Optimal Demand Response Scheme for Power Systems Including Renewable Energy Resources Considering System Reliability and Air Pollution

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Abstract—**Implementing an applicable demand response (DR) program enables the complete demand-side potentials and ensures a secure, more economic and greener operation of the power systems with the integration of renewable energy. Therefore, the present paper proposes a stochastic security-constraint scheduling approach for optimum operation of both supply and demand sides via well-designed pricing and incentive schemes. The DR programs are time-of-use and emergency DR programs. The study addresses the Independent System Operator (ISO)'s viewpoint, and it aims at finding the optimal DR strategy (from a set of DR programs) in a way that an efficient electricity market is obtained, ensuring the security and environmental constraints. To this end, a security constraint unit commitment (SCUC) problem considering DR and renewable energy resources is proposed. Different indices are considered through a multi-objective problem for evaluating the efficiency of the market, security of the system, reliability and air pollution. These indices include market prices, social welfare, load factor (peak-to-valley proportion), air pollution, and power security, among others. In order to find the best DR strategy, a multi-objective problem is solved to consider all the mentioned indices.**

Keywords—Air pollution; demand response scheme; multi-objective; system reliability; renewable energy;

I. NOMENCLATURE

Indices

b	Index of system buses
j	Index for loads
i	Index of generating unit
t	Index of hours
l	Index of transmission lines
s	Index of wind scenarios
w	Index of wind unit
m	Segment index for the cost of units

Parameters

$\rho^0(t)$	Initial electricity price at hour *t* (\$/MWh)
$d_j^0(t)$	Initial electricity demand of load *j* at hour *t*
$E(t, t')$	Elasticity of demand
DR^{max}	Maximum response potential
$inc(t)$	Rate of incentive at hour *t* (\$/MWh)
$\rho(t)$	Electricity tariff at hour *t* (\$/MWh)
P_i^{min}/P_i^{max}	Minimum/Maximum output limit of generation unit *i* (MW)
MUT_i/MDT_i	Minimum up/down time of generation unit *i*
RU_i/RD_i	Ramp up/down of generation unit *i*
SUC_i	Start-up cost of generation unit *i*
NLC_i	No load cost of unit *i*
SUR_i/SDR_i	Spinning up/down reserve of generation unit *i*
$C_i^e(m)$	Slope of segment m in linearized fuel cost curve of unit *i* (\$/MWh)
C_i^{RU}/C_i^{RD}	Offered capacity cost of reserve up/down of unit *i* (\$/MW)
C_i^{ERU}/C_i^{ERD}	Offered energy cost of reserve up/down of unit *i* (\$/MWh)
$E_i^{SO_2}/E_i^{NO_x}$	Emission rate of SO_2 and NO_x pollutants (\$/Kg)
X_l	Reactance of line l
C_{wt}^{wind}	Cost of wind power producer
π_{cur}	Cost of wind power curtailment
ω_s	Probability of wind power scenario *s*
$VOLL_j$	Value of lost load in bus *j* (\$/MWh)
$P_w^{install}$	Installed capacity of wind farms (MW)
W_{wt}^{max}	Available wind power of wind unit *w* in hour *t* (MWh)

Variables

F_{cost}	Total expected cost (\$)
$F_{emissions}$	Total emissions (Kg)
δ_{bts}	Voltage angle at bus *b* in hour *t* of scenario *s* (rad)
F_{lts}	Power flow through line l in hour *t* of scenario *s* (MW)
$P_{it}^e(m)$	Generation of segment m in linearized fuel cost curve of unit *i* (MWh)
C_{it}^{ST}	Start-up cost of generation unit *i* in hour *t* (\$)
P_{it}^{tot}	Total scheduled power of unit *i* in hour *t* (MW)
P_{wt}^{wind}	Scheduled wind power of wind unit *w* in hour *t* (MW)
SR_{it}^U/SR_{it}^D	Scheduled up/down reserve of unit *i* in hour *t* (MW)

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P_{its}^{tot}	Total scheduled power of unit i in hour t of scenario s (MW)
$sr_{its}^{U}/sr_{its}^{D}$	Deployed up/down reserve of unit i in hour t (MW)
LS_{jts}	Involuntary load shedding in load j in hour t of scenario s (MW)
W_{wst}^{cur}	Curtailment wind power of wind farm w in hour t of scenario s (MW)
$d_j(t)$	Modified demand of load j in hour t after implementing DRP's
$L_j(t)$	Load after implementing DRP's
$L^{final}(t)$	Hourly load after implementing DRP's
I_{it}	Binary status indicator of generating unit i in hour t
y_{it}/z_{it}	Binary start-up/shutdown indicator of unit i in hour t

II. Introduction

Since wind power and other renewable energy are deployed recently, the uncertainties in addition to unforeseen network contingencies cause to systematic changes and serious challenges face to the ISO's performance. In this condition, innovative and reliable DR approaches results in more flexibility, providing the comprehensive and workable solutions for compensation of the wind units uncertainty and mitigation power systems concerns.

Based on the last investigations on DR programs, it can be found that such comprehensive programs are workable solutions for movement in the direction of increasing the flexibility of the electrical systems [1]–[3]. In [4], a novel method is presented for the scheduling of electricity and reserve capacity along with the unit commitment associated with reliability limitations. In addition, it is considered the uncertainty of wind and load for the 24 hours plan. In [5] and [6], DR is combined with SCUC program.

In [5] a stochastic SCUC was proposed to plan how to schedule reserve capacity supplied through DR in the upper level market. Hourly DR combined with SCUC results in minimization of the cost of the power system operation. Besides, the amount used of fuel and the numbers of congestions at the transmission lines of the system are reduced because of reforming the hourly load profile [7]–[9]. Moreover, in [6] a stochastic approach was proposed that the optimal Tariff of Usage (TOU) prices were calculated in SCUC considering grid reliability indices.

Nevertheless, later references report approximate complete frameworks, the variety of DR programs as well including the best ones, have not been mentioned. The presented model is formulated as a bi-level stochastic program. One of the problems complicating the ISO or generator's decisions making is the uncertainties which affect its decision condition or making a profit.

Two more important resources of uncertainties in the presented model are market prices and consumer's demands [10], [11]. Such uncertainties facts would have an influence on generator's profit in addition to decision variables. The approaches of modeling the uncertainties are probabilistic.

In the stochastic method, the Probability Density Function (PDF) of the uncertainties has been employed to gain the PDF of the problem[12]–[14].

Based on last references, the proposed work presents an SCUC model associated with DR programs considering renewable energy resources. Indeed, system uncertainties including an outage power of wind sources and implementation of DR programs are merged in a stochastic model. In this approach self and cross elasticity is used for modeling the customers' behavior modeling.

Besides the considerable impact of DR programs on the energy market prices in the peak period, the best tariffs of different kinds of DR programs and some other indices of market power are investigated to achieve an appropriate reliability level in addition to the market power mitigation.

The paper is structured in five sections. In Section II, the different types of modeling the DR programs in this work are introduced, and their mathematical model is proposed. In Section III, the procedure of two-stage stochastic model is formulated. Numerical results of the model are in Section IV, and the conclusion is in the final Section V.

III. The Proposed Model

In this paper, a stochastic scheduling framework is employed to model the electricity markets. On one hand, each market participant submits its offers to the market in a way that it maximizes its profit. On the other hand, the ISO clears the electricity markets by using an SCUC approach maximizing the social welfare by taking security limits of the power system into account.

The problem is modeled through a multi-objective model by considering the fuel cost, air pollution, and system reliability. In addition, the complicated issues of renewable energy uncertainties as well as the optimum DR strategies are also considered. A schematic of the proposed model is illustrated in Fig. 1.

In this work, two approaches have been integrated into the proposed model: stochastic optimization method and augmented ε-constraint multi-objective method. The objective of the augmented ε-constraint multi-objective method is the minimization of costs and emissions. The costs are modeled by a stochastic function which is divided into two parts.

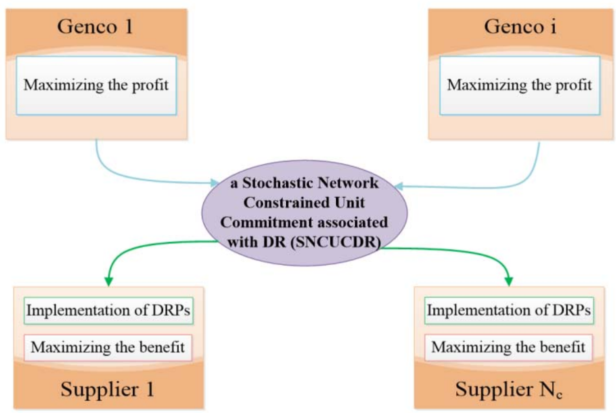

Fig. 1. The proposed energy market model.

Following the objective functions and the constraints are described. The multi-objective function of the proposed model is presented as follows:

$$\text{Minimize } \{F_{cost}\ , F_{emissions}\ \} \tag{1}$$

The cost objective function is given as follows:

$$F_{cost}= \sum_t \left\{ \sum_i \left[\left(NLC_i \,.\, \mathrm{y}_{it} + SUC_i + \sum_m \left(P_{it}^{e}(m) \,.\, C_i^{e}(m) \right) \right) + (C_i^{RU}.SR_{it}^{U} + C_i^{RD}.SR_{it}^{D}) + \sum_w \left(C_{wt}^{wind}.P_{wt}^{wind} \right) \right. \right. \tag{2}$$

$$+ \sum_s \sum_t \omega_s \,. \left\{ \sum_i [(C_i^{ERU}.sr_{its}^{U}) - (C_i^{ERD}.sr_{its}^{D})] + \sum_w (\pi_{cur}.W_{wst}^{cur}) + \sum_j \left(VOLL_j.\mathrm{LS}_{jts} \right) \right\}$$

The cost function includes two stages. The first stage represents the decisions to be declared as hourly unit commitment statuses of conventional units which are not dependent of scenario's realization. These decisions include the start-up, energy and up and down reserve capacity costs. The second stage is related to the possible instances of wind generation that should be considered according to their probability (ω_s).

Here is considered deployed up and down reserve costs in scenario s, wind power curtailment cost and involuntary load shedding cost. The objective function related to the total emissions during the planning period is calculated as follows:

$$F_{emission}= \sum_i \sum_t \left[P_{it}^{tot}.\left(E_i^{SO_2} + E_i^{NO_x} \right) \right] \tag{3}$$

The constraints are as follows:

A. Day-ahead dispatch constraints

- DR constraints:

$$ENS = \sum_j \sum_w \sum_t \left(\mathrm{LS}_{jts} \right) \tag{4}$$

$$\mathrm{d}_j(t) = DR^{max}.d_j^0(t). \left(1 + \sum_t \left[\frac{\left(E\,(t,t') \right).(inc\,(t) + (\rho(t) - \rho^0(t)))}{\rho^0(t)} \right] \right) \tag{5}$$

$$\mathrm{L}_j(t) = \mathrm{d}_j(t) + (1\text{-}DR^{max}).\, d_j^0(t) \tag{6}$$

$$L^{final}(t) = \sum_j \mathrm{L}_j(t) \tag{7}$$

- Demand Balance dispatch in day-ahead.

$$\sum_i P_{it}^{tot} + \sum_w P_{wt}^{wind} = \sum_j \mathrm{d}_j(t) \tag{8}$$

- Startup cost

$$0 \le SUC_i \le C_{it}^{ST}(\mathrm{I}_{it}\text{-}\mathrm{I}_{i,t-1}) \tag{9}$$

- Max Wind Scheduled in DA

$$P_{wt}^{wind} \le W_{wt}^{max}.\, P_w^{install} \tag{10}$$

- Maximum conventional scheduled power and reserve capacity

$$P_{it}^{tot} + SR_{it}^{U} \le P_i^{max}.\,\mathrm{I}_{it} \tag{11}$$

$$P_{it}^{tot} - SR_{it}^{D} \ge P_i^{min}.\,\mathrm{I}_{it} \tag{12}$$

- Reserve constraints of conventional power plants

$$SR_{it}^{U} \le \mathrm{I}_{it}\ .RU_i \tag{13}$$

$$SR_{it}^{D} \le \mathrm{I}_{it}\ .\ RD_i \tag{14}$$

B. Balancing Stage constraints

- Load Shedding and Wind Spillage

$$\mathrm{LS}_{jts}\ \le\ \mathrm{L}_j(t) \tag{15}$$

$$W_{wst}^{cur}\ \le\ P_{wt}^{wind}.\, P_w^{install} \tag{16}$$

- Demand Balance in RT

$$\sum_i (\,sr_{its}^{U} - sr_{its}^{D}) + \sum_j \mathrm{LS}_{jts} + \sum_w (\,P_w^{install} - P_{wt}^{wind} - W_{wst}^{cur}) = \sum_l (\,\mathrm{F}_{lts}) \tag{17}$$

$$\mathrm{F}_{lts} = \frac{\delta_{bts} - \delta'_{b}ts}{x_l} \tag{18}$$

- Reserve constraints of conventional power plants

$$sr_{its}^{U} \le SR_{it}^{U} \tag{19}$$

$$sr_{its}^{D} \le SR_{it}^{D} \tag{20}$$

- Constraints for reserve limitations

$$P_{its}^{tot} = P_{it}^{tot} + sr_{its}^{U} \text{ - } sr_{its}^{D} \tag{21}$$

$$P_{its}^{tot}\ \le\ P_i^{max}.\,\mathrm{I}_{it} \tag{22}$$

$$P_{its}^{tot}\ \ge P_i^{min}.\,\mathrm{I}_{it} \tag{23}$$

- Energy not supplied (ENS)

In order to obtain the minimization of both objective functions is used the augmented ε-constraint method, which is formulated as:

$$Min\left(F_{cost} - \delta \times \left(\frac{S_2}{r_2}\right)\right) \quad (24)$$

$subject\ to$: $F_{emissions} + S_2 = \varepsilon_2^k, S_2 \in R^+$, where

$$\varepsilon_2^k = F_{max}^{Emission} - \left(\frac{F_{max}^{Emission} - F_{min}^{Emission}}{q_2}\right) \times \mathrm{k}, \quad (25)$$
$$\mathrm{k} = 0, 1, \dots, q_2$$

where:

δ	is a scaling factor;
S_2	is a slack variable;
$F_{max}^{Emission}, F_{min}^{Emission}$	represent the maximum and minimum values of the emission objective function, based on the payoff table, respectively;
ε_2^k	is the k-th range of $F_{emissions}$;
r_2	is the range of the total air pollutants emission;
q_2	is the number of equal part;

For the best comprise solution is selected one of the Pareto solutions and DSO is assumed as the decision maker.

IV. Numerical Study

In order to indicate the impact of DR programs in this model, the IEEE 24-bus test system is employed. This test system has 26 generators, 24 buses, 6 wind farms, 5 transformers, 17 loads with the total generation capacity of 2850 MW. The simulation results are presented in six cases.

The base case is related to conventional scheduling of system without considering any DR Program. For the first case is assumed that the costumer's participation level on TOU program is 10% and for the second case is 20%. In case three and four is assumed a level of participation on EDRP equal to 10% and 20%, respectively. For the fifth and sixth cases, both TOU and EDRP program are assumed where 10% and 20% of consumers participate in these programs.

Table 1 shows the prices for tariffs and incentives in different load periods (valley, off-peak and peak) for the different programs. In base case the tariffs is all equal for the different periods of hours. As can be seen, TOU program has three steps of tariffs that corresponding the higher tariff to peak hours. It should be noted that EDRP's tariffs are the same as base case, but with an incentive equal to tariff.

The total system modified load curve is obtained in next three figures to see the impact of different programs on final load. In Fig. 2 different levels of costumer's participation on TOU program are compared with base case. As it can be seen, the demand during the peak period is reduced and recovered later in low-load hours. This happen due to the fact the tariffs on TOU program in peak hours are higher than the flat rate.

With a higher costumer's participation (20%), it can be seen that the demand during peak hours has a lower level than that reached with a costumer's participation equal to 10%. Comparing TOU programs with base case, they can produce a flatter load curve. Fig. 3 shows the effect of implementation of different EDRP's. Here, the demand in peak hours is reduced and recovered in low-load hours and in off-peak hours.

By joining TOU and EDRP the demand in peak hours is significantly reduced (Fig. 4), due to the fact of having as the same time, a high tariff for TOU program and an incentive for EDRP, and it is recovered in low-load and off-peak hours. On this basis, the demand on peak hours is reduced, while the demand on valley is increased based on the low tariff.

TABLE I: TARIFFS/INCENTIVES OF CONSIDERED DRP'S ($/MWH)

Case	Valley (t1 to t8)	Off-peak (t9 to t16)	Peak (t17 to t24)
Base case	15	15	15
TOU	7.5	15	30
EDRP	15	15	Tariff: 15 Inc: 15

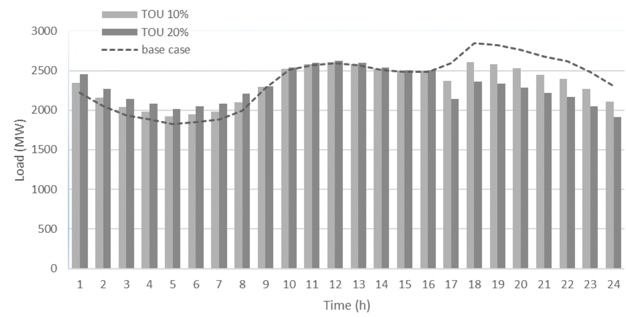

Fig. 2. Impact of different participation level on TOU program on the final load.

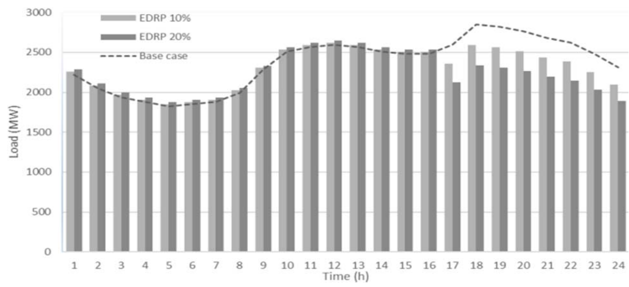

Fig. 3. Impact of different participation level on EDRP program on the final load.

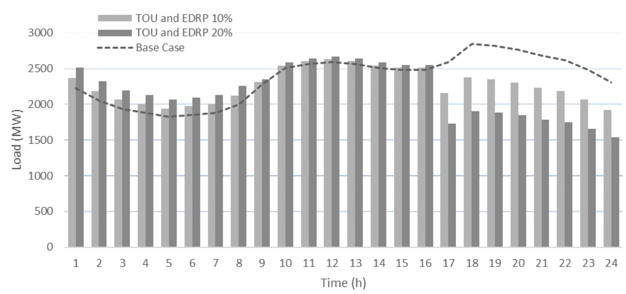

Fig. 4. Impact of different participation level on TOU and EDRP program on the final load.

A. Load Factor

Analyzing now Fig.5, it can be concluded that comparing all the cases with base case, the DRP's achieve smother load curves, except the last one, corresponding to TOU and EDRP with 20% of costumer's participation on programs. The costumer's participation affects the load curve. It is achieved smother loads profile for lower participation levels.

B. Price

Fig.6, Fig.7 and Fig.8 show the impact of different programs on the market clearing prices. As can be seen, the price is reduced in peak hours for all the cases. The price increases in the for TOU programs due to the fact of that program be able to shift some loads in peak period to off-peak. The same effect happens with EDRP (Fig. 7). As it can be observed in Fig.8 there is a significant increase in the price in low-load periods with a higher percentage of costumer's participation and as well a large reduction in market clearing price in peak hours.

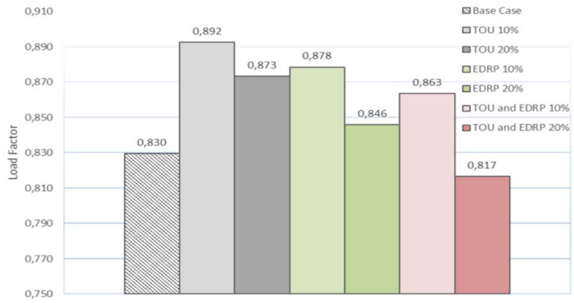

Fig. 5. Load factor for the different cases.

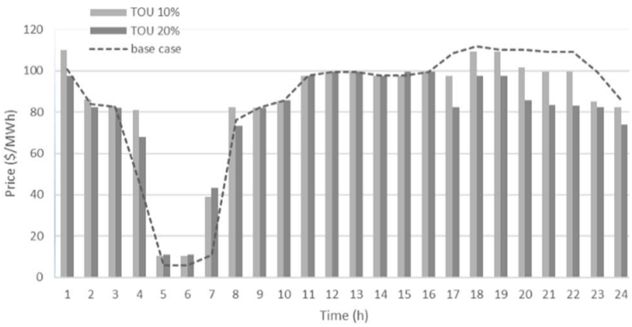

Fig. 6. Impact of different participation level on TOU program on market clearing price.

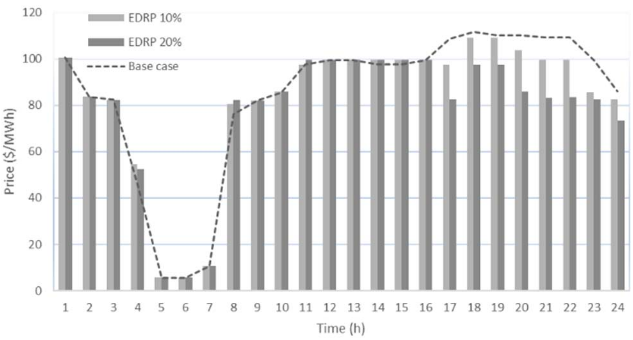

Fig. 7. Impact of different participation level on EDRP program on market clearing price.

C. ENS and Lerner Index

Table II shows the amount of energy not supplied for different DR programs. As can be seen, the application of DRP's allow the reduction of energy not supplied. With the increase of the costumer's participation level in each program, is provided a reduction on the ENS. The Lerner Index is illustrated in Fig. 9 and 10 for all of generating units. By comparing the different indices with the base case, the DRPs are able to mitigate the market power and its efficiency.

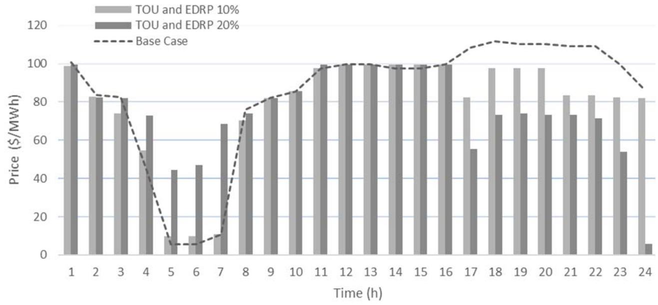

Fig. 8. Impact of different participation level on EDRP program on market clearing price

TABLE II: ENERGY NOT SUPPLIED FOR DIFFERENT DRP'S

Case	ENS (MW)
Base case	153.272
TOU 10%	100.356
TOU 20%	36.122
EDRP 10%	120.872
EDRP 20%	106.232
TOU & EDRP 10 %	118.871
TOU & EDRP 20 %	98.316

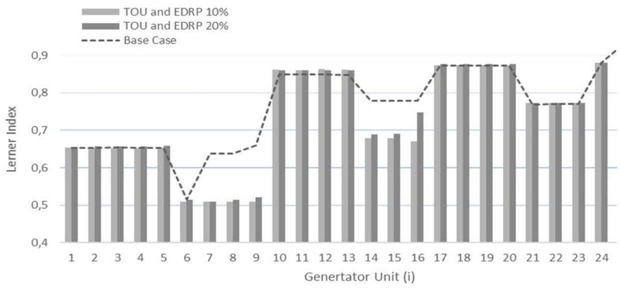

Fig. 9. Impact on Lerner Index of different levels of costumer's participation on TOU program

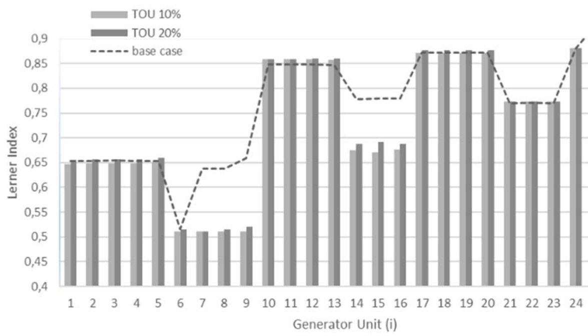

Fig. 10. Impact on Lerner Index of different levels of costumer's participation on TOU and EDRP programs

V. CONCLUSIONS

In this paper, in addition to using a stochastic model for economic dispatch and network constrained unit commitment, a DR model was applied for obtaining the helpful instruments for an ISO. A scenario-based contingencies analysis was performed. Innovative numerical indices for evaluating the reliability and market power were employed to indicate the efficiency of DR strategies. Different kinds of DR and the variety of customers' participation level were the important elements to improve the demand pattern. Furthermore, a comprehensive cost/benefit analysis of DR was carried out. A two-stage stochastic SCUC was used in such a way that contingencies were analyzed in the second stage for security aspects, and the final decision on units' commitment states and their optimal generation along with DR program were made in the first stage by minimizing the total operation cost through mixed-integer linear programming. Based on the numerical results, the implementation of DR caused a decrease in total operation cost.

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