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Demand Response in Real Time Congestion Management

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Abstract— **Load participation is vital for the Smart Grid development. As an effective tool to improve reliability, stability, and financial efficiency of the power grids, Demand Response (DR) has brought significant financial and technical benefits to power systems. Demand Side Management (DSM) is one of the most important methods which has been used to maximize the benefits of the electric power market participants. In this paper DR is modelled for Time-of-use (TOU) based on load elasticity model. As one of the price-based DR programs with less control costs, the Time-of-Use (TOU) program has been applied as default rate structure by many utility companies. To avoid financial risks and make the most profit out of the market, utility companies treat TOU as an effective strategy to change customers electricity consumption patterns. The main purpose of this work is determination of optimal Demand Response Program for reducing the market power and electricity price from the Independent System Operator viewpoint. The proposed model is implemented on IEEE 30 bus system.**

Keywords—TOU, Demand Response, Demand Side Management

I. INTRODUCTION

Demand Side Management (DSM) introduced by Electric Power Research Institute (EPRI) in the 1980s. DSM consists of a series of activities that governments or utilities design to change the amount or time of electric energy consumption, to achieve better social welfare or sometimes for maximizing the benefits of utilities or consumers. In fact, DSM is a global term that covers activities such as: Load Management, Energy Efficiency, Energy saving and so on. Electric power industry has been faced with restructuring and deregulation. Meanwhile a few new terms created in this new environment, such as "Demand Response" (DR). DR is defined by Department of Energy (DOE) 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 incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized". DR is able to change the amount and time of electric energy usage so that the best efficiency of consumption takes place in the peak interval. In this paper, we discuss about different DR methods, Especially TOU (Time of Use). Then the demand reaction to price is analyzed (self and cross elasticity). In section 3, DR is modeled considering the electricity spot price (TOU). The numerical results are shown and the effect of running TOU programs, are discussed.

II. DEMAND RESPONSE PROGRAM

In strategic plan of International Energy Agency (IEA), for 2004-2009 years, DR (analysis and implementation) is dedicated to United State of America [4]. Federal Energy Regulatory Commission (FERC) reported the results of DR investigations and implementations in US utilities and Power Markers [5,6]. In the report Various types of DR include:

A. Incentive-Based Programs:

a) Direct Load Control (DLC)

b) Curtailable Demand Response Program (CDRP)

c) Demand Bidding (DB)

d) Emergency Demand Response Program (EDRP)

e) Capacity Market Program (CMP)

f) Ancillary Service Market Program (ASMP)

B. Time-Based Programs:

a) Time Of Use (TOU) program

b) Real Time Pricing (RTP) program

c) Critical Peak Pricing (CPP) program

In this paper TOU is discussed and the following program is introduced briefly. In TOU program, the electricity prices in the low peak, off-peak and peak period will be cheap, moderate and high. By running this program, the customers especially who are able to move their consumption will adjust themselves with the prices. So, the peak demand will be reduced and loads will transfer from the peak period to off-peak or low periods.

Elasticity of demand can be defined as the ratio of the relative change in demand to the relative change in price. Elasticity can be written as [10],

$$E = \frac{\partial D}{\partial \rho} = \frac{\rho_o}{D_o} \cdot \frac{dD}{d\rho} \quad (1)$$

where,

E is the demand elasticity.

ρ_O is the initial electricity price in $/MWh.

D_o is the initial demand in MW.

The elastic loads are classified into self and cross elastic loads. Loads which are not able to move from one period to another (e.g. illuminating loads) and they could be only "on" or "off". Such loads are called self-elastic loads and they have a negative elasticity value. Loads which could be transferred from the peak period to the off-peak or low periods. Such loads are called cross elastic loads and they always have positive value

III. ECONOMIC LOAD MODEL

The amount of load that the customer can consume for the maximization of benefits is determined. Assuming that the customer changes his demand from initial value to final value, based on the value of electricity price:

$$\Delta D(i) = D_o(i) - D(i)(MWh) \ \forall i = 1:24 \quad (2)$$

Where,

$\Delta D(i)$ is the change in demand during ith hour.

$D_o(i)$ is the initial demand.

$D(i)$ is the demand after TOU.

The customers' benefit S($), for the i-th hour will be as following:

$$S(D(i)) = B(D(i)) - D(i).\rho(i)(\$) \ \forall i = 1:24 \quad (3)$$

Where,

S is the customers' benefit.

B is the benefit function.

$\rho(i)$ is the electricity price during ith hour.

To maximize the customers' benefit, $\frac{\partial S}{\partial D(i)}$ should be equal to zero:

$$\frac{\partial S}{\partial D(i)} = \frac{\partial B(D(i))}{\partial D(i)} - \rho(i) = 0 \quad \forall i = 1to24 \quad (4)$$

$$\frac{\partial B(D(i))}{\partial D(i)} = \rho(i) \ \forall i = 1to24 \quad (5)$$

The benefit function can be defined as:

$$B(D(i)) = B(D_o(i) + \rho_o[D(i) - D_o(i)]\{1 + \left(\frac{D(i) - D_o(i)}{2E(i) \cdot D_o(i)}\right) \forall i = 1to24 \quad (6)$$

$$\frac{\partial B(D(i))}{\partial D(i)} = \rho_o(i)\left\{1 + \frac{D(i)}{E(i) \cdot D_o(i)} - \frac{1}{E(i)}\right\} \forall i = 1to24 \quad (7)$$

Where,

$\rho_O(i)$ is the initial electricity price during ith hour.

Considering equations (5) and (6),

$$\rho(i) = \rho_o(i)\left\{1 + \frac{D(i)}{E(i) \cdot D_o(i)} - \frac{1}{E(i)}\right\} \forall i = 1to24 \quad (8)$$

The demand response to price variation will be as following:

$$D(i) = D_o(i).\left\{1 + \frac{E(i)[\rho(i) - \rho_o(i)]}{\rho_o}\right\} \quad (9)$$

The estimated demand in equation (9) depends on electricity price during peak, off-peak and low peak hour which are to be predicted by system operator.

A. Market Mechanism

Any market mechanism proposed for the short-run efficient determination of trades in a wholesale electricity market must address four tasks. Initially, the buyers and sellers who would benefit from trade must be identified. Next, these buyers and sellers must be matched so as to maximize total gains to trade. Third, a specific price and quantity level must be determined for each matched buyer-seller pair. Finally, trades between matched buyers and sellers must be carried out within the constraints of the electric power transmission grid. The practical advantage of an auction mechanism is that its trading and settlement rules do not require the clearinghouse to know in advance the number of participants, their private costs, or their privately held beliefs and preferences. Small numbers of buyers and sellers submit price offers repeatedly to a clearinghouse double auction in an attempt to maximize their profits. The buyers and sellers have multi-unit capacities and differentiated revenues and costs, private information that other traders cannot observe directly. Moreover, each buyer and seller continuously updates its price offers

B. Market Clearing

Customers can bid a price at which they would be willing to curtail their loads during times of congestion. The ISO clears the market without considering the line flow constraints. A modified auction dispatch based on bidding can be formulated as:

$$Max: \sum_{i=1}^{N_D} \sum_{k=1}^{N_{Di}} (\lambda_{DiK} P_{DiK}) - \sum_{j=1}^{N_g} C_j(P_g) \quad (10)$$

Where,

N_g is the total number of demand buses.

N_{Di} is the number of demand power blocks.

λ_{DiK} is the demand price blocks in \$/MWh.

N_g is the total number of generators.

C_j is the generation cost function.

P_g is the generated power in MW.

P_{DiK} is the demand power block in MW.

Subject to:

$$0 \le P_{DiK} \le P_{DiK}^{\max} \forall i = 1,\ldots N_{Di}, k = 1,\ldots N_{Di} \quad (11)$$

$$P_{gi}^{\min} \le P_{gi} \le p_{gi}^{\max} \forall i = 1,\ldots N_G \quad (12)$$

$$\sum_{i=1}^{N_D} \sum_{k=1}^{N_{Di}} P_{DiK} = \sum_{j=1}^{N_G} P_{gi} \quad (13)$$

The first term in equation (10) is the sum of accepted demand bids corresponding to their bid prices. The second term in equation (11) is the sum of accepted production bids corresponding to the bid prices. It should be noted that producer bids are considered convex and monotonically increasing; and consumer bids, concave and monotonically decreasing. The constraint in equation (13) specifies the size of the demand bids. The constraint in equation (12) ensures that every generator if running should run between its minimum and its maximum limits.

To solve this kind of a problem, the optimization techniques such as particle swarm optimization (PSO) can be applied effectively.

C. Congestion Management by Demand

In general, both generation and demand re-dispatch is demand response. So, to manage congestion, the amount of demand reduction by TOU is calculated. In auction-based market clearing, the dispatch is performed without taking network limitations such as transmission line and voltage limit constraints. To manage congestion due to such limits, the problem is formulated as

$$\min : \mathrm{T}.\sum_{j=1}^{N_G} \left| \mathrm{C_j}(\mathrm{P_{gi}^0} + \Delta \mathrm{P_{gi}}) - \mathrm{C_j}(\mathrm{P_{gi}^0}) \right| + \sum_{\mathrm{i} \in \mathrm{reD}} \mathrm{r_{Di}^{down}} \Delta \mathrm{P_{reDi}^{down}} . \mathrm{d_i} \quad (14)$$

Where,

$\Delta \mathrm{P_{gi}}$ is the *change* in generation in MW.

reD is the number of responsive demands

r_{Di}^{down} is the price offered for demand reduction in \$/MWh.

ΔP_{reDi}^{down} is the change in demand of responsive loads after DR in MW

di is commitment variable.

$$d_i = \begin{cases} 1, \text{if the demand participate in DR program} \\ 0, \text{if it doesn't participate in DR program} \end{cases}$$

Subject to:

$$\sum_{j=1}^{N_G} \Delta \mathrm{P_{gj}^{+}} = \sum_{\substack{k=1 \\ k \ne j}}^{\mathrm{N_G}} \Delta \mathrm{P_{gk}^{-}} \quad (16)$$

$$\Delta \mathrm{P_{gj}^{+}} + \Delta \mathrm{P_{gk}^{-}} - \Delta \mathrm{P_{reD}} = 0 \quad \forall \mathrm{j} = 1,\ldots \mathrm{N_G} \quad (17)$$

$$-\mathrm{P_{ij}^{max}} \le \mathrm{P_{ij}} \le \mathrm{P_{ij}^{max}} \quad \forall \mathrm{ij} = 1,\ldots \mathrm{NL} \quad (18)$$

$$\mathrm{V_i^{min}} \le \mathrm{V_i} \le \mathrm{V_i^{max}} \quad \forall \mathrm{i} = 1,2\ldots \mathrm{n} \quad (19)$$

$$\mathrm{P_{gi}^{min}} \le P_{gi}^{o} \pm \Delta \mathrm{P_{gj}} \le \mathrm{P_{gj}^{max}} \quad \forall \mathrm{j} = 1,\ldots . \mathrm{N_G} \quad (20)$$

D. Generation Shift Factor

Based on the generation, the line flows under normal condition are given in Appendix A. It is seen that all the lines are under limits. In order to create congestion, severity index is calculated for all the lines. Severity Index is given as,

$$SI = \left(\frac{P_{ij}}{P_{ij}^{\max}} \right)^2 \quad (21)$$

where,

P_{ij} is the power flow on line ij

$P_{ij}^{\max}$ is the maximum power flow on line ij

IV. RESULT

The auction dispatch clears the generators production by using the initial demand values. The electricity market is cleared without considering the electricity network. The generator schedule following electricity market clearing is shown

TABLE I. AUCTION RESULTS FOR GENERATOR

GENERATOR NO.	BUS NO.	GENERATION (MW)
1	1	57.44
2	2	36.84
3	13	48.73
4	22	25.60
5	23	22.48
6	27	29.47

For successful implementation of demand response programs, a set of candidate load buses are selected based on their

influences on network response. To achieve this goal, generation shift factor (GSF) is used. It is seen that the line 12-16 has the maximum value(0.4555), which indicates the severity of line. So, the line 12-16 is outaged for creation of congestion. The line 12-13 is overloaded i.e., line is congested. Now, congestion management is performed based on TOU. Generation Shift Factor represents the change in flow with respect to change in generation. 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. Seven load buses as shown in A. are selected based on load shift factor to participate in demand response program. The price of electricity in DR programs is assumed to be equal to 30 $/MWh.

IV-1 Congestion management by TOU

Congestion management by TOU during off-peak and peak hour is presented. The electricity price during off-peak and peak hour is considered as 250 $, 300 $ per MWh. The off-peak hour is considered from 11:00 to 16:00 and peak hours are considered from 6:00 to 10:00 and from 17:00 to 21:00. Demand values of responsive loads during off-peak and peak hours after implementation of TOU are shown in Table II

TABLE II. DEMANDS OF RESPONSIVE LOADS DURING OFF-PEAK AND PEAK HOUR

Responsive load bus number	**Initial Demand (*10 MW)**	**Change in Demand after DR (*10 MW)**		
		Peak	**Off-Peak**	**Low Peak**
7	22.8	21.785	22.184	22.583
8	30	28.665	29.190	29.715
12	11.2	10.702	10.898	11.094
17	9	8.599	8.757	8.915
19	9.5	9.077	9.243	9.410
21	17.5	16.721	17.028	17.334
30	10.6	10.128	10.314	10.499

It is seen that there is a greater decrease in demand value during peak hour when compared with off-peak hour. During peak hour there is an average decrease of 5% of demand and during off-peak hours there is an average decrease of 4% of demand.

TABLE III. RESULT OF GENERATOR RE-DISPATCH NY FOR CONGESTION MANAGEMENT BY TOU

Generator Number	**Bus number**	**Generation Rescheduling Values (MW)**		
		peak hour	**Off-Peak hour**	**Low Peak**
1	1	60.9875	60.9875	60.9875
2	2	60.9875	60.9875	60.9875
3	13	38.3000	38.3000	38.3000
4	22	38.3000	38.3000	38.3000
5	23	22.6875	22.6875	22.6875
6	27	41.8375	41.8375	41.8375

TABLE IV. RESULT OF GENERATOR RE-DISPATCH NY FOR CONGESTION

	Normal Case (without DR)	**With TOU**		
		peak	**off-Peak**	**Low Peak**
Fuel Cost ($)	691.4370	645.8086	649.1574	652.6652

Normal case is the condition where the fuel cost is calculated when the line flows are within limits, with TOU are the conditions where fuel cost is calculated after managing congestion by this method. Auction-based dispatch method, which is adopted in several electricity markets and as a relatively simple procedure was considered. The results confirm that the demand response programs can play a major role in competitive electricity markets, particularly in case of congestion.

V. CONCLUSION

In this work, DR program as a new procedure for congestion management has been discussed. For the implementation of DR program, loads considered here are to be elastic i.e., the loads vary with respect to change in electricity price. Based on electricity prices charged, the demand for customer during ith hour and for ith bus is calculated. From this it is seen how the TOU affects the customers' demand thereby achieving maximum benefit of customers. In this regard, auction-based dispatch method is adopted in deregulated electricity markets. Congestion has been relieved by decrement in initial production of generators and reduction of demands, which was achieved by implementation of TOU. From the results, it is confirmed that the demand response programs can play a major role in competitive electricity markets, particularly in case of congestion. It is also seen that DR can improve the system reliability of the deregulated power system.

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