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Congestion management in transmission lines using demand response and FACTS devices

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***Abstract*— Congestion in transmission system is the condition where desired transmission line-flows exceed reliability limits. In a deregulated electricity market, it may not always be possible to dispatch all of the contracted power transactions due to congestion in the network. Congestion management can be considered as any systematic approach used in scheduling and matching generation and loads in order to manage congestion. An 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 effectiveness of the method has been tested and validated with TCSC and SVC in IEEE 30 bus test system.**

Keywords*— *Congestion management, Demand response(DR), FACTS devices, Static Var compensator (SVC), Thyristor controlled series compensator (TCSC).

I. INTRODUCTION

Restructuring in electric power industry has led to intensive usage of transmission grids. 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 of the contracted power transactions 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. When the producers and consumers of electric energy desires to produce and consume in amounts that would cause the transmission system to operate at or beyond one or more transfer limits, the system is said to be congested. 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 [3–8]. 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 [9–11]. 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 system voltages and/or power flow limits are violated [2]. A congestion management method proposed here 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. Demand response is defined as Changes in electric usage by end use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. In fact, the responsive demand improves the operation of electricity market and also would make electricity market more efficient and more competitive [12].

II. NOTATION

P_{Dik}^{max} maximum power output of generator i

P_{gi}^{max} minimum power output of generator i
$\Delta P_{reDi_{min}}^{down}$ minimum load reduction by responsive demand i
$\Delta P_{reDi_{max}}^{down}$ maximum load reduction by responsive demand i
$C_i(P_{gi})$ generation cost function
X_{TCSC}^{max} maximum reactance limit of TCSC
X_{TCSC}^{min} minimum reactance limit of TCSC
B_{SVC}^{max} maximum susceptance limit of SVC
B_{SVC}^{min} minimum susceptance limit of SVC
E(i) elasticity of the demand
$\rho(i)$ electricity price
L0(i) customer demand before demand response program
L(i) customer demand after demand response program
P_{Dik} power block k that demand i is willing to buy at price up to a maximum of P_{Dik}^{max}
P_{fd} non-dispachable load.
λ_{Dik} price offered by demand i to buy power block k
r_{Di}^{down} price offered by demand response i to decrease its demand
ΔP_{reDi}^{down} decrement in the schedule of demand response i
N_D number of demands
N_{Di} number of blocks requested by demand i
N_G number of generators

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III. DEMAND RESPONSE BIDDING FORMULATION

A. Demand Response Allocation

For successful implementation of demand response programs, a set of candidate 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. To achieve this goal, generation shift factor (GSF) is used [14]. In addition, 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. However, this 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.

B. 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 A formulates the bidding curve to be submitted to the market operator. The load change at the i^{th} bus arising from demand response can be expressed as follows:

$$\Delta L(i) = L_0(i) - L(i) \tag{1}$$

In (1), $L_0(i)$ and $L(i)$ are the load at the i^{th} 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).

$$P(\Delta L(i)) = CR(i) \cdot [L_0(i) - L(i)] \tag{2}$$

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(ΔL(i)) is calculated as follows:

$$PEN(\Delta L(i)) = pen(i) \cdot \{LR(i) - [L_0(i) - L(i)]\} \tag{3}$$

The requested load reduction level, LR(i), is limited to the maximum value $LR_{max}(i)$ 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:

$$S = B(L(i)) - L(i) \cdot \rho(i) + P(\Delta L(i) - PEN(\Delta L(i)) \tag{4}$$

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

To maximize the customer's net benefit, $\frac{\partial S}{\partial L(i)}$ in Eq. (5) is set to zero.

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

from (5):

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

In general, various forms of function have been proposed for expressing the customer revenue in terms of demand [15–18]. In this paper, an exponential function of demand elasticity as given in [28] is adopted for deriving the optimal demand response:

$$B(L(i) = B_0(L_0(i)) + \frac{\rho_0(i)L(i)}{1+E(i)}\left\{\left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} - 1\right\} \tag{7}$$

In (7), E(i) is the self-elasticity of the load and $\rho_0(i)$ is the market price prior to demand response implementation.

Differentiating Eq. (7) yields:

$$\frac{\partial B(L(i))}{\partial L(i)} = \frac{\rho_0(i)}{1+E(i)^{-1}}\left\{\left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} - 1\right\} + \frac{\rho_0(i)L(i)}{1+E(i)}\left\{E(i)^{-1} \cdot \frac{1}{L_0(i)}\left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}}\right\} \tag{8}$$

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

$$(1 + E(i)^{-1}) \cdot \frac{\rho(i) + CR(i) + pen(i)}{\rho_0(i)} = \left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} - 1 + E(i)^{-1} \cdot \left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} \tag{9}$$

Rearranging Eq. (9) leads to:

$$\frac{\rho(i) + CR(i) + pen(i)}{\rho_0(i)} = \left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} - \frac{1}{(1+E(i)^{-1})} \tag{10}$$

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:

$$L(i) = L_0(i) \cdot \left(\frac{\rho(i) + CR(i) + pen(i)}{\rho_0(i)}\right)^{E(i)} \tag{11}$$

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

IV. MARKET CLEARING FORMULATION

A. Outline Of Market Clearing Procedure

A two-step market clearing procedure is formulated in this paper. 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

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constraints including those of congestion as described in Section C. Optimal power flow is performed using Genetic Algorithm solver.

B. First Step: Market Price Determination

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

Maximize: $\sum_{i}\sum_{k}\lambda_{ik}P_{ik} - \sum_{j}C_j(P_{Gj})$ (12)

Subject to:

$P_{ik}^{min} \le P_{ik} \le P_{ik}^{max}$ i=1,……N_d (13)

$k = 1, \ldots N_{b,i}$ (14)

$P_{Gj}^{min} \le P_{Gj} \le P_{Gj}^{max}$ i=1,……N_g (15)

$\sum_{i}\sum_{k}P_{ik} + P_L = \sum_{j}P_{Gj}$ (16)

Where P_{ik} is the power block k that demand i is willing to buy at price λ_{ik} up to a maximum of P_{ik}^{max}, λ_{ik} the price offered by demandi to buy power block k, P_L is the fixed load based on demand forecasting and $C_j(P_{Gj})$ is the generation cost function.

The objective function in 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 specifies the sizes of the demand bids. The block of constraints limits the sizes of the production bids. The equality constraint 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.

C. Congestion Management Formulation

To manage the congestion due to thermal limit of transmission lines and voltage constraints, the following constrained optimization problem is to be solved.

Minimize: $T\{\sum_{j}[C_j(P_{Gj}^{0} + \Delta P_{Gj}) - C_j(P_{Gj}^{0})] + \sum_{i}\rho_i^{dr}\Delta P_i^{dr}\delta_i\}$ (16)

Subject to:

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

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

where ΔP_{Gj} is the change in the schedule of the jth generator, P_{Gj}^{0} is the j[th] generator schedule in step 1, ρ_i^{dr} is the price offered by demand response i to decrease its demand, δ_i 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 are the sets of equality and inequality constraints. Vector u 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 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. Typically, the bidding comprises a number of power blocks each of which with block size and bidding price as shown in Fig.1. A constraint in dispatching demand responses is that only whole blocks can be committed.

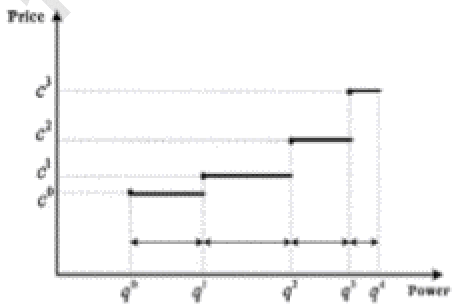

Fig.I. A typical demand response bidding

The set of inequality constraints denoted by H 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.

v. Ancillary service 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.

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

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(20)

For each TCSC, X_{TCSC} 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, B_{SVC}, within its limits, as shown. The SVC susceptance is determined by the voltage controller for achieving its control objective as described in [5,20]. In the current research, FACTS devices are modeled in steady state mode and dynamic studies regarding the effects of FACTS devices are not considered [21,22].

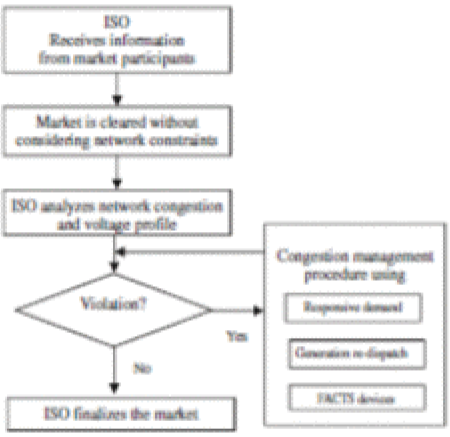

Fig.II. Two step market clearing procedure

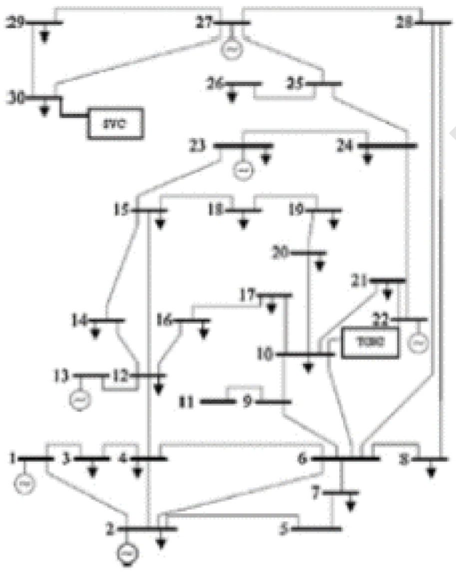

Fig.III. IEEE 30 bus system

V.CASE STUDY

A case study based on the modified IEEE 30 bus system which is shown in Fig. III is presented in this section. Load demands are presented in Table I. Seven load buses as specified in Table II are selected for demand response participation based on their potential to reduce the transmission line congestion according to generation shift factor referred to in Section A. The elasticity values which are used for simulating the demand response participants are presented in Table III [24]. The data for generator cost functions are presented in Table IV. Each generation bidding is specified in terms of its capacity and cost function expressed as:

(21)

The data for the TCSC and SVC in the system of Fig. III in terms of their reactance/susceptance limits is shown in Table V.

Table I. Load demands with power factor 0.9

Bus number	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

Table II. Selected buses for demand response implementation.

Demand response number	Bus number
1	7
2	8
3	12
4	17
5	19
6	21
7	30

Table III. Self and cross elasticity

	Peak	Off-peak	Low
Peak	− 0.1	0.016	0.012
Off-peak	0.016	− 0.1	0.01

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Low	0.012	0.01	− 0.1

Table IV. Generator cost function coefficients

Generator bus number	Coefficient α	Coefficient β	Coefficient γ
1	1.87	2	0.3
2	1.67	1.98	0.3
22	2.92	1.5	0.3
27	1.88	3	0.3
23	2.75	3.25	0.3
13	2.95	2.2	0.3

Table V. FACTS devices data

Type of FACTS	TCSC	SVC
Operating limit	$0.105 \leq X_{TCSC} \leq 0.105$	$0.15 \leq B_{SVC} \leq 0.15$ (p.u on 100 MVA)
Location	Line 28(bus 10-bus 22)	Bus 30

VI.RESULTS AND DISCUSSION

Table VI The results of step 1 for generators participating in electricity market.

Generator Bus number	Generation
2	58.7680
22	59.4468
27	23.2184
23	16.3653
13	5.4349

Table VII Re-dispatch cost in different options

	Without DR with FACTS	With DR with FACTS
Total re-dispatch cost($/h)	5468.82	4789.03

Using MATLAB and system data given in section V the results of market clearing together with congestion management are obtained and discussed in this section. Table IV shows the generator schedule following electricity market clearing. Generator at bus number 1 is assumed as reference. 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 formed. The problem is formed and solved for two options.

Option 1. Without demand response and FACTS devices.
Option 2. With demand response and FACTS devices.

As indicated in Table VII, the total amount of re-dispatch for generators without using demand response is noticeably higher in comparison with the other option.

VII. CONCLUSION

The primary objective of the paper is to minimize congestion cost using combination of demand response and FACTS devices. The paper has developed a re-dispatch formulation for transmission congestion management in which the traditional approach of using conventional generators and/or FACTS devices is augmented by demand responses. Optimal power flow is performed using genetic algorithm to find the optimum values. The effectiveness of the method is illustrated using IEEE 30 bus system with a representative market clearing study in which various options of using FACTS devices and/or DR are compared. Using combination of incentive based demand response programs and FACTS devices the total amount of re-dispatch cost can be reduced.

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