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Unit commitment by Lagrangian Relaxation Incorporating Optimal Power Flow by Particle Swarm Optimization

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Abstract— In this paper Lagrangian Relaxation (LR) has been applied to unit commitment (UC) problem incorporating optimal power flow (OPF) by particle swarm optimization (PSO). The proposed method is a blend of LR and PSO. The UC problem is handled by LR, while PSO solves the OPF problem. Problem formulation takes into consideration the minimum up and down time constraints, start up cost, spinning reserve, generation limits, ramp rate constraints and power flow constraints. Problem formulation, representation and the simulation results for a 24 bus, 10 generator system are presented.

Keywords – Unit commitment (UC), Lagrangian Relaxation (LR), optimal power flow (OPF), particle swarm optimization (PSO).

I. INTRODUCTION

UNIT commitment (UC) is used to schedule the generating units for minimizing the overall cost of the power generation over the scheduled time horizon while satisfying a set of system constraints. UC problem is a nonlinear, combinatorial optimization problem. The global optimal solution can be obtained by complete enumeration, which is not applicable to large power systems due to its excessive computational time requirements [1]. Up to now, many methods have been developed for solving the UC problem such as priority list method [2],[3], integer programming [4],[5], dynamic programming (DP) [6]-[8], branch-and bound methods [9], mixed-integer programming [10] and Lagrangian Relaxation (LR) [11]-[13]. Among these methods, the priority list method is simple and fast technique for solving UC problem but the quality of solution is low. Dynamic programming method, which is based on priority list method, is flexible and has ability to maintain solution feasibility. But, this method has dimensional problem with a large power system because the problem size increases rapidly with the number of generating units to be committed, which results in an unacceptable solution time [14]. The shortcoming of branch-and-bound is the exponential growth in the execution time with the size of UC problem. The integer and mixed integer methods adopt linear programming technique to solve and check for an integer solution. These methods have only been applied to small UC problems and have required major assumptions which limit the solution space [15], [16]. Lagrange relaxation for UC problem was superior to dynamic programming due to its faster computational time. However, it suffers from numerical convergence and solution quality problems in the presence of identical units. Furthermore, solution quality of LR depends on the method to initialize and update Lagrange multipliers [17].

This paper proposes a new method for solving UC problem incorporating optimal power flow. The proposed method is developed in such way that Lagrangian Relaxation (LR) is used to obtain the unit commitment schedule and particle swarm optimization (PSO) technique is used to find optimal power generations of the units and system losses. The LR method uses single-unit dynamic programming and uses an improved procedure to initialize Lagrange multipliers and to update them. The PSO is applied to obtain optimal generations and losses incorporating power flow constraints and voltage stability. In the UC solutions so far published mainly economic dispatch was done without considering transmission losses. That is UC was obtained only at one bus. In this paper UC for entire network consisting of many generator and load buses was considered. So, considering transmission losses, which generator buses are to be switched on or off is obtained. So, instead of generating units' on / off status at a bus generating stations' on / off status in a system is obtained. The UC solution gives optimal scheduling of the generator buses of any standard system containing generator and load buses. To illustrate the effectiveness of the proposed method, it is tested on 10-generator, 24-bus system and simulation results are presented.

II. NOMENCLATURE

CSC_i Cold startup cost of unit i.

DC_i^t Value of the on / off decision criterion of unit i at hour t.

F_i^t Generator fuel cost in quadratic form.

$$F_i^t = a_i + b_i P_i^t + c_i (P_i^t)^2 \text{ (in units/h).}$$

$FLAPM_i$ Full load average production cost of unit i at hour t, $F(P_{i,\max}) / P_{i,\max}$ (in units/mwh).

$G^{(k)}$ Relative duality gap at iteration k.

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HSC_i Hot startup cost of unit i.

$J^{(k)}$ Total economic dispatch production cost at iteration k.

k ALR iteration counter.

N Total number of generator units.

$P_{i,\min}$ Minimum real power generation of unit i (in megawatts).

$P_{i,\max}$ Maximum real power generation of unit i (in megawatts).

P_i^t Real power generation of unit i at hour t (in megawatts).

$P_{i,opt}^t$ Optimal generation output of unit i at hour t (in megawatts).

P_D^t Load demand at hour t (in megawatts).

P_L^t Power loss at hour t (in megawatts).

R^t Spinning reserve at hour t (in megawatts).

ST_i^t Startup cost of unit i at hour t.

T Total number of hours.

$T_{i,cold}$ Cold start hours of unit i (in hours).

$T_{i,down}$ Minimum down time of unit i (in hours).

$T_{i,off}$ Continuously off time of unit i (in hours).

$T_{i,on}$ Continuously on time of unit i (in hours).

$T_{i,up}$ Minimum up time of unit i (in hours).

$U_{i,t}$ Status of unit i at hour t (on = 1, off = 0).

UR_i Ramp-up rate limit of unit i

DR_i Ramp-down rate limit of unit i

ε Duality gap tolerance.

$\lambda^{t(0)}, \mu^{t(0)}$ Initial Lagrangian multipliers at hour t (in units / mwh, units / mw).

$\lambda^{t(k)}, \mu^{t(k)}$ Lagrangian multipliers at hour t at iteration k (in units / mwh, units / mw).

P_{gi}: real power generation at bus i

Q_{gi}: reactive power generation at bus i

$|V_i|$: voltage magnitude at bus i

$|V_j|$: voltage magnitude at bus j

G_{ij}, B_{ij}: real/reactive part of the ij[th] element of the bus admittance matrix

$P_{gi\min}, P_{gi\max}$: minimum/maximum real power generation at generation bus i

$Q_{gi\min}, Q_{gi\max}$: minimum/maximum reactive power generation at generation bus i

$|V_i|_{min}, |V_i|_{max}$: minimum/maximum voltage magnitude at bus i

P_{ij}, Q_{ij} : real /reactive power flow through transmission line ij

$S_{ij\max}$:maximum apparent power flow allowable through the ij[th] line

δ_{ij}: angle difference between the voltage phasors at bus i

III. PROBLEM FORMULATION

The objective of unit commitment problem is to minimize the production cost over the scheduled time horizon (e.g., 24h) under the generator operational and spinning reserve constraints. The objective function to be minimized is [1]

$$F(P_i^t, U_{i,t}) = \sum_{t=1}^{T}\sum_{i=1}^{N}[F_i(P_i^t) + ST_{i,t}(1-U_{i,t-1})]U_{i,t} \tag{1}$$

subject to the following constraints

(a) power balance constraint

$$\sum_{i=1}^{N} P_i^t U_{i,t} = P_D^t + P_L^t \tag{2}$$

(b) spinning reserve constraint

$$\sum_{i=1}^{N} P_{i,\max} U_{i,t} \geq P_D^t + R^t \tag{3}$$

(c) generator limit constraints

$$P_{i,\min} U_{i,t} \leq P_i^t \leq P_{i,\max} U_{i,t},\ i = 1, \ldots, N \tag{4}$$

(d) minimum up and down time constraints

$$U_{i,t} = \begin{cases} 1, & if\ T_{i,on} < T_{i,up}, \\ 0, & if\ T_{i,off} < T_{i,down}, \\ 0\ or\ 1, & otherwise \end{cases} \tag{5}$$

(e) startup cost

$$ST_{i,t} = \begin{cases} HSC_i & if\ T_{i,down} \leq T_{i,off} \leq T_{i,cold} + T_{i,down}, \\ CSC_i & if\ T_{i,off} > T_{i,cold} + T_{i,down} \end{cases} \tag{6}$$

(f) ramp rate constraints

For each unit, output is limited by ramp up/ down rate at each hour as follows:

$$P_{i,\min}^t \leq P_i^t \leq P_{i,\max}^t \tag{7}$$

where

$$P_{i,\min}^t = \max(P_{i,t-1} - DR_i,\ P_{i,\min}^t)$$

$$P_{i,\max}^t = \min(P_{i,t-1} + UR_i,\ P_{i,\max}^t)$$

g) power flow equality constraints

$$P_G = \sum_{j=1}^{n} |V_i||V_j|(G_{ij}\cos\delta_{ij} + B_{ij}\sin\delta_{ij}) \tag{8}$$

$$Q_i = \sum_{j=1}^{n} |V_i||V_j|(G_{ij}\sin\delta_{ij} - B_{ij}\cos\delta_{ij})$$

h) power flow inequality constraints

$$P_{gi}^{\min} \leq P_{gi} \leq P_{gi}^{\max}$$

$$Q_{gi}^{\min} \leq Q_{gi} \leq Q_{gi}^{\max} \tag{9}$$

$$|V_i|_{min} \leq |V_i| \leq |V_i|_{max}$$

$$P_{ij}^2 + Q_{ij}^2 \leq S_{ij\max}^2$$

IV. IMPLENETATION OF THE PROPOSED METHOD

The LR procedure solves the UC problem by relaxing or temporarily ignoring the coupling constraints and solving the problem as if they did not exist. This is done through the dual optimization procedure attempting to reach the constrained optimum by maximizing the Lagrangian

$$L(P,U,\lambda,\mu)=F(P_i^t,U_{i,t})+\sum_{t=1}^{T}\lambda^t(P_D^t-\sum_{i=1}^{N}P_i^tU_{i,t}) + \sum_{t=1}^{T}\mu^t(P_D^t+R^t-\sum_{i=1}^{N}P_{i,\max}U_{i,t}) \quad (10)$$

with respect to nonnegative λ^t and μ^t whereas minimizing it with respect to the other control variables in the problem, that is

$$q^*(\lambda,\mu)=\underset{\lambda^t,\mu^t}{Max}\; q(\lambda,\mu) \quad (11)$$

where

$$q(\lambda,\mu)=\underset{P_i^t,U_{i,t}}{Min}\; L(P,U,\lambda,\mu) \quad (12)$$

Equations (2) and (3) are the coupling constraints across the units. In particular, what is done to one unit affects the other units. The Lagrangian function is rewritten as

$$L=\sum_{i=1}^{N}\sum_{t=1}^{T}\left\{\left[F_i(P_i^t)+ST_{i,t}(1-U_{i,t-1})\right]U_{i,t}-\lambda^tP_i^tU_{i,t}-\mu^tP_{i,\max}U_{i,t}\right\}+ \sum_{t=1}^{T}(\lambda^tP_D^t+\mu^t(P_D^t+R^t)) \quad (13)$$

The term $\sum_{t=1}^{T}\left\{\left[F_i(P_i^t)+ST_{i,t}(1-U_{i,t-1})\right]U_{i,t}-\lambda^tP_i^tU_{i,t}-\mu^tP_{i,\max}U_{i,t}\right\}$ can be minimized separately for each generating unit, when the coupling constraints are temporarily ignored. Then, the minimum of the Lagrangian function is solved for each generating unit over the time horizon, that is

$$\underset{P_i^tU_{i,t}}{Min}\; L(P,U,\lambda,\mu)=\sum_{i=1}^{N}\min\sum_{t=1}^{T}\begin{matrix}\left[F_i(P_i^t)+ST_{i,t}(1-U_{i,t-1})\right]U_{i,t}-\\ -\lambda^tP_i^tU_{i,t}-\mu^tP_{i,\max}U\end{matrix} \quad (14)$$

subject to

$U_{i,t}P_{i,\min}\le P_i^t\le U_{i,t}P_{i,\max}$ for t=1, ….., T and the constraints in (5).

On/Off decision criterion:

In the Lagrangian relaxation method, the dual solution is obtained by using dynamic programming for each unit separately. This can be visualized in Fig.1 showing the only two possible states for unit i (i.e., $U_{i,t}=0\ or\ 1$):

At the $U_{i,t}=0$ state, the value of the function to be minimized is trivial (i.e., it equals zero), at the state where $U_{i,t}=1$, the function to be minimized is the startup cost and the term $\mu^tP_{i,\max}$ are dropped here since the minimization is with respect to P_i^t) $\min\left[F_i(P_i^t)-\lambda^tP_i^t\right]$.

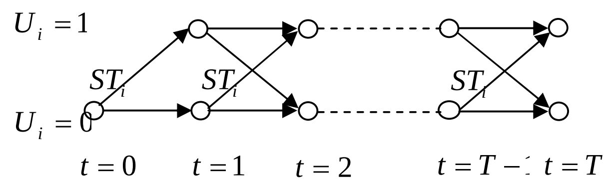

Fig. 1: Two-state dynamic programming.

To find the dual power, the term $\min\left[F_i(P_i^t)-\lambda^tP_i^t\right]$ will be minimized by the optimality condition

$$\frac{d}{dP_i^t}\left[F_i(P_i^t)-\lambda^tP_i^t\right]=0. \quad (15)$$

The solution to this equation is

$$\frac{dF_i(P_i^{t,\,dual})}{dP_i^t}=\lambda^t \quad (16)$$

The dual power is obtained

$$P_i^{t,\,dual}=\frac{\lambda^t-b_i}{2c_i} \quad (17)$$

There are three cases to check $P_i^{t,\,opt}$ against its limits

1) If $P_i^{t,\,dual}<P_{i,\min}$, then $P_i^t=P_{i,\min}$.
2) If $P_{i,\min}\le P_i^{t,\,dual}\le P_{i,\max}$, then $P_i^t=P_i^{t,\,dual}$.
3) If $P_i^{t,\,dual}>P_{i,\max}$, then $P_i^t=P_{i,\max}$.

Dynamic programming is used to determine the optimal schedule of each unit over the scheduled time period. More specifically, for each state in each hour, the on / off decision making is needed to select the lower cost by comparing the combination of the startup cost and accumulated costs from two historical routes. The dual power calculated by (14) and within the limit, will be substituted in the new on / off decision criterion

$$\left[F_i(P_i^t)+ST_{i,t}(1-U_{i,t-1})-\lambda^tP_i^t-\mu^tP_{i,\max}\right] \quad (18)$$

To minimize the above term in (18) at each hour, if $\left[F_i(P_i^t)+ST_{i,t}(1-U_{i,t-1})-\lambda^t-\mu^tP_{i,\max}\right]\le 0$, this unit will be committed if it does not violate the minimum downtime constraint ($U_{i,t}=1$). Otherwise, this unit will not be committed if it does not violate the minimum uptime constraint ($U_{i,t}=0$).

Initialization of Lagrangian Multipliers:

The initial values of Lagrangian multipliers are very important in LR method since they may prevent LR from reaching the optimal solution or require a longer computational time to reach one [17]. Different initial values may also lead LR to different solutions.

The initialization procedure is taken such that a quality feasible solution is obtained in the first iteration [18]. The generating units are sorted in the ascending order of full load average production cost, $FLAPM_i$. For each of the 24 h, the units with the least $FLAPM_i$ will be committed one by one until power balance constraint is satisfied. Subsequently, economic dispatch in each hour is carried out to obtain the hourly equal lambda which is initially set to Lagrangian multipliers $\lambda^{t(0)}$, in each hour. For the hours with insufficient spinning reserves, more units are needed to be committed to give the initial feasible solution. This is obtained by committing units with least $FLAPM_i$ one by one until the spinning reserve is satisfied.

For each of the 24 h, each non-negative $\mu_i^{t(0)}$ is determined as follows:

$$\mu_i^{t(0)} = \max\left[\frac{1}{P_{i,\max}}\left[F_i(P_i^t) + \frac{CST_i}{T_{i,up}} - \lambda^{t(0)}P_i^t\right],\ 0\right]. \quad (19)$$

The initial $\mu^{t(0)}$ is determined by the highest $\mu_i^{t(0)}$ among the committed units as

$$\mu^{t(0)} = \max\left[\mu_1^{t(0)}, \ldots\ldots, \mu_m^{t(0)}\ \right] \quad (20)$$

where m is the unit with the highest $FLAPM_i$ giving the sufficient spinning reserve at t.

Updating of the Lagrangian Multipliers:

In general, adjusting Lagrangian multiplier by subgradient method is not efficient in the presence of the spinning reserve constraint [19]. The Lagrangian relaxation solution quality is dependent on the method used to update the multipliers. In this paper, the Lagrangian multiplier update rule is designed such that the step size is large at the beginning of iterations and smaller as the iterations grow [4]. The values of α and β are determined heuristically [20]. Each non-negative λ^t and μ^t are adaptively updated by,

$$\lambda^{t(k)} = \max\left[\lambda^{t(k-1)} + \frac{pdif^t}{(\alpha+\beta\times k)\times norm(pdif)},\ 0\right] \quad (21)$$

where

$$pdif^{\,t} = P_d^t - \sum_{i=1}^{N} P_i^t U_{i,t} \quad (22)$$

$$norm(pdif) = \sqrt{(pdif^{\,1})^2 + (pdif^{\,2})^2 + \ldots\ldots + (pdif^{\,T})^2} \quad (23)$$

$$\mu^{t(k)} = \max\left[\mu^{t(k-1)} + \frac{rdif^t}{(\alpha+\beta\times k)\times norm(rdif)},\ 0\right] \quad (24)$$

where

$$rdif^{\,t} = P_d^t + R^t - \sum_{i=1}^{N} P_{i,\max} U_{i,t} \quad (25)$$

$$norm(rdif) = \sqrt{(rdif^{\,1})^2 + (rdif^{\,2})^2 + \ldots\ldots\ldots + (rdif^{\,T})^2} \quad (26)$$

α and β are divided into three cases depending on the signs of $pdif^{\,t}$ and $rdif^{\,t}$ as follows:

Case 1) $pdif^{\,t} \geq 0$ and $rdif^{\,t} \geq 0$: updating both λ^t and μ^t by using α =0.02 and β =0.05;

Case 2) $pdif^{\,t} < 0$ and $rdif^{\,t} < 0$: updating both λ^t and μ^t by using α =0.6 and β =0.4;

Case 3) $pdif^{\,t} < 0$ and $rdif^{\,t} > 0$: updating only μ^t by using α =0.02 and β =0.05;

Excess spinning reserve is undesirable due to increase in generation cost and it should be eliminated. Every hour it is checked that if the spinning reserve is more than the maximum generation of the unit with highest full load average production cost, then that unit is decommitted without violating the uptime constraint. This process is done for all hours until excess reserve is eliminated without sacrificing uptime constraint.

OPF by PSO

With the switched on generators for each hour optimal power flow is performed to obtain optimal real power generations, power loss and other optimal control variables. Here, optimal power flow is done instead of economic dispatch. The reason to do this is as follows: The generators with different fuel characteristics may be located at different places of the network. It may not be realistic to ignore the real power losses. The optimal generations may be different if losses are included.

For this purpose, the 24-bus system data are modified to incorporate the 10-generator unit commitment data. Second bus is taken as the slack bus for the optimal power flow.

The real and reactive loads at the individual load buses are adjusted proportionately as per the UC 24 hour load data using multiplication factor (MF) given by

$$MF = \frac{Load\ Demand\ for\ t^{th}\ hour}{Maximum\ load\ of\ 24\ bus\ system} \quad (27)$$

The control variables for optimal power flow are real power generations, taps for the regulating transformers, generator voltages and shunt capacitors. Shunt capacitors are placed at two buses viz. 13th and 23 rd buses.

In the tackling of ramp rate constraints, in any hour if the increase of real power generation of any unit is more than the ramp up rate, then peak units with least full load average production cost are to be switched on one by one until power balance constraint is satisfied. If the ramp down rate is not satisfied when a generator is to switched off, then outputs of that unit in the previous hours are to be reduced so that ramp down rate would be satisfied at the time of stopping of any unit . To compensate the reduction in power generation, peak units are to be switched on.

It is necessary to point out that peaking units, rather than the more economical units which have longer ramping up/down times, are used in compensating for the deficiency or surplus caused by the unit ramping characteristics. As we would require a short period of compensation, units with lower operating costs and longer ramping up/ down times are not efficient and may not be regarded as economical for this purpose [21].

PARTICLE SWARM OPTIMIZATION (PSO)

PSO was introduced by Kennedy and Eberhart in 1995 [22] as an alternative to GAs. The PSO technique has ever since turned out to be a competitor in the field of numerical optimization. Similar to GA, a PSO consists of a population refining its knowledge of the given search space. PSO is inspired by particles moving around in the search space. The individuals in a PSO thus have their own positions and velocities. These individuals are denoted as particles. Traditionally, PSO has no crossover between individuals, has no mutation, and particles are never substituted by other individuals during the run. Instead, the PSO refines its search by attracting the particles to positions with good solutions. Each particle remembers its own best position found so far in the exploration. This position is called personal best and is denoted by 'pbest' in (28). Additionally, among these, there is only one particle that has the best fitness, called the global best and is denoted by 'gbest' in (28). The velocity of the i[th] dimension is defined as

$$V_i = wV_i + c_1\ rand(\,)\ (gbest - X_i) + c_2\ rand(\,)\ (pbest - X_i) \quad (28)$$

where is known as the inertia weight. The best found position for the given particle is denoted by pbest, whereas gbest is the best position known for all particles. The parameters c_1 and c_2 are set at 2, whereas $rand(\,)$ is a randomly generated value between 0 and 1. As mentioned, the subscript i denotes the i th dimension of a particle. The position of each particle is updated on every iteration. This is done by adding the velocity vector to the position vector, as described in

$$X_i = X_i + V_i \quad (29)$$

The constraints are incorporated into the fitness function as quadratic penalty terms as follows:

$$\sum k_p\ (x_i - x_i^{\lim})^2 \quad (30)$$

Where

k_p is the penalty factor and $x_i^{\lim}$ is the limit value of the var iable x given as

$$x_i^{\lim} = \begin{Bmatrix} x_i^{\max};\ x_i > x_i^{\max} \\ x_i^{\min};\ x_i < x_i^{\min} \end{Bmatrix} \quad (31)$$

The fitness function is given by

$$f = \sum_{t=1}^{T} \begin{Bmatrix} \sum_{i=1}^{N} [F_i(P_i^t) + ST_{i,t}(1 - U_{i,t-1})]U_{i,t} + \\ k_p \sum\ (x_i - x_i^{\lim})^2 \end{Bmatrix} \quad (32)$$

Stopping criterion:

The relative duality gap is

$$G^k = \frac{J\left(\left[U_{i,t}^{(k)}\right]\right) - L(P^{(k)}, U^{(k)}, \lambda^{(k)}, \mu^{(k)})}{L(P^{(k)}, U^{(k)}, \lambda^{(k)}, \mu^{(k)})} \quad (33)$$

where

$$J\left(\left[U_{i,t}^{(k)}\right]\right) = \sum_{t=1}^{T}\sum_{i=1}^{N}\left[F_i(P_{i,ed}^t) + ST_{i,t}(1 - U_{i,t-1})\right]U_{i,t}$$

and $L(P^{(k)}, U^{(k)}, \lambda^{(k)}, \mu^{(k)})$ is calculated from (13).

The relative duality gap is used to measure the solution quality, by checking against the stopping criterion. The iteration process stops when either the relative duality gap is less than the specified tolerance or the iteration counter exceeds the maximum allowable number of iterations.

The flowchart for the proposed method is shown in Fig. 2 below.

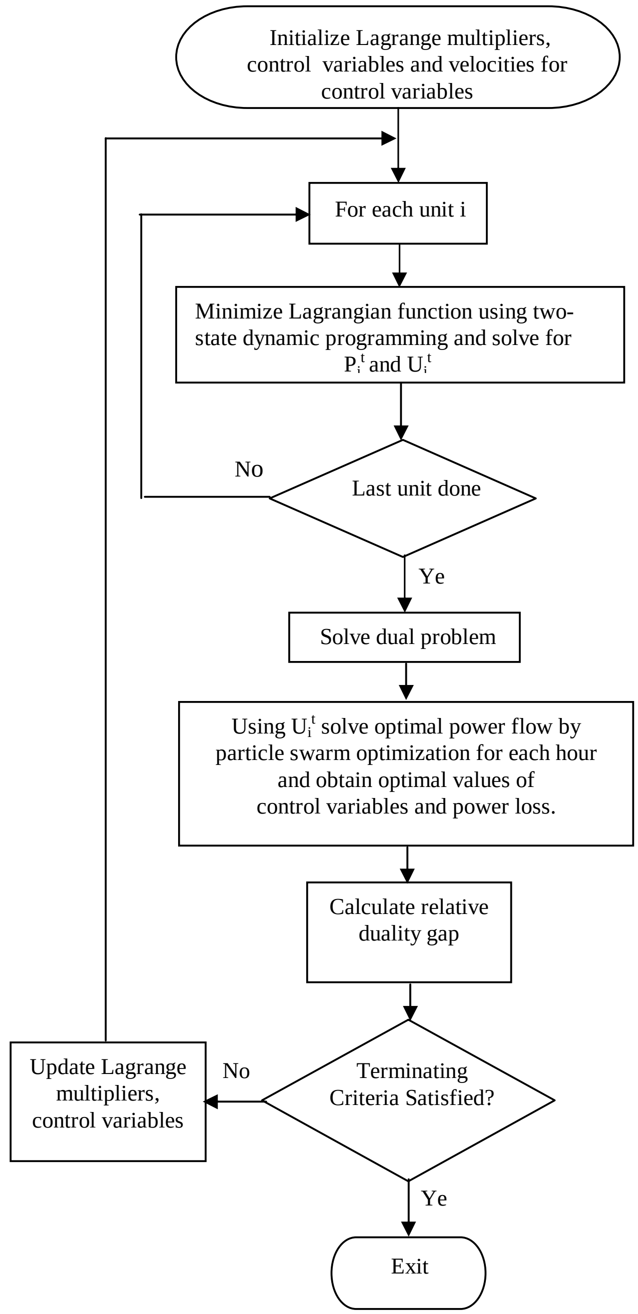

Fig. 2. Flowchart of the proposed method

V. RESULTS AND DISCUSSIONS

All simulations have been run on MATLAB environment with Pentium-IV, 2.66 GHz computer with 512 MB RAM. Base ten-unit characteristics are taken from [17] and are given in Table I. The ramp rates taken for the generators are given in Table II. The one line diagram for the IEEE 24-bus system is given in Fig. 3. The spinning reserve requirement is considered to 10% of the load demand; cold startup cost is double that of hot startup cost and total scheduling period is 24 hours. The simulations are performed on 24-bus, 10-

generator system with and without considering ramp rate constraints. Maximum generations taken are 100. The weights for updating the velocity are chosen as $c_1 = 2.0 \; and \; c_2 = 2.0$, as this method performed best with these settings. The maximum velocity is taken as 10% of maximum generation of each generator. Population size is taken as 10 for OPF parameters. Out powers of the 10 generators, power loss, fuel cost, startup cost and total cost of the best solution without and with ramp rate constraints are shown in Table III and Table IV respectively. The fitness and total cost characteristics are shown in figures 4, 5, 6 and 7.

All the papers to solve the UC problem considered commitment of units without considering transmission losses. In this paper, UC problem is considered with transmission losses for IEEE 24-bus system. Also, ramp rate limits are considered for the generator output.

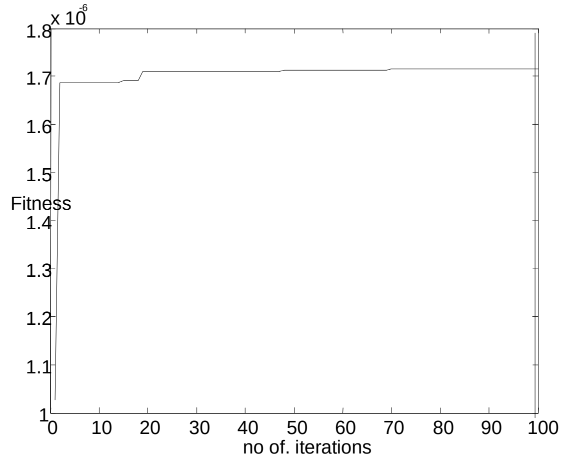

Fig. 4. Fitness without ramp rate constraints

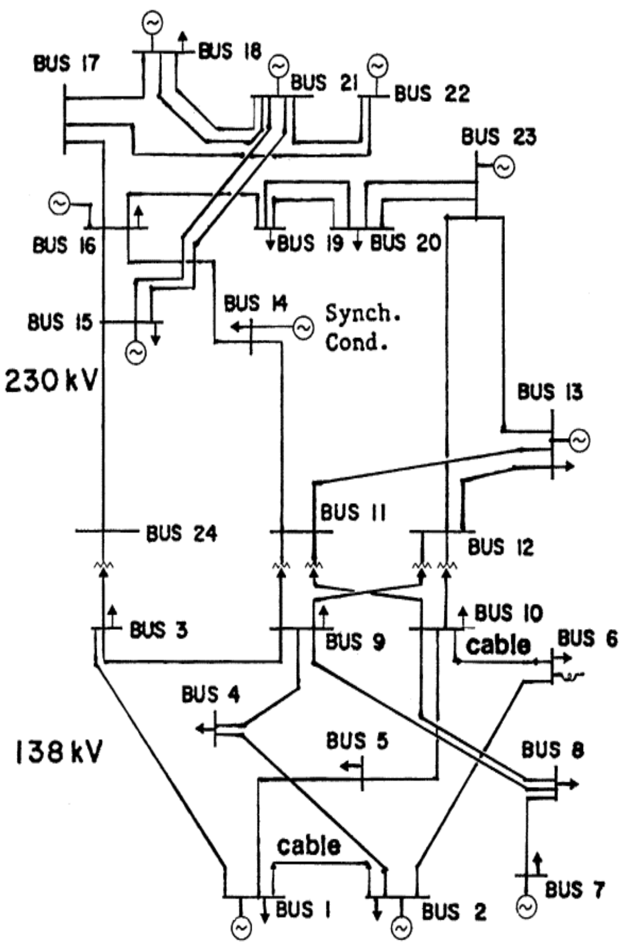

Fig. 3: Single line diagram of IEEE 30-bus test system

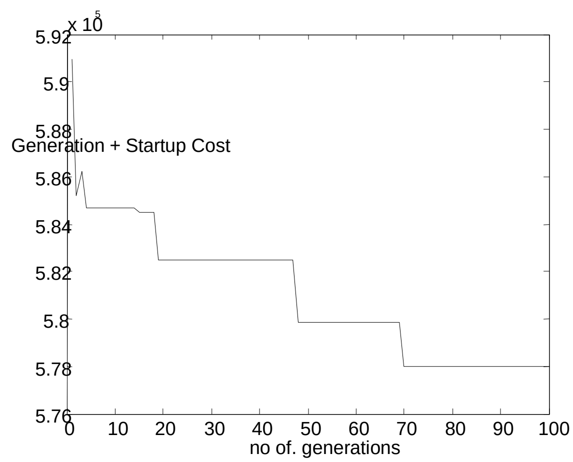

Fig. 5. Total cost without ramp rate constraints

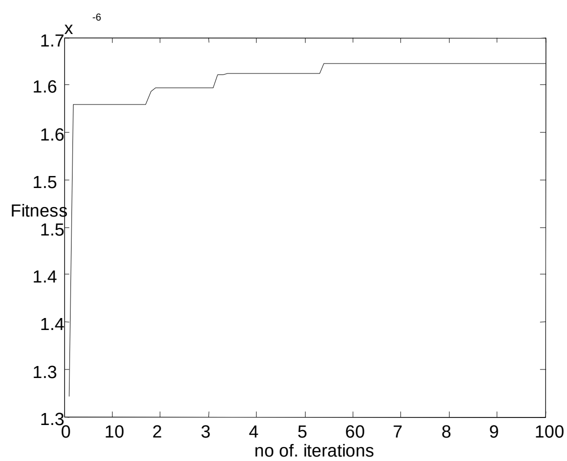

Fig. 6. Fitness with ramp rate constraints

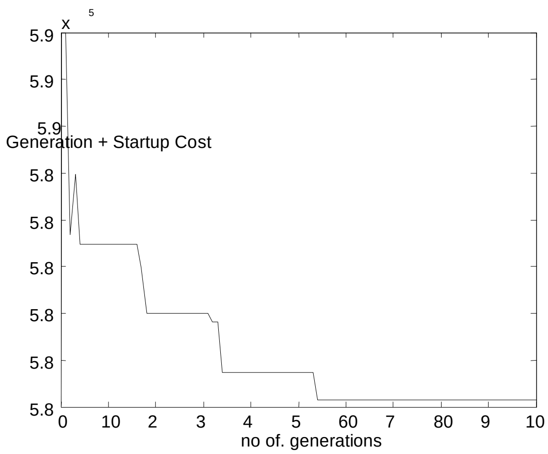

Fig. 7. Total cost with ramp rate constraints

VI. CONCLUSION

In this paper, the proposed method is effectively implemented to solve the UC problem with OPF. The effectiveness of this method is tested on 24-bus, 10-generator system. Results demonstrate that this is a robust method to solve the UC problem incorporating OPF. Unlike in other UC methods, OPF is incorporated in to UC problem to include transmission losses so that UC solution gives optimal scheduling of the generator buses of any standard system containing generator and load buses. In this way, this approach goes beyond the normal method of obtaining UC solution with economic dispatch of units at one bus. Accordingly, this method is very suitable for UC problem if OPF is to be included. This approach may be suitable for conventional methods of solving UC problem with OPF because with evolutionary methods the solution may not be obtained in real time as computational load involved will be too much. In future, there is enough scope to develop more appropriate heuristic methods to consider evolutionary methods for solving UC problem incorporating OPF.

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VIII. BIBLIOGRAPHIES

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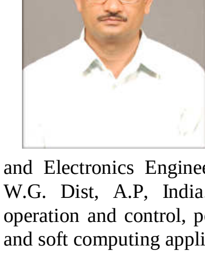

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TABLE I

UNIT DATA FOR THE TEN-UNIT SYSTEM

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
$P_{\max}(MW)$	455	455	130	130	162
$P_{\min}(MW)$	150	150	20	20	25
$a\ (units/h)$	1000	970	700	680	450
$b\ (units/MWh)$	16.19	17.26	16.60	16.50	19.70
$c\ (units/MW^2-h)$	0.00048	0.00031	0.002	0.00211	0.00398
min up (h)	8	8	5	5	6
min down(h)	8	8	5	5	6
hot start cost (units)	4500	5000	550	560	900
cold start cost (units)	9000	10000	1100	1120	1800
cold start hours (h)	5	5	4	4	4
initial status (h)	8	8	-5	-5	-6

	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
$P_{\max}(MW)$	80	85	55	55	55
$P_{\min}(MW)$	20	25	10	10	10
$a\ (units/h)$	370	480	660	665	670
$b\ (units/MWh)$	22.26	27.74	25.92	27.27	27.79
$c\ (units/MW^2-h)$	0.00712	0.00079	0.00413	0.00222	0.00173
min up (h)	3	3	1	1	1
min down(h)	3	3	1	1	1
hot start cost (units)	170	260	30	30	30
cold start cost (units)	340	520	60	60	60
cold start hours (h)	2	0	0	0	0
initial status (h)	-3	-3	-1	-1	-1

TABLE II Generating units Ramp Rate Limits

Unit	1	2	3	4	5	6	7	8	9	10
UR_i (MW/h)	91.00	91.00	32.50	32.50	40.50	26.67	28.33	27.50	27.50	27.50
DR_i (MW/h)	91.00	91.00	32.50	32.50	40.50	26.67	28.33	27.50	27.50	27.50

The ramp rates selected are for 1 and 2 units 1/5 of Pmax; for 3,4 and 5 units 1/4 of Pmax; for 6 and 7 units 1/3 of Pmax and 8,9and 10 units 1/2 of Pmax.

TABLE III – Solution of UC with OPF without ramp rate constraints

Hour	Load (MW)	UC	Generation Schedule 1	2	3	4	5	6	7	8	9	10	Power Loss (MW)	Fuel Cost ($)	Startup Cost ($)	Total Cost ($)
1	700	110000000	455	257.88	0	0	0	0	0	0	0	0	12.88	13907.4755	0	13907.475
2	750	110000000	455	310.92	0	0	0	0	0	0	0	0	15.92	14832.1825	0	14832.182
3	850	110010000	455	391.70	0	0	25	0	0	0	0	0	21.70	17189.1318	900	18089.131
4	950	110010000	455	454.99	0	0	66.18	0	0	0	0	0	26.17	19124.3195	0	19124.319
5	1000	110110000	455	411.01	0	130	25	0	0	0	0	0	21.01	20387.9418	560	20947.941
6	1100	111110000	455	389.33	130	130	25	0	0	0	0	0	29.33	22900.0073	1100	24000.007
7	1150	111110000	455	436.64	130	130	32.21	0	0	0	0	0	33.85	23872.4087	0	23872.408
8	1200	111110000	455	454.98	130	130	65.46	0	0	0	0	0	35.44	24861.9608	0	24861.960
9	1300	111111100	455	454.95	130	129.98	117.54	20	25.00	0	0	0	32.47	27917.0939	860	28777.093
10	1400	111111110	455	454.95	130	130	149.77	77.36	25.00	10.00	0	0	32.09	30823.0359	60	30883.035
11	1450	111111111	455	455	130	130	161.88	79.38	25.03	30.36	14.72	0	31.39	32723.6523	60	32783.652
12	1500	111111111	455	454.99	130	130	162	55.54	37.59	51.41	37.70	16.49	30.72	34831.9410	60	34891.941
13	1400	111111110	455	454.95	130	130	149.77	77.36	25.00	10.00	0	0	32.09	30823.0359	0	30823.035
14	1300	111111100	455	454.95	130	129.98	117.54	20	25.00	0	0	0	32.47	27917.0939	0	27917.093
15	1200	111110000	455	454.98	130	130	65.46	0	0	0	0	0	35.44	24861.9608	0	24861.960
16	1050	111110000	455	334.20	130	130	25	0	0	0	0	0	24.20	21936.1784	0	21936.178
17	1000	111110000	455	281.11	129.84	130	25	0	0	0	0	0	20.95	21006.9377	0	21006.937
18	1100	111110000	455	389.33	130	130	25	0	0	0	0	0	29.33	22900.0073	0	22900.007
19	1200	111110000	455	454.98	130	130	65.46	0	0	0	0	0	35.44	24861.9608	0	24861.960
20	1400	111111011	455	455	130	129.97	161.99	71.25	0	10.27	10.01	10.02	33.50	31656.8927	350	32006.892
21	1300	111111010	455	454.87	130	130	124.80	29.90	0	10.02	0	0	34.59	28036.1271	0	28036.127
22	1100	110111000	455	455	0	130	64.02	20	0	0	0	0	24.02	22759.4780	0	22759.478
23	900	110010000	455	446.11	0	0	25	0	0	0	0	0	26.11	18142.3358	0	18142.335
24	800	110000000	455	364.65	0	0	0	0	0	0	0	0	19.65	15770.8718	0	15770.871
Total														574044.031	3950	577994.03

TABLE IV – Solution of UC with OPF with ramp rate constraints

Hour	Load (MW)	Unit Number										Power Loss (MW)	Fuel Cost ($)	Startup Cost ($)	Total Cost ($)
		1	2	3	4	5	6	7	8	9	10				
1	700	455	257.88	0	0	0	0	0	0	0	0	12.88	13907.4755	0	13907.4755
2	750	455	310.92	0	0	0	0	0	0	0	0	15.92	14832.1825	0	14832.1825
3	850	455	374.27	0	0	40.50	0	0	0	0	0	19.77	17290.8739	900	18190.8739
4	950	455	455	0	0	66.25	0	0	0	0	0	26.25	19125.8934	0	19125.8934
5	1000	455	454.80	0	32.50	83.23	0	0	0	0	0	25.53	20685.5330	560	21245.5330
6	1100	455	454.91	32.50	65	119.32	0	0	0	0	0	26.72	23211.8912	1100	24311.8912
7	1150	455	454.27	65	97.45	108.28	0	0	0	0	0	30.00	24065.7326	0	24065.7326
8	1200	455	394.28	97.50	129.95	148.78	0	0	0	0	0	25.51	24955.6552	0	24955.6552
9	1300	455	454.44	129.96	129.97	118.32	20	25	0	0	0	32.70	27923.5560	860	28783.5560
10	1400	455	454.78	128.89	130	158.04	44.35	46.56	16.00	0	0	33.62	30966.0863	60	31026.0863
11	1450	455	454.98	130	130	162	65.69	52.80	15.58	17.40	0	33.45	32866.1012	60	32926.1012
12	1500	455	454.91	129.35	130	162	79.63	45.51	29.91	18.47	27.50	32.29	34814.8328	60	34874.8328
13	1400	455	454.97	130	130	161.63	53.32	37.41	10.00	0	0	32.33	30858.9494	0	30858.9494
14	1300	455	444.12	130	130	121.13	26.65	25	0	0	0	31.90	27951.8961	0	27951.8961
15	1200	455	437.60	130	130	80.63	0	0	0	0	0	33.23	24864.9866	0	24864.9866
16	1050	455	350.18	97.50	130	40.13	0	0	0	0	0	22.81	21963.0860	0	21963.0860
17	1000	455	284.91	65	130	80.63	0	0	0	0	0	15.54	21090.9329	0	21090.9329
18	1100	455	315.81	97.50	130	121.13	0	0	0	0	0	19.44	23010.4172	0	23010.4172
19	1200	455	383.35	97.50	130	161.63	0	0	0	0	0	27.48	25034.2567	0	25034.2567
20	1400	455	455	97.50	130	162	26.65	25.02	26.60	25.69	26.20	29.66	32558.9920	610	33168.9920
21	1300	455	455	65	97.50	121.50	53.28	50.09	27.41	0	0	24.79	29173.2848	0	29173.2848
22	1100	455	438.83	32.50	65	81	26.61	25	0	0	0	23.94	24286.0129	0	24286.0129
23	900	455	392.65	0	32.50	40.5	0	0	0	0	0	20.65	18733.6885	0	18733.6885
24	800	455	364.65	0	0	0	0	0	0	0	0	19.65	15770.8718	0	15770.8718
Total													579943.1885	4210	584153.1885