Electrical Power and Energy Systems 37 (2012) 78–85

Contents lists available at SciVerse ScienceDirect

Electrical Power and Energy Systems

journal homepage: www.elsevier.com/locate/ijepes

Congestion management using demand response and FACTS devices

A. Yousefi [a,*], T.T. Nguyen [a], H. Zareipour [b], O.P. Malik [b]

[a] University of Western Australia, Perth, Australia
[b] University of Calgary, Calgary, Canada

ARTICLE INFO

Article history:
Received 31 May 2011
Received in revised form 4 November 2011
Accepted 5 December 2011
Available online 20 January 2012

Keywords:
Demand response (DR) program
FACTS devices
Congestion management

ABSTRACT

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. To achieve this aim, a two-step market clearing procedure is formulated. 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. Network constraints including those related to congestion management are represented in the second step of the market-clearing procedure. The paper develops, using mixed integer optimization technique, a re-dispatch formulation for the second step in which demand responses and FACTS device controllers are optimally coordinated with conventional generators.

1. Introduction

1.1. Motivation and technique

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. 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 [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 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 [12–14]. In fact, the responsive demand improves the operation of electricity market and also would make electricity market more efficient and more competitive [12].

1.2. Literature review and contribution

In general, three main forms of congestion management exist in competitive electricity markets [2]. The first is based on centralized optimization with some form of optimal power flow program or depends on specific control measures operated by the independent system operator (ISO). The second is based on tariff and use of price signals derived from the market to release congestion by generator re-scheduling. Lastly, the third form seeks to mitigate congestion

* Corresponding author. Tel.: +61 433786405.
E-mail addresses: a.yousefi@ieee.org (A. Yousefi), tam@ee.uwa.edu.au (T.T. Nguyen), h.zareipour@ucalgary.ca (H. Zareipour), maliko@ucalgary.ca (O.P. Malik).

0142-0615/$ - see front matter © 2012 Elsevier Ltd. All rights reserved.
doi:10.1016/j.ijepes.2011.12.008

Nomenclature

$P_{gi}^{\max}$	maximum power output of generator i
$P_{gi}^{\min}$	minimum power output of generator i
$P_{reDi_{\min}}^{down}$	minimum load reduction by responsive demand i
$P_{reDi_{\max}}^{down}$	maximum load reduction by responsive demand i
$C_i(P_{gi})$	generation cost function
$X_{\mathrm{TCSC}}^{\min}$	minimum reactance limit of TCSC
$X_{\mathrm{TCSC}}^{\max}$	maximum reactance limit of TCSC
$B_{\mathrm{SVC}}^{\min}$	minimum susceptance limit of SVC
$B_{\mathrm{SVC}}^{\max}$	maximum susceptance limit of SVC
$E(i)$	elasticity of the demand
$\rho(i)$	electricity price
$L_0(i)$	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 λ_{Dik} 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
N_{reD}	number of demand responses

by allowing or disallowing bilateral transmission agreements between a producer and a consumer [1,2].

FACTS devices are considered to be one technology that can benefit transmission systems in many ways including congestion management and enhancing the loadability of the transmission lines [6]. FACTS devices and their associated benefits for efficient operation of electricity markets have been widely addressed in the literature [2–4,6,7,15].

The effectiveness of FACTS devices in congestion management depends importantly on their locations. The issue of FACTS devices placement has been extensively investigated and reported in literature [3,6,7,15].

Additionally, a significant volume of technical literature focuses on demand response [16–20] and the associated benefits for electricity network which include the improvement in the operation of renewable generation [21], providing ancillary services for the market [22,23], enabling infrastructure for utilizing large amount of renewable resources [24], network reliability enhancement [25], improving the loadability of the transmission lines and congestion management in electricity networks [9].

The role of demand elasticity in congestion management in a competitive electricity market is investigated in [10], where elasticity of demand at different prices is known. The load at each bus ceases to be a fixed quantity and becomes a decision variable in the ISO's optimization problem. In this way, the ISO has additional degrees of freedom in determining the necessary actions for congestion management. An optimal power flow based framework is proposed in [26] to determine the optimal incentive rates in an interruptible tariff mechanism. It is shown that interruptible tariffs are able to aid system operation during peak load periods by increasing the reliability margin, improving voltage profile and relieving network congestion. An integrated technical market based framework for congestion management, that uses interruptible load services as a tool for the ISO to provide transmission congestion relief is investigated in [9], where interruptible load service procurement by the ISO is explored. Additionally, the technical literature includes a significant number of references dealing with demand response modeling and its effects on improving the market operation. The impact of incentive-based demand response (DR) programs on capacity markets is investigated in [27]. The response of a nonlinear mathematical model is analyzed in [28] for the calculation of optimal prices for electricity assuming typical customers under different scenarios using five different mathematical functions. The electricity cost saving potential of real time pricing (RTP) through demand management is presented in [29].

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.

1.3. Paper organization

The rest of this paper is organized as follows. The demand response formulation is presented in Section 2. The proposed method including the problem formulation is described in Section 3. Results from a case study are provided and discussed in Section 4 and some relevant conclusions are given in Section 5.

2. Demand response bidding formulation

2.1. 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 [30]. 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.

2.2. Economic model of elastic demand

2.2.1. Outline

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:

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

In (1), $L_0(i)$ 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).

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

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 $PEN(\Delta L(i))$ 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), $\rho(i)$ 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 [31–34]. In this paper, an exponential function of demand elasticity as given in [28] is adopted for deriving the optimal demand response:

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

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:

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

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:

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

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.

3. Market clearing formulation

3.1. 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 constraints including those of congestion as described in Section 3.3. The electricity market-clearing procedure considered in the paper is similar to the one used by the Ontario electricity market operator [35,36].

3.2. First step: market price determination

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

$$\text{Maximize}: \quad \sum_{i=1}^{N_D}\sum_{k=1}^{N_{Di}}(\lambda_{Dik}P_{Dik}) - \sum_{i=1}^{N_G}C_i(P_{gi}) \tag{12}$$

Subject to:

$$P_{Dik}^{\min} \leqslant P_{Dik} \leqslant P_{Dik}^{\max} \quad i=1,\ldots,N_D, \quad k=1,\ldots,N_{Di} \tag{13}$$

$$P_{gi}^{\min} \leqslant P_{gi} \leqslant P_{gi}^{\max} \quad i=1,\ldots,N_G \tag{14}$$

$$\sum_{i=1}^{N_D}\sum_{k=1}^{N_{Di}}P_{Dik} + P_{fd} = \sum_{i=1}^{N_G}P_{gi} \tag{15}$$

where P_{Dik} is the power block k that demand i is willing to buy at price λ_{Dik} up to a maximum of $P_{Dik}^{\max}$, λ_{Dik} the price offered by demand i to buy power block k, P_{fd} the fixed load based on demand forecasting and $C_i(P_{gi})$ is the generation cost function.

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.

3.3. Congestion management formulation

In Section 3.2, 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.

$$\begin{aligned} \textit{Minimize}: \quad & T \cdot \sum_{j=1}^{N_G} \left| C_j\left(P_{gj}^0 + \Delta P_{gj}\right) - C_j\left(P_{gj}^0\right) \right| \\ & + \sum_{i \in reD} r_{Di}^{down} \Delta P_{reDi}^{down} \cdot d_i \end{aligned} \tag{16}$$

Subject to:

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

$$H(|V|, \theta, u) \leqslant 0 \tag{18}$$

where ΔP_{gj} is the change in the schedule of the jth generator, P_{gj}^0 is the jth generator schedule in step 1, r_{Di}^{down} is the price offered by demand response i to decrease its demand, d_i is the demand response commitment variable which has a binary value, $|V|$ is the vector of voltage magnitudes, θ 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. 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.

The set of equality constraints in (17) includes the power-flow equations for generator nodes and load nodes. For each generator node, the nodal active-power is the algebraic sum of power generation as determined in the first step described in Section 3.2, and the changes supplied by ancillary service providers at the node. 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:

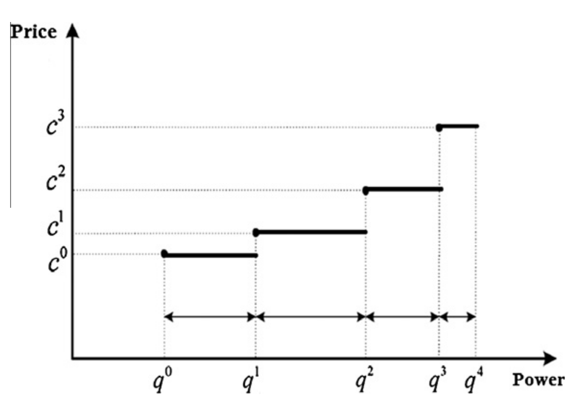

Fig. 1. A typical demand response bidding.

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).

$$X_{TCSC}^{min} \leqslant X_{TCSC} \leqslant X_{TCSC}^{max} \tag{19}$$

$$B_{SVC}^{min} \leqslant B_{SVC} \leqslant B_{SVC}^{max} \tag{20}$$

For each TCSC, X_{TCSC} 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, B_{SVC}, within its limits, as shown in (20). The SVC susceptance is determined by the voltage controller for achieving its control objective as described in [5,37]. In the current research, FACTS devices are modeled in steady state mode and dynamic studies regarding the effects of FACTS devices are not considered [38,39].

v. Ancillary service limits

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

$$\Delta P_{gj\,\min} \leqslant \Delta P_{gj} \leqslant \Delta P_{gj\,\max} \quad j = 1, 2, \ldots, N_G \tag{21}$$

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

Solution of the problems (16)–(18) provides the modified generation levels, demand response commitments, generator and network controller input references which satisfy system operating constraints.

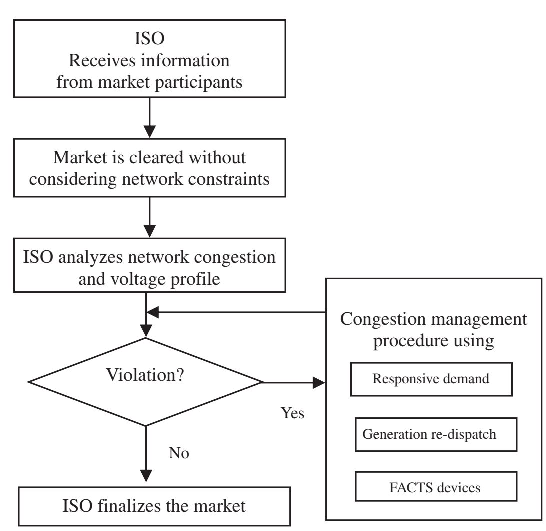

Fig. 2. Two-step market clearing procedure.

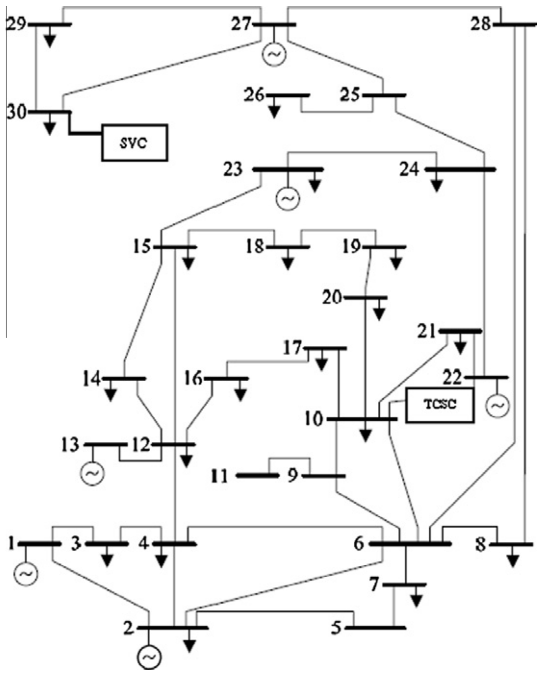

Fig. 3. IEEE 30-bus system.

Table 1
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

3.4. Overall optimization procedure

The details of the two steps for market clearing with congestion management are summarized in the flowchart in Fig. 2. A software system based on mixed integer constrained optimization is solved using CPLEX under GAMS software [40]. The study in the following section draws on the software system developed.

Table 2
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 3
Self and cross elasticity.

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

Table 4
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 5
FACTS devices data.

Type of FACTS	TCSC	SVC
Operating limit (p.u on 100 MVA)	$-0.105 \leqslant X_{TCSC} \leqslant 0.105$	$-0.15 \leqslant B_{SVC} \leqslant 0.15$
Location	Line 28 (bus10–bus 22)	Bus 30

4. Representative studies

4.1. Data

A case study based on the modified IEEE 30 bus system which is shown in Fig. 3 is presented in this section. Line, generator, and demand data can be found in [41]. Load demands are presented in Table 1.

Seven load buses as specified in Table 2 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 2.1. The elasticity values which are used for simulating the demand response participants are presented in Table 3 [42]. The amount of incentive and penalty for demand response program are considered as fixed values which are \$100 and \$150 per MWh. The data for generator cost functions are presented in Table 4. Each generation bidding is specified in terms of its capacity and cost function expressed as:

$$C_i(P_{gi}) = \alpha_i.P_{gi}^2 + \beta_i.P_{gi} + \gamma_i \quad i = 1, 2, \ldots, N_G \tag{22}$$

The data for the TCSC and SVC in the system of Fig. 3 in terms of their reactance/susceptance limits is shown in Table 5.

Table 6
The results of step1 for generators participating in electricity market.

Generator bus number	Generation (MW)
1	35
2	33.37
22	36
27	36
23	18.39
13	32.24

Table 7
Generation increment and decrement for all generators (MW).

Generator bus number	Without DR with FACTS	With DR with FACTS	With DR without FACTS
22	16.24	8.36	12.24
27	12.18	9.83	8.17
23	0.22	0	0.22
Generation decrement			
1	0.4	0.79	0.4
2	12.16	6.67	6.14
23	0	0.29	0
13	12.89	6.96	10.59

Table 8
Demand response contribution for congestion management (MW).

DR bus number	With DR with FACTS	With DR without FACTS
7	1.4	1.6
8	1.6	2.2
12	0.8	0.8
17	0.4	0.6
19	0.6	0.8
21	1.2	1.2
30	0.4	0.8

Table 9
The reference setting of the controller.

Controller	Reference setting (pu)
TCSC	−0.0835
SVC	0.0997

4.2. Results and discussion

Using the software system developed and system data given in Section 4.1, the results of market clearing together with congestion management are obtained and discussed in this section. Applying the procedure in Section 3.2, the electricity market is cleared without considering the electricity network. The generator schedule following electricity market clearing is shown in Table 6.

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 in Section 3.3. 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.

Table 10
Total cost of market operation and re-dispatch cost in different options.

	Without DR with FACTS	With DR with FACTS	With DR without FACTS
Total market cost ($/h)	19,150	17,761	19,364
Total re-dispatch cost($)	4849	3460	5063

Option 3. With demand response and without FACTS devices.

Results of generation re-dispatch for congestion management for options 1–3 are given in Table 7. The total amount of re-dispatch for generators without using demand response (option 1) is noticeably higher in comparison with two other options. This reduction is a consequence of using combination of incentive-based demand response programs and FACTS devices.

The load reduction associated with each responsive demand is presented in Table 8. This table shows the demand response locations and the reduction level that is achieved based on the solution of the optimization problem presented in Section 3.3. The optimal FACTS devices input references for congestion management is presented in Table 9. The total cost of market operation in three different options are shown in Table 10. Comparison of different options shows that using the combination of DR and FACTS devices can reduce the total market cost (including market clearing and congestion cost). The re-dispatch costs are shown separately in Table 10 for comparison purpose.

As indicated in Table 10, the total market cost is the lowest when the market operator deployed the combination of FACTS and DR programs.

5. 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 mixed integer 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.

Appendix A

A.1. Static model of TCSC

In the current paper, the static model of TCSC is used and the maximum line compensation by TCSC is limited to 50%. In the steady-state operation, the equivalent TCSC reactance is presented as follows:

$$X_{tcsc} = X_{tcsc\,ref} \tag{A.1}$$

In (A.1) X_{tcsc} and $X_{tcscref}$ are the reactance and its reference value, respectively. On this basis, a TCSC is represented as a controllable reactance as shown in Fig. A.1

The nodal powers at nodes K and L in Fig. A.1 are described as follows:

$$P_K + j \cdot Q_K = V_K \cdot \left[\sum_{i \neq L} Y_{Ki} V_i + \frac{(V_K - V_L)}{j \cdot X_{tcsc}} \right]^* \tag{A.2}$$

$$P_L + j \cdot Q_L = V_L \cdot \left[\sum_{i \neq K} Y_{Li} V_i + \frac{(V_L - V_K)}{j X_{tcsc}} \right]^* \tag{A.3}$$

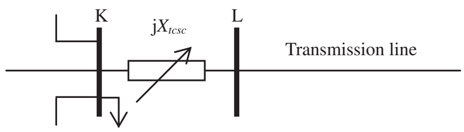

Fig. A.1. TCSC model.

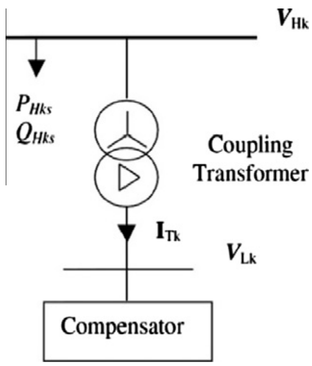

Fig. A.2. The SVC connected to the grid via a transformer.

In (A.2) and (A.3), Y_{Ki} and Y_{Li} are the elements (K,i) and (L,i) of the admittance matrix of the power system excluding the TCSC; V_K, V_L and V_i are nodal voltages at nodes K, L and i, respectively.

A.2. Static model of SVC

SVC has capacitive and inductive characteristics, and is predominantly utilized to improve voltage profile, reduce network active power loss, and enhance security margin. A typical SVC, connected to the network via a coupling transformer, is shown in Fig. A.2. The active and reactive-power constraint Eqs. (A.4) and (A.5), are applicable to the high-voltage node:

$$P_{HK} = P_{HKs} \tag{A.4}$$

$$Q_{HK} = Q_{HKs} \tag{A.5}$$

where P_{HK} and Q_{HK} are nodal active and reactive-power at the high-voltage node.

However, there is another constraint at the high-voltage node in Fig. A.2 as its voltage magnitude is controlled based on steady-state terminal voltage and current characteristic at the supply frequency as shown in Fig. A.3:

$$|V_{Hk}| = V_{refk} + a_k \cdot I_{Tk} \tag{A.6}$$

In (A.3), $|V_{Hk}|$ is the magnitude of the voltage at the high voltage node of SVC; V_{refk}, a_k and I_{Tk} are reference voltage, slope reactance and current of SVC, respectively.

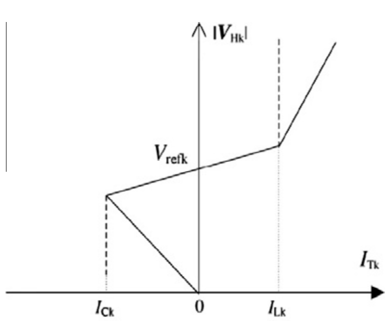

Fig. A.3. The operating limit of SVC.

The linear control represented by (A.3) is valid only when the operating limits of SVC are not exceeded. For SVC, the operating limits are specified in terms of susceptances:

$$B_{Lsvck} \leqslant B_{svck} \leqslant B_{Csvck} \tag{A.7}$$

where B_{svck}, B_{Csvck} and B_{Lsvck} are equivalent susceptance, limit of capacitive and inductive susceptance of SVC, respectively.

References

[1] Christie RD, Wollenberg BF, Wangensteen I. Transmission management in the deregulated environment. Proc IEEE 2000;88:170–95.
[2] Kumar A, Srivastava SC, Singh SN. Congestion management in competitive power market: a bibliographical survey. Electr Power Syst Res 2005;76:153–64.
[3] Acharya N, Mithulananthan N. Locating series FACTS devices for congestion management in deregulated electricity markets. Electr Power Syst Res 2007;77:352–60.
[4] Besharat H, Taher SA. Congestion management by determining optimal location of TCSC in deregulated power systems. Int J Electr Power Energy Syst 2008;30:563–8.
[5] Nguyen TT, Nguyen VL. Application of wide-area network of phasor measurements for secondary voltage control in power systems with FACTS controllers. In: Power engineering society general meeting, IEEE2005, vol. 3; 2005. p. 2927–34.
[6] Rahimzadeh S, Tavakoli Bina M. Looking for optimal number and placement of FACTS devices to manage the transmission congestion. Energy Conver Manage 2011;52:437–46.
[7] Singh SN, David AK. Optimal location of FACTS devices for congestion management. Electr Power Syst Res 2001;58:71–9.
[8] Ying X, Song YH, Chen-Ching L, Sun YZ. Available transfer capability enhancement using FACTS devices. IEEE Trans Power Syst 2003;18:305–12.
[9] Tuan LA, Bhattacharya K, Daalder J. Transmission congestion management in bilateral markets: an interruptible load auction solution. Electr Power Syst Res 2005;74:379–89.
[10] Bompard E, Carpaneto E, Chicco G, Gross G. The role of load demand elasticity in congestion management and pricing. In: Power Engineering Society Summer Meeting, IEEE2000, vol. 4; 2000. p. 2229–34.
[11] Singh K, Padhy NP, Sharma J. Congestion management considering hydro-thermal combined operation in a pool based electricity market. Int J Electr Power Energy Syst 2011;33:1513–9.
[12] Kirschen DS. Demand-side view of electricity markets. IEEE Trans Power Syst 2003;18:520–7.
[13] Strbac G. Demand side management: benefits and challenges. Energy Policy 2008;36:4419–26.
[14] Albadi MH, El-Saadany EF. Demand response in electricity markets: an overview. In: Power engineering society general meeting, IEEE2007; 2007. p. 1–5.
[15] Acharya N, Mithulananthan N. Influence of TCSC on congestion and spot price in electricity market with bilateral contract. Electr Power Syst Res 2007;77:1010–8.
[16] Le Anh T, Bhattacharya K. Competitive framework for procurement of interruptible load services. IEEE Trans Power Syst 2003;18:889–97.
[17] Fahrioglu M, Alvarado FL. Designing incentive compatible contracts for effective demand management. IEEE Trans Power Syst 2000;15:1255–60.
[18] Aazami R, Aflaki K, Haghifam MR. A demand response based solution for LMP management in power markets. Int J Electr Power Energy Syst 2011;33:1125–32.
[19] Affonso CM. Silva LCPd. Potential benefits of implementing load management to improve power system security. Int J Electr Power Energy Syst 2010;32:704–10.
[20] Fu X, Wang X. Determination of load shedding to provide voltage stability. Int J Electr Power Energy Syst 2011;33:515–21.
[21] Sioshansi R, Short W. Evaluating the impacts of real-time pricing on the usage of wind generation. IEEE Trans Power Syst 2009;24:516–24.
[22] Parvania M, Fotuhi-Firuzabad M. Demand response scheduling by stochastic SCUC. IEEE Trans Smart Grid 2010;1:89–98.
[23] Shayesteh E, Yousefi A, Parsa Moghaddam M. A probabilistic risk-based approach for spinning reserve provision using day-ahead demand response program. Energy 2010;35:1908–15.
[24] Moura PS, de Almeida AT. Multi-objective optimization of a mixed renewable system with demand-side management. Renew Sust Energy Rev 2010;14:1461–8.
[25] Billinton R, Lakhanpal D. Impacts of demand-side management on reliability cost/reliability worth analysis. In: IEE Proc – generation, transmission and distribution, vol. 143; 1996. p. 225–31.
[26] Bhattacharya K, Bollen MHJ, Daalder JE. Real time optimal interruptible tariff mechanism incorporating utility-customer interactions. IEEE Trans Power Syst 2000;15:700–6.
[27] Horowitz I, Woo CK. Designing Pareto-superior demand-response rate options. Energy 2006;31:1040–51.

[28] Yusta JM, Khodr HM, Urdaneta AJ. Optimal pricing of default customers in electrical distribution systems: effect behavior performance of demand response models. Electr Power Syst Res 2007;77:548–58.
[29] Roos JG, Lane IE. Industrial power demand response analysis for one-part real-time pricing. IEEE Trans Power Syst 1998;13:159–64.
[30] Allen J, Wood BFW. Power generation, operation, and control. 2nd ed. Wiley-Interscience; 1996.
[31] Fred C, Schweppe MCC, Tabors Richard D, Bohn Roger E. Spot pricing of electricity. Boston: Kluwer Academic Publishers; 1989.
[32] Joon Young C, Seong-Hwang R, Jong-Keun P. Optimal real time pricing of real and reactive powers. IEEE Trans Power Syst 1998;13:1226–31.
[33] Kim BH, Baughman ML. The economic efficiency impacts of alternatives for revenue reconciliation. IEEE Trans Power Syst 1997;12:1129–35.
[34] Schweppe FC, Caramanis MC, Tabors RD. Evaluation of spot price based electricity rates. IEEE Trans Power Apparatus Syst 1985;PAS-104:1644–55.
[35] Conejo AJ, Galiana FD, Arroyo JM, Garcia-Bertrand R, Cheong Wei C, Huneault M. Economic inefficiencies and cross-subsidies in an auction-based electricity pool. IEEE Trans Power Syst 2003;18:221–8.
[36] Lawrence DJ, Neenan BF. The status of demand response in New York. In: Power engineering society general meeting, 2003, IEEE2003, vol. 4; 2003. p. 2274.
[37] Nguyen TT, Nguyen VL. Power system security restoration by secondary control. In: Power engineering society general meeting; 2007. p. 1–8.
[38] Nguyen TT, Nguyen VL. Power system security restoration by secondary control. In: Power engineering society general meeting, IEEE2007; 2007. p. 1–8.
[39] Nguyen TT, Yousefi A. Multi-objective approach for optimal location of TCSC using NSGA II. In: Power System Technology (POWERCON), International Conference on2010; 2010. p. 1–7.
[40] CPLEX TI. GAMS; 2008.
[41] Bompard E, Wene L, Napoli R. Network constraint impacts on the competitive electricity markets under supply-side strategic bidding. IEEE Trans Power Syst 2006;21:160–70.
[42] Aalami H, Yousefi GR, Moghadam MP. Demand response model considering EDRP and TOU programs. In: Transmission and distribution conference and exposition, IEEE/PES2008; 2008. p. 1–6.