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Market Clearing Price Calculation for a Deregulated Power Market

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Abstract

Background/Objectives: Most of the electricity markets are controlled by particular small group of firms rather than perfect competition. The electricity price determination is the long term process which depends upon cost of production, load demand, availability of generation, unit commitment and the transmission constraints. The main objective of this work is to maximize the social welfare function for the society. In the present scenario, the market clearing is based on stepped bids received from generators and consumers. **Methods/Statistical Analysis:** This paper focuses on implementing power systems optimization for forecasting Market Prices in deregulated electricity markets. In the recent energy trading scenario, determining the market clearing price place a vital role. **Findings:** The necessary solution is computing by collecting the clearing price from the generating station and load center and bids are offered in the closed loop form. **Application/Improvements:** To have a strategic bidding modelling the PDC in the oligopoly market is essential to have a accurate price in calculating the incomes from a new investment, so that it is not undervalued.

Keywords: Deregulation, Locational Marginal Price, Market Clearing Prices, Optimal Power Flow

1. Introduction

Deregulation of the power market the electric supply in many countries has a natural monopoly without any limitations. This affects the consumers because the electric supply cost will not be in an optimized form. So it is necessary to define the electricity market models for balancing the prices, short-term forward transactions and spot and. The fundamental concepts of Market Clearing Price (MCP) and Locational Marginal Price (LMP) has been discussed by Zuyi Li, Hossein Daneshi. He has analyzed MCP and LMP for various cases. In MCP if the demand curve does not intersect with the supply curve, it indirectly defines that MCP may not exists or the probability of its occurrence is very high. Whereas for LMP, the analysis with and without loads are different. One of the important fact about the LMP is that, if its value is higher, then the bidding price of the generation will also high. The main reason behind it was transmission congestion. In order to supply the additional MW load at the defined bus, the generation unit should be increased with cheaper cost[1]. Quadratic bid functions are used to calculate the market clearing price and also the schedules of the existing generator in MATLAB using simple iterative coding scheme. Quadratic bit functions are used for determining the market clearing price in graphical interface scheme. Also closed simulation is carried out for the incremental cost by considering the clearing price and the schedules corresponding to each generator and consumer bid. Using the iterative approach, the system efficiency is increased with reduced computational time by calculating the intermediate values of incremental cost[2]. In order to determine the optimal power flow, it necessary to know about the dispatch schedule of power generators with low cost with satisfying the system constraints like real and reactive power. It has been simulated in the power world software. The software employs linear programming method for finding optimal solution.

Various factors are considered to minimize the operation cost and to solve the problems. In this method,

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they considered the analysis for varying MVAR load and various capacitor to check its operational cost. High power system is considered for better suppleness in OPF analysis. System is represented with one line diagram and the analysis has been carried out using power world simulator, users can transfer the OPF results to a spread sheet, a text file, or a Power World AUX file for added functionality[3]. In the modest electricity market impact of congestion in the transmission strip is one of the chief problems. The congestion quantities and locational marginal price has been determined using power word simulator tools for various electricity environment[4,5].

LMP for congestion management in electricity market in IEEE 6 bus system is simulated in power world simulator. Performance of the system is analyzed during the congestion period. The stability of the system and economic operation of the power system is maintained. Also it is found that marginal cost satisfies both power producers and consumers[6]. The transition from monopolistic to a competitive deregulated market though found to be more advantageous, encountered certain drawbacks, such as Congestion and difficulty in pricing. In this work, the LMP was proved to be an effective solution in overcoming the above said barriers of deregulation[7,8]. The LMPs are computed for the Indian utility system under normal and eventuality conditions. Increase in LMP holds to be a good signal for classifying the Congested locations. The congestion component of LMP is suggested to be used in congestion relief methods, such as totaling of transmission line and injection of VAR. These methods proved well in releasing the system from congestion and have brought LMPs within limits[9-11].

2. Problem Formulation

Consider a system with N supply bit function and M load consumers. Let the bid function generator for the ith generator be

$$C_i\left(P_{gi}\right) = a_i P_{gi}^2 + b_i P_{gi}^2 + C_1 \tag{1}$$

And the consumer benefit function for the jth load be

$$Bf_i(P_{di}) = \alpha_j P_{di}{}^2 + \beta_i P_{di}{}^2 + \gamma_i \tag{2}$$

The objective of the pool market operator is to maximize the social welfare function

$$\sum_{j=1}^{M} Bf_i(P_{di}) - \sum_{i=1}^{N} C_i(P_{gi}) \tag{3}$$

Subject to power balance constraint

$$\sum_{i=1}^{N}(P_{gi}) = \sum_{j=1}^{N}(P_{gi}) \tag{4}$$

Hence the augmented objective function for unconstrained optimization is

$$L = \sum_{i=1}^{N} C_i(P_{gi}) - \sum_{i=1}^{M} Bf_i(P_{di}) - \lambda\left(\sum_{i=1}^{N}(P_{gi}) - \sum_{j=1}^{M}(P_{di})\right) \tag{5}$$

Where λ is the lagrangian multiplier, the conditions for optimality of L are given by

$$\frac{dL}{d\lambda} = \frac{dC_i}{dp_{gi}} = 0 \forall i \tag{6}$$

$$\frac{dL}{d\lambda} = \frac{dB_{fi}}{dp_{di}} = 0 \forall j \tag{7}$$

Equations (6) and (7) imply that for optimality, the incremental cost of all the generation as well as the incremental utility function of all the generation as well as the incremental utility function of all loads must be equal to λ, the incremental cost for generators can also be written as

$$\frac{dC_i}{dp_{gi}} = \lambda = b_i + 2a_i P_{gi}, \quad i \in N \tag{8}$$

At the optimum, the incremental costs of all the generators are same and we have

$$b_i + 2a_i P_{gi} = b_k + 2a_k P_{gk} = \lambda \quad i \in N \tag{9}$$

For a particular k € N

$$P_{gi} = \frac{b_k + 2a_k P_{gk} - b_i}{2a_i} \quad \forall i \in N \tag{10}$$

Let the total demand be given as P_R

$$\sum_{i=1}^{N}(P_{gi}) = \sum_{i=1}^{N}\frac{b_k + 2a_k P_{gk} - b_i}{2a_i} = P_R \tag{11}$$

Define two parameters A and B,

$$A = \sum_{i=1}^{N}\frac{1}{a_i} \tag{12}$$

$$B = \sum_{i=1}^{N}\frac{b_i}{a_i} \tag{13}$$

And (11) can be written as

$$(b_k + 2a_k P_{gk})A = 2P_R + B \tag{14}$$

Where

$$b_k + 2a_k P_{gk} = \lambda \tag{15}$$

Hence the value of λ is obtained as

$$\lambda = \frac{2P_R + B}{A} \tag{16}$$

Similarly with the demand offers, it can be shown that

$$\lambda = \frac{2P_R + B_d}{A_d} \tag{17}$$

Where

$$A_d = \sum_{i=1}^{M} \frac{1}{\alpha_i} \ \& \ B_d = \sum_{i=1}^{M} \frac{\beta_i}{\alpha_i} \tag{18}$$

Solving (16) and (17), we have

$$P_r = \frac{A B_d - B A_d}{2(A_d - A)} \ \& \ \lambda = \frac{B_d - B}{A_d - A} \tag{19}$$

The schedules for each of the generators and demand of each consumer that can be met is obtained as

$$P_{gi} = \frac{\lambda - b_i}{2a_i} \ \& \ P_{di} = \frac{\lambda - \beta_i}{2\alpha_i} \tag{20}$$

3. Solution Methodology

3.1 Gradient Method

The solution for economic dispatch was analyzed and losses were neglected. But, if the losses consider then the equations become non-linear and are to be solved iteratively. Thus, we calculate the Pi iteratively. In an iterative search technique, start with two values of λ. A more accurate value of λ can be found by extrapolation and the process is continued till we get a value of ΔPi within the specified accuracy range. However, the gradient method gives us a faster solution to obtain the value of ΔPi. To do this P_D is written as

$$f(\lambda) = \sum_{j=1}^{M} P_{dj} \tag{21}$$

Expanding the left-hand side of the above equation in

$$f(\lambda)^{(k)} + \frac{df(\lambda)^{(k)}}{d\lambda} . \Delta\lambda^{(k)} = P_D \tag{22}$$

$$\Delta\lambda^{(k)} = \frac{\Delta p^{(k)}}{\frac{df(\lambda)^{(k)}}{d\lambda}} = \frac{\Delta p^{(k)}}{\sum \frac{dP_{Dj}^{(k)}}{d\lambda}} \tag{23}$$

And therefore,

$$\Delta\lambda^{(k+1)} = \lambda^{(k)} + \Delta\lambda^{(k)} \tag{24}$$

Where

$$\Delta P^{(k)} = \sum_{i=1}^{n_g} P_g^{(k)} - \sum_{i=1}^{n_g} P_d^{(k)} \tag{25}$$

And then after sufficient accuracy of Δλ is obtained then the schedules are found using (21) and (22).

3.2 Scheduling of Power Including Losses (without any constraint)

Transmission losses are not necessary to consider if the transmission distances are very small with high load density. The common practice for counting the consequence of transmission losses is to rapid the total transmission loss as a quadratic function of the generator power outputs. The simplest quadratic form is

$$P_L = \sum_{i=1}^{n_g} \sum_{j=1}^{n_g} P_i B_{ij} P_j \tag{26}$$

A more general formula containing a linear term and a constant term, referred to as Kron's loss formula, is

$$P_L = \sum_{i=1}^{n_g} \sum_{j=1}^{n_g} P_i B_{ij} P_j + \sum_{i=1}^{n_g} B_{0i} P_i + B_{00} \tag{27}$$

The coefficients B_{ij} are called loss coefficients or B-coefficients. An approximate loss formula is expressed by

$$P_L = \sum_{i=1}^{n_g} B_{ii} P_i^2 \tag{28}$$

Is used where $B_{ij} = 0$, $B_{00} = 0$, and solution is obtained. The social welfare function for economic dispatching problem is given by

$$\sum_{j=1}^{M} B f_i(P_{dj}) - \sum_{j=1}^{N} C_i(P_{gj}) \tag{29}$$

Subject to the constraint that generation should equal total demands plus losses, i.e.,

$$\sum_{i=1}^{N} P_{gj} = \sum_{j=1}^{N} (P_{dj} - P_L) \quad (30)$$

Using the Lagarange multiplier and adding additional terms the augmented objective function for unconstrained optimization is

$$L = \sum_{i=1}^{M} C_i(P_{dj}) - \sum_{j=1}^{M} Bf_i P_{dj} - \lambda(\sum_{i=1}^{N} P_{dj} - \sum_{j=1}^{N} P_{dj} - P_L) \quad (31)$$

Where λ is the Lagrangian multiplier.

$$\frac{\partial L}{\partial P_{gi}} = 0 \quad (32)$$

$$\frac{\partial L}{\partial P_D} = 0 \quad (33)$$

From (33)

$$\frac{\partial c_t}{\partial P_g} - \lambda(1 - \frac{\partial P_L}{\partial P_{gi}}) = 0 \quad (34)$$

$$\frac{\partial c_t}{\partial P_g} + \lambda(\frac{\partial P_L}{\partial P_{gi}} - 1) = 0 \quad (35)$$

$$\frac{dc_i}{dP_{gi}} + \lambda(\frac{\partial P_L}{\partial P_{gi}} - 1) = 0 \quad (36)$$

$$b_i + 2a_i P_{gj} + 2\lambda \sum_{i=1}^{n_g} B_{ij} P_{gj} = \lambda \quad (37)$$

$$(\frac{a_i}{\lambda} + B_{ii}) P_{gj} + \sum_{\substack{j=1 \\ j \neq i}}^{n_g} B_{ij} P_{gj} = \frac{1}{2}(1 - \frac{b_i}{\lambda}) \quad (38)$$

As B_{ij}=0,

$$(\frac{a_i}{\lambda} + B_{ii}) P_{gj} = \frac{1}{2}(1 - \frac{b_i}{\lambda}) \quad (39)$$

$$(\frac{2a_i}{\lambda} + 2B_{ii}) P_{gj} = (1 - \frac{b_i}{\lambda}) \quad (40)$$

$$P_{gi} = \frac{\lambda - b_i}{2a_i + 2B_{ii}\lambda} \quad (41)$$

From (3.36),

$$\text{i.e.,} \frac{\partial L}{\partial P_D} = 0 \quad (42)$$

$$-\frac{\partial B_t}{\partial P_D} + \lambda = 0 \quad (43)$$

$$\frac{dB_t}{dP_D} = \lambda \quad (44)$$

From the gradient method,

$$\Delta\lambda^{(k)} = \frac{\Delta p^{(k)}}{\sum \frac{1}{2a_j}} \quad (45)$$

Where,

$$\Delta p^{(k)} = P_D + P_L^k - \sum_{i=1}^{n_g} P_i^k \quad (46)$$

$$\lambda^{(k+1)} = \lambda^{(k)} + \Delta\lambda^{(k)} \quad (47)$$

Assuming the initial value for λ, the numerical solution is determined using the gradient method,. To get the values of schedules Pgi and that of Pdj using the equations (41). Kron's formula is used to calculate the real power loss is calculated. And then after sufficient accuracy of Δλ is obtained, then the schedules are found using (44) and (45).

4. Simulation

Figure 1 shows an optimal power flow diagram of an IEEE 30 bus system with using of power world simulator. The market clearing price of the real power flow is determined. This power flow is very economic with given line constraints. Table 1 shows the MW Marginal Cost at optimal power flow

Here the black colour horizontal lines represents buses and they are interconnected with transmission lines, through which the supply can be distributed by creating loops(Loop Flow) and they are denoted with arrow marks. Loads and generators are connected to the buses

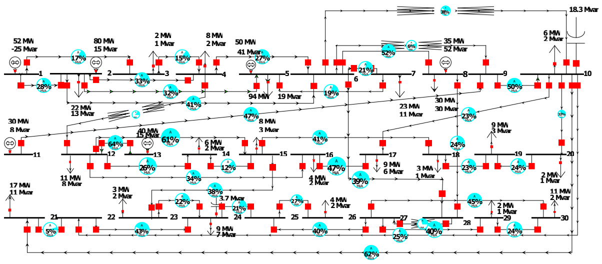


Figure 1. Simulation diagram.

Table 1. Load forecasting table

Time (Hours)	Load (MW)	Avg. Bus Marginal cost (Rs/MWh)	Total Cost*10^3(Rs/MWh)
0:00-1:00	150	81.72	20.7001
1:00-2:00	140	72.40	19.930
2:00-3:00	120	37.85	18.755
3:00-4:00	135	66.44	19.565
4:00-5:00	150	81.72	20.700
5:00-6:00	170	93.60	22.507
6:00-7:00	180	96.55	23.454
7:00-8:00	210	144.97	27.340
8:00-9:00	220	159.05	28.912
9:00-10:00	240	181.54	32.527
10:00-11:00	250	214.72	34.510
11:00-12:00	255	224.49	35.596
12:00-13:00	260	224.88	36.698
13:00-14:00	260	224.88	36.698
14:00-15:00	255	224.49	35.596
15:00-16:00	270	268.99	39.013
16:00-17:00	270	268.99	39.013
17:00-18:00	255	224.49	35.596
18:00-19:00	240	181.54	32.527
19:00-20:00	230	181.54	30.699
20:00-21:00	220	159.05	28.912
21:00-22:00	180	96.55	23.454
22:00-23:00	150	81.71	20.712
23:00-0:00	130	67.68	19.340

as per the data, their output will be shown above the load or generator. The percentage in the pie chart in between the transmission line represents rate of flow through the transmission line. The colour of the pie chart is important to know the performance of the system.

Colour indications:

- Blue – No congestion.
- Orange – Congestion may occur.
- Red – Congestion occured.

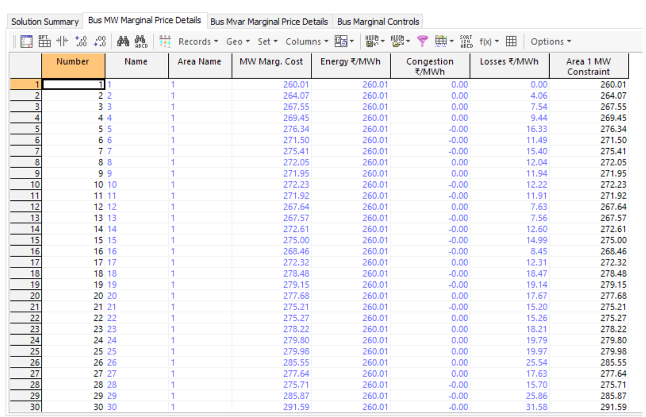
Capacitor was used in the system as shown in the simulation figure this is to inject reactive power at that bus so that the voltage drop will be decreased and the transmission line will not be effected by congestion.

Figure 2 shows the market clearing price that is the MW marginal. Cost, also its shows the losses across each bus and also price for those losses are also included. In the case no congestion occurred so it was shown as 0 if it is congested, losses and cost will increase depends upon number of lines congested

4.1 Load Forecasting (for 24 hours)

The below table shows the load variations of each 1 hour for 24 hours and also it shows the average bus marginal cost and the total final cost for that corresponding load variations. These load variations made with reference of the daily load curve for the real time power system and the bus marginal cost, total final cost is obtained with of help of this software power world simulator. The load variation in between the range of 130MW to 270MW which is shown in table 1.

The graph shown in Figure 3 drawn between the Load & average bus marginal cost. This curve shows the total cost obtained in each 1 hour of load variation. This graph represents with the variation of the load the increase in market clearing price. Here it is clearly shown that at increasing demand the market clearing price also increases. Load & total cost curve is shown in Figure 4.



Solution Summary | Bus MW Marginal Price Details | Bus Mvar Marginal Price Details | Bus Marginal Controls

Records Geo Set Columns Options

	Number	Name	Area Name	MW Marg. Cost	Energy ₹/MWh	Congestion ₹/MWh	Losses ₹/MWh	Area 1 MW Constraint
1	1	1	1	260.01	260.01	0.00	0.00	260.01
2	2	2	1	264.07	260.01	0.00	4.06	264.07
3	3	3	1	267.55	260.01	0.00	7.54	267.55
4	4	4	1	269.45	260.01	0.00	9.44	269.45
5	5	5	1	276.34	260.01	-0.00	16.33	276.34
6	6	6	1	271.50	260.01	-0.00	11.49	271.50
7	7	7	1	275.41	260.01	-0.00	15.40	275.41
8	8	8	1	272.05	260.01	0.00	12.04	272.05
9	9	9	1	271.95	260.01	0.00	11.94	271.95
10	10	10	1	272.23	260.01	-0.00	12.22	272.23
11	11	11	1	271.92	260.01	-0.00	11.91	271.92
12	12	12	1	267.64	260.01	0.00	7.63	267.64
13	13	13	1	267.57	260.01	-0.00	7.56	267.57
14	14	14	1	272.61	260.01	-0.00	12.60	272.61
15	15	15	1	275.00	260.01	-0.00	14.99	275.00
16	16	16	1	268.46	260.01	-0.00	8.45	268.46
17	17	17	1	272.32	260.01	0.00	12.31	272.32
18	18	18	1	278.48	260.01	-0.00	18.47	278.48
19	19	19	1	279.15	260.01	-0.00	19.14	279.15
20	20	20	1	277.68	260.01	0.00	17.67	277.68
21	21	21	1	275.21	260.01	-0.00	15.20	275.21
22	22	22	1	275.27	260.01	0.00	15.26	275.27
23	23	23	1	278.22	260.01	0.00	18.21	278.22
24	24	24	1	279.80	260.01	0.00	19.79	279.80
25	25	25	1	279.98	260.01	0.00	19.97	279.98
26	26	26	1	285.55	260.01	0.00	25.54	285.55
27	27	27	1	277.64	260.01	0.00	17.63	277.64
28	28	28	1	275.71	260.01	-0.00	15.70	275.71
29	29	29	1	285.87	260.01	-0.00	25.86	285.87
30	30	30	1	291.59	260.01	-0.00	31.58	291.59

Figure 2. Result obtained from simulator.

4.2 Generator Outage

The above Figure 5, shows the IEEE 30 bus system at the time of generator outage. It is observed that the generator at bus number 8 is made open using the circuit breakers. After opening the circuit breakers, a generator outage is created in the system. Here the generator of 35MW of capacity is made out of service in the system. When the system is made to run and OPF analysis is done, a transmission which is located between the bus 6 and 8 gets overloaded.

Thus, we can observe that congestion occurs during generator outages. The congestion in this transmission line is 130%. The table 2 shows the comparison of marginal costs between the reference system model without congestion and at the time of generator outage i.e., during congestion. We also observe that there is a drastic increase in marginal cost at bus number 8 due to generator outage and a notable increase in marginal costs at other buses.

The marginal cost at bus 8 is increased from 272.05 Rs/MWh to 1047.5 Rs/MWh.

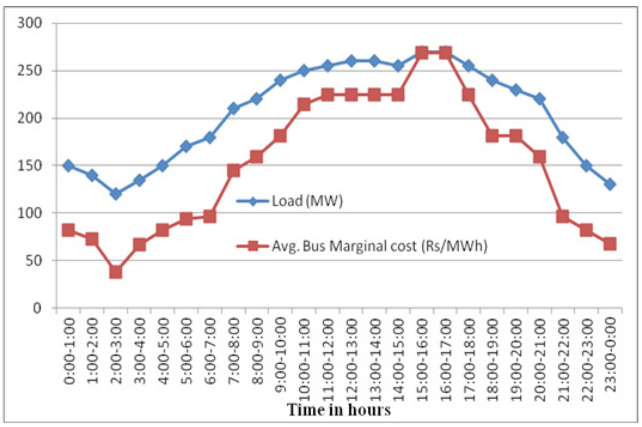


Figure 3. Load and average bus marginal cost graph.

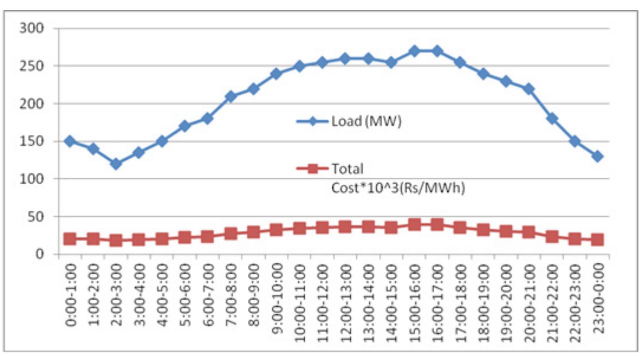


Figure 4. Load and total cost curve.

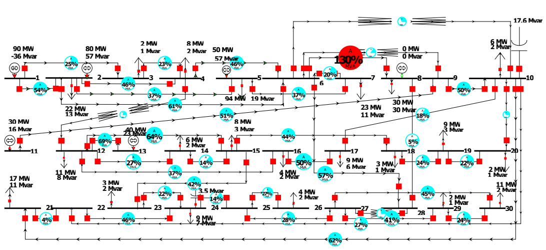


Figure 5. Simulation diagram (Generator Outage).

4.3 Increase in Load

The IEEE 30 bus system during the time of sudden increase in load. The load at bus 23 is 3.2 MW before the increase. Finally the load is increased to 23.2 MW i.e., 7.25 times the previous value. After the increase in load, the system is made to run and OPF analysis is done. After doing this, we can observe that the transmission line which is located between the bus 15 and 23 is overloaded. Thus, we can observe that congestion occurs during the time of drastic increase in load. The congestion in this transmission line is 110%. Also, we observed that the transmission line between the bus 12 and 15 is near to congestion i.e., 84%. Table 3, shows the comparison of marginal costs of reference model without congestion and at the time of increase in load i.e., during congestion. The marginal costs are drastically increased in buses23,24,25 and 26 and notable increase in other buses. A very drastic increase can be observed at bus 23 which is raised from 278.22 Rs/MWh to 951.65 Rs/MWh. The marginal cost at bus 24 is increased from 279.8 Rs/MWh to 621.74 Rs/MWh, the marginal cost at bus 25 is increased from 279.98 Rs/MWh to 515.47 Rs/MWh and the marginal cost at bus 26 is increased from 285.55 Rs/MWh to 527.09 Rs/MWh.

4.4 Line Outage

The marginal cost of the line outage is shown table 4. The voltage variations are listed in table 5. Total cost of the whole IEEE 30 bus system is compared during congestion and after reducing the congestion is listed in table 6. The total cost increased greatly during congestion time. During line outage, the total cost is increased to 42.96102*10^{3} Rs/MWh. During generator outage, the total cost is increased to 58.42606*10^{3} Rs/MWh. During the time of sudden increase in load, the total cost raised to 49.97956*10^{3} Rs/MWh. After doing necessary management to decrease the congestion i.e., using switched shunt capacitor and adding new transmission line congestion is reduced. For both line outage and generator outage cases, a switched shunt is used to reduce the congestion.

Table 2. MW Marginal Cost (Generator Outage)

BUS No.	MW Marginal Cost (Rs/MWh)		BUS No.	MW Marginal Cost (Rs/MWh)	
	Generator Outage (Congestion)	After Reducing Congestion		Generator Outage (Congestion)	After Reducing Congestion
1	380.01	380.01	16	416.09	401.26
2	391.38	391.34	17	426.26	407.91
3	397.94	397.48	18	440.04	417.14
4	402.6	402.01	19	440.77	418.37
5	411.68	411.85	20	437.93	416.19
6	405.33	407.08	21	437.29	412.73
7	411.12	412.16	22	447.26	412.86
8	1047.5	411.26	23	458.57	416.96
9	419.31	407.62	24	485.87	420.14
10	427.56	408.06	25	571.34	421.87
11	418.69	407.5	26	584.94	430.68
12	413.22	399.77	27	617.21	418.98
13	412.62	399.63	28	664.94	415.74
14	425.87	407.48	29	640.4	432.18
15	434.74	411.47	30	656.67	441.37

Table 3. MW Marginal cost (Load increase)w

BUS No.	MW Marginal Cost (Rs/MWh)		BUS No.	MW Marginal Cost (Rs/MWh)	
	Load Increase At Bus 23	After Reducing Congestion		Load Increase At Bus 23	After Reducing Congestion
1	297.6	260.01	16	256.84	271.24
2	306.09	266.09	17	324.45	276.53
3	306.47	270.10	18	223.96	281.74
4	308.97	272.67	19	268.85	282.91
5	324.95	279.20	20	290.69	281.70
6	325.51	275.48	21	381.55	279.77
7	327.74	279.01	22	441.12	279.59
8	329.04	276.12	23	951.65	279.39
9	342.69	276.90	24	621.74	282.65
10	352.77	276.98	25	515.47	282.88
11	342.09	278.14	26	527.09	288.37
12	222.46	270.16	27	446.38	280.65
13	223.96	270.08	28	350.32	279.83
14	179.79	274.92	29	462.25	288.85
15	145.12	277.39	30	473.34	294.53

Table 4. MW Marginal Cost (Line Outage)

BUS No.	MW Marginal Cost (Rs/MWh)		BUS No.	MW Marginal Cost (Rs/MWh)	
	Line Outage (During Congestion)	After Reducing Congestion		LINE Outage (During Congestion)	After Reducing Congestion
1	260.01	260.01	16	269.7	269.51
2	264.1	264.08	17	271.91	271.76
3	267.78	267.7	18	1292.66	290.42
4	269.74	269.64	19	1329.97	295.43
5	276.31	276.28	20	1333.68	295.92
6	271.46	271.37	21	274.41	274.21
7	275.38	275.31	22	274.75	274.5
8	271.98	271.92	23	282.08	280.96
9	271.24	271.16	24	281.12	280.49
10	271.19	271.07	25	280.7	280.32
11	271.19	271.14	26	286.33	285.87
12	269.08	268.92	27	277.97	277.76
13	268.92	268.84	28	275.78	275.64
14	275.52	274.92	29	286.27	285.98
15	280.67	279.27	30	292.04	291.7

Table 5. Voltage variations (Line from 10 to 20 Outage)

Congested Buses	Voltage During Congestion (Pu)	Voltage After Reducing Congestion (Pu)
15	0.9503	0.95566
18	0.91931	0.93763

But in the case of sudden increase in load, a new transmission line is used to reduce the congestion. These two things increases the p.u voltage levels at buses where there is a heavy drop in voltage and reduces the congestion and total cost.

Therefore, after reducing the congestion the total cost of line outage is reduced to 42.47929*10^3 Rs/MWh, the total cost is reduced to 48.64309*10^3 Rs/MWh for generator outage and finally the total cost for sudden increase in load is reduced to 47.83195*10^3 Rs/MWh.

Table 6. Total Cost Comparisons

During Congestion	Total Cost*10^3 (Rs/Mwh)	After Reducing Congestion	Total Cost*10^3 (Rs/Mwh)
Line Outage	42.96102	Line Outage	42.47929
Generator Outage	58.42606	Generator Outage	48.64309
Increase in Load	49.97956	Increase in Load	47.82645

5. Conclusion

In this paper, the market clearing price was calculated and it's variations due to various constraints were shown in this project. The whole analysis has been done on an IEEE 30 bus system. The reference data for doing analysis has been taken from IEEE papers. This has been used as reference for further study of optimal power flow analysis, congestion, and for reducing the congestion. Since in the basic case, as there is no congestion both market clearing price and locational marginal price both are same. OPF analysis has been done using LP method in power world simulator to find the marginal price of the system. As this software tool is more feasible to use, the analysis has been done very easily. The model clearly shows the outputs of generators and loads after running the system. As we know that, the main aim of OPF is to minimize the total cost of the generating system. So, this analysis clearly gives the clearing prices of the system. Further, load forecasting has been done using the OPF analysis. Short-term load forecasting has been done i.e., for one day with 1 hour interval of time. From this analysis it has been observed that, with the increase in load both the average marginal cost and total cost also increased.

Further congestion and congestion management was done on the system by considering three cases. As we know that, congestion occurs when the line limits gets violated i.e., during overload condition. They are transmission line outage, generator outage and increase in load. It has been observed that the marginal costs are increased drastically violating the limits in the system. To reduce the congestion a shunted capacitors and a new transmission lines are been used. For this system, it has been observed that a heavy voltage drop occurred in the lines where congestion occurred. Depending on the requirement a capacitor or a new transmission line was used to reduce the value of congestion. From the analysis, a table has been prepared comparing the marginal costs during congestion and after reducing the congestion. It has been observed that the marginal costs and total costs are greatly reduced.

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