DEMAND RESPONSE AND FACTS DEVICES USED IN RESTRUCTURED POWER SYSTEMS TO RELIVE CONGESTION

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Abstract- In the approach is proposed for transmission lines congestion management in a restructured market environment using a combination of demand response (DR) and flexible alternating current transmission system (FACTS) devices. The overall objective of FACTS device placement can be either to minimize the total congestion rent. Market clearing procedure is formulated is based on two steps. In the first step, generation companies bid to the market for maximizing their profit, and the social welfare maximization. Second step of the market-clearing procedure can determine to the network constraints. The main motivation of the work is to carry out the contingency selection by calculating the Generation shift factor (GSF) for generator outage and to implement the demand response and Flexible AC Transmission Systems (FACTS) in managing the transmission congestion. The paper develops, using PSO optimization technique, a re-dispatch formulation in which demand responses and FACTS device controllers are optimally coordinated with conventional generators.

Keyword: *Demand response (DR) program, FACTS devices, Congestion management.*

I. INTRODUCTION

Restructuring in electric power industry has led to intensive usage of transmission grids. In a competitive market environment, transmission companies usually maximize the utilization of transmission systems as construction of new transmission lines is not as straightforward as in centrally planned systems. Customer response is a neglected way of solving electricity industry problems. Historically, providers have focused on supply, assuming that consumers are unwilling or unable to modify their consumption. Thus, in high demand periods, the system operates near its transmission capacity limit with security margin being reduced [1]. Existence of network constraints dictates the finite amount of power that can be transferred between two points on the electric grid. In practice, it may not always be possible to deliver all bilateral and multilateral contracts in full and to supply the entire market demand due to violation of operating constraints such as voltage and line power flow limits. The presence of such network or transmission limitation is referred to as congestion. Congestion or overload in one or more transmission lines may occur due to the lack of coordination between generation and transmission companies or as a result of contingencies [2]. Congestion may be relieved, in many cases by cost-free means such as network reconfiguration, operation of transformer taps and operation of flexible alternating current transmission system (FACTS) devices. In other case, however, it may not be possible to remove or relieve congestion by cost-free means, and some non-cost-free control methods, such as re-dispatch of generation and curtailment of loads, are required. Since there is a wide range of events which can lead to transmission system congestion, a key function in system operation is to manage and respond to operating conditions in which power flow limits and system voltages are violated [2]. A congestion management method proposed in this paper is based on a combination of FACTS devices and demand response programs. In the present paper, Demand response is modeled considering incentives and penalty factors. The incentive and penalty factors would lead to more control on responsive demand contributions rather than just relying on changing the electricity price in the market and its effects on response rate of elastic loads. The penalty factor can also improve the response rate of responsive demands and also enhance the reliability level of these resources by decreasing the rate of response failure. In addition, deploying demand response resources at appropriate locations would allow generation to operate at a lower cost as the congestion is reduced and also transmission network investment can be postponed while maintaining the existing level of security. In fact, the responsive demand improves the operation of electricity market and also would make electricity market more efficient and more competitive.

The main contribution of this paper is to develop a formulation for coordinating both FACTS device controllers and demand responses through constrained optimization to achieve congestion management at a minimum cost. In addition, the incentive and penalty terms are added to the existing mathematical model of demand response to enable the ISO through the aggregator to have two factors to control the capacity of responsive demands, and also increase the number of demand response participants at specific load buses which are important for the security of the system.

II. DEMAND RESPONSE BIDDING FORMULATION

2.1. Demand response allocation

A successful implementation of demand response programs, a set of load buses should be selected, based on their influences on network response. In this regard, loads with high impact on transmission system element loadings are chosen. This index could be either positive or negative, and for effective demand response implementation, those buses with negative indices are selected from a ranking process where higher priority is given to index with greater magnitude. The selection criterion is subject to the availability of the responses from the demand side at the identified locations. The load model developed in the following section will be used to quantify the expected demand response at load buses.

2.2. Economic model of elastic demand

This section derives an elastic demand model based on incentive and penalty together with the customer benefit function for the purpose of estimating the demand response capacity. This provides an economic basis on which the demand response aggregator at each location as identified in Section 2.1 formulates the bidding curve to be submitted to the market operator. The load change at the ith bus arising from demand response can be expressed as follows:

$$\Delta L(i) = L_O(i) - L(i) \qquad (1)$$

In (1), L0 (i) and L (i) are the load at the ith location before and after demand response, respectively. If CR (i) is paid as incentive to the customer for each unit of load reduction, the total incentive for participating in DR program will be calculated based on Eq. (2). The incentive amount is a fixed value which is determined by market operator. The amount of penalty is also assumed to be a fixed amount, and for the purpose of the paper the penalty is set to be 1.5% CR (i).

$$P(\Delta L(i)) = CR(i).[L_O(i) - L(i)] \qquad (2)$$

If the customers participating in the DR program do not respond to the minimum load reduction as required in the contract, the customers will have to pay the penalty which is determined by the aggregator. If the reduction level requested from the aggregator and penalty for the same period are denoted by LR(i) and pen(i), respectively, then the total penalty PEN(DL(i)) is calculated as follows:

$$PEN(\Delta L(i)) = pen(i).\{LR(i) - [L_O(i) - L(i)]\} \quad (3)$$

The requested load reduction level, LR(i), is limited to the maximum value LRmax(i) as agreed in the contract between the aggregator and customers. If the customer revenue is considered as B(L(i)) for using L(i), the customer net benefit can be calculated as follows:

$$S = B(L(i)) - L(i).\rho(i) + P(\Delta L(i)) - PEN(\Delta L(i)) \qquad (4)$$

In (4), q (i) is the price after the demand response.

To maximize the customer's net benefit, @S from (5):

$$\frac{\partial S}{\partial L(i)} = \frac{\partial B(L(i))}{\partial L(i)} - \rho(i) + \frac{\partial P(\Delta L(i))}{\partial L(i)} - \frac{\partial PEN(\Delta L(i))}{\partial L(i)} = 0 \qquad (5)$$

$$\frac{\partial B(L(i))}{\partial L(i)} = \rho(i) + CR(i) + pen(i) \qquad (6)$$

In general, various forms of function have been proposed for expressing the customer revenue in terms of demand. In this paper, an exponential function of demand elasticity as given in is adopted for deriving the optimal demand response:

$$B(L(i)) = B_O(L_O(i)) + \frac{\rho_O(i)L(i)}{1 + E(i)^{-1}} \left\{ \left(\frac{L(i)}{L_O(i)} \right)^{E(i)^{-1}} - 1 \right\} \qquad (7)$$

In (7), E (i) is the self-elasticity of the load and q0 (i) is the market price prior to demand response implementation.

Differentiating Eq. (7) yields:

$$\frac{\partial B(L(i))}{\partial L(i)} = \frac{\rho_O(i)}{1+E(i)^{-1}}\left\{\left(\frac{L(i)}{L_O(i)}\right)^{E(i)^{-1}} - 1\right\} + \frac{\rho_O(i).L(i)}{1+E(i)^{-1}}\left\{E(i)^{-1}.\frac{1}{L_O(i)}\left(\frac{L(i)}{L_O(i)}\right)^{E(i)^{-1}}\right\} \quad (8)$$

Simplifying Eq. (8) and substituting into Eq. (6) yields Eq. (9).

$$\left(1+E(i)^{-1}\right).\frac{\rho(i)+CR(i)+pen(i)}{\rho_O(i)} = \left(\frac{L(i)}{L_O(i)}\right)^{E(i)^{-1}} - 1 + E(i)^{-1}\left(\frac{L(i)}{L_O(i)}\right)^{E(i)^{-1}} \quad (9)$$

Rearranging Eq. (9) leads to:

$$\frac{\rho(i)+CR(i)+pen(i)}{\rho_O(i)} = \left(\frac{L(i)}{L_O(i)}\right)^{E(i)^{-1}} - \left(\frac{1}{1+E(i)^{-1}}\right) \quad (10)$$

The second term of Eq. (10) can be discarded for small amount of elasticity, and finally the demand response model can be achieved as follows:

$$L(i) = L_O(i).\left(\frac{\rho(i)+CR(i)+pen(i)}{\rho_O(i)}\right)^{E(i)} \quad (11)$$

The estimated demand response in (11) depends on market prices which are to be forecasted by the aggregator using historical data.

III. MARKET CLEARING FORMULATION

In the first step, generation companies bid to the market for maximizing their profit, and the ISO clears the market based on social welfare maximization without considering the electricity network constraints. In the second step, the ISO will consider network losses, network constraints including those of congestion .The electricity market-clearing procedure considered in the paper is similar to the one used by the Ontario electricity market operator.

3.1. First step: market price determination

In this step, it is required to solve the following constrained optimization problem:

Maximize:

$$\sum_{i=1}^{N_D}\sum_{K=1}^{N_{Di}}\left(\lambda_{Dik}P_{Dik}\right) - \sum_{i=1}^{N_G}C_i\left(P_{gi}\right) \quad (12)$$

Subject to:

$$P_{Dik}^{\min} \le P_{Dik} \le P_{Dik}^{\max} \quad \mathrm{i}=1,...,\mathrm{N_D}, K=1,..., \ N_{Di} \qquad (13)$$

$$P_{gi}^{\min} \le P_{gi} \le P_{gi}^{\max} \quad \mathrm{i}=1,...,\mathrm{N_G} \qquad (14)$$

$$\sum_{i=1}^{N_D}\sum_{K=1}^{N_{Di}} P_{Dik} + P_{fd} = \sum_{i=1}^{N_G} P_{gi} \qquad (15)$$

The objective function in (12) represents the social welfare, and it has two terms. The first term consists of the sum of accepted demands times their corresponding bidding prices, and the second term is the sum of the individual generator cost functions. The block of constraints in (13) specifies the sizes of the demand bids. The block of constraints in (14) limits the sizes of the production bids. The equality constraint in (15) ensures that the production should be equal to the total demand.

The solution of the constrained optimization problem described in (12)–(15) specifies the power produced by every generator and the power supplied to customers together with the market price.

3.2. Congestion management formulation

The dispatch calculations are performed without taking into account the electricity network limitations such as thermal limit of transmission lines and voltage constraints. To manage the congestion due to such limits, the following constrained optimization problem is to be solved.

Minimize:

$$T.\sum_{j=1}^{N_G}\left|C_j\left(P_{gj}^{o} + \Delta P_{gj}^{o}\right)\right| + \sum_{i \in reD} r_{Di}^{down}\Delta P_{reDi}^{down}.d_i \qquad (16)$$

Subject to:

$$E(|V|,\theta,u) = 0 \qquad (17)$$

$$H(|V|,\theta,u) \le 0 \qquad (18)$$

where DPgj is the change in the schedule of the jth generator, P0gj is the jth generator schedule in step 1, r down Di is the price offered by demand response i to decrease its demand, di is the demand response commitment variable which has a binary value, |V| is the vector of voltage magnitudes, h the vector of phase angles, T is the dispatch time interval and u is the vector of control variables. E and H in (17) and (18) are the sets of equality and inequality constraints. Vector u in (17) and (18) is the control vector comprising active-power generation changes, demand response commitments, input references to generator excitation controllers and network controllers including those of FACTS devices.

The objective function in (16) has two parts. The first part is the sum of the payments received by the generators for changing their output as compared to the original generation schedule, and the second term shows the total payment received by demand response participants to reduce their load. Each demand response service provider submits to the system operator a bidding curve to specify prices and capacity. A constraint in dispatching demand responses is that only whole blocks can be committed. The set of equality constraints in (17) includes the power-flow equations for generator nodes and load nodes For each load node, the total nodal active-power is the algebraic sum of load demands before the demand response and the decrement after demand response at the node. The nodal reactive-power at each load node used in forming the power-flow equation is determined from the active-power together with a specified power factor. The set of inequality constraints denoted by H in (18) is related to operating limits which include:

i. Power-flow constraints for transmission circuits. These constraints are required in congestion management.

ii. Nodal voltage constraints. These are related to network voltage security.

iii. Generator reactive power limits.

iv. Power system controllers limits.

In the paper, network controllers based on FACTS devices in the form of TCSCs and SVCs are considered. The functions of these controllers include those for mitigating congestion and/or enhancing network voltage security. The operating limit constraints on these FACTS device controllers, which are to be included in the set of inequalities in (18) are expressed in (19) and (20).

$$X_{TCSC}^{\min} \le X_{TCSC} \le X_{TCSC}^{\max} \qquad (19)$$

$$B_{SVC}^{\min} \le B_{SVC} \le B_{SVC}^{\max} \qquad (20)$$

For each TCSC, XTCSC in (19) is the TCSC reactance variable which is a controllable quantity. In the context of steady-state analysis, a TCSC can be modeled in terms of a variable reactance within its specified limits. Similarly, an SVC is modeled as a variable susceptance, BSVC, within its limits. The SVC susceptance is determined by the voltage controller for achieving its control objective as described. In the current research, FACTS devices are modeled in steady state mode and dynamic studies regarding the effects of FACTS devices are not considered.

IV. ANCILLARY SERVICE LIMITS

Also included in the set of inequality constraints in (18) are the limits on generation regulation supplied by ancillary service providers:

$$\Delta P_{gj\min} \le \Delta P_{gj} \le \Delta P_{gj\max} \quad j = 1,2,...,N_G \qquad (21)$$

Where N_G is the set of generators participating in the ancillary service market.

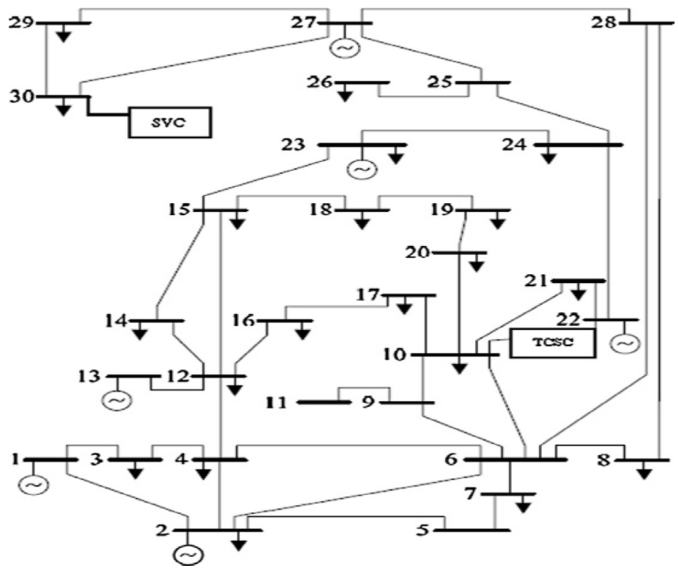

Figure. 1. IEEE 30-bus system.

V. PSO Algorithm

- Step 1: Line and bus data are input to obtain power flow analysis solution.
- Step 2: Check whether any line is overloaded.
- Step 3: If overload exists, find the GS values at generator buses.
- Step 4: Calculate the power flow analysis to the load demand with power factor..
- Step 5: Placement of facts devices in the system for the congestion line.
- Step 6: PSO parameters such as inertia weight, acceleration coefficients, and number of particles and iterations are specified.
- Step 7: Finding the demand response to the given system.
- Step 8: Perturb the change in power generation of participating generators randomly.
- Step 9: Particle’s positions are randomly initialized and the iteration counter is set as 1.
- Step 10: Particle’s fitness is evaluated by the objective function.
- Step 11: Particle positions and velocities are updated.

- Step 12: To determine the self and cross elasticity based on the demand response in the system
- Step 13: If the maximum PSO iteration is reached, the optimal solution is the position of the global best particle. Otherwise increase the iteration counter by 1 and go to Step 8.
- Step 14: Obtain the demand response contribution in the congestion management.
- Step 15: Check, whether with placement of facts devices, any line is congested. If yes, go to step 6, otherwise stop.
- Step 16: Calculate the cost of total re-dispatch of demand response.

TABLE 1: LOAD DEMANDS WITH POWER FACTOR 0.9.

BUS NO	LOAD DEMAND
1	0
2	21.7
3	7.6
4	7.6
5	0
6	0
7	22.8
8	30
9	0
10	5.8
11	0
12	11.2
13	0
14	6.2
15	8.2
16	7.8
17	9

18	3.2
19	9.5
20	11.6
21	17.5
22	0
23	12.5
24	8.7
25	0
26	3.5
27	0
28	0
29	2.4
30	10.6

Load demands are presented in Table 1.

TABLE 2: SELECTED BUSES FOR DEMAND RESPOSE IMPLEMENTATION

DEMAND RESPOSE NUMBER	**BUS NUMBER**
1	5
2	8
3	7
4	2
5	21
6	12
7	30

Seven load buses as specified in Table 2 is selected for demand response participation based on their potential to reduce the transmission line congestion according to generation shift factor.

TABLE 3: SELF AND CROSS ELASTICITY

PEAK	**OFF-PEAK**	**LOW**
-0.01	0.0040	0.0090

Table 3 is presented in the elasticity values which are used for simulating the demand response participants.

TABLE 4: GENERATOR COST FUNCTION COEFFICIENTS

GEN BUS NO	COEFFICIENT α	COEFFICIENT β	COEFFICIENT
1	1.87	2	0.3
2	1.67	1.98	0.3
13	2.95	1.5	0.3
22	1.88	3	0.3
23	2.75	3.25	0.3
27	2.92	2.2	0.3

Table 4 is presented in the data for generator cost functions.

TABLE 5: FACTS DEVICES DATA

TYPES OF FACTS	UPFC	TCSC	SVC
Operating limit	$-0.102 \leq X_{upfc} \leq 0.102$	$-0.105 \leq X_{tcsc} \leq 0.105$	$-0.15 \leq X_{svc} \leq 0.15$
Location	LINE 28 (BUS10-BUS22)	LINE 28 (BUS10-BUS22)	BUS 30

A case study based on the modified IEEE 30 bus system which is shown in Fig. 1 is presented in this section. The amount of incentive and penalty for demand response program are considered as fixed values which are \$100 and \$150 per MWh. Each generation bidding is specified in terms of its capacity and cost function expressed as:

$$C_i\left(P_{gi}\right) = \alpha_i . P_{gi}^{\ 2} + \beta_i . P_{gi} + \gamma_i \quad \mathrm{i} = 1,2,..., \mathrm{N_G} \qquad (22)$$

Table 5 is shown in the data for the UPFC, TCSC and SVC in the system in terms of their reactance/susceptance limits.

TABLE 6: THE RESULTS OF STEP 1 FOR GENERATORS PARTICIPATING IN ELECTRICITY MARKET.

Generator bus number	Generation (MW)
1	17
2	24
13	29
22	29
23	27
27	34

Table 6 can be determining the generator schedule following electricity market clearing.

Table 7: GENERATION INCREMENT AND DECREMENT FOR ALL GENERATORS (MW).

Gen bus .no	Without DR with FACTS	With DR with FACTS	With DR without FACTS
1	13	16	-8
2	6	1	-5
13	14	3	1
22	-9	-11	-10
23	-14	-1	-9
27	0	5	-1

Table 7 which can be represents as Results of generation re-dispatch for congestion management for options 1–3.

TABLE 8: DEMAND RESPONSE CONTRIBUTION FOR CONGESTION MANAGEMENT (MW).

DR bus number	With DR with FACTS	With DR without FACTS
5	1.4871	1.3587
8	04082	1.4508
7	0.2498	1.1250
2	0.2215	1.2422
21	0.2580	1.3658
12	0.1589	1.4059
30	0.1839	1.3084

The total cost of re dispatch for generators without using demand response (option 1) is somewhat higher in comparison with two other options. This reduction is a consequence of using combination of incentive based demand response programs and FACTS devices. Table 8 is presented in load reduction associated with each responsive demand. This table shows the demand response locations and the reduction level that is achieved based on the solution of the optimization problem.

TABLE 9: THE REFERENCE SETTING OF THE CONTROLLER.

Controller	Reference setting (pu)
TCSC	-0.0852
SVC	0.0976

Table 9 is presented in the optimal FACTS devices input references for congestion management.

VI. RESULTS AND DISCUSSION

Subject to network constraints including those arising from congestion, the generator schedule and load demands would be augmented, drawing on the solution of the constrained optimization problem. The problem is formed and solved for three options.

Option 1. Without demand response and with FACTS devices. In this case, demand response is not considered for congestion management.

Option 2. With demand response and with FACTS devices.

Option 3. With demand response and without FACTS devices.

TABLE 10: TOTAL RE-DISPATCH COST IN DIFFERENT OPTIONS.

Without DR with FACTS	With DR with FACTS	With DR without FACTS
634.27	253.708	2895.18

Table 10 represents the total cost of re-dispatch in three different options. Comparison of different options shows that using the combination of DR and FACTS devices can reduce the total congestion cost). The re-dispatch costs are shown separately for comparison purpose.

VII. CONCLUSIONS

The paper has developed a methodology for transmission congestion management in which the traditional approach of using conventional generators and/or FACTS devices is augmented by demand responses. The method proposed draws on a PSO optimization required of DR dispatches. The effectiveness of the method is illustrated with a representative market clearing study in which various options of using FACTS devices and/or DR are compared.

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APPENDIX

The transmission line model with a TCSC connected between the two buses *i* and *j* is shown in Figure A1. Equivalent pi model is used to represent the transmission line. TCSC can be considered as a static reactance of magnitude equivalent to *-jXc*. The controllable reactance *Xc* is directly used as control variable to be implemented in power flow equation.

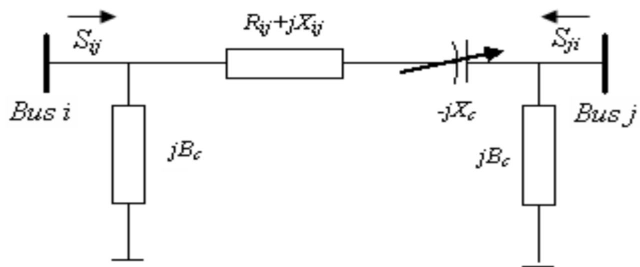

Figure.A1. MODELING OF TCSC

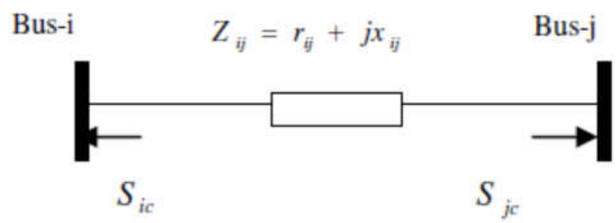

Figure.A2. Injection of TCSC

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