Proceedings of the Fourth IASTED International Conference
POWER AND ENERGY SYSTEMS (AsiaPES 2008)
April 2-4, 2008 Langkawi, Malaysia
ISBN CD: 978-0-88986-732-1

ENHANCEMENT OF SPINNING RESERVE CAPACITY BY MEANS OF OPTIMAL UTILIZATION OF EDRP PROGRAM

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ABSTRACT
Various ancillary services are needed in a deregulated power system to ensure the electricity to be delivered reliably and the system be operated securely. Spinning reserve is one of these ancillary services which a reasonable amount of such reserve is essential to satisfy system security constraints when the power system faces with a contingency. Emergency Demand Response Program (EDRP) is one of the incentive-based demand response (DR) programs which is usually used for reducing the peak demand in order to improve the system reliability. In this paper it will be shown that how EDRP program can be implemented as a source for spinning reserve considering its economical and technical aspects. Numerical studies based on IEEE 14 bus system is conducted for evaluating performance of the proposed method.

KEY WORDS
Demand Response (DR), Ancillary Services, Spinning Reserve, Emergency Demand Response Program (EDRP)

1. Introduction

In the past decade, power industry has moved from a vertically integrated and highly regulated industry to deregulated one. In this new environment, generation, transmission, and distribution facilities are unbundled, and consumers are allowed to choose their suppliers [1].

To ensure that the electricity is delivered reliably and the system be operated securely, various ancillary services are needed. There are different types of ancillary services such as voltage support, regulation, etc. The real power generating capacity related to the ancillary services include regulation down reserve (RDR), regulation up reserve (RUR), spinning reserve (SR), non-spinning reserve (NSR) and replacement reserve (RR)[2].

Spinning reserve is that extra amount of generating capacity, spinning and synchronized with the power system and available for immediate use when system demand increases significantly and suddenly, or when a contingency (generator or transmission line outage) occurs [3]. Power system operators need to maintain acceptable level of spinning reserve at all time in order to withstand possible demand excursions, control contingencies, etc. In traditional utility structure, spinning reserve was determined and allocated during the unit commitment process, but in competitive electricity market spinning reserve is procured from the market.

In competitive markets two alternatives for dispatching energy and reserve services are sequential dispatch and simultaneous dispatch. The sequential dispatch would progressively conduct the market commodities based on a priority list. Usually the energy is cleared first and then the reserve. Theoretical analysis and practical experience have shown that sequential auction would result in price reversals [4]. The simultaneous dispatch is to clear the market for all the commodities such as energy and reserve at the same time, so the combination cost is minimized.

Demand Response (DR) is one of the well known tools which have been widely used to release the power investment, mitigate the generation, transmission line intensity and maximize the benefits of both electric utilities and customers.

According to the definition reported by Department of Energy (DOE), DR is: "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over the time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized"[5].

Recently in some of the developed countries demand response is used to directly supply reliability services to the power system. Rather than reducing overall power system stress by reducing peak loading over multiple hours. These programs are targeted to immediately respond to specific reliability events. This is possible if developing in application of communication and control systems in power system be continued, these changes have benefits for both of the power system and the loads.

One of the important approaches of demand response in emergency condition is Emergency Demand Response Program (EDRP) where, the loads which had been contracted would reduce their consumption.

In this paper, EDRP program has been considered as one of the spinning reserve resources from both economical and reliability criteria viewpoints. For this purpose, contingency analysis is performed and the most severe contingency is selected. Then, by using an economic load model, the amount of customer participations in EDRP program is determined. Finally, the value of ENS (Energy Not Supplied) for the most severe contingency without/with EDRP program implementation are calculated and compared.

The remaining of this paper is organized as following, section 2 provides mathematical formulation of the problem, section 3 is devoted to numerical study and discussions, and section 4 concludes the paper.

2. Problem Formulation

2.1 Benefits and barriers of using EDRP program as spinning reserve

Historic demand response programs have focused on reducing overall electricity consumption (increasing efficiency) and shaving peaks. Most of these programs have been successfully experienced; however demand response resources could not achieve to their complete potential till now. FERC has found that about five percent of customers in the U.S are on some form of demand response programs [6]. These programs reduce overall energy consumption and they also reduce stress on the power system at peak periods.

Modern communications and control technologies make fast response possible from loads as diverse as residential air conditioners to 80,000 hp pumps or 400 MW aluminum smelters. Half of the ERCOT spinning reserve requirement is now allowed to come from responsive load and PJM now also allows load to provide spinning reserve [7].

Most of the loads have a fundamental characteristic, that they can be interrupted frequently but can not sustain their response indefinitely. Residential water heating, residential and commercial air conditioning, refrigeration, water pumping, aluminum smelters, etc. are all examples of loads that can be interrupted, most frequently, but only for limited times.

Communications and control technology enable these loads to be curtailed immediately in the event of a frequency deviation and quickly when called upon by the system operator. NERC rules state that generators supplying spinning reserve must begin responding immediately and be fully responsive within ten minutes [8]. Loads can respond much faster than ten minutes, being fully responsive essentially immediately.

One obstacle for using responsive loads as spinning reserve is the typically specified two hour response duration capability. This specification is in contrast with the way spinning reserve is typically used. Reserves are typically deployed for only about ten minutes in New York, California and New England. Longer response events are important for reliability, but are occasionally required. [8]. Loads like residential air conditioners could provide infrequent long response for critical emergencies and would be comfortable providing the typical ten to thirty minute response more frequently.

One approach to solve long response duration is splitting thirty-minute-capable reserves into blocks and deploying them sequentially [7].

Interestingly there is good reason to believe that the inherent reliability of the response from aggregations of small loads (which individually may be less reliable) is actually better than the reliability of response from large generators (which individually may be more reliable) [6]. Larger aggregation of individually smaller loads provides an even more vertical response characteristic. The aggregated load response is much more predictable and the response that the system operator can “count on” is actually greater [6].

2.2 Load Economic Model

In the beginning of deregulation, usually consumers had not effective participation in the power markets, and Independent Power Producers (IPPs), Regional Transmission Organizations (RTOs) and Regulatory Bodies have been the most effective players in the markets. The consumers were isolated from the benefits and the information of the markets. They had not enough knowledge and hardware to participate in the markets, effectively. On the other hand, so many of consumers prefer to be isolated from the price fluctuations and the risks in the volatile power markets.

This kind of consumers’ behavior and their absence in the electricity markets, caused spike prices and congestion in the transmission lines [9].

Fig. 1 shows how the demand elasticity could effect on electricity price, significantly [10].

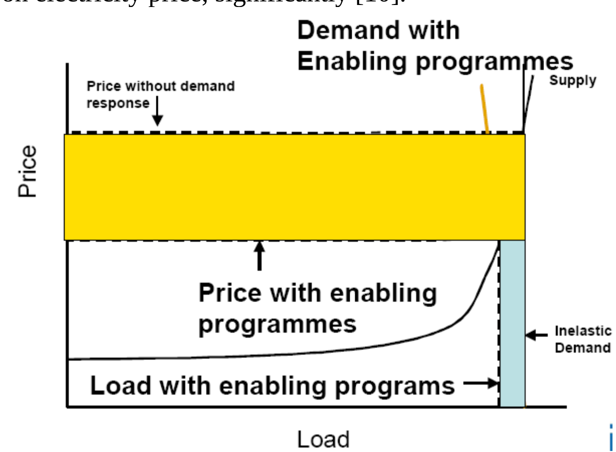

Figure 1. Effect of demand variation on the electric energy price [10]

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

$$E = \frac{\partial q}{\partial \rho} = \frac{\rho_0}{q_0} \cdot \frac{dq}{dp} \tag{1}$$

where;

E=elasticity of the demand

q= demand value (MWh)

ρ = electricity price ($/MWh)
ρ_0 = initial electricity price ($/MWh)
q_0 = initial demand value (MWh)

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

i) Some of the loads are not able to move from one period to another and they could be only "on" or "off". So, such loads have sensitivity just in a single period which is called "self elasticity" [11], it always has a negative value.
ii) 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 equ. (1), self elasticity (E_{aa}) and cross elasticity (E_{ab}) could be written as:

$$E_{aa} = \frac{\Delta D_a}{\Delta \rho_a} \leq 0 \tag{2}$$

$$E_{ab} = \frac{\Delta D_a}{\Delta \rho_b} \geq 0 \tag{3}$$

where;
ΔD_a = demand changes in period "a"
$\Delta \rho_a$ = price changes in period "a"
$\Delta \rho_b$ = price changes in period "b"

In this section, we are going to model and formulate how EDRP program affect on the electricity demands and how the maximum benefit of customers could be achieved due to this program.

2.2.1 Load Economic Model

Suppose that:
d(i) = customer demand in i-th hour (MWh)
ρ(i) = spot electricity price in i-th hour ($/MWh)
A(i)= incentive in i-th hour ($/MWh)
B(d(i)) = customer's income in i-th hour ($)

Also suppose that the customer changes its demand from $d_o(i)$ (initial value) to d(i), based on the value which is considered for the incentive (A(i)):

$$\Delta d(i) = d_o(i) - d(i) \qquad (MWh) \tag{4}$$

So, incentive prize P ($), due to running EDRP will be as:

$$P(\Delta d(i)) = A(i).\Delta d(i) \qquad \$ \tag{5}$$

Therefore, the customer's benefit S ($), for the i-th hour will be as follow:

$$S(d(i)) = B(d(i)) - d(i).\rho(i) + P(\Delta d(i)) \qquad \$ \tag{6}$$

To maximize the customer's benefit, $\frac{\partial S}{\partial d(i)}$ should be equal to zero, so:

$$\frac{\partial S}{\partial d(i)} = \frac{\partial B(d(i))}{\partial d(i)} - \rho(i) + \frac{\partial P(\Delta d(i))}{\partial d(i)} = 0 \tag{7}$$

$$\frac{\partial B(d(i))}{\partial d(i)} = \rho(i) + A(i) \tag{8}$$

The benefit function, most often used, is a quadratic benefit function [12,13]:

$$B(d(i)) = B_0(i) + \rho_0(i)\left[d(i) - d_0(i)\right]\left\{1 + \frac{d(i) - d_0(i)}{2E(i).d_0(i)}\right\} \tag{9}$$

where;
$B_0(i)$ = benefit when the demand is at nominal value ($d_0(i)$)
$\rho_0(i)$ = nominal electricity price when the demand is nominal.

Considering (8) and (9):

$$\rho(i) + A(i) = \rho_0(i)\left\{1 + \frac{d(i) - d_0(i)}{E(i).d_0(i)}\right\} \tag{10}$$

$$\rho(i) - \rho_0(i) + A(i) = \rho_0(i).\frac{d(i) - d_0(i)}{E(i).d_0(i)} \tag{11}$$

Therefore, customer's consumption will be as following:

$$d(i) = d_0(i).\left\{1 + \frac{E(i).\left[\rho(i) - \rho_0(i) + A(i)\right]}{\rho_0(i)}\right\} \tag{12}$$

In the above equation, if A(i) be equal to zero (i.e. no incentive prize), d(i) will be equal to $d_0(i)$. Thus, the electricity price will not change and load elasticity will be equal to zero.

2.2.2 Multi Period Modeling

The cross elasticity between i-th and j-th hour is defined as [14]:

$$E_0(i,j) = \frac{\rho_0(j)}{d_0(i)}.\frac{\partial d(i)}{\partial \rho(j)} \tag{13}$$

$$\begin{cases} E_0(i,j) \leq 0 & if \quad i = j \\ E_0(i,j) \geq 0 & if \quad i \neq j \end{cases}$$

In (13), we suppose that $\frac{\partial d(i)}{\partial \rho(j)}$ is constant. So, the demand response to the price variation could be defined as a linear function [15]:

$$d(i) = d_0(i) + \sum_{i=1}^{24} E_0(i,j).\frac{d_0(i)}{\rho_0(j)}.[\rho(j) - \rho_0(j)] \qquad i = 1,2,...,24 \tag{14}$$

In (14), we have considered a 24 hours interval. If the incentive in the j-th hour, A(j), for EDRP program is considered in the energy price, we can write:

$$\Delta\rho(j) = \rho(j) - \rho_0(j) + A(j) \tag{15}$$

A(j) in $/MWh is the incentive which is paid in the j-th hour, and it could be defined as a positive value in peak periods and zero in other periods.

Finally, the customer's demand function, considering prices and incentives, could be written as:

$$d(i) = d_0(i) + \sum_{i=1}^{24} E_0(i,j).\frac{d_0(i)}{\rho_0(j)}.[\rho(i) - \rho_0(j) + A(j)] \quad (16)$$

$$i = 1,2,...,24$$

2.2.3 Responsive Load Model

Combining (12) and (16), we will have the customer Load model as:

$$d(i) = \left\{ d_0(i) + \sum_{j=1}^{24} E_0(i,j).\frac{d_0(i)}{\rho_0(j)}.[\rho(j) - \rho_0(j) + A(j)] \right\}. \quad (17)$$

$$\left\{ 1 + \frac{E(i)[\rho(i) - \rho_0(i) + A(i)]}{\rho_0(i)} \right\} \quad i = 1,2,...,24.$$

Equation (17) shows the amount of customers consumption during 24 hours intervals until maximize their benefits. In the next part, we will show how incentives could change the demand curve while running EDRP Program.

2.3 Priority of EDRP implementation

In this paper, all possible contingencies for both generators and lines are assumed and total amount of overloading (TAO) for each contingency are calculated. Then, by multiplying TAO in the probability of different contingencies (p), the most severe contingencies are ranked.

$$Rank = TAO.p \quad (18)$$

To implement EDRP program, loads (bus) with high impact on line overloads and loads with high impact on network restoring to normal situation are chosen.
To achieve this goal, GSF index (generation shift factor) is used [16].GSF for the i-th load bus and the l-th line is represented by the following equation:

$$a_{l,i} = \frac{1}{x_l}(X_{ni} - X_{mi}) \quad (19)$$

where,

$a_{l,i}$ Generation shift factor of l-th line and i-th load bus

x_l reactance of l-th line

X_{ni} Real part of (n , i) element of impedance matrix

X_{mi} Real part of (m , i) element of impedance matrix

This index shows the impact of load increase in i-th load bus, on l-th line loading. GSF could be positive or negative. The positive value means that increasing of the load in i-th load bus will results in increasing of the l-th line load, so for EDRP implementation the most negative indices are preferred. Negative index means that the i-th load bus has a potential to decrease the l-th line overload.

3. Numerical Results

The proposed method has been tested on IEEE-14 bus standard system which has 5 generator buses (bus 1-slack bus, 2, 3, 6 and 8) and 9 load buses, Fig 2.
The voltage limits at load buses, V min and V max , are 0.95 [pu] and 1.05 [pu] respectively.

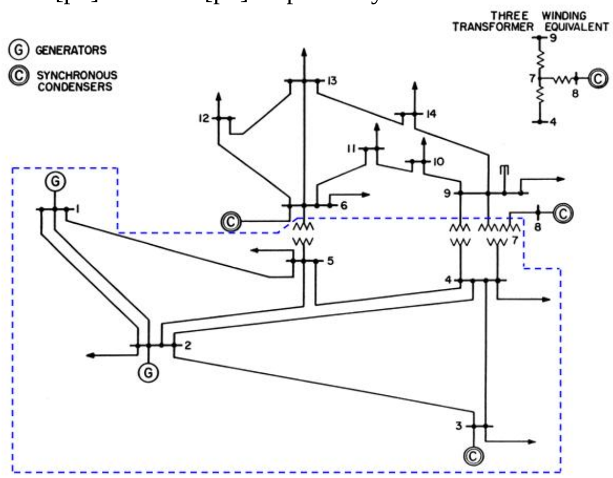

Figure 2. IEEE 14-bus system

The amount of incentive payment and the price of electrical energy are assumed to be same and equal to 50 $/MWh. And also we have considered the self and cross elasticity as table 1.

Table 1
Self and cross elasticity

	Peak	Off-Peak	Low
Peak	-0.02	0.0032	0.0024
Off-Peak	0.0032	-0.02	0.002
Low	0.0024	0.002	-0.02

The initial load curve, used here for the load buses is referred to PJM market (MID ATLANTIC REGION) [17]. Where, the respected load curve is normalized to IEEE-14 bus system. Fig 3, represents the initial load profile for bus 3.The average of the peak demand for this load bus is 94.2 MW[18].

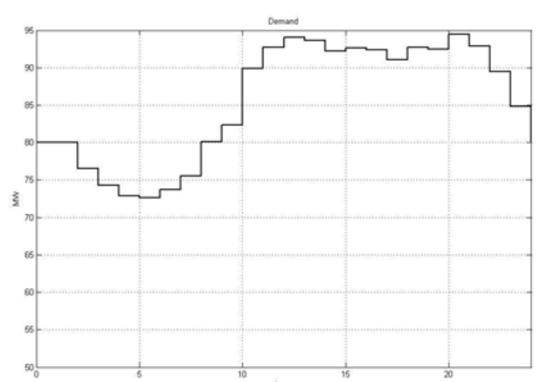

Figure 3. The initial load curve for bus 3.

The load curve is divided into three intervals as following:

Low load period (12.00 p.m. to 9:00 a.m.), peak period (10:00 a.m. to 10:00 p.m.) and off-peak period (10:00 p.m. to 12:00 p.m.).

3.1 Calculation of ENS without EDRP program

The area enclosed by the dashed frame in figure 2, including lines 1-2, 1-5, 2-3, 2-4, 2-5, 3-4, 4-5,4-7, 4-9, and 5-6, is defined as the line set H. The apparent power limits (rated apparent power) for these lines are assigned as 1.2 times of power flow through lines in normal condition. In this study, all possible line contingencies are considered.

Line overloads for all contingencies of H set lines are calculated and listed in Table 2. It is assumed that the outage probabilities of all transmission lines are equal to 0.02.

Table 2
Rank of transmission lines overloads of set H.

Number	Lines Outages	Total amount of overloads (MW)	Probabilities * overloads	Rank
1	1-2	144.70	2.894	2
2	1-5	91.83	1.836	4
3	2-3	145.08	2.901	1
4	2-4	44.68	0.893	5
5	2-5	8.13	0.162	10
6	3-4	10.13	0.202	8
7	4-5	29.56	0.591	6
8	4-7	16.17	0.323	7
9	4-9	9.66	0.193	9
10	5-6	112.46	2.249	3

According to the results of Table 2, lines 1-2, 2-3 and 5-6 are selected as the most sensitive lines during contingencies.

For these lines, the GSF of all load buses, $a_{l,i,}$, are calculated. For instance, outage of line 2-3 causes overloading of line 3-4, and the GSF for overloaded line in this contingency are listed in Table 3.

Table 3
Generation Shift Factors for line 3-4.

Generation Shift Factors	value	Rank
$a_{3\text{-}4,2}$	-0.0877	2
$a_{3\text{-}4,3}$	-0.532	1
$a_{3\text{-}4,4}$	0.0993	-
$a_{3\text{-}4,5}$	0.0467	-
$a_{3\text{-}4,6}$	0.0701	-
$a_{3\text{-}4,9}$	0.0877	-
$a_{3\text{-}4,10}$	0.0818	-
$a_{3\text{-}4,11}$	0.0760	-
$a_{3\text{-}4,12}$	0.0701	-
$a_{3\text{-}4,13}$	0.0701	-
$a_{3\text{-}4,14}$	0.0818	-

For three severe line contingencies (1-2,2-3,5-6) the amounts of load curtailment to restore the network to normal condition are calculated according to the respected GSF and then the amount of ENS for these contingencies are calculated, the result of which are represented in tables 4 and 5.

3.2 Calculation of ENS with EDRP program

To remove the overload of lines for the above mentioned contingencies, in first step the EDRP program is performed, if it is not enough, then load curtailment is implemented. Three scenarios are assumed for the different participants' potential in EDRP program. EDRP participants potential are assumed to be 15%, 30% and 50%. In three different scenarios, the initial load curve, have changed due to running of EDRP program in single period case and multi period case which was mentioned in section 2.2. For load bus 3 by using these scenarios the load curve changes are shown in Figures 4-6 .

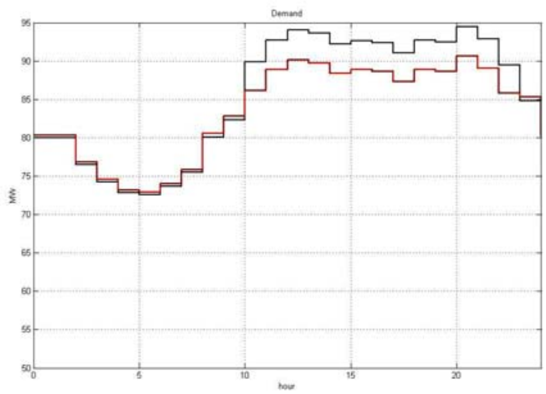

Figure 4. Result of implementation of EDRP program for load bus 3 with potential of 15%

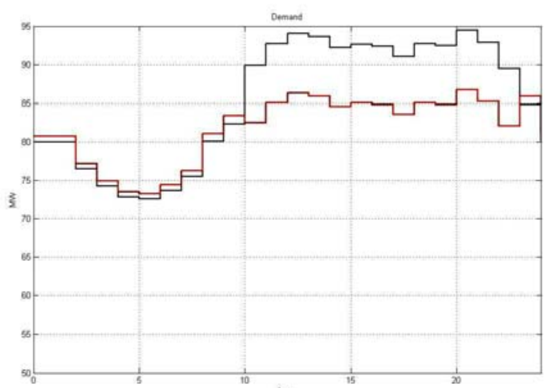

Figure 5. Result of implementation of EDRP program for load bus 3 with potential of 30%

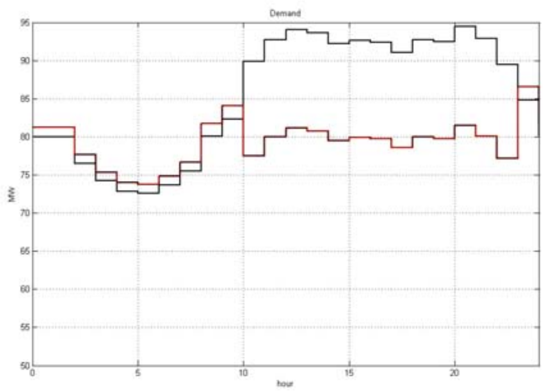

Figure 6. Result of implementation of EDRP program for load bus 3 with potential of 50%.

As it is shown in the above figures, by implementing EDRP program, according to different elasticity and different periods, the load is transferred from peak periods to valley periods, so the amount of load curtailment and ENS for three mentioned contingencies will be changed. Table 4 shows the amount of load curtailment and table 5 represents the amount of ENS with/without EDRP program implementation in three mentioned scenarios.

Table 4
Amount of load curtailment without/with three scenarios of EDRP program for the most sensitive contingencies (MW).

Fault	Without EDRP	With EDRP		
		Potential equals 15%	Potential equals 30%	Potential equals 50%
Line 1-2	193.3	189.75	187.64	184.85
Line 2-3	66.63	60.75	57.26	52.62
Line 5-6	99.5	86.62	79.11	69

Table 5
Amount of ENS without/with three scenarios of EDRP program for the most sensitive contingencies (MWh).

Fault	Without EDRP	With EDRP		
		Potential equals 15%	Potential equals 30%	Potential equals 50%
Line 1-2	2512.9	2466.8	2439.3	2403.1
Line 2-3	866.2	789.8	744.4	684.1
Line 5-6	1293.5	1126.1	1028.4	897

According to the results of tables 4 and 5, the amount of load curtailment and ENS will be reduced by implementation of EDRP program. By assuming the amount of VOLL equal to 6$/KWh[19], the total value of load not supplied can be calculated, as table 6.

Table 6
Total value of load not supplied (*$10^{6}\$$).

Fault	Without EDRP	With EDRP		
		Potential equals 15%	Potential equals 30%	Potential equals 50%
Line 1-2	15.0774	14.801	14.636	14.418
Line 2-3	5.1972	4.7388	4.466	4.1046
Line 5-6	7.761	6.7566	6.17	5.382

In the case of more secure systems, implementation of EDRP programs may result in more proper solutions, i.e. the need for load shedding may be removed.

Another major point is the dependency of participants of EDRP program to the amount of incentive payments.

Figures 7 and 8 show the result of implementation of EDRP program for bus 3 with different incentives and same potentials.

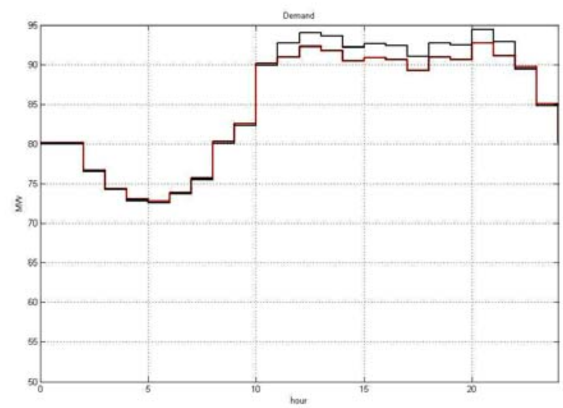

Figure 7. Result of implementation of EDRP program for load bus 3 with potential of 20% and incentive equals to 50$/MWh

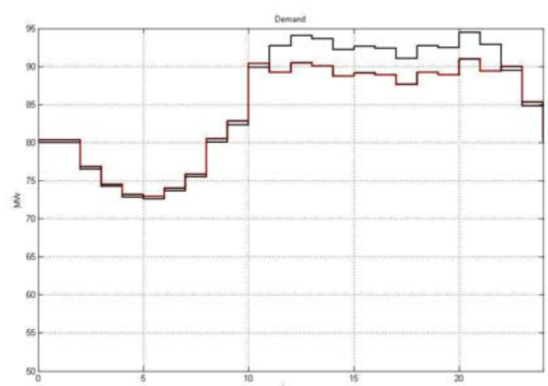

Figure 8. Result of implementation of EDRP program for load bus 3 with potential of 20% and incentive equals to 100$/MWh

It can be seen that higher rates of incentives results in more participation of customers in EDRP program.

4. Conclusion

This paper presented a new approach for enhancement of spinning reserve by means of EDRP program. An economic model for formulating of EDRP program has been formulated. Furthermore, customers' participation in EDRP program has been simulated by different scenarios. Contingency analysis was performed to illustrate the impact of EDRP program on ENS reduction. Simulation studies have been carried out to evaluate the performance of the proposed method using IEEE 14-bus test system. The result confirms that EDRP program can be recognized as a valuable resource for enhancement of spinning reserve. Further researches are under study for investigation about economical aspects of EDRP programs in real world systems.

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