of considering market power in DG placement decisions, offering insights into how market forces, system optimization, and regulations can be interacted to create more efficient and fair electricity markets.

The content of the rest of the paper is organized as follows: Section 2 outlines the mathematical model for determining the surplus of GENCOs in a pool-based electricity market. The research methodology for finding the optimal DG placement to reduce market power is presented in Section 3. Section 4 discusses the results and analysis of the case studies, while Section 5 concludes the paper.

2. Mathematical Problem Formulation for Optimal Placement of DG in a Pool-Based Electricity Market

In this paper, the optimal placement of DG in a pool-based electricity market has been accomplished for mitigation of GENCOs' market power. For identifying market power of GENCOs in electricity market, their surplus over the twelve-monthly peaks of one year have been utilized. The GENCOs' surpluses have been determined from the solution of electricity market's scheduling problem, which has been formulated to maximize the social welfare function while adhering to operational load flow and transmission capability constraints. The social welfare function is based on real power demand benefit functions of Distribution Companies (DisCos), and real and reactive power generation cost functions of the GENCOs.

This problem formulation incorporates nonlinear AC power flow constraints, thereby implicitly accounting for the cost of transmission losses within the generation cost objective functions.

The real power demand benefit of any DisCo located at i^{th} bus during t^{th} monthly peak ($B_i({P_{di}}^t)$) as a function of its real power demand (${P_{di}}^t$) can be obtained from area covered under its demand bid (which is having negative slope as shown in Figure 1), as given in (1):

$$B_i\left({P_{di}}^t\right) = -\frac{1}{2}{c_{di}}^t({P_{di}}^t)^2 + {d_{di}}^t({P_{di}}^t) \ \$/h, \quad \text{for all} \quad 0 \le {P_{di}}^t \le P^t_{di,max} \qquad (1)$$

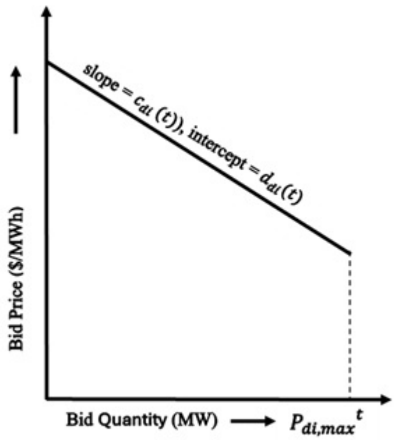

Figure 1
Demand bid of DisCo located at ith bus during t^th monthly peak

Where $P_{di,max}{}^{t}$ represents maximum value of $P_{di}{}^{t}$, and $c_{di}{}^{t}$ and $d_{di}{}^{t}$ represent slope and intercept of the demand bid of corresponding DisCo, respectively.

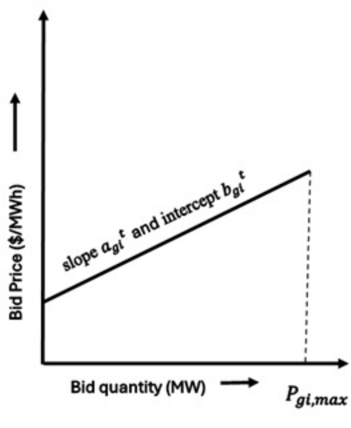

Figure 2
Supply bid of GENCO located at i^th bus during t^th monthly peak

The real power generation cost of any GENCO located at i^th bus during t^th monthly peak ($C_{pi}\left(P_{gi}{}^{t}\right)$) as a function of its real power generation ($P_{gi}{}^{t}$) can be obtained from area covered under its supply bid (which is having positive slope as shown in Figure 2), as given in (2):

$$C_{pi}\left(P_{gi}{}^{t}\right) = \frac{1}{2} a_{gi}{}^{t} \left(P_{gi}{}^{t}\right)^{2} + b_{gi}{}^{t} \left(P_{gi}{}^{t}\right) \$/h, \text{ for all } 0 \le P_{gi}{}^{t} \le P_{gi,max} \quad (2)$$

Where $P_{gi,max}$ represents maximum value of $P_{gi}{}^{t}$, and $a_{gi}{}^{t}$ and $b_{gi}{}^{t}$ represent slope and intercept of the supply bid of corresponding GENCO, respectively.

According to the typical generator loading capability curve, the GENCO has to lower the value of real power for supplying the required leading/lagging reactive voltamperes (VARs). The reactive power generation cost function of any GENCO located at ith bus during tth monthly peak ($C_{qi}\left(Q_{gi}{}^{t}\right)$) as a function of its reactive power generation ($Q_{gi}{}^{t}$) can be obtained from the approximated generator capability curve in the form of a semicircle as given in [24, 25], as given in (3):

$$C_{qi}\left(Q_{gi}{}^{t}\right) = 0.05 \left[\frac{1}{2} a_{gi}{}^{t} \left(P_{gi,max}\right)^{2} + b_{gi}{}^{t} P_{gi,max} - \frac{1}{2} a_{gi}{}^{t} \left\{\left(P_{gi,max}\right)^{2} - \left(Q_{gi}{}^{t}\right)^{2}\right\} - b_{gi}{}^{t} \left\{\left(P_{gi,max}\right)^{2} - \left(Q_{gi}{}^{t}\right)^{2}\right\}^{0.5}\right] \frac{\$}{h}, \text{ for all}$$

$$Q_{gi,min} \le Q_{gi}{}^{t} \le Q_{gi,max} \quad (3)$$

Where $Q_{gi,min}$ and $Q_{gi,max}$ represent minimum and maximum value of $Q_{gi}{}^{t}$ respectively.

The social welfare function (SW^{t}) during tth monthly peak can be obtained from $B_{i}\left(P_{di}{}^{t}\right)$, $C_{pi}\left(P_{gi}{}^{t}\right)$ and $C_{qi}\left(Q_{gi}{}^{t}\right)$, as given in (4):

$$SW^{t} = \sum_{i \in N_{d}} B_{i}\left(P_{di}{}^{t}\right) - \sum_{i \in N_{g}} C_{pi}\left(P_{gi}{}^{t}\right) \quad (4)$$

Where N_{d} and N_{g} are the sets of buses having DisCos and GENCOs, respectively. The electricity market's scheduling problem has been formulated to maximize SW^{t} over the twelve-monthly peaks of one year subject to load flow, DG placement, generator capability curve, constant power factor of DisCo buses, transmission loading constraints and bounds on decision and control variables.

2.1 *Objective Function*

The SW maximization as the objective function of the said problem is given in (5):

$$Max.SW = Max.\ \sum_{t=1}^{M} \left(SW^{t}\right) \quad (5)$$

Here M represents set of twelve-monthly peaks of one year, the present problem formulation is of generic nature and it may be easily extended to include higher number of years.

2.2 Constraints

a) The non-linear modelling of power system (having N number of system buses) leads to the real and reactive power flow equality constraints as given in (6) and (7):

$$P_{gi}{}^{t} - P_{di}{}^{t} = \sum_{j=1}^{N} |V_i^t||V_j^t|\,|Y_{ij}| \cos(\delta_i^t - \delta_j^t - \theta_{ij})$$
$$\text{for all } i = 1,2, \ldots \text{N}, i \neq k, \quad t \in M \tag{6}$$

$$Q_{gi}{}^{t} - Q_{di}{}^{t} = \sum_{j=1}^{N} |V_i^t||V_j^t|\,|Y_{ij}| \sin(\delta_i^t - \delta_j^t - \theta_{ij})$$
$$\text{for all } i = 1,2, \ldots \text{N}, t \in M \tag{7}$$

Where:

$|V_i^t|$ and δ_i^t indicate magnitude and angle of the voltage at ith bus during tth monthly peak,

$|Y_{ij}|$ and θ_{ij}^t indicate magnitude of (i-j)th element of bus admittance matrix and respective angle of that element, and

$Q_{di}{}^{t}$ indicate reactive power demand at ith bus during tth monthly peak

b) At the kth bus, solar PV modules-based DG has been placed, which produces $P_{pvk}{}^{t}$ real power, due to which the real power flow equality constraint (6) has been modified as given in (8):

$$P_{gi}{}^{t} - P_{pvi}{}^{t} - P_{di}{}^{t} = \sum_{j=1}^{N} |V_i^t||V_j^t|\,|Y_{ij}| \cos(\delta_i^t - \delta_j^t - \theta_{ij})$$
$$\text{for } i = k \text{ and for all } t \in M \tag{8}$$

For the maximum environment benefits, the solar PV modules have been considered to be price taker and feeds into the grid whenever available [26].

c) The power factor of DisCos buses is considered to be constant and is given by the following constraints:

$$Q_{di}{}^{t} = P_{di}{}^{t} \tan\theta_i^t \qquad \text{for all } i = 1,2, \ldots \text{N}, t \in M \tag{9}$$

d) Considering the approximate power generation capability curve [24, 25], the real and reactive power generations at GNECO buses are constrained by (10) below:

$$\left(P_{gi}{}^{t}\right)^2 + \left(Q_{gi}{}^{t}\right)^2 \leq S_{gi,max}^2 \quad \text{for all } i \in N_g, t \in M \tag{10}$$

Where $S_{gi,max}$ indicates maximum value of apparent power of GENCO at ith bus in MVA

e) The transmission line loadings between “from” and “to” buses (S_{ij}^t) and between “to” and “from” buses (S_{ji}^t) in MVA as functions of bus voltage magnitudes and angles during tth monthly peak are constrained by the maximum line loading limits ($S_{ij,max}^t$) [27, 28]:

$$S_{ij}^t\left(|V_i^t|, |V_j^t|, \delta_i^t, \delta_j^t\right) \leq S_{ij,max}^t \text{ for all } (i-j) \in N_l \in M \tag{11}$$

$$S_{ji}^t\left(|V_i^t|, |V_j^t|, \delta_i^t, \delta_j^t\right) \leq S_{ij,max}^t \quad \text{for all } (i-j) \in N_l, t \in M \tag{12}$$

Where N_l indicates set of number of lines represented in terms of “from” and “to” buses.

f) The various decision and control variables are constrained by their minimum and maximum limits as follows:

$$\left.\begin{array}{lll} 0 \le P_{gi}{}^{t} \le P_{gi,max} & \text{for all} & i \in N_g,\ t \in M \\ Q_{gi,min} \le Q_{gi}{}^{t} \le Q_{gi,max} & \text{for all} & i \in N_g,\ t \in M \\ 0 \le P_{di}{}^{t} \le P^{t}_{di,max} & \text{for all} & i \in N_d,\ t \in M \\ 0 \le Q_{di}{}^{t} \le Q^{t}_{di,max} & \text{for all} & i \in N_d,\ t \in M \\ \left|V_{i,min}\right| \le \left|V_i^t\right| \le \left|V_{i.max}\right| & \text{for all} & i \in N,\ t \in M \\ \delta_{i,min} \le \delta_i^t \le \delta_{i.max} & \text{for all} & i \in N,\ t \in M \end{array}\right\} \quad (13)$$

3. Solution Methodology

In this paper, Optimal placement of DG is accomplished depending upon the existence of market power of GENCOs. The optimization problem discussed in Section 2 takes the form of nonlinear programming and has been solved using AMPL software employing KNITRO solver with NEOS server [29, 30]. In order to identify the GENCOs possessing or exercising market power, the said optimization problem has been solved for peak monthly conditions without DG placement. The solution of the optimization problem provides the values of state and control variables, and market clearing prices (MCPs) of real and reactive powers at various buses of power system. MCPs can be used to obtain GENCOs' surpluses, which in turn can be used to identify their market power.

The MCPs of real power ($\lambda_{pi}{}^{t}, t \in M$), MCPs of reactive power ($\lambda_{qi}{}^{t}, t \in M$) and corresponding ($P_{gi}{}^{t}, Q_{gi}{}^{t}, t \in M$) during 12 monthly peaks have been obtained from the solution of above optimization problem, which gives surplus of a GENCO at ith bus (SG_i) during one year and is given in (14):

$$SG_i = \sum_{t=1}^{M}\left(\lambda_{pi}{}^{t}P_{gi}{}^{t} + \lambda_{qi}{}^{t}Q_{gi}{}^{t} - C_{pi}\left(P_{gi}{}^{t}\right) - C_{qi}\left(Q_{gi}{}^{t}\right)\right) \quad \text{for all} \quad i \in N_g \tag{14}$$

Now the DG locations have been identified based on the ranking of market powers. The optimization problem has been resolved considering DG placement as given by market power ranking and best DG location has been selected which leads to maximum mitigation of GENCOs' market power and relieving of congestion. GENCOs' surpluses have been recalculated and compared with corresponding original values to demonstrate the mitigation of market powers.

For the information flow for the proposed DG placement strategy is shown in Figure 3.

In the Base Case scenario, no Distributed Generator (DG) is placed in the system. The system operator receives essential inputs for the N-bus network, including supply bids, demand bids, and load requirements. Using this information, the operator schedules the market operation and determines the Market Clearing Price (MCP). This market outcome is then communicated to the system planner. The planner analyses the system performance both before and after the placement of DG. By comparing the results of the two cases, the planner identifies the optimal location for DG placement within the network.

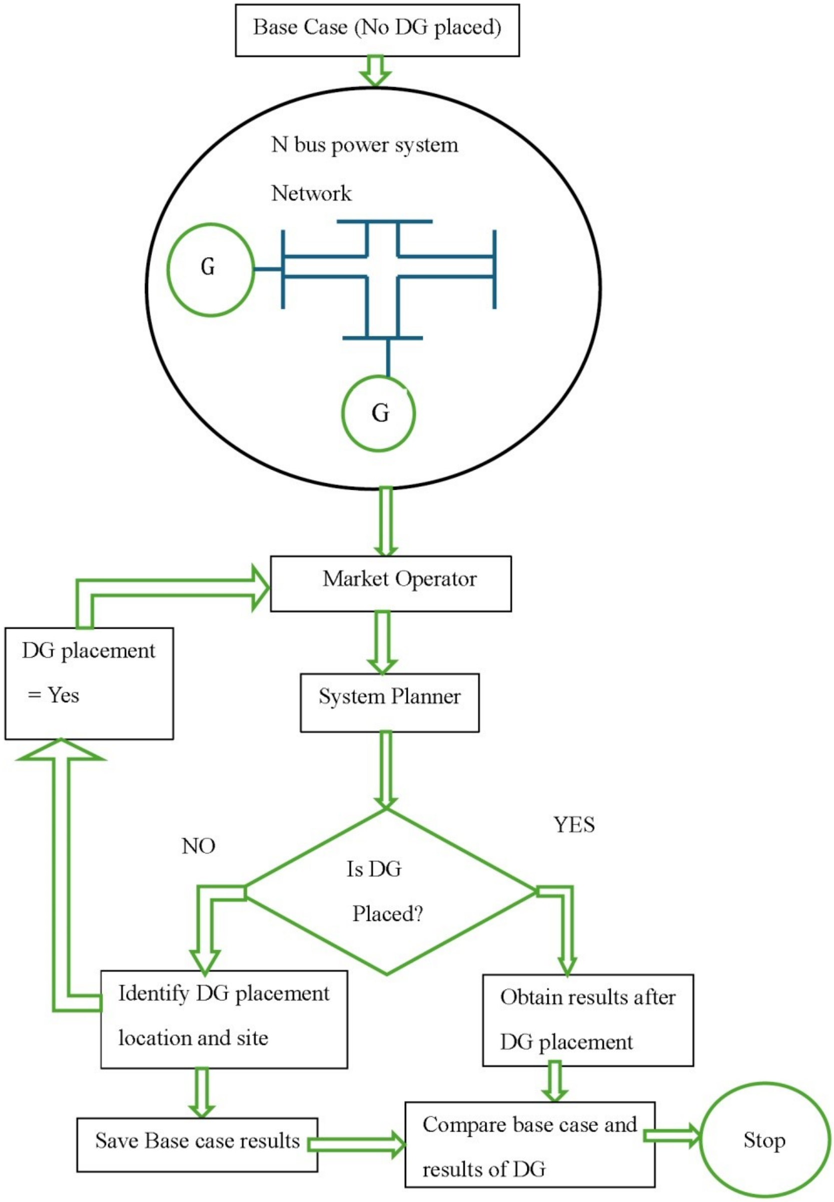

Figure 3
Information flow diagram for proposed DG placement strategy

4. Results and discussion

4.1 *Details of test system*

The proposed approach for obtaining optimal placement of DG to mitigate GENCOs' market powers has been tested on IEEE 118-bus test system [31].

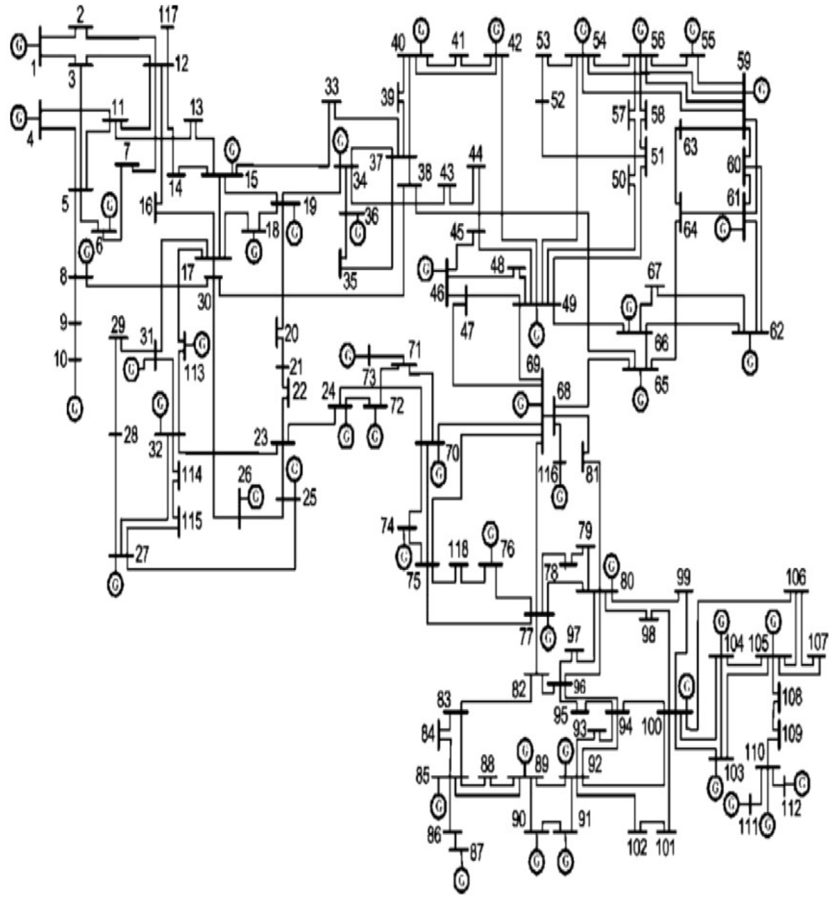

Figure 4

Single line diagram of IEEE 118-bus test system [31]

The single line diagram of IEEE 118-bus test system, which consists of 54 GENCOs, 186 transmission lines and 99 load buses, has been shown in Figure 4. The line- and bus-data for the considered system with the 100 MVA base has been taken from [31]. The minimum and maximum bus voltage limits are taken as 0.94 p.u. and 1.06 p.u., respectively.

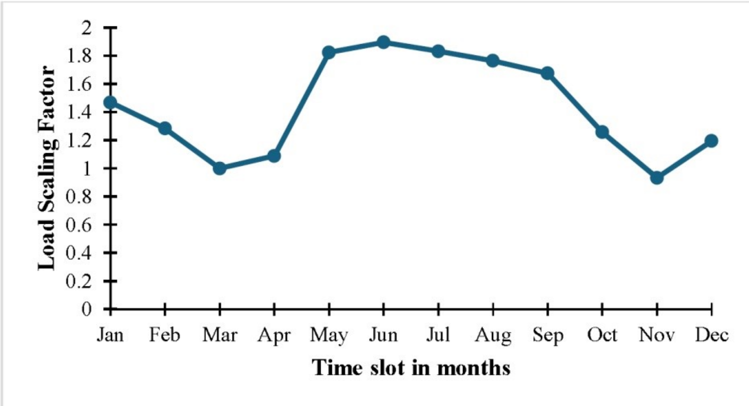

Figure 5
Monthly peak load demand pattern of 2024 for a typical Northern Indian state [32]

Table 1
GENCOs' Data [31]

GENCO	$\frac{1}{2}a_{gi}^{t=3}$ (\$/MW^{2}h)	$b_{gi}^{t=3}$ (\$/MWh)	$P_{gi,max}$ (MW)	$Q_{gi,min}$ (MVAr)	$Q_{gi,max}$ (MVAr)	GENCO	$\frac{1}{2}a_{gi}^{t=3}$ (\$/MW^{2}h)	$b_{gi}^{t=3}$ (\$/MWh)	$P_{gi,max}$ (MW)	$Q_{gi,min}$ (MVAr)	$Q_{gi,max}$ (MVAr)
1	0.01	40	100	-5	15	28	0.025575	20	491	-67	200
2	0.01	40	100	-300	300	29	0.02551	20	492	-67	200
3	0.01	40	100	-13	50	30	0.019365	20	805.2	-300	300
4	0.01	40	100	-300	300	31	0.01	40	100	-10	32
5	0.022222	20	550	-147	200	32	0.01	40	100	-100	100
6	0.117647	20	185	-35	120	33	0.01	40	100	-100	100
7	0.01	40	100	-10	30	34	0.01	40	100	-6	9
8	0.01	40	100	-16	50	35	0.01	40	100	-8	23
9	0.01	40	100	-8	24	36	0.01	40	100	-20	70
10	0.01	40	100	-300	300	37	0.020964	20	577	-165	280
11	0.045455	20	320	-47	140	38	0.01	40	100	-8	23
12	0.031847	20	414	-1000	1000	39	2.5	20	104	-100	1000
13	0.01	40	100	-300	300	40	0.016474	20	707	-210	300
14	1.428571	20	107	-300	300	41	0.01	40	100	-300	300
15	0.01	40	100	-14	42	42	0.01	40	100	-100	100
16	0.01	40	100	-8	24	43	0.01	40	100	-3	9
17	0.01	40	100	-8	24	44	0.01	40	100	-100	100
18	0.01	40	100	-300	300	45	0.039683	20	352	-50	155
19	0.01	40	100	-300	300	46	0.25	20	140	-15	40
20	0.526316	20	119	-100	100	47	0.01	40	100	-8	23
21	0.04902	20	304	-85	210	48	0.01	40	100	-8	23
22	0.208333	20	148	-300	300	49	0.01	40	100	-200	200
23	0.01	40	100	-8	23	50	0.01	40	100	-8	23
24	0.01	40	100	-8	15	51	0.277778	20	136	-100	1000
25	0.064516	20	255	-60	180	52	0.01	40	100	-100	1000
26	0.0625	20	260	-100	300	53	0.01	40	100	-100	200
27	0.01	40	100	-20	20	54	0.01	40	100	-1000	1000

The load demand pattern of monthly peaks assumed for the present paper has been taken from the government website [32] for a typical state of Northern India of the year 2024 and is shown in Figure 5. For the month of March (t=3), the Load Scaling Factor (LSF) has been taken as 1 for mapping the data considered with that provided in [31]. For all other months, the respective data have been considered by scaling using LSFs as shown in Figure 5. For instance, the LSF of January (t=1) is 1.468, which means the demand profile for t=1 will be 1.468 times that of t=3. Similarly, the other time variable data provided here corresponds to t=3, and for remaining months the LSFs as shown in Figure 4 have been used to project the corresponding data. The GENCOs data, which consist of $\frac{1}{2}a_{gi}{}^{t=3}$, $b_{gi}{}^{t=3}$, $P_{gi,max}$, $Q_{gi,min}$ and $Q_{gi,max}$ are given in Table 1. For demand bids, the intercept for t=3 is taken as 50 $/MWh, and slope is assumed to be zero, which represent that any particular DisCo is willing to pay a maximum price of $50 for the consumption of unit MWh, at the monthly peak of March.

4.2 *Identification and Mitigation of Market Power*

In order to apply the proposed solution methodology as discussed in Section 3, a Base Case is solved in which proposed problem has been solved without considering DG placement and transmission congestion. Then for identifying the change in SG_i, Case 1 is considered as extension of Base Case with congestion in transmission network included. The transmission network congestion is considered over the four lines numbering 7, 8, 9 and 51 by considering the power flow limits as 300, 300, 300 and 200 MVA respectively. Based on the comparison between Case 1 and Base Case, it has been obtained that bus numbers 4, 6, 46, 42, 1, 25, 19, 24, 27, 34, 40, 49 and 18 report significant increase in SG_i (in descending order) which varies between 231.78% to 17.09%. Hence these locations are considered to be promising for DG placement for market power mitigation.

For DG placement, a typical solar PV system of 50kWp with a 50% certainty level is considered [30], whose monthly output pattern is taken from [32], as shown in Figure 6. At 50% certainty level the average PV output obtained is 25.375 MW in the month of March, where the scaling factor is unity (Figure 6). The average solar PV output of remaining months is obtained by simply multiplying with corresponding scaling factors. There happens to somewhat increase in solar PV output by reducing the certainty level considered and vice-versa [30]. This solar PV based DG has been modelled in Case 2 considering first five priority locations viz. bus numbers 4, 6, 46, 42, and 1, and results obtained are shown in Table 2.

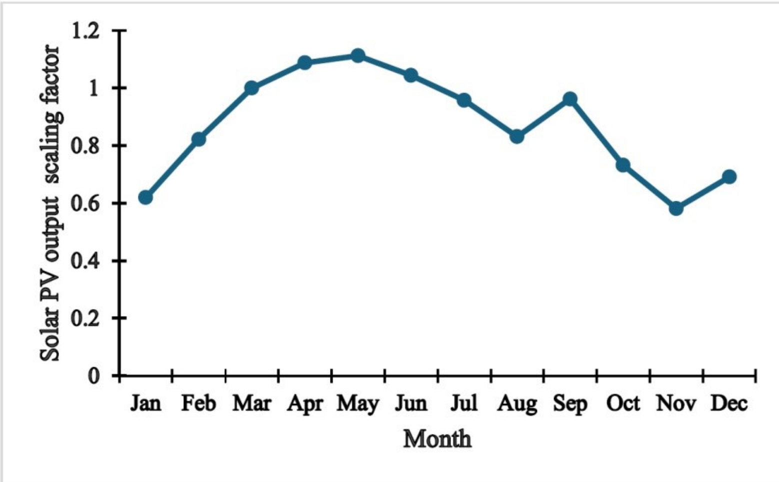

Figure 6
Monthly pattern of Solar PV output [33]

Table 2
Comparison of Case 2 with Case 1 for Optimal Placement of Solar PV DG for market power mitigation

GENCO at Bus	Increase in Surplus from Base Case to Case 1 (%age)	Decrease in Surplus from Case 1 to Case 2 (%age)				
		DG Placed at Bus 4 (%age)	DG Placed at Bus 6 (%age)	DG Placed at Bus 36 (%age)	DG Placed at Bus 34 (%age)	DG Placed at Bus 1 (%age)
4	231.782	17.239	13.505	-0.4243	-0.377	13.695
6	128.661	12.649	13.999	-0.189	-0.1499	11.27
36	110.742	-0.274	-0.159	8.864	6.815	-0.108
34	109.928	-0.243	-0.1329	6.844	7.096	-0.082
1	86.977	9.209	8.002	0.0213	0.046	16.348
19	51.0714	3.5816	3.2549	2.50284	2.57165	3.4531
15	47.3744	4.1466	3.7692	1.86585	1.90631	3.9942
113	46.0082	7.0750	6.3864	1.14277	1.21655	6.7953
18	41.1010	4.1910	3.8114	1.7306	1.79386	4.0428
24	30.91	4.7010	4.0965	1.46577	1.50706	4.1908
27	20.4468	3.8212	3.3508	0.80349	0.84059	3.4443
32	20.340	3.72778	3.28712	0.77444	0.81278	3.394
40	19.146	0.02683	0.02228	0.4477	0.4799	0.0177
12	17.095	3.0458	2.8952	-0.0362	-0.0242	3.0058

Following insights can be derived from Table 2:

- The highest decrease in market power of a particular location happens when DG is placed at that bus location.
- The highest market power ($SG_i$of 231.782%) exist at bus 4, which decreases highly by DG placement at that location and cross decrease in market power is also maximum at this location, which makes it most suitable choice for DG placement.
- Bus number 1 and Bus number 6 performs fairly good, they can be the next priority location for DG placement.
- DG located at bus number 4, 1 and 6 causes slight increase in SG_i of bus number 36 and 34, hence after for placing second DG these should be taken as the priority locations.

4.3 *Comparison with Conventional Approaches*

The proposed approach has been compared with available approaches of DG placements for maximizing SW (Case 3), minimizing transmission losses (Case 4) and that based on highest MCP bus (Case 5). It has been obtained that bus numbers 52 and 118 are the most favourable locations for DG placement for the present system data which causes maximization of SW and minimization of transmission losses, respectively. The SW increases from 1711285.53 $ in Case 1 to 1729092.64 $ in Case 3 and transmission losses reduces from 128.8 MW in Case 1 to 127.2 MW in Case 4 in the peak demand month (i.e., June) when the LSF is maximum. The largest reduction in MCP value occurs at bus 58 at the peak LSF period of June, where it drops from 93.52 $/MWh in Case 1 to 92.37 $/MWh in Case 5 by the placement of the considered solar PV system-based DG. The percentage reduction in MCPs in this scenario at the system buses is shown in Figure 7.

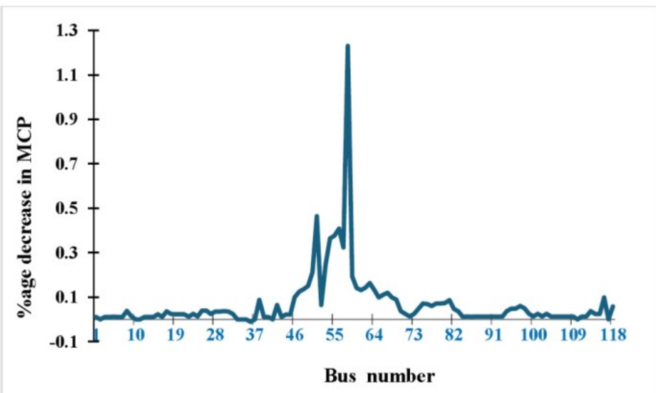

Figure 7

Percentage decrease in MCPs at system buses from Case 1 to Case 5 during peak LSF of June

As far as mitigation of market power is concerned, a comparison of conventional approaches (Case 3, Case 4 and Case 5) with proposed approach (Case 2) is shown in Table 3. This demonstrates that the conventional approaches cause minute reduction in surplus of those GENCOs who have very high market power impact. Hence conventional DG placement approaches of SW maximization, transmission losses minimization and that based on MCP minimization are not able to address the issue of market power mitigation.

Table 3

Comparison of proposed approach (Case 2) with conventional approaches (Case 3, Case 4 and Case 5)

GENCO at Bus	Increase in Surplus from Base Case to Case 1 (%age)	Decrease in Surplus (%age) for various Cases			
		DG Placed at Bus 4 (Case 2)	DG Placed at Bus 52 (Case 3)	DG Placed at Bus 118 (Case 4)	DG Placed at Bus 58 (Case 5)
4	231.782	17.24	0.174	0.329	0.252456
6	128.661	12.65	0.158	0.279	0.219292
36	110.742	-0.27	0.023	-0.124	-0.01358
34	109.928	-0.24	0.035	-0.115	-0.00045
1	86.977	9.21	0.123726	0.194	0.162
19	51.07147	3.58	0.222131	0.421	0.300
15	47.37445	4.15	0.221204	0.400	0.298
113	46.00822	7.07	0.542213	1.252	0.816
18	41.10106	4.19	0.291997	0.581	0.409
24	30.91	4.70	0.893621	5.895	1.386
27	20.447	3.82	0.387	1.047	0.554
32	20.340	3.73	0.368	1.0125	0.525
40	19.146	0.027	0.163	0.0265	0.152
12	17.095	17.24	0.174	0.329	0.252

On the other hand, the DG placement in the proposed approach led to increase in SW in the range of 0.973 % - 1.009% as compared to maximum increase of SW of 1.041 % in Case 3. However, there happens to be somewhat increase in transmission losses of the order of 0.6%. The highest MCP decreases by 1.06% during peak scenario with DG placement at bus 4 in the proposed approach in comparison to 1.23% decrease due to DG placement at bus 58 in Case 5. This shows that proposed approach of DG placement performs fairly good on the basis of SW maximization and MCP minimization in addition to meeting the criterion of market power mitigation.

5. Conclusion

This paper presents a novel methodology for optimal placement of solar PV system-based DG for market power mitigation of GENCOs by making use of non-linear modelling of power system for electricity market clearing mechanism. The market power of various GENCOs have been identified by making use of their surplus indices over the twelve-monthly peaks of one year under congested transmission conditions. The proposed methodology gives priority to those locations for DG placement which causes maximum reduction in surplus of GENCOs who are most likely to exercise their market powers. The detailed analysis and comparative studies on IEEE 118-bus system shows that the proposed methodology demonstrates its robust performance for market power mitigation. Whereas the conventional methods of DG placement are not able to address the issue of market power mitigation, the proposed methodology performs fairly good for conventional fronts of SW maximization and MCP reduction in addition to meeting the proposed objective of market power mitigation. Without any doubt, the insights obtained from the present analysis are able to contribute valuably to meet the ongoing global efforts to enhance affordability and sustainability of the systems as well as it opens directions for future research on the said issues.

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