

## ORIGINAL RESEARCH

# Facilitating DER participation in wholesale electricity market through TSO-DSO coordination

Megha Gupta  | Shri Ram Vaishya | Abhijit R. Abhyankar

Electrical Engineering Department, IIT Delhi, New Delhi, India

## Correspondence

Megha Gupta, Electrical Engineering Department, IIT Delhi, New Delhi, India.

Email: [meghagupta1191@gmail.com](mailto:meghagupta1191@gmail.com)

## Abstract

In this study, a novel coordinated market scheme is proposed, enabling the participation of distributed energy resources (DERs) in the wholesale as well as local energy market (LEM). First, a day-ahead energy market framework is proposed that is operated by a distribution system operator (DSO) in coordination with the transmission system operator (TSO). The DERs present in a distribution system have the freedom to select among the local or wholesale electricity markets (WEM) to offer their energy. The DSO aggregates all DERs' services and power demand to represent them in a WEM operated at the transmission level. The proposed model allows the DSO to select more economical ways of allocating the resources utilising the TSO-DSO coordination strategy. The objective is to maximise social welfare in light of network constraints. Furthermore, a practical method is developed for DSOs to redistribute any monetary surplus among different DERs participating in the WEM. Numerical simulations indicate the proposed model's economic effectiveness compared to the scenario where DERs are allocated only at the local market level.

## KEYWORDS

distributed energy resources, local energy market, locational marginal price, TSO-DSO coordination, wholesale electricity market

## 1 | INTRODUCTION

Power systems across the globe are undergoing critical changes through the integration of distributed energy resources (DERs), especially at the medium and low voltage levels [1]. This has posed many challenges, such as load balancing, congestion management, volt-var compensation, handling bi-directional power flow in the distribution network, etc., to system operators at the transmission and distribution levels [2].

The rapid growth of DERs in distribution systems (DSs) has motivated the assessment of the potential for coordination between the operations of transmission system operators (TSOs) and distribution system operators (DSOs) [3, 4]. Moreover, TSO-DSO coordination plays an important role in making decisions such as future infrastructure investments, operational planning, utilisation of local resources as ancillary services, and better renewable generation and load forecasting [2].

Locally distributed DERs, that is, those connected to the DS, can be more efficiently utilised at the transmission level for different services, such as energy distribution, power reg-

ulation, reserve allocation, and available capacity [5]. Hence, DERs and flexible consumers should have the option to participate in the wholesale electricity market (WEM) operating at the transmission level through the DSO. Previous well-established approaches focus on the WEM, in which the entities directly connected to the transmission network can participate [6, 7]. However, over the past few years, interest has been drawn towards the development of distribution-level local energy markets (LEMs) and coordinated energy market frameworks [8, 9]. The former market model is a promising means for efficient utilisation of DERs in DS [10–12], whereas the latter market framework establishes coordination between TSOs and DSOs to make DERs in the DS accessible to the TSO. Studies presented in the literature mainly focus on two aspects of TSO-DSO coordination: suggesting possible coordination schemes [13, 14], and formulating a market clearing framework [15–20].

Many countries are exploring various options for the practical implementation of TSO-DSO coordination [21]. In some countries, a few pilot projects are in operation, such as in Great Britain [22, 23]. However, the European Union (EU) has taken a more significant step in this regard, as is evident from the

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EU SmartNet project [3, 13]. In general terms, five different TSO-DSO coordination schemes have gained popularity across the globe:

- 1) TSO model: a TSO coordinates directly with DERs and no congestion management is carried out on the distribution network.
- 2) DSO model: a DSO manages any local congestion and transfers unused resources to the TSO.
- 3) TSO and DSO hybrid model: a TSO manages congestion and balancing at the transmission level, whereas the DSO manages congestion and balancing at the distribution level.
- 4) Common TSO-DSO model: the TSO and DSO together manage the balancing and congestion of the entire system.
- 5) Third party model: the TSO and DSO procure ancillary services from a market operated by a third party operator.

The selection of a coordination scheme depends on many key factors, such as present market operation and scheduling philosophy, status and structure of the network, types of DERs connected, and types of services to be traded. Another important aspect of TSO-DSO coordination is information exchange. As the number of DERs increases, the amount of information exchange may also increase, which can play a crucial role in the selection of a particular TSO-DSO coordination model. The market design, and advantages and disadvantages of each coordination scheme are discussed in ref. [13, 14]. Similarly, United Kingdom (UK) Open Networks has proposed six different TSO-DSO coordination models in UK [24]. The primary focus of all models proposed in European countries is on the utilisation of local resources as ancillary services at the transmission and/or distribution levels. However, local resources can also be used for energy arbitrage, although few electricity markets are exploring such options [25]. However, the United States Federal Energy Regulatory Commission (FERC) issued Order no. 2222 to enable the participation of DERs in WEMs in 2020 [26].

The theoretical realisation of various coordination schemes for the procurement of DER services by the TSO is presented in ref. [13]. Moreover, various hierarchical and distributed approaches involving TSO-DSO coordination have been proposed in the literature [15–19]. In all approaches, the DSO responds to the locational marginal price (LMP) at the interfacing bus of the transmission and distribution (T&D) system evaluated by the WEM. For example, a bi-level optimisation based market clearing framework was proposed in ref. [15]. The upper-level optimisation is formulated to maximise the payoff of the individual entities, whereas the DSO performs lower-level optimisation to clear the market. However, the market clearing framework is based on the DC formulation, which is not valid for a distribution network. In ref. [16], a day-ahead transactive market framework was proposed. The DSO balances the local market at the distribution level and coordinates with the TSO for wholesale and retail market clearing. An iterative distributed architecture to calculate transmission and distribution LMPs through a co-optimised power and reserve market for an integrated T&D system was proposed in ref. [17]. In a separate study, a feasible region projection-based approach was proposed

to optimally integrate DS into the TSO's market clearing problem by modelling the DS configuration details, voltage limits, and line flow limits [18]. In ref. [19], a distributed dispatch scheme applicable to an integrated T&D system was proposed for efficient coordinated real-time dispatch based on the concept of an optimal power exchange interval. A generalised master-slave-splitting method was proposed in ref. [20] for T&D coordinated power flow, contingency analysis, voltage stability assessment, economic dispatch, and optimal power flow.

Most of the approaches presented in the literature for performing market operations through TSO-DSO coordination involve (a) the DSO submitting a single aggregated demand bid to the TSO after clearing the market at the DS level, and (b) modelling the DS and its elements as an entity that can be integrated into the WEM. Limited discussion can be found for the condition in which the DSO is submitting aggregated generation offers and demand bids simultaneously. Furthermore, the non-linearity associated with the DS and losses occurring at the transmission level are also ignored. Although the non-linearity of the DS is addressed in ref. [14], the TS system is modelled as a lossless system, and the provision allowing DERs to participate in the WEM is not modelled. Thus, there is a gap in the literature addressing the detailed modelling of T&D systems and the mathematical formulations needed for market clearing through TSO-DSO coordination. In addition, a communication procedure demonstrating the sequence of operations performed by various entities involved in market clearing has not been explored. Furthermore, there is little discussion available with respect to allowing DERs to participate in the WEM in addition to the LEM level. The important aspect in this regard is for the DSO to make a settlement for the entities participating in the WEM. This is because the TSO only provides a price signal at the common bus connecting T&D systems. Then, the DSO has to decide further on the prices of the DERs which are not connected directly to the boundary bus.

In this study, a day-ahead energy market framework is proposed that is operated by a DSO in coordination with a TSO. The characteristics of the Common TSO-DSO market [13] model are used to design the proposed framework. The DERs at the distribution level have the opportunity to participate in the WEM through TSO-DSO coordination in addition to participation in the distribution level (the LEM). Thus, the DSO is both an importer and exporter of energy. The mathematical models for performing market operations separately at the T&D levels [27, 28] account for losses in the TS and for the non-linearity in the DS. These are modified by adding relevant constraints to represent the participation of various entities involved in the market clearing operation. The objective is to maximise the social welfare (SW) of a DSO subject to the distribution network constraints and to allow DSOs to select more economical ways of allocating their resources. In addition, different possible methods are discussed to calculate the incentives for DERs participating in the WEM, and an appropriate method for the distribution of incentives is suggested.

The remainder of this paper is organised as follows. Section 2 discusses the proposed market model for TSO-DSO coordination. The mathematical formulation for TSO market clearing,

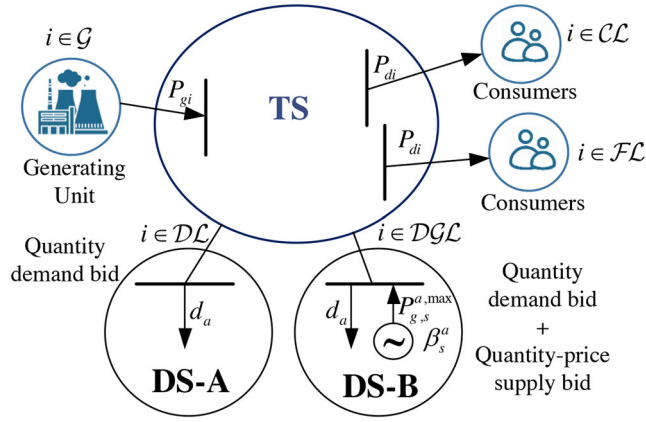


FIGURE 1 Illustration of an integrated power system

DSO market clearing, and settlement mechanisms for DERs participating in the WEM are presented in Section 3. The proposed coordination scheme is illustrated and analysed through various suitable case studies in Section 4. Finally, concluding remarks are presented in Section 5.

## 2 | PROPOSED MARKET MODEL FOR TSO-DSO COORDINATION

A typical integrated power system consists of a transmission system (TS) connected to different distribution systems (DSs) embedded with multiple DERs is shown in Figure 1. The  $i^{th}$  entity connected directly to the TS can be a

- (1) generating units ( $i \in \mathcal{G}$ ),
- (2) constant load units ( $i \in \mathcal{CL}$ ),
- (3) flexible load units ( $i \in \mathcal{FL}$ ), and
- (4) distribution system ( $i \in \mathcal{DL}$  &  $i \in \mathcal{DGL}$ ).

The transmission bus at which  $a^{th}$  DS is connected to the TS is referred as a boundary bus (BB), where  $a \in \mathcal{N}^D$  and  $\mathcal{N}^D = \{1, 2, \dots, |\mathcal{A}|\}$ . There can be two types of distribution system, namely, Type A DS and Type B DS. In the Type A DS, DERs can participate in the LEM only; whereas, in the Type B DS, DERs can participate in the WEM and LEM. The DSOs in the Type A and Type B DSs can coordinate with TSO as follows:

- Type A:**  $a^{th}$  DSO connected at  $i^{th}$  TS bus communicates only power demand from the grid ( $d^i$ ), where  $i \in \mathcal{DL}$ .
- Type B:**  $a^{th}$  DSO connected at  $i^{th}$  TS bus communicates power demand from the grid ( $d^i$ ), generation quantity offered  $\bar{P}_{g,i}$  at offer price  $\beta_{g,i}$ , where  $i \in \mathcal{DGL}$ .

Further, we can consider two types of DERs (for instance, distributed generation, that is, DG is modelled in this paper) based on the market in which they are participating (a) Type 1 DG:  $j^{th}$  unit offering their generation in WEM operated by TSO,  $j \in \mathcal{N}^{DG1,a}$  (b) Type 2 DG:  $j^{th}$  unit participating only in LEM operated by DSO,  $j \in \mathcal{N}^{DG2,a}$ .

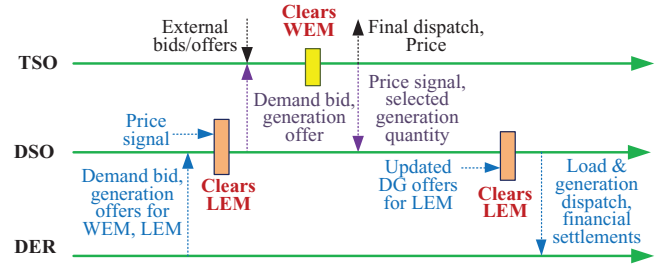


FIGURE 2 Sequence in the proposed TSO-DSO coordination

In the Type A DS,  $j^{th}$  DG participates in the LEM by offering generation quantity  $\bar{P}_{g,j}^a$  at an offer price  $\beta_{g,j}^a$ . In the Type B DS,  $j^{th}$  DG can participate in the WEM and LEM by offering generation quantity  $\gamma_{g,j}^a \bar{P}_{g,j}^a$  and  $(1 - \gamma_{g,j}^a) \bar{P}_{g,j}^a$ , respectively, at a price  $\beta_{g,j}^a$ . If DG has to participate only in LEM then  $\gamma = 0$ .

### 2.1 | Role of a DSO

The two types of DSOs (i.e. Type A and Type B) operate local energy markets in their respective distribution system. Both types of DSOs take the price,  $\pi_0^a$  at the BB for buying/ selling the power from/to the WEM operated by TSO. DSO is responsible for aggregating the quantum and price of power to be offered and the quantum of power to be purchased from WEM. It evaluates the share of each DER and their associated price plus incentive. DSO has the flexibility to alter the quantum of generation offer and power demand from the grid according to the price provided by TSO. While it is the choice of a DER owner whether they want to participate in LEM or WEM and how much percentage of their total capacity they wish to offer for each market. Also, DSO schedules demand of flexible loads.

### 2.2 | TSO-DSO coordination

The sequence of information exchange between TSO and DSO is vital for efficient market operation. Figure 2 shows the sequence of operations that will take place at transmission and distribution levels and illustrates the coordination between TSO and DSO. Firstly, DERs and loads submit their offers and bids to the DSO. The DSO clears the local energy market with the price at reference bus derived from past trends and estimates the power to be drawn from grid. It prepares generation offer for the DGs who want to participate in the WEM and power demand from the grid to be communicated to the TSO. The DERs present in the DS thus gets a chance to participate in the WEM. Subsequently, the TSO clears WEM and communicates the LMP and the cleared quantities of DERs in WEM to the DSOs. Finally, the DSO clears the LEM again with the updated price at the reference bus and DG offers that were not cleared in WEM. Hence, final dispatches and prices to be paid/charged for all the loads and DGs are provided by a DSO to the respective units.

### 3 | MATHEMATICAL FORMULATION OF THE MARKET CLEARING FRAMEWORK AND SETTLEMENT

A day-ahead market clearing models for the TSO and DSOs are presented in the following subsections.

#### 3.1 | TSO market clearing model

The market clearing model of the WEM operated at the TS level is formulated based on the loss compensated DCOPF model [27]. The objective of the TSO's market clearing problem is social welfare maximisation. TSO considers offers and bids from different entities directly connected to transmission system and different DSOs. As explained in Section 2, the Type B DSOs will participate in the WEM by offering aggregated DER offers. TSO incorporates the offers provided by distribution systems in its objective function. The mathematical expression of the objective function can be written as follows:

$$\begin{aligned} \max_{P_{d,i}, P_{g,i}} \sum_{i \in FL} \mathcal{U}_i(P_{d,i}) - \sum_{i \in \mathcal{G}} C_i(P_{g,i}) \\ - \sum_{i \in \mathcal{DGL}} \sum_{s \in \mathcal{N}^{DG1,i}} (\beta_{g,s}^i P_{g,s}^i). \end{aligned} \quad (1)$$

Here,  $d^{th}$  DSO connected at  $i \in \mathcal{DGL}$  submits generator offers as a block bid [29]: vector of offer price arranged in ascending order  $\beta_{g,i} = [\beta_{g,1}^a, \beta_{g,2}^a, \dots, \beta_{g,s}^a]$  and offer quantity  $\bar{P}_{g,i} = [\bar{P}_{g,1}^{a,WEM}, \bar{P}_{g,2}^{a,WEM}, \dots, \bar{P}_{g,s}^{a,WEM}]$  where  $s$  denotes number of the Type 1 DG units in  $d^{th}$  DS and  $\bar{P}_{g,s}^{a,WEM} = \gamma_{g,s}^a \bar{P}_{g,s}^a$ . Above objective function is subjected to the nodal power balance constraints, line flow constraints, upper and lower limits on the offers and bids of different entities. The nodal power balance constraint can be written as follows:

$$P_{g,i} - P_{d,i} + \sum_{s \in \mathcal{N}^{DG1,i}} P_{g,s}^i - \sum_j P_{loss,ij} - \sum_j P_{ij} = 0, \quad \forall i \in \mathcal{N}. \quad (2)$$

The first two terms in the above constraint are generation and loads, respectively, that are directly connected to the TS. The third term is offers from DGs submitted through DSOs. Fourth and fifth terms represent power loss and flow in the lines connected to Bus  $i$ , respectively. The power loss in the  $l^{th}$  line connected between Buses  $i$  and  $j$  ( $i \sim j \in \mathcal{L}$ ) can be written as follows:

$$P_{loss,ij} - r_{ij} P_{ij}^2 = 0, \quad \forall l : i \sim j \in \mathcal{L}. \quad (3)$$

The power flow ( $P_{ij}$ ) in the  $l^{th}$  line is shown in (4).

$$P_{ij} - (\delta_i - \delta_j)/x_{ij} = 0, \quad \forall l : i \sim j \in \mathcal{L}. \quad (4)$$

The power flow limits on transmission lines in the forward and reverse directions can be written as follows:

$$P_{ij} - \bar{P}_{ij} \leq 0, \quad \forall l : i \sim j \in \mathcal{L} \quad (5)$$

$$-P_{ij} - \bar{P}_{ij} \leq 0, \quad \forall l : i \sim j \in \mathcal{L}. \quad (6)$$

Here, limits in the forward and reverse directions are taken to be same. Finally, limits are incorporated on the generation offers and load bids submitted by the entities connected to transmission system.

$$P_{g,s}^i - P_{g,s}^{i,\max} \leq 0, \quad \forall i \in \mathcal{DGL}, s \in \mathcal{N}^{DG1,i}, \quad (7)$$

$$-P_{g,s}^i \leq 0, \quad \forall i \in \mathcal{DGL}, s \in \mathcal{N}^{DG1,i}, \quad (8)$$

$$P_{g,i} - \bar{P}_{g,i} \leq 0, \quad \forall i \in \mathcal{G}, \quad (9)$$

$$-P_{g,i} + \underline{P}_{g,i} \leq 0, \quad \forall i \in \mathcal{G}, \quad (10)$$

$$P_{d,i} - \bar{P}_{d,i} \leq 0, \quad \forall i \in \mathcal{FL}, \quad (11)$$

$$-P_{d,i} + \underline{P}_{d,i} \leq 0, \quad \forall i \in \mathcal{FL}. \quad (12)$$

The demand for the price-insensitive loads are presented as follows:

$$P_{d,i} - \bar{P}_{d,i} = 0, \quad \forall i \in \mathcal{CL}, \quad (13)$$

$$P_{d,i} - d^i = 0, \quad \forall i \in \mathcal{DL}, \mathcal{DGL}. \quad (14)$$

The locational marginal prices for the above market-clearing framework can be calculated from the Lagrangian function using KKT conditions [30]. The mathematical expression of the LMP ( $\pi_i$ ) at the  $i^{th}$  bus can be written as follows:

$$\pi_i = \lambda_i, \quad (15)$$

where,  $\lambda$  is the Lagrangian multiplier corresponding to the nodal power balance constraint. A generator/load entity is paid/charged according to LMP at its location. TSO passes LMP information at BB to the corresponding DSO.

#### 3.2 | DSO market clearing model

The market clearing problem for each DSO is formulated using a second order cone program (SOCP) [14, 28] that addresses non-linearity associated with the DS and ensures a superior optimal solution under mild assumptions [14]. The objective function of market clearing problem is to maximise the social welfare. DSO considers bids and offers from flexible loads and DGs who want to participate in the local energy market. In addition, the DGs cleared in the WEM through DSO are considered as inflexible entities. The mathematical expression of the



objective function for the  $d^{th}$  DSO can be written as follows:

$$\max_{j_i^a} \sum_{i \in \mathcal{N}^a} \mathcal{U}_i^a(P_{d,i}^a) - \pi_0^a d^a - \sum_{i \in \mathcal{N}^{DG2,a}} \mathcal{C}_i^a(P_{g,i}^a), \quad (16)$$

where first term denotes the utility function of the flexible loads and second term is the cost of purchasing active power from WEM. The last term represents the cost of generation for DGs participating in the LEM. The objective function is subjected to the constraints (17)–(26) [28]. The nodal power balance constraints can be written as follows:

$$P_{g,j}^a + P_{g,j}^{a'} - P_{d,j}^a + f_{ij}^{p,a} - R_{ij}^a l_{ij}^a - \sum_k f_{jk}^{p,a} = 0, \quad \forall i, j \in \mathcal{N}^a, \quad (17)$$

$$Q_{g,j}^a - Q_{d,j}^a + f_{ij}^{q,a} - X_{ij}^a l_{ij}^a - \sum_k f_{jk}^{q,a} = 0, \quad \forall i, j \in \mathcal{N}^a. \quad (18)$$

Here, the second term  $P_{g,j}^{a'}$  in (17) denotes the generation of  $j^{th}$  DG unit cleared in WEM. Distribution network constraints are presented in (19)–(21).

$$u_i^a - u_j^a - 2(f_{ij}^{p,a} R_{ij}^a - f_{ij}^{q,a} X_{ij}^a) + (R_{ij}^2 + X_{ij}^2) l_{ij}^a = 0, \quad \forall i, j \in \mathcal{N}^a, \quad (19)$$

$$-u_i^a + \frac{1}{l_{ij}^a} \left( (f_{ij}^{p,a})^2 + (f_{ij}^{q,a})^2 \right) \leq 0, \quad \forall i, j \in \mathcal{N}^a, \quad (20)$$

$$\left( (f_{ij}^{p,a})^2 + (f_{ij}^{q,a})^2 \right) - (\bar{f}_{ij}^a)^2 \leq 0, \quad \forall i, j \in \mathcal{N}^a. \quad (21)$$

The bus voltage magnitudes should be within an upper and lower limits as shown below:

$$v_i^a \leq v_i^a \leq \bar{v}_i^a, \quad \forall i \in \mathcal{N}^a. \quad (22)$$

The constraints for the generation offers of Type 1 and Type 2 DGs are shown in (23) and (24), respectively.

$$0 \leq P_{g,i}^a \leq \left( (1 - \gamma_{g,i}^a) \bar{P}_{g,i}^a + P_{g,i}^{a''} \right), \quad \forall i \in \mathcal{N}^{DG1,a} \quad (23)$$

$$0 \leq P_{g,i}^a \leq \bar{P}_{g,i}^a, \quad \forall i \in \mathcal{N}^{DG2,a}. \quad (24)$$

Type 1 DG offers their generation  $\gamma_{g,i}^a P_{g,i}^{a,max}$  in WEM and offers  $(1 - \gamma_{g,i}^a) P_{g,i}^{a,max}$  in local energy market. Once the WEM is cleared and  $P_{g,i}^{a'}$  of Type 1 DG is cleared there then the uncleared part of their offers from WEM ( $P_{g,i}^{a''}$ ) can participate in the LEM along with  $(1 - \gamma_{g,i}^a) P_{g,i}^{a,max}$  as modelled in (24). The reactive power generation constraint of DGs is shown below:

$$Q_{g,i}^a \leq Q_{g,i}^a \leq \bar{Q}_{g,i}^a, \quad \forall i \in \mathcal{N}^{DG1,a}, \mathcal{N}^{DG2,a}. \quad (25)$$

The flexible load bids are subjected to following constraint

$$P_{d,i}^a \leq P_{d,i}^a \leq \bar{P}_{d,i}^a, \quad \forall i \in \mathcal{N}^{fl,a}, \quad (26)$$

where  $\mathcal{N}^a$  is the set of nodes in  $d^{th}$  DS,  $u_i = v_i^2$ ,  $l_{ij} = \mathcal{L}_{ij}^2$ ,  $d^a = P_{12}^a$ , and  $P_{d,i}^a = \chi_i^a \bar{P}_{d,i}^a$ . Here,  $\chi_i^a$  denotes the essential part of the flexible load that is needed to be served irrespective of the price.

The Lagrangian multiplier corresponding to (17) is the distribution locational marginal price ( $\pi_i^a$ ) of  $i^{th}$  node in  $d^{th}$  DS [31]. All the loads and Type 2 DGs are charged and paid as per the LMP at their nodes, respectively. While Type 1 DGs are paid as per LMP for the portion that they are offer in the LEM and the settlement for the portion they offer in the WEM is explained in the following subsection.

### 3.3 | Settlement for Type 1 DGs

Let there are two units of Type 1 DGs (DG-1 and DG-2) in a DS offering quantities  $P_1$  and  $P_2$  at price  $\beta_1$  and  $\beta_2$ , respectively, with  $\beta_2 > \beta_1$ . The LMP at BB (obtained from the WEM clearing) is  $\pi_0$ . Now, there can be following scenarios.

- (1)  $\pi_0 < \beta_1$  and  $\pi_0 < \beta_2$ . DG-1 and DG-2 will not get cleared in the WEM.
- (2)  $\pi_0 \geq \beta_1$  and  $\pi_0 < \beta_2$ . DG-1 is partially or fully cleared and DG-2 is not cleared.
- (3)  $\pi_0 > \beta_1$  and  $\pi_0 \geq \beta_2$ . DG-1 is fully cleared and DG-2 is partially or fully cleared.

Here, it can be observed that if DG-2 is cleared in the WEM then the LMP at BB will be more than or equal to its offer price. This higher LMP is getting set because DG-2 is offering at a higher price. As per an intuitively straightforward approach, both the DGs should be paid according to the LMP at BB. In this case, DG-1 will earn more profit as compared to DG-2. However, DG-2 is taking risk of not getting cleared by offering at a higher price. Thus, DG-2 should be incentivized for taking this risk. Now, the key issue arises is to decide that how DSO should pay these DGs. In the proposed methodology for settlement of Type 1 DGs, DSO can pay both DGs using pay-as-bid method along with the incentives. The incentives are paid from the surplus amount available with DSO as defined below:

$$S = \pi_0 (P_1^* + P_2^*) - (\beta_1 P_1^* + \beta_2 P_2^*), \quad (27)$$

where  $S$  is the total surplus of DG-1 and DG-2. The  $P_1^*$  and  $P_2^*$  are cleared amounts of DG-1 and DG-2 in the WEM, respectively. The surplus amount can be distributed as incentives  $S_1$  and  $S_2$  among DG-1 and DG-2, respectively, using the following methods:

- a) *Method-1*: The surplus can be distributed equally among DG-1 and DG-2.

$$S_1 = \frac{1}{2} S; \quad S_2 = \frac{1}{2} S. \quad (28)$$

- b) *Method-2*: The surplus can be distributed in proportion to pay-as-bid payment.

$$S_1 = \frac{\beta_1 P_1^*}{\beta_1 P_1^* + \beta_2 P_2^*} S; \quad S_2 = \frac{\beta_2 P_2^*}{\beta_1 P_1^* + \beta_2 P_2^*} S. \quad (29)$$

- c) *Method-3*: The surplus can be distributed in proportion to offered prices.

$$S_1 = \frac{\beta_1}{\beta_1 + \beta_2} S; \quad S_2 = \frac{\beta_2}{\beta_1 + \beta_2} S. \quad (30)$$

- d) *Method-4*: The surplus can be distributed in proportion to LMPs in LEM.

$$S_1 = \frac{\pi_1}{\pi_1 + \pi_2} S; \quad S_2 = \frac{\pi_2}{\pi_1 + \pi_2} S. \quad (31)$$

- e) *Method-5*: The surplus can be distributed in proportion to weighted sum of LMPs in LEM.

$$S_1 = \frac{\pi_1 P_1^*}{\pi_1 P_1^* + \pi_2 P_2^*} S; \quad S_2 = \frac{\pi_2 P_2^*}{\pi_1 P_1^* + \pi_2 P_2^*} S, \quad (32)$$

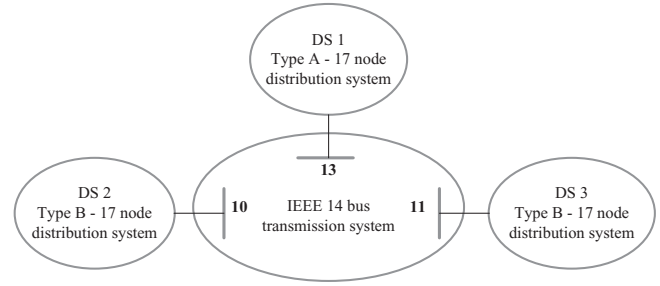
where,  $\pi_1$  and  $\pi_2$  are the LMPs in the LEM at the DG-1 and DG-2 nodes, respectively.

Now, the final payments to DG-1 and DG-2 are  $(\beta_1 P_1^* + S_1)$  and  $(\beta_2 P_2^* + S_2)$ , respectively. DSO can adopt any of the above methods to redistribute the surplus amount among DGs.

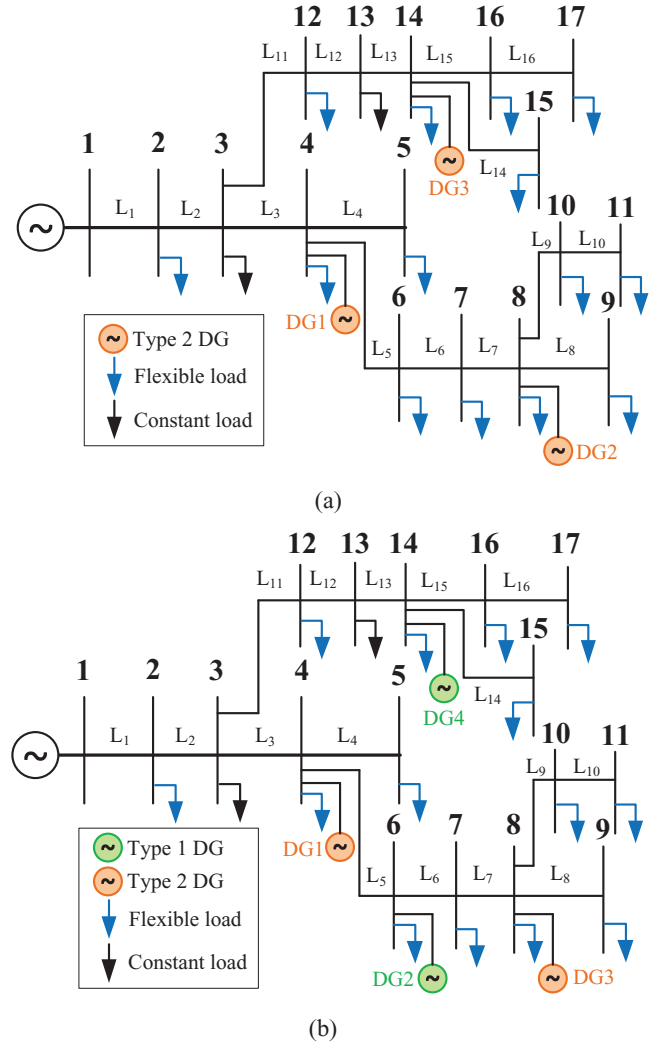
#### 4 | CASE STUDIES AND RESULTS

The proposed energy market clearing framework for TSO-DSO coordination is implemented on an integrated T&D test system. The IEEE 14 bus system is taken as transmission network [32]. Three distribution systems are connected to IEEE 14 bus transmission system at buses 10, 11, and 13, that is,  $\mathcal{A} = \{10, 11, 13\}$ . All the three distribution systems are a single feeder 17 nodes radial distribution network [33]. The integrated transmission and distributed system is shown in Figure 3. There are five generating units in the TS at buses  $\mathcal{G} = \{1, 2, 3, 6, 8\}$  with cost function as  $C_i(P_{g,i}) = \alpha_i P_{g,i}^2 + \beta_i P_{g,i}$  where  $\alpha$  and  $\beta$  are the generator cost function coefficients. The generator parameters considered are:  $\alpha_i = \{0.001, 0.005, 0.001, 0.005, 0.001\}$  \$/MWh<sup>2</sup>,  $\beta_i = \{17, 25, 20, 15, 25\}$  \$/MWh, and  $\bar{P}_{g,i} = \{160, 60, 50, 50, 50\}$  MW. Location and quantity information of the loads directly connected to the TS is taken from [32].

At  $\mathcal{A} = \{10, 11\}$ , Type B DSs are connected and contains two units of Type 1 DG at node  $\{6, 14\}$  and two units of Type 2 DG at nodes  $\{4, 8\}$ , and a mix of constant and flexible loads. At  $\mathcal{A} = \{13\}$ , Type A DS is connected and contains three units of Type 2 DGs at nodes  $\{4, 8, 14\}$ . The topology and connection of DER units (flexible loads and Type 1, Type 2 DGs)



**FIGURE 3** Integrated IEEE 14 bus transmission and 17 node distribution systems



**FIGURE 4** Topology of (a) Type A, and (b) Type B, 17-node distribution system

for Type A and Type B single feeder 17 node radial distribution system is shown in Figure 4. The other parameters of DGs (such as maximum generation capacity, offer price, percentage of generation offered in WEM) considered for each DS are presented in Table 1. Market clearing by TSO and DSO are performed by solving optimisation problems (3)-(14) and (16)-(26), respectively. All the calculations are carried out on a PC

**TABLE 1** DER's information in different distribution systems

BB ( $\mathcal{A}$ )	Nodes	$\bar{P}_{g,i}^a$ (MW)	$\beta_{g,i}^a$ (\$/MWh)	$\gamma_{g,i}^a$ (%)
10 (DS 1)	[4,8,14]	[4,2,3]	[15,13,12]	—
11 (DS 2)	[4,6,8,14]	[3,4,2,3]	[12,11,15,14]	[0,60,0,50]
13 (DS 3)	[4,6,8,14]	[3,4,2,3]	[16,19,13,26]	[0,50,0,60]

running MATLAB 2018b with Intel Core i7, 1.99 GHz CPU and 16 GB of RAM. MOSEK solver is used to solve the DSO market clearing problem.

To assess the effectiveness of proposed framework, different loading level scenarios are considered. The hourly variation of load across 24 h of the day is taken from [34]. Three time intervals,  $t = \{4, 10, 19\}$  are selected to represent the scenarios with different percentages of load level. The net demand at  $t = 4$  is 64%, that is, off-peak load period,  $t = 10$  is 80%, that is, medium-peak load period, and  $t = 19$  is 100%, that is, peak-load period. The computational time is around 6.61 s for the given system to obtain the outcomes of the proposed market framework, for various time intervals.

#### 4.1 | Illustration of the proposed market clearing framework

The input parameters and outcomes of the proposed market clearing at the transmission and distribution levels are presented in Figures 5, 6, and 7 for time periods  $t = 4$ ,  $t = 10$ , and  $t = 19$ , respectively. The DGs at nodes 6 and 14 (i.e. DG2 and DG4) of both DS 2 and DS 3 are Type 1 DGs and are chosen to offer their energy in WEM. DG2 and DG4 of DS 2 offers 2.4 MW and 1.5 MW at 11 \$/MWh and 14 \$/MWh, respectively. Whereas, DG2 and DG4 of DS 3 offer 2 MW and 1.5 MW at 19 \$/MWh and 26 \$/MWh, respectively.

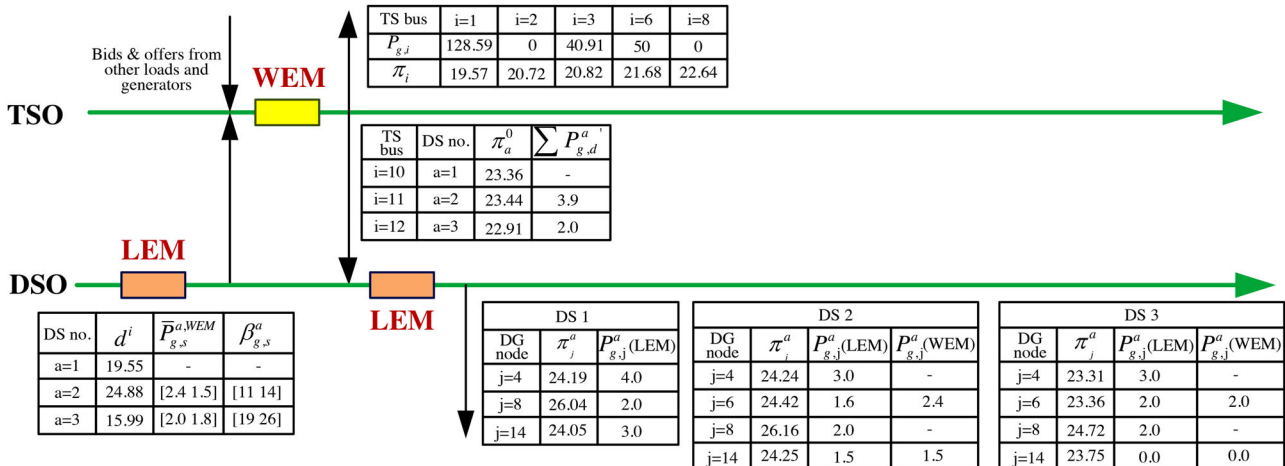
DSOs of respective distribution systems clear the market by solving optimisation problem (16)–(26) and aggregate the DG offers and power demand from the grid to communi-

cate to the TSO. Thus, the input parameters for TSO market clearing model given by DSO include power demand from the grid ( $d^i$ ), generation quantity offered by Type 1 DGs in WEM ( $\bar{P}_{g,s}^{a,WEM}$ ) and the generation offer price ( $\beta_{g,s}^a$ ). Other input parameters to TSO market clearing model are the offers and bids submitted by directly connected generating and load units [32].

Next, TSO clears the market by solving optimisation problem (3)–(14) and communicates back the scheduled generation ( $P_{g,i}$ ), and LMPs ( $\pi_i$ ) at the boundary buses ( $i \in \mathcal{A}$ ) to the respective DSOs as shown in Figures 5, 6, and 7. TSO also provides generation and demand schedules of directly connected units ( $P_{g,i}$ ,  $P_{d,i}$ ) and LMPs ( $\pi_i$ ) of the corresponding buses ( $i \in \mathcal{G}, \mathcal{FL}$ ).

Further, with the obtained price at reference bus ( $\pi_0^a$ ) and generation schedule cleared in WEM ( $P_{g,j}^{a'}$ ),  $d^{th}$  DSO clears the LEM to calculate the dispatches of flexible load units and DG units, and the corresponding LMPs. The values of  $P_{g,j}^a$  (LEM),  $P_{g,j}^a$  (WEM) and  $\pi_j^a$  for  $j \in \mathcal{N}^{DG1}$ ,  $j \in \mathcal{N}^{DG2}$  and  $a = 1, 2, 3$  are shown in Figures 5, 6, and 7. Here, while calculating the dispatches of Type 1 DG units, DSO has the opportunity to utilise the unscheduled quantity of generation (in the WEM,  $P_{g,j}^{a''}$ ) in the local market. Further analysis of the proposed market framework at different time intervals is discussed as follows:

- 1) *At  $t = 4$  time interval:* It can be observed that due to the less demand at  $t = 4$ , the costlier unit DG4 at node 14 of DS 3 is not selected in WEM and LEM. While the other cheaper generating units having the sufficient capacity to serve the off-peak load are cleared in WEM and LEM.
- 2) *At  $t = 10$  time interval:* At  $t = 10$ , due to the high offer price DG4 of DS 3 is not cleared in the WEM while DG2 at node 6 is cleared, thus at the transmission level  $P_{g,13} = 2$  MW though,  $\bar{P}_{g,13} = 2.0 + 1.8 = 3.8$  MW. The uncleared amount of DG4 is then scheduled in LEM and  $P_{g,14}^3 = 3$  MW. At the same time in DS 2, both DGs at node 6 and 14 are cleared in WEM due to the lower offer prices.

**FIGURE 5** Market Clearing results for integrated transmission and distribution system at  $t=4$

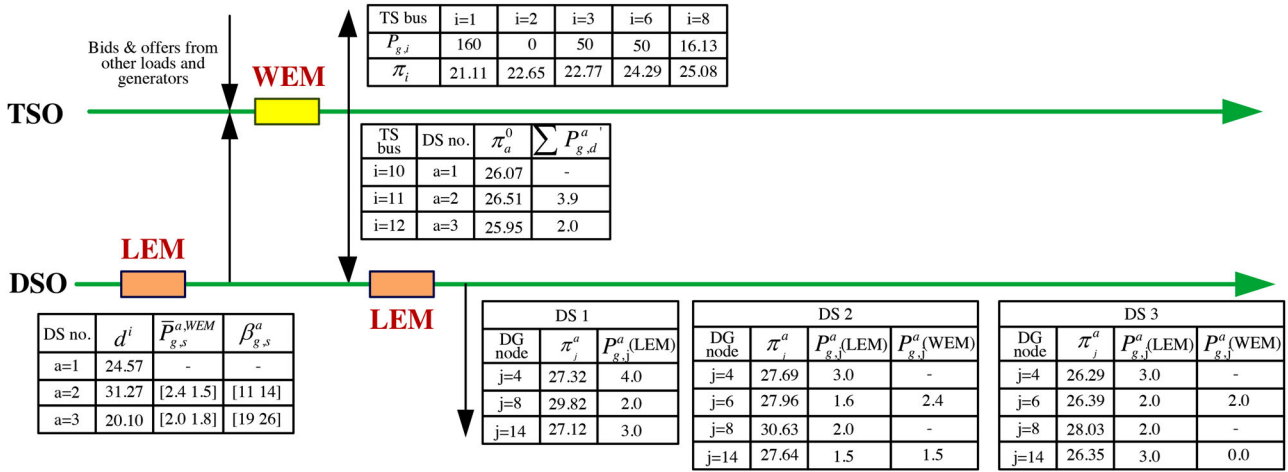


FIGURE 6 Market clearing results for integrated transmission and distribution system at  $t = 10$

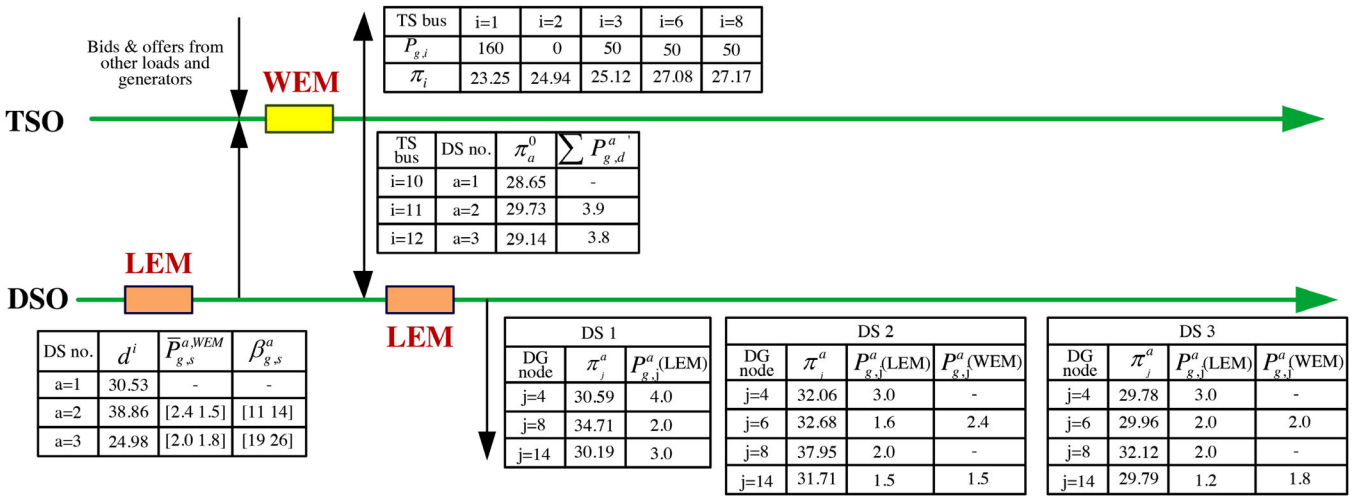


FIGURE 7 Market clearing results for integrated transmission and distribution system at  $t = 19$

- 3) *At  $t = 19$  time interval:* At  $t = 19$ , as the demand is at peak thus, DG4 at node 14 of DS 3 also gets cleared in WEM (i.e. at the transmission level  $P_{g,13} = 3.8$  MW) even at a high offer price and the remaining quantity of 1.2 MW is scheduled in LEM. Similarly, other DG units in DS 2 and DS 3 are also scheduled to serve the peak load. Further, it can be observed that the DG units present in Type A DS 1 are cleared in LEM and the corresponding DSO provides only power demand from the grid to the WEM.
- 4) *LMP at the transmission system buses:* The LMP at different buses of the transmission system that is, generator buses (1, 2, 3, 6, 8) and boundary buses (10, 11, 13) is shown in Figure 8. Also, the value of LMPs at transmission buses and at the DG nodes of all distribution systems are given in Figures 5, 6, and 7. It can be clearly observed that the value of LMP is varying according to the loading level at different hours of the day and is higher at the peak load period.

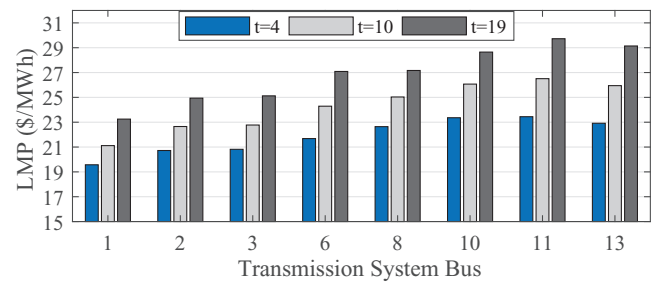


FIGURE 8 LMPs of generator buses and boundary buses in the transmission system

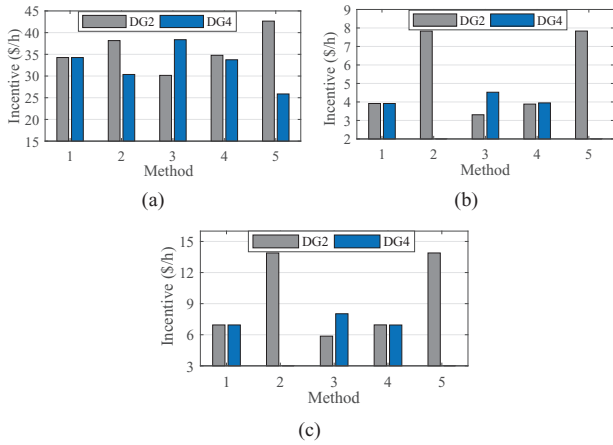
## 4.2 | Incentive redistribution for Type 1 DGs

The incentives (in \$/h) for DG2 at node 6 and DG4 at node 14 of distribution systems DS 2 and DS 3 are shown in Table 2 for all five methods as discussed in Section 3.3. The zero-entry



**TABLE 2** Incentives for DGs participating in the WEM

DSs	DGs	Time	Method-1	Method-2	Method-3	Method-4	Method-5
DS 2	DG2	t=4	22.0162	24.5244	19.3743	22.0916	27.1682
		t=10	27.9892	31.1779	24.6305	28.1517	34.6019
		t=19	34.2614	38.1646	30.1501	34.7773	42.6546
	DG4	t=4	22.0162	19.5081	24.6582	21.9409	16.8643
		t=10	27.9892	24.8006	31.3479	27.8267	21.3765
		t=19	34.2614	30.3582	38.3728	33.7456	25.8683
DS 3	DG2	t=4	3.9165	7.8330	3.3073	3.8843	7.8330
		t=10	6.9451	13.8902	5.8647	6.9501	13.8902
		t=19	12.9647	11.6193	10.9480	12.9996	13.6818
	DG4	t=4	3.9165	0	4.5257	3.9487	0
		t=10	6.9451	0	8.0254	6.9401	0
		t=19	12.9647	14.3101	14.9814	12.9298	12.2476

**FIGURE 9** Incentives for DGs participating in WEM in (a) DS 2 at  $t = 19$ , (b) DS 3 at  $t = 4$ , and (c) DS 3 at  $t = 10$ 

indicates that the particular DG is not cleared in the WEM in that time interval. To compare the adequacy of various methods discussed for redistributing the incentives to Type 1 DGs, the incentives given to DG2 and DG4 of each distribution system DS 2 and DS 3 at different time intervals is shown in Figure 9.

The incentives in each method on the basis of the information available with DSO, that is, offer price of DG units ( $\beta_{gi}^a$ ), LMP at nodes connected to DG units ( $\pi_i^a$ ), LMP at the BB ( $\pi_a^0$ ) and the power schedule of DGs in wholesale energy markets ( $P_{gi}^{a'}$ ), are evaluated as follows:

- Method-1: The surplus is distributed equally among DGs.
- Method-2: The surplus is distributed in proportion to pay-as-bid payment ( $\beta_{gi}^a P_{gi}^{a'}$ ).
- Method-3: The surplus is distributed in proportion to offered prices ( $\beta_{gi}^a$ ).
- Method-4: The surplus is distributed in proportion to LMPs in LEM ( $\pi_i^a$ ).

- Method-5: The surplus is distributed in proportion to a weighted sum of LMPs in LEM ( $\pi_i^a P_{gi}^{a'}$ ).

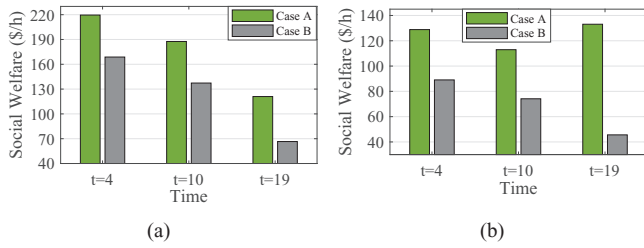
It can be observed that the incentives for both the DGs are equally distributed in Method-1. In Method-2, incentive for DG2 is higher as compared to DG4, whereas the reverse case can be observed for Method-3 for DG2 and DG4. The incentives are nearly same in Method-4. Again in Method-5, the incentive for DG2 is higher as compared to DG4. Here, it can be observed that the incentive for DG2 is higher as compared to DG4 in Methods-2, 4, and 5. In contrast, the incentive is higher for DG4 (which is offering at a higher price in the WEM and LMP at BB is set according to that) in Method-3 only. Thus, it can be inferred that the Method-3 is more suitable to provide suitable incentives to the DERs participating in the WEM.

### 4.3 | Social Welfare of DSOs

The performance of the proposed energy market framework is evaluated in terms of Social Welfare of DSOs for the following two cases:

- Case A:** Type 1 DGs are participating both in WEM and LEM (i.e.  $\gamma \neq 0$ ).
- Case B:** Type 1 DGs are participating only in LEM (i.e.  $\gamma = 0$ ).

The social welfare of DSOs (DS 2 and DS 3) at different load levels (i.e. at different time periods,  $t = 4$ ,  $t = 10$ , and  $t = 19$ ) are given in Figure 10a and Figure 10b, respectively, for Case A and Case B. A notable difference in the value of social welfare can be clearly observed for both distribution systems at different time intervals in Figure 10. The improvement in the social welfare of each DSO when DGs present in the distribution system are participating in the WEM, confirms the effectiveness of the proposed market model.



**FIGURE 10** Social Welfare at different load levels for (a) DS 2, and (b) DS 3

#### 4.4 | Performance validation on large scale systems

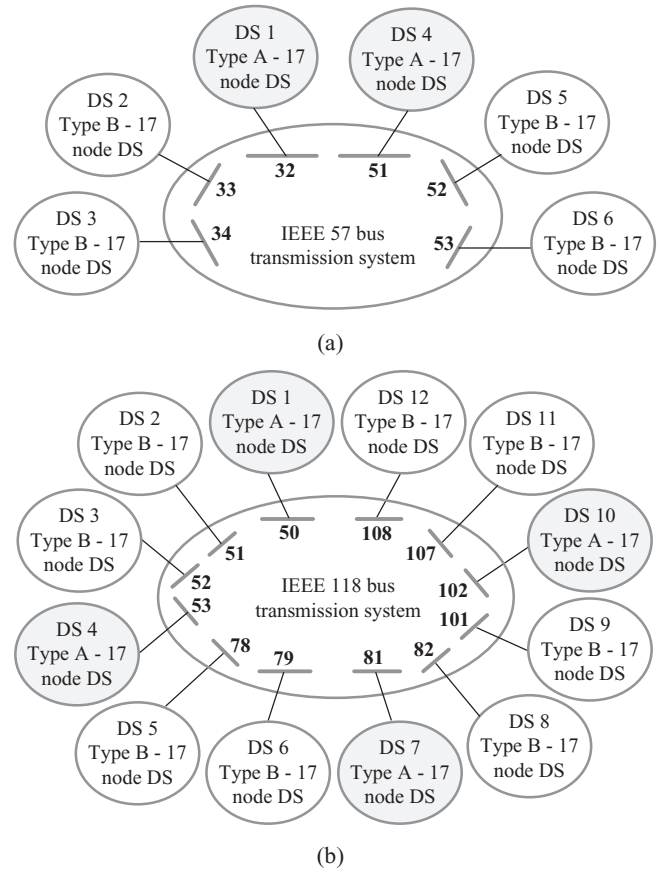
To further validate the effectiveness of proposed market framework, it has been implemented on a large scale integrated T&D systems namely,

1. **System T57D6:** IEEE 57 bus system connected to 6 DSs (at  $\mathcal{A} = \{32, 51\}$  Type A DSs are connected and at  $\mathcal{A} = \{33, 34, 52, 53\}$  Type B DSs are connected)
2. **System T118D12:** IEEE 118 bus system connected to 12 DSs (at  $\mathcal{A} = \{50, 53, 81, 102\}$  Type A DSs are connected and at  $\mathcal{A} = \{51, 52, 78, 79, 82, 101, 107, 108\}$  Type B DSs are connected).

The topological connections of the test systems are shown in Figure 11. The topology and network data of distribution systems are same as considered in the test system studied in the previous subsection.

The computational time is around 11.24 s and 26.64 s for System T57D6 and T118D12, respectively, to obtain the outcomes of the proposed market framework for various time intervals. Though the time taken would increase with the size of system, the fact that very less time is required for combined TS-DS calculation and that the simultaneous communication of all DSOs with TSO is being done, feasibility of the proposed approach for large-scale systems gets established.

The outcomes of the proposed market framework at the transmission and distribution levels for Systems T57D6 and T118D12 are presented in the Table 3 for time periods  $t = 4$ ,

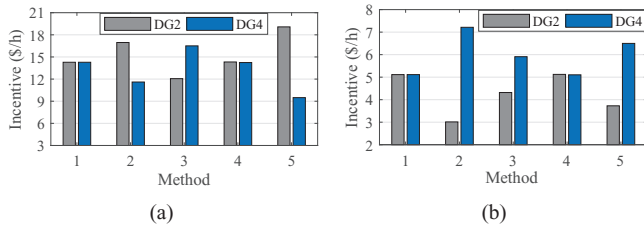


**FIGURE 11** Illustration of test systems (a) T57D6, and (b) T118D12

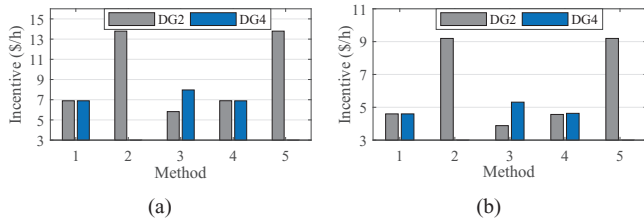
$t = 10$ , and  $t = 19$ . It can be observed from Table 3 that the costlier DG4 unit is getting selected in WEM only when its offer price is less than the LMP at the corresponding reference bus, else it will get scheduled locally when the offer price is less than the LMP of corresponding node. Figures 12 and 13 show the incentives given to Type 1 DGs (DG2 and DG4) of each distribution system DS 3 and DS 6 at  $t = 19$  for System T57D6, and DS 3 and DS 9 at  $t = 10$  for System T118D12, respectively. From the values of incentives obtained in multiple scenarios, it can be followed that Method 3 is capable of making a fair distribution of incentives among DERs participating in WEM.

**TABLE 3** LMP (\$/MWh) and power schedules (MW) of DG4 unit of type B DSs for system T57D6 and T118D12

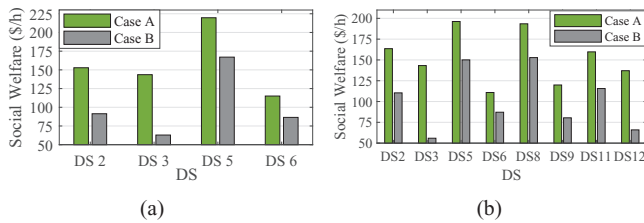
		t = 4					t = 10				t = 19			
System	DS no.	$\gamma_{g,14}^a$	$\pi_0^a$	$\pi_{14}^a$	$P_{g,14}^a$ (LEM)	$P_{g,14}^a$ (WEM)	$\pi_0^a$	$\pi_{14}^a$	$P_{g,14}^a$ (LEM)	$P_{g,14}^a$ (WEM)	$\pi_0^a$	$\pi_{14}^a$	$P_{g,14}^a$ (LEM)	$P_{g,14}^a$ (WEM)
T57D6	a = 3	0.4	26.85	26.89	1.8	1.2	28.40	28.63	1.8	1.2	29.26	29.92	1.8	1.2
	a = 6	0.7	22.84	23.67	0	0	23.41	24.52	0	0	26.55	27.36	0.9	2.1
T118D12	a = 3	0.6	25.01	25.66	0	0	25.89	26.30	3.0	0	27.42	28.26	1.2	1.8
	a = 6	0.7	22.58	23.41	0	0	23.19	24.29	0	0	23.91	25.44	0	0
	a = 9	0.4	22.99	23.79	0	0	23.59	24.71	0	0	24.44	25.96	0	0
	a = 12	0.6	24.14	24.87	0	0	25.01	25.99	3.0	0	26.15	26.95	1.2	1.8



**FIGURE 12** Incentives for DGs of System T57D6 participating in WEM in (a) DS 3 at  $t = 19$ , and (b) DS 6 at  $t = 19$



**FIGURE 13** Incentives for DGs of System T118D12 participating in WEM in (a) DS 3 at  $t = 10$ , and (b) DS 9 at  $t = 10$



**FIGURE 14** Social Welfare of Type B DSs of System (a) T57D6 for  $t = 10$ , and (b) T118D12 for  $t = 19$

Further, the social welfare of all Type B DSOs at  $t = 10$  for System T57D6 and at  $t = 19$  for System T118D12 are given in Figure 14a and Figure 14b, respectively, for Case A and Case B. From Figure 14, the improvement in social welfare of all DSOs is clearly noticeable when DGs are participating at the transmission level market for both systems T57D6 and T118D12.

## 4.5 | Observations

The following observations can be made from the results obtained:

- The proposed market framework provides a platform for DERs present at the distribution level to participate in the WEM through DSOs in the light of network constraints.
- The DERs are getting selected in WEM only when they aid in improving TSO's social welfare. However, the unscheduled quantity of DERs will further get an opportunity to participate in LEM. DSO will schedule the available generation with the objective to maximise its social welfare.

- An improvement in the social welfare of DSOs by allowing the DERs to participate in WEM is a clear indicator of the effectiveness of proposed scheme.
- DSO can pay the DERs participating in WEM as per pay-as-bid method along with the incentives. The Method-3 where the surplus amount is distributed in proportion to the offered prices by the DERs is found to be suitable for redistributing the incentives among them.

## 5 | CONCLUDING REMARKS

In this study, a day-ahead energy market model is proposed that allows DERs to select among the transmission or distribution level markets in which they wish to participate. TSO-DSO coordination has been utilised to facilitate the participation of DERs in a WEM whilst considering all network constraints. The DSO has the responsibility for controlling the dispatches of DERs in each market, and can provide an aggregated generation offer along with the power demand from the grid to the TSO. Different methods have been discussed for incentive redistribution among the DERs participating in the WEM. The effectiveness of the proposed model is validated on various integrated test systems for different hours of the day representing varying load levels. An improvement in the social welfare of DSOs has been observed as compared to the scenario in which DERs participate only in the local energy market. DERs are selected in the WEM only when they aid in improving social welfare; otherwise, they can be scheduled in local markets. The analysis of various possible methods to calculate the incentives of DER units participating in a WEM demonstrates that the distribution of monetary surplus in proportion to the offered prices ensures fairness in all cases.

Furthermore, the proposed framework can be readily extended to facilitate the participation of DERs in flexibility markets by utilising TSO-DSO coordination. In addition, battery energy storage systems can be included in such energy and flexibility markets, and we will address this type of extensions in future work.

## NOMENCLATURE

### Acronyms:

BB	Boundary Bus
DER	Distributed Energy Resource
DG	Distributed Generation
DS	Distribution System
DSO	Distribution System Operator
LEM	Local Energy Market
LMP	Locational Marginal Price
T&D	Transmission and Distribution
TS	Transmission System
TSO	Transmission System Operator
SW	Social Welfare
WEM	Wholesale Electricity Market

**Sets:**

- $\mathcal{A}$  Set of boundary buses connecting TS and DS
- $\mathcal{L}$  Set of lines in the TS
- $\mathcal{N}$  Set of buses in the TS
- $\mathcal{N}^D$  Set of number of DSs connected to the TS
- $\mathcal{G}$  Set of buses with generators in the TS
- $\mathcal{FL}$  Set of buses with flexible loads in the TS
- $\mathcal{CL}$  Set of buses with fixed loads in the TS
- $\mathcal{DL}$  Set of buses connected to Type A DS
- $\mathcal{DGL}$  Set of buses connected to Type B DS
- $\mathcal{N}^a$  Set of nodes in the  $d^{th}$  DS
- $\mathcal{N}^{DG1,a}$  Set of nodes connected to Type 1 DGs in the  $d^{th}$  DS
- $\mathcal{N}^{DG2,a}$  Set of nodes connected to Type 2 DGs in the  $d^{th}$  DS
- $\mathcal{N}^{fl,a}$  Set of nodes with flexible loads in the  $d^{th}$  DS
- $\mathcal{N}^{cl,a}$  Set of nodes with fixed loads in the  $d^{th}$  DS

**Variables:**

- $\delta_i$  Voltage angle at the  $i^{th}$  bus of the TS
- $\pi_i$  LMP of the  $i^{th}$  bus in the TS
- $\pi_0^a$  LMP at the boundary bus of a  $d^{th}$  DS given by the TSO
- $d^a$  Power demand of the  $d^{th}$  DS from the grid
- $\mathcal{I}_{ij}$  Current flow of line connecting the Buses  $i - j$  in a DS
- $P_{d,i}$  Real power consumption at the  $i^{th}$  bus
- $P_{g,i}$  Real power generation at the  $i^{th}$  bus
- $P_{g,s}^i$  Real power generation of a  $s^{th}$  DG unit of the  $i^{th}$  DS
- $P_{ij}$  Real power flow of transmission line connecting the Buses  $i - j$
- $f_{ij}^{p,a}$  Real power flow of line connecting the Nodes  $i - j$  in the  $d^{th}$  DS
- $f_{ij}^{q,a}$  Reactive power flow of line connecting the Nodes  $i - j$  in the  $d^{th}$  DS
- $P_{loss,ij}$  Real power loss in transmission line connecting the Buses  $i - j$
- $Q_{d,i}^a$  Reactive power consumption at the  $i^{th}$  bus
- $Q_{g,i}^a$  Reactive power generation at the  $i^{th}$  bus
- $v_i$  Voltage magnitude of the  $i^{th}$  bus

**Parameters:**

- $\gamma_{g,i}^a$  Fraction of power offered by a  $i^{th}$  DG1 of the  $d^{th}$  DS in the WEM
- $\chi_i^a$  Percentage of essential part of  $i^{th}$  flexible load in the  $d^{th}$  DS
- $\beta_{g,s}^a$  Offer price of a  $s^{th}$  DG unit of the  $d^{th}$  DS
- $C_i(\cdot)$  Convex cost function of generating unit at the  $i^{th}$  bus
- $r_{ij}, R_{ij}$  Resistance of line connecting the buses  $i - j$
- $x_{ij}, X_{ij}$  Reactance of line connecting the buses  $i - j$
- $\bar{P}_{d,i}$  Fixed load demand at the  $i^{th}$  bus
- $\bar{P}_{d,i}, \underline{P}_{d,i}$  Maximum and minimum limits of power demand at the  $i^{th}$  bus
- $\bar{P}_{g,i}, \underline{P}_{g,i}$  Maximum and minimum real power limit of generator at the  $i^{th}$  bus
- $P_{g,s}^{i,max}$  Maximum real power limit of a  $s^{th}$  DG unit of the  $i^{th}$  DS

- $\bar{Q}_{g,i}, \underline{Q}_{g,i}$  Maximum and minimum reactive power limits of generator at the  $i^{th}$  bus
- $\bar{P}_{g,s}^{a,WEM}$  Generation offered by a  $s^{th}$  DG unit of the  $d^{th}$  DS in the WEM
- $\bar{P}_{ij}, \bar{f}_{ij}$  Power flow limit of a line connecting the Buses  $i - j$
- $\bar{v}_i, \underline{v}_i$  Maximum and minimum limits of voltage magnitude at the  $i^{th}$  bus
- $\mathcal{U}_i(\cdot)$  Concave utility function of flexible load at the  $i^{th}$  bus
- $\mathcal{S}$  Surplus amount with a DSO in \$/h

**ACKNOWLEDGEMENTS**

This work was supported by Indo-US Science and Technology Forum (IUSSTF) through Department of Science and Technology (DST) under JCERDC grant-in aid for project titled: UIASSIST: US India collaboration for Smart Distribution System with Storage.

**CONFLICT OF INTEREST**

The authors have declared no conflict of interest.

**DATA AVAILABILITY STATEMENT**

The data that support the findings of this study are openly available in "MATPOWER" at <https://doi.org/10.1109/TPWRS.2010.2051168>, reference number [24].

**ORCID**

Megha Gupta  <https://orcid.org/0000-0002-1938-3035>

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**How to cite this article:** Gupta, M., Vaishya, S.R., Abhyankar, A.R.: Facilitating DER participation in wholesale electricity market through TSO-DSO coordination. *Energy Convers. Econ.* 3, 201–213 (2022). <https://doi.org/10.1049/enc2.12063>