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# Real time procurement of energy and operating reserve from Renewable Energy Sources in deregulated environment considering imbalance penalties

Anuj Banshwar [a, *], Naveen Kumar Sharma [b], Yog Raj Sood [c], Rajnish Shrivastava [d]

[a] National Institute of Technology, Hamirpur, H.P., India
[b] Department of Electrical Engineering, IKG Punjab Technical University, Punjab, India
[c] Director, National Institute of Technology, Puducherry, India
[d] Department of Civil Engineering, Maulana Azad National Institute of Technology, Bhopal, M.P., India

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ABSTRACT

Renewable Energy Sources (RES) have prompted an additional burden on power system planners due to their stochastic nature. Hence it increases the need for Ancillary Services (AS) in power system. In deregulated electricity markets, AS has become an important issue because they are necessary for reliable and secure operation of a power system. Operating Reserve (OR), considered in this paper, is a measure of generators ability to increase their output under contingencies. ISO uses this service either for balancing purpose or for replacing the energy that had been scheduled to be provided by the unit that malfunctions. Thus establishing an efficient market for reserve services has become crucial. The premises of this paper is the development of penalty based Short-Term Market (STM) for the procurement of energy and OR. The effects of stochastic behavior of WPP on Social Benefit (SB) and Procurement Cost (PC) are investigated for the development of efficient STM. The proposed approach has been analyzed on IEEE-30 bus test system by implementing a sequential dispatch approach on various market structures. The results obtained under different market scenarios shows that there is a mandated requirement of effective penalty mechanism in order to discourage the imbalance behavior of RPPs.


## 1. Introduction

Traditional power systems have been dominated by large Vertical Integrated Utilities (VIU) that performs all the activities related to generation, transmission and distribution of electric power within their obliged domain. These bundled utilities generally work under the regulated environment of the government jurisdiction [1]. During the early nineties, various electrical utilities of mostly developed economies have undergone through the unbundling process by changing their way of operation from being VIU to open market systems that consist of three independent components viz. Generation Companies (GENCOs), Transmission Companies (TRANSCOs), and Distribution Companies (DISCOs) [2]. The deregulation of power sector provides a fair competition among producers as well as consumers. Unbundling of these utilities primarily focuses on improving system efficiency, cost minimization by introducing more choices to the utilities by developing competitive markets and, better service to the electrical consumers [3].

In deregulated paradigm, the market existing between suppliers (GENCOs) and retailers (DISCOs) is called the wholesale marketplace. An ISO as an independent authority is appointed for the creation of the set of rules for ensuring sufficient control over producers and consumers for maintaining security and reliability of the electrical system while maximizing market efficiency. The GENCOs sell their energy either through long-term bilateral contracts with DISCOs or by bidding in STM operated by the ISO [4]. The basic bidding structure in STM is shown in Fig. 1.

Substantial unbundling of products and services is to be expected under restructuring process. Surely electricity provided at different times will be treated differently. It also raises the issue of AS that could be separated or bundled depending on the economics of supply and the nature of customer demand [5]. AS has become an important issue because they are necessary for the reliable and secure operation of a power system. It is essential to procure these

* Corresponding author.
*E-mail address:* anujbanshwar@gmail.com (A. Banshwar).

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**Nomenclature:**

*Abbreviations*

| | |
|---|---|
| AC | Available Capacity |
| AS | Ancillary Services |
| AEMO | Australian Energy Market Operator |
| ARC | Available Reserve Capacity |
| ASM | Ancillary Services Market |
| CAISO | California Independent System Operator |
| CBM | Cross-Border Balancing Market |
| CEM | Competitive Electricity Market |
| CPP | Conventional Power Plants |
| CSP | Concentrated Solar Power |
| DAM | Day Ahead Market |
| DAEM | Day Ahead Energy Market |
| DARM | Day Ahead Reserve Market |
| DISCOs | Distribution Companies |
| ERCOT | Electric Reliability Council of Texas |
| EM | Energy Market |
| ESS | Energy Storage Scheme |
| FD | Firm Demand |
| FM | Forward Market |
| GENCOs | Generation Companies |
| IDM | Intra Day Market |
| IDEM | Intra Day Energy Market |
| IDRM | Intra Day Reserve Market |
| ISO | Independent System Operator |
| LMP | Locational Marginal Price |
| MW | Mega Watt |
| MWh | Mega Watt-hour |
| NFD | Non-Firm Demand |
| OF | Objective Function |
| OEM | Ontario Electricity Market |
| OPF | Optimal Power Flow |
| OR | Operating Reserve |
| PAB | Pay-As-Bid |
| PC | Procurement Cost |
| PEV | Plug-in Electric Vehicle |
| PJM | Pennsylvania-New Jersey-Maryland Interconnection |
| PVP | Photo-Voltaic Plant |
| RES | Renewable Energy Source |
| RPP | Renewable Power Producer |
| RM | Reserve Market |
| RR | Ramp Rate |
| RT | Real Time |
| RTM | Real Time Market |
| RTEM | Real Time Energy Market |
| RTRM | Real Time Reserve Market |
| SB | Social Benefit |
| STM | Short Term Market |
| TRANSCOs | Transmission Companies |
| VIU | Vertical Integrated Utilities |
| VPP | Virtual Power Producer |
| WPP | Wind Power Plant |

*Symbols*

| | |
|---|---|
| $AC_i$ | Available capacity of $i^{th}$ GENCO |
| $ARC_i$ | Available reserve capacity of $i^{th}$ GENCO |
| $E_i$ | Quantity of energy accepted in EM by $i^{th}$ GENCO |
| $E_{gi}^{j}$ | Quantity of energy offered in EM by $i^{th}$ GENCO |
| $E_{NFDi}^{k}$ | Quantity of energy bid in EM by $i^{th}$ NFD |
| $E_L$ | Energy requirement |
| $E_{Losses}$ | Energy losses in EM |
| $\mathrm{EP}_{\mathrm{gi}}$ | Energy payment by the ISO to the $i^{th}$ GENCO |
| $EP_{NFDi}$ | Energy payment received by the ISO from the $i^{th}$ NFD |
| $g(V,\varphi)$ | Power flow vectors |
| $MVAf_{ij}^{max}$ | Maximum rating of transmission line connected between bus $i$ and $j$ |
| $N_g$ | Total number of GENCOs |
| $N_{FD}$ | Total number of Firm Demand |
| $N_{NFD}$ | Total number of Non-Firm Demands |
| $P_{gi}$ | Real power generation at PV bus $i$ |
| $P_{gi}^{min}$ | Minimum value of real power generation allowed at PV bus $i$ |
| $P_{gi}^{max}$ | Maximum value of real power generation allowed at PV bus $i$ |
| $P_i$ | Calculated real powers for PQ bus $i$ |
| $P_i^{net}$ | Specified real power for PQ bus $i$ |
| $P_m$ | Calculated real power for PV bus$m$ |
| $P_m^{net}$ | Specified real power for PV bus$m$ |
| $PE_{gi}^{j}$ | Price of energy offered in EM by $i^{th}$ GENCO |
| $PE_{NFDi}^{k}$ | Price of energy bid in EM by $i^{th}$ NFD |
| $PR_{gi}^{l}$ | Price of reserve offered in RM by $i^{th}$ GENCO |
| $R_{gi}^{l}$ | Quantity of reserve capacity offered in RM by $i^{th}$ GENCO |
| $Q_{gi}$ | Reactive power generation at PV bus $i$ |
| $Q_{gi}^{min}$ | Minimum & maximum value of reactive power generation allowed at PV bus $i$ |
| $Q_{gi}^{max}$ | Maximum value of reactive power generation allowed at PV bus $i$ |
| $Q_i$ | Calculated reactive powers for PQ bus $i$ |
| $Q_i^{net}$ | Specified reactive power for PQ bus$i$ |
| $R_i$ | Quantity of reserve accepted in RM by $i^{th}$ GENCO |
| $R_L$ | Reserve requirement |
| $R_{Losses}$ | Reserve losses in RM |
| $RR_i$ | Ramp rate offered by $i^{th}$ GENCO |
| $V$ | Voltage magnitude |
| $V_i$ | Value of voltage magnitude of each PQ bus |
| $V_i^{min}$ | Minimum value of voltage magnitude of each PQ buses |
| $V_i^{max}$ | Maximum value of voltage magnitude of each PQ buses |
| $\Phi$ | Phase angle |
| $\varphi_i$ | Value of voltage angle at bus $i$ |
| $\varphi_i^{min}$ | Minimum allowed value of voltage angle at bus $i$ |
| $\varphi_i^{max}$ | Maximum allowed value of voltage angle at bus $i$ |
| $\lambda_i$ | Locational marginal price at bus $i$ |
| $\tau$ | Specific response time for reserve |
| $\phi$ | Penalty Factor |

services in order to maintain required generation-demand balance and to guarantee the security of the supply. Frequency control, load following, operating reserves, voltage regulation, black-start services, etc. are considered as main AS in almost every country [6,7].

Under this regime, ISO has to procure these services from AS providers as these are no longer be treated as an integral part of the system. It is the matter of discussion and market structure about how to obtain and paid these services [8]. Our attention in this paper is limited to procurement of OR, which is a measure of GENCOs ability to increase their output under contingencies like unscheduled generation outages or sudden unexpected load variation, as one of the important AS [9]. Establishing an efficient

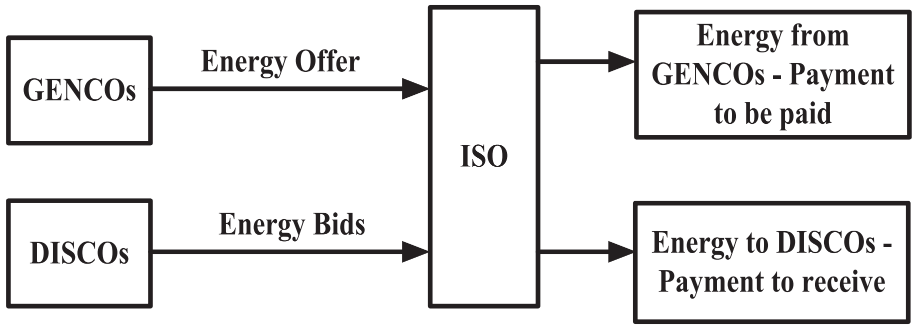


**Fig. 1.** Basic structure of bidding process in STM.

market structure for the procurement of OR has become important for grid stability.

Traditionally energy and AS are procured from Conventional Power Plants (CPPs) like thermal and hydro based plants. Nowadays, Renewable Power Producers (RPPs) like Wind Power Plants (WPPs) and Photo-voltaic Power Plants (PVPs) are also capable of participating in both energy and AS markets in order to maximize their profits due to their fast responding ability.

In literature, numerous publications focus the impact of integrating RES in energy and AS markets worldwide. Banshwar et al. [3] presented a market-based approach for the participation of RES like wind and PV to procure energy and AS with an objective to reduce the reserve procurement cost in energy and AS markets. Reddy et al. [10] proposed a market clearing process for wind integrated thermal system for energy and spinning reserve procurement while considering uncertainties in the RE generation and load forecasts errors.

Faria et al. [11] suggested a methodology that considers demand response and distributed generation based Virtual Power Producer (VPP) to provide both energy and reserve in the context to a distribution network. Similar work has been carried out by Mashhour et al. [12,13] that addresses the bidding problem faced by a VPP with centralized control in a joint clearing of energy and spinning reserve based on the deterministic price-based unit commitment.

Concentrated Solar Power (CSP) plants with thermal energy storage system can provide energy and AS including frequency regulation, OR, and reactive control services [14,15]. Based on the variable source of energy, Plug-in Electric Vehicle (PEV) can participate in the joint day-ahead energy, SR, and regulation markets by incorporating stochastic programming approach for profit maximization [16,17]. Hochloff and Braun [18] examined the participation of biogas plants in electricity market of Germany to provide energy and reserve.

Zou et al. [19] presented an approach for assessing the contribution of Energy Storage Schemes (ESS) to support the large scale integration of RPPs in joint energy, regulation and Reserve Markets (RM). Considering a stochastic optimization approach, WPP has more potential to provide regulation down services as compare to regulation up services when the WPP is integrated with ESS to provide both energy and AS [20].

Relatively lesser work has been carried out regarding the establishment of an efficient market for the integration of these variable energy sources in Competitive Electricity Market (CEM) for the procurement of AS. RPPs trades in a market and sell electricity under supply and price uncertainty [21]. Due to stochastic nature and the low predictability of RES, their participation in electricity market may imply large deviations from the initial commitments, which lead to a revenue reduction that has to be borne by the owners. Hence an efficient market needs to be established so that the effect of imbalances caused by CPPs and RPPs on market will be discouraged and the associated parties will be penalized.

This paper proposes an efficient STM design for real-time procurement of energy and OR in deregulated environment considering both CPPs and RPPs. There is a number of balancing objectives that must be taken into consideration while designing payment mechanism for such markets. It includes payment to the units for serving their capacity in Energy Market (EM) and Ancillary Services Market (ASM) along with penalty mechanism for market participants who deviates from their schedules. The proposed approach is applied to different market structures which are discussed in detail in Section 2.

The paper is organized as follows. In brief, Section 2 presents an overview of different market structures under STM. The problem will be formulated in Section 3. Proposed penalty mechanism and step-by-step algorithm for market clearing will be discussed in Section 4. In Section 5 simulation results of procuring energy and OR are presented. Finally, main conclusions are reported in Section 6.

## 2. Short-term market design and clearing mechanism for energy and AS

In general, for delivering power from supplier to the retailers, some arrangement in the form of central auction is required. STM is responsible for ensuring flexibility and reliability of the power system over a shorter timeframe.

### 2.1. Market structure design

The market structure could differ according to their time of operation, the amount of information individual participant provide to the ISO and the role of ISO in facilitating or controlling these markets [22]. Forward market and real-time markets are the two auction market designs used for energy and/or AS dispatch.

#### 2.1.1. Forward market (FM) design

Depending on the timeframe, the forward market design is classified as Day-Ahead Market (DAM) and Intra-Day Markets (IDM). DAM operates on a day-ahead timeline, where the suppliers or retailers on the basis of their forecast commit respectively their generated or required power 24-h before actual delivery [23,24]. Retailers are responsible for procuring energy on behalf of their customer base whereas ISO requires AS for grid reliability. Markets of Spain, Germany, UK and liberalized Iberian electricity market allow participation of RES in DAM to compensate their imbalances [25,26]. IDM is used for adjusting deviations from the day-ahead schedule. Trading in IDM commences after the gate closure of the DAM and continues until the predetermined time before real-time delivery. This predetermined time varies from market-to-market, as in the UK, ISO receives bids and offers up to 3.5 h before real-time delivery [27]. It is found that when RPPs participates in IDM, the errors obtained in DAM decrease drastically [28].

#### 2.1.2. Real-time market (RTM) design

It covers all the actions and activities performed by the ISO to ensure supply-demand balance on Real-Time (RT) basis. The objective of such markets is to efficiently obtain the resources required to meet the reliability of the system. If reliability needs are not fully satisfied by the market, the ISO must acquire needed resources such as AS [29]. In actual, these markets are operated and cleared around 5–15 min prior to the actual delivery.

The increasing RE penetration in the system and prediction errors result in an additional requirement for balancing activities [30]. For power system security, ISO contracts reserve services in advance, mainly from conventional power plants, which quickly activates upward or downward reserves to cover system imbalances during real-time [31]. In most of the US Regional Transmission Operators (RTOs), Australian Energy Market Operator (AEMO) and the Ontario Electricity Market (OEM), such type of market design is instituted [32,33].

Energy trading is usually operated in forward markets, while AS trading is operated in both forward and real-time markets [34]. The basic structure of energy and AS dispatch auction market design is shown in Fig. 2.

### 2.2. Market clearing mechanism for energy and AS markets

Sequential and simultaneous are the two approaches which are used to dispatch energy and AS that depend on the control provided to the ISO. The sequential approach identifies the fact that both energy and AS consume the same generating capacity. It involves sequential dispatch of EM and ASM in which one of the markets (mainly energy) is cleared first and the results would represent the starting point for the next market that is AS [35,36]. The market clearing in old California-ISO (CAISO), Italy, and the Nordic pool is based on this approach.

The simultaneous co-optimized approach involves the joint co-optimization of both energy and AS markets. Here, both EM and ASM are simultaneously dispatched [37]. In this approach, it is hard to justify the schedule and pricing for the product. The markets of PJM, Electric Reliability Council of Texas (ERCOT) and new-CAISO employ this approach [38,39].

## 3. Problem formulation

In this section, the formulation of the proposed approach is described. For this, first general assumption about the market clearing is presented along with objective function and proposed penalty mechanism in STM will then be discussed.

### 3.1. Assumptions for market clearing under STM

The following assumptions are considered while carrying out clearing of EM and RM under STM.

1. GENCOs (both CPPs and RPPs) can re-bid into the RM if their capacities are not being selected in the EM. No commitment charges would be payable to these GENCOs for making themselves available in the RM.
2. Any participant that failed to meet the scheduled capacity in the market would lead to stringent imbalance penalties on account of revenue reduction.
3. Any deviation in the scheduled capacity from the participant during real-time delivery in EM will be considered by the ISO as emergency requirements and procured from the RM.
4. Market participants do not provide transmission losses payment. Hence, transmission losses payments in the pool are considered to be supplied by the ISO itself.

### 3.2. Market model and proposed payment mechanism

The market model in proposed work is considered to be sequential or disaggregated. Lower complexity and transparency of clearing results is an attractive feature of disaggregated framework. In present work, ISO is considered as the sole authority behind market clearance. Under the competitive market scenario, GENCOs submit their bids in each time interval that to be cleared by the ISO.

The market performance is measured by its Social Benefit (SB). SB is the difference between the benefit of the energy to society as measured by society's willingness to pay for its demand and the cost of energy [40]. Supply-demand balance sets the market clearing price and quantities. The SB, subject to constraints, is optimal at this equilibrium point. In the case of single auction pool markets where only GENCOs bid into the pool, maximization of SB is similar to the minimization of GENCOs costs. Therefore in case of double auction markets, where both GENCOs and DISCOs bid into the pool, the SB maximization problem becomes minimization of

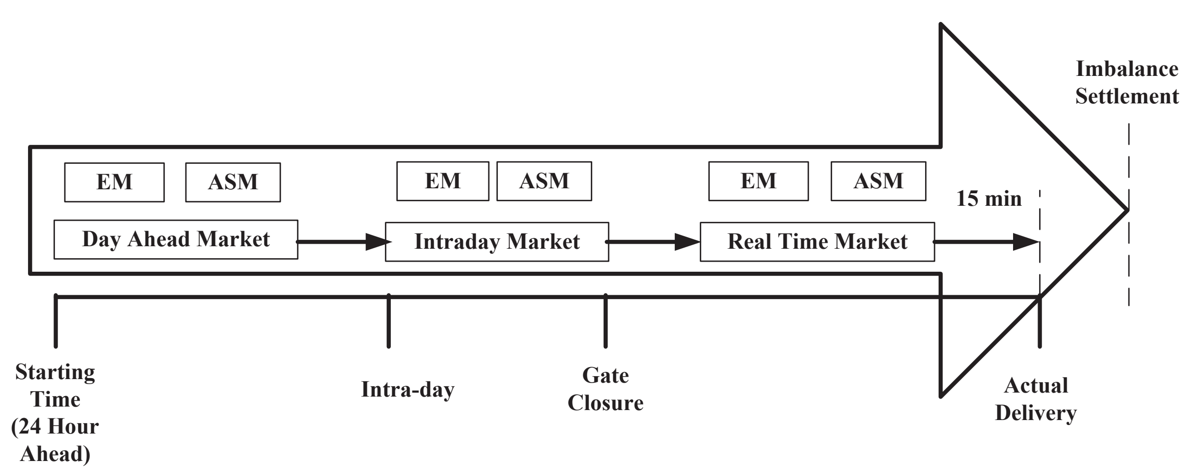


**Fig. 2.** Energy and ancillary services dispatch auction market design.

the GENCOs cost and maximization of the revenues collected from the DISCOs. This will not only increases the efficiency of generation but also improves efficient utilization of electricity under deregulated environment.

Suppliers or retailers usually owns many utilities and can, therefore, well approximate its optimal quantity-price pair using a step function with several steps. The proposed work considers piecewise offers and bids respectively from the suppliers (or GENCOs) and the retailers (or DISCOs) in terms of quantity of energy (in MWh) and the prices (in $/MWh) that they are willing to sell or buy in each operating period (h) under STM [41]. As discussed, suppliers bids two prices, one for energy and second for reserve capacity. Under deregulated environment, suppliers' (CPPs and RPPs) tries to maximize their profit in RM by offering their unloaded capacity at higher prices as compared to energy prices.

Both Firm Demand (FD) and Non-Firm Demand (NFD) are considered in the present work. All pool generations and demands for both FD and NFD are determined with optimization of SB while satisfying all system constraints. Herein, transmission losses payments in the pool are considered to be supplied by the ISO itself. This is a realistic approach since transmission loss payment contracts are difficult to build and operate [42].

Let the total number of GENCOs is considered to be $N_g$ and number of NFDs (non-firm demand or dispatchable loads) be $N_{NFD}$. Each GENCO submits individual bidding blocks in EM and RM whereas NFD submits bidding blocks in EM only as:

In EM -

$$\text{GENCOs} \;:\; E^j_{gi},\; PE^j_{gi};\quad j = 1, 2, 3, \ldots\ldots, n_{egi}$$

$$\text{NFDs} \;:\; E^k_{NFDi},\; PE^k_{NFDi};\quad k = 1, 2, 3, \ldots\ldots, n_{eNFDi}$$

In RM -

$$\text{GENCOs} : R^l_{gi}, R^l_{gi},\quad l = 1, 2, 3, \ldots\ldots, n_{rgi}$$

where $E^j_{gi}$ and $PE^j_{gi}$ is the quantity and price of energy offered by $i^{th}$ GENCO in the $j^{th}$ band in the EM. Similarly, $E^k_{NFDi}$ and $PE^k_{NFDi}$ is the quantity and price of energy bid by $i^{th}$ NFD in the $k^{th}$ band, $n_{egi}$ and $n_{eNFDi}$ be the number of bid bands offered by the $i^{th}$ GENCO and NFD respectively in EM whereas $R^l_{gi}$ and $PR^l_{gi}$ is the quantity and price of reserve capacity offered by $i^{th}$ GENCO in the $l^{th}$ band in the RM.

#### 3.2.1. Payment mechanism in EM

- The energy payment ($EP_{gi}$) to the $i^{th}$ GENCO with accepted energy ($E_{gi}$) can be expressed as per Pay-As-Bid (PAB) technique [43].

$$EP_{gi}(E_{gi}) = \sum_{j=1}^{a} E^j_{gi}\left(PE^j_{gi}\right) + \left(E_{gi} - \sum_{j=1}^{a} E^j_{gi}\right) PE^{a+1}_{gi} \tag{1}$$

$$\sum_{j=1}^{a} E^j_{gi} \le E_{gi} \le \sum_{j=1}^{a+1} E^j_{gi}$$

where $a$ is the primary slot of the $j^{th}$ band in EM.

- The energy payment ($EP_{NFDi}$) received by ISO from $i^{th}$ NFD with energy ($E_{NFDi}$) delivered can be expressed as per PAB technique and is given as:

$$EP_{NFDi}(E_{NFDi}) = \sum_{k=1}^{b} E^k_{NFDi}\left(PE^k_{NFDi}\right) + \left(E_{NFDi} - \sum_{k=1}^{k} E^k_{NFDi}\right) PE^{b+1}_{NFDi} \tag{2}$$

$$\sum_{k=1}^{b} E^k_{NFDi} \le E_{NFDi} \le \sum_{k=1}^{b+1} E^k_{NFDi}$$

where $b$ is the primary slot of the $k^{th}$ band in EM.

- Since, FDs do not bid in the EM, hence the energy payment ($EP_{FD}$) received by the ISO from FDs is as per Location Marginal Price ($\lambda$) (LMP) and can be expressed as [44]:

$$EP_{FDi} = \lambda_i \cdot E_{FD} \tag{3}$$

where $i$ is the bus at which FD is connected.

#### 3.2.2. Payment mechanism in RM

The reserve payment ($RP_{gi}$) to the accepted reserve ($R_{gi}$) from $i^{th}$ GENCO will be-

$$RP_{gi}(R_{gi}) = \sum_{l=1}^{c} R^l_{gi}\left(PR^l_{gi}\right) + \left(R_{gi} - \sum_{l=1}^{c} R^l_{gi}\right) PR^{c+1}_{gi} \tag{4}$$

$$\sum_{l=1}^{c} R^l_{gi} \le R_{gi} \le \sum_{l=1}^{c+1} R^l_{gi}$$

where $c$ is the primary slot of the $l^{th}$ band in RM.

### 3.3. The objective function and constraints

The Objective Function (OF) corresponding to EM and RM is as follows-

#### 3.3.1. Energy Market (EM)

The aim of the EM is to maximize SB, by minimizing the payments to the GENCOs ($\mathrm{EP_{gi}}$) and maximizing the revenues from NFDs ($EP_{NFDi}$). Firm (or fixed) demands does not bid and are ready to pay LMP. Thus the OF in EM becomes:

$$max\left\{\sum_{i=1}^{N_{NFD}} EP_{NFDi}(E_{NFDi}) - \sum_{i=1}^{N_g} EP_{gi}(E_{gi})\right\} \tag{5}$$

subject to

$$\sum_{i=1}^{N_g} E_{gi} = \sum_{i=1}^{N_{NFD}} E_{NFDi} + \sum_{i=1}^{N_{FD}} E_{FDi} + E_{Losses}$$

$$E^{min}_{gi} \le E_{gi} \le E^{max}_{gi}$$

The first term in the OF corresponds to the total revenue obtained by the ISO from NFDs whereas the second term is total cost given by the ISO to the GENCOs for procuring the required energy.

#### 3.3.2. Reserve market (RM)

The objective is to minimize the reserve payment to the $i^{th}$ GENCOs for procuring required service. Hence the OF in RM becomes-

$$Min \sum_{i=1}^{N_g} RP_{gi}(R_{gi}) \tag{6}$$

subject to

$$\sum_{i=1}^{N_g} R_{gi} = R_L + R_{Losses}$$

$$R_{gi}^{min} \le R_{gi} \le R_{gi}^{max}$$

The objective functions in Eqns. (5) and (6) is subject to the following transmission network constraints after adding all FDs.

*3.3.2.1. Power flow constraints: the power flow equation of the power network.*

$$g(V,\varphi) = 0 \tag{7}$$

where

$$g(V,\varphi) = \begin{cases} P_i(V,\varphi) - P_i^{net} & \leftarrow \text{For each PQ bus} \\ Q_i(V,\varphi) - Q_i^{net} & \\ P_m(V,\varphi) - P_m^{net} & \leftarrow \text{For each PV bus } m, \text{ not including the reference bus} \end{cases}$$

where $P_i$ and $Q_i$ are respectively calculated real and reactive powers for PQ bus $i$. $P_i^{net}$ and $Q_i^{net}$ are respectively specified real and reactive power for PQ bus $i$.$P_m$ and $P_m^{net}$ are respectively calculated and specified real power for PV bus $m$. $V$ and $\varphi$ are voltage magnitude and phase angles at different buses.

*3.3.2.2. Inequality constraints on real and reactive power generation*

- The inequality constraint on real power generation $(P_{gi})$ at PV buses

$$P_{gi}^{min} \le P_{gi} \le P_{gi}^{max} \tag{8}$$

where $P_{gi}^{min}$ and $P_{gi}^{max}$ are respectively minimum and maximum real power generation allowed at PV bus $i$.

- The inequality constraint on reactive power generation $(Q_{gi})$ at PV buses

$$Q_{gi}^{min} \le Q_{gi} \le Q_{gi}^{max} \tag{9}$$

where $Q_{gi}^{min}$ and $Q_{gi}^{max}$ are respectively minimum and maximum value of reactive power generation allowed at PV bus $i$.

*3.3.2.3. Inequality constraints on phase voltage.* The inequality constraint on phase voltage $(V)$ of each PQ bus

$$V_i^{min} \le V_i \le V_i^{max} \tag{10}$$

where $V_i^{min}$ and $V_i^{max}$ are respectively minimum and maximum voltage at bus $i$.

*3.3.2.4. Transmission limit constraints: the branch flows are limited by MVA flow limit constraints.*

$$MVAf_{ij} \le MVAf_{ij}^{max} \tag{11}$$

where $MVAf_{ij}^{max}$ is the maximum transmission limit of the line connecting bus $i$ and $j$.

Optimization problem in Eqns. (5) and (6) with constraints given in Eqns. (7)–(11) along with generation and demand constraints is formulated and solved using Optimal Power Flow (OPF) technique which has an ability to take care of transmission constraints and power flow limits.

### 3.4. Proposed model for imbalance penalties

The delivery of energy in real-time greatly depends on participants commitments into the pool in DAM. Large deviations in load or forced outages require the dispatch of OR in RTM that results in a revenue reduction obtained from these markets. Therefore, the market participants must be penalized whenever they fail to deliver their commitments by not providing services in the energy and reserve market.

Imbalance costs penalization mechanism has to be created by the ISO which could charge to all the participants responsible for imbalances. To discourage this behavior of the participants some mechanisms need to be adopted depending on market rules that are different from market-to-market. In India, sellers failing to provide capacity as scheduled in frequency support AS market will liable to pay the penalty either equal to 1.5 times the bid price or the applicable unscheduled-interchange rate whichever is higher [45]. Similarly, in Italy, generating plants with rated power greater than 10 MVA are liable to pay imbalance penalties based on the marginal price of the RTBM whereas penalties for plants less than 10 MVA are settled according to the average price of ASM or DAM. Since RES, like wind, are difficult to schedule in the DAM, penalty payments are settled using the pool market price [46].

In proposed imbalance penalty mechanism, the penalty for failing to provide the scheduled capacity commitments in STM should at least equal to the replacement cost that the ISO must pay for obtaining this service in RM. The entity that failed to meet its scheduled capacity commitment for the particular period would be liable for this cost, as well as any additional penalties that ISO might deem necessary to discourage this behavior. Retailers are also liable to pay penalties for deviating their DAM schedule for real-time delivery in a similar manner. Therefore, penalty charges are based on the amount of revenue reduction caused due to imbalances $(Rev_{red})$ and penalty factor $(\psi)$ that depends on the type of market whether it is IDM or RTM. Penalty factor is a measure of an effect caused by imbalances on market structure.

$$Penalty\ Charge = \psi \times Rev_{red}$$

Also, frequent deviation from the participant may result in cancellation of contract and confiscation of security money.

## 4. Step-by-step algorithm for market clearing in STM

The proposed algorithm for EM and RM clearing under STM for period of 1-h is given as follows:

Step 1: All loads and generations are set to zero with system voltages, transformer ratios, etc. to their initial conditions.

### 4.1. For Energy Market

Step 2: With the bidding characteristics from all CPPs, RPPs and NFD, OPF technique has been used for the optimization of Eqn. (5) while considering all constraints related to generations and demands. All FDs are added to the system as fixed components, i.e. under optimization process, these are not subjected to any curtailment.

Step 3: After optimization, power generation from $i^{th}$ GENCO ($P_{gi}$), schedule of FD ($P_{FDi}$) and NFD ($P_{NFDi}$) at all concerned buses are obtained.

Step 4: The amount to be paid by the ISO to each GENCO and received from each NFD is determined based on PAB mechanism whereas FDs will pay as per LMP ($\lambda_i$).

Step 5: The SB has been then determined on the basis of total payment to the GENCOs and revenue collected from FDs and NFDs.

Step 6: At the end of hour considered, the imbalances caused by each participant are obtained. The parties responsible for deviation is required to pay penalties against their imbalances as discussed in Section 3.4.

### 4.2. For reserve market

If there is no reserve requirement then the process stops at Step-6, it means no RM clearing is required. The RM will be cleared in continuation with the steps followed in EM clearing.

Step 7: Using Step-3, obtain Available Capacity ($AC_i$) at $i^{th}$ GENCO using relation:

$$AC_i = P_i^{max} - P_{gi}$$

where $P_i^{max}$: Maximum capacity of the $i^{th}$ GENCO.

$P_{gi}$ : Power generated by the $i^{th}$ GENCO in EM.

Step 8: Calculate Available Reserve Capacity ($ARC_i$) offered by $i^{th}$ GENCO in RM. The ARC at the GENCOs depends on the Ramp Rate (RR) which means the ability of the GENCO to move from one generation level to another. ARC is calculated using relation:

$$ARC_i = min(AC_i, \tau \times RR_i)$$

where $AC_i$: Available capacity at $i^{th}$ GENCO in RM

$RR_i$: Ramp Rate of the $i^{th}$ GENCO.

$\tau$: Specific response time for reserve (in present case$\tau = 10$)

The ramp rate of RPPs is much larger as compared to CPPs. Hence the complete AC at RPP after EM clearing is allowed to bid into the RM as ARC.

Step 9: Similar to Step-2, with the bidding characteristics of all available resources in RM, the optimization of Eqn. (6) has been carried out satisfying all constraints, using OPF technique. Reserve requirements are considered as FD.

Step 10: After the optimization, voltages, taps settings and pool reserve generation by $i^{th}$ GENCO ($R_{gi}$) has been obtained.

Step 11: The amount to be paid to each GENCO is determined based on PAB mechanism.

Step 12: The reserve payment has been then determined on the basis of total payment to the GENCOs for obtaining required reserve.

Step 13: Calculate the penalties against deviation caused by the participants in RM similar to Step-6.

## 5. Simulation analysis

The proposed approach has been analyzed on IEEE-30 bus test system in which NFDs have been added in addition to already existing GENCOs and FDs. The modified system consists of 7 GENCOs, 5 FDs, and 4 NFDs. Out of the seven GENCOs, one GENCO is considered as RPP (that is, WPP) that bids in all three markets whereas one GENCO that is connected at bus 11 bids only in real-time RM. The single line diagram is shown in Fig. 3.

The clearing of EM and RM in DAM, IDM, and RTBM under STM is discussed as:

### 5.1. EM and RM clearing under DAM

In DAM, suppliers and retailers offers and bids respectively to the ISO 24-h ahead of the actual delivery. It is considered that the total energy requirement from the retailers is 240 MWh, out of which 136 MWh is from NFDs whereas remaining 104 MWh is required from FDs. The ISO requires additional 30 MW as a reserve based on his own load forecast for maintaining the reliability of the system and required to be cleared under RM. DAM clearing consists of –

#### 5.1.1. Day-ahead Energy Market (DAEM) clearing

Based on the offers and bids provided by the participants in DAM, ISO clears the EM. In DAEM, Step-6 of the step-by-step algorithm is not considered. The offers and bids respectively from GENCOs, NFDs, and FDs are given in Table 1.

The revenue details, schedule of each GENCO, NFDs and FDs for dispatching energy demand and the SB obtained according to Step-5 in DAEM is given in Table 2.

#### 5.1.2. Day-ahead reserve market (DARM) clearing

RM clearing under DAM is based on DAEM. After clearing of DAEM, ISO clears DARM based on the results obtained. In DARM, Step-13 is not considered. According to Step 7–12, the result obtained in RM clearing is given in Table 3.

The PC of the reserve is equal to the revenue paid to the GENCOs. Since there is no bidding from the retailer side hence these markets don't provide any SB.

### 5.2. EM and RM clearing under IDM

This type of market is used for adjusting deviations obtained in the day-ahead schedule. Same energy and reserve requirement is considered in IDM as that was in DAM. It has been noticed that due to stochastic behavior, WPP deviates from its scheduled commitment as made in DAM to deliver in RTM, hence WPP is subjected to pay penalties. Under this circumstance, IDM clearing includes –

#### 5.2.1. Intra-day Energy Market (IDEM) clearing

In EM, WPP now offers to deliver only 40 MW (two-third of that offered in DAM) as given in Table 4. With this, the EM is cleared as per new scenario in which WPP will participate in IDEM with its reduced capacity of 40 MW and its backed-down energy will be compensated by other participants available in the IDEM, resulted in the reduction of SB. Hence it is required that WPP has to pay the penalties.

Table 5 shows revenue details, the schedule of each GENCO, NFD, FD and social benefit in IDEM under such circumstances. The SB in IDEM is obtained in a similar manner as that was in DAEM.

The deviation caused by WPP in IDEM results in the reduction in

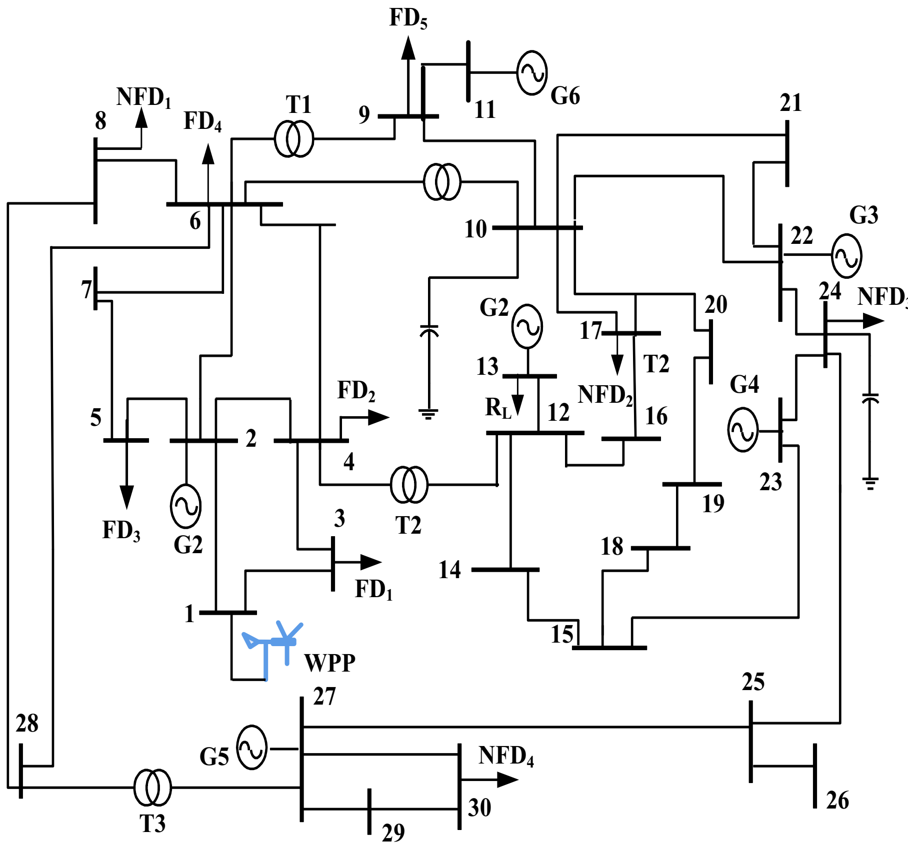


**Fig. 3.** Single line diagram of modified IEEE-30 bus test system.

**Table 1**
Details regarding GENCOs offers and NFDs, FDs bids in DAEM.

| Bus No. | Unit | Maximum Limit (MW) | Capacity (MWh, $/MWh) | | |
|---|---|---|---|---|---|
| | | | Block 1 | Block 2 | Block 3 |
| **GENCOs Offer** | | | | | |
| 1 | WPP | 60 | (30, 38) | (20, 42) | (10, 46) |
| 2 | G1 | 80 | (40, 42) | (20, 46) | (20, 50) |
| 13 | G2 | 40 | (20, 53) | (10, 57) | (10, 61) |
| 22 | G3 | 50 | (20, 50) | (15, 53) | (15, 57) |
| 23 | G4 | 30 | (15, 57) | (10, 61) | (05, 65) |
| 27 | G5 | 55 | (30, 46) | (15, 50) | (10, 53) |
| **NFDs Bid** | | | | | |
| 8 | NFD 1 | 56 | (56, 114) | – | – |
| 17 | NFD 2 | 40 | (15, 122) | (25, 118) | – |
| 24 | NFD 3 | 20 | (20, 110) | – | – |
| 30 | NFD 4 | 20 | (20, 114) | – | – |
| **FDs Bid** | | | | | |
| 3 | FD 1 | 21.7 | Pay to the ISO as per LMP ($\lambda$) | | |
| 4 | FD 2 | 22.8 | | | |
| 5 | FD 3 | 30 | | | |
| 6 | FD 4 | 12 | | | |
| 9 | FD 5 | 17.5 | | | |

SB of about 63$ when comparing with DAEM. With penalty factor $\psi = 1$, WPP is liable to pay 63$ as a penalty.

### 5.2.2. Intra-day reserve market (IDRM) clearing

IDRM has been cleared after the clearing of IDEM. Since supplier WPP has rescheduled to 40 MW in IDEM results in a reduction of AC and ARC at different GENCOs in IDRM. With ARC in RM, ISO clears the reserve requirement of 30 MW according to Step 7–12. The results obtained in the clearing of IDRM is given in Table 6.

Due to the deviation in the schedule of WPP in EM, less ARC is available at cheaper GENCOs resulted in the increase in PC. Hence, according to Step-13, WPP is liable to pay the difference of PC between DARM and IDRM as a penalty. This amount is about 23.73$/hr. The details of penalty payment by supplier WPP to ISO in IDM is given in Table 7.

## 5.3. EM and RM clearing under RTM

RTM is used to match supply-demand on a real-time basis. Herein, energy and reserve requirements remain same as considered in DAM that to be delivered in RTM. During real-time delivery, it has been observed that the same supplier WPP fails to deliver any capacity as shown in Table 8, hence WPP is subjected to pay the required penalties. Under this scenario, RTM clearing results in –

### 5.3.1. Real-time Energy Market (RTEM) clearing

Under RTEM, the schedule and offer of all other GENCOs, FDs and NFDs will remain same as it was in IDEM with an exception that deviation from WPP that results in the reduction of 40 MW in EM will be considered as an emergency requirement by ISO and need to be procured from RM. The schedule of GENCOs to dispatch required energy in RTEM is given in Table 8.

Procuring the capacity of WPP (i.e. 40 MW) from RM in place of EM results in the reduction in SB because procuring a service from RM is costlier than that in EM. Hence, the SB under this market will be obtained after the clearing of RTRM. Therefore, the SB in RTEM will be obtained as SB in IDEM minus extra revenue spends to procure 40 MW from RTRM.

**Table 2**
Revenue details for GENCOs (as per PAB), NFDs (as per PAB) and FDs (as per LMPλ) in DAEM.

| (a) Revenue description regrading GENCOs | | | (b) Revenue description regrading NFDs | | | (c) Revenue description regrading FDs | | | |
|---|---|---|---|---|---|---|---|---|---|
| Unit | Generation Accepted (MWh) | Revenue paid by the ISO ($/h) | Unit | Real demand Accepted (MWh) | Revenue received by the ISO ($/h) | Unit | Demand Accepted (MWh) | LMP ($/MWh) | Revenue received by the ISO ($/h) |
| WPP | 60 | 2440.00 | NFD 1 | 40.92 | 4664.88 | FD 1 | 21.7 | 51.662 | 1121.06 |
| G1 | 79.46 | 3573.00 | NFD 2 | 40 | 4780.00 | FD 2 | 22.8 | 51.866 | 1182.54 |
| G2 | 1.04 | 55.12 | NFD 3 | 20 | 2200.00 | FD 3 | 30 | 51.71 | 1551.30 |
| G3 | 35 | 1795.00 | NFD 4 | 20 | 2280.00 | FD 4 | 12 | 51.885 | 622.62 |
| G4 | 0 | 0 | – | – | – | FD 5 | 17.5 | 53.167 | 930.42 |
| G5 | 55 | 2660.00 | – | – | – | – | – | – | – |
| Total | 230.5 | 10523.12 | | 120.92 | 13924.88 | | 104 | | 5407.94 |
| **Social Benefit: [(b) + (c) - (a)]** | | | | | | | | | **8809.70** |

**Table 3**
Revenue paid to the GENCOs in DARM (as per PAB).

| Bus No. | Unit | Available Capacity (AC) | Ramp Rate ($RR_i$) | Available Reserve Capacity ($ARC_i$) | Reserve Offer | | Demand Accepted (MW) | Revenue paid by the ISO ($/h) |
|---|---|---|---|---|---|---|---|---|
| | | | | | MW | ($/MWh) | | |
| 1 | WPP | 0 | – | 0 | 60 | 55 | – | – |
| 2 | G1 | 0.54 | 3 | 0.54 | 80 | 60 | 0.54 | 32.40 |
| 13 | G2 | 38.96 | 3 | 30 | 40 | 73 | 30 | 2190.00 |
| 22 | G3 | 15 | 3 | 15 | 50 | 85 | 0 | 0 |
| 23 | G4 | 30 | 3 | 30 | 30 | 82 | 5.32 | 436.24 |
| 27 | G5 | 0 | 3 | 0 | 55 | 64 | – | – |
| Total | | 84.5 | | 75.54 | | | | 2658.64 |

**Table 4**
Details regarding reduced GENCOs offer in IDEM.

| Bus No. | Unit | Maximum Limit (MW) | GENCOs Offer (MWh, $/MWh) | | |
|---|---|---|---|---|---|
| | | | Block 1 | Block 2 | Block 3 |
| 1 | WPP | 40 | (30, 38) | (10, 42) | – |
| 2 | G1 | 80 | (40, 42) | (20, 46) | (20, 50) |
| 13 | G2 | 40 | (20, 53) | (10, 57) | (10, 61) |
| 22 | G3 | 50 | (20, 50) | (15, 53) | (15, 57) |
| 23 | G4 | 30 | (15, 57) | (10, 61) | (05, 65) |
| 27 | G5 | 55 | (30, 46) | (15, 50) | (10, 53) |

### 5.3.2. Real-time reserve market (RTRM) clearing

Since supplier WPP isn't able to deliver any capacity during real-time delivery, hence this capacity is required to be procured from RM in order to avoid re-dispatching of EM. The suppliers selected in IDEM are allowed to provide their scheduled generation as committed. Hence a total of 70 MW of the reserve is required to be procured under RTRM.

In addition to other participants in RM, G6 offers to provide capacity only in RTRM with relatively high ramp rate of 5 MW/min. The procurement of required reserve of 30 MW and an emergency reserve of 40 MW (due to failure of WPP) under RTRM is given in Table 9.

The revenue paid by the ISO for procuring emergency reserve of 40 MW from RM in place of EM has been obtained by comparing IDRM and RTRM and is given in Table 10.

From Table 10, it has been seen that the total revenue of 3540.20$ is paid by the ISO to procure emergency reserve in RTRM. This results in the reduction of the SB obtained in RTEM and given in Table 11.

Under this scenario, the supplier WPP responsible for reducing the SB will be liable to pay the penalty. In order to discourage deviations in real-time delivery, penalty factor ($\psi$) in this market should be more than that in other markets. The imbalance settlement in RTM is given in Table 12.

Therefore, SB obtained under RTEM is decreased by about 1980$/h. Therefore, with the penalty factor of $\psi = 5$, WPP has to pay a net penalty of 9900$ for the concerned period under RTM.

## 6. Conclusion

It is an exciting but meaningful challenge to integrate renewables in electricity markets for the procurement of energy and

**Table 5**
Revenue details for GENCOs (as per PAB), NFDs (as per PAB) and FDs (as per LMPλ) in IDEM.

| (d) Revenue description regrading GENCOs | | | (e) Revenue description regrading NFDs | | | (f) Revenue description regrading FDs | | | |
|---|---|---|---|---|---|---|---|---|---|
| Unit | Generation Accepted (MWh) | Revenue paid by the ISO ($/h) | Unit | Real demand Accepted (MWh) | Revenue received by the ISO ($/h) | Unit | Demand Accepted (MWh) | LMP ($/MWh) | Revenue received by the ISO ($/h) |
| WPP | 40 | 1560.00 | NFD 1 | 41.2 | 4696.80 | FD 1 | 21.7 | 52.101 | 1130.59 |
| G1 | 80 | 3600.00 | NFD 2 | 40 | 4780.00 | FD 2 | 22.8 | 52.216 | 1190.52 |
| G2 | 19.79 | 1048.87 | NFD 3 | 20 | 2200.00 | FD 3 | 30 | 52.227 | 1566.81 |
| G3 | 35 | 1795.00 | NFD 4 | 20 | 2280.00 | FD 4 | 12 | 52.271 | 627.25 |
| G4 | 0 | 0 | – | – | – | FD 5 | 17.5 | 53.637 | 938.64 |
| G5 | 55 | 2660.00 | – | – | – | – | – | – | – |
| Total | 229.79 | 10663.87 | | 121.2 | 13956.80 | | 104 | | 5453.81 |
| **Social Benefit: [(e) + (f) - (d)]** | | | | | | | | | **8746.74** |

**Table 6**
Revenue paid to the GENCOs in IDRM (as per PAB).

| Bus No. | Unit | Available Capacity ($AC_i$) | Ramp Rate ($RR_i$) | Available Reserve Capacity ($ARC_i$) | Reserve Offer | | Real demand Accepted (MW) | Revenue paid by the ISO ($/h) |
|---|---|---|---|---|---|---|---|---|
| | | | | | MW | ($/MWh) | | |
| 1 | WPP | 0 | – | 0 | 40 | 55 | – | – |
| 2 | G1 | 0 | 3 | 0 | 80 | 60 | – | – |
| 13 | G2 | 20.21 | 3 | 20.21 | 40 | 73 | 20.21 | 1475.33 |
| 22 | G3 | 15 | 3 | 15 | 50 | 85 | 0 | 0 |
| 23 | G4 | 30 | 3 | 30 | 30 | 82 | 14.72 | 1207.04 |
| 27 | G5 | 0 | 3 | 0 | 55 | 64 | – | – |
| Total | | 65.21 | | 65.21 | | | 34.93 | 2682.37 |

**Table 7**
Penalty paid by WPP to ISO in IDM (with penalty factor $\psi = 1$).

| S. No. | Type of Market | Penalty ($/h) |
|---|---|---|
| 1 | Intra-Day Energy Market (IDEM) | 63.00 |
| 2 | Intra-Day Reserve Market (IDRM) | 23.73 |
| Total | | 86.73 |

In total, supplier WPP has to pay a penalty of around 87$ for the concerned period in IDM.

**Table 10**
Revenue paid by the ISO to the GENCOs for procuring emergency reserve.

| S. No. | Description | Revenue paid by the ISO to the GENCOs ($/h) |
|---|---|---|
| (g) | Total cost of procurement of 70 MW in RTRM (Table 9) | 6222.57 |
| (h) | Revenue paid by ISO to procure 30 MW in IDRM (Table 6) | 2682.37 |
| (i) | Revenue paid by ISO to procure 40 MW in RTRM [(g) − (h)] | 3540.20 |

ancillary services. Since, integration of renewables in electricity markets is a practical situation hence the effect of stochastic nature of these variable energy sources must be incorporated while designing a suitable market structure for energy and operating reserve. The procurement of OR is necessary for the reliable and secure operation of a power system. In this paper, a sequential market clearing approach has been employed for penalty based real-time procurement of energy and OR from RPPs and CPPs under short-term market environment. In order to examine the practicability of the proposed approach, a competitive model has been considered to discuss the techno-economic effect of imbalance caused by WPP on associated revenues. An ISO dispatches energy in such a way as to maximize the social welfare given the demand energy bids and supply offers and reserve services with an objective of reserve procurement cost minimization.

The DAM is used to balance the demand with the supply 24-h ahead the actual delivery. For energy and reserve demand of 240 MWh and 30 MW respectively, ISO obtained SB of 8810.70$ from DAEM and has to pay 2658.64$ for procuring reserve in DARM. With the same requirement in IDM, the SB is decreased by 63$ in IDEM and the PC of the reserve is increased by 23.73$ in IDRM due to the reduction in one-third of the capacity from one of the suppliers (WPP considered in this paper), who was committed to supply in DAM. Therefore the supplier WPP has been liable to pay a total of 86.73$ as a penalty in IDM with a penalty factor of 1. Penalty factor is a measure of an effect caused by the imbalances on various

**Table 8**
Revenue paid by ISO to the GENCOs in RTEM (as per PAB).

| Bus No. | Unit | Maximum Limit (MW) | GENCOs Offer (MW, $/MWh) | | | Generation Accepted (MW) | Revenue paid by the ISO ($/h) |
|---|---|---|---|---|---|---|---|
| | | | Block 1 | Block 2 | Block 3 | | |
| 1 | WPP | Failed to deliver any capacity in RTEM | | | | To be procured from RTRM | |
| 2 | G1 | 80 | (40, 42) | (20, 46) | (20, 50) | 80 | 3600.00 |
| 13 | G2 | 40 | (20, 53) | (10, 57) | (10, 61) | 19.79 | 1048.87 |
| 22 | G3 | 50 | (20, 50) | (15, 53) | (15, 57) | 35 | 1795.00 |
| 23 | G4 | 30 | (15, 57) | (10, 61) | (05, 65) | 0 | 0 |
| 27 | G5 | 55 | (30, 46) | (15, 50) | (10, 53) | 55 | 2660.00 |
| Total | | 255 | | | | 189.79 | 9103.87 |

**Table 9**
Revenue paid to the GENCOs in RTRM (as per PAB).

| Bus No. | Unit | Available Capacity ($AC_i$) | Ramp Rate ($RR_i$) | Available Reserve Capacity ($ARC_i$) | Reserve Offer | | Energy Accepted (MW) | Revenue paid by the ISO ($/h) |
|---|---|---|---|---|---|---|---|---|
| | | | | | (MW) | ($/MW) | | |
| 2 | G1 | 0 | 3 | 0 | 80 | 60 | – | – |
| 13 | G2 | 20.21 | 3 | 20.21 | 40 | 73 | 20.21 | 1475.33 |
| 22 | G3 | 15 | 3 | 15 | 50 | 85 | 15 | 1275.00 |
| 23 | G4 | 30 | 3 | 30 | 30 | 82 | 22.72 | 1863.04 |
| 27 | G5 | 0 | 3 | 0 | 55 | 64 | – | – |
| 11 | G6 | 50 | 5 | 50 | 50 | 90 | 17.88 | 1609.20 |
| Total | | 115.21 | | 115.21 | | | 75.81 | 6222.57 |

**Table 11**
Social Benefit obtained in RTEM.

| Revenue Details | S. No. | Description | Revenue ($/h) |
|---|---|---|---|
| Revenue paid by ISO to GENCOs | (j) | For procuring 189.79 MW from RTEM (Table 8) | 9103.87 |
| | (k) | For procuring emergency reserve of 40 MW from RTRM (Table 10) | 3540.20 |
| Revenue received by the ISO | (l) | From NFD in IDEM (Table 5(e)) | 13956.80 |
| | (m) | From FD in IDEM (Table 5(f)) | 5453.81 |
| Social Benefit: [{(l) + (m)} − {(j) + (k)}] | | | 6766.54 |

**Table 12**
Imbalance settlement in Real-time.

| S. No. | Description | Amount ($/h) |
|---|---|---|
| (n) | Social Benefit obtained in IDEM (Table 5) | 8746.74 |
| (o) | Social Benefit obtained in RTEM (Table 12) | 6766.54 |
| Reduction in SB due to WPP: [(n) − (o)] | 1980.20 | |

market performance under STM.

It is further observed that the supplier WPP is completely failed to deliver any capacity that was scheduled in IDM to provide during RT delivery resulting in heavy loss of revenue. Therefore the concerned supplier will be required to pay the penalty against the imbalance caused. Under this circumstance, an ISO needs to procure this capacity as an emergency requirement from RM in place of EM in order to avoid re-dispatch of the market. Hence, in RTM, a net penalty of 9900$ has to be paid by the supplier with relatively higher penalty factor of 5. The penalty received by the ISO may be utilized to provide incentives to the parties for their positive commitments and for the social welfare of the society.

The results obtained under different market scenarios shows that there is a mandated requirement of effective penalty mechanism for procurement of both energy and AS from CPPs and RPPs in order to discourage the imbalance behavior.

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