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Curtailment of Renewable Energy Resources for Increasing Capacity of Distribution Grids

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Abstract: The objective of this paper is to formulate a chance-constrained multivariate stochastic optimization problem which would perform the stochastic unit commitment and simultaneously would create an optimal combination of wind power curtailment and reserve scheduling to reduce overall cost of the system. As an initial step, the combination of the reserves and wind power curtailment (the convex mixture approach) was once modelled by using the convex mixture approach. The optimization problem corresponding to the convex combination model was formulated to find an optimal combination of reserve dispatch and wind energy curtailment. Later, the combination of reserve scheduling and the wind power curtailment was modelled using the mixed logic dynamical systems framework (MLD). The optimization problem corresponding to the MLD method was once formulated to locate an optimal combination of reserve dispatch and wind power curtailment. A randomization technique was used to generate several eventualities of the uncertain wind power. Based on a prior violation levels of the grid limits, we perform scenario-based stochastic optimization to obtain an optimal combination of reserve scheduling and wind power curtailment in both the approaches for each and every scenario to lower the overall costs of the system. The theoretical traits proposed had been evaluated on an IEEE-30 bus network. The static and the dynamic demand cases were simulated. In both cases, the proposed strategies outperformed the reserve scheduling method.

Keywords: Load Flow Optimization, Renewable energy Resources, Reserve Scheduling, CCPs (Chance Constrained Programs), MLD, YALMIP.

I. INTRODUCTION

Two methods were proposed to find out an optimal combination of reserve dispatch and wind power curtailment, in order to provide a cost-efficient solution to reduce the overall system costs compared to the reserve scheduling approach are:

A. Convex Combination Approach

For the problem of stochastic unit commitment, integrated reserve scheduling and the wind power curtailment, a mathematical model which takes a convex combination of reserves and wind power curtailment terms was proposed. By taking the advantage of the proposed modelling approach, an optimization problem which integrates reserve scheduling and the wind power curtailment was formed. This problem was solved using a mixed integer chance constrained stochastic optimization framework.

The main reasons for the generation load mismatches are:

- The difference in the actual wind power and the predicted wind power.
- The generator outages or load losses.

The above-mentioned cases might lead to frequency deviations in the grid. The secondary frequency control or the automatic generation control (AGC) is activated to minimize the frequency deviations in the grids.

1) *Modelling of Reserve Scheduling and Wind Power Curtailment:* There are two ways to deal with the frequency deviations caused by the excessive wind power in the grid rather than the estimated wind power. They are:

a) Down spinning of the reserves (reserve regulation)
b) Wind power curtailment (wind power spillage)

An optimal combination of reserve regulation and wind power curtailment would result in an enhanced solution in terms of total system costs compared to the reserve scheduling approach. A control scheme like the AGC control algorithm called the convex combination approach has been developed to obtain an optimal combination of the reserves and wind power curtailment.
The power balance equation with a day ahead estimated wind power is given by:

$$\sum_{i=1}^{N_g} P_{i,t}^{g} + \sum_{i=1}^{N_w} P_{i,t}^{w,f} - \sum_{i=1}^{N_d} P_{i,t}^{d} = 0$$

where $P_{i,t}^{g}$ denotes power from every generation unit i at time step t, and the terms $P_{i,t}^{w,f}$, $P_{i,t}^{d}$ denotes the power from the i^{th} wind power plant and the power from demand unit i respectively at time step t. But this equation will not hold in the presence of wind power uncertainty, So the equation along with the convex combination model would be:

$$\sum_{i=1}^{N_g}\left(P_{i,t}^{g}-R_{i,t}^{ds}\right)+\sum_{i=1}^{N_w}\left(P_{i,t}^{w}-P_{i,t}^{w}\right)-\sum_{i=1}^{N_d}P_{i,t}^{d}=0$$

Where the terms $P_{i,t}^{w}$ and $R_{i,t}^{ds}$ denote the amount of the wind power curtailment and amount of the down-spinning reserves respectively.

A schematic diagram of this control approach can be seen in Figure 1.

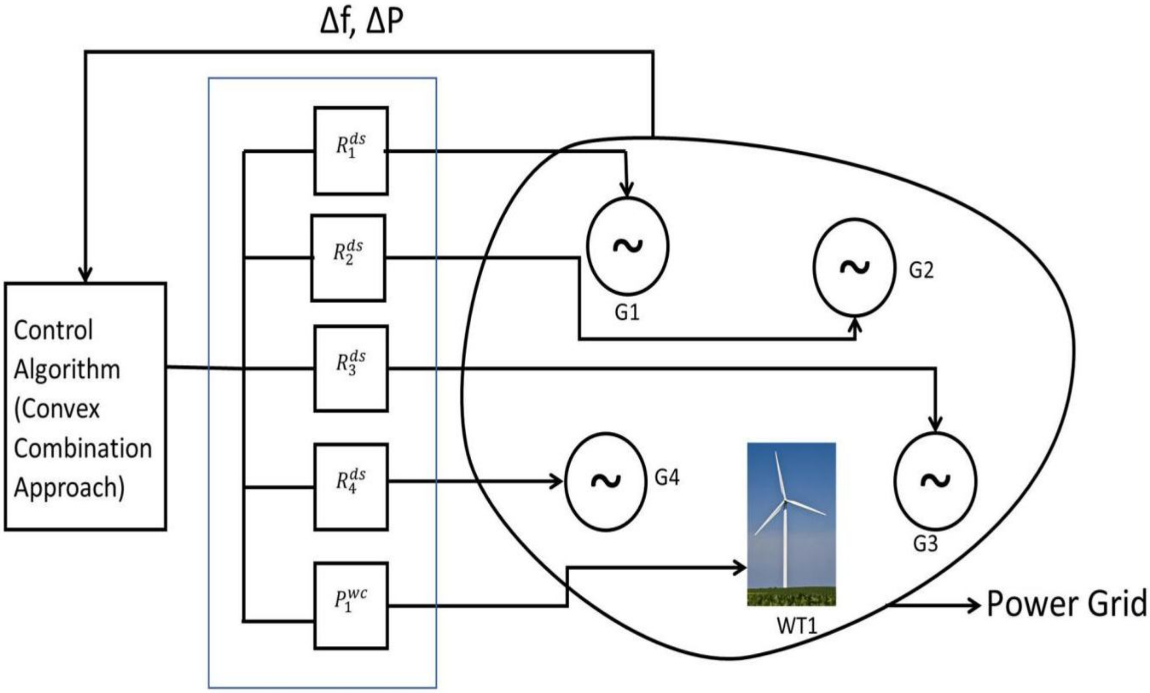

Figure 1: The schematic diagram of the convex combination approach. The terms G1, G2, G3, G4 represents the four generation units. The term of WT1 denotes the wind turbines.

2) *Optimization Scheme: Convex Combination Approach:* A power system with N_b buses, N_l lines, N_w wind farms, N_g conventional generators and N_d load sinks was considered to form the optimization problem. The vector of decision variables at every time step t will be:

$$x_{i,t}=\left[P_{i,t,s}^{g},\gamma_{i,t,s}^{g},z_{i,t,s}^{g},R_{i,t,s}^{ds},C_{i,t,s}^{su},C_{i,t,s}^{su}\right]$$

where $P_{i,t,s}^{g}$ denotes the scheduled power from every generation unit i at time step t for every scenario s, while the term $\gamma_{i,t,s}^{g}$ denotes the binary variable to control the on-off status of every generation unit. The term $z_{i,t,s}^{g}$ represents the auxiliary variables to model the minimum up and down times of every generation unit. The variable $R_{i,t,s}^{ds}$ denotes the amount of down-spinning of the generation unit in the presence of excessive wind power generation when compared to the predicted wind power in the grid. If a generation unit doesn't participate in control then the term $R_{i,t,s}^{ds}$ corresponding to the generation unit would be zero. The term $C_{i,t,s}^{su}$ denote effective start-up cost of every generation unit. The last term, $P_{i,t,s}^{wc}$ represents the amount of the wind power curtailment from every wind power plant. All the decision variables are defined for every time step t, where $t \in \{1, 2, 3....N_t\}$. The value $N_t = 24$ corresponds to a day ahead optimization problem.

3) *Cost-Function of the Optimization:* The total system costs are divided into three parts, they are:

a) The production costs of the system. The production costs are considered to be in quadratic form.

b) The reserve costs of the system. these reserve costs are linear.

c) The wind power curtailment costs. Like reserve costs, the wind power curtailment costs are also considered to be linear. The system operators are penalized for curtailing wind power. Hence the system also has wind power curtailment costs.

The final cost function of the optimization problem is:

$$\min_{x_{i,t}}\left(\sum_{t=1}^{N_t}\sum_{i=1}^{N_g} f_c(P^{g}_{i,t,s}) = \sum_{s=1}^{N_s} p_s\left(\sum_{t=1}^{N_t}\sum_{i=1}^{N_g}\left(f_{cc}(R^{ds}_{i,t,s})\right)\right) + \sum_{s=1}^{N_s} p_s\left(\sum_{t=1}^{N_t}\sum_{i=1}^{N_w}\left(f_{wc}(P^{wc}_{i,t,s})\right)\right)\right)$$

Where,

$$f_c = (a_i + b_i P^{g}_{i,t,s} + c_i (P^{g}_{i,t,s})^2 + C^{su}_{i,t,s})$$

$$f_{cc} = (C^{rs}_{i}(R^{ds}_{i,t,s}))$$

$$f_{cw} = (C^{wc}_{i}(P^{wc}_{i,t,s}))$$

where the function f_c denotes quadratic cost function which must be minimized for the economic dispatch from every generation unit *i*. The terms c_i and b_i denote the quadratic costs and the linear costs respectively of every mega-watt of production per hour. The function f_{cc} represents the linear reserve costs of the system to be minimized, while the term C_i^{rs} denotes the reserve costs of each mega-watt per hour of the i^{th} generation unit. The term P_s denotes the probability of each scenario of the uncertain wind power. Finally, the function f_{wc} denotes the linear cost function of the wind power curtailment. The term C_i^{wc} denotes the costs of every megawatt of wind power curtailed per hour.

4) *Constraints of the Optimization.*

The constraints of the optimization problem are:

a) The most important constraint is power balance of the network:

$$\sum_{i=1}^{N_g} P^{g}_{i,t,s} + \sum_{i=1}^{N_w} P^{w,f}_{i,t,s} - \sum_{i=1}^{N_d} P^{d}_{i,t} = 0$$

where $P_{i,t}{}^{d}$ denotes the i^{th} demand power of the grid at time step *t*. This constraint ensures that the combination of power from conventional generators and wind power should be equal to the total demand of the system when the actual wind power is equal to the wind power forecast ($P_{i,t}{}^{w} = P_{i,t}{}^{w,f}$).

b) The power generation from every conventional generator should be within the generator limits. This is written as:

$$\left[P^{g}_{\min,i}\right]\gamma^{g}_{i,t,s} \le P^{g}_{i,t,s} \le [P^{g}_{\max,i}]\gamma^{g}_{i,t,s}$$

Where $P_{\min}{}^{g}{}_{,i}$ denotes the minimum power generation of every generation unit (*i*) and $P_{\max}{}^{g}$ denotes maximum power of every generation unit (*i*). The term $\gamma_{i,t}{}^{g}$ denotes the on-off status of every generation unit.

c) The power flow in the transmission lines should be within the line limits of the grid.

$$-P_{line} \le P^{f}_{i,t,s} \le P_{line}$$

The power in each line depends upon the power injection vector.

d) Every conventional generation unit should ramp-up and ramp-down within the limits.

$$-P^{g}_{down,i} \leq P^{g}_{i,t,s} - P^{g}_{i,t-1,s} \leq P^{g}_{up,i}$$

Where, $P^{g}_{down.i}$ *and* $P^{g}_{up.i}$ denote the ramp-up and ramp-down limits of the generation unit *i*.

e) The power balance constraint in the presence of wind power uncertainty, reserve scheduling and wind power curtailment can be written as:

$$\sum_{i=0}^{N_g}(P^{g}_{i,t,s} - R^{ds}_{i,t,s}) + \sum_{i=1}^{N_w}(P^{w}_{i,t,s} - P^{wc}_{i,t,s}) - \sum_{i=1}^{N_d} P^{d}_{i,t} = 0$$

f) The next constraint ensures that the amount of down-spinning and the wind curtailment in combination should be equal to the uncertain wind power in the grid.

$$\sum_{i=0}^{N_g} R^{ds}_{i,t,s} + \sum_{i=1}^{N_w} P^{wc}_{i,t,s} = \Delta P^{w}_{i,t,s}$$

II. SMIXED LOGICAL DYNAMICAL APPROACH.

Another way to develop a cost-efficient solution is to use the mixed logic dynamical (MLD) approach to find out an optimal combination of the reserves and the wind power curtailment. In this method, the combination of reserves and wind power curtailment was modelled using the MLD framework. Like the convex combination approach, a chance-constrained stochastic optimization problem was formulated and solved. This optimization framework determines the optimal generation unit to provide reserves and the amount of reserves and the optimal wind power plants to curtail wind power and amount wind power to be curtailed.

A. Modelling using the MLD Framework

To elaborate the MLD framework that has been used as part of this paper, we consider a function *f* (.) defined over a bounded set. The upper and the lower bounds of the sets are *M* and *m*. In the case of binary decision variable $\delta \in \{0, 1\}$ the following statements hold :

$$[\, f(x) \leq] \Leftrightarrow [\delta =] \text{ is equivalent to } \begin{cases} f(x) \leq M(1-\delta) \\ f(x) \geq \epsilon + (m-\epsilon)\delta \end{cases}$$

Where ϵ is a very small tolerance value called machine precision, which is used to change the strict inequality into non-strict inequality. The product of two binary variables δ_1 and δ_2 can be replaced by an axillary binary variable δ_3□ $\delta_1\delta_2$.

$$\delta_3 = \delta_3\delta_1 is \text{ equivalent to } \begin{cases} -\delta_1 + \delta_3 \leq 0 \\ -\delta_2 + \delta_3 \leq 0 \\ \delta_1 + \delta_2 - \delta_3 \leq 0 \end{cases}$$

The final one is multiplication of a function $f : \mathbb{R}^n \rightarrow \mathbb{R}$ with a binary variable. The product of binary variable and the function can be replaced by an auxiliary variable $z \triangleq \delta f(x)$. This means the term $z = 0$ when $\delta = 0$, and $z = f(x)$ when $\delta = 1$. An equivalent representation would be:

$$z = \delta f(x) \text{ is equivalent to } \begin{cases} z \le M\delta \\ z \ge m\delta \\ z \le f(x) - m(1-\delta) \\ z \ge f(x) - M(1-\delta) \end{cases}$$

In the above-mentioned rules, we use only above equivalent equation to transform the convex combination model into the MLD model. To elaborate the transformation of the convex combination into the MLD framework, we introduce two logic variables:

- **$\delta \in \{0,1\}$**
- **$\mu \in \{0,12\}$**

At the same time, we introduce two auxiliary variables called x^{ds} and y^{wc}. These two auxiliary variables represent the amount of reserve regulation and the amount of wind power curtailment respectively. By applying the equivalent equation (z) for the reserve's regulation, we obtain:

$$x_i^{ds} = \delta_i R_i^{ds} \text{ is equivalent to } \begin{cases} x_i^{ds} \le M_i \delta_i \\ x_i^{ds} \ge m_i \delta_i \\ x_i^{ds} \le R_i^{ds} - m(1-\delta_i) \\ x_i^{ds} \ge R_i^{ds} - M_i(1-\delta_i) \end{cases}$$

where R_i^{ds} denotes the amount of reserve dispatch from every generation unit. The terms M_i and m_i denote the maximum and minimum values of the reserves from the i^{th} generation unit. The binary variable δ_i represents a switch which is used to control the "on-off" behaviour of the reserves of the i^{th} generation unit. The term x_i^{ds} is the auxiliary variable which represents the amount of reserve regulation from the i^{th} generation unit. By applying the same equivalent equation (z) to the wind power curtailment, the following equations are obtained:

$$y_i^{wc} = \mu_i P_i^{wc} \text{ is equivalent to } \begin{cases} y_i^{wc} \le M_i \mu_i \\ y_i^{wc} \ge m_i \mu_i \\ y_i^{wc} \le P_i^{wc} - m_i(1-\mu_i) \\ y_i^{wc} \ge P_i^{wc} - M_i(1-\mu_i) \end{cases}$$

Where M_i and m_i denote the maximum and the minimum values of wind power curtailment respectively. The term P_i^{wc} denotes the amount of wind power curtailment of every wind power plant i. The term μ_i is the logic variable to control the "on-off" behaviour of the wind power curtailment of every wind power plant i. The term y_i is the auxiliary variable of the wind power curtailment. The power balance equation in this MLD approach would be:

$$\sum_{i=1}^{N_g}(P_{i,t}^{g} - x_{i,t}^{ds}) + \sum_{i=1}^{N_w}(P_{i,t}^{w} - y_{i,t}^{wc}) - \sum_{i=1}^{N_d} P_{i,t}^{d} = 0$$

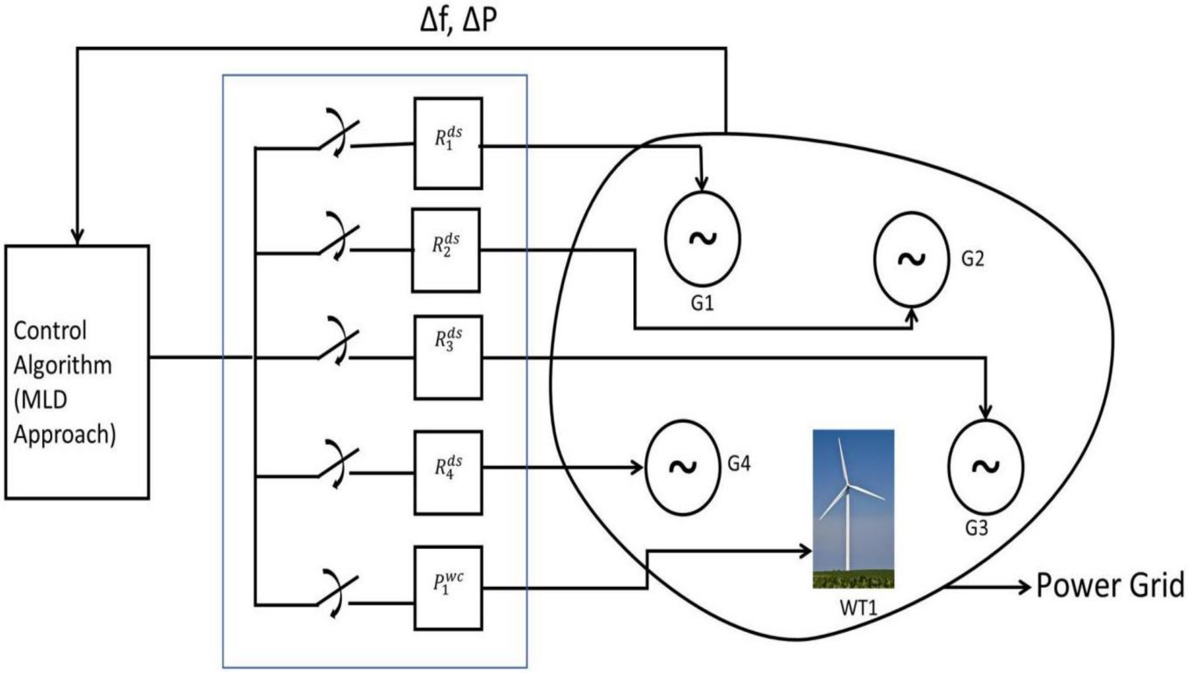

Figure 2: The schematic diagram of the MLD approach. The terms G1, G2, G3, G4 represents the four generation units. The term of WT1 denotes the wind turbines.

The convex combination model is transformed into the MLD model. The next focus is on the optimization problem corresponding to the MLD model.

B. Optimization Scheme: MLD Approach.

The optimization problem in the MLD approach is similar to the convex combination approach, but a few variables were changed in the cost function and a few extra constraints were added to the optimization problem. The optimization variables in the MLD approach are:

$$x_{i,t,s} = [P^{g}_{i,t,s}, \gamma^{g}_{i,t,s}, z^{g}_{i,t,s}, R^{ds}_{i,t,s}, C^{su}_{i,t,s}, \delta_{i,t,s}, \mu_{i,t,s}, y^{wc}_{i,t,s}, x^{ds}_{i,t,s}]$$

The extra optimization variables when compared to the previous optimization problem are $\delta_{i,t,s}, \mu_{i,t,s}, x_{i,t,s}, y_{i,t,s}$. These extra optimization variables appear as a result of modelling reserves and wind power curtailment using the MLD approach. The cost function of the optimization problem is:

$$\min_{x_{i,t,s}} \left(\sum_{t=1}^{N_t}\sum_{i=1}^{N_g} f_c(P^{g}_{i,t}) + \sum_{s=1}^{N_s} p_s \left(\sum_{t=1}^{N_t}\sum_{i=1}^{N_g} (f_{cc}(x^{ds}_{i,t,s}))\right) + \sum_{s=1}^{N_s} p_s \left(\sum_{t=1}^{N_t}\sum_{i=1}^{N_w} (f_{wc}(y^{wc}_{i,t,s}))\right)\right)$$

The functions and the terms used in the optimization are explained in the convex combination approach. The terms $x^{ds}_{i,t,s}$ and $y^{wc}_{i,t,s}$ represent the auxiliary variables of the reserves and the wind power curtailment respectively. In this optimization scheme of the MLD approach, we have a few modified constraints and few extra constraints because of the MLD model.

C. Modified and Extra Constraints of the MLD Approach.

1) The power balance equation in this MLD approach would be:

$$\sum_{i=1}^{N_g}(P_{i,t,s}^{g}-x_{i,t,s}^{ds})+\sum_{i=1}^{N_w}(P_{i,t}^{w}-y_{i,t,s}^{wc})-\sum_{i=1}^{N_d}P_{i,t}^{d}=0$$

2) The constraint on the amount of down-spinning and wind power curtailment.

$$\sum_{i=0}^{N_g}x_{i,t,s}^{ds}+\sum_{i=1}^{N_w}y_{i,t,s}^{wc}=\Delta P_{i,t,s}^{w}$$

The sum of the auxiliary variables should be equal to the amount of the uncertain wind power in the grid.

III. RESULTS and DISCUSSIONS

The theoretical frameworks were applied to a static demand case as an initial step. Later, the dynamic demand case was also simulated. The day ahead wind power forecast throughout the optimization horizon is shown in Figure 3.

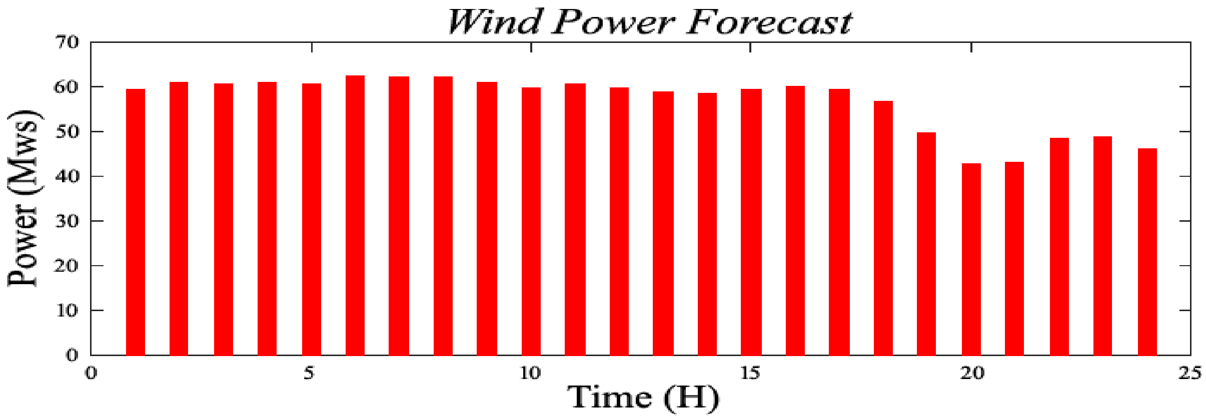

Figure 3: The day ahead wind power forecast at an interval of one hour and length of each bar represents the amount of the wind power at every time step.

In order to approximate the uncertainty, various scenarios of the uncertainty are generated using the Monte Carlo simulations.The various scenarios of the actual wind power in the grid are generated using the Monte Carlo simulations. All the scenarios at every time step is shown in figure 4.

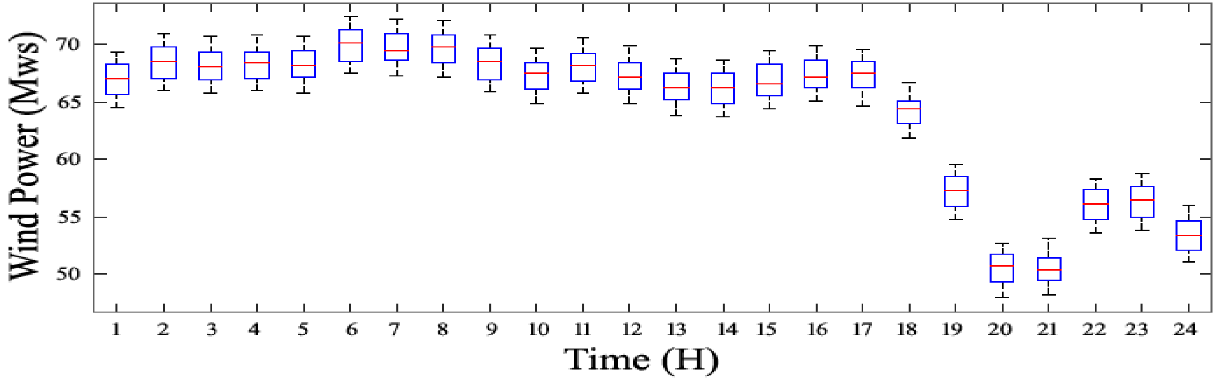

Figure 4: Various scenarios of the actual wind power penetration into the grid. The box at every time step represents various possible realizations of the wind power. The red line indicates the median value. The edges of the box at every time step correspond to the 25th and the 75th percentile values of the wind power scenarios.

An IEEE-30 bus network was used to implement the proposed optimization strategies along with the reserve scheduling. The one-line diagram of the IEEE-30 bus network is shown in Figure 5.

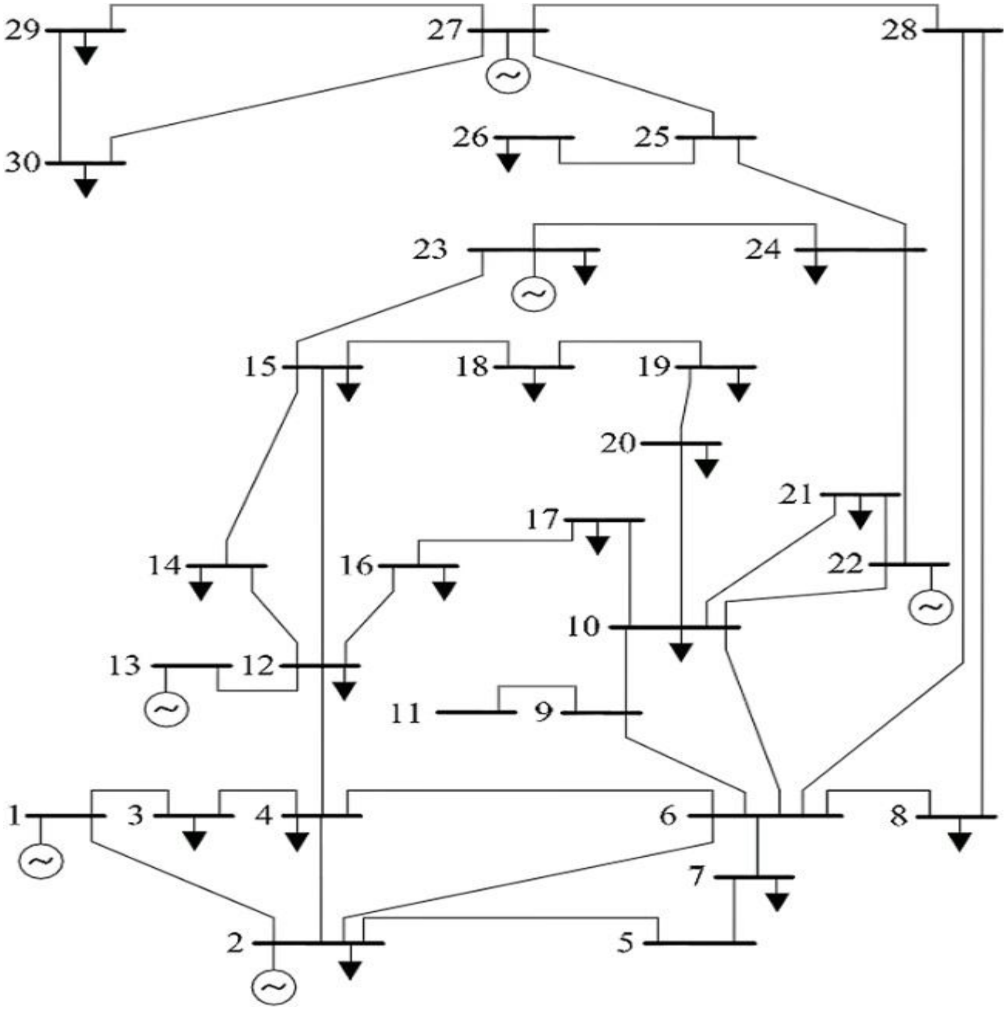

Figure 5: The one-line diagram of IEEE-30 bus network.

There are six generation units and twenty load profiles in the network. The wind power plant was modelled as a single in-feed at bus number six, as the wind power has a single output. The location of the generation units in the grid and the maximum and the minimum generation limits of the generation units are given in Table 1.

Generation Unit (N_g)	Bus Number	Maximum Generation (Mws)	Minimum Generation (Mws)
1	1	80	0
2	2	80	0
3	22	50	0
4	27	55	0
5	23	30	0
6	13	40	0

Table 1: The maximum and minimum generation levels and the bus number of the generation units .

The generation costs per megawatt of every generation unit are given in Table 2.

Generator	Linear Costs (Euros)	Quadratic Costs (Euros)	Reserve Costs (Euros)
1	300	200.00	414.00
2	300	175.00	396.00
22	300	625.00	551.30
27	300	83.40	311.300
23	300	250.00	337.50
13	300	250.00	360.00

Table 2: The linear costs, quadratic costs and the reserve costs of every generation unit per megawatt.

A. *Number of Scenarios*

The scenarios of the actual wind power were generated using the Monte Carlo simulations. Now the question is, "How many scenarios should be generated to represent the uncertainty?" The lower bound of scenarios depends on the number of decision variables (Nd), the allowed level of constraints violations (ϵ) and the confidence parameter (β). The mathematical representation of the number of scenarios is:

$$N_s = \frac{2}{\text{ò}}\left(N_d N_t + \ln\left(\frac{1}{\beta}\right)\right)$$

where Ns denotes the number of scenarios and N_t denotes the time horizon of the optimization. The allowed violation levels and the confidence parameter were 5% and (10^{-5}) respectively to ensure minimum constraint violation. The number of scenarios for all three optimization methods differ as the number of decision variables are different for each optimization method.

Number	Optimization Algorithm	$N_d \times N_t$	N_s
1	Reserve Scheduling Approach	30 × 24	29, 260
2	Convex Combination Approach	31 × 24	30, 221
3	MLD Approach	45 × 24	43, 661

Table 3: The number of scenarios to be generated for different optimization methods.

Table 3 provides information on the number of scenarios to be generated for every optimization method. However, there are some problems associated with these high number of scenarios. They are impractical or not realistic and might result in an intractable solution. To avoid these two problems, only 100 scenarios at every time step and 2400 scenarios throughout the optimization horizon were considered. The uncertainty is assumed to be bounded between 0 and 10, this can be mathematically represented as:

$$\Delta P_t^w \in [0,10]$$

Where P_t^w denotes the wind power forecast error. The MATLAB optimization interface called YALMIP was used in the optimization. The solver named Gurobi was used to solve the mixed integer programming problem. The simulations were executed on an i-0 processor with 8GB RAM. The results of the computation time of all the three optimization problems might be biased because of the optimization interface YALMIP.

IV. CASE STUDY A: STATIC DEMAND

The net demand of the system remains constant throughout the optimization horizon in astatic demand case as shown in Figure 6.The length of each bar denotes the magnitude of net demand power of the network at every time step.

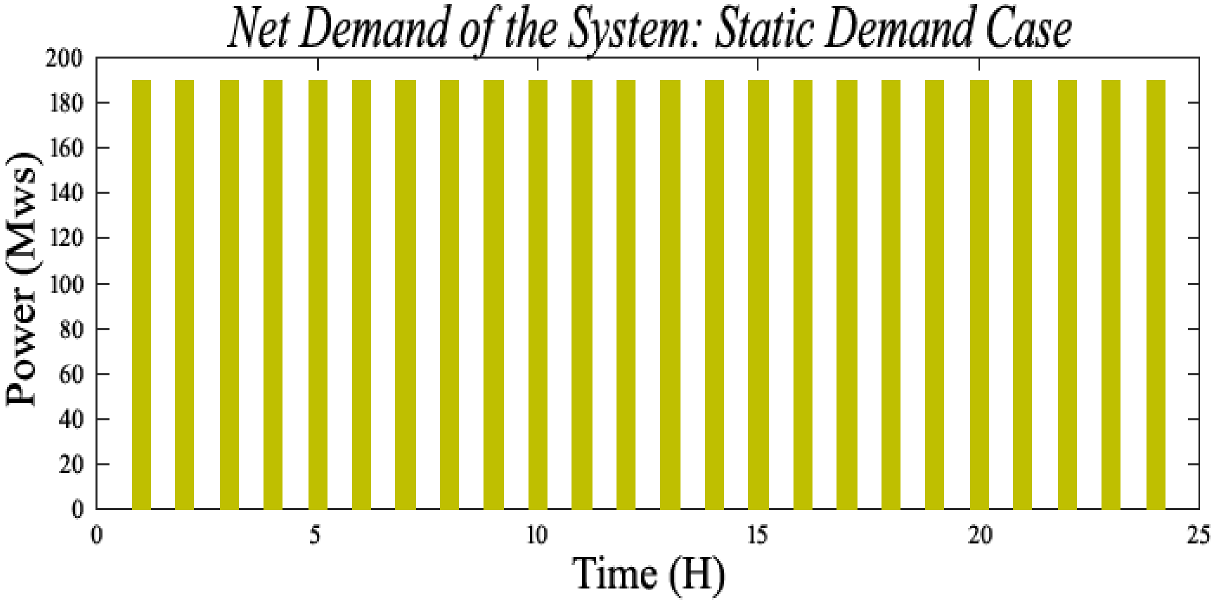

Figure 6: The net demand of the system throughout the optimization horizon for the static demand case.

A. *The Total System Costs*

The total system costs include the generation, the effective start-up, the reserves and the wind power curtailment costs of the system. It can be observed from the Table 4 that the MLD and the convex combination approaches have outperformed the reserve scheduling approach by 1.104%.

Methods	Total costs (Euros)
Reserve Scheduling Approach	2.20183×10^9
Convex Combination Approach	2.17901×10^9
MLD Approach	2.17901×10^9

Table 4: The total costs of the system for all the three different optimization algorithms.

However, the total system costs are the same for the MLD and the convex combination approaches. To analyses this effect, the averaged total system costs for different optimization techniques at every time steps were monitored carefully from figure 7.

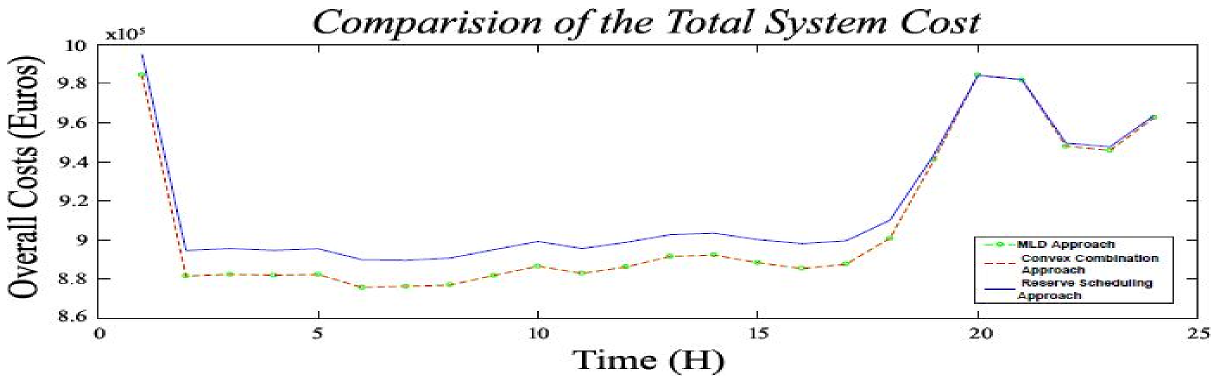

Figure 7: Comparison of the average total system costs of all three optimization methods.

The total system costs are very high at the initial time step in all three optimization methods because of the effective start-up costs of the system. Initially, all the generation units were in the off status. Once the optimization starts, all the generation units change their status from off to on in order to satisfy the demand power.

B. Generator Dispatch

The active power dispatch of the reserve scheduling, the convex combination and the MLD approaches are represented in Figures 8.

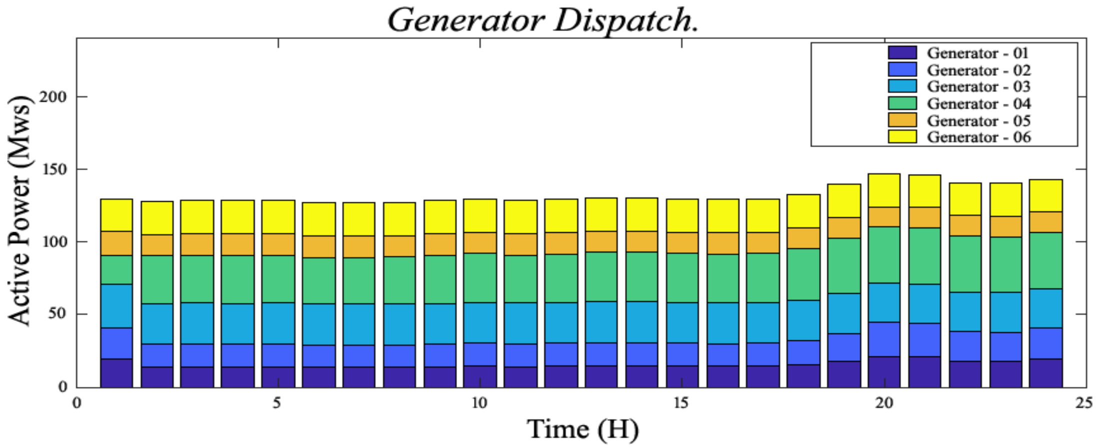

Figure 8: The active power dispatch from the different generation units in the reserve scheduling, the convex combination and the MLD approaches.

The different colors indicate the power from the different generation units respectively. The corresponding color from each of generation units can be observed from the graph. An important observation is that all the three optimization techniques have a similar generator dispatch. The generation levels are relatively high from time step 19 to time step 24 due to the drop in the wind power at these time steps. The generator-04 accounts for the variance in the wind power, because the generation costs of the generator-04 are lower when compared to the other generation units. Another observation is at every time step of the optimization horizon, all the generators are contributing for the demand power.

C. Reserves Dispatch and Wind Power Curtailment

A combination of reserves and wind power curtailment is used to deal with the uncertainty of the wind power generation. In the case of reserve scheduling approach, only the reserves are regulated, while the other two proposed approaches have wind power curtailment along with the reserve regulation.

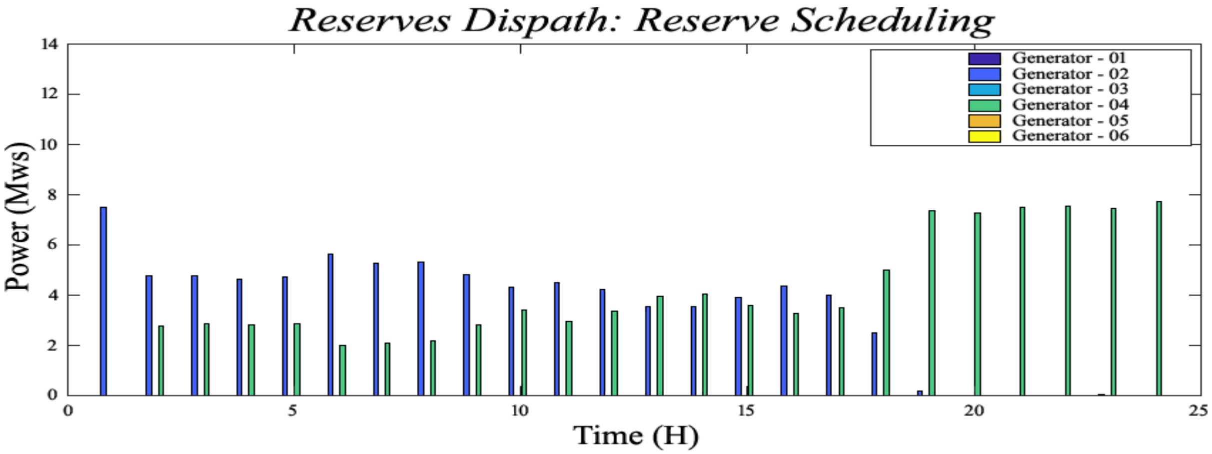

Figure 9: The reserves dispatch from the different generation units in the reserve scheduling approach. The height of each bar denotes the amount of the reserves dispatch from every generation unit. If there is no colour bar corresponding to the generator that means, there are no reserves from that generation

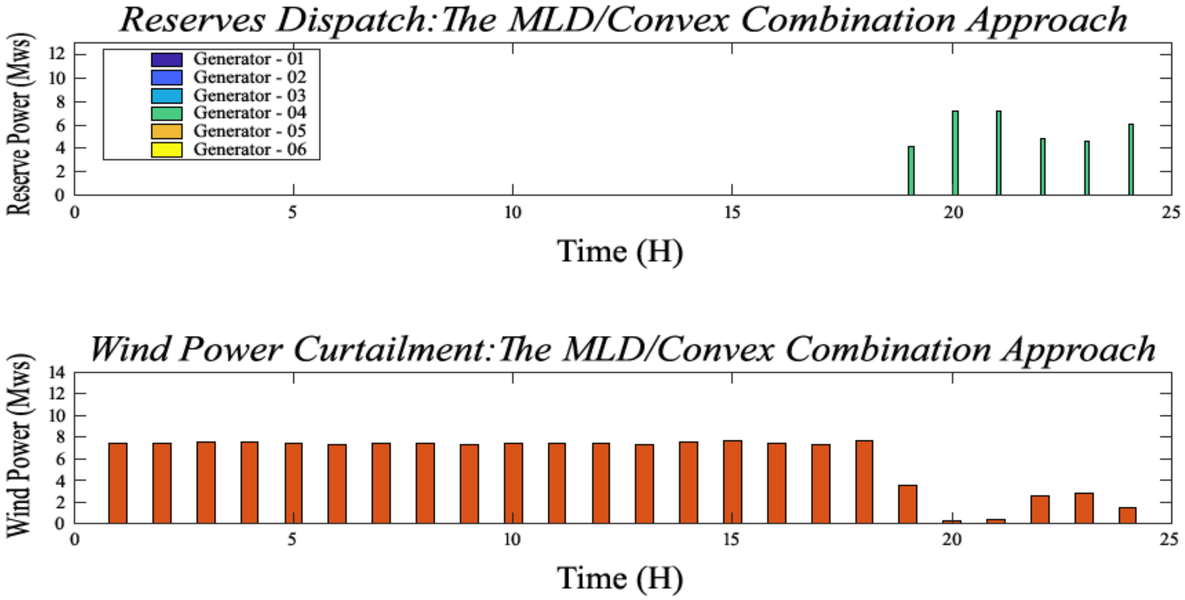

Figure 10: The reserves dispatch and the wind power curtailment of the MLD/ Convex Combination approach. The second graph corresponds to the wind power curtailment and the height of each bar denotes the amount of wind power curtailed at every time step.

A combination of the reserves dispatches and the wind power curtailed of the convex combination approach is shown in Figure 4.12. Only the wind power is curtailed and there are no reserves dispatched from the generation units from time-step 01 to time step 19. The reason is analogous to the reserve scheduling case, the wind power is very high when compared to the generators dispatch in these time-steps. At the same time, from time step 19, the generation levels of the generator-04 are high and the wind power generation drops down. To conclude, the switching behavior of the reserves and the wind power curtailment depends upon three important factors, they are:

1) The spatial relations.
2) The costs of the reserves and the wind power curtailment.
3) The generation levels and the wind power penetration into the grid.

The generation levels and the wind power levels play a key role in the optimal switching of the generation units to dispatch reserves and the wind power units to curtail the wind power. Due to the above-mentioned reasons, the total system costs of the convex combination approach and the MLD approach are the same.

D. Computation Time

An overview of the computation time of all three optimization methods is provided by Table 5. It can be observed that the computation time of the MLD approach is significantly higher than the other two approaches. This is due to an increase in several the optimization variables in the MLD approach. Another observation is that the computation time of the reserve scheduling and the convex combination method are almost the same. This is because of the similar number of the decision or the optimization variables in both approaches.

Methods	Computation time (secs)
Reserve Scheduling Approach	5.70
Convex Combination Approach	5.77
MLD Approach	6.21

Table 5: The table provides comparison of the computation time of all the three optimization Methods.

V. CASE STUDY B: DYNAMIC DEMAND

The net demand profile of the grid varies with respect to time throughout the optimization horizon in the dynamic demand case as shown in Figure 11. The length of each bar denotes the magnitude of the net demand power of the network. It is assumed that the demand profile is known in advance and all the PQ buses (Load Buses) are multiplied with this demand profile to get a net time-varying demand of the network.

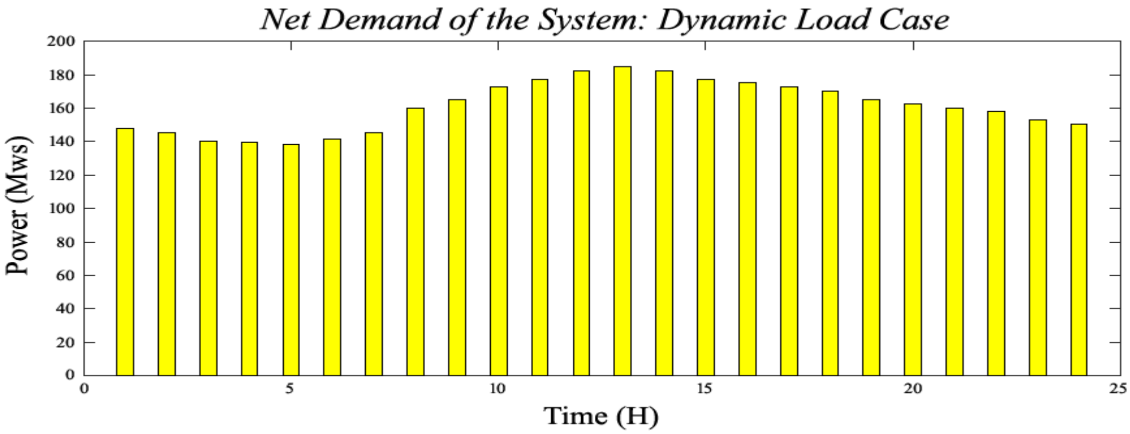

Figure 11: The net demand of the system throughout the optimization horizon for the dynamic demand case.

A. *The Total System Costs*

The total system costs of the convex combination and the MLD approaches are compared with the reserve scheduling approach to analyse the performance of the proposed theoretical developments in the dynamic demand case.

Methods	Total costs (Euros)
Reserve Scheduling Approach	1.13120×10^9
Convex Combination Approach	1.12354×10^9
MLD Approach	1.12354×10^9

Table 6: The total costs of the system for all the three different optimization algorithms.

There is an improvement of 0.64% in the MLD and the convex combination approaches when compared to the reserve scheduling approach. The total system costs of the MLD and the convex combination approaches are same. An overview of the average total systems costs throughout the optimization horizon is shown in Figure 12

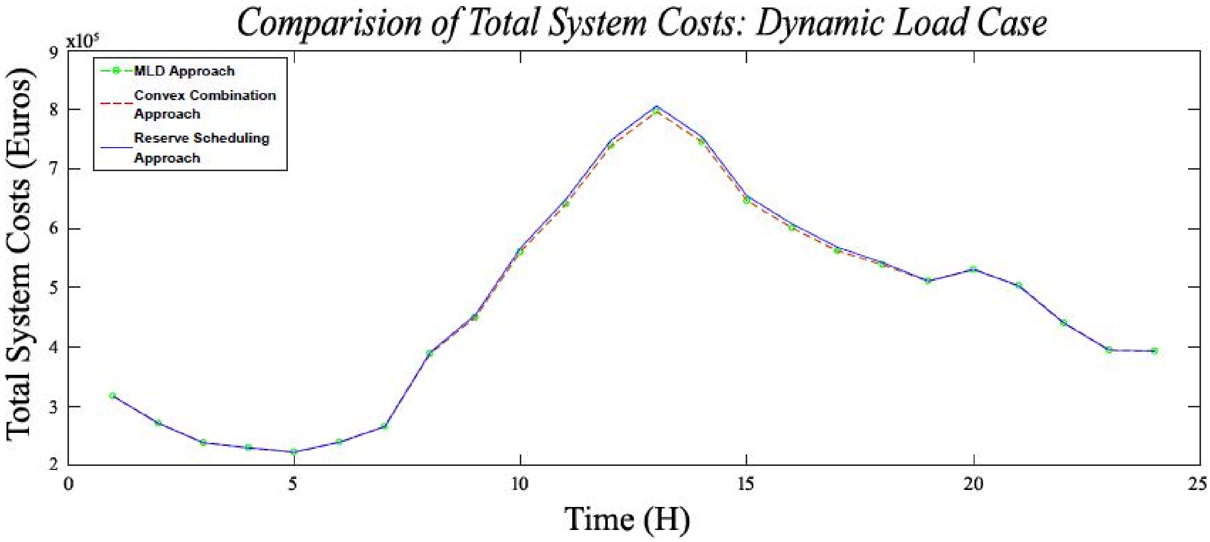

Figure 12: Comparison of the average total system costs of all three optimization methods of the dynamic demand case.

The relative costs of the MLD and the Convex combination approaches with respect to the reserve scheduling approach are shown in figure 13.

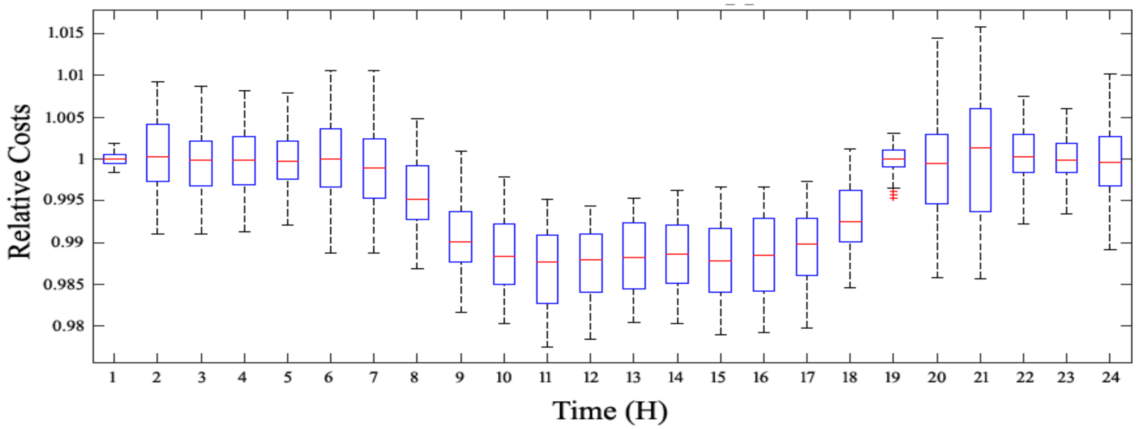

Figure 13: The relative costs of the convex combination approach and MLD approach with respect to the reserve scheduling approach for the dynamic demand case. The red line indicates the median value. The edges of the box at every time step corresponds to the 25th and the 75th percentile values of the total system costs. The red lines denote the outliers of the data.

B. *Generator Dispatch*

The active power dispatch from all the three optimization methods were similar as shown in figure 14.

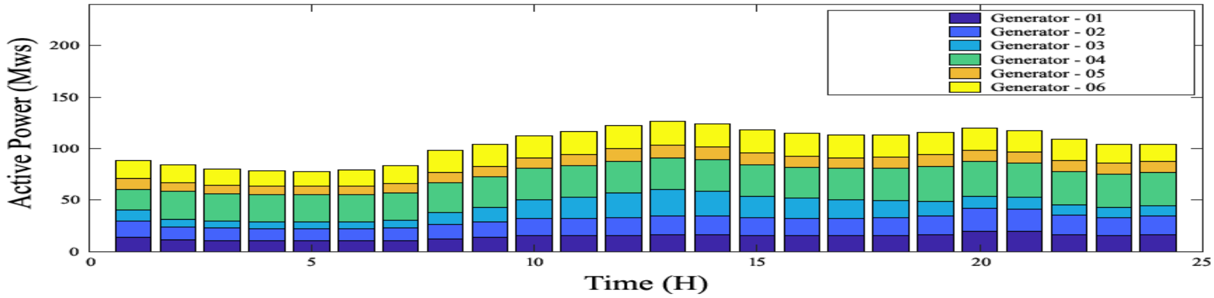

Figure 14: The active power dispatch from the different generation units in the convex combination, MLD and reverse scheduling approach.

C. *Reserves Dispatch and Wind Power Curtailment*

The reserves dispatch of reserve scheduling approach is shown in Figure 15. It can be observed that the three generation units are contributing to the reserves dispatch at different time steps in an asymmetric manner. Especially, three generation units, generator-02, generator-05 and generator-04 contribute for the reserves during the start and end of the peak demand hours.

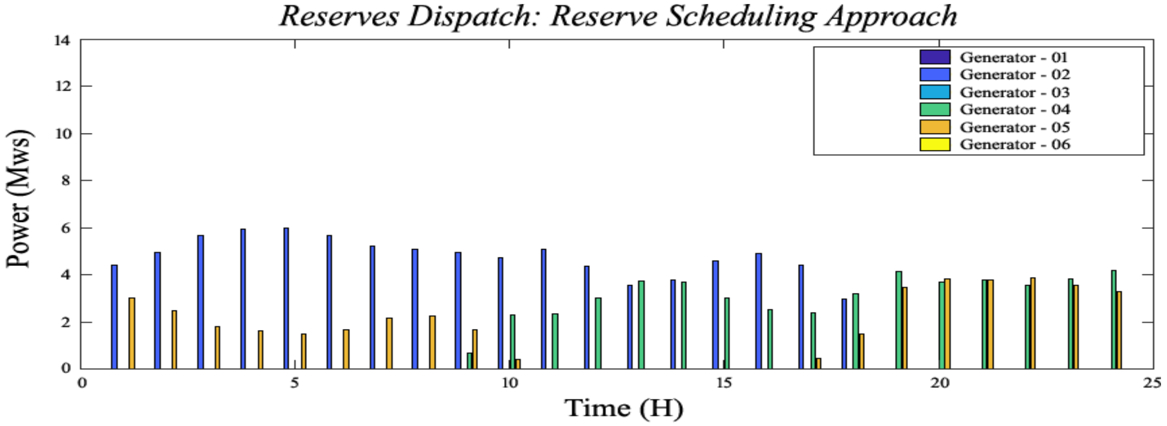

Figure 15: The reserves dispatch from the different generation units of the reserve scheduling for the dynamic demand. The height of each bar denotes the amount of the reserves dispatch from every generation unit. If there is nor bar corresponding to the colour, it means the generator is not contributing for the reserves.

The main causes for the wind power curtailment and the asymmetrical reserves dispatch are spatial relations, generator dispatch, and the wind power penetration into the grid.

The wind power curtailment and the reserve scheduling of the convex combination approach and the MLD approach can be seen from Figures 16. From this Figures, it can be observed that the wind power curtailment and the reserves generated are same for both the convex combination and the MLD approaches. As mentioned in the static demand case, switching depends upon the generation levels, the costs of the reserves and in addition the spatial relations. So, no need of an extra switch like the MLD approach, the convex combination approach performs similarly to the MLD approach with less computation time.

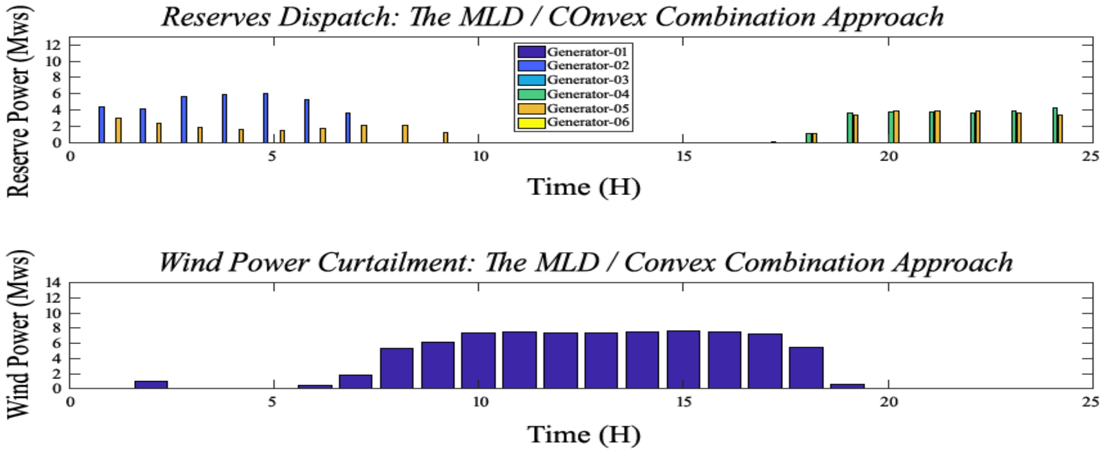

Figure 16: The reserves dispatch and the wind power curtailment of the convex combination approach for the dynamic demand case. The height of each bar denotes the amount of the reserves dispatch from every generation unit. If there is nor colour bar corresponding to the generation unit, then it means there are no reserves from that generation unit. The second graph corresponds to the wind power curtailment. The height of each bar denotes the amount of wind power curtailed at every time step.

D. Computaton Time

Table 7 provides an overview of the computation time of all three optimization methods. It can be observed that the computation time of the MLD approach is significantly higher than the other two approaches. This is due to an increase in the number of the optimization variables in the MLD approach which can be observed from Table 4.3. The computation time is higher when compared to the static load case due to time-varying nature of the demand power.

Methods	**Computation time (secs)**
Reserve Scheduling Approach	6.70
Convex Combination Approach	6.74
MLD Approach	7.21

Table 7: The table provides comparison of the computation time of all the three optimizations methods.

VI. PROPOSED SOLUTION.

There are multiple solutions to prevent this grid potential problem.

A. The first solution is the physical extension of the grid; however, this requires widespread capital investments. Moreover, the frequency of the worst-case scenarios (maximum technology coinciding with minimum load) is very low and grid expansion is much slower process, so this solution is now not optimal.
B. The second solution is to save the excessive power using batteries. The batteries can't store power efficiently because of the storage losses and they also degrade with time. The initial setup of the batteries and their replacement/alternative (in the case of degradation) would require big capital investments.
C. The third solution is reserve regulation of the generation units to deal with the uncertainty of wind power.
D. The final solution is to reduce the curtail percentage of wind power feed to the grid.

VII.FINDINGS

The proposed optimization strategies were applied to two case studies, these are:

A. The first is the static demand case and.
B. The second one is the dynamic demand case.

In both case studies, the MLD and the convex combination approaches have outperformed the reserve scheduling approach in terms of the total system costs. The total system costs of the MLD approach and the convex combination approach were same. However, the reserves dispatch, and the wind power curtailment were same for the MLD approach and the convex combination approach. This is the reason why both the approaches have the same total system costs.

The convex combination approach has an inherent switching behaviour. The switching of the reserves depends upon the generator dispatch, wind power penetration into the grid and the spatial relations between the demand units, the generators and the wind power plants. So, an extra switch like the MLD approach is not required for the operational conditions considered in this research. The MLD approach just increases the computation time of the system and won't improve the performance of the system when compared to convex combination approach. So, the convex combination approach would be preferable over the MLD approach.

VIII. CONCLUSION

Two methods were proposed to unify the reserve scheduling and the wind power curtailment to tackle with the problem of uncertain wind power generation in the smart grids. The DC power flow framework was used to formulate the optimization problem. An approach presented in [3] has been modified to unify the reserve scheduling and the wind power curtailment. Later, two different CCPs (chance constrained programs) were proposed to create an optimal trade-off between the reserve's regulation and the wind power curtailment in the smart grids.

The proposed theoretical developments have been implemented on an IEEE-30 bus network. They were compared with the reserve scheduling approach to demonstrate the performance of the proposed algorithms. The proposed methodologies were implemented on two case studies, as follows:

A. The first case was the static demand case where the net demand of the system was constant throughout the optimization horizon. The proposed methods had outperformed the reserve scheduling approach. However, the computation time was higher in both the approaches as they have a greater number of decision variables when compared to the reserve scheduling.
B. The second case was the dynamic demand case where the net demand of the system was varying with respect to the time. In the dynamic demand case also the reserve scheduling was outperformed by the proposed methods.

However, the performance of convex combination and MLD approaches was the same in both the case studies. To analyse this, the generator dispatch, reserves dispatch, and the wind power curtailed were observed in both the approaches. They were also the same. The switching of reserve's and wind power curtailment depend on various parameters such as the costs of reserve's and wind power curtailment, the spatial relations, the generator dispatch and the wind power generated in the grid. So, an extra switch as proposed in the MLD approach is not necessary to minimize the total system costs for the operational conditions considered in this PAPER.

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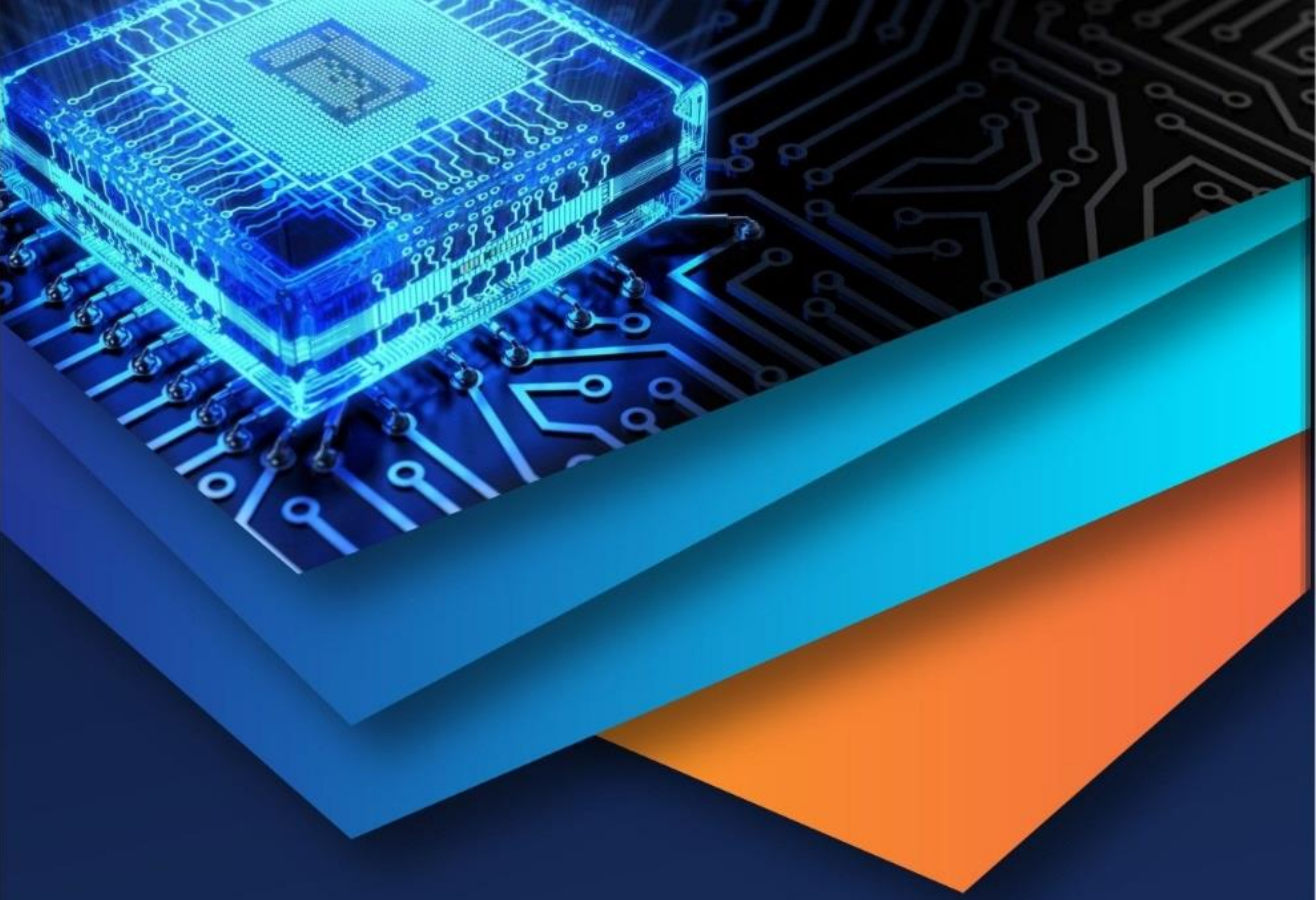

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