Simultaneous Employment of Generation Rescheduling and Incentive-based Demand Response Programs for Congestion Management in Case of Contingency

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***Abstract*—Relieving congestion significantly influences the operation and security of the transmission network. Consequently, the congestion alleviation of transmission network in all power systems is imperative. Moreover, it could prevent price spikes and/or involuntary load shedding and impose high expenses on the transimission network, especially in case of contingency. Traditionally, the increasing or decreasing generation rescheduling has been used as one of the most imperative approaches for correctional congestion management when a contingency occurs. However, demand response programs (DRPs) could also be a vital tool for managing the congestion. Therefore, the simultaneous employment of generation rescheduling and DRPs is proposed for congestion management in case of contingency. The objective is to reschedule the generation of power plants and to employ DRPs in such a way so as to lessen the cost of congestion. The crow search algorithm is employed to determine the solution. The accuracy and efficiency of the proposed approach are assessed through the tests conducted on IEEE 30-bus and 57-bus test systems. The results of various case studies indicate the better performance of the proposed approach in comparison with different approaches presented in the literature.**

***Index Terms*—Congestion management, demand response, generation rescheduling transmission economy, transmission lines.**

NOMENCLATURE

δ	Voltage angle
θ_{km}	Admittance angle of line connecting buses k and m
Γ	Load proportion parameter
A	Incentive for demand response program (DRP) participation
AP	Awareness probability
C	Congestion cost
$Cost_{DRP}$	Total cost paid to DRP through incentives
D	Demand
D^{DRP}	Demand after DRP implementation
$\Delta D_k^{\max}$	The maximum allowable change in power consumption of bus k
E	Elasticity of DRPs
$F(\cdot)$	Fitness function
$F_l^{\max}$	The maximum allowable power transmission over line l
f_l	Power transmitted over line l
FL	Flight length
$F_{T,l}$	Penalty function for violation of transmission line limit
$F_{V,k}$	Penalty function for violation of voltage limits at bus k
i, n	Indices of a solution of crow search algorithm (CSA)
$iter$	Index of iteration in CSA
I_j	Incremental price offer of generation company (GenCo) j
j	Index of GenCo
k, m	Indices of buses
l	Index of transmission line
m_i	Memory of the i^{th} crow
N_b	Number of buses
N_g	Number of GenCos
N_l	Number of transmission lines
P_{Dk}	Active power demand of bus k
$P_{k\text{-}m}$	Active power of line between buses k to m
Pen	Penalty for failing to comply with independent system operator's orders
PF_T, PF_V	Penalty functions for violation of line limit and bus voltage constraints
$P_{Gj}^{\min}$, $P_{Gj}^{\max}$	The minimum and maximum active generating capacities of GenCo j

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P_{Gj}	Active power generation of GenCo j
P_{Gj}^0	Active power generation of GenCo j at the time of congestion occurrence
$\Delta P_{Gj}^{+}, \Delta P_{Gj}^{-}$	Active power increment and decrement of GenCo j
P_{Gk}	Active power generation at bus k
P_{Gk}^0, P_{Dk}^0	Active generated and consumed power at bus k at the time of congestion occurrence
Pr	Energy price after DRPs
Pr_0	Energy price before DRPs
Q_{Dk}	Reactive power demand of bus k
$Q_{Gj}^{\min}, Q_{Gj}^{\max}$	The minimum and maximum reactive generating capacities of GenCo j
Q_{Gj}	Reactive power generation of GenCo j
Q_{Gk}	Reactive power generation at bus k
R_j	Decremental price offer of GenCo j
r	Randomly generated value between 0 and 1
x_{rand}	A randomly generated position
t	Time in hour
V	Voltage of a bus
$V^{\min}$, $V^{\max}$	The minimum and maximum voltage constraints
x_i	Position of the i^{th} crow
Y_{km}	Admittance of line connecting buses k and m

I. Introduction

THE advent of the smart grid has enabled the customers to play a vital role in the electricity market and change their power consumption when called upon or when the security of the power system is endangered. To participate in the electricity market, the customers should enroll in the programs called demand response (DR) provided by the aggregators. Fast response time is benificail for the DR in congestion management in case of a contingency.

The restructuring of the power system has been proposed to raise the competition in production, resulting in lower prices, increased efficiency, and improved service in the power system. On one hand, in this environment, the investment in the production sector and operation decisions are left to competitive mechanisms while, on the other hand, the transmission network remains a shared and non-competitive service. As a result, in today's electricity market, the transmission systems are usually utilized at their near full capability. Therefore, they are susceptible to congestion, especially in case of a contingency. The congestion is the use of a power grid outside the permitted range of operation. From the perspective of transmission system, any overload on the transmission lines that occurs in the peak load or under other emergency conditions such as the outage of lines and generators is referred to as a congestion. The combination of the competitive generation sector and the public transmission system has made congestion management arduous. This difficulty will increase as the congestion swells due to the higher rate of increase in transactions of the electricity market compared with that in transmission system expansion.

In the traditional structure, the congestion is resolved using certain instructions. Since the transmission lines prone to congestion are known and their required amount of capacity at a given period depending on the load is almost constant, the main solution to alleviate the congestion increases the installed capacity of transmission lines and/or generation rescheduling. However, in the restructuring era and with the open-access scheme of the transmission network, the congestion has become acuter and its occurrence from a fixed state in traditional systems has altered to an obscure and uncertain state, with extra costs imposed to the power system and sometimes in the places not expected. Under these new conditions, the power system operator has faced many limitations to relieve the congestion, which has eventually resulted in new and different ways of congestion management.

The most common approach for congestion management in case of a contingency has been generation rescheduling. However, the environmental concerns and limited fossil fuel resources have required and motivated the electricity market to fully employ the potentials of DR programs. One of the areas that DR could be implemented is for congestion management. Although there are many studies for utilizing the DR in the day-ahead market for congestion management, only a few studies explore the use of these resources for real-time deployment of DR for congestion management, especially in case of a contingency. Therefore, we mainly aim to simultaneously utilize the generation rescheduling and DR programs (DRPs) for relieving the congestion in case of a contingency in a way that reduces the operation costs.

Considering the importance and significance of congestion mitigation in the restructured power systems, several schemes have been proposed in the literature. These approaches include flexible AC transmission system (FACTS) devices [1]-[3], distributed generations [4]-[6], congestion-driven transmission expansion planning [7], [8], and generation rescheduling [9]-[12], etc. Reference [9] suggests the power transfer distribution coefficients for congestion management. Then, using these coefficients, a corrective method is proposed for congestion management. In [10], after identifying the sensitivity of the congestion to the power production of willing power plants to participate in the congestion management, attempts are made to reduce the congestion by changing the power generation of these units. In this way, the goal is set to be the minimization of variation in the power production of generators. The generators' sensitivity factor regarding the congested line is employed for rescheduling, and the whale optimization approach is applied for decreasing the congestion with the least cost possible [11].

Reference [12] proposes congestion management considering transient and voltage stability. The congestion is relieved by implementing the variation in the power production of generators as well as the power consumption of some loads. In [13], congestion management is proposed by changing the power production of thermal units and changing the consumption of consumers according to the prices provided by them as well as the load curtailment, if necessary.

Generation rescheduling for congestion management using evolutionary algorithms is the subject of many researchers in recent years. The differential evolution algorithm is proposed in [14]. Besides, the effect of the presence of wind turbines is also considered in the optimization problem, and the optimal wind turbine location for managing the congestion has been determined. Firefly algorithm (FFA) is used in [15] for optimization of congestion management. The generation rescheduling approach is utilized and the optimization aims to minimize the cost. In [16], a real-time intelligent method is proposed for the alleviation of congestion. The particle swarm optimization (PSO) is employed for optimization. In [17], improved PSO (IPSO) is utilized for rescheduling-based congestion management schemes. Obtained results demonstrate the superiority of the IPSO regarding the standard PSO. The symbiotic organic search algorithm is proposed in [18] to discover the optimal variation in power generation of generation units to alleviate the congestion. The teaching-learning-based optimization (TLBO) algorithm is proposed in [19] for optimal rescheduling of the active power of generation units to lessen the congestion. Higher quality solutions are obtained compared with other approaches. Reference [20] suggests the use of PSO for congestion management with the aim of the minimum deviation from the primary market arrangement. Comparing the results with those of simulated annealing (SA) and random search method (RSM) shows better performance of the proposed approach.

In [21], flower pollination algorithm (FPA) is employed for congestion management using the generation rescheduling. The obtained results reveal better performance of this algorithm in comparison with PSO, SA, and RSM. The glowworm swarm optimization algorithm is proposed in [22] to solve the multi-objective congestion management problem. The objectives considered are congestion cost mitigation and loss reduction. A survey of different approaches employed for congestion management is provided in [23]. Various optimization algorithms are critically analyzed and the key features and challenges are discussed. While [9]-[23] fully investigate the generation rescheduling for congestion management, they do not take advantage of DRPs.

Approaches are involved by DRPs to lessen power consumption. Furthermore, enough motivations could entice customers to participate in the electricity market and lead to a completely competitive market. DRPs have designed exceptional chances for consumers to be a part of the market and play an essential role [24]. DRPs could be employed by the ISO in case of an emergency. Therefore, these resources could be deployed in case of congestion due to the contingency occurrence. Reference [25] discusses the incorporation of distributed energy resources into the market from the aggregator's perspective. It proposes that with an optimized schedule and reschedules of small-size resources, the aggregator could participate in the market as a DR provider.

DRPs are used for congestion management in several studies. In [26], a transmission congestion management approach is proposed using a combination of DRPs and FACTS devices. A two-tier DRP method is suggested in [27] with flexible demand swaps for congestion relieve in the distribution system. Reference [28] presents a stochastic chance constraint optimization approach for mitigating the congestion in the day-ahead market. In [29], a novel scheme for managing the congestion is proposed to ascertain the best location and hour of deployment of DRPs using the power transfer distribution factors. An original design based on the modified PSO approach is developed for congestion management in [30] in which generation rescheduling and DRPs are employed to tackle the congestion problem. The above studies propose the use of DRPs for planning purposes [26] and the day-ahead market [27]-[30]. Accordingly, the application of these resources in real-time congestion management in case of a contingency is not explored.

Recent decades have been the realm of evolutionary algorithms, and many approaches are introduced that have evolved the optimization process in many subjects, especially in engineering, and many of these approaches are used in practical cases. Crow search algorithm (CSA) is one of the latest and sturdiest evolutionary algorithms [31], which shows great efficiency when employed to solve the power system's optimization problems [32]-[35]. Proper rescheduling of real power generation and deployment of DRPs for mitigating congestion via CSA is proposed in this paper.

The main contributions of this study are twofold.

1) As discussed in the literature review, on one hand, the DRPs are previously applied in day-ahead electricity markets to mitigate transmission network congestion [27]-[30]. However, the exploitation of the positive effects of DRPs on congestion management in case of contingencies in real time has remained unprecedented. On the other hand, the previous studies which consider the rescheduling of generation units as a solution for congestion alleviation, e.g., [9]-[23], do not entail the potential of DRPs. The real-time simultaneous employment of generation rescheduling and incentive-based DRPs for congestion management in case of contingencies due to the unforeseen load fluctuations and failure in the system components are proposed in the present study.

2) A novel formulation is proposed for DRPs to develop a relationship between the value of incentive paid to customers and the value of their participations in DRPs using the concept of price elasticity. Employing this relationship, the proposed approach evaluates the value of incentive which allows for the exploitation of customers' participation in DRPs. The best buses for the deployment of DRPs are also discovered. In most of the studies of utilizing DRPs for congestion management, the location of DRPs or the value of the incentive is presumed. While in this paper, the best location for the deployment of incentive-based DRPs and the proper value of incentive paid to the customers are determined.

Other features of this paper are as follows.

1) The CSA is employed as a powerful optimization tool [32]-[35] to reduce the rescheduling and the employment costs of DRPs considering various contingencies for the two case studies, i.e., IEEE 30-bus and 57-bus standard test systems.

2) The overload in the transmission lines arisen by several studied contingencies is efficiently eliminated with the DRPs

and the least alteration in the generation schedule.

3) The total quantity of rescheduling and losses is depreciated for different considered crises.

4) Several security restrictions including line loading and bus voltage are considered while modeling and solving this optimization problem.

5) An effective penalty mechanism is deployed to penalize constraint violations and at the same time prevent the elimination of good solutions that slightly infringe one or a few limits. Therefore, with a slight modification, they could become free of constraint contravention.

6) The effectiveness of the proposed approach is proven over other approaches.

The rest of this paper is organized as follows. The problem modeling and formulation are provided in Section II. Section III deals with the optimization procedure and the obtained results are provided and discussed in detail in Section IV. Concluding remarks are drawn in Section V.

II. Problem Modeling and Formulation

This section provides the problem formulation of congestion management. Primarily, the objective function for generation rescheduling without DRPs is mathematically delineated and then the equality and inequality constraints are presented. Afterward, the model of DRPs developed for this paper is explained. Finally, the objective function for generation rescheduling with DRPs is provided.

A. Primary Objective Function

The primary purpose of congestion management is to minimize the costs while meeting the constraints of power system and units. In this paper, the generation rescheduling is used to mitigate the congestion caused by contingencies such as transmission line outages. However, the generation companies (GenCos) change their output active power at a cost, which is provided in their offers. Therefore, the objective function is to minimize the congestion costs [15] as:

$$C=\sum_{j}(I_j\Delta P_{Gj}^{+}+R_j\Delta P_{Gj}^{-}) \quad \forall j\in N_g \tag{1}$$

This optimization problem is subjected to various equality and inequality constraints presented in the following subsection.

B. Constraints

The following equations provide the equality constraints of the optimization problem under study. Equations (2) and (3) represent the active and reactive power balance constraints at each bus, while (4) and (5) illustrate the final generated and consumed power secured from the electricity market mechanisms [15].

$$P_{Gk}-P_{Dk}=\sum_{k=1}^{N_b}|V_k||V_m||Y_{km}|\cos(\delta_k-\delta_m-\theta_{km}) \tag{2}$$

$$Q_{Gk}-Q_{Dk}=\sum_{k=1}^{N_b}|V_k||V_m||Y_{km}|\sin(\delta_k-\delta_m-\theta_{km}) \tag{3}$$

$$P_{Gk}=P_{Gk}^{0}+\Delta P_{Gk}^{+}-\Delta P_{Gk}^{-} \quad \forall k\in N_b \tag{4}$$

$$P_{Dk}=P_{Dk}^{0} \quad \forall k\in N_b \tag{5}$$

It should be noted that index k is for all the buses of the system, and if there is no generation at a given bus, the values of P_{Gk} and Q_{Gk} will be zero. If there is more than one unit at a bus, the values of P_{Gk} and Q_{Gk} will be the sum of active and reactive generations at that bus, respectively.

The inequality constraints are those related to operation and physical limitations of the transmission facilities and generators as provided in (6)-(10) [36]. These constraints include bus voltage constraint (6), upper boundary of transmission lines in (7), and active and reactive power limits of generation units in (8) and (9), respectively. Note that (4) presents the amount of power injected to bus k, while (10) provides the amount of variation in power generation of unit j. Moreover, (11) enforces that the decrease or increase in the power generation of a unit is constrained by the capacity limits.

$$V_k^{\min}\le V_k\le V_k^{\max} \quad \forall k\in N_b \tag{6}$$

$$f_l\le F_l^{\max} \quad \forall l\in N_l \tag{7}$$

$$P_{Gj}^{\min}\le P_{Gj}\le P_{Gj}^{\max} \quad \forall j\in N_g \tag{8}$$

$$Q_{Gj}^{\min}\le Q_{Gj}\le Q_{Gj}^{\max} \quad \forall j\in N_g \tag{9}$$

$$P_{Gj}=P_{Gj}^{0}+\Delta P_{Gj}^{+}-\Delta P_{Gj}^{-} \quad \forall j\in N_g \tag{10}$$

$$P_{Gj}^{0}-P_{Gj}^{\min}=\Delta P_{Gj}^{\min}\le\Delta P_{Gj}\le\Delta P_{Gj}^{\max}=P_{Gj}^{\max}-P_{Gj}^{0} \tag{11}$$

C. Modeling and Formulation of DRP

We aim to deploy the incentive-based DRPs along with generation rescheduling to manage the congestion in case of contingency. For a sufficiently high remuneration, it is assumed that customers enlisted in DRPs will reduce their power consumption when needed. However, the relationship between the participation level of customers in DRPs and the value of incentive that they receive should be determined.

References [37] - [39] introduce the economic representation of DRPs, considering the price elasticity of demand, penalty, and award. The elasticity is defined as the DR toward changes in the price [37]:

$$E(t,t)=\frac{Pr(t)}{D(t)}\frac{\partial D(t)}{\partial Pr(t)} \tag{12}$$

Therefore, the consumption of customers after the deployment of DRPs is as follows [37]:

$$D^{DRP}(t)=D(t)\left\{1+E(t,t)\frac{Pr(t)-Pr_0(t)+\Gamma(t)A(t)+\Gamma(t)\cdot Pen(t)}{Pr_0(t)}\right\} \tag{13}$$

Since the real-time congestion management in case of contingency is considered, the parameter t could be ignored. Moreover, the proper value of incentive and the best level of participation of DRPs are determined. The participation level of DRPs at each bus should be lower than a predefined value.

$$\begin{cases}\Delta D_k=D_k-D_k^{DRP}\\ \Delta D_k\le\Delta D_k^{\max}\end{cases} \tag{14}$$

The cost of employing DRPs could be calculated using the value of incentive and the participation level of DRPs.

$$Cost_{DRP}=\sum_{k}A(D_k-D_k^{DRP}) \quad \forall k\in N_b \tag{15}$$

$Cost_{DRP}$ indicates the total value of incentive paid to customers. Therefore, neglecting the penalties, A could be written as (16) using (13).

$$A(t)=\frac{\dfrac{D^{DRP}/D-1}{E(t,t)}Pr_0(t)-Pr(t)+Pr_0(t)}{\Gamma(t)} \tag{16}$$

Combining the constant indices, $A(t)$ can be rewritten as:

$$A(t)=\varphi\frac{D^{DRP}-D}{DE(t,t)}+\gamma \tag{17}$$

$$\varphi=\frac{Pr_0(t)}{\Gamma(t)} \tag{18}$$

$$\gamma=\frac{Pr_0(t)-Pr(t)}{\Gamma(t)} \tag{19}$$

Furthermore, D and $E(t,t)$ are pre-specified and constant. Consequently, the total value of incentive paid to the customers in (15) could be rewritten as:

$$Cost_{DRP}=\left[\lambda(D_k-D_k^{DRP})^2+\gamma(D_k-D_k^{DRP})\right] \tag{20}$$

$$\lambda=\frac{-Pr_0(t)}{E(t,t)\Gamma(t)} \tag{21}$$

It should be noted that the higher the value of the incentive is, the more customers are enticed to participate in the electricity market.

D. Objective Function with DRPs

Considering that DRPs for congestion management changes the formulation of the objective function, the cost of deploying DRPs should also be considered to realize the contributions. Therefore, the objective function considering DRPs is to minimize total costs related to generation rescheduling and the implementation of DRP and could be formulated as:

$$C=\sum_{j\in N_g}(I_j\Delta P_{Gj}^{+}+R_j\Delta P_{Gj}^{-})+\sum_{k\in N_b}\left[\lambda(D_k-D_k^{DRP})^2+\gamma(D_k-D_k^{DRP})\right] \tag{22}$$

The objective is to simultaneously minimize the cost of generation rescheduling $\sum_{j\in N_g}(I_j\Delta P_{Gj}^{+}+R_j\Delta P_{Gj}^{-})$ and the cost of DRPs $\sum_{k\in N_b}\left[\lambda(D_k-D_k^{DRP})^2+\gamma(D_k-D_k^{DRP})\right]$. The variables optimized are the increment and decrement of active power for generators and the amount of load reduction for DRPs at each bus of the power system. With (17), the value of incentive paid to the customers that are employed for DR provision is determined by using the values found for load reductions in the optimization problem. The constraints are the same as those presented in Section II-B along with the constraint related to DRPs in (14).

III. CSA for Congestion Management Problem

One of the foremost inspirations of this paper is to create a user-friendly evolutionary approach with a simple concept and easy implementation that can achieve satisfactory results while solving the optimization problem. In this regard, CSA [31] is employed to solve the congestion management problem. In this problem, there are N parameters, which in total represent N_g and N_b participating in DRPs for congestion management. Therefore, each crow has N variables. The objective is the minimization of costs. Therefore, lower costs mean better fitness.

For the optimization problem, there could be a solution that has great fitness but slightly violates a constraint. From the crisp perspective, this solution will be discarded. However, with a small modification, a good solution may result. Therefore, in this paper, a penalty approach is applied from [40], which builds a single objective with constraints.

The inequality limits, including power flow limit on transmission lines and constraints regarding the voltage of each bus, are turned into the penalty functions which in turn are combined with the objective function. The equality limits as well as reactive power inequality constraints are effectively managed by Newton-Raphson power flow [41]. The fitness function of the congestion management problem is then presented [40] as:

$$\min\ F=PF_T\cdot PF_V\cdot C \tag{23}$$

C is the objective function calculated using (1) and (22) without and with DRP, respectively, and PF_T and PF_V are calculated using (24) and (25), respectively, based on [29].

$$PF_T=\prod_{l=1}^{N_l}F_{T,l} \tag{24}$$

$$PF_V=\prod_{k=1}^{N_b}F_{V,k} \tag{25}$$

Note that the fitness function incorporating the constraints is determined, and the proposed approach based on CSA could be applied. This procedure is explained as follows.

Step 1: read the load, line, and bus data along with the price bids and the information of GenCos and DRPs.

Step 2: design a contingency by line outage and/or load increase.

Step 3: perform the load flow and determine the overloaded lines and violation of bus voltage.

Step 4: determine the permissible range of rescheduling of each generator using (11).

Step 5: determine the permissible range of each bus for participating in DRPs.

Step 6: initialize the first population of CSA and memory of crows, which is randomly resolved within the limits determined in the above steps.

Step 7: execute load flow for each member of the population and and check the equality and inequality constraints.

Step 8: using the data obtained from the load flow execution, penalty functions are determined using (24) and (25). Consequently, the fitness function is appraised by (23).

Step 9: create a new population of crows using the following equation.

$$x_i^{iter+1}=\begin{cases}x_i^{iter}+r_i\cdot FL_i^{iter}\cdot(m_i^{iter}-x_i^{iter}) & r_n\geq AP_n^{iter}\\ x_{rand} & r_n<AP_n^{iter}\end{cases} \tag{26}$$

Employing (26), the position of the i^{th} crow, when following crow n, is updated using its current location x_i^{iter}, the flight length FL, the memory of the i^{th} crow m_i^{iter}, the awareness probability of the n^{th} crow AP_n^{iter}, and a randomly generated value for the following n^{th} crow r_n. It should be noted that the memory of a crow represents the best location that the crow has ever visited. More details can be found in [31].

Step 10: evaluate the fitness function for the new population and update the memory of crows. The new position of a crow has better fitness (lower objective function) compared with the current memory of the same crow.

Step 11: stop the optimization procedure if it arrives at the maximum number of iterations. Otherwise, it returns to *Step 9*.

IV. Simulation Results and Discussion

To verify the effectiveness of the CSA in solving the congestion management problem, the proposed approach is carried out on the modified IEEE 30-bus and 57-bus test systems. The data of these test systems are extracted from [15]. For each test system, four different cases are considered to thoroughly examine the effects of DRPs on congestion management and to evaluate the performance of the proposed approach. Moreover, the results obtained are compared with those in [15] and [19]-[21]. To simulate and highlight the congestion problem, the capacities of lines decrease to the associated standard boundaries. Furthermore, line overloads are created by considering generator or line outage as well as load increase. The proposed approach has been implemented and solved in MATLAB 2017a using a laptop with a 2.67 GHz Intel Core i5 CPU, 4 GB memory.

The loads, offers of GenCos, and transmission network data for both test systems can be found in [15] and the modifications with respect to the base data from [19]-[21] are applied. It is assumed that all buses can participate in DRPs and each bus includes up to 10% of the responsive demand. It is evident that the buses with no load cannot provide this service. Moreover, the market price is considered to be 20 $/MWh before Pr_0 and after Pr deployment of DRPs. The elasticity of demand E for all buses is supposed to be equivalent to −0.1 [26]. Γ is equal to be 0.1 and for bus k, $\Delta D_k^{\max}$ is set to be 10% of D_k [38], [39].

The best solution is reported out of 20 independent execution of the proposed approach. It should be noted that FL and AP are set to be 0.19 and 0.1, respectively. Besides, the maximum number of iterations is 100 for all cases.

For each test system, four different cases of congestion are considered. In cases 1 and 2, DRPs are not considered. The objective function is provided in (1). While in cases 3 and 4, DRPs are integrated in the electricity market for congestion management, and the objective function is provided in (22). Note that the fitness function should be evaluated using (23) in which C is calculated using (1) or (22).

A. Modified IEEE 30-bus Test System

This test system has 41 transmission lines, 24 load buses, and 6 generators. The cumulative active and reactive loads are 283.4 MW and 126.2 Mvar, respectively. The price bids provided by the GenCos for IEEE 30-bus test system are presented in Table I [15].

TABLE I
Price Bids Provided by GenCos for IEEE 30-bus Test System

Bus No.	Increment ($/MWh)	Decrement ($/MWh)
1	22	18
2	21	19
3	42	38
4	43	37
5	43	35
6	41	39

The primary market-clearing values are considered to be the same as the generation and load values in [15]. It is assumed that the congestion is created due to the unexpected line failure and/or load increase.

1) Case 1

In case 1, it is assumed that line 1 that connects the buses 1 and 2 of the systems experiences an outage. Due to the disconnection of this line, the congestion occurs, and lines 2 (between buses 1 and 7) and 4 (between buses 7 and 8) are overloaded. Right after the outage of line 1, the flows of these lines are equivalent to 147.43 MW and 136.29 MW, respectively, which violates the line limit of 130 MW for both lines. Therefore, the generation rescheduling should be employed to mitigate the congestion. The best rescheduling arrangement obtained by the proposed approach to solve the congestion problem is illustrated in Table II. To provide comparability, the results of other approaches including FFA [15], TLBO [19], FPA [21], RSM, SA, and PSO [20] are also included in Table II. The CSA offers the best solution at a cost of 490.14 $/h. The total system loss before the congestion management is 16.32 MW, while the value is reduced to 12.21 MW after the proposed congestion management is applied.

TABLE II
Comparison of Results of Different Approaches in Case 1 of Modified IEEE 30-bus Test System

Approach	C ($/h)	$P_{1\text{-}7}$ (MW)	$P_{7\text{-}8}$ (MW)	ΔP_{G1} (MW)	ΔP_{G2} (MW)	ΔP_{G3} (MW)	ΔP_{G4} (MW)	ΔP_{G5} (MW)	ΔP_{G6} (MW)	Total generation rescheduled (MW)
CSA	490.1414	129.957	120.770	–8.6341	7.3731	1.7189	2.6065	1.2878	1.4246	23.0452
TLBO [19]	494.6600	130.000	120.780	–8.5876	12.9855	0.4598	0.7289	–0.0093	0.3988	23.1690
FPA [21]	519.6200	130.000	120.780	–9.1278	14.1400	–0.2060	–0.0188	0.1890	1.0130	24.7030
FFA [15]	511.8737	129.812	120.617	–8.7783	15.0008	0.1068	0.0653	0.1734	–0.6180	24.7425
PSO [20]	538.9500	129.970	120.780	–8.6123	10.4059	3.0344	0.0170	0.8547	–0.0122	22.9360
RSM [20]	716.2500	129.780	120.600	–8.8086	2.6437	2.9537	3.0632	2.9136	2.9522	23.3390
SA [20]	719.8610	129.510	120.350	–9.0763	3.1332	3.2345	2.9681	2.9540	2.4437	23.8090

From the results in Table II, it can be concluded that the proposed approach delivers the best solution by giving the minimum cost of generation rescheduling compared with other approaches reported in previous studies. The comparison of the results demonstrates that the proposed approach has been able to lessen the value of the objective function. In addition, the system losses of the best solution of the proposed approach are the least among the compared approaches. The proposed approach has been subjected to less variation in the generation output of the GenCos than all approaches except for PSO, thereby yielding a lower cost for congestion management.

2) Case 2

In case 2, it is assumed that line 2 that connects buses 1 and 7 of the systems encounters an outage. To exert more pressure on the transmission network, an increase in the system load by 50% is considered. It is assumed that the load of all buses is 1.5 times the base state and the load of each bus is proportional to its baseload. This increase is considered for both active and reactive power. After the outage of line 2, an overload is observed in lines 1 (connecting buses 1 and 2), 3 (connecting buses 2 and 8), and 6 (connecting buses 2 and 9). The power flow [36] results show that the power flows over these lines are equal to 310.917 MW, 97.353 MW, and 103.524 MW, respectively, while the transmission power flow constraints of these lines are 130 MW, 65 MW, and 65 MW, respectively.

Therefore, the proposed approach is employed to alleviate the congestion. The obtained results using the proposed approach for this case are presented in Table III. Moreover, the results for the FFA [15], TLBO [19], FPA [21], RSM, SA, and PSO [20] are also incorporated in the table. The proposed approach yields the best solution of 5303.0240 \$/h. The total system loss before congestion management is 37.8 MW, while this value is reduced to 15.8235 MW after the implementation of the proposed approach, which is very significant. Table III shows that the proposed approach delivers the best solution compared with other approaches.

TABLE III
COMPARISON OF RESULTS OF DIFFERENT APPROACHES IN CASE 2 OF MODIFIED IEEE 30-BUS TEST SYSTEM

Approach	C (\$/h)	$P_{1\text{-}2}$ (MW)	$P_{2\text{-}8}$ (MW)	$P_{2\text{-}9}$ (MW)	ΔP_{G1} (MW)	ΔP_{G2} (MW)	ΔP_{G3} (MW)	ΔP_{G4} (MW)	ΔP_{G5} (MW)	ΔP_{G6} (MW)	Total generation rescheduled (MW)
CSA	5303.024	129.898	62.732	64.837	–8.6919	72.0424	6.9032	43.6675	20.4562	15.9538	167.7572
TLBO [19]	5306.500	130.000	62.340	65.000	–8.5876	75.6500	0.0120	34.3570	31.4791	17.8300	168.0880
FPA [21]	5320.800	130.000	60.775	65.000	–8.5890	74.0240	0	13.5174	43.8650	27.8900	167.8960
FFA [15]	5304.400	130.000	62.713	64.979	–8.5798	75.9954	0.0575	42.9944	23.8325	16.5144	167.9740
PSO [20]	5335.500	129.700	61.100	64.670							168.0300
RSM [20]	5988.050	129.910	52.360	55.430							164.5500
SA [20]	6068.700	129.780	51.470	54.040							164.5300

3) Case 3

Case 3 is similar to case 1 and the only difference is the consideration of DRPs for congestion management. Therefore, it is assumed that line 1 ceases to connect buses 1 and 2 of the test system, which will lead to the congestion in the transmission network like case 1. Therefore, the generation rescheduling and DRPs should be utilized suitably to alleviate the congestion. The results for case 3 are shown in Table IV.

TABLE IV
RESULTS FOR CASE 3 OF MODIFIED IEEE 30-BUS TEST SYSTEM

Scenario	$P_{1\text{-}7}$ (MW)	$P_{7\text{-}8}$ (MW)	ΔP_{G1} (MW)	ΔP_{G2} (MW)	ΔP_{G3} (MW)	ΔP_{G4} (MW)	ΔP_{G5} (MW)	ΔP_{G6} (MW)	Total generation rescheduled (MW)	Generation rescheduling cost (\$/h)	DRP cost (\$/h)	Total congestion cost (\$/h)
Without DRPs	129.9570	120.7700	–8.6341	7.3731	1.7189	2.6065	1.2878	1.4246	23.0452	490.1414		490.1414
With DRPs	129.8210	120.6400	0.1425	4.5618	2.2191	1.5460	2.6958	2.5466	13.7119	385.9101	60.3306	446.2407

It should be noted that in order to prevent the complications in managing the transmission network, only the buses that provide more than 0.5 MW in DRPs are considered here and all values for load reduction are not allowed. In case 3, DRP is employed in bus 4 and the participation level is 0.95 MW. The total congestion cost for case 3 is 446.2407 \$/h, which shows about a 9% reduction compared with that of case 1.

In this case, the cost of generation rescheduling is 385.9101 \$/h and the cost of the employment of DRP is 60.3306 \$/h. The results obtained demonstrate that the deployment of DRP could effectively reduce the congestion cost. The value of incentive for this case is 63.4195 \$/MWh, which is much higher than the cost of all generators' increment, but it could reduce the total congestion cost of power system.

4) Case 4

In case 4, line 2 fails to serve. A growth of 50% in the load of all buses of the power system is also taken into account, which is considered for both active and reactive power. In this case, generators along with DRPs are deployed to solve the problem of congestion in the transmission network. The results for case 4 are shown in Table V.

TABLE V
RESULTS FOR CASE 4 OF MODIFIED IEEE 30-BUS TEST SYSTEM

Scenario	$P_{1\text{-}2}$ (MW)	$P_{2\text{-}8}$ (MW)	$P_{2\text{-}9}$ (MW)	ΔP_{G1} (MW)	ΔP_{G2} (MW)	ΔP_{G3} (MW)	ΔP_{G4} (MW)	ΔP_{G5} (MW)	ΔP_{G6} (MW)	Total generation rescheduled (MW)	Generation rescheduling cost ($/h)	DRPs cost ($/h)	Total congestion cost ($/h)
Without DRPs	129.8981	62.7324	64.8371	–8.6919	72.0424	6.9032	43.6675	20.4562	15.9538	167.7572	5303.0240		5303.0240
With DRPs	129.9484	61.5325	63.6196	6.1489	60.1607	6.7668	39.7611	20.1392	15.7873	148.7643	4930.0757	267.4961	5197.5718

The proposed approach employs DRPs at buses 2-4 to help reduce the congestion. The amount of load reductions are 1.07 MW for bus 2, 3.26 MW for bus 3, and 1.02 MW for bus 4. Moreover, the total variation in generation scheduling is about 12% lower when DRPs are deployed. As shown in Table V, the integration of DRP reduces the congestion cost. The cost of generation rescheduling is 7% lower for case 4 than that of case 2, and the cost of DRPs is 267.4961 $/h that has led to more than 100 $/h reduction in the total cost of congestion.

The value of incentive paid to each customer is a function of the bus load and the amount of load reduction. In case 4, the values of incentive for customers 2, 3, and 4 are 65.82 $/h, 46.158 $/h, and 45.4317 $/h, respectively, which demonstrates that the proposed approach effectively determines the proper value of incentive and the best amount of load reduction at each bus for congestion mitigation.

B. Modified IEEE 57-bus Test System

This test system has 7 generators, 50 load buses, and 80 transmission lines. Aggregated active and reactive loads are 1250.8 MW and 336 Mvar, respectively. Four different cases are investigated for this test system.

1) Case 1

In case 1, to create the congestion, the line limits are set to be 175 MW for line 8 (5-6) and 35 MW for line 10 (6-12), instead of 200 MW and 50 MW in the original test system, respectively. Due to these changes, the overload is observed in lines 5-6 and 6-12 that are transferring the electric power of 195.97 MW and 49.35 MW, respectively. Therefore, CSA is employed to eliminate the overloads in the transmission network. As a result, the congestion is entirely managed and the overloads are lifted. Details of the results are presented in Table VI and are compared with those obtained by FFA [15], TLBO [19], FPA [21], PSO [20], RSM [20], and SA [20]. From Table VI, it can be remarked that the proposed CSA renders the least total congestion cost management, e. g., 5378.23 $/h, compared with other approaches. However, the total load losses of the transmission system before generation rescheduling are 21.458 MW, and after congestion management, it increases to 27.4292 MW. However, since the proposed approach imposes lower changes to active power generation of GenCos, less cost is achieved.

TABLE VI
COMPARISON OF RESULTS OF DIFFERENT APPROACHES IN CASE 1 OF MODIFIED IEEE 57-BUS TEST SYSTEM

Approach	C ($/hour)	$P_{5\text{-}6}$ (MW)	$P_{6\text{-}12}$ (MW)	ΔP_{G1} (MW)	ΔP_{G2} (MW)	ΔP_{G3} (MW)	ΔP_{G4} (MW)	ΔP_{G5} (MW)	ΔP_{G6} (MW)	ΔP_{G7} (MW)	Total generation rescheduled (MW)
CSA	5378.23	174.686	34.980	29.3525	18.7677	13.1412	–2.9703	–42.5276	–6.79560	–2.1332	115.6884
TLBO [19]	5981.30	174.914	35.000	38.1219	0.7801	9.0766	–0.0179	–43.2018	–29.9082	22.8093	143.9158
FPA [21]	6340.80	163.676	35.000	0.8768	0.0009	9.2476	–1.3623	–52.4794	–24.5482	64.3341	152.8493
FFA [15]	6050.10	174.318	34.993	5.6351	2.5230	0.5098	0.1070	–39.1514	–35.1122	62.1938	145.2270
PSO [20]	6951.90	141.000	34.670	23.1350	12.4470	7.4930	–5.3850	–81.2160	0	39.0300	168.7000
RSM [20]	7967.10	148.400	35.000	59.2680	0	37.4520	–47.3910	–52.1250	0	0	196.2300
SA [20]	7114.30	146.600	34.840	74.4990	0	–1.5150	9.9520	–85.9200	0	0	171.8700

2) Case 2

In case 2, to create the congestion, the capacity limit of line 2 (connecting buses 2 and 3) is set to be 20 MW (initial value is 85 MW). Under the base condition, 37.048 MW of electric power is flowing over this line, consequently, there will be an overload in this line after diminishing its limit. To relieve the congestion, active power rescheduling of GenCos is executed by applying the proposed approach.

The results of the proposed approach are tabulated in Table VII along with the results of other approaches published in the literature, i.e., FFA [15], TLBO [19], FPA [21], PSO [20], RSM [20], and SA [20]. Interpreting this table demonstrates that the proposed approach incurs the lowest cost (2596.1 $/h) among different approaches. The total load losses of the test system marginally increase to 29.437 MW following congestion remission, which is originally 21.458 MW.

3) Case 3

Similar to case 1, in case 3, the transfer limits of lines 8 and 10 reduce to 175 MW and 35 MW, respectively. The proposed approach is employed to manage the congestion using generation rescheduling and DRPs. All buses are the candidates to provide demand reduction and 10% of the load of each bus is considered as the price responsive load that could diminish its power consumption regarding the incentive that they receive.

Table VIII shows that the DRPs could effectively help the ISO mitigate the congestion in the transmission system. Buses 1, 5, 6, 7, 16, 17, 47, and 50 participate in DRPs in case 3 with the load reductions of 1.69 MW, 5.74 MW, 4.64 MW, 13.28 MW, 1.69 MW, 1.52 MW, 1.22 MW, and 0.59 MW, respectively. About 110 \$/h decrease in the total congestion cost is observed, which is the result of DRPs. Comparing the results with those in case 1, it is noticeable that in case 4, all of the generators have reduced their power generation and the power transmitted over congested lines. To cover the deficiency of power production, customers reduce their power consumption via DRPs. The best values of incentive for the participation of DRPs at buses 1, 5, 6, 7, 16, 17, 47, and 50 are 61.51 \$/h, 76.59 \$/h, 76.76 \$/h, 70.44 \$/h, 78.77 \$/h, 72.61 \$/h, 81.90 \$/h, and 56.51 \$/h, respectively. Since the suitable value of the incentive is directly related to the bus load and the percentage of load reduction, the more each load reduces their power consumption, the higher the value of incentive that they receive.

TABLE VII
COMPARISON OF RESULTS OF DIFFERENT APPROACHES FOR CASE 2 OF MODIFIED IEEE 57-BUS TEST SYSTEM

Approach	C (\$/h)	$P_{2\text{-}3}$ (MW)	ΔP_{G1} (MW)	ΔP_{G2} (MW)	ΔP_{G3} (MW)	ΔP_{G4} (MW)	ΔP_{G5} (MW)	ΔP_{G6} (MW)	ΔP_{G7} (MW)	Total generation rescheduled (MW)
CSA	2596.116	19.8091	0.5844	–21.3304	33.3714	0.3264	–1.9315	1.9672	1.9921	61.5034
TLBO [19]	2916.400	20.0000	–1.0174	–24.6365	36.0991	–6.2282	–0.2811	–1.2540	–2.5732	72.0890
FPA [21]	2912.600	20.0000	–0.0060	–35.6234	20.0979	0.0286	1.4297	–0.0305	13.9650	71.1810
FFA [15]	2618.100	19.7900	0.3704	–27.5084	31.6294	0.3308	–2.2549	–1.9354	–0.5101	64.5393
PSO [20]	3117.600	19.8800								76.3140
RSM [20]	3717.900	20.0000								89.3200
SA [20]	4072.900	18.4300								97.8870

TABLE VIII
RESULTS FOR CASE 3 OF MODIFIED IEEE 57-BUS TEST SYSTEM

Scenario	$P_{5\text{-}6}$ (MW)	$P_{6\text{-}12}$ (MW)	ΔP_{G1} (MW)	ΔP_{G2} (MW)	ΔP_{G3} (MW)	ΔP_{G4} (MW)	ΔP_{G5} (MW)	ΔP_{G6} (MW)	ΔP_{G7} (MW)	Total generation rescheduled (MW)	Generation rescheduling cost (\$/h)	DRP cost (\$/hour)	Total congestion cost (\$/h)
Without DRPs	174.6858	34.9801	29.3525	18.7677	13.1412	–2.9703	–42.5276	–6.7956	–2.1332	115.6884	5378.2304		5378.2304
With DRPs	173.3558	34.5218	–0.6223	–3.0437	–2.8992	–25.0794	–33.4317	–13.9504	–4.3973	79.0268	3056.3570	2213.1582	5269.5153

4) Case 4

Similar to case 2 for the test system, there is a congestion in line 2 because of the capacity limit reduction. DRPs along with generation rescheduling of GenCos are employed together to alleviate the congestion. The proposed approach is utilized to find a proper strategy of the deployment of DRPs and a best approach of using GenCos to solve the congestion problem for this case. The best solution attained is provided in Table IX and a comparison between the results for case 4 and case 2 is provided. The obtained solution shows an 18% reduction in the total congestion cost of case 4 compared with that of case 2. The generation rescheduling cost is about half of the cost of case 2, which demonstrates the effectiveness of the application of DRPs that only impose about 841 \$/h on the power system.

TABLE IX
RESULTS FOR CASE 4 OF MODIFIED IEEE 57-BUS TEST SYSTEM

Scenario	$P_{2\text{-}3}$ (MW)	ΔP_{G1} (MW)	ΔP_{G2} (MW)	ΔP_{G3} (MW)	ΔP_{G4} (MW)	ΔP_{G5} (MW)	ΔP_{G6} (MW)	ΔP_{G7} (MW)	Total generation rescheduled (MW)	Generation rescheduling cost (\$/h)	DRP cost (\$/h)	Total congestion cost (\$/h)
Without DRPs	19.8091	0.5844	–21.3304	33.3714	0.3264	–1.9315	1.9672	1.9921	61.5034	2596.1161		2596.1161
With DRPs	19.8695	–0.6366	–1.1405	20.5242	0.1176	–8.5661	–0.3656	16.7537	48.1045	1286.3649	841.0903	2127.4553

In case 4, customers at buses 1, 4, and 5 are asked to reduce their power consumption by 1.82 MW, 3.12 MW, and 5.89 MW, respectively. The value of incentive paid to each customer is different so that the customer at bus 1 receives 66.017 \$/MWh reduction in their power consumption. The value of 83.085 \$/MWh is paid to the end-users at bus 4 for the same service, while customers at bus 5 receives 78.517 \$/MWh.

Table X provides the statistical results and the computation time (CT) of the proposed approach for different cases.

In this table, the best, mean, and worst solution obtained by the proposed approach for each case is presented. Even though the metaheuristic algorithms are stochastic in nature and the best solution is not guaranteed, the deviation of the value of the objective function for these 20 runs is less than 3.5%. It should be noted that these values are not reported for FFA [15], TLBO [19], FPA [21], and RSM, SA, and PSO [20].

TABLE X
STATISTICAL RESULTS AND CT OF PROPOSED APPROACH FOR DIFFERENT CASES

System	Case	CT (s)	Statistical result ($/h)		
			Best	Worst	Mean
IEEE 30-bus	Case 1	7.20	490.141	504.54	492.25
	Case 2	12.68	5303.020	5484.73	5361.87
IEEE 57-bus	Case 1	17.45	5378.230	5518.44	5443.65
	Case 2	14.52	2596.120	2642.64	2610.16

V. CONCLUSION

We attempt to determine the suitable generation rescheduling of GenCos and the best strategy for deploying DRPs to minimize the congestion cost of transmission network. All restrictions regarding the power system, transmission lines, DRPs, and GenCos are also contemplated. Contingencies including sudden load variations and line outage are assumed to create the congestion, and CSA is executed for proper generation rescheduling and the implementation of DRPs. The proposed approach is carried out on the IEEE 30-bus and 57-bus test systems. The results obtained show that DRPs could be of great help to lessen the cost of congestion in case of contingencies. Moreover, the appropriate values of incentive paid to each customer for participation in DRPs and the their participation level are determined.

The proper value of the incentive is different for each bus which is accurately determined by the proposed approach. Different case studies indicate the better execution of the proposed approach in finding the solution. Comparing the results with those of other approaches presented in the literature, it is shown that the proposed approach shows a better performance in finding the solution, so that the cost of congestion is less than other approaches. The electric vehicles along with DRPs and the rescheduling could be the direction of future studies.

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