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A Novel Techno-economical Virtual Combinatorial Bidding Strategy for Power Supply Market

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Abstract: The trading process in contemporary competitive power supply market needs modifications from time to time to meet the upcoming global fossil fuel crisis and social welfare challenges. Although the existing supplies market bidding structures have adequate mechanisms in place, yet there is room to improve them in terms of enhancing reliability and efficiency. The prudent deciding factor for GENCOs' profit is the strategy of their time variant maximum equitable profitability. This paper presents a case study of three generating units, feeding three constant loads at different points of time whereas each generating unit can run at any of the three pre-decided marginal costs individually. This forms a combinatorial matrix comprising of twenty-seven combinations of bidding strategies. The Particle Swarm Optimization method on the matrix laboratory software platform is applied to obtain the load dispatch for all such combinations providing marginal cost of each generator. A comparison of the costs is carried out for the three loading conditions individually and a logical conclusion is reported in this paper. Generalized set of equations are finally developed to represent the self-enforcing combinations leading to the most economical solution for each GENCO keeping it at its lowest risk of losing economy.

Keywords: Power supply market, Marginal cost, Economic load dispatch, Combinatorial bidding strategy

1 Introduction

In this digital era, accessibility to information is increasing day by day. This situation warrants the development of more robust and efficient bidding strategies for GENCOs to satisfy their conflicting interests of maximizing their individual profits [1] in the most amicable and convincing manner. In the competitive power market, generation companies can sell their power on the basis of real-time market demand [2]. A number of possible operating bidding strategies can be developed to meet the essential power demand. However, it is desirable to evolve an optimal or suboptimal bidding strategy constructed on the basis of economic criteria for efficiency, storage and security of supply [3]. For the sake of GENCOs and world welfare for the better future of power system market, there is need to improve the robustness, reliability, efficiency safety and diversity at the generation side, considering economic load dispatch constraints and to establish an optimal bidding strategy [4], [5], [6]. In power market due to uncertainties in load and need of real-time power management, there is non-cooperative scenario because of incomplete information of each GENCO [7], [8], [9]. This creates complex problems related to economic scheduling of generators together with supply and demand cost satisfaction. A perfect power market should have optimal bidding strategy for a given load demand in a competitive scenario to bid at its short-term marginal cost, as per microeconomic theory [10], [11]. The possibilities of the Nash equilibrium point have also been reported to decide the optimal operating of generation [12], [13].

The optimal pricing problem was first addressed on the basis of spot pricing theory [14]. The conceptual bidding model with programming and system demand with unit commitment costs approach was developed [15]. The self-unit commitment based profitable bid for cooperative and non-cooperative approaches are proposed to study the behavior of suppliers [16], [17]. The market price based unit commitment problem is solved including profit and risk simultaneously to a set of prices for fuel [1], [4], [18], [19]. The techno-economical feasibility study is gaining importance by developing deeper insight into devising bidding techniques for betterment by redefining the generation scheduling problem to share the prevailing demand satisfactorily by developing an advanced technique and strategies for overcoming the different techniques as well as electricity management challenges [20], [21], [22].

2 Problem Formulations

The aim of the study is to develop a profit giving strategy for three generators feeding constant loads. The issue of profit making is discussed from market viewpoint while the sharing of load among three generators is decided on minimum fuel cost basis.

2.1 Economic Load Dispatch

The fuel cost function of a generator, mostly used in power system operation and control problems, is represented with a second-order polynomial. $FC_i(P_i)$ is the fuel cost of ith unit in $\Re$ where P_i is the power output of ith generating unit in MW [23].

$$FC_i(P_i) = A_i + B_i(P_i) + C_i(P_i)^2 \qquad (1)$$

The System total fuel cost function for n number of generating units is defined as

$$FC_T = \sum_{i=1}^{n} FC_i(P_i) = \sum_{i=1}^{n} \{A_i + B_i(P_i) + C_i(P_i)^2\} \qquad (2)$$

Where, A_i, B_i and C_i are non-negative cost coefficient constants of the ith generator in $\Re$, $\Re$ /MW, $\Re$ /MW^2 respectively.

The constraints considered here are as follows [24].

Constraint of Power Balance. P_i is the generation in MW of ith unit and L_d is the load demand. Then,

$$\sum_{i=1}^{n} P_i = L_d \qquad (3)$$

Inequality Constraints of Generation Limit. The output power of any generator should not exceed its operating range of rating which is predefined as the maximum generation amounts of the generator.

If $P_{i\,(min)}$ is the maximal generation in MW of i[th] unit.
Then,

$$P_{i(\min)} \le P_i \le P_{i(\max)} \quad (4)$$

The real power generation is obtained for each GENCO by solving equation (2) with constraints considered here from equation (3) and (4).

2.2 Pricing

The prime objective of GENCOs is to maximize the profit by selecting an optimal bidding strategy while satisfying the load demand under economic load dispatch constraints.

In this study, it is assumed that the market clearing price of the generating system is the minimum of the marginal costs among the scheduled generators for meeting the next hour MW of generation individually [25], [26], [27]. Thus, $MC_i(P_i)$ is the marginal cost of i[th] unit in $\Re$/MW with power output (P_i) in MW. The expression for marginal cost is given by equation (5) [16], [25].

$$MC_i(P_i) = B_i(P_i) + 2C_i(P_i) \quad (5)$$

In order to evolve efficient optimal bidding strategies of GENCOs, it is essential to estimate the marginal cost for each participating generator accurately. It is envisaged that the GENCOs can set their bidding marginal costs slightly lower or higher than their respective marginal costs [25], [26], [28]. Thus combinations of different bidding strategies of generators get created reflecting their incremental costs for further analysis and interpretation.

3 Solution Methodologies and Case Study

Three generators have been considered whose minimum and maximum generation capacities with their fuel cost coefficients are given in section 3.1. These generators feed constant loads of 485 MW, 585 MW and 685 MW of loads at different points of time. PSO based load dispatch schedule is obtained by varying the bidding strategies into three categories viz; low, base and high. The marginal costs for each generator are obtained and compared.

3.1 Economic Load Dispatch

The test case system considered for the study contains three thermal generating units satisfying a constant load at a time. Particle swarm optimization method is applied to obtain the load dispatch solution such that the overall cost of generation remains at its minimum [29]. Equations (6) to (11) show the data used [24].

$$FC_1 = 561 + 7.92P_1 + 0.00156P_1^2 \ \Re \quad (6)$$

$$FC_2 = 310 + 7.85P_2 + 0.00194P_2^2 \ \Re \quad (7)$$

$$FC_3 = 78 + 7.97P_3 + 0.00482P_3^2 \ \Re \quad (8)$$

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Where, '$\Re$' is any arbitrary currency.
The unit operating ranges are

$$150MW \le P_1 \le 600MW \quad (9)$$
$$100MW \le P_2 \le 400MW \quad (10)$$
$$50MW \le P_3 \le 200MW \quad (11)$$

3.2 Marginal Cost

The marginal cost is a derivative of incremental cost [28]. Expressions of the marginal costs for the three generators under consideration are given by equations (12) to (14).

$$MC_1 = 7.92 + 2 \times 0.00156 P_1 \ \Re / MW \quad (12)$$
$$MC_2 = 7.85 + 2 \times 0.00194 P_2 \ \Re / MW \quad (13)$$
$$MC_3 = 7.97 + 2 \times 0.00482 P_3 \ \Re / MW \quad (14)$$

Strategy Formulation. The bidding for the next MW of generation by a unit should be such that its marginal cost equals the market clearing cost [25], [26], [27]. The load scheduling of the three generators is done by varying their marginal costs by +/- 20% individually in combination. Table 1 shows the bidding strategies applied in this study.

Table 1. Bidding Strategies

Bidding Strategy	Cost
Low (α)	0.8 of the marginal cost of unit
Base (β)	Marginal cost of unit
High (γ)	1.2 of the marginal cost of unit

For all the possible sets of bidding strategies, the marginal costs are evaluated. The lowest marginal cost among all three generators for each set is then considered to be the market clearing price for that particular set. The underlying reason for the above is that if the cost of generation of one additional MW of a generator is higher than the overall lowest marginal cost, then that generator will be selling the power at loss and vice a versa. This exercise created a combination of strategies revealing the contributions of all the three generators in terms of revenue.

4 Simulation Results

The Matrix Laboratory software simulation of economic load dispatch for three different constant loads by three generators was carried out separately. The three strategies were applied on all the three generators individually to evolve 3^3 =27 sets of the combinations for each load. The costs for all the sets were evaluated for the three loads of 485MW, 585MW, and 685MW as shown in Table 2, Table 3 and Table 4 respectively.

Table 2. Simulation result of optimal bidding strategy with scheduled load of 485MW

S.No	Strategies			Generation (MW)			Marginal Cost of Generator (ℜ /MW)			Marginal Cost - Market Clearing Price (ℜ /MW)		
	a	b	c	P_1	P_2	P_3	MC_1	MC_2	MC_3	R_1	R_2	R_3
1	α	α	α	150	248	87	7.574	7.049	7.046	0.528	0.003	0
2	α	α	β	150	285	*50*	70574	7.164	8.452	0.41	0	*1.288*
3	α	α	γ	150	285	50	7.574	7.164	10.142	0.41	0	2.978
4	α	β	α	188	*100*	197	7.888	*8.238*	7.895	0.003	*0.343*	0
5	α	β	β	264	*171*	*50*	8.515	*8.513*	8.452	0.063	*0.061*	*0*
6	α	β	γ	264	*171*	50	8.515	*8.513*	10.142	0.002	*0*	1.629
7	α	γ	α	188	100	197	7.888	9.885	7.895	0	1.997	0.007
8	α	γ	β	299	100	*86*	8.804	9.885	8.799	0.005	1.086	*0*
9	α	γ	γ	335	100	50	9.101	9.885	10.142	0	0.784	1.041
10	β	α	α	*150*	248	87	*8.388*	7.049	7.046	*1.342*	0.003	0
11	β	α	β	*150*	285	*50*	*8.388*	7.164	8.452	*1.224*	0	*1.228*
12	β	α	γ	*150*	285	50	*8.076*	7.164	10.142	*0.912*	0	2.978
13	β	β	α	*150*	*135*	200	*8.388*	*8.373*	7.918	*0.470*	*0.455*	0
14	β	β	β	*222*	*196*	*67*	*8.612*	*8.610*	8.615	*0.002*	*0*	*0.005*
15	β	β	γ	*231*	*204*	50	*8.640*	*8.641*	10.142	*0*	*0.001*	1.502
16	β	γ	α	*185*	100	200	*8.497*	9.885	7.918	*0.579*	1.967	0
17	β	γ	β	*295*	100	*90*	*8.840*	9.885	8.837	*0.003*	1.048	*0*
18	β	γ	γ	*335*	100	50	*8.965*	9.885	10.142	*0*	0.92	1.117
19	γ	α	α	150	248	87	10.065	7.049	7.046	3.019	0.003	0
20	γ	α	β	150	285	*50*	10.065	7.164	8.452	2.901	0	*1.288*
21	γ	α	γ	150	285	50	10.065	7.164	10.142	2.901	0	2.978
22	γ	β	α	150	*135*	200	10.065	*8.373*	7.918	2.147	*0.455*	0
23	γ	β	β	150	*248*	*87*	10.065	*8.812*	8.808	1.257	*0.004*	0
24	γ	β	γ	150	*285*	50	10.065	*8.955*	10.142	1.110	*0*	1.187
25	γ	γ	α	150	135	200	10.065	10.048	7.918	2.147	2.13	0
26	γ	γ	β	150	135	*200*	10.065	10.048	9.898	0.167	0.15	*0*
27	γ	γ	γ	222	196	67	10.335	10.332	10.339	0.003	0	0

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Table 3. Simulation result of optimal bidding strategy with scheduled load of 585MW

S.No	**Strategies**			**Generation (MW)**			**Marginal Cost of Generator ($\Re$ /MW)**			**Marginal Cost - Market Clearing Price ($\Re$ /MW)**		
	a	**b**	**c**	**P_1**	**P_2**	**P_3**	**MC_1**	**MC_2**	**MC_3**	**R_1**	**R_2**	**R_3**
1	α	α	α	150	319	116	7.574	7.270	7.270	0.304	0	0
2	α	α	β	150	385	*50*	7.574	7.475	8.452	0.099	0	*0.977*
3	α	α	γ	150	385	50	7.574	7.475	10.142	0.099	0	2.667
4	α	β	α	248	*137*	200	8.383	*8.381*	7.918	0.463	*0.463*	0
5	α	β	β	287	*221*	*77*	8.705	*8.707*	8.712	0	*0.002*	*0.007*
6	α	β	γ	296	*239*	50	8.779	*8.777*	10.142	0.002	*0*	1.365
7	α	γ	α	285	100	200	8.688	9.885	7.918	0.770	1.907	0
8	α	γ	β	353	100	*132*	9.246	9.885	8.586	0.660	1.299	*0*
9	α	γ	γ	432	103	50	9.900	9.900	10.142	0	0	0.242
10	β	α	α	*150*	319	116	*8.388*	7.269	7.271	*1.119*	0	0.002
11	β	α	β	*150*	385	*50*	*8.388*	7.475	8.452	*0.913*	0	*0.977*
12	β	α	γ	*150*	385	50	*8.388*	7.475	10.142	*0.913*	0	2.667
13	β	β	α	*203*	*182*	200	*8.554*	*8.554*	7.918	*0.636*	*0.636*	0
14	β	β	β	*269*	*234*	*82*	*8.758*	*8.759*	8.760	*0*	*0.001*	*0.002*
15	β	β	γ	*269*	*248*	50	*8.813*	*8.814*	10.142	*0*	*0.001*	1.329
16	β	γ	α	*285*	100	200	*8.809*	9.885	7.918	*0.891*	1.967	0
17	β	γ	β	*370*	100	*115*	*9.075*	9.885	9.075	*0*	0.810	*0*
18	β	γ	γ	*435*	100	50	*10.409*	9.885	10.142	*0.524*	0	0.257
19	γ	α	α	150	319	116	10.065	7.271	7.267	2.798	0.004	0
20	γ	α	β	150	385	*50*	10.065	7.475	8.452	2.590	0	*0.977*
21	γ	α	γ	150	385	50	10.065	7.475	10.142	2.590	0	2.667
22	γ	β	α	150	*235*	200	10.065	*8.761*	7.916	2.149	*0.845*	0
23	γ	β	β	150	*318*	*117*	10.065	*9.085*	9.094	0.980	*0*	0.009
24	γ	β	γ	150	*385*	50	10.065	*9.343*	10.142	0.722	*0*	0.799
25	γ	γ	α	203	182	200	10.265	10.265	7.918	2.347	2.347	0
26	γ	γ	β	203	182	*200*	10.265	10.265	9.898	0.367	0.367	*0*
27	γ	γ	γ	269	234	81.8	10.510	10.510	10.510	0	0	0

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Table 4. Simulation result of optimal bidding strategy with scheduled load of 685MW

S.No	**Strategies**			**Generation (MW)**			**Marginal Cost of Scheduled Generator (ℜ /MW)**			**Marginal Cost - Market clearing Price (ℜ /MW)**		
	a	**b**	**c**	$\mathbf{P_1}$	$\mathbf{P_2}$	$\mathbf{P_3}$	$\mathbf{MC_1}$	$\mathbf{MC_2}$	$\mathbf{MC_3}$	$\mathbf{R_1}$	$\mathbf{R_2}$	$\mathbf{R_3}$
1	α	α	α	150	400	135	7.574	7.521	7.417	0.157	0.104	0
2	α	α	β	235	400	*50*	8.276	7.521	8.452	0.755	0	*0.931*
3	α	α	γ	235	400	50	8.276	7.521	10.142	0.755	0	2.621
4	α	β	α	280	*205*	200	8.647	*8.645*	7.918	0.729	*0.727*	0
5	α	β	β	312	*275*	*98*	8.911	*8.917*	8.914	0	*0.006*	*0.003*
6	α	β	γ	328	*307*	50	9.043	*9.041*	10.142	0.002	*0*	1.101
7	α	γ	α	385	100	200	9.514	9.885	7.918	1.596	1.967	0
8	α	γ	β	406	100	*179*	9.687	9.885	90695	0	0.198	*0.008*
9	α	γ	γ	466	165	54	10.183	10.188	10.188	0	0.005	0.005
10	β	α	α	*150*	400	135	*8.388*	7.521	7.417	*0.971*	0.104	0
11	β	α	β	*219*	400	*66*	*8.603*	7.521	8.606	*1.082*	0	*1.085*
12	β	α	γ	*235*	400	50	*8.653*	7.521	10.142	*1.132*	0	2.621
13	β	β	α	*259*	*226*	200	*8.728*	*8.726*	7.918	*0.810*	*0.808*	0
14	β	β	β	*316*	*272*	*97*	*8.905*	*8.905*	8.905	*0*	*0*	*0*
15	β	β	γ	*342*	*293*	50	*8.987*	*8.986*	10.142	*0.001*	*0*	1.156
16	β	γ	α	*385*	100	200	*9.121*	9.885	7.918	*1.203*	1.967	0
17	β	γ	β	*446*	100	*139*	*9.311*	9.885	9.309	*0.002*	0.576	*0*
18	β	γ	γ	*535*	100	50	*9.589*	9.885	10.142	*0*	0.296	0.553
19	γ	α	α	150	400	135	10.065	7.521	7.417	2.648	0.104	0
20	γ	α	β	150	400	*135*	10.065	7.521	9.271	2.544	0	*1.750*
21	γ	α	γ	219	400	66	10.323	7.521	10.327	2.802	0	2.806
22	γ	β	α	150	*335*	200	10.065	*9.149*	7.918	2.147	*1.231*	0
23	γ	β	β	150	*390*	*145*	10.065	*9.363*	9.367	0.702	*0*	0.004
24	γ	β	γ	219	*400*	66	10.323	*9.402*	10.327	0.921	*0*	0.925
25	γ	γ	α	259	226	200	10.473	10.472	7.918	2.555	2.554	0
26	γ	γ	β	259	226	*200*	10.473	10.472	9.898	0.575	0.574	*0*
27	γ	γ	γ	316	272	97	10.687	10.686	10.686	0.001	0	0

The zero values in the above tables indicate that the corresponding generator would run on no profit, no loss basis. The others, however, would run in a loss.

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5 Results Analysis

On the basis of case study for three different loads, the Matrix Laboratory software simulation output data, as shown table 1, table 2 and table 3, is plotted in figure 1, figure 2 and figure 3 respectively.

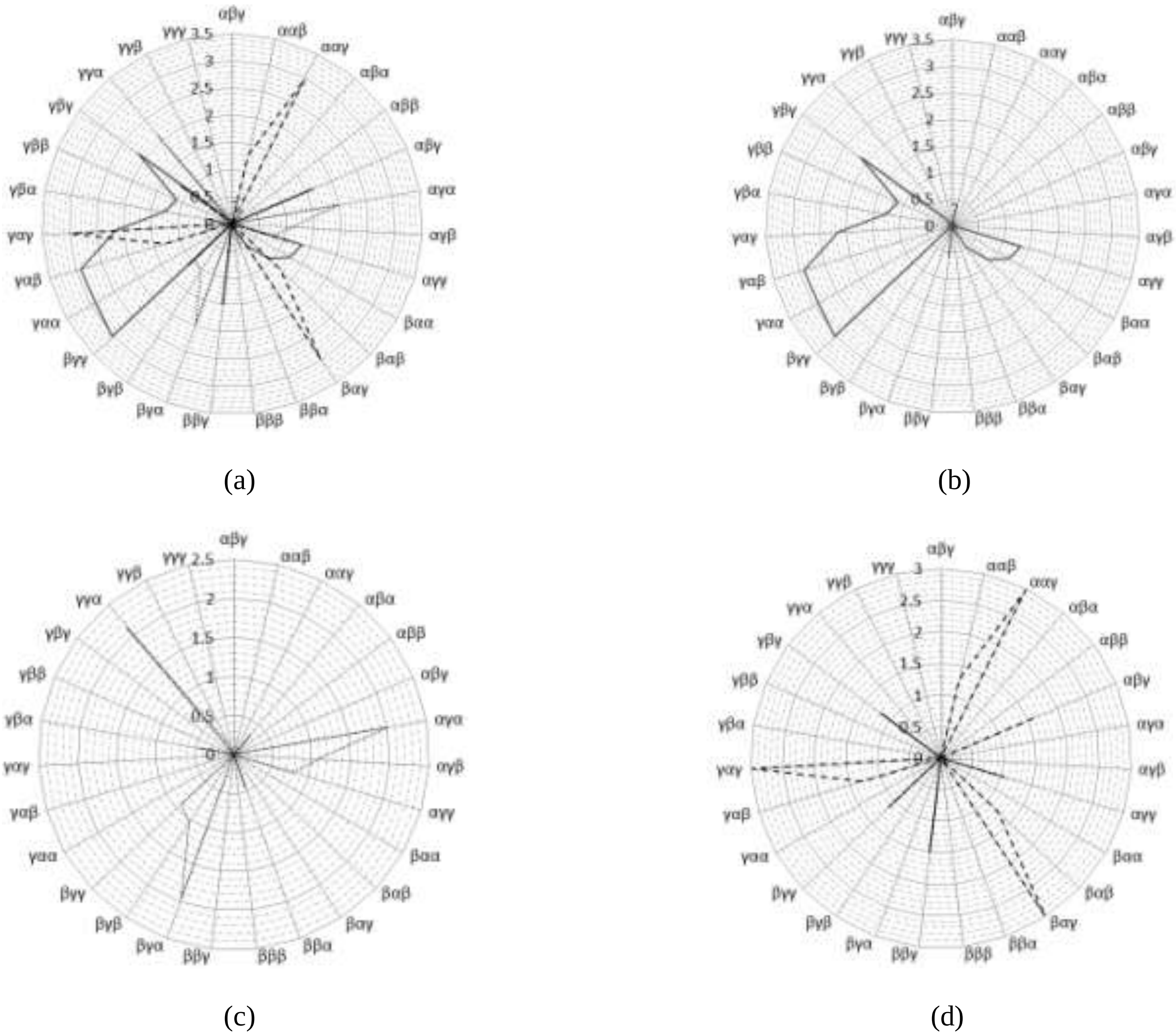
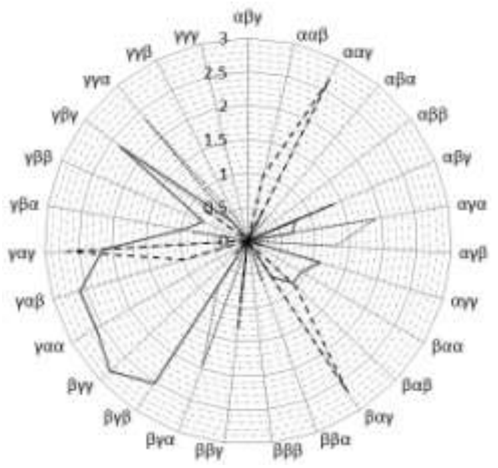
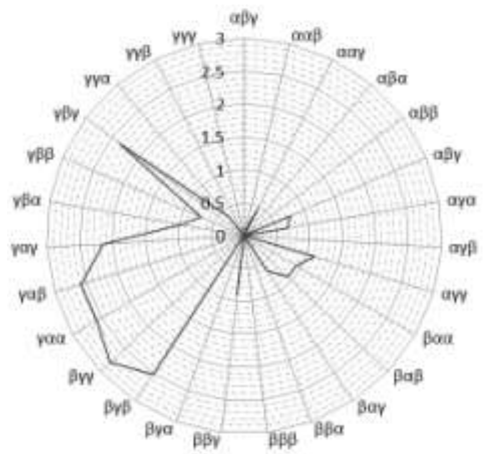


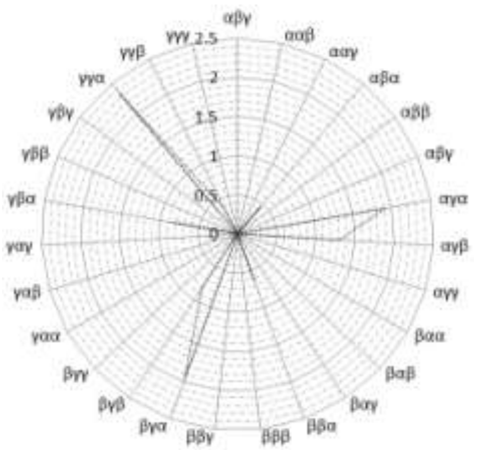
Figure. 1. Impact of strategies: 485MW- (a) G1, G2 and G3 (b) G1 (c) G2 (d) G3



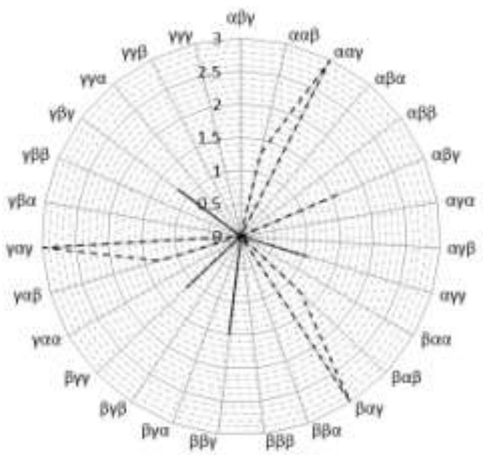
(a)



(b)

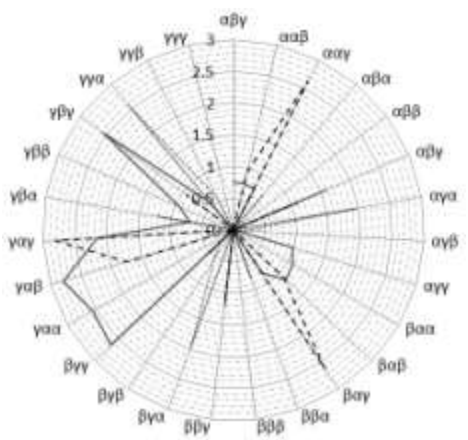


(c)

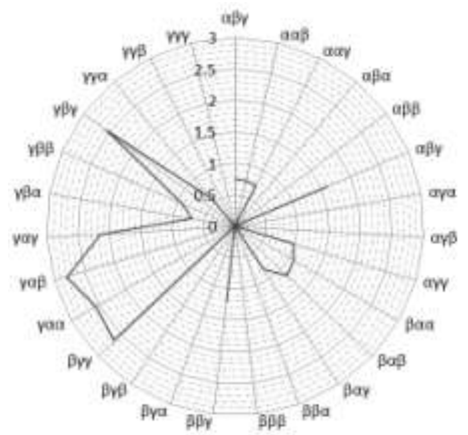


(d)

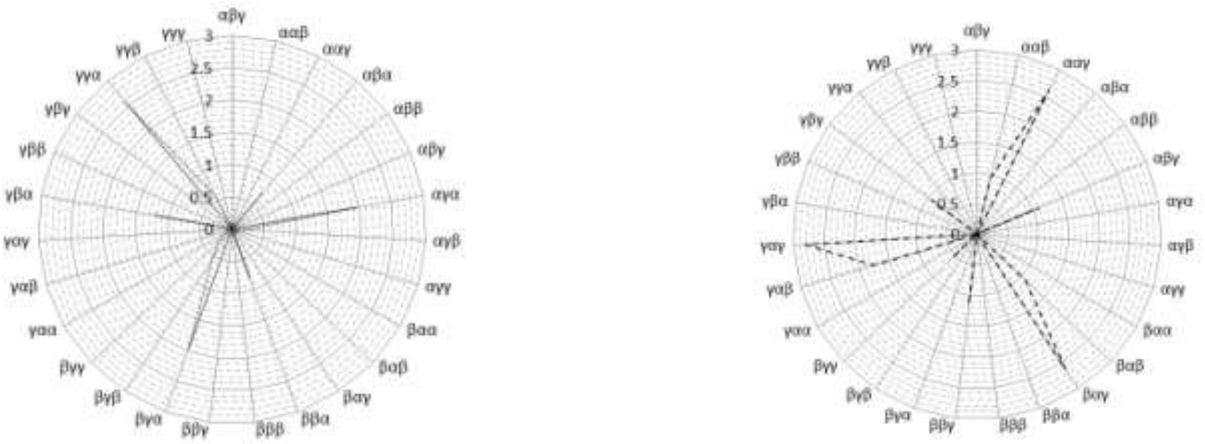
Figure. 2. Impact of strategies: 585MW- (a) G1, G2 and G3 (b) G1 (c) G2 (d) G3



(a)



(b)



(c) (d)

Figure. 3. Impact of strategies: 485MW- (a) G1, G2 and G3 (b) G1 (c) G2 (d) G3

The performance analysis of the application of various bidding strategies applied on the three generators is getting reflected against each of the 27 sets in the form of corresponding revenue impact regions. The area encompassed within the boundary shown by solid lines show the revenue impact of G1. The area covered under round dotted lines show the revenue impact of G2 while the area shown under dash lines show the revenue impact of G3 for all the three designated loads.

It is interesting to note that the areas bounded under the three types of lines in all the figures above indicate the impact in terms of loss. In other words, the generators operating within these areas under the corresponding strategies will lead the particular unit to run under loss condition. This implies very clearly that the areas beyond the bounded ones indicate that the generators operating in these regions will lead to profit-making conditions.

Inference 1. The inference drawn from the figures are summarized in Table 5. The overall trend of revenue obtained through this study reveals that the highest capacity generator G1 operates in a mixed revenue mode for any bidding strategy. For intermediate and lowest capacity generators G2 and G3 respectively, a similar trend is observed under the three strategies. That is, for strategy γ, the revenue is always high. If the strategy followed is β, then it may be low or high. Further, if the strategy is α, the revenue is always low.

Table 5. The summary of proposed bidding strategies

Generator	Bidding Strategies	Revenue
Highest capacity generator	α	Gain/Loss
Highest capacity generator	β	Gain/Loss
Highest capacity generator	γ	Gain/Loss
Intermediate capacity generator	α	Gain
Intermediate capacity generator	β	Gain/Loss
Intermediate capacity generator	γ	Loss
Lowest capacity generator	α	Gain
Lowest capacity generator	β	Gain/Loss
Lowest capacity generator	γ	Loss

Inference 2. Figures 1, 2 and 3 exhibit a similar trend of the strategic combinations through the areas covered under them for all the three loads. This similarity is further analyzed from a fresh perspective.

Table 6. Combinatorial Strategic Matrix: Strategies Independent of load variations

Matrix for three Generator		G3								
		α			β			γ		
		G2								
		α	β	γ	α	β	γ	α	β	γ
G1 (485MW)	α	001	001	100	010	001	001	010	010	100
	β	001	001	001	010	010	001	010	100	100
	γ	001	001	001	010	001	001	010	010	011
G2 (585MW)	α	011	001	001	010	100	001	011	010	110
	β	010	001	001	010	100	101	010	100	010
	γ	001	001	001	010	010	001	010	010	111
G3 (685MW)	α	001	011	001	010	100	100	010	010	100
	β	001	001	001	010	111	001	010	010	100
	γ	001	001	001	010	010	001	010	010	011

Values '1' and '0' are assigned to the conditions of ‘no loss- no gain' and of 'loss' respectively. Now, if the three generators are considered to be the three players in the power market, then in the combinatorial strategic environment of 27 possibilities, the 13combinations remain the same for each load. This is shown with the help shadowed combination blocks in the combinatorial strategic matrix given in Table 6.

Inference 3. The combinatorial matrix was further investigated to reveal the maximum profit giving combinations. It was found that there were 9 similar strategic combinations that gave maximum profit for all the loads. This is depicted by shadowed strategic combination blocks in Table 7.

Table 7. Combinatorial Strategic Matrix: Highest Profit Trend

Matrix for three Generator		G3								
		α			β			γ		
		G2								
		α	β	γ	α	β	γ	α	β	γ
G1 (485MW)	α	001	001	100	010	001	001	010	010	100
	β	001	001	001	010	010	001	010	100	100
	γ	001	001	001	010	001	001	010	010	011
G2 (585MW)	α	011	001	001	010	100	001	011	010	110
	β	010	001	001	010	100	101	010	100	010
	γ	001	001	001	010	010	001	010	010	111
G3 (685MW)	α	001	011	001	010	100	100	010	010	100
	β	001	001	001	010	111	001	010	010	100
	γ	001	001	001	010	010	001	010	010	011

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Inference 4. After establishing the strategic combinations that are independent of load variations (Table 6), and also have identified the strategic combinations giving the highest profit (Table 7), it was of interest to combine the two and get the strategic combinations which give the highest profit while remaining independent of load. This result is shown by the shadowed strategic combination blocks in Table 8.

Table 8. Combinatorial Strategic Matrix: Highest Profit, Independent of Load

Matrix for three Generator		**G3**								
		α			**β**			**γ**		
		G2								
		α	**β**	**γ**	**α**	**β**	**γ**	**α**	**β**	**γ**
G1 (485MW)	**α**	001	001	100	010	001	001	010	010	100
	β	001	001	001	010	010	001	010	100	100
	γ	001	001	001	010	001	001	010	010	011
G2 (585MW)	**α**	011	001	001	010	100	001	011	010	110
	β	010	001	001	010	100	101	010	100	010
	γ	001	001	001	010	010	001	010	010	111
G3 (685MW)	**α**	001	011	001	010	100	100	010	010	100
	β	001	001	001	010	111	001	010	010	100
	γ	001	001	001	010	010	001	010	010	011

Inference 5. An overall generalized set of logic is finally developed to give the best response in terms of identification of the most profitable strategic combinations. This set of logic is described by the equations (15), (16), and (17).

Let the notations $G_i(j)$ represents the j^{th} strategy applied to i^{th} generator; where i=1, 2, 3 in decreasing order of the capacities of generators. Let the strategies α, β and γ be denoted by 1, 2 and 3 respectively, then

$$G2(X) \leq G1(X) \text{ for X = 1, 2 and 3} \quad (15)$$

$$G3(X) < G2(X) \text{ for X = 2 and 3} \quad (16)$$

$$G3(X) = G2(X) \text{ for X = 1} \quad (17)$$

To achieve optimal bidding strategy in highest capacity generator G1, the equations 15, 16 and 17 dictate that when G1is offering bid α, then G2 and G3 should also offer bid α only. Next, when G1 offers bid β, then G2 can offer bid α or β but G3 should offer bid α only. Further, when G1 offers bid γ, then G2 can offer bid α, β or γ but G3 should offer bid α or β only.

6 Conclusions

In the competitive power market, bidding is done on real-time basis. The risk with the real-time market is very high where the participants do not have permission to change their decisions once taken. This case study presents a novel techno-economical model in terms of the development of different combinatorial strategic matrices and the logic equations to help the participants take an appropriate decision before deciding their bids. After simulating the economic load dispatch through

Matrix Laboratory software, the individual behavior and performance as per possible virtual bidding strategies for the three thermal units in competitive electricity power market are obtained and analyzed. From the market designer's point of view, the proposed solution methodology, using combinatorial strategic logic, gives a perfect realization of the plausible improvement in the competitive market. The proposed mechanism develops a knowledge base about the exact predetermined revenue regions in terms of loss or gain to a particular unit pertaining to each specific strategy. The GENCOs could take advantage of the situations by judiciously selecting the strategies by either necessarily avoiding the loss or by tending to increase gain; thus reducing the risk of making loss and limiting themselves in the gain dominated regions.

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