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Computation and Analysis of Market Clearing Price for A Deregulated Power Market

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Abstract:

This paper focuses on implementing power system optimization for forecasting market prices in deregulated electricity markets. 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. In order to determine the optimal power flow, it is necessary to know about the dispatch schedule of power generators with low cost by satisfying the system constraints like real and reactive power. In the recent energy trading scenario, determining the market clearing price place a vital role. The marginal costs are analysed during congestion on the power system by considering three cases viz. line contingency, generator contingency and increase in load. Power World Simulator is used for simulation of the IEEE 30-bus system for optimal power flow and practical analysis. By employing linear programming method, the effect of marginal cost is observed with and without congestion.

Keywords:

Optimal Power Flow (OPF), Deregulated Power Market (DPM), Market Clearing Price (MCP), Contingency;

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1. INRODUCTION

The efficient and optimum economic operation and planning of electric power generation systems have always occupied an important position in the electric power industry. The optimal power flow[1] techniques are applied to scheduling both real and reactive power sources, as well as establishing tap positions for transformers and phase shifters. With the growth of non-utility participants, the increasing requirement for access to transmission has come a desire to introduce a degree of economic competition into the market for electric energy.

With multiple parties in the bulk power system new arrangements are required. A world with a transmission-operation entity required to provide access to many parties, both utility and non-utility organizations. This entity has the task of developing operating schedules to accomplish the deliveries scheduled in some optimal fashion within the physical constraints of the system, while maintaining system reliability and security.

Tackling network congestion is one of the challenging issues of the de-regulated era. Transmission network provides the path through which transactions are made in a power market. But each transmission network has its own physical and operating limits like line flow limits, bus voltage magnitude limits and more. The power injection and withdrawal configuration should be such that no limit gets violated. If the network is operated beyond these limits, it may even result in the entire system blackout. Therefore, any arbitrary set of transactions can't be organized on the power network. This has given rise to a new problem under the restructured power system environment, referred to as congestion management. The purpose of congestion management is to make necessary corrections in order to relieve congestion. In deregulated power systems, transmission networks are available for third party access to allow power wheeling. In such an environment, the ancillary services are no longer treated as an integral part of the electric supply. They are unbundled and priced separately and system operators may have to purchase ancillary services from ancillary service providers.

The Locational Marginal Pricing (LMP)[2,3] mechanism is one of the most commonly employed tools for market settlement in the deregulated power system environment. The calculation of LMPs implicitly involves congestion management. Compared to other approaches of congestion management, the LMP approach has found very wide acceptance throughout the world due to its inherent efficiency in the network capacity allocation.A market-clearing price is the price of a good or service at which quantity supplied is equal to quantity demanded, also called the equilibrium price. If the sale price is higher than the market-clearing price, then supply will exceed demand and a surplus inventory will build up over the long run.

2. Problem Formulation

Consider a system with N supply bit function and M load consumers. Let the bid function generator for the i[th] generator be

$$C_i(P_{gi}) = a_i P_{gi}^2 + b_i P_{gi} + c_i \qquad (2.1)$$

And the consumer benefit function for the j[th] load be

$$Bf_i(P_{di}) = \alpha_j P_{di}^2 + \beta_i P_{di}^2 + \lambda_i \qquad (2.2)$$

The objective of the pool market operator is to maximize the social welfare function subject to power balance constraint

$$\sum_{i=1}^{N} (P_{gi}) = \sum_{j=1}^{N} (P_{gj}) \qquad (2.3)$$

Hence the augmented objective function for unconstrained optimization is

$$L = \sum_{i=1}^{N} C_i(P_{gi}) - \sum_{i=1}^{M} Bf_i(P_{di}) - \lambda\left(\sum_{i=1}^{N}(P_{gi}) - \sum_{j=1}^{M}(P_{di})\right) \qquad (2.4)$$

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

$$\frac{dL}{d\lambda} = \frac{dC_i}{d\lambda} = 0 \forall i \qquad (2.5)$$

$$\frac{dL}{d\lambda} = \frac{dBf_i}{dP_{di}} = 0 \forall j \qquad (2.6)$$

Equations (2.5) and (2.6) imply that for optimality, the incremental cost of all the generation as well as the incremental utility function of all the generation and the incremental utility function of all loads must be equal to λ. The incremental cost for generators can also be written as

$$\frac{dC_i}{dP_{gi}} = \lambda = b_i + 2a_i P_{gi}, i \in N \qquad (2.7)$$

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

$$b_i + 2a_i P_{gi} = b_k + 2a_k P_{gk} = \lambda, i \in N \qquad (2.8)$$

For a particular k € N

$$P_{gi} = \frac{b_k + 2a_k P_{gk} - b_i}{2a_i} \forall i \in N \qquad (2.9)$$

Let the total demand be given as P_R

$$\sum_{i=1}^{N}(P_{gi}) = \sum_{i=1}^{N}\left(\frac{b_k + 2a_k P_{gk} - b_i}{2a_i}\right) = P_R \qquad (2.10)$$

Define two parameters A and B,

$$A = \sum_{i=1}^{N} \frac{1}{a_i} \qquad (2.11)$$

$$B = \sum_{i=1}^{N} \frac{b_i}{a_i} \qquad (2.12)$$

and (2.9) can be written as

$$(b_k + 2a_k P_{gk})A = 2P_R + B \qquad (2.13)$$

Where $b_k + 2a_k P_{gk} = \lambda$ (2.14)

Hence the value of λ is obtained as

$$\lambda = \frac{(2P_R + B)}{A} \tag{2.15}$$

Similarly with the demand offers, it can be shown that

$$\lambda = \frac{(2P_d + B_d)}{A_d} \tag{2.16}$$

Solving (2.7) and (2.8), we have

$$P_R = \frac{AB_d - BA_d}{2(A_d - A)} \ \& \ \lambda = \frac{B_d - B}{(A_d - A)} \tag{2.17}$$

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

$$P_{gi} = \frac{\lambda - b_i}{2a_i} \ \& \ P_{di} = \frac{\lambda - \beta_i}{2\alpha_i} \tag{2.18}$$

The objective function of generator is calculated using the gradient method. By substituting λ**,** the gradient of λ is found with respect to the control variables. The gradient will give the direction of maximum increase in the cost function as a function of the adjustments in each of the variables. To decrease the objective function, it is required to move in the direction of the negative of the gradient. The gradient method gives no indication how far along the negative gradient direction it is required to move. The gradient method should be repeated until the gradient itself becomes sufficiently close to the zero vector, indicating that all conditions for the optimum have been reached.

3. LINEAR PROGRAMMING METHOD

The gradient and Newton methods of solving an OPF suffer from the difficulty in handling inequality constraints. Linear programming, however, is very adept at handling inequality constraints as long as the problem to be solved is such that it can be linearized without loss of accuracy. The power flow equations could be for the DC representation, the decoupled set of AC equations or the full AC power flow equations. The choice will affect the difficulty of obtaining the linearized sensitivity coefficients and the convergence test used. In the formulation below, it is shown that how the OPF can be structured as an LP. First, tackle the problem of expressing the nonlinear input-output or cost functions as a set of linear functions. Let the cost function be Fi(P_i). Approximate this nonlinear function as a series of straight-line segments. The three segments will be represented as P_{i1}, P_{i2}, P_{i3}, and each segment will have a slope designated: S_{i1},S_{i2},S_{i3}. Then the cost function itself is

$$F_i(P_i) = F_i(P_i^{\min}) + S_{i1}P_{i1} + S_{i2}P_{i2} + S_{i2}P_{i3} \tag{3.1}$$

$0 \le P_{ik} \le P^{+}_{ik}$ for k=1,2,3

$$P_i = P_i^{\min} + P_{i1} + P_{i2} + P_{i3} \tag{3.2}$$

The cost function is now made up of a linear expression in the P_{ik} values. In the formulation of the OPF using linear programming, we only have the control variables in the problem. We do not attempt to place the state variables into the LP, nor all the power flow equations. Rather, constraints are set up in the LP that reflect the influence of changes in the control variables only. The control variables will be limited to generator real power, generator voltage magnitude and transformer taps. The control variables will be designated as the *u* variables . The next constraint to consider in an LPOPF are the constraints that represent the power balance between real and reactive power generated and that consumed in the loads and losses. The real power balance equation is:

$$P_{gen} - P_{load} - P_{loss} = 0 \tag{3.3}$$

The loss term here represents the $(I)^2$*R losses in the transmission lines and transformers.

4. MODELLING OF IEEE-30 BUS SYSTEM

The market clearing price of the system can be found by implementing linear programming method by optimizing the values of proposed IEEE-30 bus system. The proposed work discusses the concept of calculation and analysis of market clearing price for a deregulated power market using linear programming method [4-8]. The standard values of IEEE-30 bus system are taken from the data shaeets. The 30 bus system is the representation of 6 generators, 37 transmission lines, 4 transformers and 21 loads as shown in fig 4.1. For the each contingency Newton Raphson load flow method has been employed for identifying the results.

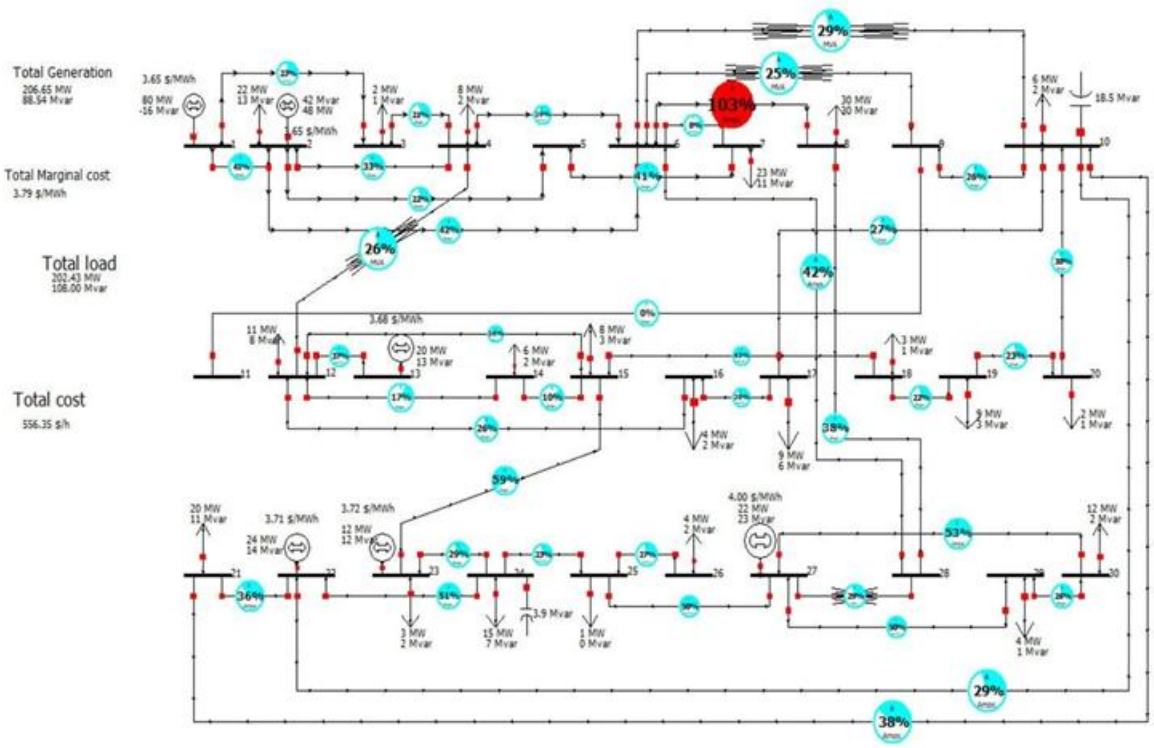


Figure 4. 1 Connection diagram of IEEE-30 using power world simulator bus system after running OPF

Generator No.	Generator data after running optimal power flow				
	Generated MW	Generated MVAR	a_i	b_i	c_i
1	80	-15.96	0.26013	138.074	0
2	47.93	41.68	1.2139	121.3975	0
3	20	13.12	4.3356	69.37	0
4	24.47	14.4	0.00834	225.4525	0
5	12	12.28	1.7342	208.11	0
6	22.26	23.02	1.7342	208.11	0

Table 4. 1 Healthy generator data after running OPF

Table 4.1 shows the general healthy systems generator data where every parameter is under limits and system is not violating any of the system limits i.e; voltage limit, temperature limit or stability limit.

5. SIMULATION RESULTS AND ANALYSIS

The method, linear programming for optimal operation of power system is tested on IEEE-30 bus system for its effectiveness. The proposed approach has been applied to solve the problem in IEEE-30 bus system. The data pertaining to the generator, transmission line and generator cost coefficients have been used to solve power flow problems using Power World Simulator.

5.1 CONTINGENCY ANALYSIS

5.1.1 Generator outage contingency

In IEEE-30 bus system contingency is created on each generating units and full security constrained optimum power flow (SCOPF) is carried out. For all the six generators, MW marginal costs are compared at the time of contingencies. It is noticed that the bus 8 is most sensitive to generator contingencies. It is observed that there are total 7 violations as shown in table 5.1 and particularly 3 violations due 6th generator outage i.e; increase in branch MVA from bus 6-8, bus low p.u voltages at buses 29 and 30. MW marginal cost at bus 8 has been increased drastically from 347.544 Rs/MW to 40455 Rs/MW due to 6th generator contingency and considerable increase at buses 25 to 30 and considerable increase and decrease in MW marginal cost at other buses.

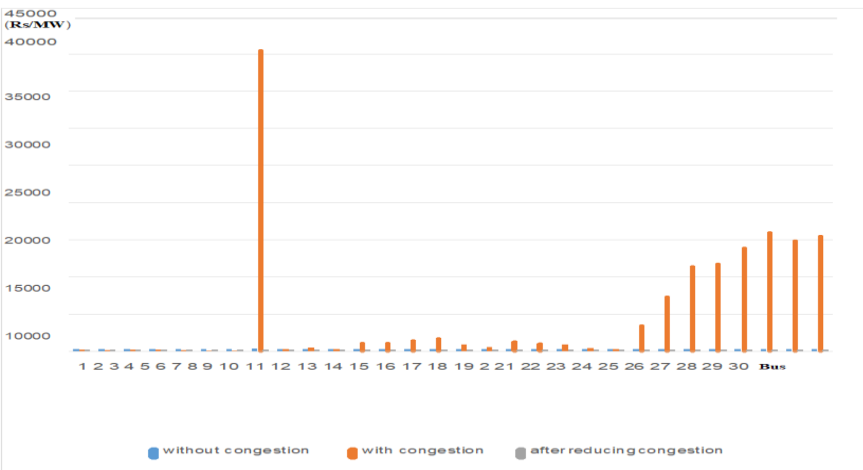
Generator No.	Violations	Max Bus MVA%
1	1	100
2	0	-
3	1	101.3
4	1	102.9
5	1	101.6
6	3	113

Table 5.1 Violations data for various generators outage

To reduce the MW marginal cost, shunted capacitor can be used. There are many methods for optimal location of capacitors in power system. An attempt is made for reducing MW marginal cost by using discrete capacitor location which supplies reactive power. A capacitor is placed at bus 8 since it is more effective to generator contingencies. The results are positive and there is decrease in MW marginal cost at bus 8 and considerable decrease at buses 25 to 30.

The MW marginal cost is decreased from 40455.06Rs/MW to 236.44Rs/MW at bus 8 and at buses 25, 26, 27, 28, 29, 30 i.e.; from 11392.4Rs/MW to 238.35Rs/MW, 11762.2Rs/MW to 238.25Rs/MW, 13889Rs/MW to 237.71Rs/MW, 15945.82Rs/MW to 236.44Rs/MW, 14868.19Rs/MW to 237.71Rs/MW, 15468Rs/MW to 237.71Rs/MW respectively.

Graph 5.1 describes the MW marginal cost comparison at every bus during three cases i.e before congestion, during congestion and after reduction in congestion. It is observed that there is drastic increase in MW marginal cost at bus 8 as said before and decrease in MW marginal cost after placing a capacitor.



Graph 5.1 MW marginal cost comparison for generator contingency

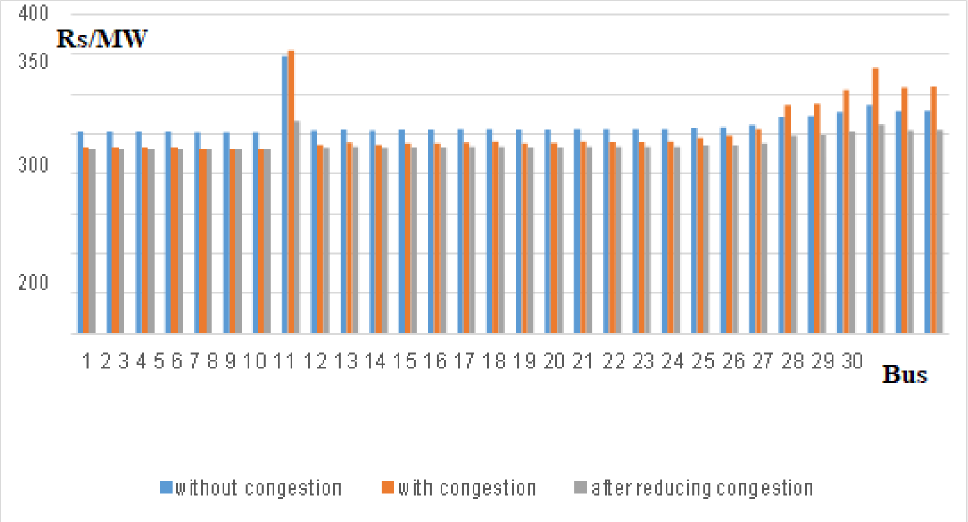
5.1.2 Transmission line outage contingency

In IEEE 30 bus system contingency is created on transmission line and full Security Constrained Optimum Power Flow (SCOPF) is carried out. MW marginal costs are compared at the time of contingencies.

It is noticed that the MW marginal cost at bus 8 is increased and considerable increase at buses 25 to 30. There are total 23 violations and particularly 3 violations at bus 8 and 2 violations at buses 20,29,30 respectively. MW marginal cost at bus 8 has been increased from 347.544 Rs/MW to 354.58 Rs/MW. Increase in MW marginal cost at buses 25 to 30 due to first transmission line contingency and there is not much effect on MW marginal cost due to second contingency.

To reduce MW marginal cost the shunted capacitor is placed and there is decrease in MW marginal cost at buses 25, 26, 27, 28, 29, 30 i.e; from 286.58Rs/MW to 247.85Rs/MW, 287.97Rs/MW to 248.49Rs/MW, 305.32Rs/MW to 253.56Rs/MW, 333.07Rs/MW to 261.80Rs/MW, 308.09Rs/MW to 254.19Rs/MW, 309.48Rs/MW to 254.83Rs/MW respectively.

Graph 5.2 describes about the MW marginal cost comparison at each and every bus before congestion, during congestion and after reducing congestion of transmission line contingency.



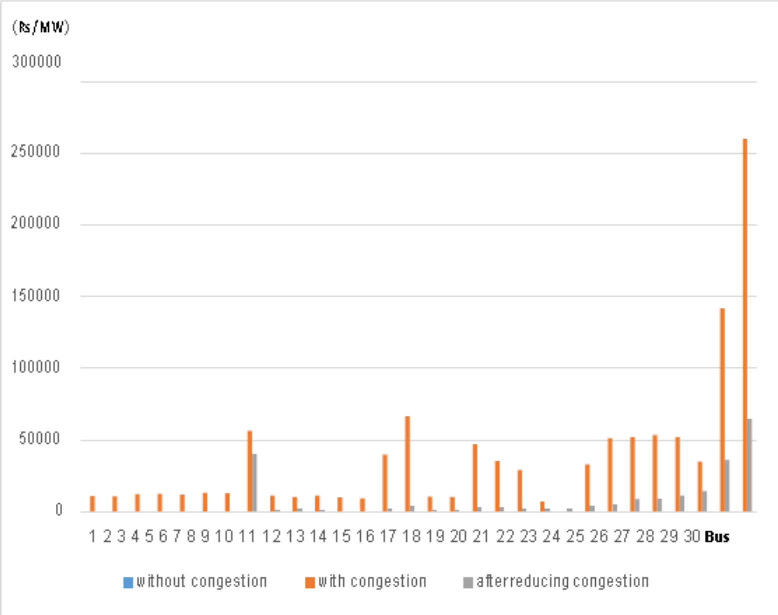
Graph 5.2 MW marginal cost comparison for transmission line contingency

5.1.3 Contingency due to Overload

The total generation capacity of all generator units is 315MW and the load is set to 320MW i.e increase in load. After the increase in load, the system is made to run and OPF analysis is done. After doing this, it is observed that the transmission lines which are located between the bus 27 and 30, 27 and 29, 15 and 23, 22 and 24 are overloaded. Thus it is observed that congestion occurs during the time of drastic increase in load. The congestion in this transmission line is 294%, 224%, 141%, 128% respectively. The comparison of marginal costs is made using reference model without congestion at the time of increase in load i.e. during congestion and after adding transmission line between buses 15 and 23, 22 and 30.

It is observed that there is drastic decrease in MW marginal cost at all the buses except 8, 14, 15, 21, 22. By adding transmission line between buses 15 and 23, 22 and 30 at the time of congestion, there is maximum decrease at bus 30 and 29 i.e; from 141946.69Rs/MW to 36234.36Rs/MW at bus 29 and from 260258.42Rs/MW to 65002.64Rs/MW at bus 30 since load is increased at buses 15 and 30.

Graph 5.3 describes about the MW marginal cost comparison during congestion and after reducing the congestion of contingency due to overload.



Graph 5.3 MW marginal cost comparison of contingency due to overload

6. CONCLUSION

In this paper, the market clearing price is calculated and its variations due to various constraints are shown. The whole analysis is done on an IEEE-30 bus system. Since in the normal condition as there is no congestion both market clearing price and locational marginal price are same. OPF analysis has been done using LP method using Power World Simulator to find the marginal price of the system. The model clearly shows the outputs of generators and loads after running the system. As it is known that, the main aim of OPF is to minimize the total cost of the generating system, this analysis clearly gives the clearing prices of the system. From this analysis it is observed that, with the increase in load both the average marginal cost and total costs are increased.

Further congestion and congestion management are done on the system by considering three cases. They are transmission line outage, generator outage and increase in load. It is observed that the marginal costs are increased drastically, which violates the transmission line limits in the system viz, voltage limit , temperature limit and stability limit. For this system, it is observed that a heavy voltage drop occurred in the lines where congestion occurred.

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