Electrical Power and Energy Systems 135 (2022) 107546

Contents lists available at ScienceDirect

International Journal of Electrical Power and Energy Systems

journal homepage: www.elsevier.com/locate/ijepes

A new flexibility based probabilistic economic load dispatch solution incorporating wind power

Homayoun Berahmandpour *, Shahram Montaser Kouhsari, Hassan Rastegar

Electrical Engineering Department of Amirkabir University, 424 Hafez Str., Tehran, Iran

ARTICLE INFO

Keywords:
Dynamic Economic Load Dispatch
Probabilistic load dispatch
Generation system flexibility
Flexibility index
Economic trade-off

ABSTRACT

Nowadays, by the growing in renewable energies in the power system, the uncertainty of power output related to these resources increases. This needs to improve power system flexibility to reduce the risk of load shedding or renewable curtailment due to the mentioned challenge. So, nowadays power system flexibility is an important characteristic especially in power system operation which should be evaluated continuously and maintained in the desired value. In operation horizon time such as operational planning or real time operation the system generation flexibility should be monitored, and sufficient system flexibility should be provided to avoid unacceptable generation/load unbalance cause unwanted renewable curtailment or load shedding.

This paper presents a new flexibility based risk limiting dynamic economic load dispatch solution incorporating wind power. In the proposed method the generation system flexibility index, introduced by the authors is converted to economic value and included in the total operation cost function. Then by the suitable economic trade-off between system flexibility level and risk of load shedding and wind power curtailment, the best reduction in these two unwanted risks are obtained. Increasing the system generation flexibility comes from the generation rearrangement of thermal generation units imposes more cost to the generation cost but is balanced by reduction in unwanted renewable curtailment or load shedding.

1. Introduction

The increasing penetration of renewable energy systems (RES) causes to operate the system at low cost and low pollution. On the other hand, the noticeable uncertainties caused by the forecast errors of renewable generation and also the variable nature as well as load demand can restrict the utilization of renewable energy by RES/load curtailment and moreover bring the main challenges to maintain system reliability. Currently, many studies have been proposed to solve the Dynamic Economic Load Dispatch (DELD) in the presence of the wind farms to overcome the uncertainty nature of the wind power output. Risk limiting economic dispatch is another concept to solve this problem. Also, some other studies are focused on generation system flexibility improvement using flexible ramping products to overcome the wind power uncertainty. In all the above approaches a probabilistic cost function is used to optimize the total system operation cost by reduction of the risk of load shedding and wind curtailment.

In [1] a probabilistic framework for economic dispatch is proposed based on Weibull Probability Density Function (PDF) which is near to the current paper approach as shown in Fig. 1. Where the probabilistic functions due to the wind power uncertainty are as wind curtailment, load shedding, upward reserve and downward reserve included in the system generation cost function.

Another approach on the risk-limiting economic dispatch is proposed in [2] based on Model Predictive Control (MPC). An illustration of the control zones for this control scheme is shown in Fig. 2. Where g and r stand for generator power output and ramp rate respectively.

Each of the triangles shows the permitted region of the generation output power in the specific time interval. This is very similar to the Flexibility Area Index (FIA) approach used in the current paper illustrated later. Also, A risk-based admissibility assessment approach is proposed in [3] to quantitatively evaluate how much wind generation can be accommodated to the power system. Fig. 3 shows the concept of this paper. Where two different regions as admissible and inadmissible are defined for the wind power generation. Again this approach is used in the current paper where the inadmissible region for the wind power is equivalent to the wind curtailment and the load shedding (upper/lower sections).

Again a multi-objective dynamic economic dispatch model with renewable obligation requirements is proposed in [4]. Where the two objective functions are presented aim to increase the level of renewable

* Corresponding author.
E-mail address: hberahmandpour@aut.ac.ir (H. Berahmandpour).

https://doi.org/10.1016/j.ijepes.2021.107546
Received 21 May 2021; Received in revised form 28 July 2021; Accepted 24 August 2021
Available online 10 September 2021
0142-0615/

Nomenclature

Indices

i	counter
t	time
N_g	number of thermal units
N_w	number of wind units

Parameters

A_1	area corresponds to $P_w = P_n$
A_2	area corresponds to $P_w = 0$
a, b, c	thermal unit operation cost coefficients
B, B0, B00	power loss coefficients
c	scale factor of Weibull function
C	thermal unit generation cost function
Cost	total cost function
C_w	wind power cost function
CD	downward reserve cost function
CU	upward reserve cost function
Ccur	wind curtailment cost function
Csched	load shedding cost function
d	wind power operation cost
k	shape factor of Weibull function
KD	downward reserve cost coefficient
KU	downward reserve cost coefficient
P^{max}	maximum unit generation
P^{min}	minimum unit generation
P_n	wind farm nominal power
PD	load demand
Rampup	unit ramp up rate constraint
Rampdn	unit ramp down rate constraint
S	area corresponds to flexibility
S_1	upper side of flexibility area
S_2	lower side of flexibility area
$v_{cut\text{-}in}$	starting wind speed
$v_{cut\text{-}out}$	shut down wind speed
v_{rated}	nominal wind speed
W_w	available wind power
Δt	time step

Variables

P	generation unit scheduled
P_{loss}	system loss
P_w	wind power allocated (or dispatched)
v	wind speed
V_w	optimal wind power

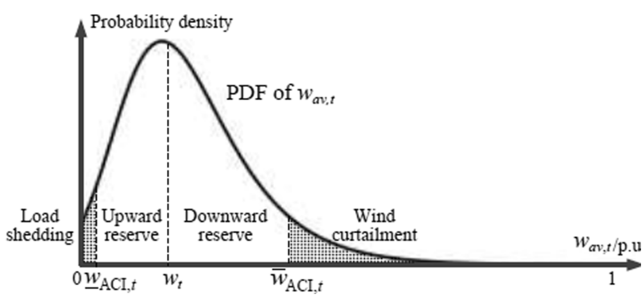

Fig.1. Probabilistic ED framework based on Weibull PDF [1].

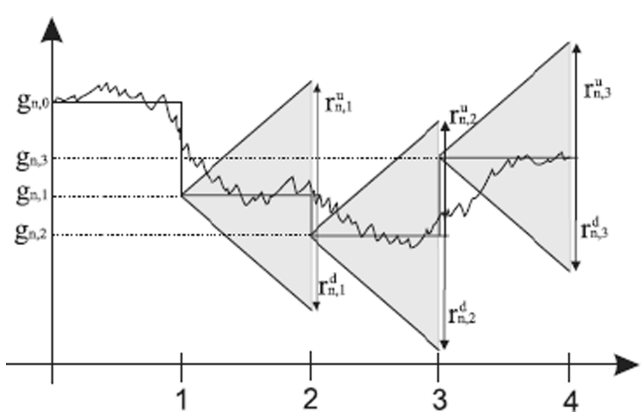

Fig. 2. Sequential control zones in MPC approach [2].

energy sources in the grid while minimizing the total operating cost and respecting the spinning reserves required to maintain continuity of supply. A novel real-time Generation Schedule (GS) integrated with RES' power curtailment is proposed in [5]. The proposed real-time GS become to effectively compute the outputs of the associated generating units so as to meet the required electricity load. The proposed approach is applied for real-time dynamic economic load dispatch for a real time

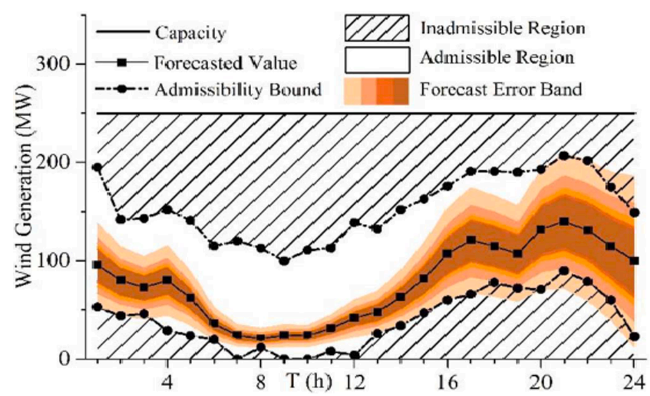

Fig.3. Schematic diagram of the admissibility assessment risk based approach.

GS that completely treats the limited controllable energy resources under the uncertainties. The approach presented in [6] focuses on planning the day-ahead schedule based on optimal trade-off between regulation of generators and wind curtailment. Where both the generator regulation and wind curtailment form the objective function and the wind curtailment is modeled by penalty. This approach is also similar to the current paper concept for economic trade-off between the generation cost and the wind curtailment/load shedding costs.

Now as this paper focuses on generation system flexibility, some related articles based on power system flexibility are reviewed. A conceptual view as the hybrid robust stochastic approach is presented in [7] which is based on the flexibility envelopes concept. It circumvents the curse of dimensionality by using probability weighted envelopes to enclose the evolution of the net load uncertainty over the planning horizon. The flexibility envelope concept is shown in Fig. 4. Here l stands for the net load.

As can be seen the red envelope shows the required (or accessible) system generation can overcome uncertainty or variability in RES' power. If the blue net load curve crosses this envelope, RES or load curtailment can occur.

The reserved ramp-up and ramp down capacities at T as Flexible

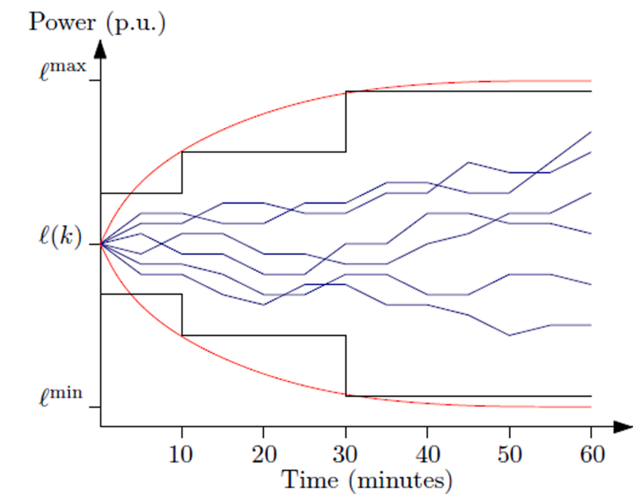

Fig. 4. Categorical reserve types (black), flexibility requirement envelope (red), sample net load realization (blue).

Ramp Up (FRU) and Flexible Ramp Down (FRD) are also two main indices used to evaluate the generation system flexibility. These two indices show the Upward and Downward flexibility specification of the generation system. Fig. 5 shows FRU and FRD indices [8]. Again this approach is very similar to the proposed index (FAI).

Now by reviewing about risk-based DELD approaches and also evaluation of the generation system flexibility, the main approach and the contribution of the current paper is described.

2. Paper contribution

This paper presents a flexibility based DELD framework in the presence of wind farms to reduce the risk of load shedding and wind curtailment due to the wind power uncertainty. Here by introducing a suitable generation system flexibility index, a probabilistic DELD framework is introduced including the economic value of the system flexibility. This framework uses of three concepts which were previously introduced by the authors as Flexibility Area Index (FIA) for system generation flexibility [9], a new method for wind power curve linearization based on Least Square Error (LSE) line fitting [10] and an analytical optimization routine to solve the probabilistic DELD in the presence of wind power [11]. So, the main contribution of the current paper is to develop the probabilistic DELD objective function including the economic flexibility value which leads to a good trade-off between the flexibility improvement and the wind curtailment/load shedding costs reduction. The simulation shows by increasing the economic value of the flexibility index, total system cost reduces mainly due to the rescheduling of the thermal generation units without considerably reduction in the wind power.

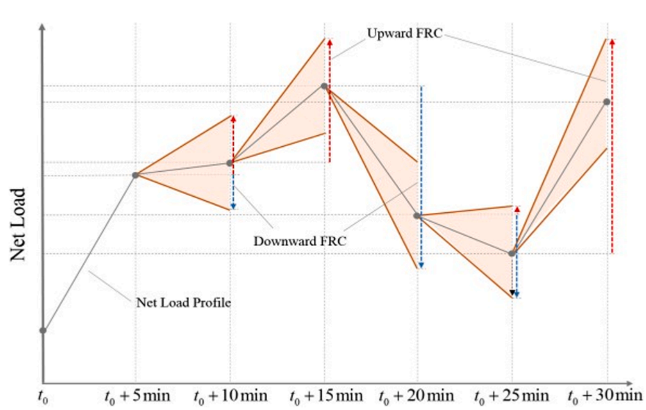

Fig. 5. Flexibility Ramp Capability (FRC), Up (FRU) and Down (FRD).

The next parts of this paper are arranged as below. The main description of the proposed framework for probabilistic DELD is presented in Section 3. The mathematical model for probabilistic DELD incorporating wind power is illustrated in Section 4. The main contribution of the current paper is presented in Section 5 as flexibility based economic dispatch which is included in the main DELD model. The simulations and analysis are presented in Sections 6 and 7 includes conclusion.

3. Main description

Here the two main prerequisites to the current paper is illustrated briefly. At first the linear model for wind power curve with respect to wind speed based on the Least Square Error (LSE) line fitting is described which is proposed in [10] by details.

Fig. 6 shows the proposed linear model against the conventional linear model. It should be noted in the conventional linear model the point (v_{cutin}, 0) is connected to the point (v_{rated}, P_n) by a straight line. The blue curve shows the real nonlinear model and two linearization approaches as the conventional (red) and proposed (green) linear models. As is illustrated in [10], the proposed LSE line fitting is more accurate with respect to the conventional model. The second prerequisite is the Flexibility Area Index (FAI) for generation system flexibility evaluation which is presented in [9] by details.

Flexibility Area Index comes from the two main specifications of the generation unit as generation capacity and ramp rate ability. Suppose $P_i(t)$ is the unit generation i at time t (Fig. 7). So, at time $t + \Delta t$ we have the triangle shown by $P_i(t)$, $P_{i,rampup}$ and $P_{i,rampdn}$ where $P_{i,rampup}$ and $P_{i,rampdn}$ are the permitted up and down unit generation boundary points at time $(t + \Delta t)$ which are limited by the ramp up and ramp down unit constraints (such as FRU and FRD). It is clear that the points inside this triangle are the permitted operating points for the unit generation i in $[t, t + \Delta t]$ time interval to meet the ramp up/down constraints. Crossing this triangle by horizontal lines as P_i^{min} or P_i^{max} generation unit constrains, reduces the flexibility area and also the flexibility index.

The flexibility indices related to the thermal generation units are combined to make the generation system flexibility index by summation of all the partial flexibility indices for all the generation units (Fig. 8).

This is done by a simple summation for all partial flexibility areas in each dt division as shown in Fig. 8. The two partial flexibility areas as S_1 and S_2 in Figs. 7 and 8 are named as the upper/lower components of the generation unit/generation system flexibility area indices [12]. These

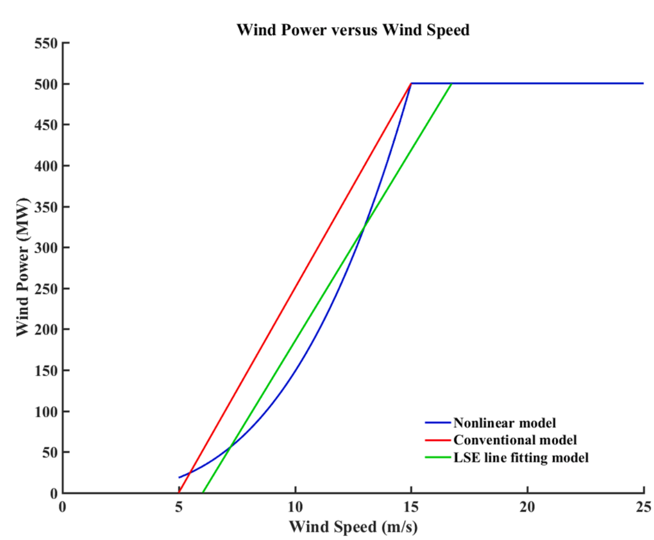

Fig. 6. Nonlinear wind power and two linearized models.

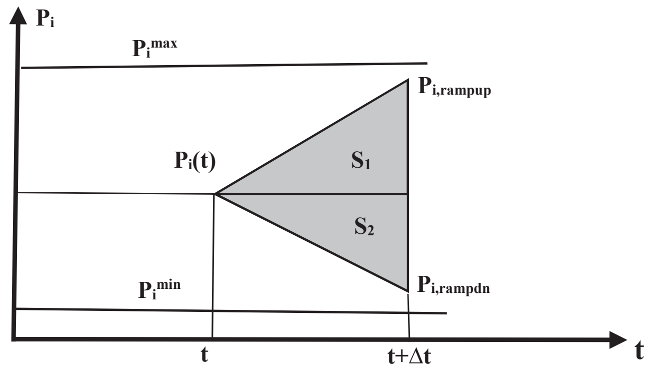

Fig. 7. Concept of Flexibility Area Index (FAI).

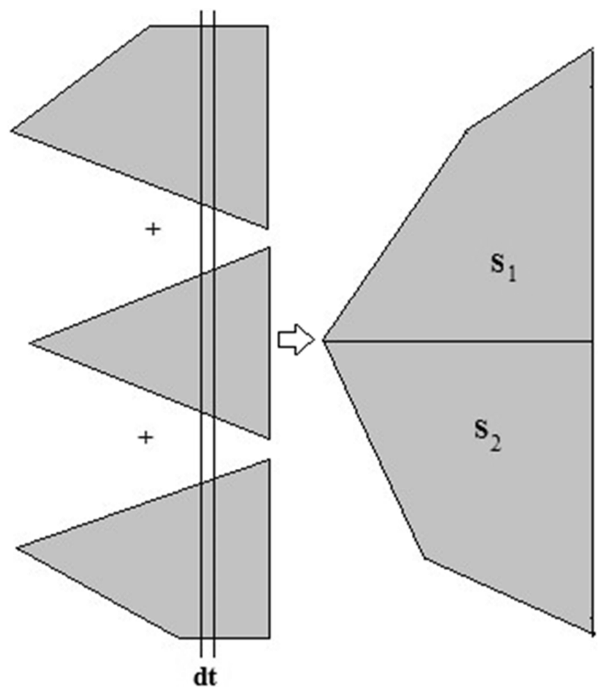

Fig. 8. General case of flexibility area indices combination.

components are related to the system ability against load shedding/wind curtailment respectively described later.

Now the main concept about the probabilistic dynamic economic load dispatch is expressed. This is illustrated by Fig. 9 as the wind speed Weibull PDF.

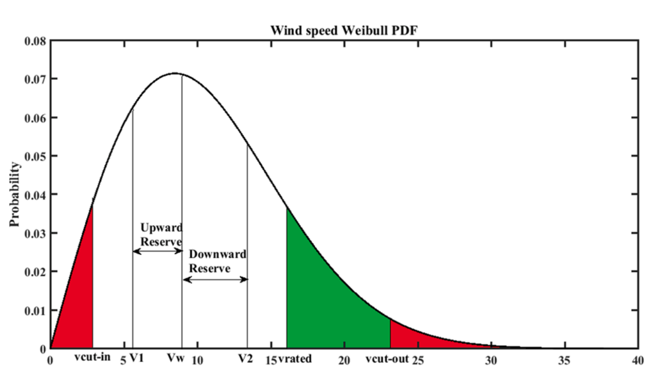

Fig. 9. Probabilistic DELD concept.

Referred to [10], the LSE linear wind power model can be expressed as:

$$\begin{array}{ll} 0 & v < v_{cut-in},\ v > v_{cut-out} \\ P_w = mv + n & v_{cut-in} \leq v \leq v_{rated} \\ P_n & v_{rated} \leq v \leq v_{cut-out} \end{array} \quad (1)$$

where m and n are the line coefficients obtained by LSE line fitting. The red and green areas show zero and constant wind power (P_n) respectively (correspond to the first and the third relations in (1) respectively). Now suppose the dispatched wind power is P_w corresponds to V_w. There is an admissible zone between V_1 and V_2 for V_w comes from the system generation upward and downward reserve capacities respectively [1]. So, load shedding is forced for the wind speed less than V_1 and wind curtailment will occur for the wind speed more than V_2. In the $[V_1,V_w]$ and $[V_w,V_2]$ intervals the upward and downward reserves should be used to compensate wind power uncertainty. This will be discussed later by the details.

4. Dynamic economic load dispatch model

Now the dynamic economic load dispatch objective function is described. This function consists of six parts as is described by (2)

$$\min\ Cost = \min[\sum_{t=1}^{T}\{\sum_{i=1}^{N_g} C_i(P_i(t)) + \sum_{i=1}^{N_w} C_{wi}(P_{wi}(t)) + \sum_{i=1}^{N_w} CD_{wi} + \sum_{i=1}^{N_w} CU_{wi} + \sum_{i=1}^{N_w} Ccur_{wi} + \sum_{i=1}^{N_w} Cshed_{wi}]\} \quad (2)$$

Each of the six terms of this objective function is explained here. The first term is the generation system operation cost as:

$$\sum_{i=1}^{N_g} C_i(P_i(t)) = \sum_{i=1}^{N_g} a_i P_i(t)^2 + b_i P_i(t) + c_i \quad (3)$$

The second term defines the wind power operation cost directly related to the wind power:

$$\sum_{i=1}^{N_w} C_{wi}(P_{wi}(t)) = \sum_{i=1}^{N_w} d_i P_{wi}(t) \quad (4)$$

The next two functions in (2) model the cost functions for downward and upward reserve costs:

$$\begin{aligned} \sum_{i=1}^{N_w} CD_{wi} = \sum_{i=1}^{N_w} K_{Di}[\int_{P_{wi}}^{P_{2i}} (W_{wi}(t) - P_{wi}) f(W_{wi}) d(W_{wi}) \\ + \int_{P_{2i}}^{P_{ni}} (P_{2i} - P_{wi}) f(W_{wi}) d(W_{wi})] \end{aligned} \quad (5)$$

$$\begin{aligned} \sum_{i=1}^{N_w} CU_{wi} = \sum_{i=1}^{N_w} K_{Ui}[\int_{P_{1i}}^{P_{wi}} (P_{wi} - W_{wi}(t)) f(W_{wi}) d(W_{wi}) \\ + \int_{0}^{P_{1i}} (P_{wi} - P_{1i}) f(W_{wi}) d(W_{wi})] \end{aligned} \quad (6)$$

P_1 and P_2 correspond to V_1 and V_2 (Fig. 9). The fifth and the sixth functions in (2) are defined as:

$$\sum_{i=1}^{N_w} Ccur_{wi} = \sum_{i=1}^{N_w} K_{curi}[\int_{P_{2i}}^{P_{ni}} (W_{wi}(t) - P_{2i}) f(W_{wi}) d(W_{wi}) + (P_{ni} - P_{wi}) A_{1i}] \quad (7)$$

$$\sum_{i=1}^{N_w} Cshed_{wi} = \sum_{i=1}^{N_w} K_{shedi}[\int_{0}^{P_{1i}} (P_{1i} - W_{wi}(t)) f(W_{wi}) d(W_{wi}) + P_{wi} A_{2i}] \quad (8)$$

A_1 and A_2 refer to the green and red areas in Fig. 9 respectively. The main constraints of the mentioned objective function are:

$$P_i^{min}(t) \leq P_i(t) \leq P_i^{max}(t) \quad (9)$$

$$0 \leq P_{wi}(t) \leq P_{ni} \quad (10)$$

$$\sum_{i=1}^{N_g} P_i(t) + \sum_{i=1}^{N_w} P_{wi}(t) = PD(t) + P_{loss}(t) \tag{11}$$

Where:

$$P_i^{max}(t) = \min(P_i^{max}, P_i(t) + Rampup_i \Delta t) \tag{12}$$

$$P_i^{min}(t) = \max\left(P_i^{min}, P_i(t) - Rampdn_i \Delta t\right) \tag{13}$$

$$P_{loss}(t) = \sum_{i=1}^{N_g}\sum_{i=1}^{N_g} P_i(t)B_{ij}P_j(t) + \sum_{i=1}^{N_g} B_{0i}P_i(t) + B00 \tag{14}$$

V_1 (t) is the admissible down limit of the wind speed in each time step can be found as:

$$V_1(t) = \frac{(PD(t) + P_{loss}(t) - \sum_{i=1}^{N_g} P_i^{max}(t)) - n}{m} \tag{15}$$

If V_1 (t) is less than $v_{cut\text{-}in}$, it is fixed to $v_{cut\text{-}in}$. So, if the wind speed is less than $V_1(t)$, load shedding is needed. On the other hand, $V_2(t)$ is the admissible up limit of the wind speed in each time step can be calculated as:

$$V_2(t) = \frac{(PD(t) + P_{loss}(t) - \sum_{i=1}^{N_g} P_i^{min}(t)) - n}{m} \tag{16}$$

Clearly if $V_2(t)$ is more than v_{rated}, it is fixed to v_{rated}. So, if the wind speed is more than $V_2(t)$, wind curtailment occurs. As can be seen $V_1(t)$ and V_2 (t) change in each time step (or each DELD solution iteration) cause the different values for the wind curtailment/load shedding. The flexibility approach helps to increase the distance between V_1&V_w and V_w&V_2 to reduce the load shedding/wind curtailment.

Objective function (2) should be optimized with respect to P_i's and P_{wi}'s in each time step. Here the main complexity is the calculation of (5)–(8) as the probabilistic functions. As the optimization of (2) is done in the interval [$v_{cut\text{-}in}$, v_{rated}], so the desired equations are established in this interval. In the proposed linear model we have:

$$W_w = mv + n \tag{17}$$

$$d(W_w) = mdv \tag{18}$$

$$V_w = \frac{P_W - n}{m} \tag{19}$$

The mathematical details of the integration of the probabilistic functions are described in [11] by details. So, here only the final result is presented. For simplicity and not missing generality, only one wind farm is assumed. So the index i is dropped in the equations.

$$CD_w = K_D m^2[(V_2 - V_w)F(v_{rated}) + G(V_w) - G(V_2)] \tag{20}$$

Where F is Weibull Cumulative Density Function (CDF) and G is the initial function of F.

$$CU_w = K_U m^2[(V_1 - V_w)F(v_{cut-in}) + G(V_w) - G(V_1)] \tag{21}$$

$$Ccur_w = K_{cur}\{m^2[(v_{rated} - V_2)F(v_{rated}) - G(v_{rated}) + G(V_2)] + (P_n - P_w)A_1\} \tag{22}$$

$$Cshed_w = K_{shed}\{m^2[(v_{cut-in} - V_1)F[1(v_{cut-in}) - G(v_{cut-in})] + G(V_1) + P_w A_2\} \tag{23}$$

Now the derivative of each of the four probabilistic cost functions with respect to V_W is calculated simply. Obviously, Ccur and Cshed have no derivative with respect to V_W:

$$\frac{\partial CD_w}{\partial V_w} = K_D m[F(V_w) - F(v_{rated})] \tag{24}$$

$$\frac{\partial CU_w}{\partial V_w} = K_U m[F(V_w) - F(v_{cut-in})] \tag{25}$$

As can be seen G does not appear in the derivatives, and it is only needed to calculate the cost functions. So, it is only used for the final solution of V_W which can be accessed by a simple look up table method. Now it is ready to describe the optimization procedure for the objective function. The suitable method for minimization of (2) is the Lagrange Multiplier method because of its quadratic form and linear form for constraints as (26):

$$\min LG = \min \sum_{t=1}^{T}[\sum_{i=1}^{N_g} C_i(P_i(t)) + d(mV_w(t) + n) + CD_w + CU_w + Ccur_w + Cshed_w\text{-Î»}(\sum_{i=1}^{N_g} P_i(t) + P_w(t)\text{-}PD(t)\text{-}P_{loss}(t))] \tag{26}$$

Now the partial derivatives of LG with respect to P_i's, V_W and λ in each time step are derived and set them equal to zero.

$$\frac{\partial LG}{\partial P_i(t)} = 2a_iP_i(t) + b_i - \lambda\left(1 - \frac{\partial P_{loss}(t)}{\partial P_i(t)}\right) = 0 \tag{27}$$

$$\frac{\partial LG}{\partial V_w(t)} = m(d-\lambda) + m^2[K_D(F(V_w) - F(v_{rated})) + K_U(F(V_w) - F(v_{cut-in}))] \tag{28}$$

$$\frac{\partial LG}{\partial \lambda} = -\sum_{i=1}^{N_g} P_i(t) + mV_w(t) + n - PD(t) - P_{loss}(t) = 0 \tag{29}$$

Where:

$$\frac{\partial P_{loss}(t)}{\partial P_i(t)} = 2B_{ii}P_i(t) + \sum_{\substack{j=1 \\ j\neq i}}^{N_g} B_{ij}P_j(t) + B0_i \tag{30}$$

By considering $F(V_W) = Z$, a simple iterative method can be used to solve the above equations. Using an initial guess for V_W (maybe v_{rated}), P_i's are calculated using (27) and (29) by a conventional DELD solution algorithm as the first step. Finally, by substitution the calculated λ, V_W is updated by (28) and this procedure is repeated until convergence is accessed.

As can be seen the optimization equations don't include V_1 and V_2. So, the optimum wind power is not dependent on these parameters. On the other hand, since the downward reserve /upward reserve costs are much less than wind curtailment/load shedding costs, no trade-off for downward reserve/wind curtailment costs or upward reserve/load shedding costs is possible. Therefor, V_1 and V_2 are determined only by upward/downward reserve constraints as (12) & (15) and (13) & (16) respectively.

5. Flexibility based economic dispatch

Now the main contribution in this paper is described. By increasing the [V_1,V_2] interval, it is expected more use of upward/downward reserves which leads to the less load shedding or wind curtailment as the desired situation. So, the main goal is to schedule the thermal generation units to increase the [V_1,V_2] interval. It is done by generation system flexibility increase. The basic idea for improving flexibility comes from increasing the flexibility area index by rescheduling of the unit generations. But in this way the operation point deviates from the optimum DELD solution yields to some higher cost. So, it makes a good way for economic trade-off between operation cost and system flexibility cost. Where the system flexibility cost shows the wind curtailment/load shedding costs.

Suppose $P_i(t)$ is the solution of the objective function (2) for unit i in each iteration (not final solution). Two cases of flexibility area limitation are shown in Fig. 10 [9]. As can be seen by reduction in $P_i^{max}(t)$ for each

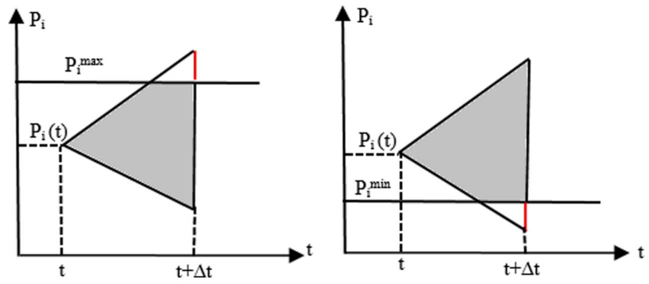

Fig. 10. Penalty approach for flexibility area reduction.

unit by (12), $V_1(t)$ increases as (15) and reduces the upward reserve interval. On the other hand, by increasing in $P_i^{min}(t)$ by (13), $V_2(t)$ reduces as (16) and again causes reduction in downward reserve interval. Both of them lead to reduction in generation system flexibility index.

If $P_i(t)$ causes the reduction in flexibility area in the next time step $(t + \Delta t)$, the penalty related to this reduction should be added to the objective function. Here the difference between P_i^{max} and $(P_i(t) + Rampup_i\ \Delta t)$ or P_i^{min} and $(P_i(t)\text{-}Rampdn_i\ \Delta t)$ (the red lines shown in Fig. 10) are added to the objective function by the penalty factor as KF. So, it forces $P_i(t)$ down/up respectively to increase the flexibility area for the next time step (decreasing $V_1(t)$ or increasing $V_2(t)$ respectively). So, the generation cost function can be easily extended to include the penalty related to the flexibility area reduction as:

$$C(t) = \sum_{i=1}^{N_g} a_i P_i^2(t) + b_i P_i(t) + c_i +$$

$$\sum_{i=1}^{N_g} KF\left(P_i(t) + Rampup_i\Delta t - P_i^{max}\right)^2 + \sum_{i=1}^{N_g} KF\left(P_i(t) - Rampdn_i\Delta t - P_i^{min}\right)^2 \tag{31}$$

Obviously in each iteration only one of the two added terms may be none zero. The economic trade-off between the generation cost and flexibility cost can be achieved by changing KF. If the same procedure is done for Lagrange function and calculating the derivatives, it can be found that only 'a' and 'b' generation cost coefficients should be modified to 'aa' and 'bb' as:

$$aa_i = a_i + KF \tag{32}$$

$$bb_i = b_i + 2KF\left(\left(Rampup_i\Delta t - P_i^{max}\right)\right) \tag{33-1}$$

Or:

$$bb_i = b_i - 2KF\left(\left(Rampdn_i\Delta t + P_i^{min}\right)\right) \tag{33-2}$$

When $(P_i(t) + Rampup_i\ \Delta t)$ is more than P_i^{max} or $(P_i(t)\text{-}Rampdn_i\ \Delta t)$ is less than P_i^{min}, (33-1) or (33-2) are used respectively. But where no violation, 'a' and 'b' coefficients have no change. Therefore, DELD improvement is done by needed modification for 'a' and 'b' coefficients for each generator in each iteration of DELD solution.

6. Simulation

The proposed flexibility based dynamic economic load dispatch method is used for the six unit test system. The main data for this test system are presented in [13]. A load profile is suggested for this system by 15 min time sample (96 samples for 24 h) as shown in Table 2 in the Appendix 1. A wind farm is also considered by nominal power as 500 MW and $v_{cut\text{-}in}$, v_{rated} and $v_{cut\text{-}out}$ as 5, 15 and 25 m/s respectively. Weibull function scale and shape factors are 6 and 2 respectively. Wind power cost (d) is equal to one. The linear wind power coefficients can be easily found [9]. At first the initial simulation is done with no wind farm incorporation as the base case. Fig. 11 shows the total generation and

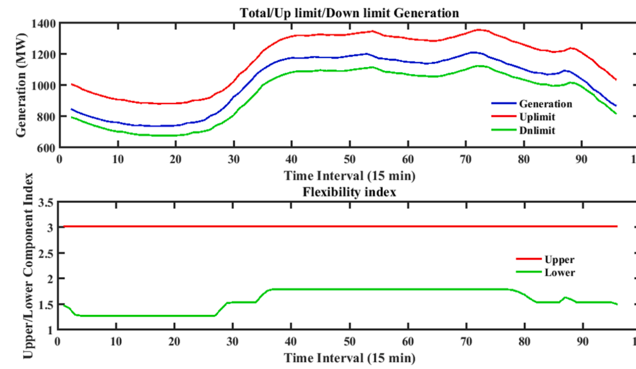

Fig. 11. Results with no wind power incorporation.

up/down generation limits with the upper and lower components of the flexibility index. (Correspond to S_1 and S_2 in Fig. 8)

As can be seen, the flexibility upper component is fixed on its maximum value, shows no reduction in the upper component. But the lower component varies with respect to the generation changes. It goes down when system generation approaches its minimum value causes reduction in downward reserve. Maximum values for upper/lower components are 3.0208 and 1.7969 respectively show more generation flexibility for upward load variation.

Now the main simulations in the presence of the wind power is done. As the average cost per one MW is about 12 \$/MW, the downward and upward reserve cost parameters (KD and KU) are assumed 2 (\$/MW). Also, Kcur and Kls are also assumed 20 and 30 (\$/MW) respectively. This simulation is done for different values of KF as 0.0, 0.02, 0.03 and 0.05. Fig. 12 shows the variation of the important parameters as the wind power, the lower flexibility component, the optimum wind speed (V_w) and the upper and lower wind speeds (V_1 and V_2). As the net load is always less than system load, the flexibility upper component is always constant and equals to its maximum value as 3.0208 in all simulations. But the lower component varies because of the reduction of the net load and approaching it to the system generation down limit. So, only the lower component of the flexibility index is shown in the next simulations.

The optimum and lower wind speeds (V_w and V_1) are the same with no change for all KF's. But the upper wind speed (V_2) has considerably increase by increase in KF. It is completely compatible with the upper and lower flexibility index components. The difference between the values of the upper wind speeds correspond to the different values of KF, shows the improvement of the wind curtailment. Table 1 shows the wind curtailment and total system cost for different values of KF.

The wind curtailment and the total cost decrease by increase in KF and also improvement in generation system flexibility level. As V_1 is near $v_{cut\text{-}in}$, the load shedding is near zero for all KF's. It should be noted the wind power curve has no considerable difference for all KF's and

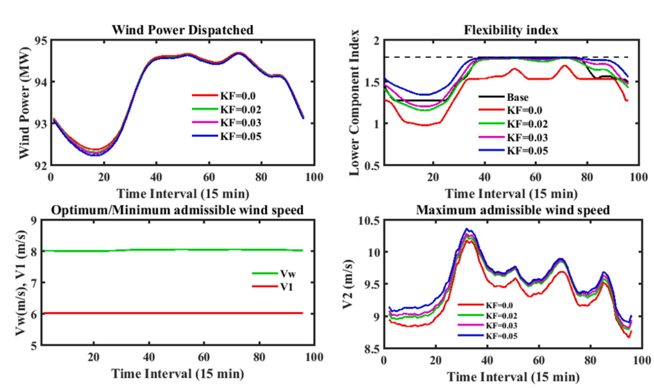

Fig. 12. Results with KD = KU = 2.

Table 1
Wind curtailment/Total system cost.

KF	0.0	0.02	0.03	0.05
WC (MWH)	28.85	26.65	26.03	25.08
Cost (k$)	513.86	505.62	503.29	499.79

flexibility improvement is mainly related to the generation rescheduling not the reduction in the wind power. Now to change the upward and downward reserve regions (Fig. 9), KU and KD are changed. At first KD is increased to 5 where KU and also Kcur and Kls are the same. Fig. 13 shows the variation of the same parameters as Fig. 12 only for KF = 0 & 0.05 for the better resolution.

Again the optimum and lower wind speeds (V_W and V_1) are the same with no change for the both KF's. The wind power has considerably increased because of the lower cost of the upward reserve with respect to the downward. Also, the lower component of the flexibility index has reduction due to the wind power increase. Load shedding is about 4 (MWH) for the both cases. Where wind curtailments are 10.15 and 8.62 (MWh) for KF = 0&0.05 respectively. Also, total system costs are 407.54 and 404.04 (k$) again for KF = 0&0.05 respectively.

The last simulation is down by KU increases to 5 and KD returns to 2. The results are shown in Fig. 14.

The optimum and lower wind speeds have no change for the both cases. The wind power has considerably reduced because of the higher cost of the upward reserve with respect to the downward. The load shedding is near zero for the both cases where V_1 is near $v_{cut\text{-}in}$. But the wind curtailment again differs for the two cases as 45.62 and 41.19 (MWh) for KF = 0&0.05 respectively. The increase in the wind curtailment with respect to the previous case is due to the reduction in V_2. Also, total system costs are 554.12 and 534.18 (k$) again for KF = 0&0.05 respectively. The considerable increase in total system cost is mainly related to the reduction in the wind power dispatched and also the increase in the wind curtailment.

7. Conclusion

A flexibility based probabilistic dynamic economic load dispatch framework was proposed in this paper for the wind power incorporation. The proposed generation system flexibility index has a meaningful relation with respect to the wind curtailment/load shedding due to the wind power uncertainty. So, the economic value of the mentioned index can be easily related to the wind curtailment/load shedding costs. Where it suggests a good approach for economic trade-off between the system operation cost and the flexibility economic value to obtain the best level of the system generation flexibility index. On the other hand, the desired flexibility index has two components each of them related to the downward/upward generation system reserve and also to the wind curtailment/load shedding respectively. The main advantage of the proposed method is to increase the system flexibility index without considerable decrease in the wind power as the low-cost energy source.

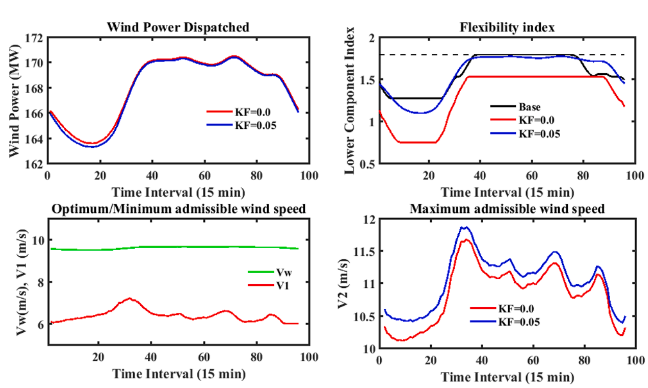

Fig. 13. Results with KD = 5 & KU = 2.

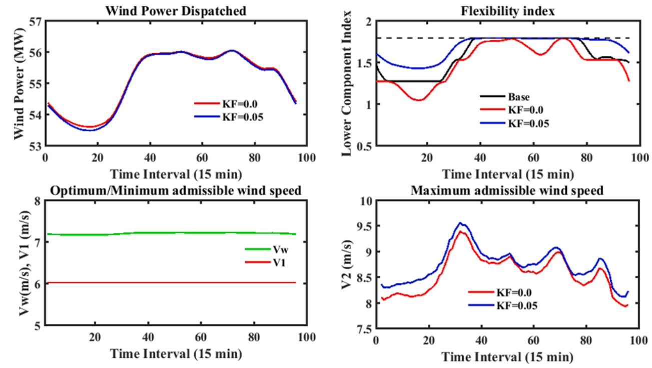

Fig. 14. Results with KD = 2 & KU = 5.

As said this is down by generation rescheduling without noticeable increase in the generation cost. As Eq. (32), the increase in 'a' coefficient for each generation unit which violates the generation constraints leads to increase in generation cost. But as KF is directly added to 'a', it should be sufficiently small avoiding the large increase in generation cost which may cause the solution diverging. The proposed solution routine is simple and fast suitable for power system real time operation. Also, the up/down system flexibility index components can be used as the indicators to show the generation system up/down reserve margins to alert the increasing of wind curtailment/load shedding risks.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix 1. System load data

See Table 2.

Table 2
System daily load profile data (MW) (15 min).

00.00	00.15	00.30	00.45	01.00	01.15
856.4	**843.1**	**823.2**	**809.7**	**796.6**	**786.1**
01.30	01.45	02.00	02.15	02.30	02.45
775.3	**765.9**	**759.0**	**757.1**	**748.7**	**742.6**
03.00	03.15	03.30	03.45	04.00	04.15
737.2	**738.4**	**734.9**	**733.0**	**733.5**	**734.2**
04.30	04.45	05.00	05.15	05.30	05.45
734.5	**737.2**	**741.1**	**753.4**	**755.1**	**762.2**
06.00	06.15	06.30	06.45	07.00	07.15
771.8	**798.4**	**812.4**	**839.7**	**872.1**	**918.8**
07.30	07.45	08.00	08.15	08.30	08.45
945.4	**984.2**	**1020.3**	**1064.8**	**1091.8**	**1114.7**
09.00	09.15	09.30	09.45	10.00	10.15
1135.8	**1149.1**	**1159.0**	**1165.8**	**1164.9**	**1164.4**
10.30	10.45	11.00	11.15	11.30	11.45
1168.3	**1172.7**	**1168.0**	**1169.3**	**1167.8**	**1167.3**
12.00	12.15	12.30	12.45	13.00	13.15
1172.5	**1177.9**	**1182.8**	**1186.7**	**1191.6**	**1178.9**
13.30	13.45	14.00	14.15	14.30	14.45
1163.1	**1160.2**	**1154.5**	**1153.3**	**1144.7**	**1140.5**
15.00	15.15	15.30	15.45	16.00	16.15
1136.8	**1135.8**	**1130.2**	**1131.7**	**1136.8**	**1147.9**
16.30	16.45	17.00	17.15	17.30	17.45
1155.0	**1166.8**	**1176.9**	**1190.2**	**1200.0**	**1198.3**
18.00	18.15	18.30	18.45	19.00	19.15
1191.2	**1171.2**	**1159.0**	**1147.9**	**1129.0**	**1119.9**
19.30	19.45	20.00	20.15	20.30	20.45
1107.1	**1094.6**	**1080.5**	**1071.2**	**1070.0**	**1060.6**
21.00	21.15	21.30	21.45	22.00	22.15
1063.1	**1067.8**	**1085.0**	**1078.6**	**1056.7**	**1031.1**
22.30	22.45	23.00	23.15	23.30	23.45
1006.8	**967.7**	**946.1**	**913.6**	**882.9**	**862.0**

References

[1] Tang C, Xu J, Sun Y, Liu Ji, Li X, Ke D, et al. Look-Ahead Economic Dispatch With Adjustable Confidence Interval Based on a Truncated Versatile Distribution Model for Wind Power. IEEE Trans Power Syst 2018;33(2):1755–67. https://doi.org/10.1109/TPWRS.2017.2715852.

[2] Wu C, Hug G, Kar S. Risk-Limiting Economic Dispatch for Electricity Markets With Flexible Ramping Products. IEEE Trans Power Syst 2016;31(3):1990–2003. https://doi.org/10.1109/TPWRS.2015.2460748.

[3] Wang C, Liu F, Wang J, Wei W, Mei S. Risk-Based Admissibility Assessment of Wind Generation Integrated into a Bulk Power System. IEEE Trans Sustainable Energy 2016;7(1):325–36. https://doi.org/10.1109/TSTE.2015.2495299.

[4] Hlalele TG, Naidoo RM, Zhang J, Bansal RC. Dynamic Economic Dispatch With Maximal Renewable Penetration Under Renewable Obligation. IEEE Access 2020; 8:38794–808. https://doi.org/10.1109/ACCESS.2020.2975674.

[5] Sasaki Y, Tsurumi T, Yorino N, Zoka Y, Beni Rehiara A. Adelhard Beni Rehiara "Real-Time Dynamic Economic Load Dispatch Integrated with Renewable Energy Curtailment". J Int Council Electr Eng 2019;9(1):85–92.

[6] Li J, Fang J, Wen I, Pan Y, Ding Q. Optimal Trade-off between Regulation and Wind Curtailment in the Economic Dispatch Problem. CSEE J Power Energy Syst 2015;1 (4):37–45.

[7] Nosair H, Bouffard F. Economic Dispatch Under Uncertainty: The Probabilistic Envelopes Approach. IEEE Trans Power Syst 2017;32(3):1701–10.

[8] Chen R, Wang J, Botterud A, Sun H. Wind Power Providing Flexible Ramp Product. EEE Trans Power Syst 2017;32(3):2049–61.

[9] Berahmandpour H, Kuhsari SM, Rastegar H. Development the Flexibility Metric Incorporating Wind Power in the Presence of Energy Storage. Int Power Syst Conf (PSC) 2019;2019:548–56. https://doi.org/10.1109/PSC49016.2019.9081515.

[10] Berahmandpour H, Kouhsari S, Rastegar H. A New Method for Real Time Economic Dispatch Solution Including Wind Farms. Renewable Energy Res Appl 2020;1(2): 51–160.

[11] Berahmandpour H, Kouhsari SM, Rastegar H. Probabilistic Dynamic Economic Dispatch in Presence of Wind Farms. Accepted paper in 29th Iranian Conference on Electrical Engineering (ICEE). 2021.

[12] Berahmandpour H, Monraser Kuhsari S, Rastegar H. A New Approach on Development of Power System Operational Flexibility Index by Combination Generation Unit Flexibility Indices. AUT J Electr Eng 2020. https://doi.org/10.22060/eej.2020.18574.5358 (in Press).

[13] Bisharathu Beevi A .Economic Load Dispatch and Optimal Allocation of Reactive Power in Power Systems. Ph.D. dissertation. Department of Electrical Engineering College of Engineering Trivandrum. 695016, Kerala (India) December-2010. [Online]. Available: http://hdl.handle.net/10603/107531.

Homayoun Berahmandpour was born in Tehran, Iran, on September 6, 1964. He received B.Sc. and M.Sc. degrees both in Electrical Power Engineering from Amirkabir University in 1988 and 1991, respectively. Currently, he is a Ph.D. student in Amirkabir University. His employment experiences include in Electric Power Research Center (EPRC) from 1990 until 1998 and Niroo Research Institute (NRI) from 1998 until now. His current position is head of bulk power transmission technology center. He has more than 100 national and international papers. His interests include power system planning and operation and power system renewable integration.

Shahram Montaser Kouhsari, member of IEEE received the B.Sc. degree in Electrical Engineering from Sharif University of Technology, Tehran, Iran, in 1980 and the M.Sc. and Ph.D. degrees in Electrical Power Engineering from the University of Manchester Institute of Science and Technology, Manchester, UK in 1984 and 1988, respectively. Currently, he is a Full Professor in the Department of Electrical Engineering, Amirkabir University of Technology, Tehran, Iran. His research interests include Power System analysis and Power System Software development especially Power System simulation softwares; somehow that he is the main developer of two worldwide well-known simulation programs named PASHA and POUYA.

Hassan Rastegar received B.Sc., M.Sc. and Ph.D. degrees in Electrical Engineering from the Amirkabir University of Technology, Tehran, Iran, in 1987, 1989 and 1998, respectively. Currently, he is a Full Professor in the Department of Electrical Engineering, Amirkabir University of Technology, Tehran, Iran. He has published more than 200 papers in journals and conferences. His research interests include power system control, application of computational intelligence in power systems, Simulation and Analysis of Power Systems and Renewable Energy.