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Transmission Congestion Management Through LMP Difference Minimization: A Renewable Energy Placement Case Study

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Abstract New generation units based on renewable energy resources (RER) are being installed in power systems more frequently. As one of the important tasks of system planners and/or independent system operators, they have to propose appropriate sites and sizes for new RER installation. In present work, a novel approach for determining the site and size of new RER is proposed for relieving congestion in transmission lines. This method is based on minimizing the differences among locational marginal prices considering $N-1$ security criteria. For the case of wind farms (WF), the appropriate size and location of WF are determined considering the probabilistic nature of wind speed; the probability of wind generation output power is utilized in WF placement and sizing.

Keywords Transmission congestion management · Renewable resources · Wind power · Optimal power flow

الخلاصة

يجري تركيب وحدات توليد جديدة تقوم على مصادر الطاقة المتجددة (RER) في أنظمة الطاقة على نحو أكثر تواترا. وباعتبارها واحدة من المهام الهامة لمخططي النظام و / أو مشغلي النظام المستقل (ISO)، لذا عليهم اقتراح المواقع المناسبة والأحجام لتركيب مصادر RER جديدة. وفي العمل الحالي، تم اقتراح نهج جديد لتحديد موقع وحجم مصادر RER جديدة لتخفيف الازدحام في خطوط النقل. ويستند هذا الأسلوب على تقليل الفروق بين الأسعار المكانية الهامشية (LMP) بالنظر في معايير الأمن N-1. بالنسبة لقضية مزارع الرياح (WF)، وتم تحديد الحجم المناسب والمكان من WF بالنظر في الطبيعة الاحتمالية لسرعة الرياح؛ واستُخدمت احتمالية توليد الكهرباء باستخدام الرياح في إنتاج الطاقة في تنسيب وتحجيم WF.

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List of Symbols

a_i, b_i, c_i	Cost function coefficients of generator i
c	Scale factor
k	Shape factor
n	Number of buses
N_g	Number of generators
N_L	Number of lines
p_d	Load demand (MW)
p_f	Line flow (MW)
p_f^{min}, p_f^{max}	Limits on line flows (MW)
p_g	Active power generation (MW)
p_g^{min}, p_g^{max}	Limits on generator's active power (MW)
p_w	Wind turbine output power (MW)
p_{wr}	Rated power of wind turbine (MW)
v	Wind speed (m/s)
v_{in}	Cut-in wind speed (m/s)
v_{out}	Cut-out wind speed (m/s)
v_r	Rated wind speed (m/s)
η, γ	Lagrange multipliers for inequality constraints
θ	Voltage angle (rad.)
λ, α	Lagrange multipliers for equality constraints

1 Introduction

From the view point of power system operation, several factors limit the power transfer capability through the transmission system. This is calculated based on thermal limits, transient stability limits, voltage stability limits and other system security criteria. Because of these limits, transmission lines are prone to congestion from time to time due to load and generation variations and system conditions. Congestion, if happens, would prevent the low-price generation units from producing more power and thus the system costs would increase. Consequently, it would influence the locational marginal prices (LMP) in such a way that the LMP for some consumers would rise. Solutions to relieve congestion, generally referred to as congestion management schemes, are of interest to both system operators and planners.

Several methods have been proposed in the literature for congestion management which can be categorized in five groups:

1. Generation and load re-dispatch
2. Auction-based solutions
3. Price-based solutions
4. Optimal system reconfiguration
5. Generation expansion
6. Transmission expansion

The above classification also shows the priority of actions that are taken for congestion management by the independent system operator (ISO) according to their applicability. The last two groups are actually long-term solutions and require high investments. Besides these, there are many difficulties in installing new lines or generation units [1]. The first three groups are well described in [2] and are not discussed here and only some recent research studies are reviewed. A generation and load re-scheduling optimization problem is formulated and solved using particle swarm optimization techniques in [3]. Also, voltage and frequency dependency of loads as well as generators' regulation characteristics are considered in [3]. A multi-objective decentralized congestion management approach is proposed which uses a modified Genetic Algorithm to solve the problem in [4].A congestion management technique which takes into account the voltage stability limits is proposed in [5] and some of the system security criteria are also considered in the proposed congestion management scheme. Optimal system reconfiguration using transmission lines switching is also studied in detail for the purpose of congestion management in [6–9]. Although transmission line switching method can relieve congestion in some cases, it may incur security risks for the system operation.

Recently, some research work has been conducted in the context of generation expansion aiming at congestion relief [10]. Distributed generation (DG) resources are also used as tools for congestion management in distribution networks [11]. In [12], the bus with maximum LMP is selected as first candidate for DG placement and considering some cost functions for DGs, the OPF is reformulated including the new generations; hence, the optimal size of DG is calculated. The results show that the proposed method in [12] has reduced the LMP differences to some extent. It is shown in [13] that the highest LMP method for DG placement may cause congestion in other lines; thus, congestion rent difference METHOD has been proposed in [13] for this purpose. After determination of appropriate buses for DG placement, the size of the DG is calculated based on evaluating all possible sizes and maximizing the benefit.

The ISO is usually involved in studies pertaining to find candidate site(s) as well as appropriate size(s) for installing renewable energy resources (RER) including wind, photovoltaic, biomass, and so forth. There are many factors that should be taken into account in these studies. For example, transmission system loadings should not exceed predetermined values. Moreover, system security criteria such as transient stability and frequency stability should be respected as well [14]. Similar studies in distribution systems are conducted in [15,16] and the maximum penetration level of DG is calculated accordingly.

In the present study, it is assumed that a list of places in the system is given as sites for installing new RERs derived based on geographical and technical aspects. This paper is aimed at prioritizing and determining the size of the new RER in the given list. It would be of great interest if, besides providing clean energy, one could also take advantage of new RER for congestion management. Here, an algorithm is proposed to find the optimal place and size of the new RER to help the system to relieve congestion.

Congestion in transmission system leads to LMP variations at buses across the system. By ignoring the effects of losses on LMPs, the only factor that causes LMP differences is congestion [17]. Consequently, to alleviate congestion, the objective function should be minimizing the LMP differences while keeping them as low as possible, which is done in this paper. Also, if the system suffers a contingency, all the physical limits such as line flow limits have to be respected as well. Hence, the $N - 1$ security criteria for line outages are also considered in this paper.

In the case, that the RER is a wind farm (WF), a new challenge is encountered: the randomness and intermittency of wind speed. This means that the determined size of WF is actually the required output power from the power system perspective. However, the actual capacity of WF is not simply the same as the determined size. It is proposed here to calculate the actual capacity of the WF based on probabilistic methods. The proposed approach is evaluated in a test system.

The rest of the paper is organized as follows. In Sect. 2, the proposed approach is described. For the case of WF, the actual capacity is determined in Sect. 3. The optimal size and site of new RER for congestion management is calculated for a test system in Sect. 4. Main contributions of this paper are summarized in the last section.

2 Proposed Approach

The following assumptions are made here:

1. The appropriate sites for new RER are determined according to geographical and technical conditions includ-

ing wind availability and transmission system capability.
2. New RER should not be installed at buses which already have generation units connected to.
3. The aim of new installation is to relieve congestion without causing new congestion in other lines, even considering $N-1$ contingency for lines' outages.

Without loss of generality, assume that all the non-generation buses are appropriate places for installing the new RER. Two scenarios are discussed as follows.

2.1 DCOPF with Limits on Line Flows

The DCOPF problem for generic power system is formulated as follows:

$$\text{Minimize} \quad f(P_g) = \sum_{i=1}^{N_g} (a_i p_{gi}^2 + b_i p_{gi} + c_i) \tag{1}$$

$$\text{Subject to}: \quad P_g - P_d = A.\theta \tag{2}$$

$$\theta_1 = 0 \tag{3}$$

$$P_g^{\min} \leq P_g \leq P_g^{\max} \tag{4}$$

$$P_f^{\min} \leq P_f \leq P_f^{\max} \tag{5}$$

in which $P_g \in \Re^{n\times 1}$ and $P_d \in \Re^{n\times 1}$ are vectors of nodal generations and demands; $P_f \in \Re^{N_L\times 1}$ is the vector of power flows through lines which is calculated as $P_f = B.\theta^*$; $\theta \in \Re^{n\times 1}$ is the vector of bus voltage angles; $\theta^* \in \Re^{(n-1)\times 1}$ is the vector of bus voltage angles in which the reference bus is eliminated; $A \in \Re^{n\times n}$ and $B \in \Re^{N_L\times(n-1)}$ are constant matrices which are calculated according to network parameters [17].

This is a convex quadratic programming with linear equality and box constraints [18]. Therefore, the Lagrange Dual function of this problem can be written as:

$$\begin{aligned} L(\lambda, \gamma_U, \gamma_L, \eta_U, \eta_L, \alpha) &= f(P_g) + \lambda^T(P_g - P_d - A.\theta) \\ &+ \gamma_U^T(P_g - P_g^{\max}) + \gamma_L^T(P_g^{\min} - P_g) \\ &+ \eta_U^T(P_f - P_f^{\max}) + \eta_L^T(P_f^{\min} - P_f) + \alpha.\theta_1 \end{aligned} \tag{6}$$

Since the Primal problem is convex, according to the Karush–Kuhn–Tucker (KKT) conditions [18], the Dual problem can be formulated as the following partial derivatives:

$$\frac{\partial L}{\partial p_{gi}} = (2a_i p_{gi} + b_i) + \lambda_i + \gamma_{Ui} - \gamma_{Li} = 0 \tag{7}$$

$$\frac{\partial L}{\partial \lambda_i} = p_{gi} - p_{di} - A_i.\theta = 0 \tag{8}$$

$$\frac{\partial L}{\partial \theta_i} = \sum_{j=1}^{n} (\lambda_j a_{j,i}\theta_i) \pm \eta_l \cdot b_{l,i-1} = 0 \quad i = 2, 3, \ldots, n \tag{9}$$

$$\frac{\partial L}{\partial \theta_1} = \sum_{j=1}^{n} (\lambda_j a_{j,1}\theta_1) + \alpha = 0 \tag{10}$$

$$\frac{\partial L}{\partial \alpha} = \theta_1 = 0 \tag{11}$$

If any of the inequality constraints is violated, the corresponding Lagrange multiplier is non-zero and two constraints should be added to the above problem [18]. For example, if the upper bound on Line l flow is reached, the following should hold:

$$\eta_{Ul}(P_{f,l} - P_{f,l}^{\max}) = 0 \;\Rightarrow\; P_{f,l} = P_{f,l}^{\max} \quad \eta_{U,l} > 0 \tag{12}$$

in which $\eta_{U,l}$ is the Lagrange multiplier corresponding to the upper bound of lth inequality in (5). Other Lagrange multipliers and associated derivatives (corresponding to the inequalities which are not active) are zero.

If any congestion occurs, it means that for some l, $\eta_{U,l} > 0$. It can be proved that [19]:

$$\sum_{i=1}^{n} \lambda_i p_{di} - \sum_{i=1}^{n} \lambda_i p_{gi} = \sum_{i=1}^{nl} \eta_i p_{fi} \tag{13}$$

Observe that if all the LMPs are equal, the left-hand side of (13), which is usually called transmission congestion surplus or simply congestion rent, would be zero in a lossless system. Since the flow-constraint Lagrange multipliers η_i are nonnegative, it is concluded that all η_i should be zero. The last statement means that the congestion has been removed. Therefore, this idea is inspired in mind to minimize the LMP differences to alleviate transmission congestion. This idea is evaluated here using the optimal size and place of renewable energies to help congestion relief.

Now, consider that some injections at non-generator buses should alleviate transmission system congestion. This means that the LMP differences should be minimized, preferably to be zero. This cannot be done using conventional DCOPF in which the objective function is to minimize the total generation cost and LMPs are known after the problem is solved. Therefore, a new problem is defined to carry out this task, as follows:

$$\text{Minimize } g(\lambda_i) = \sum_{i,j\in\mathbb{S}} (\lambda_i - \lambda_j)^2 \tag{14}$$

$$\text{Subject to: } (4)-(5),\ (6)-(7),\ (9)-(12),\ (15) \tag{15}$$

in which $\mathbb{S}$ is the set of couples (i, j) which are directly connected through a line. Observe that the upper and lower bounds on p_{gi}'s at non-generation buses were assumed to be zero in the DCOPF formulation. By removing the limits on p_{gi}'s at some non-generation buses and assuming no cost for these new generations, (8) needs slight modification. Assume that the new generations (P_w) are installed at

m non-generation buses which are the last buses in the formulation. Then (8) would be represented in more detail as:

$$[p_{g1} \quad \cdots \quad p_{gk} 0 \quad \cdots \quad 0 p_{w1} \quad \cdots \quad p_{wm}]^T - [p_{d1} \quad \cdots \quad p_{dn}]^T = A.\theta \tag{16}$$

Notice that at the initial condition in which $P_w = 0$, (16) is equivalent to (8). This optimization problem tries to take advantage of new RER for reducing LMP differences (i.e., congestion relief) while keeping system cost as minimum as possible and respecting power system criteria.

2.2 DCOPF with Limits on Line Flows Considering Single Line Outage

In this part, an outage of one transmission line is considered for which no congestion has to occur. For modeling this outage, line outage distribution factors (*LODF*) are employed. *LODF*(x, y) shows that if Line y is suddenly disconnected, what portion of its power would immediately appear on Line x. The $N-1$ line outage security-constrained DCOPF is then formulated as follows:

$$\text{Minimize } f(p_{gi}) = \sum_{i=1}^{k} (a_i p_{gi}^2 + b_i p_{gi} + c_i) \tag{17}$$

$$\text{Subject to: } (2), (3), (4) \tag{18}$$

$$\begin{bmatrix} p_{f,h}^{\min} \\ \vdots \\ p_{f,h}^{\min} \end{bmatrix} \le \begin{bmatrix} p_{f,h} \\ \vdots \\ p_{f,h} \end{bmatrix} + \begin{bmatrix} \text{LODF}(h,1).\, p_{f,1} \\ \vdots \\ \text{LODF}(h,N_L).\, p_{f,N_L} \end{bmatrix} \le \begin{bmatrix} p_{f,h}^{\max} \\ \vdots \\ p_{f,h}^{\max} \end{bmatrix}, \quad h = 1, \ldots, N_L \tag{19}$$

Note: LODF$(h, h) = -1$.

Equation (19) adds $2N_L \times (N_L - 1)$ linear inequality constraints to the above problem. The remaining parts are similar to the previous section.

3 Probabilistic Determination of Wind Farm Capacity

This section explains the required background for Sect. 4.3, which follows this section. Wind speed is a random variable and, consequently, the output power of a WF is also a random variable. The most widely-accepted probability distribution function (PDF) for wind speed in long-term studies is the two-parameter Weibull distribution [20]. The Weibull PDF is [21,22]

$$f_v(v) = \frac{k}{c}\left(\frac{v}{c}\right)^{k-1} e^{-(\frac{v}{c})^k} \tag{20}$$

in which $f_v(v)$ is the PDF of wind speed. Parameter estimation methods for determining the values of c and k from the measured data of wind speed have been reported in the literature [23]. These parameters depend on the geographical characteristics of a region, thus their values vary from area to area [24,25].

The output power of a wind turbine is calculated as [26,27]:

$$p_w = \begin{cases} 0 & v < v_{in} \text{ or } v > v_{out} \\ p_{wr} & v_r < v < v_{out} \\ p_{wr}(v - v_{in})/(v_r - v_{in}) & v_{in} < v < v_r \end{cases} \tag{21}$$

It is shown in [26] that the cumulative distribution function (CDF) of WF output power is:

$$F_W(p_w) = \begin{cases} 0 & p_w < 0 \\ 1 - \exp\left\{-\left[\frac{(1+(v_r/v_{in}-1)p_w/p_{wr})v_{in}}{c}\right]^k\right\} + \exp\left\{-\left[\frac{v_{out}}{c}\right]^k\right\} & 0 < p_w < p_{wr} \\ 1 & p_{wr} < p_w \end{cases} \tag{22}$$

Assume that we need an output power of p_w from a specific WF (p_w is the needed quantity). Here, the objective is to have the actual output power of WF (i.e. p'_w) as close as possible to the needed value (p_w) with the highest possible probability. Practically speaking, an interval around the needed value should be assumed instead of the exact required amount. Thus, a $\pm 20\,\%$ bound is considered as the needed range of WF output power, i.e., $0.8p_w \le p'_w \le 1.2p_w$. The probability of this event is calculated as:

$$\Pr\{0.8p_w \le p'_w \le 1.2p_w\} = F_W(1.2p_w) - F_W(0.8p_w) \tag{23}$$

For maximizing the above probability, the WF rated power (p_{wr}) should satisfy the following limits:

$$0.8p_w \le p_{wr} \le 1.2p_w \tag{24}$$

If someone lets p_{wr} to be out of these limits, i.e., expanding the bounds, it can be mathematically proved that the probability of desired event would be lower. With this assumption and using (22), (23) converts to:

$$\Pr\{0.8p_w \le p'_w \le 1.2p_w\} = \exp\left\{-\left[\frac{(1 + (v_r/v_{in} - 1)0.8p_w/p_{wr})v_{in}}{c}\right]^k\right\} - \exp\left\{-\left[\frac{v_{out}}{c}\right]^k\right\} \tag{25}$$

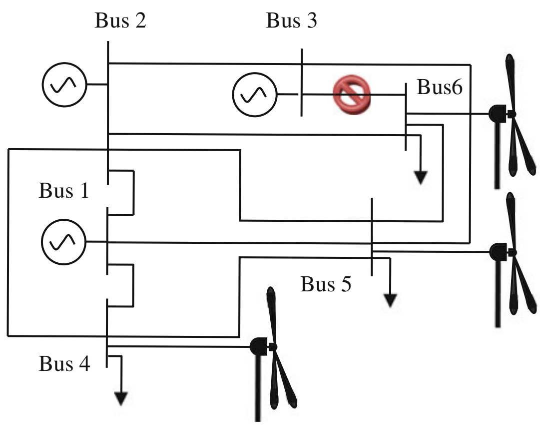

Fig. 1 The 6-bus test system

Eventually, it is possible to maximize the probability of having the output power of WF within a specific range by putting (25) as the objective function.

Some guidelines can be helpful for selecting an appropriate wind turbine type from all available choices. For instance, values for v_{in} and v_{r} are important. Equation (25), in the assumed bounds for the variables, shows a strictly increasing functionality of p_{wr} and decreasing functionality of v_{in} and v_{r}. Therefore, for maximizing the probability of (25), p_{wr} should be at its upper limit while two other variables should be at their lower limits. Bounds on v_{in} and v_{r} can be easily defined using manufacturer data provided for available commercial wind turbines.

4 Simulation Results

A 6-bus test system shown in Fig. 1 is used here for evaluating the proposed method. Bus 1 is the slack bus and buses 4 to 6 are considered as candidate areas for adding new RER. System parameters are given in Appendix. Both scenarios proposed in Sect. 2 are applied to this test system.

4.1 First Scenario

Table 1 shows the base case DCOPF results named as pre-installation (pre-inst.) which corresponds to the case that no WF is installed. Using the first scenario described and assuming a limit of 50 MW on the power flow through Line 3–6, this line undergoes congestion with a Lagrange multiplier of 1.693. It is the only violated inequality constraint in DCOPF and others have zero Lagrange multipliers. The proposed method is applied to this problem and appropriate sizes of RER are calculated (see Table 1, post-inst.). Also, the Lagrange multiplier corresponding to Line 3–6 flow limit is set to zero, according to (12). The post-installation results show that G2 has reached its lower limit due to the extra power injection from RER. The expected generation from Bus 6 has taken a bigger value compared to Buses 4 and 5. It can also be explained by means of generation shift distribution factors (GSDF) [17]. Bus 6 has the largest GSDF on Line 3–6 and, thus, is dispatched more than other buses. Observe that the objective function in (14) has reached zero and hence no further increment is needed in RER. This happens because of the criterion introduced by (12).

Table 1 DCOPF solutions for the first scenario

Bus	Pre- inst.		Post- inst.	
	P_g (MW)	LMP ($/h)	P_g (MW)	LMP ($/h)
1	85.02	12.09	63.60	11.77
2	41.00	12.11	10.00	11.77
3	63.98	11.47	81.30	11.77
4	0	12.10	7.41	11.77
5	0	12.07	8.04	11.77
6	0	12.67	19.65	11.77
Cost ($/h)	2,672.48		2,248.1	

Table 2 DCOPF solutions for the second scenario

Bus	Pre- inst.		Post- inst.	
	P_g(MW)	LMP ($/h)	P_g(MW)	LMP ($/h)
1	61.04	11.74	50.91	11.59
2	85.28	12.58	10.00	11.78
3	43.68	11.11	69.09	11.56
4	0.00	12.69	38.86	11.79
5	0.00	13.01	17.49	11.82
6	0.00	17.16	3.65	12.42
Cost ($/h)	2,700.3		1,957.3	

4.2 Second Scenario

Single-line outages are considered here and the system is required not to be congested for any line outage ($N-1$ security). In this case, the limit on Line 3–6 is assumed as 64 MW because the previously mentioned 50 MW limit yields no solution. The pre-installation dispatch and LMPs are reported in Table 2. Here, the outage of Line 2–6 would congest Line 3–6 with a Lagrange multiplier of 7.38 and outage of Line 1–4 would congest Line 1–2 with a Lagrange multiplier of 1.62. Using the proposed method, the size of new RER is calculated and reported in Table 2.

An attention should be paid when comparing the results of the two scenarios. In the first scenario, G2 has reached its lower limit and other inequalities are satisfied. The reason that the RERs are not further dispatched is that the objec-

Table 3 Parameters for wind turbine and wind speed characteristics

k	c	v_{out}	v_r^{min}	v_r^{max}	v_{in}^{min}	v_{in}^{max}
1.8	11	40	9	15	3	5

Table 4 Obtained parameters for WF connected to Bus 6

v_{in} (m/s)	v_r (m/s)	P_{wr} (MW)	Optimum value of (24) (%)
3	9	24	64.19

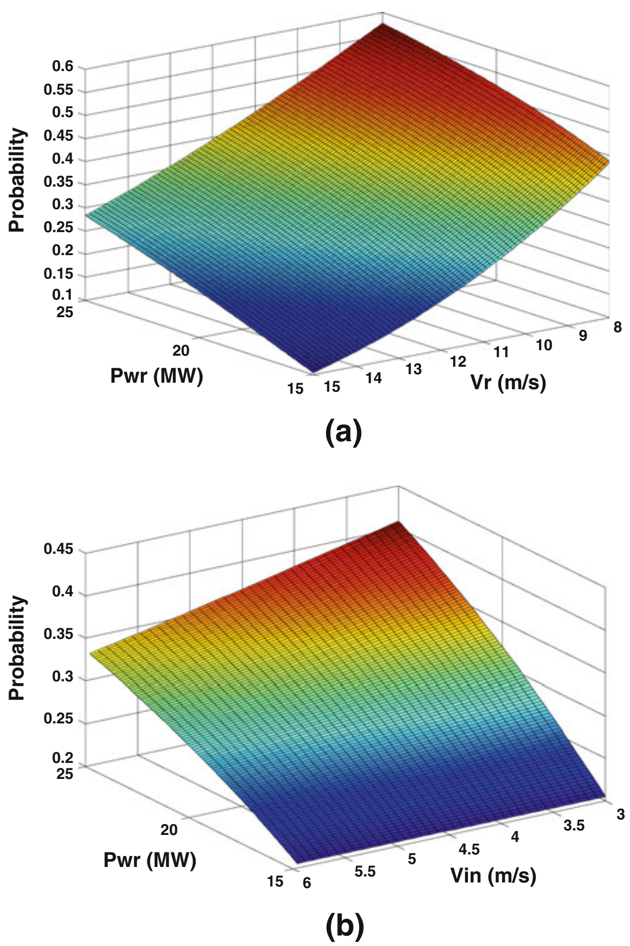

Fig. 2 Probability of (24) as a function of: **a** P_{wr} and v_r; **b** P_{wr} and v_{in}

tive function has reached its lowest feasible minimum (zero). Therefore, the binding factor for more power from RERs is the early satisfaction of the objective function. On the other hand, the second scenario leads to higher values for RER dispatch and the binding factors are the lower bound on G2 output power and congestion in Lines 1–2 and 2–3 due to the outage of Lines 1–5 and 3–6, respectively. As can be seen in Table 2, the LMP differences cannot be further reduced due to the mentioned binding factors.

4.3 Determination of Appropriate WF Capacity

If the RER is supposed to be wind generation units, the proposed approach for determining the size of WF in Sect. 3 has to be utilized. The results obtained above for RERs installed at different buses are employed here. In the results of the first scenario reported in Table 1, the WF installed at Bus 6 was obtained as 19.65 MW. For simplicity, this value is rounded up to 20 MW here. To maximize the probability of having the actual output power of WF within ±20 % of the expected value, the range of 16 and 24 MW is assumed and an optimization problem is formulated as discussed in Sect. 3. Assumed parameters are reported in Table 3. The optimal values for p_{wr}, v_{in} and v_r after solving the optimization problem are reported in Table 4. These results indicate that if we need the output power of WF to be within the range of 16–24 MW most of the time (with the highest probability), we need to install a WF with a size of 24 MW with the optimal turbine parameters given in Table 4. Consider that the WF size is limited to 24 MW, as given in (24). If any larger/smaller WF size is taken, then the probability of having its output power within the range of interest would be lower than the obtained value here, i.e., 64.19 %.

As mentioned in Sect. 3, the probability of desired event is a monotonic function of its variables. This is demonstrated in Fig. 2a and b for this test case. Similarly, the optimal capacity of WFs which should be installed at other buses can be calculated.

5 Conclusion

A novel approach for transmission line congestion management using new generation resources has been introduced. The objective function is selected so that the total congestion rent which is related to the LMP differences can be reduced. ACOPF could also be applied to this method. In that case, the objective function would not reach zero due to the losses in the system. The main contributions of this paper are summarized as follows:

- LMP differences by which the congestion rents are calculated have been used to minimize congestion in the system.
- $N-1$ contingency for line outages is considered for which the system should not undergo overloading in other transmission lines.
- An algorithm for calculating the size and site of new generation units to relieve congestion in transmission system has been proposed.
- Solution methods are described for determining the appropriate size of wind farms considering the probabilistic characteristics of wind speed.

Appendix

Table 5 Cost function and generation limits for the 6-bus system

Bus	P_g^{max}	P_g^{min}	c_i (\$/MW^{2}h)	b_i (\$/MWh)	a_i (\$)	Load bus	P_d (MW)	Q_d (MVAr)
1	318	10	100	10.833	0.00741	4	135	60
2	200	10	213.1	11.669	0.00533	5	18	50
3	200	10	200	10.333	0.00889	6	70	30

Table 6 Line parameters for the 6-bus system

From bus	To bus	R	X	B	Power flow limit (MW)
2	3	0.05	0.25	0.06	30.82
3	6	0.02	0.1	0.02	75
4	5	0.2	0.4	0.08	17.96
3	5	0.12	0.26	0.05	65.85
5	6	0.1	0.3	0.06	32
2	4	0.05	0.1	0.02	136
1	2	0.1	0.2	0.04	25.91
1	4	0.05	0.2	0.04	90
1	5	0.08	0.3	0.06	84.78
2	6	0.07	0.2	0.05	80
2	5	0.1	0.3	0.04	71.14

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