pp.149:159

Congestion Management in Electricity Markets Using Demand Response Programs and Series FACTS Devices

Mohammad Moradi[1], MahmoudReza Haghifam[2], Soudabe Soleymani[3]

[1]Department of Electrical Engineering, Science and Research Branch, Islamic Azad University, Tehran, Iran.
Email: moradi_mohammad63@yahoo.com
[2]Department of Electrical and Computer Engineering, Tarbiat Modares University, Tehran, Iran. Email: haghifam@modares.ac.ir
[3]Department of Electrical Engineering, Science and Research Branch, Islamic Azad University, Tehran, Iran.
Email: soodabeh_soleymani@yahoo.com

Abstract

In today's restructured environment, congestion management plays an essential role in power system operation. Different methods are presented and discussed in this respect for congestion management in short-term and long-term intervals. It is attempted in the present paper to investigate the impact mechanism of FACTS devices and demand response programs together with generation re-dispatch as some facilities from transmission, consumption and generation sides on short-term congestion management of electricity market. For this purpose, Thyristor controlled Series Capacitor (TCSC) representing series FACTS devices and Direct Load Control (DLC) program representing demand response programs in day-ahead power pool market are mathematically modeled and results will be numerically studied and analyzed on the 14-bus IEEE test system.

Keywords: Congestion Management, Series FACTS Devices, Thyristor controlled Series Capacitor (TCSC), Demand Response Programs, Direct Load Control (DLC).

1. Nomenclatures

N_G	Number of participating generators
N_D	Number of consumers
N_{DR}	Number of consumers participating in demand response program
L_G	Number of blocks offered by generators
$u(n_g,t)$	Binary variable representing "on/off" state of unit "ng" at hour "t"
$su(n_g,t)$	Binary variable representing "start-up" state of unit "ng" at hour "t"
$sd(n_g,t)$	Binary variable representing "shut-down" state of unit "ng" at hour "t"
$NLC(n_g)$	No-load cost of unit "ng"
$SUC(n_g)$	Start-up cost of unit "ng"
$SDC(n_g)$	Shut-down cost of unit "ng"
$\rho_{Pg}(n_g,l_g,t)$	Price offered by unit "ng" to generate in block "lg" at hour "t"
$P_g^{offer}(n_g,l_g,t)$	Active power offered by unit "ng" to generate in block "lg" at hour "t"
$P_g(n_g,l_g,t)$	Active power generated by unit "ng" in block "lg" at hour "t"
$P_g^{min}(n_g)$	Minimum power output of unit "ng"

$P_g^{max}(n_g)$	Maximum power output of unit "ng"
$P_d(n_d,t)$	Active power demand of consumer "nd" at hour "t"
$P_{dr}(n_{dr},t)$	Active power demand of consumer "ndr" at hour "t", after participating in demand response program
$RampDown^{max}(n_g)$	Maximum ramp-down rate of unit "ng"
$RampUp^{max}(n_g)$	Maximum ramp-up rate of unit "ng"
$DownTime(n_g,t)$	Down-time of unit "ng" until hour "t"
$UpTime(n_g,t)$	Up-time of unit "ng" until hour "t"
$DownTime^{min}(n_g)$	Minimum down-time of unit "ng"
$UpTime^{min}(n_g)$	Minimum up-time of unit "ng"
$P^{max}(n_1,n_2)$	Maximum transmissible power flow through the line between buses "n1" and "n2" (in MW)
$\delta(n,t)$	Voltage angle of bus "n" at hour "t"
$B(n_1,n_2)$	Element (n1, n2) in susceptance matrix of DC power flow
ref	System reference bus
$baseMVA$	System base MVA
$CF(n_{dr})$	Contribution factor of consumer "ndr" in demand response program
$A(t)$	incentive of demand response program for each KWh of power decrement at hour "t"
k_{TCSC}	Compensation factor of line reactance by means of TCSC
k_{TCSC}^{min}	Minimum compensation factor of line reactance by means of TCSC
k_{TCSC}^{max}	Maximum Compensation factor of line reactance by means of TCSC
Y_{ij}^{old}	Element "ij" of system Ybus matrix before TCSC installation
Y_{ij}^{new}	Element "ij" of system Ybus matrix after TCSC installation
ΔY_{ij}	Change in element "ij" of system Ybus matrix after TCSC installation
$E(i,i)$	Self-elasticity of demand at hour "i"
$E(i,j)$	Cross-elasticity of demand between hours "i", "j"
$\rho(i)$	Electricity energy price at hour "i"
$\rho_0(i)$	Initial electricity energy price at hour "i"
$d(i)$	Demand value at hour "i"
$d_0(i)$	Initial demand value at hour "i"
$LDF_{l,p}$	Line Distribution Factor of Line "l" with respect to line "p"
x_l	Reactance of line "l" between buses "i","j"
x_p	Reactance of line "p" between buses "m","n"
$GSF_{l,k}$	Generation Shift Factor of Line "l" with respect to bus "k"
$X_{n,i}$	Element (n, i) in reactance matrix of DC power flow

2. Introduction

By obsolescence of conventional power systems and development of competitive markets, numerous challenges have been encountered; congestion occurrence is one of the most important challenges. The essential solution of congestion in the long-term is development and construction of transmission lines. This solution, however, is accompanied by environmental and political issues in addition to requiring enormous expenses. Short-term solutions include re-scheduling of contracts, generation re-dispatch, and even, load shedding in critical conditions. Besides being costly, these methods raise the prices by disrupting the market. Nonetheless in certain cases, some control devices such as FACTS and etc. are available that have low operation costs. On the other hand, with further availability of smart network infrastructures, the system operators are provided with other facilities called demand response programs, which can be utilized for alleviation or mitigation of congestion problem.

The following procedure is normally performed in restructured power systems and in holding one-sided or two-sided pool electricity markets: Independent System Operator (ISO) maximizes the social welfare (in two-sided auctions) or minimizes the generation costs (in one-sided auctions) after receiving production offers from suppliers and consumption offers from consumers (in two-sided auctions) or through assuming fixed consumption (in one-sided auctions). Accordingly, having obtained the market economic equilibrium point, generation value of generators and consumption value of consumers are determined in the time interval for which the market has been formed. However, because the respective interactions shall be established through electrical energy transmission system, such operations would be sometimes impossible due to physical restrictions in the transmission lines and networks. To resolve this problem commonly referred to as “congestion management” in electricity market contexts, the ISO -possessing the available options in the generation side, consumption side and also in the transmission system- would be able to design a strategy such that the network constraints are observed with minimal reduction in the social welfare or increase in the generation cost. Consequently, energy transmission becomes possible as such. These options might include generation re-dispatch in the generation side, demand response programs in the consumption side, and FACTS devices in the transmission system. In order to have an optimal usage of the available facilities for congestion management, the system operator must choose and apply the best scenario from economic, technical, and environmental aspects with the aid of models that incorporate impact of these facilities on congested lines and also analysis of different scenarios resulting from combination of the parameter affecting the model responses.

It is attempted in the present research to analyze the impact mechanism of these facilities (FACTS devices and demand response programs) as well as generation re-dispatch as options for short-term congestion management through modeling of Thyristor Controlled Series Capacitor (TCSC) which represents series FACTS devices and Direct Load Control (DLC) program which represents demand response programs. Since issues like minimum up-time and down-time of units, also start-up and shut-down costs of them significantly affect the on/off schedules of units and can accordingly result in price volatility at certain hours [1], thus the respective market is considered as a day-ahead pool market based on unit commitment scheduling.

The current paper is composed of different parts; sections 3 and 4 are respectively devoted to brief description of FACTS devices and demand response programs. The mathematical model of day-ahead market is proposed based on unit commitment scheduling in section 5. And in section 6, the proposed model is numerically implemented on the 14-bus IEEE test system. Finally, section 7 incorporates the conclusions.

3. FACTS devices

This technology is based on application of controllable-power electronic devices for enabling transmission systems to utilize these systems proportional to their thermal capacities through controlling three main parameters i.e. impedance, voltage amplitude and angle [2]. In general, FACTS devices can be divided into four major categories considering their way of connection to the network [3]:

- Series controllers
- Parallel controllers
- Series-series hybrid controllers
- Series-parallel hybrid controllers

If the FACTS devices are applied to control the current or power or to damp the oscillations, series controllers will be more powerful and cost-effective than the parallel ones (with equal MVA values). Nonetheless, parallel controllers are very suitable for voltage control in their point of connection to the network (or around their connection points).

According to above discussions, in terms of technical and economic assessments, series FACTS devices are the best choices among the variety of FACTS devices for resolving congestion problem in transmission system. Meanwhile, TCSC is one of the most suitable choices for the aforementioned objective, thanks to flexible and smooth control of line impedance and high responsivity. Effective application of these devices could lead to alleviation or mitigation of line congestions, and as a result, improvement in system security margin [4]. Therefore, this device will be modeled in the following section.

- TCSC static model:

Impedance model can be used for static modeling of TCSC [5]. In the impedance model, as observed in Fig.1, TCSC is considered as a series static reactance ($-jx_c$) between “i”th and “j”th buses. This causes the system Y_{bus} matrix to change.

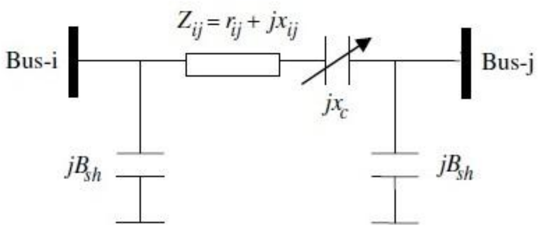

Fig.1. TCSC impedance model

Y_{bus} matrix changes after TCSC installation in “ij”th line as below:

$$Y_{ii}^{new} = Y_{ii}^{old} + \Delta Y_{ij} \quad (1)$$

$$Y_{ij}^{new} = Y_{ij}^{old} - \Delta Y_{ij} \quad (2)$$

$$Y_{jj}^{new} = Y_{jj}^{old} + \Delta Y_{ij} \quad (3)$$

Where:

$$\Delta Y_{ij} = \frac{x_c r_{ij}(x_c - 2x_{ij}) - x_c(r_{ij}^2 - x_{ij}^2 + x_c x_{ij})}{(r_{ij}^2 + x_{ij}^2)(r_{ij}^2 + (x_{ij} - x_c)^2)}$$

- Optimal place of TCSC:

To determine the optimal place of TCSC for managing congestion in the network, Line Distribution Factors (LDF) derived from DC power flow studies can be used via equation (4) [6]:

$$LDF_{l,p} = \frac{\frac{x_p}{x_l}(X_{n,i}-X_{j,n}-X_{m,i}+X_{j,m})}{x_p-(X_{n,n}+X_{m,m}-2X_{n,m})} \quad (4)$$

Considering the fact that LDF sensitivity factors are representative of flow variation in a line is caused by change in another line flow. Therefore, the line with smallest positive LDF factor compared to the congested line(s) will be the optimal place for TCSC installation because increase in the respective line flow leads to maximum reduction in the flow(s) of congested line(s).

4. Demand response programs

According to a definition by US Department of Energy (DOE), demand response signifies: "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" [7].

Demand response programs are divided into two primary categories and each category includes several major options [8]:

- Incentive-based demand response
  - Direct load control
  - Interruptible/curtailable rates
  - Demand bidding/buyback programs
  - Emergency demand response programs
  - Capacity market programs
  - Ancillary-services market programs
- Time-based rates
  - Time-of-use
  - Critical-peak pricing
  - Real-time pricing

As the present paper is focused on Direct Load Control (DLC) program, the next section briefly discusses this program.

- Direct Load Control (DLC) program:

In this program, utility or system operator can remotely disconnect the costumer's electrical equipment by means of a controllable switch in exchange for an incentive payment or bill credit on short notice to address system or local reliability contingencies. Normally, this happens during the electrical peak loads and when the prices are high. The instances of this situation include demands such as air conditioners and water heaters [9].

- Load economic model in DLC program:

In the beginning of the deregulation, usually consumers had not effective participation in the power markets and therefore they were not able to response to the prices effectively. Fig.2 shows how the demand elasticity could effect on electricity prices [10].

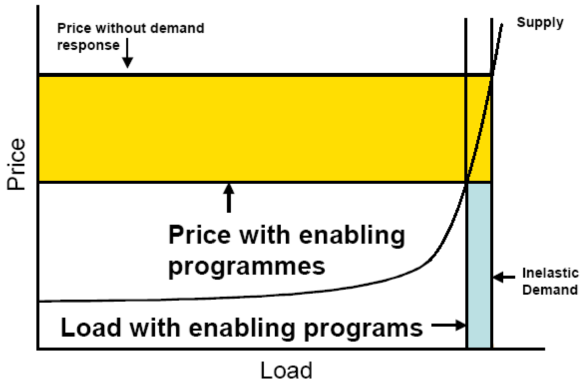

Fig.2. Effect of demand variation on the electric energy price

Elasticity is defined as the demand sensitivity with respect to the price [11]:

$$E = \frac{\partial d}{\partial \rho} \cdot \frac{\rho_0}{d_0} \quad (5)$$

If the electric energy prices vary for different periods, then the demand reacts one of followings:

- Some of loads are not able to move from one period to another (e.g. illuminating loads) and they could be only "on" or "off". So, such loads have sensitivity just in a single period and it is called "self-elasticity" [10], and it always has a negative value.
- Some consumption could be transferred from the peak period to the off-peak or low periods. Such behavior is called multi-period sensitivity and it is evaluated by "cross-elasticity". This value is always positive.

According to equation (6), self-elasticity (E(i, i)) and cross-elasticity (E(i, j)) can be written as:

$$\begin{cases} E(i,i) = \frac{\Delta d(i)}{\Delta \rho(i)} \leq 0 \\ E(i,j) = \frac{\Delta d(i)}{\Delta \rho(j)} \geq 0 \end{cases} \quad (6)$$

The detailed process of modeling and formulating how the DLC program effects on the electricity demand and how the maximum benefit of customers is achieved, are discussed in [12]. Accordingly the final responsive economic model is presented by equation (7):

$$d(i) = d_0(i).\left\{1 + E(i,i).\frac{(\rho(i)-\rho_0(i)+A(i))}{\rho_0(i)}\right\} + d_0(i).\left\{\sum_{\substack{j=1 \\ j\neq i}}^{24} E(i,j).\frac{(\rho(j)-\rho_0(j)+A(j))}{\rho_0(j)}\right\}$$
$$i = 1, 2, \dots, 24 \quad (7)$$

The above equation shows how much the customer's demand should be, in order to achieve maximum benefit in a 24 hours interval.

- Optimal place of responsive demand:

Generation shift factors (GSF) derived from DC power flow studies are used to determine the optimal place of responsive demand; these sensitivity factors are evaluated via Equation (8) [6]:

$$GSF_{l,k} = \frac{1}{x_l}\left(X_{i,k} - X_{j,k}\right) \quad (8)$$

Due to the fact that GSF sensitivity factors represent flow variation in a line results from changes in the power injected into a bus. Thus, the bus with the largest negative GSF factor compared to the congested line(s) will be the best place for responsive demand(s) because this means, reduction of consumed power in the respective bus (equivalent of increasing the injected power in the same bus) leads to maximum reduction in the flow(s) of congested line(s).

5. Mathematical model of day-ahead electricity market based on unit commitment scheduling

5.1. Ignoring the network:

In this state, the ISO plans the units' commitment after receiving complex offers including electrical energy sales offers along with information such as no-load, start-up and shut-down costs, minimum up and down-times, ramp rates, and so on by suppliers and also by considering the network load at each hour. The planning is made such that the network and power flow constraints are not observed in order to achieve the economic equilibrium point for each hour of the schedule intervals. The optimization problem in this state is formulated as follows:

$$Min\ \sum_{t=1}^{24}\{\sum_{n_g}^{N_G}\left[\sum_{l_g}^{L_G}\left(\rho_{Pg}(n_g,l_g,t)\times P_g(n_g,l_g,t)\right)\right] + NLC(n_g)\times u(n_g,t) + SUC(n_g)\times su(n_g,t) + SDC(n_g)\times sd(n_g,t)\} \quad (9)$$

$Subject\ to$:

$$P_g(n_g,l_g,t) \le P_g^{offer}(n_g,l_g,t)\times u(n_g,t) \quad (10)$$

$$\sum_{l_g}^{L_G} P_g(n_g,l_g,t) \ge P_g^{min}(n_g)\times u(n_g,t) \quad (11)$$

$$\sum_{l_g}^{L_G} P_g(n_g,l_g,t) \le P_g^{max}(n_g)\times u(n_g,t) \quad (12)$$

$$\sum_{l_g}^{L_G} P_g(n_g,l_g,t-1) - P_g(n_g,l_g,t) \le RampDown^{max}(n_g) \quad (13)$$

$$\sum_{l_g}^{L_G} P_g(n_g,l_g,t) - P_g(n_g,l_g,t-1) \le RampUp^{max}(n_g) \quad (14)$$

$$DownTime(n_g,t-1) \ge DownTime^{min}(n_g)\times su(n_g,t) \quad (15)$$

$$UpTime(n_g,t-1) \ge UpTime^{min}(n_g)\times sd(n_g,t) \quad (16)$$

$$\sum_{n_g}^{N_G}\sum_{l_g}^{L_G} P_g(n_g,l_g,t) = \sum_{n_d}^{N_D} P_d(n_d,t) \quad (17)$$

$$su(n_g,t) - sd(n_g,t) = u(n_g,t) - u(n_g,t-1) \quad (18)$$

Here, Equation (9) represents the objective function of optimization problem which incorporates the costs associated with electrical energy like energy purchase, no-load, start-up and shut-down costs of generation units. Equation (10) indicates the upper limit of purchasable blocks of electrical energy; Equations (11) and (12) represents the constraints of maximum and minimum energy that can be generated by the participating units while Equations (13) and (14) pertain to constraint of maximum ramp-down and ramp-up rates of participating units. Equations (15) and (16) show the constraints of minimum down and up-times of participating units. Equation (17) dictates the equality constraint of electrical energy generation and demand, and finally, Equation (18) represents a logical relation between binary variables in the optimization problem.

5.2. Considering the network:

As mentioned in the introduction section, when network and power flow constraints are observed in the electricity market, energy transmission in accordance with market equilibrium point might be impossible at the respective hours due to congestion occurrence in the network. Thereby, in order to manage short-term congestion in the network using the generations re-dispatch, demand response programs and FACTS devices as well as better analysis of results, the respective optimization problem will be considered in four different states depending on presence or absence of demand response programs and FACT devices.

5.3. In the absence of demand response programs and FACTS devices:

By changing the generations schedule of suppliers in this state (generation re-dispatch), the ISO also establishes the network and power flow constraints besides observing the constraints related to unit commitment scheduling in the least-cost manner. Obviously, difference between the cost of this state and the initial cost (without considering the network) will represent the congestion cost of the network. The objective function and the constraints of optimization problem in this state resemble those described in A. The only difference is addition of the following constraints:

$$\sum_{l_g}^{L_G} P_g(n,l_g,t) - P_d(n,t) = \sum_{n_2=1}^{N} B(n,n_2)\times\left(\delta(n,t)-\delta(n_2,t)\right)\times baseMVA \quad (19)$$

$$n \ne ref; \delta(n,t) = 0 \quad ; \quad n = ref \quad (20)$$

$$B(n_1,n_2)\times\left(\delta(n_1,t)-\delta(n_2,t)\right)\times baseMVA \le P^{max}(n_1,n_2) \quad (21)$$

$$B(n_1,n_2)\times\left(\delta(n_1,t)-\delta(n_2,t)\right)\times baseMVA \ge -P^{max}(n_1,n_2) \quad (22)$$

Where; Equation (19) represents DC power flow equation, Equation (20) describes zero voltage angle in the reference bus of the network, and, Equations (21) and (22) are indicative of the constraints of maximum transmissible flows through the network lines in KW.

5.3. In the presence of demand response programs:

In this state, through signing contracts with the consumers participating in the demand response programs and determination of their participation percentages and elasticity values coupled with making changes in the generations schedule of participating units (generation re-dispatch), the ISO establishes the network and power flow constraints at minimum costs besides observing the constraints related to unit commitment scheduling.

The objective function and constraints of optimization problem are similar to those in case B-1 just with the difference that Equations (17) and (19) are modified due to variation in the consumption level of demand response program's participants as below:

$$\sum_{n_g}^{N_G}\sum_{l_g}^{L_G} P_g(n_g,l_g,t) = \sum_{n_d}^{N_D}\left[P_d(n_d,t) - \left(CF(n_d)\times P_d(n_d,t) - P_{dr}(n_d,t)\right)\right] \quad (23)$$

$$\sum_{l_g}^{L_G} P_g(n,l_g,t) - \left[P_d(n,t) - \left(CF(n)\times P_d(n,t) - P_{dr}(n,t)\right)\right] = \sum_{n_2=1}^{N} B(n,n_2)\times\left(\delta(n,t) - \delta(n_2,t)\right)\times baseMVA \quad (24)$$

$; \ n \neq ref$

Note that the incentive in the demand response program of this state can also be optimized for congestion management in the respective market. To do so, the implementation cost of DLC program shall be considered in the form of Equation (25) in the objective function and also Equation (7) must be supposed as an equal constraint in the constraints of the optimization problem.

$$DLCcost = \sum_{t=1}^{24}\sum_{n_{dr}}^{N_{DR}}\left[A(t)\times\left(CF(n_{dr})\times P_d(n_{dr},t) - P_{dr}(n_{dr},t)\right)\right] \quad (25)$$

5.4. In the presence of FACTS devices:

In this state, the ISO establishes the network and power flow constraints at minimum costs besides observing the constraints related to unit commitment scheduling through changing the compensation level of the line reactance by means of FACTS devices mounted in the system (in this case: TCSC) coupled with modification of the generations schedule of the participating units (generation re-dispatch).

The objective function and constraints of optimization problem are similar to those in case B-1 just with the difference that matrix B in Equations (19), (21) and (22) changes commensurate with characteristics of the mounted TCSC due to use of TCSC impedance model. Furthermore, Equation (26) which reflects the limits associated with compensation level of line reactance by TCSC is considered in the constraints of optimization problem.

$$k_{TCSC}^{min} \leq k_{TCSC} \leq k_{TCSC}^{max} \quad (26)$$

5.5. In the presence of demand response programs and FACTS devices:

In this state, the ISO, establishes network and power flow constraints in the least-cost manner besides observing the constraints related to unit commitment scheduling via modifying the generations schedule of the participating units (generation re-dispatch) as well as simultaneous application of demand response programs and FACTS devices.

The objective function and constraints of optimization problem in this state is a combination of two former states i.e. B-2 and B-3.

6. Case Study

In this section, the model proposed in the former section is numerically studied and analyzed on the 14-bus IEEE test system. As observed in Fig.3, the system under study contains 14 buses, 20 lines, and 4 generators. The needed information for this system can be observed in the appendix section.

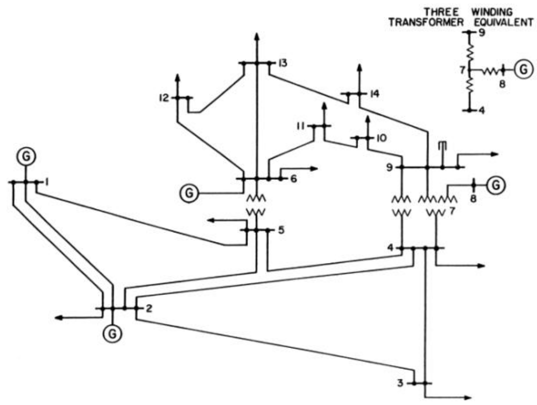

Fig.3. 14-bus IEEE test system

Also, total network load in 24 hours is illustrated in Fig.4, based on which low-load (00:00 to 7:59), off-peak (8:00 to 16:59 and 22:00 to 23:59) and peak intervals (17:00 to 21:59) were determined.

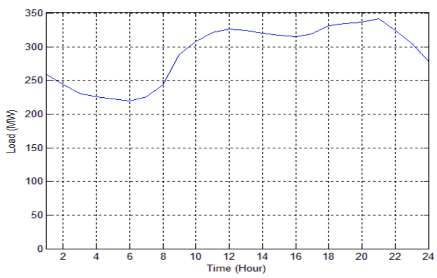

Fig.4. Network total load in 24 hours

Here, it is assumed that the generators' offers are made based on marginal costs. This assumption for offering mechanism is made for simplification because of having no effect on the analysis.

6.1. Day-ahead market settlement without considering the network:

Market settlement process is established in this part without considering the network and power flow constraints in order to obtain the market economic equilibrium point at each hour. In this state, the generation cost of units during 24 hours equals 365226.51 ($) and the rest of results are presented in Table.1.

Table.1
Generation values of units at each hour (MWh)

Hour	Generator No. 1	2	3	4
1	17	102	140	0
2	0	104.60	140	0
3	0	91.40	140	0
4	0	86.20	140	0
5	0	82.40	140	0
6	0	80	140	0
7	0	86.30	140	0
8	0	104.70	140	0
9	0	148.70	140	0
10	0	110	140	58.40
11	0	110	140	71.30
12	0	110	140	76.80
13	0	110	140	74.10
14	0	110	140	70.40
15	0	110	140	67.30
16	0	110	140	64.90
17	0	110	140	69.80
18	0	110	140	81.40
19	0	110	140	84.60
20	0	110	140	86.70
21	0	110	140	91.80
22	0	110	140	74.20
23	0	109.90	140	55
24	0	138.30	140	0

Now, in the case of applying the results obtained in this stage, power flow computations are performed on the network under study. Comparing the line flows with their thermal capacities, it is observed that the power transmitted through line 13-6 has exceeded the maximum transmissible flow through this line (30 KW), and therefore, the respective line is congested. According to Table (2), these congestion hours mainly occur during the peak, and occasionally, in the off-peak and even in the low-load interval.

Table.2
Flow through line 13-6 (MW)

Hour	Line flow	Hour	Line flow
1	31.39	13	30.86
2	30.64	14	30.86
3	29.81	15	30.98
4	29.25	16	30.53
5	29.01	17	30.31
6	29.06	18	30.39
7	29.89	19	30.81
8	31.38	20	31.69
9	33.53	21	30.79
10	31.34	22	31.20
11	31.19	23	31.07
12	31.17	24	32.99

6.2. Day-ahead market settlement, considering the network:

Keeping in mind the results of the former stage, it is observed that electrical energy transmissions are not possible at certain hours due to congestion occurrence. Thus, the efforts are made to solve the respective problem for short-term congestion management in this network by considering four states based on presence or absence of demand response programs and FACTS devices.

6.2.1. In the absence of demand response programs and FACTS devices:

In this state, generation re-dispatch is the only available option for congestion management in the network. After executing this re-dispatch, the total cost of market settlement is equal to 366229.62 ($), suggesting an increase of 1002.11 ($) compared to the former state (A), and, this cost is in fact the congestion cost of the network during 24 hours. Generation re-dispatch value in this state with respect to state (A) is 404.7 (MW) per 24 hours; the details are given in Table.3.

According to Tables (1) and (3), it can be seen that unit 4, initially in the "off" state, is switched on for alleviating congestion in the network.

6.2.2. In the presence of demand response programs:

In this state, demand response programs are deployed along with generation re-dispatch for short-term congestion management of the network. For this purpose, the DLC program is considered as a representative of incentive programs.

For simplicity in the current study, the elasticity values of demands for these program participants are assumed equal and according to Table.4. The results are nearly identical for different elasticity values but the computations will be by far more complex.

Table.3
The generations re-dispatch values of units at each hour with respect to the market equilibrium point (MWh)

Hour	Generator No. 1	2	3	4
1	0	-42	0	42
2	0	6.25	-6.25	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	0	-44.70	0	44.70
9	0	-58.40	0	58.40
10	0	-22.09	0	22.09
11	0	-19.73	0	19.73
12	0	-19.38	0	19.38
13	0	-14.14	0	14.14
14	0	-14.22	0	14.22
15	0	-16.16	0	16.16
16	0	-8.69	0	8.69
17	0	-5.06	0	5.06
18	0	-6.50	0	6.50
19	0	-13.34	0	13.34
20	0	-4.69	-8.61	13.30
21	0	-5.37	-2.83	8.20
22	0	-19.90	0	19.90
23	0	-17.69	0	17.69
24	0	-55	0	55

Table.4
Price elasticity of demand for DLC program participants

	Low	Off-Peak	Peak
Low	-0.09	0.02	0.015
Off-Peak	0.02	-0.09	0.012
Peak	0.015	0.012	-0.09

Also, the participation percentage of participants in this program equals 50% and the incentive is paid merely for the peak interval. The initial electricity price is also considered constant and equal to 60 ($/MWh).

Through implementation of the DLC programs in buses 13 and 14 (the best places for running DLC program with respect to the GSF sensitivity factors), it is observed that the generation cost in 24 hours for implementing this program together with generation re-dispatch equals 365697.36 ($). Implementation cost of DLC program is 171.22 ($), and consequently, the total cost is equal to 365868.58 ($). Also in this state, the incentive is equal to 15.98 ($/MWh) and generation re-dispatch values of units and consumption variation of responsive demands will be according to Table.5.

Table.5
Generation re-dispatch values of units and consumption variation of responsive demands at each hour with respect to market equilibrium point (MWh)

Hour	Generator No. 1	2	3	4	Bus No. 13	14
1	0	-42	0	42.28	0.13	0.15
2	0	7.71	-7.44	0	0.13	0.14
3	0	0.26	0	0	0.12	0.14
4	0	0.25	0	0	0.12	0.13
5	0	0.25	0	0	0.12	0.13
6	0	0.25	0	0	0.12	0.13
7	0	0.34	-0.08	0	0.12	0.13
8	0	-44.70	0	44.98	0.13	0.15
9	0	-59.98	0	60.23	0.12	0.13
10	0	-23.80	0	24.07	0.13	0.14
11	0	-21.49	0	21.77	0.13	0.15
12	0	-21.18	0	21.46	0.13	0.15
13	0	-15.89	0	16.17	0.13	0.14
14	0	-15.94	0	16.22	0.13	0.14
15	0	-17.89	0	18.16	0.13	0.14
16	0	-10.34	0	10.60	0.12	0.14
17	0	-6.69	0	6.95	0.12	0.13
18	0	0	0	-1.99	-0.94	-1.05
19	0	-0.10	0	-1.99	-0.99	-1.10
20	0	-13.60	0	11.33	-1.08	-1.19
21	0	0	0	-2.20	-1.05	-1.16
22	0	-6.25	0	4.09	-1.02	-1.13
23	0	-19.42	0	19.69	0.13	0.14
24	0	-54.74	0	55	0.12	0.13

According to Table.5, the value of generation re-dispatch in this state with respect to state (A) is 384.9 (MW) in 24 hours indicating a reduction of 19.8 (MW) compared to state B-1.

6.2.3. In the presence of FACTS devices:

Besides generation re-dispatch in this state, FACTS devices are used for short-term congestion management of the network. For this purpose and due to high efficiency of series FACTS devices with regard to congestion management, TCSC is considered as the representative of these devices.

Applying TCSC in line 6-12 (the best place for TCSC presence with respect to LDF sensitivity factors), generation cost in 24 hours equals 365250.61 ($) due to 50% compensation capability of line reactance. In this state, generation re-dispatch values of units and line compensation levels by means of TCSC are shown in Table.6.

According to Table.6, generation re-dispatch value in this state is 55 (MW) per 24 hours with respect to state (A), suggesting a reduction of 349.7 (MW) compared to state (B-1). Furthermore, Table (1) implies that unit 4 is switched on only at hour 9 (which was initially in the "off" state) in this state to alleviate congestion in the network while this unit had been switched on at hours 1, 8, 9 and 24 in state B-1.

Table.6
Generation re-dispatch values of units (MWh) and compensation levels of line 6-12 by means of TCSC (%) at each hour with respect to market equilibrium point

Hour	Generator No. 1	2	3	4	Compensation Levels of Line
1	0	0	0	0	%50
2	0	0	0	0	%50
3	0	0	0	0	%0
4	0	0	0	0	%0
5	0	0	0	0	%0
6	0	0	0	0	%0
7	0	0	0	0	%0
8	0	0	0	0	%50
9	0	-55	0	55	%50
10	0	0	0	0	%50
11	0	0	0	0	%50
12	0	0	0	0	%50
13	0	0	0	0	%50
14	0	0	0	0	%50
15	0	0	0	0	%50
16	0	0	0	0	%50
17	0	0	0	0	%50
18	0	0	0	0	%50
19	0	0	0	0	%50
20	0	0	0	0	%50
21	0	0	0	0	%50
22	0	0	0	0	%50
23	0	0	0	0	%50
24	0	0	0	0	%50

6.2.4. In the presence of demand response programs and FACTS devices:

In this state, in addition to generation re-dispatch, demand response programs and FACTS device are simultaneously used for short-term network congestion management.

For this purpose, the DLC program is implemented in buses 13 and 14. It is also assumed that TCSC with 50% compensation capability of line reactance is present in line 6-12. The generation cost per 24 hours equals 364950.57 ($) in this state, implementation cost of the DLC program equals 147.02 ($), and as a result, the total cost is equal to 365097.59 ($). Also in this state, the optimal incentive equals 14.80 ($/MWh) which is 1.18 ($/MWh) smaller than state B-2. Generation re-dispatch values of units, consumption variations of responsive demands and line compensation levels by TSCS are according to Table.7.

According to Table .7, generation re-dispatch value in this state is 63(MW) per 24 hours with respect to state (A), suggesting a reduction of 341.7 (MW) compared to state (B-1) and an increment of 8 (MW) compared to state (B-3). This incremental value can be justified as follows: since the congested hour (i.e. 9) is among the off-peak hours, and also, taking into account the fact that generation cost per 24 hours in this state is 275.94 ($) lower than case (B-1), thus implementation of the DLC program with load shift and reduction in different time intervals would cause greater congestion at hour 9 and load reduction at peak hours, and as a consequence, mainly reduces generation cost instead of relieving congestions.

Table.7
Generation re-dispatch values of units, consumption variation of responsive demands (MWh) and compensation levels of line 6-12 by means of TCSC (%) at each hour with respect to market equilibrium point

Hour	Generator No. 1	2	3	4	Bus No. 13	14	Compensation
1	0	0.26	0	0	0.12	0.14	%50
2	0	0.26	0	0	0.12	0.13	%50
3	0	0.24	0	0	0.11	0.13	%1.98
4	0	0.23	0	0	0.11	0.12	%0.90
5	0	0.23	0	0	0.11	0.12	%0
6	0	0.23	0	0	0.11	0.12	%0
7	0	0.24	0	0	0.11	0.12	%2.07
8	0	0.26	0	0	0.12	0.14	%50
9	0	-54.77	0	55	0.11	0.12	%50
10	0	0	0	0.25	0.12	0.13	%50
11	0	0	0	0.26	0.12	0.14	%50
12	0	0	0	0.26	0.13	0.14	%50
13	0	0	0	0.26	0.12	0.13	%50
14	0	0	0	0.25	0.12	0.13	%50
15	0	0	0	0.25	0.12	0.13	%50
16	0	0	0	0.24	0.11	0.13	%50
17	0	0	0	0.24	0.11	0.13	%50
18	0	0	0	-1.85	-0.88	-0.97	%50
19	0	0	0	-1.94	-0.92	-1.02	%50
20	0	0	0	-2.10	-1.00	-1.10	%50
21	0	0	0	-2.04	-0.97	-1.07	%50
22	0	0	0	-2.00	-0.95	-1.05	%50
23	0	0.10	0	0.15	0.12	0.13	%50
24	0	1.13	-0.89	0	0.11	0.13	%50

For better comparison of different states which were discussed before, the generation costs and also total generation re-dispatch values per 24 hours for all states can be observed in Fig.5 and 6.

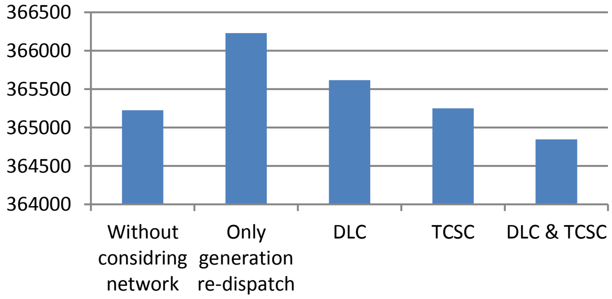

Fig.5. Generation costs in 24 hours for different states ($)

According to Fig.5 and 6, it seems that if the goal is just the removal of congestion and reduction of generation costs and generation re-dispatch values (with respect to market equilibrium point), then TCSC is a suitable tool for this purpose due to the fact that this device can reduce the transmitted power

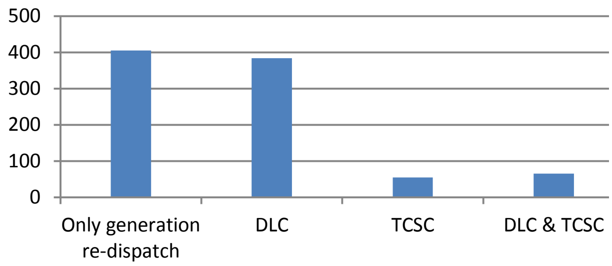

Fig.6. Total generation re-dispatch values in 24 hours for different states (MW)

in the congested line and also its operation cost is normally slight and negligible. In contrast, demand response programs are more effective in terms of load reduction and consequently, generation cost reduction but has a limited capability for congestion removal because of the fact that consumption of responsive demands usually decreases in one period and increases in another, and also, the congestion might occur at different hours such that these hours might be within peak, off-peak or even low-load intervals. On contrary, application of TCSC could lower congestion regardless of its occurrence hour.

7. Conclusion

Through modeling the Direct Load Control (DLC) program which represents demand response programs and TCSC modeling as a representative of series FACTS devices, and then, applying them in day-ahead electricity market based on unit commitment scheduling, a model was proposed in the present paper for analyzing impact mechanism of these two tools together with generation re-dispatch as options dedicated to short-term congestion management in the market. 14-bus IEEE test system was also used for numerical analysis of the respective model. Initially, the respective market was settled without considering the network and the economic equilibrium point of the market was accordingly determined for each hour. Taking the network into account in the subsequent stage, and as a result, congestion occurrence at certain hours, the short-term congestion management mechanism was investigated and analyzed in this network after considering four different states for alleviating such congestions based on presence and absence of demand response programs and FACTS devices together with generation re-dispatch.

References

[1] L. Jidong, Z. Zehui, Z. Li, H. Xueshan, “Evaluating Short Term Benefits of Demand Response”, IEEE 4th International Conference on Electric Utility Deregulation and Restructuring and Power Technologies (DRPT), pp.1211-1215, 2011.

[2] P. Moore, P. Ashmole, “Flexible AC Transmission Systems” Pt.1, Power Engineering Journal, Dec 1995.

[3] S. Grebex, Cherokaoui, A.J. Germond, “Optimal Location of FACTS Devices to Enhance Power System Security”, IEEE Power Tech Conference Proceeding, Vol.3, pp.23-26, Jun 2003.

[4] Y. Lue and A. Abur, “Improving System Static Security via Optimal Placement of Thyristor Controlled Series Capacitors (TCSC)”, IEEE Power Engineering Society Winter Meeting, Vol.2, pp.516-521, 2001.

[5] H. Besharat, S.A. Taher, “Congestion Management by Determining Optimal Location of TCSC in Deregulated Power Systems”, Electrical Power and Energy Systems, Elsevier, pp.563-568, 2008.

[6] Allen J. Wood and Bruce F. Wollenberg, “Power Generation, Operation & Control”, New York: Wiley, 1996.

[7] Federal Energy Regulatory Commission Staff, “Assessment of Demand Response and Advanced Metering”, Federal Energy Regulatory Commission, Docket AD-06-2-000, Aug 2006.

[8] Federal Energy Regulatory Commission Staff, “Assessment of Demand Response and Advanced Metering”, Federal Energy Regulatory Commission, Docket AD-06-2-000, Aug 2006.

[9] P. Jazayeri, A. Schellenberg, W.D. Rosehart, J. Doudna, “A Survey of Load Control Programs for Price and System Stability”, IEEE Transactions on Power Systems, Vol.20, No.3, pp.1504-1509, Aug 2005.

[10] A. Yousefi, E. Shayesteh, M. ParsaMoghaddam, “Enhancement of Spinning Reserve Capacity by means of Optimal Utilization of EDRP Program”, IASTED Conferences, Power and Energy Systems Conference, 2008.

[11] D. Kirschen, G. Strbac, “Fundamentals of Power System Economics”, John Wiley & Sons, 2004.

[12] H. Aalami, G.R. Yousefi, M. ParsaMoghadam, “Demand Response Model Considering EDRP and TOU Programs”, IEEE/PES Transmission and Distribution Conference & Exhibition, May 2008.

Appendix

Table.7
The data related to network generators

Generator No.	1	2	3	4
Bus No.	1	2	6	8
Min producible power (MWh)	17	12	14	11
Max producible power (MWh)	200	150	140	120
Max ramp-down rate (MW/h)	140	120	90	80
Max ramp-up rate (MW/h)	100	70	78	62
No-load cost ($)	300	300	300	300
Start-up cost ($)	60	69	150	90
Shut-down cost ($)	15	18	30	24
Min up-time (h)	4	3	5	4
Min down-time (h)	3	3	4	3
Initial state of production (MWh)	80	60	50	40
Initial up-time state (h)	3	14	17	9
Initial down-time state (h)	0	0	0	0

Table.8
The data related to generators' offers

Generator No.	Active power offered for generating in each block (MWh)			Price offered for generating in each block ($/MWh)		
1	80	70	50	64.80	73.80	81
2	60	50	40	53	58.50	63
3	50	45	45	41	42.90	44.70
4	55	35	30	56.65	59.35	61.30