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Impact of UPFC on Competitive Electricity Market Settlement in Deregulated Power System

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Abstract : *The operation and security management of deregulated power system with competitive electricity market environment is a typical task to the system operator due to its complexity under uncertainties. In order to enhance security level, unified power flow controller (UPFC) is proposed in this work. Under stressed conditions, the increment in market economic inefficiency is optimized with UPFC device support. The UPFC location and its parameters are controlled to minimize the total generation cost. The case studies are performed on IEEE 14-bus test system and the results validating the proposed approach for social welfare maximization in real time.*
Keywords :_Competitive electricity market, clearing mechanism, unified power flow controller, social welfare_

I. INTRODUCTION

In general the ISO solves the competitive market clearing problem to determine the generation levels and load withdrawals for every trading interval. The acceptable bids/quantities for a particular market clearing price resulting financial flows among the market participants. The objectives of any clearing mechanism are minimization of production cost or social welfare maximization. Minimization of production cost consists of two sub-optimization problems. The first one is fuel cost or real power generation cost minimization and next one is minimization of reactive power generation cost.

Typically generation of reactive power in the system depends on the functioning of reactive power compensation devices in the network and system loading level or stressed conditions. In this work, conventional market clearing mechanism is adopted in which active power dispatch and reactive power dispatches are optimized separately. The financial flows among market participants are directly proportional to physical flows in the network. The economic efficiency of market is mainly depended on transmission network support. The inability of transmission system to dispatch market driven schedule is known as congestion and in literature many congestion management schemes are found [1]. The choice may vary from country to country. As a long term solution for system security, flexible ac transmission system (FACTS) becomes one of the best solutions not only in terms of technical aspects but also in terms of economics benefits also.

II. COMPETITIVE ELECTRICITY MARKET

In a competitive market, the active power dispatch problem can be solved either in sequential or simultaneous market clearing mechanisms as explained in [2]. The market can be operated either single-sided or double-sided auction mechanisms.

2.1. Single-Sided Auction Market

In single-sided auction market, only power producers will offer their bid functions for the entire day or each trading period. The market clearing problem is a constrained active power generation cost optimization problem, and is mathematically formulated as,

Minimize $$C_t\left(P_G\right)=\sum_{i=1}^{NG}C_{t,i}\left(P_{g,i}\right) \tag{1}$$

Subjected to: $$P_G=P_D \tag{2}$$

$$P_G=\sum_{i=1}^{NG}P_{g,i} \tag{3}$$

and $$P_D=\sum_{j=1}^{NL}P_{d,j} \tag{4}$$

where

$$C_{t,i}\left(P_{g,i}\right)=a_iP_{g,i}^2+b_iP_{g,i}+c_i \tag{5}$$

2.2. Double-Sided Auction Market

In this auction markets, load representatives will also offer their bid functions for the entire day or each trading period. In literature, the objective function of double-sided auction market is also considered as social welfare [3] optimization problem. The market clearing problem is a constrained optimization problem, and is mathematically formulated as,

Maximize $$\left\{C_t\left(P_D\right)-C_t\left(P_G\right)\right\} \tag{6}$$

Subjected to: $$P_G = P_D, \tag{7}$$

$$P_G = \sum_{i=1}^{NG} P_{g,i} \tag{8}$$

and $$P_D = \sum_{j=1}^{NL} P_{d,j} \tag{9}$$

where

$$C_t\left(P_G\right) = \sum_{i=1}^{NG} C_{t,i}\left(P_{g,i}\right) \tag{10}$$

$$C_t\left(P_D\right) = \sum_{i=j}^{NL} C_{t,j}\left(P_{d,j}\right) \tag{11}$$

$$C_{t,i}\left(P_{g,i}\right) = a_i P_{g,i}^2 + b_i P_{g,i} + c_i \tag{12}$$

$$C_{t,j}\left(P_{d,j}\right) = -\left(d_j P_{d,j}^2 + e_j P_{d,j} - f_j\right) \tag{13}$$

2.3. Calculation of Reactive Power Cost

Currently in either single-sided auction or double-sided auction market, there is no separate market for reactive power dispatch. After the market settlement for active power demand, the feasibility of dispatch will be check using any conventional power flow method. With the satisfactory simulation result, the actual real power dispatch causes to known the reactive powers at each generator. From the obtained reactive powers, reactive power cost is calculated using Triangular approach [4],

$$C_t\left(Q_G\right) = \sum_{i=1}^{NG} C_{t,i}\left(Q_{g,i}\right) \tag{14}$$

where

$$C_{t,i}\left(Q_{g,i}\right) = a_{qi} Q_{g,i}^2 + b_{qi} Q_{g,i} + c_{qi} \tag{15}$$

Here a_{qi}, b_{qi} and c_{qi} are constants depending on power factor $\left(\cos\theta\right)$, and are calculated as follows:

$$a_{qi} = a_i \sin^2\theta,\ \ b_{qi} = b_i \sin\theta \text{ and } c_{qi} = c_i \tag{16}$$

It may be noted that this reactive power cost calculation can be suitably changed depending on the specific market practice. Finally, the total generation cost is the sum of the real power cost and the reactive power cost. At this stage of work, the transmission cost is ignored.

III. MARKET SETTLEMENT WITH UNCERTAINTIES

Generally, the offering strategies by the power producers will change according to the market signal like MCP and cleared quantity to maximize their profits. Since market economic efficiency is mainly depended on network support, it is required to consider various uncertainties in to account while doing market clearance. Hence, the previous section proceeds here with certain uncertainties like change in bid curve, error in forecasted demand and line outages etc. The change in financial flows due to uncertainties may leads to market economic inefficiency and further minimum social welfare. To prevent such issues, this section deals with market settlement with uncertainties. Such types of studies will give sufficient preventive and corrective actions in hand to the system operator.

3.1. Change in Bid Function

The strategic bidding is a process of change in bid functions to maximize GENCOs' profit. In a perfect competitive market, the supply curve created by aggregating generator offers should closely approximate the system marginal production cost of generation. Hence the bidding cost function treated as a continuous function and is given by a power producer *p* (or supply curve) is:

$$C_{b,i}(P_{g,i}) = a_{b,i}P_{g,i}{}^{2} + b_{b,i}P_{g,i} + c_{b,i} \tag{17}$$

where ($a_{b,i}$, $b_{b,i}$ and $c_{b,i}$) are the bid coefficients and related with the actual cost function coefficients (a_i , b_i and c_i) as follows [5]:

$$\xi_i = \frac{a_{b,i}}{a_i} = \frac{b_{b,i}}{b_i}, \text{ and } c_{b,i} = c_i \tag{18}$$

where ξ_i is the bidding parameter and represents mark-up above or below the marginal cost that a generator *i* decide to set its marginal bid in competitive market. Now, the marginal cost function will become as:

$$C_{t,i}(P_{g,i}) = \xi_i a_i P_{g,i}{}^{2} + \xi_i b_i P_{g,i} + c_i \tag{19}$$

Now the modified schedule with the change in bidding parameter by bus *p*, and MCP will determine as:

$$MCP = \frac{\left\{(1+\varepsilon)\times P_D\right\} + \sum_{i\in NG}\frac{b_i}{2a_i}}{\sum_{i\in NG}\frac{1}{2\xi_i a_i}} \tag{20}$$

$$P_{g,i} = \frac{MCP - \xi_i b_i}{2\xi_i a_i} \tag{21}$$

Once again, the complete schedule will determine as per previous section. After the market settlement, the ISO checks the feasibility of the scheduled generation by carrying out a load flow. The bidding parameter which causes to threat to the security will reject. Keeping in mind, to prevent the market abuse by power producers with their strategic bidding, the bidding coefficient range should be quantified properly and we have considered it as 0.5 to 2.

3.2. Error in Forecast Demand

The error, ε in forecasted demand may cause higher or lower to the cleared demand (quantity) at every trading hour in the day–ahead auction. The ε is considered in the range of [0 – 0.2]. The new demand on the entire system and corresponding load at bus *j* will alter as follows:

$$P_D^{new} = P_D^{base}(1+\varepsilon) \tag{21}$$

$$P_{d,j}^{new} = P_{d,j}^{base} \times (1+\varepsilon) \tag{22}$$

3.3. Line Outage

The line between buses *p* and *q* having self admittance y_{pq} is to be considered an outage, then the required modification in Y_{bus} is obtained by simply adding another line in parallel to the same line with negative admittance i.e. $-y_{pq}$. The new admittance matrix elements can also be updated as fallows.

$$Y_{pp}^{new} = Y_{pp}^{old} - y_{pq} \tag{23}$$

$$Y_{qq}^{new} = Y_{qq}^{old} - y_{pq} \tag{24}$$

$$Y_{pq}^{new} = Y_{qp}^{new} = Y_{pq}^{old} + y_{pq} \tag{25}$$

3.4. Generator Outage

After scheduling the generation as per Section – II, one of the generators is considered under outage. The generator outage is modeled as zero output power and treated as load bus. The required excessive generation on the system is going to supply by the slack bus. In the event of slack bus outage, we have considered next highest capacity generator as the slack bus.

3.5. Security Level

It is important to dispatch the market driven schedule under any perturbations without violating the any operating constraints. To identify the severity level of any contingency in the network, the Performance Index (PI) method [6] is adopted and is given by

$$PI = \sum_{l \in L} \left(\frac{f_l}{f_{l,\max}} \right)^{2x} \tag{26}$$

where L is the number of transmission lines, f is the absolute flow of line l and $f_{l,\max}$ is its MVA rating.

The higher value of PI for any operating state of the system indicates overloading of one or more transmission lines in the network. In the event of congestion in the transmission system, the ISO should take necessary preventive actions for security. The literature provided by [1] will give basic idea about existed congestion management techniques. In this paper, load curtailment technique is adopted and the required load curtailment on the system is modeled as:

$$P_D^{new} = (1-\tau) \times \sum_j P_{d,j}^{base} \tag{27}$$

where τ is the load curtailment factor (LCF) which is less than one and the reduced load will compensated by reference bus.

IV. UNIFIED POWER FLOW CONTROLLER

4.1. Static Model

Since UPFC can be used for many technical issues or application in the system hence its modelling is depended on the particular application. For better exploration on decoupled modelling of UPFC [7, 8], its application for congestion relief can be understood with the following example.

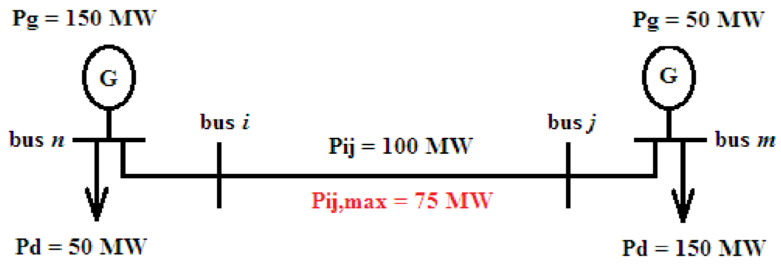

Fig. 1. Congested transmission line.

From the Fig. 1, the line connected between buses i to bus j is subjected congestion state. If that line is integrated with UPFC as shown in Fig. 2, the decoupled model and its required power injections at buses i and j are given in Fig. 3. The model modified the bus i as PV bus and bus j as PQ bus. If power direction is from bus j to i, then bus j should become PV bus and bus i should become PQ bus. The observable thing is, if the injected power is further increased to 50 MW, then the power flow will also further decreased to 50 MW in the line. So the required power control can easily be possible through this modelling.

The power extraction (i.e. reduced generation level) at *bus-i* and insertion (i.e. reduced load level) at *bus-j* should be equal for lossless UPFC operation. The reactive power generated at *bus-i* is to maintain the desired voltage by PV bus model. In order to maintain constant power factor at *bus-i*, reactive power should also modify properly.

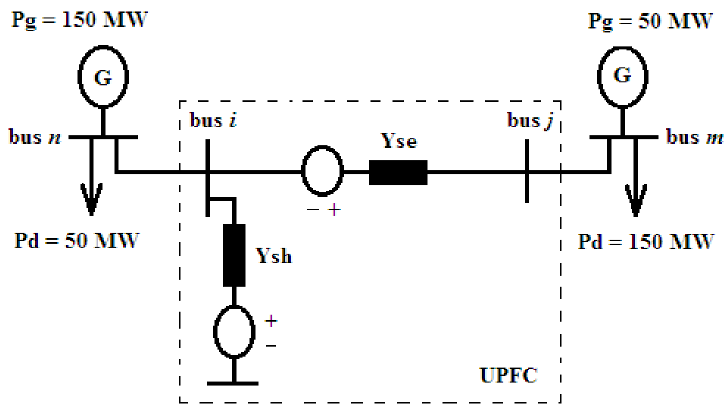

Fig. 2. UPFC in congested transmission line.

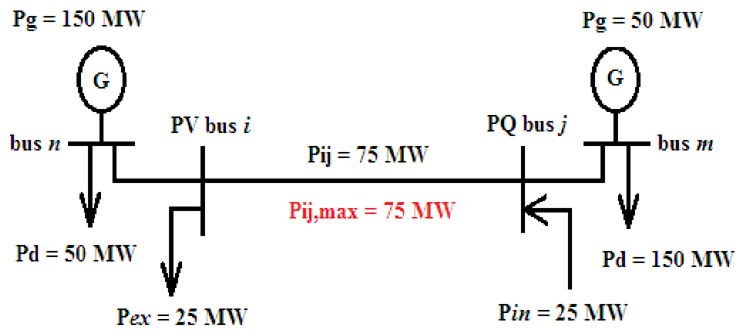

Fig. 3. Decoupled PIM of UPFC in transmission line.

If the entire complex power in line *i-j* is considered to extraction and insertion then the line flow is zero and it can be treated as outage as given by complete decoupled model of UPFC in Fig. 4.

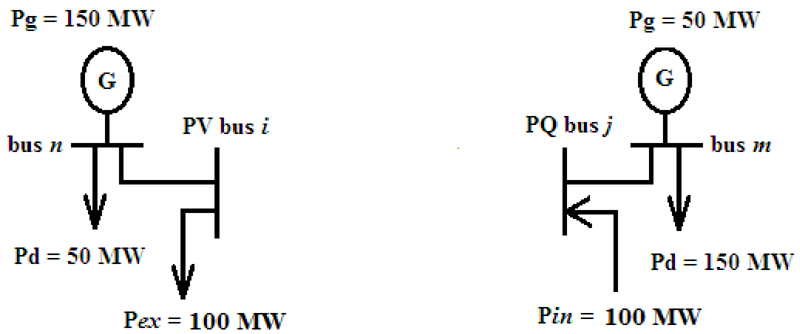

Fig. 4. Decoupled model of UPFC.

4.2. *Optimal Location*

As a long-term solution for technical issues in the system, this paper has been proposed a novel approach for UPFC location in the network. To validate UPFC function clearly during the abnormalities, the (N-1) line contingency (*i.e. also only the lines which are not incident to any generator bus in the network*) has been imposed in the network. Based on the reduced critical loading margin [9], the line was opted as a best location for UPFC installation.

4.3. *Congestion Relief with UPFC*

As explained in section B, the UPFC has been installed at its optimal interface between *bus-i* to *bus-j*. The residual powers in N-R load flow method at these buses modify with UPFC control factor τ as follows:

$$\Delta P_i = \left(P_{G,i} - P_{upfc}\right) - P_{D,i} \tag{28}$$

$$\Delta P_j = P_{G,j} - \left(P_{D,j} - P_{upfc}\right) \tag{29}$$

$$\Delta Q_j = Q_{G,j} - \left(Q_{D,j} - Q_{upfc}\right) \tag{30}$$

$$P_{upfc} + jQ_{upfc} = \tau\left(P_{D,j} + jQ_{D,j}\right) \tag{31}$$

The τ ($0 \le \tau \le 1$) will adjust up to congestion problem overcome by the network.

V. CASE STUDIES

For illustration purpose, the conventional competitive market clearing mechanism is applied to the IEEE 14-bus test system data. The complete data for this system is given in [10].

5.1. *Base Case*

The entire market schedule over 24-hour span is considered as base case. The system has a peak demand of 259MW and it will change according to load pattern illustrated in daily load curve and is given in Figure. 5.

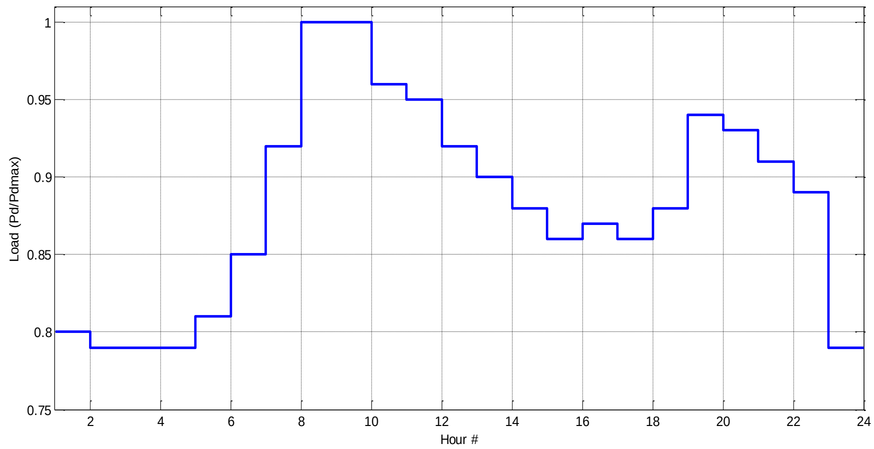

Fig. 5. Typical daily load curve.

Once market driven schedule for active power is obtained, power flow analysis is performed using NR method. The market clearing price, active power generation cost, reactive power generation cost and total generation cost at various trading hours are shown in Figures 6 – 9 respectively as base case. Fortunately, for the entire day the system does not subjected to congestion.

4.4. Uncertainty Case

The system can be subjected to uncertainties at any time during the operation. Hence in this study, we have created a stressed condition in the system by imposing a line outage of 8–9, an error of 0.2 in forecasted demand and the generator 4 with high bid parameter 2. The market settlement with all these uncertainties at peak demand is determined. The market schedule is subjected to congestion from trading hour #7 to trading hour #22. As explained in previous section, for LCF of 0.1 at all hours except hour # 8 to 10 and for LCF of 0.15, all trading hours can dispatch without congestion. The market clearing price, active power generation cost, reactive power generation cost and total generation cost at various trading hours are shown in Figures 6 – 9 respectively as uncertainty case. The observable point is increment in real power generation cost due to high MCP and in reactive power cost is due to high reactive power generation and consequently total generation cost is also increased.

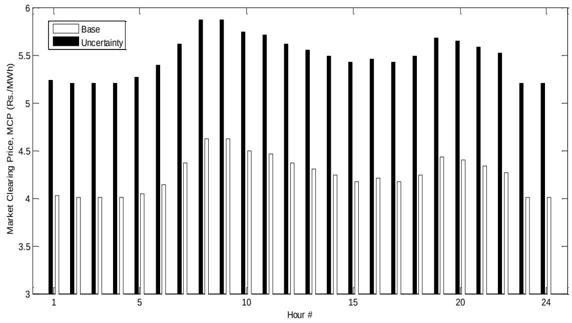

Fig. 6. MCP at various trading hours.

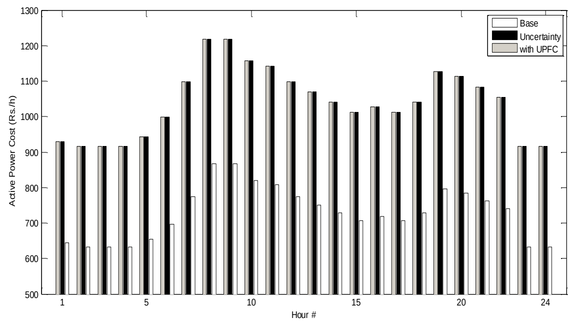

Fig. 7. Variation in active power generation cost.

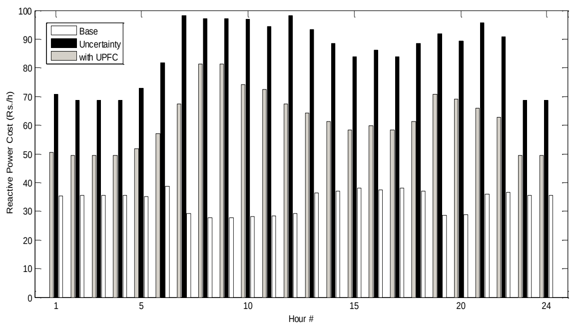

Fig. 8. Variation in reactive power generation cost.

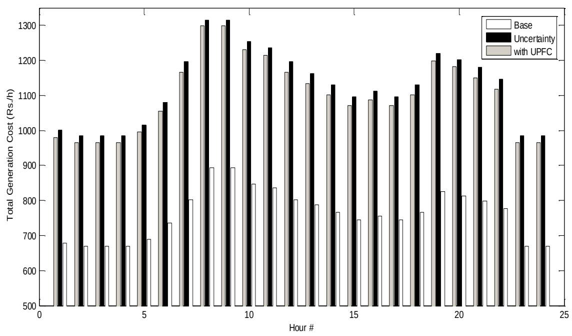

Fig. 9. Variation in total generation cost.

4.5. UPFC in Line 7 – 9

From the (N-1) line contingency analysis at peak load without uncertainties, line 7–9 outage is treated as severe contingency. The severity level is determined using PI index with x = 5. The base case power flow in line 7–9 at peak load is (30.634MW + j8.900MVAr). As explained in UPFC modelling, this power flow will be the power withdrawal at bus 7 and injection at bus 9. The bus 7 is modified as PV bus. The entire uncertainty case is simulated with UPFC. The obtained results of market economics are main focal points of this paper.

From the fundamentals, the FACTS devices are passive devices and they will not compensate active power. Due to their nature, the reactive power support are happen in the network and so the reactive power consumption is decreased even system at stressed conditions. Hence there is no change in real power generation cost but a significant decrease in reactive power cost and consequently total generation cost decrement can understood from the Figures 6 – 9 respectively.

VI. CONCLUSIONS

The paper mainly focused on reactive power compensation in the system particularly in stressed conditions. The real power generation cost increment due to market gamming with strategic bidding cannot be avoidable. On the other side the increment in reactive power generation and so cost can optimize using reactive power support. The UPFC integration in optimal location causes to reduce the reactive power consumption and so total generation cost. This reduction in production cost is termed as social welfare. In addition to the technical benefits like voltage profile increment, loss reduction, congestion relief, the economical benefits are major concern in the competitive market environment. The results on IEEE 14-bus test system are validating the proposed approach i.e., integration of UPFC for physical and financial flows optimization in real-time deregulated power system.

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