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Reliability Constrained DR and Reserve Allocation for Profit based UCP using Artificial Bee Colony Algorithm

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ABSTRACT

The strategy of scheduling generators and reliability management of power system is changing rapidly due to deregulation. Here, generating companies schedule their generators with an objective to maximize their own profit without regarding social benefits. This paper proposes a binary artificial bee colony algorithm (BABC) for solving profit based unit commitment (PBUC) problem, where the required spinning reserve (SR) is effectively scheduled according to customers' desired reliability level (CDRL). This approach gives an opportunity for the customers to declare their energy requirement and CDRL to the Independent system operator (ISO) through demand response provider (DRP). Therefore ISO has the responsibility for solving energy deficiency by implementing remedial actions such as rescheduling and/or accepting demand response (DR) offer based on CDRL and spot prices in the power market. The evaluation of the reliability index is based on loss of load method which includes both generator and transmission system outages. The proposed method is validated on 10 unit system and an IEEE RTS 24 bus system available in the literature.

Key words: *profit based unit commitment, spinning reserve, composite system reliability, demand response, loss of load probability*

NOMENCLATURE

B_i	An outage condition in the transmission network.
$C_i(P_{i,t})$	Production cost (\$). $C_i(P_{i,t}) = a_i + b_i * P_{i,k} + c_i * P_{i,k}{}^2$
a_i	Cost co-efficient of i^{th} generator unit (k\$).
b_i	Cost co-efficient of i^{th} generator unit (k\$/MW).
c_i	Cost co-efficient of i^{th} generator unit (k\$/MW^2).
$DRLP_{k,b}$	Demand response at k^{th} hour at load point b.
D_k	Total system demand at k^{th} hour.
DR(i)	Ramp-down rate limit of i^{th} generator unit.
H	Dispatch period in hours.
$I_{i,k}$	Commitment state of i^{th} unit at k^{th} hour.
$LOLP^g_{k,b}$	Loss of load probability due to generator outage at load point b at k^{th} hour.
$LOLP^t_{k,b}$	Loss of load probability due to transmission line outage at load point b at k^{th} hour.
$LOLP^c_{k,b}$	Composite system loss of load probability at load point b at k^{th} hour.
$LOAD_{k,b}$	Load at load point b at k^{th} hour.
$Load'_{k,b}$	Load at load point b after DR
$LPRC_{k,b}$	Load point reliability coefficient at k^{th} hour at load point b.
m	Total number of load point in the system.
N	Total number of generating units.
$P_{i,min}$	Minimum power output of i^{th} generator unit (MW).
$P_{i,max}$	Maximum power output of i^{th} generator unit (MW).
$P_{i,k}$	Power level of i^{th} generator unit at k^{th} hour (MW).
$P(B_i)$	Probability of occurance of outage B_i
P_{ci}	Probability of load that exceed the maximum load that can be supplied without failure.
PF	Total profit (\$).
$P_{bf,bt}$	Power flow between bus bf and bt.
$P_{bf,bt,\ max}$	Maximum power flow limit between bus bf-bt.
RP_k	Forecasted reserve price at k^{th} hour.

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$R_{i,k}$	Spinning reserve of i^{th} unit at k^{th} hour (MW/hour).
RV	Total revenue ($).
SP_k	Forecasted spot price for energy at k^{th} hour.
SR_k	Total system spinning reserve at k^{th} hour.
ST_k	Start up cost at k^{th} hour.
$T_{on}(i)$	Minimum up-time of i^{th} generator unit.
$T_{off}(i)$	Minimum down-time of i^{th} generator unit.
TC	Total cost ($).
TDR	Total Demand response
UR(i)	Ramp-up rate limit of i^{th} generator unit.
$V_{p,min}$	Minimum limit of voltage at bus p.
$V_{p,max}$	Maximum limit of voltage at bus p.
V_p	Voltage at bus p.
$X_{on}(i,k)$	On duration of i^{th} generator unit till k^{th} hour.
$X_{off}(i,k)$	Off duration of i^{th} generator unit till k^{th} hour.
b	Load point index (subscript).
g	Generator reliability index (superscript).
i	Generating unit index (subscript).
j	Contingency state index (subscript).
k	Time index (subscript).
T	Transmission line index (superscript).
α,β,τ	Start up cost coefficients.

I. INTRODUCTION

The system reliability is the most important feature of the power system operation, which cannot be neglected in the standard market design. Because of the increasing load demand, the security constrained unit commitment (SCUC) problem has an important role in daily operation and planning of power system. The SCUC has to determine the scheduling of generating units in an utility for minimizing the operating cost while satisfying the load demand, spinning reserve, physical and operational constraints of the individual unit.

In a restructured power market, the unit commitment problem (UCP) used by individual generating companies (GENCOs) refers to the optimization of generating resources in order to maximize GENCOs payoff. This UCP has a different objective than SCUC problem and is referred as PBUC problem [1] which emphasizes the importance of the price signal. In PBUC problem, satisfying hourly loads is no longer an obligation and the objective is to maximize the payoff. In this market, energy and reserve are dispatched at the same time (called as simultaneous dispatch). This approach has been adopted by several power markets, including Ontario [2], New Zealand [3], NYSIO [4], PJM [5], ISO-NE [6], and the new California [7] electricity markets.

During the last 40 years, numerous methods have been developed to incorporate probabilistic reserve criteria in the formulation of the reserve constrained UCP [8-13]. Later methods provide promising result in the evaluation of spinning reserve by including various system risks in the regulated environment.

In [14], Eric H Allen first proposed the price based decision mechanism for GENCO's to schedule their reserve based on spot market power. Here, two types of payment mechanism are used for scheduling based upon the reserve probability value of spinning reserve. In [15], Pathom Attaviriyanupap et. al proposed a Hybrid LR-EP to solve Profit based unit commitment for scheduling both power and reserve simultaneously. However the reserve is scheduled based on reserve probability value. Similarly in [16], T.A.A. Victoire et al. proposed Tabu-search based heuristic technique to solve PBUCP involving both energy and reserve schedule. Here for different values of reserve probability, the variations of energy and reserve schedules are observed in terms of profit.

In [17], Meysam Jaefari-Nokandi scheduled the spinning reserve by considering the customer choice on reliability for both energy and reserve at a particular instant. Evaluation of spinning reserve requirement is performed using a reliability index called Expected load not supplied (ELNS). However, here scheduling is carried out by considering only generator outages.

This paper presents solves a new reliability constrained PBUC problem under a competitive environment using binary coded artificial bee colony algorithm. Here, the BABC is used to determine the ON/OFF status of generating units to maximize the profit. This approach facilitates an individual customer by declaring their energy requirement and CDRL to the ISO through DRP. Therefore ISO satisfies the customer's choice by taking different remedial actions such as purchasing power from ancillary market, generator rescheduling and/or accepting the DR offer for the specified hour if generation deficiency occurs. Here, the DR program is carried out by maintaining the CDRL. Outages of both generator and

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transmission system is integrated to calculate the CDRL, using loss of load method [18].

II. PROBLEM FORMULATION

The objective of the PBUCP is to obtain the optimal unit commitment schedule thereby maximizing GENCO's profit. The problem formulation is given as follows:

$$Maximize PF = RV - TC \tag{1}$$

or

$$Minimize \quad TC - RV \tag{2}$$

where

$$TC = C_i((P_{i,k} * I_{i,k}) + (R_{i,k} * I_{i,k})) + ST_k \tag{3}$$

$$ST_k = I_{i,k}(1 - I_{i,k-1}) * [\alpha_i + \beta_i[1 - \exp(\frac{X_{off}(i,k)}{\tau_i})]] \tag{4}$$

$$RV = (SP_k * P_{i,k} * I_{i,k}) + (RP_k * R_{i,k} * I_{i,k}) \tag{5}$$

Constraints

1. Demand constraint

$$\sum_{i=1}^{N} P_{i,k} I_{i,k} \leq D_k \qquad k = 1, \ldots.., H \tag{6}$$

2. Reserve constraint

$$\sum_{i=1}^{N} R_{i,k} \leq SR_k \qquad k = 1, \ldots.., H \tag{7}$$

Here, demand and reserve constraints are different from traditional UCP. Here GENCO can schedule power and reserve less than forecasted level if it can generate a profit. Also it can set lower and upper limits of spinning reserve based on the customer reliability requirements. These constraints can be relaxed otherwise.

3. Power and reserve limits

$$P_{i,\min} \leq P_i \leq P_{i,\max} \qquad i = 1, \ldots.., N \tag{8}$$

$$0 \leq R_i \leq P_{i,\max} - P_{i,\min} \quad i = 1, \ldots..., N \tag{9}$$

$$R_i + P_i \leq P_{i,\max} \qquad i = 1, \ldots..., N \tag{10}$$

4. Minimum up and down time constraints

$$[X^{on}(i,k-1) - T^{on}(i)] * [I_{(i,k-1)} - I_{(i,k)}] \geq 0 \tag{11}$$

$$[X^{off}(i,k-1) - T^{off}(i)] * [I_{(i,k)} - I_{(i,k-1)}] \geq 0 \tag{12}$$

5. Unit ramp contraints

$$P_{(i,k)} - P_{(i,k-1)} \leq UR(i) \tag{13}$$

$$P_{(i,k-1)} - P_{(i,k)} \leq DR(i) \tag{14}$$

6. Networks constraints

a. Voltage magnitude constraints

$$V_{p,\min} \leq V_P \leq V_{p,\max} \tag{15}$$

b. Line flow constraints

$$|P_{bf-bt}| \leq P_{bf-bt,\max}, \quad bf - bt \in NB \tag{16}$$

7. Reliability constraints

Spinning reserve requirements in equation (7) can be calculated using either deterministic criteria or probabilistic techniques. However, in the proposed technique, probabilistic reserve assessment with spinning reserve requirements are assessed according to the desired level of reliability specified for the composite generation and transmission network. Therefore spinning reserve requirement should satisfy the reliability constraints given as follows:

$$LOLP^c{}_{k,b} \leq CDRL_{k,b} \quad k \in [1, H], \; b \in [1, m] \tag{17}$$

III. EVALUATION OF CDRL

A. Calculation of Generation system reliability index (LOLP^g)

For the purpose of reliability analysis, each generating unit is represented by a two-state model [7-10], according to which a unit is either available or unavailable for generation. In [10], the notion of unavailability $U_i(LT)$ of the i[th] generating unit during the short time interval (i.e. LT represent lead time) is given by equation (18).

$$U_i(LT) = \frac{\lambda_i}{\lambda_i + \mu_i}(1 - e^{-(\lambda_i + \mu_i)LT}) \tag{18}$$

where, λ_i and μ_i are failure and repair rate of i[th] generating unit. Assuming that the lead time is much smaller than the repair time, the repair process is neglected in determining the time dependent probability of generating units [19]. This assumption results in a more simplified expression for the unavailability of i[th] generating unit which is given by equation (19).

$$U_i(LT) = 1 - e^{-\lambda_i LT} \tag{19}$$

This is the time period (LT) for which no additional units can be brought in to service. The lead time may be few minutes to several hours. The lead time for all generating units is considered to be equal, to simplify the calculation. Hence the probability $U_i(LT)$ is known as the outage replacement rate(ORR) of the unit.

For each hour, a capacity outage probability table (COPT) is formed using the ORR for the committed units [19]. Each row j=1…….n of the COPT represents a generation level that cannot be met, CR_j is the total capacity of generation that remains in service and PR_j is the probability of availability that corresponds to j[th] state. The LOLP index for each hour is calculated by using equation (20).

$$LOLP^g{}_{k,b} = \sum_{j=1}^{n} PR_j \times LOSS_j, k \in [1, H],\ b \in [1, m] \tag{20}$$

where,

$$LOSS_j = \begin{cases} 1, \ if \ CR_j < LOAD_{k,b} \\ 0, otherwise. \end{cases} \tag{21}$$

While calculating LOLP for generating unit, it is assumed that the transmission line is available at all time (i.e probability of transmission line is 1). A reduction in time can be achieved by omitting the outage level for which the cumulative probabilities of the generation availability is less than a predefined limit (e.g., 10^{-7}) [19].

B. Calculation of Transmission system reliability index ($LOLP^t$)

Electrical energy is delivered from a generating system (GS) to each of the customer load points (CLPs) through the transmission network. Failures of transmission network components can affect the capacity that can be transferred from GS to its corresponding CLPs. In the composite power system, it is virtually impossible to provide the same level of service reliability to every customer. There are two basic types of transmission failures which affect reliability level of transmission system at each CLP. The first type of failure is caused due to the isolation between CLPs and GS. Therefore the energy delivered at each of the affected CLPs is 0. The second type of failure is due to the line flow constraint violation such as congestion. Therefore AC power flow has to be carried out to determine network violations for each area. If there is no network violation, then the energy that can be delivered at each of the CLPs can be up to their peak loads. If network violation exists, load has to be shed for all the affected CLPs proportionally to release the network violation (corrective action). The energy delivered for an affected CLP can be calculated by detecting the load that has been shed from its peak load [19].

The LOLP index for the PBUC problem solution is calculated using the conditional probability approach. The reliability indices at each of the CLPs are calculated using equation (22).

$$LOLP^t{}_{k,b} = \sum_{j=no.\ of\ states} [P(B_j) * P_{cj}],\ k \in [1, H], b \in [1, m] \tag{22}$$

At each contingency state j, voltage at each bus and line flows are maintained within a permissible limit by taking corrective action such as load curtailment at the affected bus. Here the availability of adequate generation is assumed and a single line outage is considered. Therefore it is obvious that the loss of load at any of the CLPs is due to transmission unavailability.

C. Calculation of Composite system reliability index ($LOLP^c$)

Composite system reliability index is calculated by adding the generation and transmission system reliability indices using equation (23).

$$LOLP^c{}_{k,b} = LOLP^g{}_{k,b} + LOLP^t{}_{k,b} \tag{23}$$

IV. DR PPROGRAM

Demand response programs can be classified into two types according to demand reduction action. They are time-based DR programs and incentive-based DR programs. Both types of programs are currently under operation in many ISOs around the world which includes the NYSIO [4], PJM [5], ERCOT [6] and the ISO-NE [7] electricity markets. Time based DR programs paved the way for more efficient markets thereby replacing the flat or averaged pricing options. Many types of DR programs such as time-of-use tariffs, critical-peak pricing and real time pricing are designed by different ISOs. In incentive-based DR programs, a set of demand reduction signals (i.e. DR signals) are issued by the ISO to the participating customers through DRP in the form of voluntary demand reduction requests or mandatory commands. Once the customers bid their choice on reliability levels, it is the responsibility of the ISO for meeting the desired target. In case of contingency, ISO can maintain the reliability level by sending the demand response signal to the CLP. Therefore, the evaluation of DR at each load point is based on $CDRL_{k,b,}$ achieved by calculating load point reliability coefficient ($LPRC_{k,b}$) using equation (24).

$$LPRC_{k,b} = \frac{CDRL_{k,b}}{\sum_{b=1}^{m} CDRL_{k,b}} \tag{24}$$

The DR contribution at each of the load point is determined by calculating DR at each load point ($DRLP_{k,b}$) from the following equation.

$$DRLP_{k,b} = LPRC_{k,b} \times TDR_k \quad i \in [1, m] \tag{25}$$

A. Step by step Demand Response Program

DR procedure at each load point b is based on $CDRL_{k,b.}$ However, it should be noted that if there is a higher reliability level, then the reliability index value is small.

Step 1: Set b=1.

Step 2: Calculate $LPRC_{k,b}$ using equation (24).

Step 3: If calculated customer load point reliability index $LOLP^{c}_{k,b}$ is less than the $CDRL_{k,b}$, then go to step 6, else go to next step.

Step 4: Calculate $DRLP_{k,b}$ using equation (25).

Step5:Do load shedding at load point b (i.e. $CLP_{k,b}=CLP_{k,b}-DRLP_{k,b}$) and then go to step 7.

Step 6:Once the CDRL at load point b is satisfied, then load shedding at the load point b is stopped (i.e. $LPRC_{k,b}=0$).

Step 7: Do b=b+1.

Step 8: If $b \leq m$, then go to step 3, else go to next step.

Step 9: End.

V. OVERVIEW OF ARTIFICIAL BEE COLONY ALGORITHM

Social insects like ants, bees, wasps and termites work by themselves in their simple tasks, independently of other members of the colony. However, when they act as a community, they are able to solve complex problems emerging in their daily lives, by means of mutual cooperation. This emergent behavior of a group of social insects is known “swarm intelligence”. The Artificial Bee Colony (ABC) algorithm is a swarm based meta-heuristic algorithm that was introduced by Karaboga in [20-21] for optimizing numerical problems. It has been developed by simulating the intelligent behavior of honeybees. It is a population-based search procedure that is used as an optimization tool in solving complex, nonlinear and non-convex optimization problems. An important and interesting behavior of bee colony is their foraging behavior and, particularly how it flies around in a multidimensional search space and finding the food sources and back to nest. The foraging behavior of real bees in finding food sources is shown in Fig. 1. The model consists of three essential components: employed bees, unemployed bees and food sources.

Fig. 1a clearly shows the essential parts of the model, employed bees, unemployed bees and food sources and dancing area. Employed bees fly around in a multidimensional search space and choose their food sources depending on their own experience which is shown in Fig. 1b. Once the employed bees complete their search process, it shares their food source information with unemployed bees or onlooker bees waiting in the hive by dancing in the dancing area which is shown in Fig.1c.

Onlooker bees probabilistically choose their food sources depending on this information gained from the employed bees using equation (26) which is shown in Fig. 1d. If there is no improvement in the food source (fitness) then the scout bees fly and choose the food sources randomly without using experience which is also shown in Fig. 1d.

$$\mathrm{Pro}_p = \frac{\mathrm{FIT}_p}{\sum_{z=1}^{F} \mathrm{FIT}_z} \tag{26}$$

where FIT_p is the fitness value of the solution p which is proportional to the nectar amount of the food source in the position p and F is the number of food sources which is equal to the number of employed bees, n_e. Now the onlookers produce a modification in the position selected by it using (27) and evaluate the nectar amount of the new source.

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$$V_{pq} = x_{pq} + \phi_{pq}(x_{pq} - x_{fq}) \qquad (27)$$

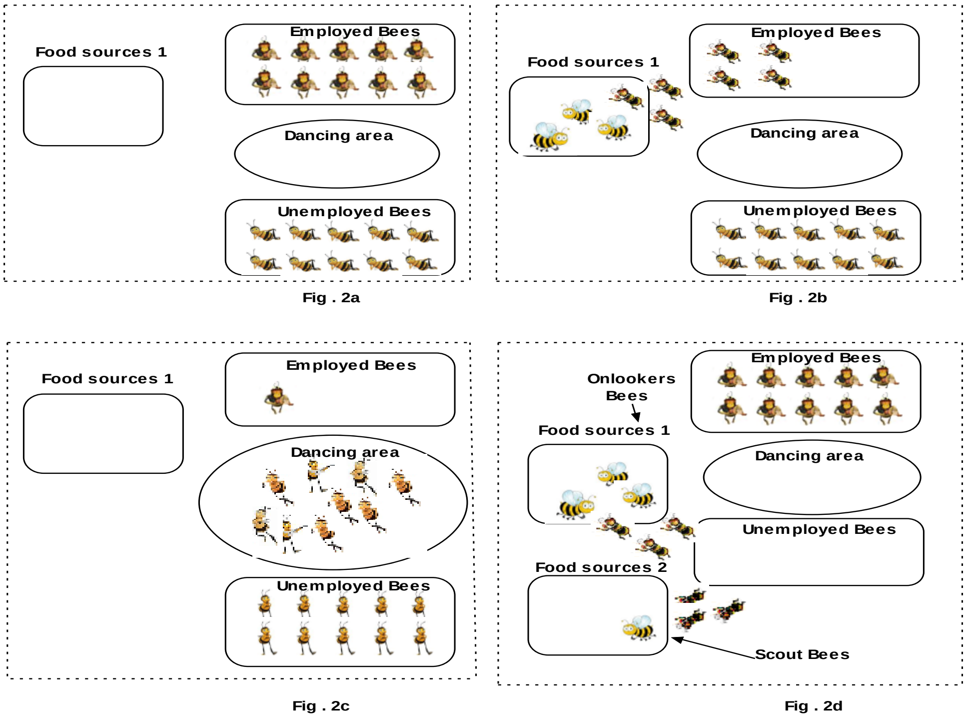

Fig. 1: Behavior of Artificial Bee colony

where f $\in$ {1, 2… n_e} and q $\in$ {1, 2…D} are randomly chosen indexes. Although f is determined randomly, it has to be different from p and D is the number of parameters to be optimized. φ_{pq} is a random number between [0, 1]. It controls the production of neighborhood food sources. If the nectar amount of the new source is higher than that of the previous one, the onlookers remember the new position; otherwise, it retains the old one. In other words, greedy selection method is employed as the selection operation between old and new food sources.

If a solution representing a food source is not improved by a predetermined number of trials, then that food source is abandoned and the employed bee associated with that food source becomes a scout. The number of trials for releasing a food source is equal to the value of 'limit', which is an important control parameter of ABC algorithm. The limit value usually varies from 0 to 100. If the abandoned source is x_{pq}, q $\in$ {1, 2…D} then the scout discovers a new food source x_{pq} using equation (28).

$$x_{pq} = x_{q\min} + rand(0,1) * (x_{q\max} - x_{q\min}) \qquad (28)$$

where x_{qmin} and x_{qmax} are the minimum and maximum limits of the parameter to be optimized.

VI. IMPLEMENTATION OF BINARY ABC ALGORITHM FOR PBUC PROBLEM

In UCP, binary numbers 0 and 1 are used to indicate the unit status (i.e., OFF or ON). The ABC algorithm used in Ref. [20-21] is essentially a real-coded algorithm, thus some revisions are needed to enable it to deal with the binary-coded optimization problem. In the proposed binary ABC, the relevant variables are interpreted in terms of changes of probabilities. In binary ABC, x_{pq} and x_{fq} take values of 0 or 1 and φ_{pq} is a random number generated in the range (-1, 1). When the position of the bees is modified, V_{pq} will vary between 0 to 2 and 1 to -1 for the extreme limits of φ_{pq}. It can be either 0 or 1 based on the values taken by x_{pq} and x_{fq} and is given in Table I. To decide the unit status as 1 or 0, a threshold level has to be fixed. If V_{pq} is higher than the threshold, the individual is more likely to choose a 1 otherwise it chooses 0. The threshold level can be made to range from 0 to 1. To accomplish this, sigmoid function [22] as in (29) can be used.

$$f(x_{pq}) = \frac{1}{1 + \exp(-x_{pq})} \qquad (29)$$

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A random number is generated between 0 and 1, to decide the unit status as 0 or 1. If $f(x_p)$ is greater than *rand* (*0, 1*) then unit status is 1 otherwise 0.

A. Initial Generation of Binary String (Binary Coded ABC)

Randomly generate a population of M initial solutions represented by a binary string as bit 1 or 0. Each bit in the string represents the ON/OFF status of the generating units at the kth hour. Initialize randomly an initial population $M = [X_1; X_2; X_3; \ldots\ldots; X_m]$ of m solutions or food source positions in the multidimensional solution space where m represents the size of population. Each solution of X is represented by the D-dimensional vector. Where, D is the number of parameters to be optimized. Here, D is equal to N*H. A population of M initial solution with D dimensional vector.

B. Repair Strategy for Constraint Management (Corrective action)

The randomly generated commitment status for each time interval is checked for the violation of minimum up/ down time constraints (7-8) and reliability constraint given in equation (17).

Step 1: If the CDRL at each load point is met, then go to step 3. Otherwise, go to next step.

Step 2: Do DR program as in section IV.A to satisfy the reliability level and then go to next step.

Step 3: If the reliability constraint is satisfied, then the minimum up and down time constraints (7-8) are checked for each unit over the scheduling horizon in each interval. If there is any violation in the minimum up or down time constraint then the repair mechanism is used to overcome the violation. For instance, let us assume that the T^{on} and T^{off} for a hypothetical unit is 4 and 5. For a scheduling interval of 12 hours, if the actual off time for unit 1 is 3 hours (5th -7th hour), then it violates the T^{off} constraint. In this case, the unit status before 5th hour or after 7th hour can be made 0. By doing this change, if it violates the T^{on} constraint, then the status of the units are made 1 during the violated down time period.

Step 4: The repairing strategy in step 3 may affect the reliability level of the system. If the reliability level is met, accept the feasible solution and go to next step. Otherwise go to step 1.

Step 5: End

C. Evaluation of Fitness of the Population

Solve economic dispatch problem (EDP) by lambda iteration method to calculate the total operating cost by satisfying all system constraints and then calculate the profit using equation (1). Evaluate the fitness value of each food source positions corresponding to the employed bees in the colony. In order to avoid premature convergence a fitness function as in (30) is used.

$$FIT_p = Profit_p, \qquad if\ Profit_p > 0$$
$$= 1/(1 + abs(Profit_p)), \qquad if\ Profit_p < 0 \qquad (30)$$

Profit$_p$ is the cost of generation of pth bee. In (30) the individual with the maximum profit has the highest fitness. Determine the best fitness among the individuals and the corresponding maximum profit and the parameters responsible for the maximum profit. The step-by-step procedure for the proposed method is given as a flowchart in Fig.2.

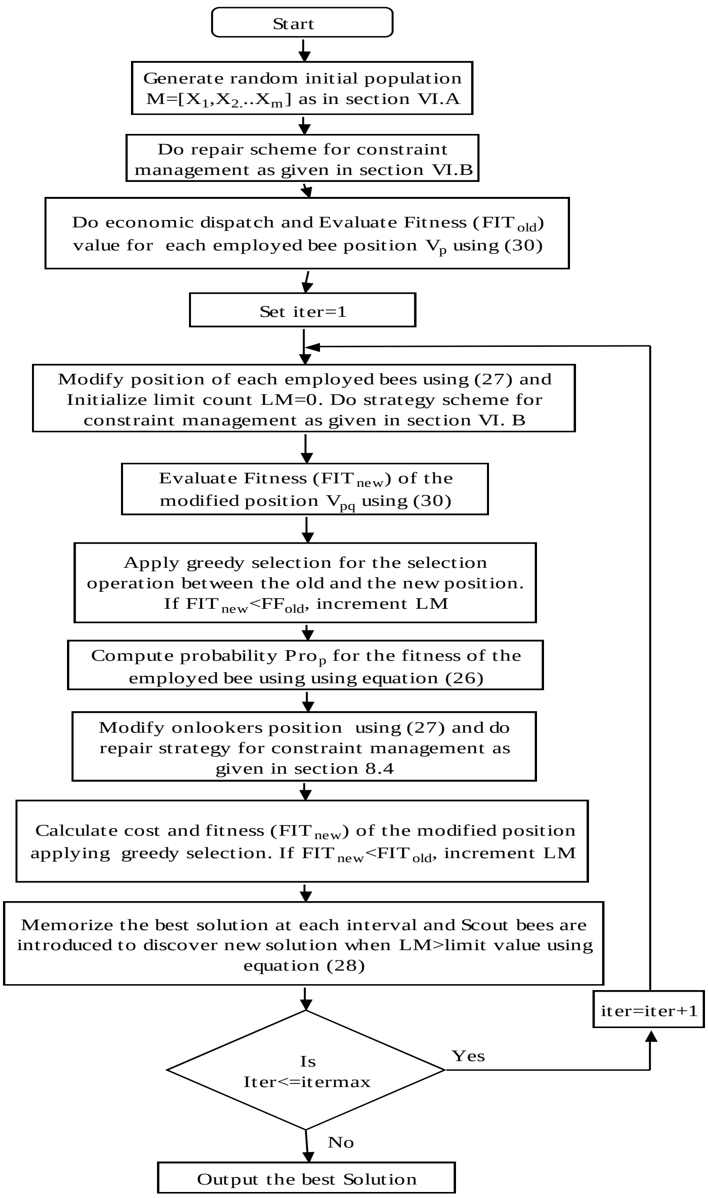

Fig. 2 Flowchart for proposed methodology

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VII. CASE STUDIES

MATLAB codes are developed and simulations are carried out using a PC with Pentium(R) 3.40 GHz, 1GB RAM system. Simulation results are tested on two categories of systems, over a scheduling-time horizon of 24 hours. The first category system is a standard 10 unit system. Here, due to the non availability of transmission line data, generation outage is solely considered for calculating spinning reserve. The second category system is an IEEE RTS 24 bus system. Here both generation and transmission system unavailability has been taken in to account for calculating spinning reserve.

A. First category system

The proposed reliability constrained method is applied for the standard 10 unit system for calculating the spinning reserve. Based on the market forecast, the power and reserve is simultaneously dispatched. The generation unit data, day-ahead hourly market energy price and load data are taken from [14] and is given in Appendix A and B. However, generation reliability data is reasonably assumed based on a practical system [23]. In [14], the reserve at each hour is evaluated based on the probability assumed by the authors. However, generation outage and customer choice on the reliability demand is not considered. In order to have an accurate assessment of spinning reserve, the proposed method evaluates the spinning reserve based on the CDRL. Due to non availability of details of transmission network, the transmission line outages are not considered for reliability calculation. In a deregulated power market, let us assume that customer (DISCO) submits their load and CDRL to the ISO. Since no transmission outages are considered, an overall single desired reliability level is submitted to ISO for each hour.

Table I: Spinning Reserve schedule and Profit for PBUCP (CDRL=0.005)

Unit no.	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	$\sum P_g$	Load MW	LPC MW	Reserve MW	Cost ($)	Startup cost ($)	Total cost ($)	Revenue ($)	Profit ($)
1	455	245	0	0	0	0	0	0	0	0	700	700	0	210	17353	0	17353	38763	21410
2	455	295	0	0	0	0	0	0	0	0	750	750	0	160	17353	0	17353	34100	16747
3	455	395	0	0	0	0	0	0	0	0	850	850	0	60	17353	0	17353	26565	9212
4	455	455	0	0	0	0	0	0	0	0	910	950	40	0	17353	0	17353	20612	3259
5	455	390	0	130	25	0	0	0	0	0	1000	1000	0	202	23960	1460	25420	46733	21313
6	455	455	0	130	60	0	0	0	0	0	1100	1100	0	102	23960	0	23960	36950	12990
7	455	455	0	130	110	0	0	0	0	0	1150	1150	0	52	23960	0	23960	31725	7765
8	455	455	0	130	160	0	0	0	0	0	1200	1200	0	2	23960	0	23960	26802	2842
9	455	455	130	130	130	0	0	0	0	0	1300	1300	0	32	26852	550	27402	33288	5886
10	455	455	130	130	140	20	0	0	0	0	1330	1400	70	82	29048	170	29218	51069	21851
11	455	455	130	130	140	20	0	0	0	0	1330	1450	120	82	29048	0	29048	52461	23413
12	455	455	130	130	140	20	0	0	0	0	1330	1500	170	82	29048	0	29048	55071	26023
13	455	455	130	130	160	0	0	0	0	0	1330	1400	70	2	26852	0	26852	32964	6112
14	455	455	130	130	130	0	0	0	0	0	1300	1300	0	32	26852	0	26852	35770	8918
15	455	455	130	130	30	0	0	0	0	0	1200	1200	0	132	26852	0	26852	41850	14998
16	455	455	0	0	140	0	0	0	0	0	1050	1050	0	22	21099	0	21099	25868	4769
17	455	455	0	0	90	0	0	0	0	0	1000	1000	0	72	21099	0	21099	30260	9161
18	455	455	0	0	160	0	0	0	0	0	1070	1100	30	2	21099	0	21099	23814	2715
19	455	455	0	0	160	0	0	0	0	0	1070	1200	130	2	21099	0	21099	23976	2877
20	455	455	0	0	160	0	0	0	0	0	1070	1400	330	2	21099	0	21099	24462	3363
21	455	455	0	0	160	0	0	0	0	0	1070	1300	230	2	21099	0	21099	24948	3849
22	455	455	0	0	160	0	0	0	0	0	1070	1100	30	2	21099	0	21099	24786	3687
23	455	445	0	0	0	0	0	0	0	0	900	900	0	10	17353	0	17353	21613	4260
24	455	345	0	0	0	0	0	0	0	0	800	800	0	110	17353	0	17353	30443	13090
Total ($)															542203	2180	544383	794893	250510

To show the effectiveness of the proposed method the commitment status given in [14] is taken and the reserve is calculated based on the CDRL. To understand and for simplicity reasons, same CDRL is fixed at 0.005 over a scheduled time horizon of 24 hours. Table I shows the energy dispatch and spinning reserve calculated based on CDRL. The proposed approach calculates the reserve based on the generation reliability, where as the method used in paper [14] does not schedule the reserve based on reliability aspects. Also without increasing the generation, the DR has been handled efficiently to meet the reliability constraints.

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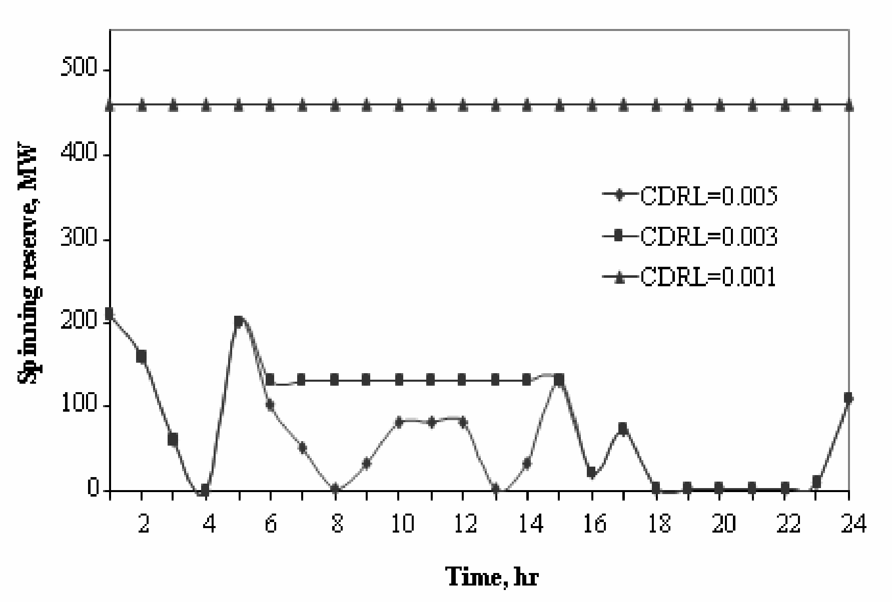

Fig.3: Spinning reserve at each hour for different reliability level

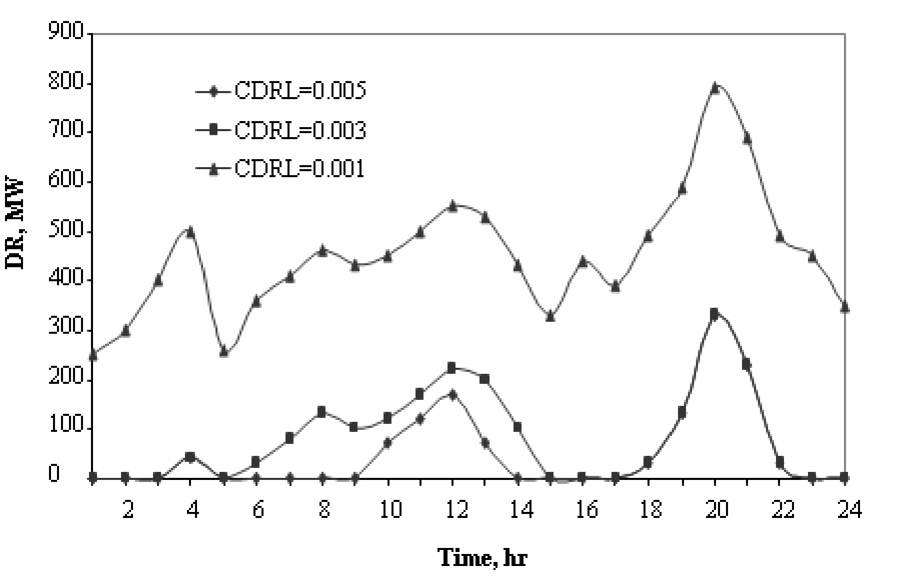

Fig. 4: Load shedding at each hour for different reliability level

To demonstrate the effect of CDRL values on spinning reserve requirement, different CDRL values are fixed same for 24 hours. The variation of spinning reserve and load curtailment is shown in Fig. 3 and Fig. 4 respectively. From the Fig. 4, it is observed that the spinning reserve from 1st – 5th hour is same when CDRL is 0.003 and 0.005. However for the next 10 hours the spinning reserve scheduled when CDRL=0.003 is more than when CDRL=0.005.

Therefore $SR(DLPR = 0.005) \leq SR(DLPR = 0.003)$.

For the 1st hour (Table I) the reserve availability is 210 MW which satisfies for both the CDRL value of 0.003 and 0.005. Similar observation of the availability of excess spinning reserve is noted for 2nd to 6th hour and 15th to 24th (refer Fig. 2). However at 7th hour, spinning reserve of 52 MW can only satisfy CDRL of 0.005. Suppose the customer demand higher reliability value at this hour (CDRL=0.003), then the proposed DR program (section IV-A) for meeting the reliability constraint has to be applied. It is found that an amount of 80 MW of load has been shed thereby satisfying the reliability constraint (CDRL=0.003). Similar observation is noted for 7th to14th hour. When the reliability value is very high (i.e. CDRL=0.001), the spinning reserve allocated is also high (refer Fig.2), therefore DR has to be increased for the same generation capacity (refer Fig.3). It can be inferred for a particular hour that lower CDRL value (higher reliability level) by default satisfies the higher CDRL value (lower

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reliability level). The scheduled spinning reserve is also calculated when the customer submit different reliability levels and load depending upon the requirement. Table II gives the PBUC solution based on the spot price and spinning reserve allocation based on CDRL demanded at each hour.

Table II. Spinning Reserve schedule and Profit for PBUCP

Hour	Generating Units U1 MW	U2 MW	U3 MW	U4 MW	U5 MW	U6 MW	U7 MW	U8 MW	U9 MW	U10 MW	$\sum P_g$ MW	CDRL	Load MW	LPC MW	Reserve MW	Cost ($)	Startup cost ($)	Total cost ($)	Revenue ($)	Profit ($)
1	455	245	0	0	0	0	0	0	0	0	700	0.003	700	0	210	17353	0	17353	38763	21410
2	455	295	0	0	0	0	0	0	0	0	750	0.002	750	0	160	17353	0	17353	34100	16747
3	455	395	0	0	0	0	0	0	0	0	850	0.003	850	0	60	17353	0	17353	26565	9212
4	455	455	0	0	0	0	0	0	0	0	910	0.002	950	40	0	17353	0	17353	20612	3259
5	455	390	0	130	25	0	0	0	0	0	1000	0.002	1000	0	202	23960	1460	25420	46733	21313
6	455	455	0	130	30	0	0	0	0	0	1070	0.003	1100	30	132	23960	0	23960	39704	15744
7	455	455	0	130	30	0	0	0	0	0	1070	0.003	1150	80	132	23960	0	23960	38925	14965
8	455	430	0	130	25	0	0	0	0	0	1040	0.002	1200	160	162	23960	0	23960	40978	17018
9	455	455	130	130	30	0	0	0	0	0	1200	0.003	1300	100	132	26852	550	27402	42408	15006
10	455	455	130	130	90	20	0	0	0	0	1280	0.003	1400	120	132	29048	170	29218	56939	27721
11	455	190	130	130	25	20	0	0	0	0	950	0.001	1450	500	462	29048	0	29048	98289	69241
12	455	455	130	130	90	20	0	0	0	0	1280	0.003	1500	220	132	29048	0	29048	61401	32353
13	455	455	130	130	30	0	0	0	0	0	1200	0.004	1400	200	132	26852	0	26852	45756	18904
14	455	455	130	130	30	0	0	0	0	0	1200	0.003	1300	100	132	26852	0	26852	45570	18718
15	455	455	130	130	30	0	0	0	0	0	1200	0.005	1200	0	132	26852	0	26852	41850	14998
16	455	455	0	0	140	0	0	0	0	0	1050	0.006	1050	0	22	21099	0	21099	25868	4769
17	455	455	0	0	90	0	0	0	0	0	1000	0.008	1000	0	72	21099	0	21099	30260	9161
18	455	455	0	0	160	0	0	0	0	0	1070	0.003	1100	30	2	21099	0	21099	23814	2715
19	455	455	0	0	160	0	0	0	0	0	1070	0.005	1200	130	2	21099	0	21099	23976	2877
20	455	430	0	0	25	0	0	0	0	0	910	0.002	1400	490	162	21099	0	21099	38958	17859
21	455	455	0	0	160	0	0	0	0	0	1070	0.003	1300	230	2	21099	0	21099	24948	3849
22	455	430	0	0	25	0	0	0	0	0	910	0.002	1100	190	162	21099	0	21099	39474	18375
23	455	445	0	0	0	0	0	0	0	0	900	0.003	900	0	10	17353	0	17353	21613	4260
24	455	345	0	0	0	0	0	0	0	0	800	0.007	800	0	110	17353	0	17353	30443	13090
Total ($)																542203	2180	544383	937947	393564

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B. Second category system

The proposed method has been applied to IEEE RTS 24 bus system which is also called as Roy Billinton test system (RBTS) [23] and is shown in Fig. 5. Generation and transmission line reliability data are taken from [23] and is given in Appendix C and D. The day-ahead hourly market price for energy is taken from [24] and load data is taken from [25] which is given in Appendix E. The generation cost coefficient and generation data are taken from [25] and is given in Appendix F. Here, the reserve cost fixed is equal to 10% of their incremental cost for producing energy [26]. GENCO consists of 26 generating units and 17 customer load points (CLPs). Assume that the CLPs (Customers) submit their loads and CDRL for a given hour to the ISO as given in Table III. However, customer choice on CDRL varies from hour to hour.

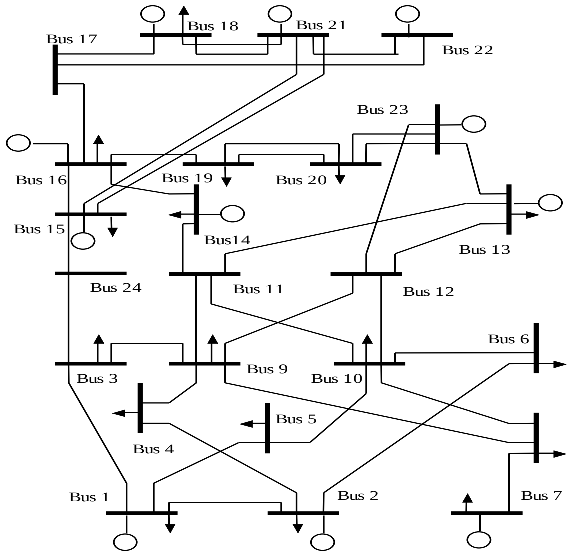

Fig. 4: IEEE RTS 24 bus system

Table III: CDRL information at each hour

Hour	CLPs																
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1-8	0.003	0.006	0.003	0.008	0.008	0.002	0.003	0.0032	0.0032	0.008	0.001	0.002	0.0032	0.0032	0.008	0.003	0.001
9-17	0.002	0.008	0.001	0.001	0.001	0.004	0.004	0.001	0.001	0.002	0.001	0.008	0.0032	0.0032	0.001	0.004	0.001
18-22	0.003	0.004	0.006	0.001	0.001	0.004	0.008	0.001	0.001	0.002	0.001	0.008	0.0032	0.0032	0.001	0.006	0.001
23-24	0.003	0.006	0.003	0.0032	0.0032	0.002	0.002	0.005	0.005	0.008	0.001	0.006	0.0032	0.0032	0.008	0.008	0.001

Table IV: Energy and available spinning reserve (Load =2508 MW, 10th hour)

Unit	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	Total MW
Power MW	0	0	0	0	0	0	0	0	0	15.2	15.2	15.2	15.2	0	0	0	126	121	117	112	0	0	0	331	400	400	1667.99
Reserve MW	0	0	0	0	0	0	0	0	0	60.8	60.8	60.8	60.8	0	0	0	28.8	33.7	38.5	43.1	0	0	0	18.8	0	0	406.01

Table V: DR schedule

CLPs	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	Total
BUS no	1	2	3	4	5	6	7	8	9	10	13	14	15	16	18	19	20	
CDRL	0.002	0.008	0.001	0.001	0.001	0.004	0.004	0.001	0.001	0.002	0.001	0.008	0.0032	0.0032	0.001	0.004	0.001	
Actual Load (MW)	95.0	85.4	158.4	65.1	62.4	119.6	110.0	150.0	154.0	171.6	233.2	170.7	278.9	88.0	293.0	159.2	112.6	2508.0

$DRLP_{k,b}$	56.3	85.3	36.5	36.5	36.5	55.3	55.3	36.5	36.5	56.3	36.5	94.3	44.3	44.3	36.5	55.3	36.5	839.9
$Load'_{k,b}$ (MW)	38.6	0.05	121.8	28.5	25.8	64.2	54.6	113.4	117.4	115.2	196.6	76.4	234.6	43.6	256.4	103.7	76.0	1668.1

Table VI: DR schedule

CLPs	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	Total
BUS no	1	2	3	4	5	6	7	8	9	10	13	14	15	16	18	19	20	
CDRL	0.002	0.008	0.001	0.001	0.001	0.004	0.004	0.001	0.001	0.002	0.001	0.008	0.0032	0.0032	0.001	0.004	0.001	
Actual Load (MW)	95.04	85.4	158.4	65.1	62.4	119.6	110.0	150.0	154.0	171.6	233.2	170.7	278.9	88.0	293.0	159.2	112.6	2508.0
$DRLP_{k,b}$	48.4	54.8	30.9	30.9	30.9	37.6	37.6	30.9	30.9	48.4	30.9	54.8	37.4	37.4	30.9	37.6	30.9	641.9
$Load'_{k,b}$ (MW)	46.6	30.5	127.4	34.1	31.5	82.0	72.3	119.0	123.0	123.2	202.2	115.9	241.5	50.5	262.0	121.4	81.6	1866.0

BABC is used to solve PBUC problem. Table IV tabulates the results of energy market clearing based on the spot price and spinning reserve allocated at 10[th] hour for a load of 2508 MW. DR at each load point (CLP) based on the desired reliability level is given in the Table V for the load of 2508 MW (10[th] hour). It is to be noted that the DR at the CLP 2 is greater than at CLP 1. This is because; CDRL at CLP 2 is comparatively lower than CLP 1. Also when CLP 2 and CLP 12 are having same CDRL (0.008), the total load curtailed at CLP 2 and CLP 12 is 85.35 MW and 94.32 MW, respectively. The difference in DR is due to the violation of network security and transmission line constraints. Similar observations can be seen at CLP 1 and CLP 15.

Table VII: Spinning reserve schedule and profit for PBUCP

Hour	Generating Units																							$\sum P_g$	Reserve	Cost	Revenue	Profit
	U1 MW	U2 MW	U3 MW	U4 MW	U5 MW	U6-U9 MW	U10 MW	U11 MW	U12 MW	U13 MW	U14 MW	U15 MW	U16 MW	U17 MW	U18 MW	U19 MW	U20 MW	U21 MW	U22 MW	U23 MW	U24 MW	U25 MW	U26 MW	MW	MW	($)	($)	($)
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	140	225	222	586.79	353.21	9616	11039	1423
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	123	118	113	109	0	0	0	240	0	0	702.9	157.0	11179	12110	931
7	0	0	0	0	0	0	0	0	0	0	0	0	0	92.1	87.8	83.8	79.9	0	0	0	226	400	400	1369.9	400.0	20028	25185	5157
8	0	0	0	0	0	0	0	0	0	0	0	0	0	91.3	87.1	83.1	79.2	0	0	0	224	400	400	1364.9	405.0	20032	29279	9247
9	0	0	0	0	0	0	15.2	15.2	15.2	15.2	0	0	0	127	122	117	112	0	0	0	333	400	400	1670.9	403.0	25105	39020	13915
10	0	0	0	0	0	0	15.2	15.2	15.2	15.2	0	0	0	126	121	117	112	0	0	0	331	400	400	1667.9	406.0	25106	44001	18895
11	0	0	0	0	0	0	31.1	29.2	27.1	37.6	25	25	25	155	155	155	155	0	0	0	350	400	400	1969.9	404.0	31500	58014	26514
12	0	0	0	0	0	0	31.1	29.2	27.1	37.6	25	25	25	155	155	155	155	0	0	0	350	400	400	1969.9	404.0	31500	58370	26870
13	0	0	0	0	0	0	31.1	29.2	27.1	37.6	25	25	25	155	155	155	155	0	0	0	350	400	400	1969.9	404.0	31500	54272	22772
14	0	0	0	0	0	0	30.8	29	26.9	37.3	25	25	25	155	155	155	155	0	0	0	350	400	400	1968.9	405.0	31502	55807	24305
15	0	0	0	0	0	0	30.6	28.8	26.7	37	25	25	25	155	155	155	155	0	0	0	350	400	400	1968.0	405.9	31504	60679	29175
16	2.4	2.4	2.4	2.4	2.4	0	76	76	76	76	69.2	62.1	54.8	155	155	155	155	69	69	69	350	400	400	2479.0	494.9	47730	90351	42621
17	2.4	2.4	0	0	0	0	76	76	76	76	100	100	100	155	155	155	155	70.8	69	69	350	400	400	2587.5	401.5	47038	87712	40674
18	0	0	0	0	0	0	76	76	76	76	100	94	87.2	155	155	155	155	69	69	69	350	400	400	2562.0	402.9	46766	77059	30293
19	0	0	0	0	0	0	76	76	76	76	100	94.7	88	155	155	155	155	69	69	69	350	400	400	2563.5	401.4	46764	73114	26350
20	0	0	0	0	0	0	76	76	76	76	99.9	93.3	86.5	155	155	155	155	69	69	69	350	400	400	2560.5	404.4	47006	64044	17038
21	0	0	0	0	0	0	15.2	15.2	15.2	15.2	0	0	0	105	100	95.8	91.7	69	69	69	265	400	400	1725.0	555.854	30768	38132	7364
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	140	0	0	140.0	0	1727.1	1202.6	-524.5
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total ($)																										536371.1	879390.6	343019.5

To validate the DR program, Table VI gives the DR at each CLP when an additional generating unit of 197 MW is committed for the same load (2508 MW, 10th hour) and same CDRL values. It is obvious that DR in load at each CLP is reduced due to the increased generation capacity. Even though the customer demands are not completely met, reliability levels are satisfied at all the CLPs. The scheduled information about the reserve and the curtailment at each CLP will help the ISO to buy reserve power from the ancillary market. Table VII and Table VIII

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tabulates the PBUC problem scheduled for spinning reserve and the corresponding DR at each CLP for the IEEE RTS 24 bus system.

Table VIII: DR schedule at each CLP

CLPs	Hour																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	73	77.8	73.4	71.3	69.1	69.16	17.44	22.63	50.1	56.31	49.02	50.23	49.02	46.61	44.24	0	0	7.089	5.435	0	41.31	99.36	93	87
2	75.66	69.8	66	64	62.1	62.11	34.88	45.25	49.48	85.35	50.69	55.52	50.69	41.03	36.21	0	0	9.452	7.246	0	55.07	89.24	84	78
3	73	130	122	119	115	69.21	17.44	22.63	31.18	36.57	30.64	31.24	30.64	29.43	29.12	0	0.75	4.632	1.324	0	82.61	165.6	157	146
4	57.72	53.3	50.3	48.8	47.4	47.39	13.02	26.86	31.18	36.52	30.64	31.24	30.64	29.43	29.12	0	0.75	26.55	26	24.38	41.96	68.08	64	59.9
5	55.38	51.1	48.3	46.9	45.4	45.47	13.02	26.86	31.18	36.7	30.64	31.24	30.64	29.43	29.12	0	0.75	26.55	26	24.38	41.96	65.32	61.8	57.5
6	95.33	97.9	92.5	89.8	87	46.14	76.96	80.42	34.87	55.35	32.71	35.13	32.71	27.89	25.47	0	0	9.452	7.246	0	55.07	125.1	118	110
7	73	90	85	82	80	69.21	17.44	22.63	34.87	55.31	32.71	35.13	32.71	27.89	25.47	0	0	6.177	1.765	0	92.65	115	109	101
8	77.87	123	116	113	109	73.82	18.6	24.14	31.18	36.5	30.64	31.24	30.64	29.43	29.12	0	0.75	26.55	26	24.38	41.96	157.3	149	138
9	77.87	126	119	116	112	73.82	18.6	24.14	31.18	36.59	30.64	31.24	30.64	29.43	29.12	0	0.75	26.55	26	24.38	41.96	161	152	142
10	152.1	140	133	129	125	124.9	13.02	26.86	50.1	56.38	49.02	50.23	49.02	46.61	44.24	0	0	39.39	38.29	33.33	70.2	179.4	170	158
11	206.7	191	180	175	170	23.07	62.98	64.71	31.18	36.6	30.64	31.24	30.64	29.43	29.12	0	0.75	26.55	26	24.38	41.96	111.8	231	215
12	95.33	140	132	128	124	46.14	76.96	80.42	49.48	94.31	50.69	55.52	50.69	41.03	36.21	0	0	6.177	1.765	0	92.65	178.5	169	157
13	77.87	228	216	209	203	73.82	18.6	24.14	27.9	44.4	26.17	28.10	26.17	22.31	20.38	0	0	7.562	5.797	0	44.06	291.6	276	257
14	77.87	72	68	66	64	64.04	18.6	24.14	27.9	44.31	26.17	28.10	26.17	22.31	20.38	0	0	7.562	5.797	0	44.06	92	87	81
15	194.7	240	226	220	213	141.5	13.02	26.86	31.18	36.5	30.64	31.24	30.64	29.43	29.12	0	0.75	26.55	26	24.38	41.96	306.4	290	270
16	73	130	123	119	116	69.21	17.44	22.63	34.87	55.37	32.71	35.13	32.71	27.89	25.47	0	0	4.632	1.324	0	82.61	166.5	157	147
17	99.84	92.2	87	84	81.9	23.07	62.98	64.71	31.18	36.52	30.64	31.24	30.64	29.43	29.12	0	0.75	26.55	26	24.38	41.96	111.8	111	104
Total (MW)	1636	2052	1938	1881	1824	1122	511	630	609	840	595	623	595	539	511	0	6	288	258	204	954	2484	2479	2308

VIII. CONCLUSION

This paper proposes a new market-clearing procedure for the reserve market considering customers choice on their reliability in PBUC problem using BABC algorithm. The decision on spinning reserve and load curtailment help the ISO to provide reliability differentiated services on an individual customer. Here, the reliability based reserve criterion is formulated, where the spinning reserve requirement is determined to meet the CDRL at the individual CLP. The accurate assessment of spinning reserve is calculated by considering both generation and transmission system outages. The impact on customer choice on various CDRL values is illustrated. Also a new scheme of DR program based on reliability level is presented. This approach will be more suitable for the ISO to rely while making decisions. The validation of the proposed method on 10 unit system and IEEE RTS 24 bus system will help to extend for a large scale power system.

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APPENDIX

Appendix A
Generator data for ten unit system

Unit no	Pmax MW	Pmin MW	ai $	bi $/MWh	ci $/MWh^2	Ton hr	Toff hr	Initial Status hr	ST $	FOR	Failure rate
1	455	150	1000	16.19	0.00048	8	8	8	4500	0.12	7.9636
2	455	150	970	17.26	0.00031	8	8	8	5000	0.12	7.9636
3	130	20	700	16.60	0.00200	5	5	-5	550	0.04	9.1250
4	130	20	680	16.50	0.00211	5	5	-5	560	0.04	9.1250
5	162	25	450	19.70	0.00398	6	6	-6	900	0.05	9.2211
6	80	20	370	22.26	0.00712	3	3	-3	170	0.02	4.4693
7	85	25	480	27.74	0.00079	3	3	-3	260	0.02	4.4693
8	55	10	660	25.92	0.00413	1	1	-1	30	0.01	19.4667
9	55	10	665	27.27	0.00222	1	1	-1	30	0.01	19.4667
10	55	10	670	27.79	0.00173	1	1	-1	30	0.01	19.4667

Appendix B
Forecasted load and spot price for ten unit system

Hour	Load MW	SP $	Hour	Load MW	SP $	Hour	Load MW	SP $
1	700	22.15	9	1300	22.80	17	1000	22.25
2	750	22.00	10	1400	29.35	18	1100	22.05
3	850	23.10	11	1450	30.15	19	1200	22.20
4	950	22.65	12	1500	31.65	20	1400	22.65
5	1000	23.25	13	1400	24.60	21	4300	23.10
6	1100	22.95	14	1300	24.50	22	1100	22.95
7	1150	22.50	15	1200	22.50	23	900	22.75
8	1200	22.15	16	1050	22.30	24	800	22.55

Appendix C
Transmission line data for IEEE RTS 24 bus system

F Bus	T Bus	R pu	X pu	B pu	Line limit MVA	Failure rate	Repair rate
1	2	0.0026	0.0239	0.4611	193	0.24	16
1	3	0.0546	0.2112	0.0572	208	0.51	10
1	5	0.0218	0.0845	0.0229	208	0.33	10
2	4	0.0328	0.1267	0.0343	208	0.39	10
2	6	0.0497	0.192	0.052	208	0.48	10
3	9	0.0308	0.119	0.0322	208	0.38	10
3	24	0.0023	0.0839	0	510	0.02	768
4	9	0.0268	0.1037	0.0281	208	0.36	10
5	10	0.0228	0.0883	0.0239	208	0.34	10
6	10	0.0139	0.0605	2.459	208	0.33	35
7	8	0.0159	0.0614	0.0166	208	0.30	10
8	9	0.0427	0.1651	0.0477	208	0.44	10
8	10	0.0427	0.1651	0.0477	208	0.44	10
9	11	0.0023	0.0839	0	510	0.02	768
9	12	0.0023	0.0839	0	510	0.02	768
10	11	0.0023	0.0839	0	510	0.02	768
10	12	0.0023	0.0839	0	510	0.02	768
11	13	0.0061	0.0476	0.0999	600	0.40	11
11	14	0.0054	0.0418	0.0879	600	0.39	11
12	13	0.0061	0.0476	0.0999	600	0.40	11
12	23	0.0124	0.0966	0.203	600	0.52	11
13	23	0.0111	0.0865	0.1818	600	0.49	11
14	16	0.005	0.0389	0.0818	600	0.38	11
15	16	0.0022	0.0173	0.0364	600	0.33	11
15	21	0.0063	0.049	0.103	600	0.41	11
15	21	0.0063	0.049	0.103	600	0.41	11
15	24	0.0067	0.0519	0.1091	600	0.41	11
16	17	0.0033	0.0259	0.0545	600	0.35	11
16	19	0.003	0.0231	0.0485	600	0.34	11
17	18	0.0018	0.0144	0.0303	600	0.32	11
17	22	0.0135	0.1053	0.2212	600	0.54	11
18	21	0.0033	0.0259	0.0545	600	0.35	11
18	21	0.0033	0.0259	0.0545	600	0.35	11
19	20	0.0051	0.0396	0.0833	600	0.38	11
19	20	0.0051	0.0396	0.0833	600	0.38	11
20	23	0.0028	0.0216	0.0455	600	0.34	11
20	23	0.0028	0.0216	0.0455	600	0.34	11
21	22	0.0087	0.0678	0.1424	600	0.45	11

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Appendix D
Bus data for IEEE RTS 24 bus system

Bus no	Bus Type	V volt	PL MW	Pg MW	Qg MVAR	Qgmax MVAR	Qgmin MVAR
1	1	1.035	108	172	28.20	80	-50
2	2	1.035	97	172	28.20	80	-50
3	0	1.000	180	0	0	0	0
4	0	1.000	74	0	0	0	0
5	0	1.000	71	0	0	0	0
6	0	1.000	136	0	0	0	0
7	2	1.025	125	240	51.60	180	0
8	0	1.000	171	0	0	0	0
9	0	1.000	175	0	0	0	0
10	0	1.000	195	0	0	0	0
11	0	1.000	0	0	0	0	0
12	0	1.000	0	0	0	0	0
13	2	1.020	265	285	122.10	240	0
14	0	1.000	194	0	13.70	0	0
15	2	1.014	317	215	0.50	116	-50
16	2	1.017	100	155	25.22	80	-50
17	0	1.000	0	0	0	0	0
18	2	1.050	333	400	137.40	200	-50
19	0	1.000	181	0	0	0	0
20	0	1.000	128	0	0	0	0
21	2	1.050	0	400	108.20	200	-50
22	2	1.050	0	300	0	0	0
23	2	1.050	0	660	135.36	310	-125
24	0	1.000	0	0	0	0	0

Appendix E
Forecasted spot price and Reserve price for IEEE RTS 24 bus system

Hour	SP ($)	RP ($)	Load MW
1	11.74	11.75	2223.0
2	7.70	7.71	2052.0
3	1.99	2.08	1938.0
4	0	0.10	1881.0
5	3.00	3.09	1824.0
6	14.08	14.09	1825.0
7	13.98	15.08	1881.0
8	16.29	17.39	1995.0
9	18.60	19.70	2280.0
10	21.00	22.10	2508.0
11	24.25	25.35	2565.0
12	24.40	25.50	2593.0
13	22.01	27.01	2565.0
14	23.32	24.42	2508.0
15	24.00	33.12	2479.5
16	29.34	35.59	2479.5
17	28.12	37.24	2593.5
18	24.75	33.87	2850.0
19	24.51	25.61	2821.0
20	21.45	22.55	2764.5
21	16.45	17.55	2679.0
22	8.59	9.69	2622.0
23	6.00	7.00	2479.5
24	0.50	0.51	2308.5

Appendix F
Generator cost coefficient for IEEE RTS 24 bus system

Unit no.	a_i	b_i	c_i	Pmax	Pmin	Min up	Min down	Initial Status	α_i	β_i	τ_i
1	24.389	25.547	0.0253	12	2.4	0	0	-1	0	0	1
2	24.411	25.675	0.0265	12	2.4	0	0	-1	0	0	1
3	24.638	25.803	0.028	12	2.4	0	0	-1	0	0	1
4	24.761	25.932	0.0284	12	2.4	0	0	-1	0	0	1
5	24.888	26.061	0.0285	12	2.4	0	0	-1	0	0	1
6	117.76	37.551	0.012	20	4	0	0	-1	20	20	2
7	118.11	37.664	0.0126	20	4	0	0	-1	20	20	2
8	118.46	37.777	0.0136	20	4	0	0	-1	20	20	2
9	118.82	37.89	0.0143	20	4	0	0	-1	20	20	2
10	81.298	13.327	0.0088	76	15.2	3	-2	3	50	50	3
11	81.298	13.354	0.0089	76	15.2	3	-2	3	50	50	3
12	81.464	13.381	0.0091	76	15.2	3	-2	3	50	50	3
13	81.626	13.407	0.0062	76	15.2	3	-2	3	50	50	3
14	217.9	18	0.0062	100	25	4	-2	-3	70	70	4
15	218.34	18.1	0.0061	100	25	4	-2	-3	70	70	4
16	218.78	18.2	0.006	100	25	4	-2	-3	70	70	4
17	142.73	10.694	0.0046	155	54.25	5	-3	5	150	150	6
18	143.03	10.715	0.0047	155	54.25	5	-3	5	150	150	6
19	143.32	10.737	0.0048	155	54.25	5	-3	5	150	150	6
20	143.6	10.758	0.0049	155	54.25	5	-3	5	150	150	6
21	259.13	23	0.0026	197	68.95	5	-4	-4	300	200	8
22	259.65	23.1	0.0026	197	68.95	5	-4	-4	300	200	8
23	260.18	23.2	0.0026	197	68.95	5	-4	-4	300	200	8
24	177.06	10.862	0.0015	350	140	8	-5	10	500	500	8
25	310	7.4921	0.0019	400	100	8	-5	10	500	500	10
26	311.91	7.5031	0.0019	400	100	8	-5	10	500	500	10