Transmission Expansion Planning of Systems With Increasing Wind Power Integration

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***Abstract*—This paper proposes an efficient approach for probabilistic transmission expansion planning (TEP) that considers load and wind power generation uncertainties. The Benders decomposition algorithm in conjunction with Monte Carlo simulation is used to tackle the proposed probabilistic TEP. An upper bound on total load shedding is introduced in order to obtain network solutions that have an acceptable probability of load curtailment. The proposed approach is applied on Garver six-bus test system and on IEEE 24-bus reliability test system. The effect of contingency analysis, load and mainly wind production uncertainties on network expansion configurations and costs is investigated. It is shown that the method presented can be used effectively to study the effect of increasing wind power integration on TEP of systems with high wind generation uncertainties.**

***Index Terms*—Benders decomposition, Monte Carlo simulation, probabilistic contingency analysis, transmission expansion planning, wind power generation.**

Nomenclature

c_{ij}	Cost of a line added to the $i-j$ right of way (\$).
γ_{ij}	Susceptance of the line between buses i and j.
$cond_{ij}$	Conductance of the line between buses i and j.
n_{ij}	Number of new lines added to the $i-j$ right of way.
n_{ij}^0	Initial number of lines between buses i and j.
$\bar{n}_{ij}$	Maximum number of lines that can be added to the $i-j$ right of way.
f_{ij}	Active power flow in the $i-j$ right of way (MW).
f_{ij}^{mn}	Active power flow in the $i-j$ right of way when a line in the $m-n$ right of way is out of service (MW).
$\bar{f}_{ij}$	Active power flow limit on the $i-j$ right of way (MW).
θ_i	Phase angle in bus i.
θ_i^{mn}	Phase angle in bus i when a line in the $m-n$ right of way is out of service.
S	Branch-node incidence matrix.
S^{mn}	Branch-node incidence matrix when a line in the $m-n$ right of way is out of service.
$\boldsymbol{g}$	Vector of active power generation with elements g_k (generation in bus k).
$\boldsymbol{g^{mn}}$	Vector of active power generation when a line in the $m-n$ right of way is out of service with elements g_k^{mn}.
$\bar{g}$	Vector of maximum generator capacity.
$\boldsymbol{d}$	Vector of the predicted load.
$\boldsymbol{r}$	Vector of load curtailment with elements r_κ.
$\boldsymbol{r^{mn}}$	Vector of load curtailment when a line in the $m-n$ right of way is out of service with elements r_k^{mn}.
p_f	Load penalty factor (\$/MW).
p_{fe}	Load penalty factor for the probabilistic approach (\$/MW).
W_0	Total load curtailment cost in normal operation without contingencies (\$).
W_1^{mn}	Total load curtailment cost in single contingency situation (\$).
W_1	Total load curtailment cost for all $N-1$ situations (\$).
$L_{\max}$	Upper bound of load curtailment for the planning horizon (MW).
$Pr\{\}$	Probability of events.
E(y)	Expected value of variable y.
Γ	Set of load buses.
Ω	Set of all existing and new right-of-ways.
Ψ	Set of selected contingencies.

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I. Introduction

THE main objective for transmission expansion planning (TEP) in deregulated power markets is to provide nondiscriminatory and competitive market conditions to all stakeholders, while maintaining power system reliability [1]. There is a number of uncertainties that have to be taken into account that can be classified into two categories [2]: 1) random uncertainties, such as load development, generators' operating costs, availability and bidding prices, availability of transmission lines, renewables production and 2) nonrandom uncertainties, such as location of new generators, available transmission expansion investment budget, etc. The statistics of random uncertainties can be derived from past observations, but nonrandom uncertainties are not repeatable and cannot be statistically represented. The large integration of renewable energy sources (RES) into modern power systems has made the TEP problem even more challenging, because the greatly increased uncertainties introduced often require new transmission lines in order to maintain a satisfactory level of power system security and adequacy [3], [4].

Independent of the market conditions, the power system should always be operated in a way that no contingency triggers cascading outages or causes any form of instability. Since securing the system against all possible contingencies is practically impossible, the system operator only checks a set of credible contingencies [5]. Most security rules therefore call for the system to be able to withstand the loss of any single component, thus being "$N-1$ secure" and sometimes the loss of a selected combination of two components, i.e., "$N-2$ secure". In transmission expansion problems, the steady state security analysis aims at satisfying the nodal power balance with no violations of the transmission lines maximum flow under normal and contingency situations.

TEP can be classified as static or dynamic according to the study period. For static planning, the developer searches for the suitable circuits that should be added in the current transmission system. If multiple years are considered and an optimal expansion along the whole planning horizon is searched, planning is classified as dynamic. Various methods have been applied to solve the transmission expansion planning problem, such as linear programming [6], dynamic programming [7], branch and bound [8], mixed integer programming [9], decomposition techniques [10], simulated annealing [11], tabu search [12], genetic algorithm [13], and differential evolution [14]. Probabilistic methods for the solution of TEP problem include probabilistic reliability criteria [15], risk assessment methods [16], and chance constrained programming [17].

In this paper, the static TEP problem is solved with the Benders decomposition technique incorporating $N-1$ security analysis. The deterministic TEP method is described first. More specifically, secure and adequate transmission solutions are determined by assuming different possible future dispatches of generators for the peak demand along with generation re-dispatching, in order to investigate the impact of generation expansion and bidding behavior to security constrained static transmission planning cost. Generation costs and bidding strategies can significantly change the outcome of TEP since they can affect lines utilization. However, the system planner can make a good assumption of these costs and incorporate them into the TEP problem, while the congestion cost reduction resulting from new lines can be compared to the new lines cost for a certain period of time in a cost-benefit analysis.

The impact of wind power integration on TEP investment cost while maintaining system security at a satisfactory level is investigated next. In the proposed probabilistic TEP method, load and wind power generation uncertainties as well as forced outage rates of the transmission lines are included and an acceptable upper bound of possible load shedding is set, in order to find secure transmission solutions with minimum investment cost. The DC power flow with the incorporation of losses is employed for the network representation. The proposed probabilistic TEP approach is formulated in Section II and solved in Section III. The method is applied to Garver six-bus test system and to IEEE 24-bus reliability test system and the results are analyzed and compared in Section IV. Conclusion are drawn in Section V.

II. Probabilistic TEP Problem

A. TEP Problem

In a power system represented by the DC load flow model, the mathematical formulation for the static deterministic TEP model is

$$Min\left\{\sum_{(i,j)} c_{ij}n_{ij} + p_f\sum_{k} r_k\right\} \tag{1}$$

subject to :

$$S^T f + g + r = d \tag{2}$$
$$f_{ij} - \gamma_{ij}\left(n_{ij}^0 + n_{ij}\right)\left(\theta_i - \theta_j\right) = 0 \tag{3}$$
$$|f_{ij}| \le \left(n_{ij}^0 + n_{ij}\right)\bar{f}_{ij} \tag{4}$$
$$0 \le g \le \bar{g} \tag{5}$$
$$0 \le r \le d \tag{6}$$
$$0 \le n_{ij} \le \bar{n}_{ij} \tag{7}$$
$$n_{ij} \text{ is integer} \tag{8}$$
$$(i,j) \in \Omega, \quad k \in \Gamma. \tag{9}$$

In the above TEP formulation, also known as adequacy TEP, the objective is to find an optimal transmission structure to meet the peak load demand with minimum investment and loss of load cost, while satisfying operational limitations. Equation (2) stands for the power nodal balance equation; (3) is the DC power flow model, while (4)–(6) specify the operational limits of the system. Constraint (7) defines the range of the investment variables. In the above formulation, re-dispatching of generators is considered.

In order to include the N-1 security criterion in the TEP formulation, problem (1) is modified as follows [18]:

$$Min\left\{\sum_{(i,j)} c_{ij}n_{ij} + p_f\sum_{k} r_k + p_f\sum_{(m,n)} r_k^{mn}\right\} \tag{10}$$

subject to :

$$(S^{mn})^T f^{mn} + g^{mn} + r^{mn} = d \tag{11}$$
$$f_{ij}^{mn} - \gamma_{ij}\left(n_{ij}^0 + n_{ij} - 1\right)\left(\theta_i^{mn} - \theta_j^{mn}\right) = 0,\ ij = mn \tag{12}$$
$$\left|f_{ij}^{mn}\right| \le \left(n_{ij}^0 + n_{ij} - 1\right)\bar{f}_{ij},\ ij = mn \tag{13}$$
$$f_{ij}^{mn} - \gamma_{ij}\left(n_{ij}^0 + n_{ij}\right)\left(\theta_i^{mn} - \theta_j^{mn}\right) = 0,\ ij \ne mn \tag{14}$$
$$\left|f_{ij}^{mn}\right| \le \left(n_{ij}^0 + n_{ij}\right)\bar{f}_{ij},\ ij \ne mn \tag{15}$$
$$0 \le g^{mn} \le \bar{g} \tag{16}$$
$$0 \le r^{mn} \le d \tag{17}$$
$$(m,n) \in \Psi \tag{18}$$
$$Eq.\ (2)-(9). \tag{19}$$

Parameters with superscript mn denote the modified variables when a line on the $m-n$ right of way is outaged. The constraints that should be met in problem (10) are constraints

(2)–(9) with the addition of constraints (11)–(18). If producers' operating costs, reflected in their bids, are taken into account or the dispatch of the generators at the specific time of the planning horizon is known, then in problems (1) and (10) vector $\boldsymbol{g}$ is constant and constraints (5) and (16) are excluded. This formulation reveals the difficulty of the network planner in the new deregulated environment where congestion cost and the need for new lines are closely related with the generators bids and cost functions.

B. Probabilistic TEP Problem Formulation

In order to consider the uncertainties in future load demand and wind power output, a probabilistic formulation of the problems (1) and (10) is needed. The expected loss of load replaces the curtailed load under normal operation and the wind power output together with the outage rate of the transmission lines and/or uncertainties in future load growth are considered using Monte Carlo simulation:

$$Min\left\{\sum_{(i,j)} c_{ij}n_{ij} + p_f E\left(\sum_k r_k\right)\right\}. \tag{20}$$

The probability of load curtailment exceeding a specified limit is included in the problem formulation as follows:

$$Min\left\{\sum_{(i,j)} c_{ij}n_{ij} + p_{fe}\Pr\left\{\sum_k r_k > L_{\max}\right\} E\left(\sum_k r_k\right)\right\} \tag{21}$$

where L_{max} is a percentage of the total peak load. This upper bound is used to find solutions that minimize the probability of having load curtailment over this threshold at the peak load of the planning horizon.

III. Solution of the TEP Problem

The Benders decomposition technique [19] is used to solve this mixed integer nonlinear problem in both deterministic and probabilistic expressions. The original problem is separated into several subproblems that are solved iteratively: 1) the master problem, which is a binary integer programming problem that identifies the candidate investments and 2) the operation subproblems that are linear problems with fixed integer variables that check whether the scheme selected from the previous master problem can meet system operation constraints. If any constraint becomes active in any of the operation subproblems, a Benders cut is formulated, based on the linear programming duality theory, and added cumulatively in the master problem for solving the next iteration of the algorithm. Benders cuts are influenced by the line limits constraints, since when congestion occurs, excessive generation cannot be transferred by the congested lines and load in some buses may be curtailed. In the probabilistic formulation the probability of load curtailment above a threshold affects the upper bound of the Benders' decomposition method. This helps the convergence of the method to solutions that have a small probability of load curtailment and at the same time almost zero probability of load curtailment above this threshold.

A. Probabilistic Operation Subproblem

The probabilistic adequacy subproblem (22)–(28) is used for the formulation in (21). In the stochastic resource planning, each possible system state is represented by a scenario. The Monte Carlo simulation technique [20] is applied to simulate the random output of wind power generation, load demand and uncertainties of system component outages. For each system state, the objective of the adequacy operation subproblem is to minimize load shedding under normal operation by applying a generation dispatch:

$$Min\{W_0\} = Min\left\{p_f \sum_k r_k\right\} \tag{22}$$

subject to :

$$S^T f + g + r = d \tag{23}$$
$$f_{ij} - \gamma_{ij}\left(n_{ij}^0 + n_{ij}^t\right)(\theta_i - \theta_j) = 0 \tag{24}$$
$$|f_{ij}| \le \left(n_{ij}^0 + n_{ij}^t\right)\bar{f}_{ij} \tag{25}$$
$$0 \le g \le \bar{g} \tag{26}$$
$$0 \le r \le d \tag{27}$$
$$(i,j) \in \Omega \tag{28}$$

where n_{ij}^t is the solution obtained at the tth Benders iteration. Generators lower limits can also be included, representing the units that must run continuously for security reasons and/or due to long term bilateral energy contracts. Estimated losses on each branch are calculated using (29):

$$Loss_{ij} \approx 2cond_{ij}(1 - \cos\theta_{ij}). \tag{29}$$

Active losses are then allocated to the loads in the extreme nodes of each branch and (22)–(28) are solved again. This leads to an iterative process that terminates when phase angles at all buses do not change significantly from the previous iteration. For fixed generation dispatch, vector $\boldsymbol{g}$ is constant and constraint (26) is excluded.

The power output P_W of a wind turbine as a function of wind speed V_W (m/s), is

$$P_W = \begin{cases} 0, & if\ 0 \le V_W \le V_{CI} \\ P_R(V_W - V_{CI})/(V_R - V_{CI}), & if\ V_{CI} \le V_W \le V_R \\ P_R, & if\ V_R \le V_W \le V_{CO} \\ 0, & if\ V_{CO} \le V_W. \end{cases} \tag{30}$$

V_{CI} is the cut-in and V_{CO} is the cut-out wind speed and P_R is the rated power of the wind turbine. From this linear wind power production approximation, the power output can be calculated if the wind speed and the wind turbine's characteristics are known. It should be noted that according to current operating practices in many countries, wind power is priority dispatched. Thus, in this formulation it is assumed that the production of a wind park can be curtailed, only if the operation subproblem is infeasible.

If line outages rates are not considered in the Monte Carlo simulations and a deterministic method is followed for the N-1 security analysis, problem (22) is solved for each of the security subproblems. The objective is to minimize load curtailment under a single contingency by applying a generation dispatch:

$$Min\{W_1^{mn}\} = Min\left\{p_f \sum_k r_k^{mn}\right\} \tag{31}$$

$$(m,n) \in \Psi. \tag{32}$$

The constraints that should be met in problem (31) are (23)–(29) and (32), with the difference that for each contingency a new branch node incidence matrix is created and the number of lines in the examined right of way is reduced by one. The security subproblem is solved for all credible contingencies mn included in set Ψ. After all contingencies have been considered, the total load curtailment is computed by (33):

$$W_1 = \sum_{mn} W_1^{mn}. \tag{33}$$

Another way of performing the security analysis is to relax constraint (25), considering vector $\boldsymbol{g}$ as the generation dispatch of the adequacy subproblem and minimize line overloads [21]. Both methods result in the same final transmission investment solutions. It should be noted that re-dispatching of generation is not based on generators' bids or costs but on minimizing total load curtailment.

The algorithm of computing the expected loss of load and the expected dual variables in the operation subproblem of each Benders iteration, follows the following ten steps, where load demand, wind speed and transmission lines availability are assumed independent:

1) Determine forced outage rate (FOR) of each transmission line and assign a standard uniform probability density function (pdf).
2) Determine the pdf of the peak load of the planning horizon.
3) Given the mean value $(\mathrm{V_{W,MEAN}})$ and the standard deviation (σ_{W}) of the wind speed, determine the parameters of the Weibull distribution function that represent the wind speed at the location of the wind turbines.
4) Generate a number from the standard uniform pdf of the FOR of each line determined in step 1, and compare it with its unavailability. If this number is less than its unavailability, then the line is on outage, otherwise it is in operation.
5) Generate a number from the pdf of the peak load determined in step 2, and compute the peak load at each bus accordingly.
6) Generate a number from the Weibull distribution of the wind speed determined in step 3, and calculate the power output of the wind turbine using (30).
7) Solve the adequacy subproblem (22) for the network configuration of step 4, load of step 5 and wind power generation of step 6 and save the outputs (W_0, Lagrange multipliers, etc.).
8) Compute the current expected values of W_0 and the dual variables needed in the next investment subproblem.
9) Repeat steps 4 to 8, until sufficient accuracy is obtained.
10) Find the probability $\Pr\{W_0 > L_{max}\}$.

B. Investment Subproblem (Master Problem)

The investment subproblem takes as input the Benders cuts formulated from the operation subproblem(s) and finds the new lines added at each iteration. This problem is a binary integer problem, which seeks for the minimum cost of new added lines with constraints provided by the corresponding subproblem(s). The formulation of the investment problem is as follows [22]:

$$Min\left\{\sum_{(i,j)} c_{ij} n_{ij}\right\} \tag{34}$$

subject to :

$$W_0^t + W_1^t + \sum_{(i,j)} \sigma_{ij}^k \left(n_{ij} - n_{ij}^t\right) \le \beta,\ k = 1,2,\ldots,t \tag{35}$$

$$0 \le n_{ij} \le \bar{n}_{ij} \tag{36}$$

$$n_{ij} \text{ is integer} \tag{37}$$

$$\beta \ge 0 \tag{38}$$

where W_0^t and W_1^t are the solutions of the adequacy and security subproblems of the previous iteration t and σ_{ij}^t is the sensitivity of the optimum values W_0^t and W_1^t with respect to the decision variable. The Benders cuts are represented by (35), and sensitivity factor σ_{ij}^t is given by

$$\sigma_{ij}^t = \sum_p \left(\pi_i^p - \pi_j^p\right)\left(\theta_i^p - \theta_j^p\right)\gamma_{ij}, \quad \mathrm{p} = 0,1,2,\ldots,\mathrm{c} \tag{39}$$

where p is the operations subproblem solved ($\mathrm{p} = 0$ for the adequacy subproblem and $\mathrm{p} = 1,2,\ldots,\mathrm{c}$ for the cth security subproblem for each contingency $(m,n) \in \Psi$). π_i are the dual variables (Lagrange multipliers) of (23) for the adequacy and the security subproblems. When node i or node j is not connected to the system, the sensitivity factor for the $i-j$ right of way is

$$\sigma_{ij}^t = \sum_p \left(\pi_i^p - \pi_j^p\right)\bar{f}_{ij}. \tag{40}$$

The total cost for Benders tth iteration is the sum of the new added lines, and the curtailed load costs, W_0 and W_1, computed from the tth investment and operation subproblems, respectively.

In the probabilistic formulation of the investment subproblem, after all the generated scenarios have been solved for the operation subproblems of the previous iteration, the expected values of loss of load and the expected values of the sensitivity factors, replace the corresponding deterministic values in (35). The Benders cuts added to the investment problem of each iteration are as follows:

$$E\left(W_0^t\right) + \sum_{(i,j)} E\left(\sigma_{ij}^k\right)\left(n_{ij} - n_{ij}^t\right) \le \beta, \quad \mathrm{k} = 1,2,\ldots,\mathrm{t}. \tag{41}$$

The total cost for Benders tth iteration is calculated by adding the cost of the new added lines and the expected curtailed load cost $E(W_0)$ multiplied by the probability $\Pr\{W_0 > L_{max}\}$ computed from the tth investment and probabilistic operation subproblems.

IV. Results and Discussion

A. Introduction

The proposed algorithm was implemented in MATLAB 7, was tested on Garver 6-bus test system [6] and IEEE 24-bus reliability test system [23] using a PC with Core 2 Duo CPU clocking at 3.0 GHz and 2 GB of RAM. First, the deterministic TEP problems (1) and (10) are investigated for both a given generator dispatch and generation re-dispatching. Then, the probabilistic TEP problem (21) is solved for various peak load uncertainties, upper load shedding bounds (L_{max}) and wind characteristics. Transmission lines outages are modeled using a failure rate of 1% in order to "capture" as many as possible of the $N-1$ contingency situations in the probabilistic framework, since a lower value could underestimate the effect of the contingency conditions in the investment plans [2]. The load penalty factor p_f is assumed equal to 10^6 \$/MW while the load penalty factor p_{fe} for the probabilistic approach is set equal to 10^8 \$/MW, in order to find the most secure expansion solutions. It should be noted that up to four and up to three circuits could be added per right of way for Garver 6-bus and IEEE 24-bus test system, respectively.

B. Garver 6-Bus Test System

1) Deterministic TEP: For the deterministic TEP approach, problems (1) and (10) are solved for both re-dispatched and fixed generation. The optimum solution for the adequacy problem (1) including losses requires the addition of 3 new lines between buses 4 and 6 ($\mathrm{n}_{46} = 3$), 1 new line between buses 3 and 5 ($\mathrm{n}_{35} = 1$) and 1 more line between buses 2 and 3 ($\mathrm{n}_{23} = 1$), while the total investment cost is 130 k\$ with zero curtailed load. The solution of the security expansion problem (10) requires the addition of 7 new lines ($\mathrm{n}_{46} = 3$, $\mathrm{n}_{35} = 2$, $\mathrm{n}_{23} = 1$ and $\mathrm{n}_{26} = 1$), while the total cost is 180 k\$ achieving zero load shedding for all the $N-1$ configurations of the system.

In order to investigate the impact of different generation dispatches on transmission planning, total generation is kept constant (760 MW), but it is dispatched differently to the three generators. If generation at buses 1, 3 and 6 is fixed at $\mathrm{g}_1 = 50\ \mathrm{MW}$, $\mathrm{g}_3 = 165\ \mathrm{MW}$ and $\mathrm{g}_6 = 545\ \mathrm{MW}$, then for the security expansion problem (10) the optimum solution requires ten new lines ($\mathrm{n}_{26} = 4$, $\mathrm{n}_{46} = 3$, $\mathrm{n}_{35} = 2$ and $\mathrm{n}_{36} = 1$) and the investment cost is 298 k\$. If the generation dispatch is $\mathrm{g}_1 = 130\ \mathrm{MW}$, $\mathrm{g}_3 = 85\ \mathrm{MW}$ and $\mathrm{g}_6 = 545\ \mathrm{MW}$, the solution obtained for the security problem requires eleven new lines ($\mathrm{n}_{26} = 4$, $\mathrm{n}_{46} = 3$, $\mathrm{n}_{35} = 2$, $\mathrm{n}_{15} = 1$ and $\mathrm{n}_{36} = 1$) and the total cost increases to 318 k\$. Finally, if the generation dispatch is 50 MW at bus 1, 265 MW at bus 3 and 445 MW at bus 6, ten lines are added for a secure system ($\mathrm{n}_{26} = 4$, $\mathrm{n}_{46} = 3$, $\mathrm{n}_{35} = 3$) with a total investment cost of 270 k\$.

From the previous analysis it is concluded that different secure and adequate configurations of the network are obtained when generation is considered fixed or when it can be re-dispatched to avoid load curtailment. In power system operation, generation production depends on generators bids, however in static TEP formulation, re-dispatched generation leads to less expensive investment plans. The cost of re-dispatching can be calculated in a cost-benefit analysis of the considered transmission plans using annual simulation. From the solutions of the fixed generation simulations, it is concluded that the final investment plans at Garver's test system strongly depend on the generation at bus 3, which is closer to the high demand buses 2 and 5.

TABLE I
TEP Schemes for Various Peak Load Uncertainties and Load Shedding Upper Bounds for Garver 6-Bus Test System

σ_{LOAD}/ E_{LOAD}	L_{MAX}	Lines added	Cost (k\$)
0%	0%	n_{46}=3, n_{35}=2, n_{23}=1, n_{26}=1	180
	5%	n_{46}=3, n_{35}=2, n_{23}=1	150
	10%	n_{46}=3, n_{35}=1, n_{23}=1	130
5%	0%	n_{46}=3, n_{35}=2, n_{23}=2, n_{26}=1	200
	5%	n_{46}=3, n_{35}=2, n_{23}=1, n_{26}=1	180
	10%	n_{46}=3, n_{35}=2, n_{23}=1	150
10%	0%	n_{46}=3, n_{35}=2, n_{23}=1, n_{26}=2	210
	5%	n_{46}=3, n_{35}=2, n_{23}=2, n_{26}=1	200
	10%	n_{46}=3, n_{35}=2, n_{23}=1, n_{26}=1	180

2) Probabilistic TEP: In the probabilistic approach, five series of tests are simulated for Garver's test system. The pdf of the peak load at each bus follows a normal distribution with a mean equal to the base case data. Only re-dispatched generation is considered.

Without Wind Generation: In the first three series of simulations, no wind power is assumed and a different standard deviation is assigned to the load pdf of each bus (0%, 5%, and 10%) representing the impact of the peak load forecast uncertainty on TEP. For each standard deviation, different upper bounds for the maximum load shedding parameter L_{max} are examined. The values assigned to these bounds are calculated as percentages of the total peak load of the system. The corresponding results for each simulation are given in Table I. These results demonstrate that the final planning schemes are significantly affected by peak load uncertainty (standard deviation over peak load, $\sigma_{\mathrm{LOAD}}/\mathrm{E}_{\mathrm{LOAD}}$) and load shedding upper bound (L_{max}). As expected, for the same load shedding, higher investment costs are needed when peak load uncertainty increases. On the other hand, when load shedding tolerance increases, less expensive configurations are selected. In this way, the proposed method provides the flexibility to the planner to balance the objectives of minimizing total investment cost and risk. It should be noted that for zero peak load uncertainty and zero load shedding, the results of the probabilistic and deterministic TEP are the same which justifies the selected failure rate for transmission lines outages.

With Wind Generation: In order to simulate the wind power uncertainty, it is considered that the installed generation at bus 3 is composed of 120 MW of wind power capacity plus 240 MW of conventional thermal power capacity. The generation output of all the wind turbines follows (30), with parameters set at $\mathrm{V_R} = 11.9\ \mathrm{m/s}$, $\mathrm{V_{CI}} = 3.5\ \mathrm{m/s}$ and $\mathrm{V_{CO}} = 25\ \mathrm{m/s}$. The wind speed characteristics for the base scenario are $\mathrm{V_{W,MEAN}} = 7\ \mathrm{m/s}$ and $\sigma_{\mathrm{W}} = 2.5\ \mathrm{m/s}$. For 10% standard deviation of the peak load and for various maximum load-shedding values, the

TABLE II
TEP SCHEMES FOR $\sigma_{\mathrm{LOAD}}/\mathrm{E}_{\mathrm{LOAD}} = 10\%$ AND WIND POWER GENERATION CONSIDERATION FOR GARVER 6-BUS TEST SYSTEM

L_{MAX}	LINES ADDED	COST (k$)
0%	n_{46}=3, n_{35}=2, n_{26}=3, n_{23}=1, n_{15}=1	260
5%	n_{46}=3, n_{35}=2, n_{26}=2, n_{23}=1, n_{15}=1	230
10%	n_{46}=3, n_{35}=2, n_{26}=2, n_{23}=1	210

TABLE III
LOAD SHEDDING PROBABILITY FOR DIFFERENT WIND SPEED CHARACTERISTICS AND $\sigma_{\mathrm{LOAD}}/\mathrm{E}_{\mathrm{LOAD}} = 10\%$ FOR GARVER 6-BUS TEST SYSTEM

LINES ADDED	WIND SPEED CHARACTERISTICS	PR{W_0>0}
n_{46}=3, n_{35}=2, n_{26}=2, n_{23}=1	$V_{W,MEAN}$=5.5m/s , σ_W=2m/s	0.112
	$V_{W,MEAN}$=7m/s , σ_W=2.5m/s	0.059
	$V_{W,MEAN}$=10m/s , σ_W=3.5m/s	0.031

results for the optimum plans are shown in Table II. Moreover, Table III provides the probability of load shedding for the less expensive configuration for various wind speed characteristics.

For the investment plan presented in Table III, the addition of only one new line (n_{26}) compared to the solution obtained in the deterministic security TEP problem, can maintain the probability of load curtailment at satisfactory level, although part of conventional generation capacity has been replaced by wind power capacity at node 3. The uncertainty of wind power generation raises the planning risk and produces more expensive network configurations to meet the same standards of system adequacy and security. The probability of having load curtailment is increasing when lower wind speeds are considered.

C. IEEE 24-Bus Reliability Test System

1) Deterministic TEP: Results from the deterministic analysis considering only re-dispatched generators are presented in Table IV. The loads and generation levels are assumed to be three times higher than their original values [23]. From the results it is concluded that the $N-1$ security constraints increase significantly the number of new added lines, especially at the lower parts of the network where buses are not so strongly connected, and raises the total investment cost by \$3.59 million for the case of considering line losses. A sensitivity analysis that takes into consideration multiple load levels, including generators cost and bid curves and outage rates is needed, to perform a cost benefit analysis for the suggested transmission investments. It is possible that a less expanded, but secure grid burdened by lines congestion costs requiring generator re-dispatching might be more cost effective for the transmission assets owner and operator than an overbuild network.

2) Probabilistic TEP: In order to simulate wind generation, half of the conventional generation capacity connected at buses 7 and 22 is assumed to be replaced by wind generators with wind power parameters equal to $\mathrm{V_R} = 11.9\ \mathrm{m/s}$, $\mathrm{V_{CI}} = 3.5\ \mathrm{m/s}$ and $\mathrm{V_{CO}} = 25\ \mathrm{m/s}$. If the two wind sites (of buses 7 and 22) are assumed uncorrelated, random wind speed numbers for the two sites are generated from two different Weibull distribution functions. If the same random number is used for both sites, the power outputs of the two wind parks become fully correlated. However, in this paper some correlation between the two sites is assumed using the cross-correlation index [24]. Fig. 1 shows the probability distribution function of the two wind farms output when $\mathrm{V_{W,MEAN}} = 5.5\ \mathrm{m/s}$ and $\sigma_{\mathrm{W}} = 2\ \mathrm{m/s}$, assuming a cross-correlation index between the two wind sites of 0.75.

TABLE IV
TEP SCHEMES FOR IEEE 24-BUS RELIABILITY TEST SYSTEM USING THE DETERMINISTIC TEP METHOD

		NUMBER OF LINES ADDED			
		ADEQUATE TEP		N-1 SECURE TEP	
FROM BUS	TO BUS	WITHOUT LOSSES	WITH LOSSES	WITHOUT LOSSES	WITH LOSSES
1	5			1	1
3	9			2	2
3	24			1	1
4	9			1	1
6	10	1	1	2	2
7	8	2	2	2	2
9	12			1	1
10	12	1	1	1	1
11	13				1
12	13			1	1
14	16	1	1	1	1
20	23		1	1	1
COST (k$)		1520	1820	4750	5410

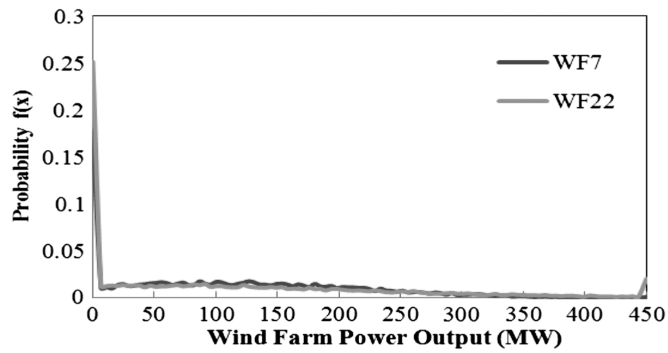

Fig. 1. Probability distribution function f(x) of generation output of WF7 and WF22 wind farms located at buses 7 and 22, respectively.

The results for 5% peak load uncertainty and for various load-shedding limits and different wind speed characteristics are presented in Table V. The probability of load curtailment exceeding the upper bound L_{max} is less than 0.05 for all investment plans. The solutions obtained for $L_{max} = 1\%$ have a greater risk of load curtailment compared to the $L_{max} = 0\%$ cases, but lead to less expensive expansion schemes with rather small probability of load curtailment. The number of iterations needed for the convergence of Benders' decomposition method is very much dependent on the number of new lines installed for each TEP scheme, while the CPU time needed for the probabilistic TEP method to converge depends also on the probabilistic adequacy subproblems solved for each Benders' algorithm iteration. The solution for the first TEP scheme of Table V, was the most time demanding. For this case, the algorithm converged after 61 iterations and 57 min of CPU time.

The cumulative distribution function (cdf), F(x), of load curtailment for zero actual wind generation production for the six plans of Table V is presented in Fig. 2. If, during

TABLE V
TEP SCHEMES FOR 5% PEAK LOAD UNCERTAINTY AND CORRELATION INDEX 0.75 BETWEEN THE TWO WIND SITES FOR IEEE 24-BUS TEST SYSTEM

		NUMBER OF LINES ADDED					
		$V_{W,MEAN}$=3m/s, σ_W=1m/s		$V_{W,MEAN}$=5.5m/s, σ_W=2m/s		$V_{W,MEAN}$=10m/s, σ_W=3.5m/s	
FROM	TO	L_{MAX}		L_{MAX}		L_{MAX}	
BUS	BUS	0%	1%	0%	1%	0%	1%
1	5	1	1	1	1	1	1
2	4	1	1	1	1	1	
3	9	1		1			
3	24	2	2	1	1	1	1
6	10	2	2	2	2	2	2
7	8	1	1	2	2	2	2
8	9	2	2	2	1		
8	10	1				1	1
9	11	1	1	1	1		1
9	12	1	1				
10	11	1	1	1	1		
10	12	1	1	1	1	2	2
11	13	1	1	1	1		
12	13	1	1	1	1	2	1
12	23	1					
14	16	2	2	2	2	2	2
15	21	1		1			
15	24	1	1	1	1	1	1
16	17	1	2	1	2	2	1
17	18	1	2	1	1	2	1
20	23	1	1	1	1	1	1
COST (k$)		11630	9430	9020	7960	7660	6610
$E(\sum r_k)$ (MW)		4.671	8.175	4.324	8.415	2.478	8.266
$PR\{W_0>0\}$		0.041	0.057	0.039	0.059	0.024	0.047

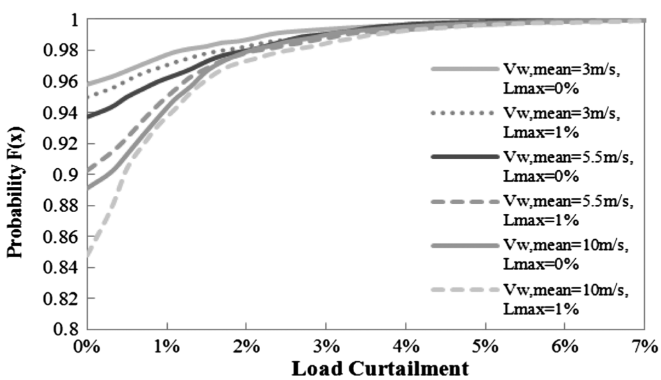

Fig. 2. Cumulative distribution function F(x) of load curtailment for zero wind power production for the six plans of Table V.

the planning process the wind speed is overestimated ($V_{W,MEAN} = 10$ m/s), then for peak load conditions, if the actual wind power production is zero, there is a high probability of load curtailment even for $L_{max} = 0\%$. On the other hand, if wind speed is underestimated ($V_{W,MEAN} = 3$ m/s), the network is overinvested and the probability of load curtailment is low for zero wind power generation. For average wind speeds ($V_{W,MEAN} = 5.5$ m/s), the probability of load curtailment for the corresponding network configuration is rather low and comparable to the low average wind speed case, while the cost of the investment needed is considerably lower.

Fig. 3 shows the TEP investment cost for different fractions of conventional generation replacement by wind power at buses 7 and 22, considering $V_{W,MEAN} = 5.5$ m/s and $\sigma_W = 2$ m/s, 5% peak load uncertainty and $L_{max} = 1\%$. It is assumed that

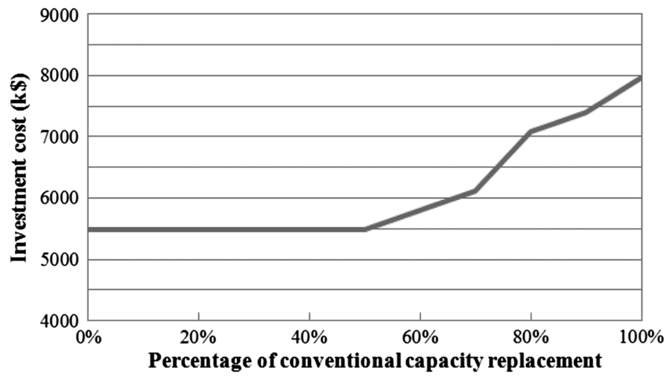

Fig. 3. TEP investment cost for various percentages of conventional capacity replacement by wind power.

the same wind generation capacity as before (450 MW at bus 7 and 450 MW at bus 22) replaces a predefined percentage of the rest 900 MW of conventional generation capacity located at the same buses. The results show that for wind generation integration up to 450 MW, i.e., lower than 50% of conventional capacity replacement, the resulting TEP investment cost remains the same. Overall, it can be concluded that the effect of high wind power integration on TEP depends critically on the level of penetration and cannot be straightforward determined. The availability of probabilistic, flexible tools, as the one presented in this paper, can effectively solve this problem.

V. CONCLUSIONS

The increase of wind power penetration into power systems has increased uncertainties and introduced new challenges to the transmission planners. This paper proposes an efficient approach to study the effect of wind power integration on transmission expansion planning. A probabilistic framework for the static TEP problem is presented that considers N-1 security analysis, as well as uncertainties in wind power generation and load demand. The Benders decomposition algorithm is adopted to solve the proposed TEP problem. The algorithm is first evaluated for the deterministic TEP problem considering the impact of re-dispatched generation on transmission investment cost. Monte Carlo simulation is used to apply the considered probabilistic approach, investigating also the introduction of an upper load shedding limit on the probabilistic TEP formulation.

The proposed method is tested on Garver 6-bus and on IEEE 24-bus reliability test systems. The results show that the incorporation of a variety of uncertainties increases transmission investment cost, which can be mitigated by the introduced upper limit in load shedding. The effect of wind integration in transmission planning is evaluated for different wind speed characteristics and for replacement of various amounts of conventional generation. Transmission investments with increased security should be decided based on a probabilistic approach that takes into consideration load demand and wind power generation uncertainties. The probabilistic method presented in this paper can be effectively used to provide effective transmission expansion plans with increased flexibility.

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