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SIMULTANEOUS CONGESTION MANAGEMENT AND COST ALLOCATION IN A SHORT-RUN MARKET MODEL*

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Abstract– This paper proposes a simultaneous approach to manage congestion, evaluate congestion cost, and to allocate this cost among consumers in a short-run market model. The proposed method consists of an iterative algorithm to search and apply a sequence of the best feasible bilateral power exchange among the generators that would optimally reduce and completely remove the congestion. The best exchanges are selected using sensitivity analysis and the AC load flow is used to apply the selected exchange on the system. Congestion cost is calculated using the change in generation cost and divided among the overloaded lines regarding the change in power flow of these lines, after applying the selected exchange. Following each exchange, the costs are allocated to consumers based on the generalized load distribution factors, which are calculated on the system operating condition. The effectiveness of the proposed approach is illustrated in two case studies on the standard IEEE 14 and 118-bus systems, and the results discussed and compared with the other methods in the paper.

Keywords– Congestion management, congestion cost allocation, generation redispatching, short-run market, pool model, restructured power system

1. INTRODUCTION

Transmission management is a key task of system operators over economic, secure, and reliable operation of the restructured power systems. Different ways of accomplishing this task have been proposed and implemented, depending upon the nature of market structures [1]. Two major issues in this task are congestion management and congestion cost allocation. A bibliographical survey of these methods has been presented in [2].

Methods of congestion management can be generally divided into two main groups: preventive and corrective methods [3]. Preventive methods are used prior to the occurrence of the congestion to facilitate the management of future congestion in the network. Definition and allocation of various transmission rights is a good example of these methods [4].Corrective methods are used to remove the occurred congestion by applying some controls such as phase shifters, tap transformers, reactive power control, FACTS devices [5, 6], redispatching generation and the curtailment of loads. These methods are normally utilized in the short-run pool type market or transmission management markets.

Generation redispatching is an applicable and accepted method to manage congestion in the short-run market models. In a modified pool model presented in [7], the generation units are allowed to have bilateral contracts with loads and sell the whole or the rest of generated power in a main energy market. Loads can also be presented with elastic or inelastic bids [8]. An unconstrained dispatch is applied to clear the market, based on coordinated bilateral contracts and submitted generator and load bids. If the

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unconstrained generation schedule violates the network constraints, the system operator will redispatch the generators considering network constraints and regulation bids to keep the system working in a more reliable condition. In this method of congestion management, the regulation bids are submitted in a transmission management market to remove congestion when the transmission lines are overloaded.

Redispatching is normally applied using an optimal power flow (OPF), formulated and solved by various classical or heuristic optimization techniques [9, 10]. The convergence and relatively slow performance of achieving accurate results are important issues in this regard. This procedure leads to an increase in total generation cost, which is considered as congestion cost and is to be recovered by consumers in a fair allocation method. Simplicity, speed, and accuracy are key issues for all these algorithms in both evaluating the congestion cost and dividing it among market participants.

2. A REVIEW OF SUGGESTED METHODS

A congestion clusters-based method has been proposed in [11] to improve the efficiency of congestion management by identifying the groups of system users according to their impact on the transmission constraints. The proposed method has been applied in [12] as a zonal congestion management approach to solve the OPF-based redispatching problem in a pool type market. In this approach, the accuracy and speed of achieving the results are strongly dependent on the decision of the operator, where regulating generators must be selected among the defined congestion clusters to remove the congestion.

Nodal pricing is an economical method which prices the congestion at each bus using the change in the short-run marginal cost obtained after redispatching. This method is very effective in operation, but it causes merchandising surplus. To modify the surplus problem of nodal pricing, an Aumann-Shapley pricing method has been proposed in [13] that combines the concepts of both short-run marginal cost and the game theory. However, this method requires complicated and long-time calculations to recover the exact amount of congestion cost.

In the other approaches, the congestion cost is calculated after redispatching and is allocated to consumers using various allocation methods. In the uplift method, the congestion cost may be shared by consumers on a pro-rata basis. This is not quite fair and does not give proper signals to consumers. In use-based allocation, congestion cost is initially divided among the overloaded lines and is then allocated to consumers based on the relative contribution of loads regarding overloaded lines. A useful method for dividing the congestion cost among the overloaded lines has been presented in [14] based on Lagrange multipliers of the transmission constraints. Another accurate method has been proposed in [15] to consider the active constraints in dividing the congestion cost by solving the redispatching problem repeatedly. Methods of computing the contribution of loads to the power flow of a particular line are normally based on sensitivity analysis or load flow studies. Two examples of contribution factors are the generalized load distribution factors (GLDF) and topological load distribution factors (TLDF), which have been defined in [16] and [17]. It should be noted that contribution factors are dependent on operating conditions and thus may result in unfair conclusions in highly congested networks. A different method has also been proposed in [18] to allocate congestion cost directly to the consumers based on the nodes' responsibility. In this method, an extra nonlinear optimization is needed to find the hypothetical changes in loads that would remove the congestion.

This paper proposes a new flexible approach to solve the redispatching problem in a short-run market model. The main idea is to develop an iterative algorithm which finds the best sequence of bilateral power exchanges to make the required changes in the generation of the regulating generators to remove the congestion. Linear prediction of effect and the price of applying each bilateral exchange on the system would enable the operator to remove the congestion in a more efficient, flexible and transparent manner.

In addition, simultaneous evaluation and allocation of the congestion cost to consumers following each bilateral exchange would improve the fairness and complexity of the previous allocation methods.

3. SIMULTANEOUS CONGESTION MANAGEMENT AND COST ALLOCATION

After redispatching, some regulating generators are invited to increase, while others are obligated to decrease their generation, compared to their unconstrained dispatch. If the change in transmission losses is neglected during redispatching, the total decrease in generation of the regulating generators would be approximately equal to the increase of the others, when the congestion is removed. This means that a power transfer is implemented from the generator of increased to decreased power in a multilateral power exchange among the regulating generators to remove the congestion. The multilateral exchange can be partitioned to several bilateral power exchanges, which can be defined among the regulating generators. Therefore, it is suggested to solve the redispatching problem by finding and applying a sequence of the bilateral exchanges, which would gradually remove the congestion.

Applying a selected bilateral exchange has two consequents in the system. It imposes an extra generation cost to the system when the congestion is reduced, and it leads to a new operating condition where the generators are partially redispatched. The imposed cost, which is a part of the total congestion cost, can be evaluated as an exchange cost and allocated to loads using the conventional use-based methods. A new operating condition is evaluated using an AC load flow to check the new condition of the congestion in the network. If the congestion remains in the network, another exchange has to be searched in the next iteration. Finding and applying the exchanges is repeated until the congestion is completely removed. At the complete congestion removal, the exchange costs allocated to each consumer would add up to calculate the total congestion cost of each consumer. An overall flowchart of the proposed method is shown in Fig. 1.

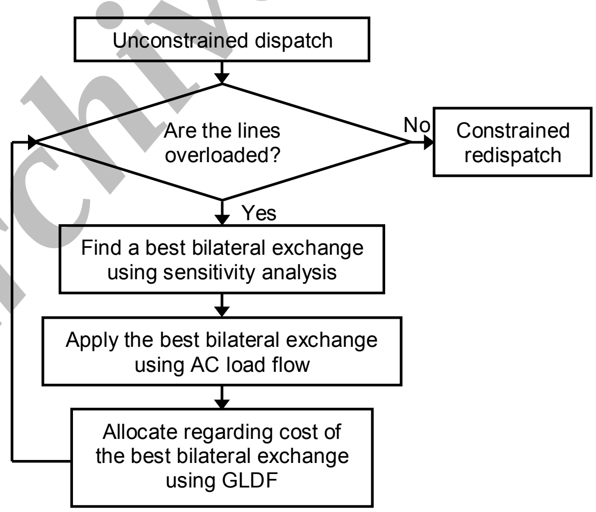

Fig. 1. Flow chart of the sensitivity-based redispatching

a) Finding bilateral exchange

In a given iteration k, a feasible bilateral exchange can be defined between the regulating generators corresponding to the remaining regulation capacities as follows:

$$Js_i^k \ \Delta P_i^+ + Js_j^k \ \Delta P_j^- = 0 \tag{1}$$

where, ΔP_i^+ and ΔP_j^- are the change in generation of *ith* and *jth* regulating generators, which are considered as up and down regulating generators to define the feasible exchange, and Js_i^k and Js_j^k, which are formulated in the appendix, are the effect of the transmission losses on the exchange in *kth* iteration.

Applying this exchange on the system imposes the following exchange cost:

$$EC_{ij} = F_i^+ \, \Delta P_i^+ + F_j^- \, \Delta P_j^- \tag{2}$$

Where, F_i^+ and F_j^- are the offered up and down regulation prices of *ith* and *jth* regulating generators.

By combining the Eqs. (1) and (2), the changes in generation of the regulating generators are obtained as follows:

$$\Delta P_j^- = -\frac{Js_i^k}{Js_j^k \, F_i^+ - Js_i^k \, F_j^-} EC_{ij} \tag{3}$$

$$\Delta P_i^+ = +\frac{Js_j^k}{Js_j^k \, F_i^+ - Js_i^k \, F_j^-} EC_{ij} \tag{4}$$

Using the sensitivity analysis, Eqs. (3) and (4) can be applied to find the change in the power flow of an overloaded line as follows:

$$\Delta Pf_l = \left(\frac{Jf_{li}^k \, Js_j^k - Jf_{lj}^k \, Js_i^k}{F_i^+ \, Js_j^k - F_j^- \, Js_i^k} \right) EC_{ij} \tag{5}$$

where, Jf_{li}^k and Jf_{lj}^k, which are formulated in the appendix, indicate the relation between the change in power flow of a particular line with respect to the change in generation of regulating generators.

The statement between parentheses on the right hand side of the Eq. (5) shows the contribution of the exchange to the power flow of the overloaded line in the *kth* iteration. In the case of more than one overloaded line, the contribution factor of the exchange to the congestion can be defined as follows:

$$CF_{ij} = \frac{\sum_{l \in Ol^k} \left(Jf_{li}^k \, Js_j^k - Jf_{lj}^k \, Js_i^k \right)}{F_i^+ \, Js_j^k - F_j^- \, Js_i^k} \tag{6}$$

where, Ol^k is a list of overloaded lines in *kth* iteration.

Since the up regulation price is normally greater than the down regulation price, the contribution factor of the exchange must be negative to cause a reduction in the congestion. Accordingly, for a fixed exchange cost, an exchange with the most negative contribution factor would be the best option among a set of feasible exchanges to make the most congestion reduction in the *kth* iteration.

Regarding these concepts, an algorithm can be developed to find the best exchange as follows:

Step 1. Obtain the current system operating condition using load flow results.

Step 2. Calculate the sensitivity of overloaded lines and injected power to the reference bus with respect to the injected power to the other buses.

Step 3. Define all feasible bilateral exchanges considering the capacity of regulating generators.

Step 4. Evaluate the contribution factors of defined exchanges using the calculated sensitivity factors and prices of regulating generators.

Step 5. Sort the defined exchanges corresponding to maximum evaluated negative contribution factors to select the proper exchange.

b) Applying bilateral exchange

After selecting an exchange on the top of the sorted exchanges, a proper amount has to be determined and assigned to apply the selected exchange on the system. This amount is initially entered by the operator. This is a flexible value which should be selected as a compromise between the required accuracy and the speed of the proposed method. However, the initial amount may be modified to satisfy the regulation capacities of the two participating generators in the selected exchange, the maximum power flow of non-overloaded lines, and the voltage limits in load buses.

Modification of the exchange amount is started corresponding to the regulation capacity of the down regulating generator as follows:

$$EA_{ij} = \Delta Pdn_j^k \quad if\ EA_{ij} > \Delta Pdn_j^k \tag{7}$$

where, EA_{ij} is the amount of exchange between *ith* up and *jth* down regulating generators and ΔPdn_j^k is the remaining down regulation capacity of the *jth* generator in the *kth* iteration.

Using Eq. (1), the regulation capacity of the up regulating may also modify the exchange amount as follows:

$$EA_{ij} = \frac{Js_i^k}{Js_j^k}\Delta Pup_i^k \quad if\ \frac{Js_j^k}{Js_i^k}EA_{ij} > \Delta Pup_i^k \tag{8}$$

where, ΔPup_i^k is the remaining up regulation capacity of the *ith* generator in the *kth* iteration.

The modified exchange amount may be reduced to avoid the violation of load voltage limits, as follows:

$$EA_{ij} = \frac{\Delta V\max_d^k}{\left(\frac{Js_j^k}{Js_i^k}Jv_{di}^k - Jv_{dj}^k\right)} \quad if\ \left(\frac{Js_j^k}{Js_i^k}Jv_{di}^k - Jv_{dj}^k\right)EA_{ij} > \Delta V\max_d^k \tag{9}$$

$$EA_{ij} = \frac{\Delta V\min_d^k}{\left(\frac{Js_j^k}{Js_i^k}Jv_{di}^k - Jv_{dj}^k\right)} \quad if\ \left(\frac{Js_j^k}{Js_i^k}Jv_{di}^k - Jv_{dj}^k\right)EA_{ij} < \Delta V\min_d^k \tag{10}$$

where, $\Delta V\min_d^k$ and $\Delta V\max_d^k$ are the minimum and maximum allowable changes in the voltage of the *dth* load and Jv_{di}^k and Jv_{dj}^k, which are formulated in the appendix, indicate the relation between the change in load voltage and the change in the generation of regulating generators in the *kth* iteration.

Meanwhile, to avoid re-overloading other lines the exchange amount may be reduced again, as follows:

$$EA_{ij} = \frac{\Delta Pfm_l^k}{\left(\frac{Js_j^k}{Js_i^k}Jf_{li}^k - Jf_{lj}^k\right)} \quad if\ \left(\frac{Js_j^k}{Js_i^k}Jf_{li}^k - Jf_{lj}^k\right)EA_{ij} > \Delta Pfm_l^k \tag{11}$$

where, ΔPfm_l^k is the maximum allowable change in the power flow of *lth* line in *kth* iteration, except for the current overloaded lines.

If the last amount is smaller than ε, a small-defined value, the selected exchange is rejected and the next exchange from the sorted exchanges is selected to be applied on the system. This process is repeated until an exchange with a proper amount is accepted to apply.

By choosing the bus of the up regulating generator as the reference bus, the best exchange can be considered as a new generation schedule as follows:

$$Pg_r^k = \begin{cases} Pg_r^{k-1} - \eta \times EA_{ij} & r = j \\ cte & r \neq j \end{cases} \tag{12}$$

where, Pg_r^k is the generation of *rth* generator in the *kth* iteration and η is a parameter between 0 and 1, which is used to eliminate the linearization error in the modification of the exchange amount.

New generation schedule can be applied to the system using AC load flow.

c) Allocating exchange cost

According to Eq. (5), the best exchange results in decrease or increase of the power flow of overloaded lines, proportional to the exchange cost. Therefore, the exchange cost can be divided among the overloaded lines as follows:

$$LC_l^k = \frac{\left(Jf_{li}^k\ Js_j^k - Jf_{lj}^k\ Js_i^k\right)}{\sum_{l \in Ol^k}\left(Jf_{li}^k\ Js_j^k - Jf_{lj}^k\ Js_i^k\right)} E_{ij} \tag{13}$$

where, LC_l^k is the congestion cost of the *lth* overloaded line in the *kth* iteration.

Using the GLDFs, congestion prices in the buses are obtained as follows:

$$CP_b^k = \sum_{l \in Ol^k}\left(\frac{GLDF_{lb}^{k-1}}{Pf_l^{k-1}} LC_l^k\right) \tag{14}$$

where, $GLDF_{lb}^{k-1}$ is the contribution factor of the load in the *bth* bus with respect to the *lth* overloaded line, and Pf_l^{k-1} is the power flow of the *lth* overloaded line, which are calculated based on the system operating condition prior to applying *kth* exchange.

4. CASE STUDIES

The standard IEEE 14 and 118 bus systems presented in [19] are used to study the proposed method.

a) IEEE 14-bus system

Unconstrained dispatch in the IEEE 14 bus system results in an overload of the lines 4-5 and 10-11 whose maximum capacities are assumed 40 MW and 15 MW, respectively. The regulation offers of the generators are presented in Table 1 to relieve the congestion.

Table 1. Up/Down regulation quantity-price bids in transmission management market for IEEE 14-bus system

Generator bus No.	Offered regulation capacity (MW)	Offered regulation price ($/MWh)	
		Down	Up
1	30	9	15
2	30	10	14
3	30	8	16
6	30	11	13
8	30	7	17

By setting the initial (σ) and minimum (ε) amount of exchange and η to 0.05 and 0.01 per unit and 0.8, respectively, the proposed redispatching approach removes the congestion by applying five bilateral exchanges, as shown in Table 2.

Table 2. Applied exchanges and regarding congestion reduction using the proposed method in the IEEE 14-bus system

Exchange no.	1	2	3	4	5
Down regulating generator bus no.	6	6	6	6	6
Up regulation generator bus no.	8	8	8	3	2
Exchange amount (MW)	4	4	2.98	4	4
Exchange cost ($)	20.87	21.07	15.82	16.97	11.62
Power flow of line 4-5 (MW)	44.23	42.60	41.38	39.99	39.46
Power flow of line 10-11 (MW)	18.66	17.45	16.55	15.75	14.97

According to Table 2, the regulating generator on bus no. 1 remains unchanged after redispatching and the amount of exchange no. 3 is only modified regarding the capacity limit of regulating generators.

The unconstrained dispatch and constrained redispatch, obtained using the proposed method, are presented in Table 3, in comparison with an OPF-based redispatching, which is solved by a pure primal dual interior point algorithm.

Table 3. Results of redispatching using the proposed method in comparison with an OPF-based method in the IEEE 14-bus system

Generator bus no.	Unconstrained dispatch (MW)	Proposed redispatch (MW)					OPF-based redispatch (MW)
		Exch. 1	Exch. 2	Exch. 3	Exch. 4	Exch. 5	
1	46.57	46.57	46.57	46.57	46.57	46.57	46.57
2	64.26	64.26	64.26	64.26	64.26	68.24	70.28
3	36.33	36.33	36.33	36.33	40.14	40.14	37.10
6	96.75	92.75	88.75	85.77	81.77	77.77	78.17
8	18.78	22.60	26.43	29.28	29.28	29.28	30.00

According to Table 3, the proposed method converges a near to accurate solution obtained by the OPF-based method, where the constraints of the network and generators are satisfied. The accuracy of the proposed solution with respect to the speed of obtaining the results is compared between two runs of the proposed method and the OPF-based method in Table 4.

From Table 4, the calculated change in the generation cost, using the proposed method, is close to the OPF-based method, while the CPU-time is considerably lower than the OPF-based redispatching. In addition, a flexible compromise is suggested between accuracy and speed, using the proposed method to solve the redispatching problem without the numerical divergence.

Table 4. Accuracy and speed of the proposed method in comparison with an OPF-based method in the IEEE 14-bus system

Redispatching method	OPF-based method	Proposed method	
		Run 1	Run 2
		σ =0.05 p.u.	σ = 0.1p.ụ.
		ε = 0.01 p.ụ.	ε = 0.01p.ụ.
		η = 0.8	η = 0.8
Change in generation cost	82.67	86.37	91.9
CPU time (s)	2.9	0.8	0.63

Congestion prices are obtained in run 1 and compared in Table 5 with the nodal and use-based prices, which are calculated using the OPF-based redispatching. The proposed method in [14] is used with GLDFs to obtain the used-based prices.

Table 5. Proposed congestion prices in comparison with the other pricing methods in the IEEE 14-bus system

Bus no.	Proposed congestion prices ($/MWh)						Use-based prices ($/MWh)	Nodal prices ($/MWh)
	Exch. 1	Exch. 2	Exch. 3	Exch. 4	Exch. 5	Total		
1	0.008	0.005	0.001	-0.005	0.035	0.045	0.107	0.297
2	0.031	0.029	0.020	0.017	0.037	0.135	0.172	0.801
3	0.095	0.096	0.072	0.079	0.043	0.386	0.354	2.249
4	0.149	0.153	0.117	0.133	0.049	0.603	0.512	3.499
5	-0.074	-0.081	-0.066	-0.087	0.029	-0.281	-0.126	-1.545
6	-0.090	-0.100	-0.082	-0.090	-0.105	-0.469	-0.411	-2.000
7	0.158	0.163	0.126	0.135	0.122	0.705	0.667	3.747
8	0.158	0.163	0.126	0.135	0.121	0.704	0.666	3.747
9	0.162	0.169	0.131	0.135	0.162	0.761	0.752	3.882
10	0.195	0.205	0.160	0.161	0.244	0.966	0.987	4.779
11	-0.179	-0.196	-0.160	-0.158	-0.312	-1.005	-1.030	-4.324
12	-0.074	-0.083	-0.069	-0.076	-0.089	-0.391	-0.339	-1.614
13	-0.056	-0.063	-0.053	-0.059	-0.069	-0.303	-0.256	-1.200
14	0.067	0.068	0.051	0.051	0.061	0.299	0.315	1.684

b) IEEE 118-bus system

To show the merit of the proposed method, the IEEE 118 bus system is considered as a larger-scale power system for the next study. Unconstrained dispatch in the IEEE 118 bus system results in the overload of the lines 8-5, 30-17, 38-37 and 89-88 whose maximum capacities are assumed 145 MW, 150 MW, 180 MW, and 70 MW, respectively. The regulation offers of the participated regulating generators are presented in Table 6.

Table 6. Up/Down regulation quantity-price bids in transmission management market for IEEE 118-bus system

Generator bus No.	Offered regulation capacity (MW)	Offered regulation price ($/MWh)	
		Down	UP
31,46,54,87,103,111	70	25	75
59,61	70	30	70
10,12,25,26,49,65,66,100	70	35	65

The congestion cost and regarding calculation time are also compared for the 118-bus example, between two runs of the proposed method and the OPF-based redispatching in Table 7.

Table 7. Accuracy and speed of the proposed method in comparison with the OPF-based method in the IEEE 118-bus system

Redispatching method	OPF-based method	Proposed method	
		Run 1	Run 2
		σ =0.01 p.u.	σ = 0.1p.u.
		ε = 0.001 p.u.	ε = 0.01 p.u.
		η = 0.8	η = 0.8
Congestion cost ($)	9697	10161	10460
CPU time (s)	491.88	162.02	21.81

From Table 7, the proposed redispatching calculates the congestion cost in run 1 and 2, with about 4.78% and 7.87% difference in comparison with the OPF-based method, while it is 3 and 22.5 times faster than the OPF-based redispatching in these two runs. A comparison among the proposed congestion prices in two runs and the other pricing methods is shown in Fig. 2.

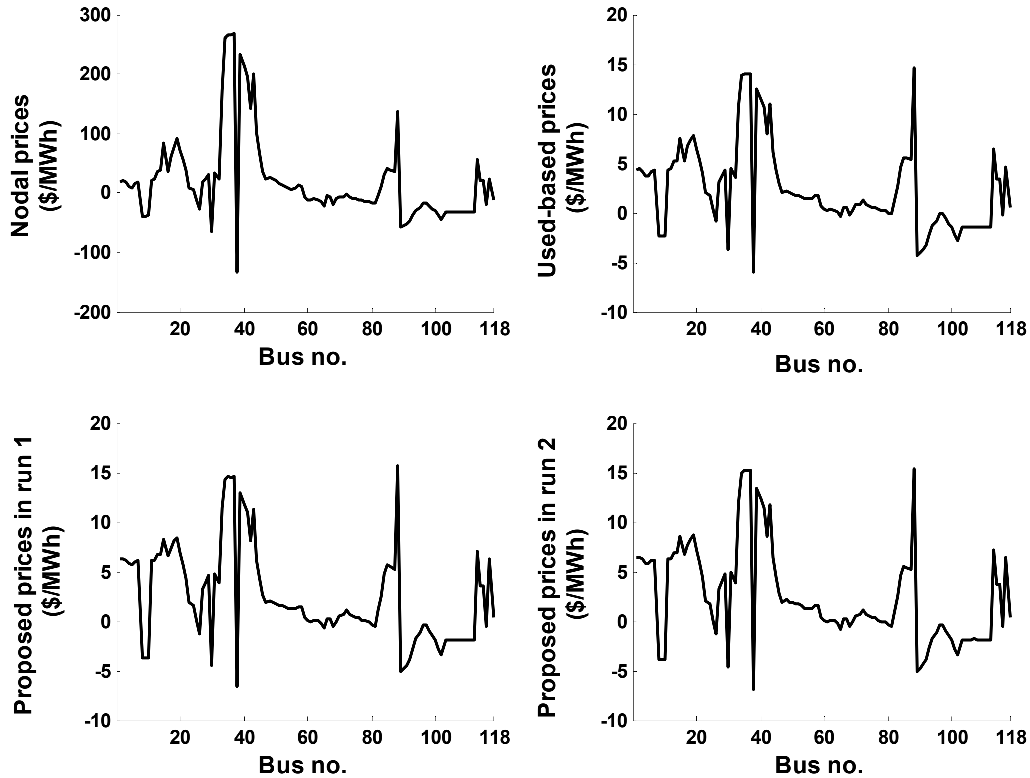

Fig. 2. Proposed congestion prices in comparison with the other pricing methods in the IEEE 118-bus system

5. CONCLUSION

A simultaneous iterative method has been suggested to solve redispatching for congestion management, evaluating the congestion cost, and to allocate the congestion cost to the consumers at the same time in a short-run market model. The market model used in the paper is a transmission management market, which is activated in a modified pool model when the transmission lines are overloaded following the clearing of the main energy market. It has been shown that:

1- The proposed approach is able to improve the efficiency of the redispatching method, where it manages the congestion close to the OPF-based method with shorter CPU time. It is possible to achieve reliable and flexible results using the proposed approach, in accordance with the requirements of the redispatching methods in restructured power systems.

2- The proposed approach allocates the congestion cost to the consumers similar to the nodal pricing and close to the use-based pricing methods, without merchandising surplus. Simple dividing of the congestion cost among the overloaded lines and updating the load contribution factors during the congestion removal leads to a fairer and more equitable allocation of congestion cost to the consumers, which is under criticism in the other cost allocation methods.

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APPENDIX

Without loss of generality, it is possible to assume the voltage of generators remains unchanged in the time of redispatching, where only overloading of the lines would be studied. This assumption is applied to simplify the Jacobean matrix, prior to selecting the *kth* best exchange as follows:

$$\begin{bmatrix} \Delta Pg \\ 0 \end{bmatrix} = \begin{bmatrix} \left(\dfrac{\partial P}{\partial \theta}\right)^k & \left(\dfrac{\partial P}{\partial Vd}\right)^k \\ \left(\dfrac{\partial Qd}{\partial \theta}\right)^k & \left(\dfrac{\partial Qd}{\partial Vd}\right)^k \end{bmatrix} \begin{bmatrix} \Delta \theta \\ \Delta Vd \end{bmatrix} \tag{A1}$$

where, ΔPg , $\Delta\theta$ and ΔVd are the vector of the change in generation of the generators, the bus angles and load voltages, respectively and P and Qd are the injected active power to the buses and the injected reactive power to the load buses. The change in active and reactive power of the loads, and the change in active generation of non-regulating generators are also replaced by zero in the above equation.

By choosing a reference bus, simplified Jacobean matrix is reversed to find the following equations:

$$\Delta\theta_n = \sum_{\substack{r=1 \\ r\neq rg}}^{Nrg} \left(\frac{\partial \theta_n}{\partial Pg_r}\right)^k \Delta Pg_r \quad n = 1 \ldots N,\ n \neq rb \tag{A2}$$

$$\Delta Vd_d = \sum_{\substack{r=1 \\ r\neq rg}}^{Nrg} \left(\frac{\partial Vd_d}{\partial Pg_r}\right)^k \Delta Pg_r \quad d = 1 \ldots Nd \tag{A3}$$

where, N, Nrg, and Nd are the number of buses, regulating generators, and load buses in the system, respectively, rb is the reference bus number, and rg indicates the regulating generator which exists on the reference bus.

Similarly, the change in power flow of a particular line and the change in generation of the regulating generator on the reference bus can be found as follows:

$$\Delta Pf_l = \begin{bmatrix} \left(\dfrac{\partial Pf_l}{\partial \theta}\right)^k & \left(\dfrac{\partial Pf_l}{\partial Vd}\right)^k \end{bmatrix} \begin{bmatrix} \Delta \theta \\ \Delta Vd \end{bmatrix} \tag{A4}$$

$$\Delta Ps = \begin{bmatrix} \left(\dfrac{\partial Ps}{\partial \theta}\right)^k & \left(\dfrac{\partial Ps}{\partial Vd}\right)^k \end{bmatrix} \begin{bmatrix} \Delta \theta \\ \Delta Vd \end{bmatrix} \tag{A5}$$

By substituting the Eqs. (A.2 and A.3 in A.4 and A.5), the following equations result:

$$\Delta Pf_l = \sum_{\substack{r=1 \\ r\neq rg}}^{Nrg} \left(\frac{\partial Pf_l}{\partial Pg_r}\right)^k \Delta Pg_r \tag{A6}$$

$$\Delta Ps = \sum_{\substack{r=1 \\ r\neq rg}}^{Nrg} \left(\frac{\partial Ps}{\partial Pg_r}\right)^k \Delta Pg_r \tag{A7}$$

For simplicity the two above equations and Eq. (A.3) can be rewritten as follows:

$$\Delta Pf_l = \sum_{r=1}^{Nrg} Jf_{lr}^k \, \Delta Pg_r \tag{A8}$$

$$\Delta Vd_d = \sum_{r=1}^{Nrg} Jv_{dr}^k \, \Delta Pg_r \tag{A9}$$

$$0 = \sum_{r=1}^{Nrg} Js_r^k \Delta Pg_r \tag{A10}$$

where, Jf_{lr}^k, Jv_{dr}^k, and Js_r^k are 0 , 0, and -1 for the regulating generator on the reference bus, respectively.