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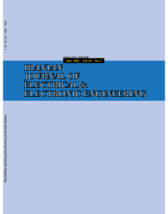

Risk Constrained Transmission Expansion Planning in Electricity Markets Considering Wind Curtailment Cost

R. Heydari* and T. Barforoushi*(C.A.)

Abstract: Curtailment of the production of wind resources due to uncertainty can affect the expansion of the transmission networks. The issue that needs to be addressed is how to expand the transmission network, which is accompanied by increasing wind energy utilization. In this paper, a new framework is proposed to solve the transmission expansion planning (TEP) problem in the presence of wind farms, considering wind curtailment cost. The proposed model is a risk-constrained stochastic bi-level problem that, the difference between the expected social welfare and investment cost is maximized at the upper level where optimal decisions on expansion plans are adopted by the independent system operator (ISO). To make the best use of wind generation resources, a new term called wind power curtailment cost is added to the upper level. Also, the risk index is included in expansion decisions. The market-clearing is considered at the lower level, aiming at maximizing social welfare. Uncertainties relating to wind power and the forecasted demand are modeled by sets of scenarios. Using duality theory, the proposed framework is modeled as mixed-integer linear programming (MILP) problem. The model is examined using the classical Garver's six-bus test system and the IEEE 24-bus reliability test system (RTS). The results show that by considering the wind curtailment cost, the transmission network is expanded in a way that increases the wind energy utilization factor from 92.05% to 95.17%.

Keywords: Duality Theory, Electricity Market, Stochastic Bi-Level Optimization, Transmission Expansion Planning (TEP), Wind Power Curtailment.

Nomenclature

Indices and Sets:

Ψ_n^D	Set of indices of the demands located at bus *n*.
Ψ_n^G	Set of indices of the fossil generating units located at bus *n*.
Ψ_n^{GW}	Set of wind power plants located at bus *n*.
Ω_i	Set of indices of the blocks of the *i*-th fossil generating unit.
Ω_j	Set of indices of the blocks of the *j*-th demand.
Ω^D	Set of indices of the demands.
Ω^G	Set of indices of the fossil generating units.
Ω^{GW}	Set of indices of the wind generating units.
Ω^L	Set of all transmission lines, prospective and existing.
$\Omega^{(L+)}$	Set of all prospective transmission lines.
Ω^N	Set of all network buses.
Ω^s	Set of all scenarios.
Ω^T	Set of indices of demand blocks.

Parameters and Constants:

b_k	Susceptance of line *k*.
c_k	Investment cost of line *k* [€].
$c^{\max}$	Investment budget [€].
N_t^h	The number of hours at demand block *t*.
C_j^U	Load shedding cost of demand *j* [€/MWh].
CRF	Capital recovery factor.
$d_{jt}^{\min}(s)$	Minimum power consumed by the *j*-th demand in demand block *t* and scenario *s* [MW].
$f_k^{\max}$	Transmission capacity of line *k* [MW].
$g_{ib}^{\max}$	Size of the *b*-th block of the *i*-th fossil generating unit [MW].
ir	Interest rate.

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M, Γ^{max} Big positive numbers.
$P_{yt}^{wmax}(s)$ Available wind power of the y-th wind generating unit in demand block t and scenario s [MW].
α Probability of non-fulfillment of profit η.
β Risk factor.
$se(k)$ Sending end bus of line k.
$re(k)$ Receiving end bus of line k.
$\delta(s)$ The weighting factor of scenarios.
λ_{Djh} The bid price of the h-th block related to the j-th load [€/MWh].
$d_{jht}^{max}(s)$ Size of the h-th block related to the j-th demand within demand block t and scenario s [MW].
λ_{Gib} The offer price of the b-th block related to the i-th fossil fuel power station [€/MWh].
λ_{wc} Wind curtailment cost [€/MWh].

Variables:

$d_{jht}(s)$ Power consumed by the h-th block of the j-th demand in demand block t and scenario s [MW].
$f_{kt}(s)$ Power flow of line k in block t and scenario s [MW].
$g_{ibt}(s)$ Produced Power of the b-th block related to the i-th fossil fuel power station within demand block t and scenario s [MW].
$gw_{yt}(s)$ Power produced by the y-th wind generating unit in demand block t and scenario s [MW].
$r_{jt}(s)$ Load shed by the j-th demand in demand block t and scenario s [MW].
S_w The amount of benefit that is less than η related to scenario s [€].
x_k The binary variable that equals 1 if the k-th line is built and equals 0 if not.
$\theta_{nt}(s)$ Voltage angle at bus n in demand block t and scenario s [radians].
η Profit at risk not met [€].

1 Introduction

WITH the increasing consumption of electricity in developed and developing societies, the need for sustainable energy sources and secure access to them has increased significantly. With increasing public awareness of environmental issues, traditional approaches to electricity generation are replacing renewable energy sources. In this regard, with the entry of the electricity industry into competitive environments, investors have considered the development of wind power generation on a large scale. On the other hand, the optimal use of wind generation resources requires the expansion of the transmission network. Therefore, transmission companies need appropriate models to realize the use of these environmentally friendly resources by selecting the optimal transmission line expansion plans. In this regard, what is important from an environmental point of view, and the focus in this paper, is to develop the transmission network in such a way as to increase the operation of wind farms as well as reduce the pollution from fossil fuel units.

A lot of researches have been conducted on TEP; however, the generation mix has mostly included fossil fuel power plants. The authors in [1] presented a chance-constrained formulation to consider load and wind uncertainty in the TEP problem. The probabilistic DC power flow and the Monte Carlo method have been used. The objective function includes the investment cost of the transmission lines and load curtailment cost. In [2] a robust MILP model is presented using the benders decomposition (BD) algorithm considering the load and wind uncertainties. Considering a maximum load curtailment determined by the sub-problem, the expansion cost is minimized in the master problem. In [3], a probabilistic TEP is presented by applying load and wind uncertainty and line outages using BD and the Monte Carlo method. The investment cost of the transmission lines and load curtailment cost are considered as the objective function. [4] and [5] introduced a multi-objective approach for TEP in the presence of large-scale wind farms. The objective function consists of investment cost, risk, and congestion cost. The risk cost is calculated based on expected energy not supplied (EENS). Solving the problem by the Non-Dominated Sorting Genetic Algorithm (NSGA II) method led to a set of non-dominated solutions. Eventually, the best solution is determined by a fuzzy satisfying decision-making method. In [6] a multi-objective model is presented for minimizing the costs of investment, congestion, and load curtailment. NSGA II along with the fuzzy decision-making method is implemented to obtain the optimal solution. [7] Modeled the TEP problem in which investigates the impact of wind power on system security. Both the reserve market and reserve availability costs are considered. Loss of load expectation (LOLE), reserve market, as well as reserve availability costs are considered. A bi-level model is presented in [8] for solving TEP within a market environment. The upper level represents the objective of the ISO, i.e., investment cost. Several market-clearing are considered at the lower level. In [9], the problem of investing in wind power and transmission lines is formulated through a bi-level model. At the upper level, the sum of investment costs of lined and wind farms, along with consumer payments, are minimized. At the lower level, market-clearing problems are solved.

A multi-objective stochastic TEP is presented in [10]. The considered objectives are the investment cost and system reliability. NSGA II algorithm and a probabilistic optimal power flow (POPF) are used to determine the Pareto solutions. A compromise method based on the preferences of the decision-maker is implemented to find the best plan. In [11], an approach based on the branch-and-cut BD method is presented to solve the security-constrained TEP problem. Using this method has resulted in a reduction in computational burden. In [12] a scenario reduction technique based on an iterative process is used for decreasing the computational time of the BD method in solving TEP problems under load and wind uncertainties. An iterative greedy process is used to select a reduced set with a minimum Kantorovich distance from the original set.

In [13], the TEP problem is solved using the GA method considering single contingency dealing with investment cost and curtailed wind power. The operational cost of thermal generating units, the investment cost of lines, and the cost relating to energy curtailment are considered. In [14] TEP is solved by considering wind power and demand response. The objective function comprises the costs of line investment, demand response, power generation, and security risk. Using the BD method, the problem has been decomposed into a master problem and two salve sub-problems.

In [15], an uncertain TEP considering demand response, wind resources, and network reliability are formulated in an electricity market. The reliability index is EENS. The objective is the investment cost, congestion, and risk, and incentive costs for participants in the demand response program. [16] Solved chance-constrained TEP considering renewable generation and load uncertainties by BD method. A new scenario generation method based on clustering techniques is proposed. The objective of the master problem is to minimize the investment cost of lines as well as the curtailed cost associated with renewable power production. The feasibility check sub-problem aims to minimize the curtailment of renewable generation and load shedding, while the objective of the optimality sub-problem is to minimize the renewable curtailment cost. Ref. [17] presented a decomposition model for uncertain security-constrained TEP. A heuristic technique is presented to bundle problem scenarios, which improved the quality of the solutions and reduced the computational time.

A three-level robust optimization model is presented in [18], considering short-term and long-term uncertainties. At the first level, the investment plan is adopted minimizing the total cost, the robust sets are implied in the middle level, and the operation cost is minimized at the third level. Long-term uncertainties are represented by robust sets while short-term uncertainties are described by scenarios. [19] presented a three-level robust model. At the upper level, minimizing the expansion cost is considered, the middle level characterizes the worst-case realizations of uncertainty, and the lower level includes the optimal operation of the power system. The max-min subproblem is solved by a block coordinate descent method. [20] Presented a clustering-based approach solving the stochastic TEP problem, taking into account the massive scenarios. The BD algorithm is used to separate the problem into a master problem and sub-problems. The master problem determines the expansion plan, while the sub-problems minimize the operation cost. The operation sub-problems are clustered using multiple parametric linear programming (MPLP). In [21], a multi-stage fuzzy-robust TEP model is presented in which, different approaches to modeling the uncertainties in demand and production of wind farms have been considered. In this regard, interval and fuzzy models have been used to model wind production uncertainty and demand, respectively. The problem is modeled on a single-level problem, where the objective function is the investment cost. In [22], a stochastic model for the expansion planning of transmission lines, wind farms, and energy storage is presented, taking into account uncertainties relating to the wind farm, demand, and locational marginal prices (LMPs). The correlation between wind productions in multiple wind farms is also considered.

A probabilistic approach is presented in [23] to solve the TEP problem in restructured power systems considering uncertainties. The approach is according to probabilistic LMPs taking into account congestion cost, transmission tariffs, and losses. The final plan is determined by minimizing the average congestion cost using AC OPF. In [24] the effect of utilizing flexible resources in the operation planning in the presence of wind sources has been investigated. A mixed-integer, tri-level robust optimization model is proposed and a decomposition-based algorithm is used to solve the problem. The upper level minimizes the operation cost, the middle level determines the worst case of nodal power imbalances, and at the lower level, the variables related to the nodal power imbalance have been minimized. A risk-based TEP is presented in [25] in the presence of wind resources. Superquantile has been utilized to manage the risk of wind curtailment. Furthermore, a relaxation method is used for decreasing the computational time. The transmission investment cost and operation cost are considered as the objective function. A scenario-based robust TEP is presented in [26] regarding N-1 security criterion, wind generation, and transmission losses. BD method is used to divide the MINLP problem into a master problem and sub-problems. The master problem determines the expansion decisions minimizing the investment cost. These expansion decisions have been evaluated by iterative DC OPF subproblems, minimizing wind spill and load shedding.

A review of research on the expansion of transmission networks in the presence of wind power resources shows that, although the uncertainty of wind production sources has been considered, the TEP that is associated with more use of wind production resources in the market environment has not been considered. In other words, the design of the transmission network has not been done with the approach of utilizing more wind production resources, which is also important from an environmental point of view. Therefore, the study of this paper is based on the planning of the transmission network in a way that reduces wind power curtailment. The main contribution of this paper is that the transmission network is expanded to be accompanied by a reduction in wind curtailment. This is done by adding the wind curtailment cost to the TEP model. So, in this paper, a new framework for TEP in electricity markets is presented under uncertainty, considering wind power curtailment cost. Wind power and the forecasted load demand are involved uncertainties, which are modeled by sets of scenarios. The proposed model is a risk-constrained stochastic bi-level problem that, the difference between the expected social welfare and investment cost is maximized at the upper level. Furthermore, optimal decisions on the expansion plans are adopted. To make the best use of wind generation resources, a new term called wind power curtailment cost is added to the upper level. The market-clearing is considered at the lower level, aiming at, maximizing the social welfare, in which the power produced by generating units as well as LMPs are obtained. With the help of duality theory, the proposed framework is modeled as stochastic mathematical programming with equilibrium constraints (MPEC) problem that is recast as a MILP model. The model is examined using the classical Garver's six-bus test system and the RTS. Since increasing the use of wind power reduces the production of fossil fuel units, the TEP plan resulting from the proposed framework can be called environmentally friendly. The main contributions of the paper are as follows:

- Including the wind curtailment cost in the risk-constrained TEP problem.
- Modeling the proposed framework in the form of a risk-constrained stochastic bi-level problem.
- Formulating the model as MILP.

1.1 Paper Organization

In Section 2, the framework is introduced. Section 3 describes the mathematical formulation, including the bi-level model, MPEC modeling, linearization, and finally MILP conversion. Section 4 deals with numerical studies. Section 5 deals with the results and findings of the simulations in this paper.

2 Framework

Fig. 1 shows the proposed framework, which is used by the ISO considering renewable generation resources in an electricity market. A pool-based competitive power market is considered. Thus, the prices offered by generating companies are assumed to be the marginal cost of units. The system includes both fossil fuel and renewable generating units. Renewable resources are wind types, whose location and capacity are known as problem input. A static approach is considered, in which planning is done for a target year. The transmission network is modeled by DC load flow. The demand side is price sensitive and load shedding is considered. The required data, including the existing system network data, candidate transmission lines, system power flow data, the forecasted demand, generating units, and wind power data, etc. are assumed to be available for the ISO and are shown in the "problem input" section.

The main part of the framework includes the stochastic bi-level model. The aim of considering wind power curtailment cost is to increase the utilization of wind production resources in TEP. This cost is calculated based on the difference between the generated power and producible capacities of wind power resources. In addition, because of the uncertainties, expansion decisions will be at risk. In this respect, Conditional Value at Risk (CVaR) is used. As a result of the upper-level problem, investment decisions enter the lower-level. At the lower level, several market clearing problems are solved aiming at maximizing social welfare. Results of the market-clearing are power produced by generating units, power consumed by consumers, load shedding results, LMPs, social welfare. Using the duality theory, the bi-level problem is recast into a stochastic MPEC model. Then, the MPEC is converted to a MILP which can be solved by the respected software [8, 27]. Transmission network expansion plans, energy consumption by consumers, LMPs, the energy produced by generating units, wind power curtailment, social welfare, load curtailment, etc. are the outputs of the framework.

According to Fig. 2, a load duration curve is used to determine the load at each bus within the planning target year. Load and wind uncertainties are defined by considering three load levels and six wind intensities per

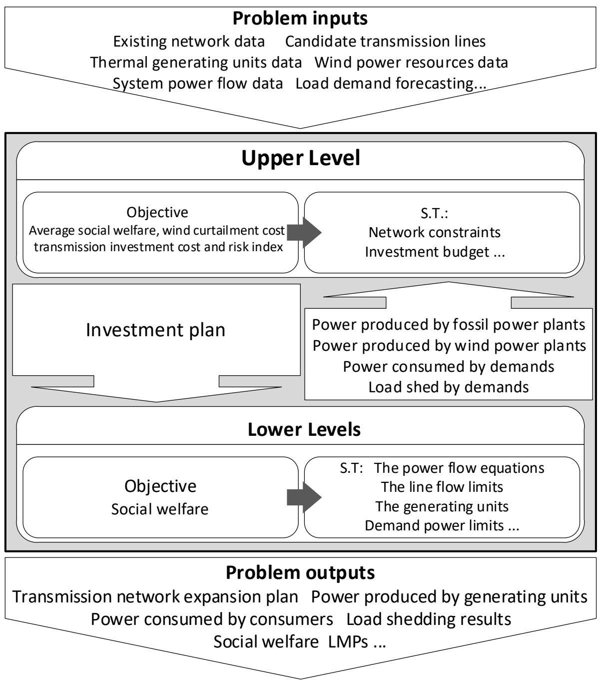

Fig. 1 The proposed framework.

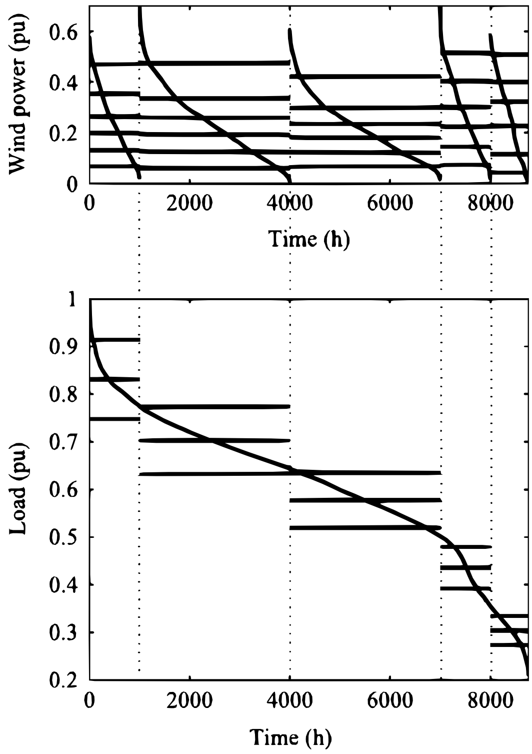

Fig. 2 Load and wind-duration curves [9].

each demand block of the load duration curve respectively which are based on that provided in [9]. In each scenario, the wind intensities and load levels multiply the wind power capacity and demand blocks, respectively. It is assumed that the weight of all scenarios in a demand block is the same.

3 Mathematical Formulation

3.1 Bi-Level Model

The mathematical formulation of the proposed model is represented by (1)-(23) [8, 28]. Dual variables are also shown in front of each constraint.

$$\max \sum_{t\in\Omega^T} N_t^h \left[\sum_{s\in\Omega^w}\delta(s)\left[\sum_{j\in\Omega^D}\sum_{h\in\Omega_j}\lambda_{Djh} d_{jht}(s) - \sum_{i\in\Omega^G}\sum_{b\in\Omega_i}\lambda_{Gib} g_{ibt}(s) - \sum_{j\in\Omega^D} c_j^U r_{jt}(s)\right]\right] - \sum_{t\in\Omega^T} N_t^h \times \left[\sum_{s\in\Omega^w}\delta(s)\left[\sum_{y\in\Omega^{GW}}\lambda_{wc}\left(P_{yt}^{w\max}(s)-gw_{yt}(s)\right)\right]\right] - CRF\times\sum_{k\in\Omega^{L+}} c_k x_k + \beta\left[\eta - \frac{1}{1-\alpha}\sum_{s\in\Omega^w}\delta(s)S_w\right] \quad (1)$$

$$\eta - \left\{\sum_{t\in\Omega^T} N_t^h \left[\sum_{j\in\Omega^D}\sum_{h\in\Omega_j}\lambda_{Djh} d_{jht}(s) - \sum_{i\in\Omega^G}\sum_{b\in\Omega_i}\lambda_{Gib} g_{ibt}(s) - \sum_{j\in\Omega^D} c_j^U r_{jt}(s)\right] - \sum_{t\in\Omega^T} N_t^h \left[\sum_{y\in\Omega^{GW}}\lambda_{wc}\left(P_{yt}^{w\max}(s)-gw_{yt}(s)\right)\right] - CRF\times\sum_{k\in\Omega^{L+}} c_k x_k\right\} \le S_w \quad (2)$$

$$\sum_{k\in\Omega^{L+}} c_k x_k \le c^{\max} \quad (3)$$

$$x_k = 1 \forall k \in \Omega^L \setminus \Omega^{L+} \quad (4)$$

$$x_k \in \{0,1\} \forall k \quad (5)$$

$$S_w \ge 0 \quad (6)$$

where, $g_{ibt}(s)$, $\forall i, b, t, s$; $gw_{yt}(s)$, $\forall y, t, s$; $d_{jht}(s)$, $\forall j, h, t, s$; $r_{jt}(s)$, $\forall j, t, s\in$

$$\arg\left\{\max.\left[\sum_{j\in\Omega^D}\sum_{h\in\Omega_j}\lambda_{Djh} d_{jht}(s) - \sum_{i\in\Omega^G}\sum_{b\in\Omega_i}\lambda_{Gib} g_{ibt}(s) - \sum_{j\in\Omega^D} c_j^U r_{jt}(s)\right]\right. \quad (7)$$

subject to

$$\sum_{i\in\Psi_n^G}\sum_{b\in\Omega_i} g_{ibt}(s) + \sum_{y\in\Psi_n^{GW}} gw_{yt}(s) - \sum_{k\,|se(k)=n} f_{kt}(s) + \sum_{k\,|re(k)=n} f_{kt}(s) + \sum_{j\in\Psi_n^D} r_{jt}(s) = \sum_{j\in\Psi_n^D}\sum_{h\in\Omega_j} d_{jht}(s) : \lambda_{nt}(s) \forall n \quad (8)$$

$$f_{kt}(s) = b_k x_k \left(\theta_{se(k)t}(s) - \theta_{re(k)t}(s)\right) : \phi_{kt}(s) \forall k \quad (9)$$

$$f_{kt}(s) \le f_k^{\max} : \phi_{kt}^{\max}(s) \forall k \quad (10)$$

$$f_{kt}(s) \ge -f_k^{\max} : \phi_{kt}^{\min}(s) \forall k \quad (11)$$

$$g_{ibt}(s) \le g_{ib}^{\max} : \phi_{ibt}^{g\max}(s) \forall b, \forall i \quad (12)$$

$$gw_{yt}(s) \le P_{yt}^{w\max}(s) : \varphi_{yt}^{gw\max}(s) \forall y \quad (13)$$

$$d_{jht}(s) \le d_{jht}^{\max}(s) : \beta_{jht}^{\max}(s) \forall h, \forall j \quad (14)$$

$$r_{jt}(s) \le \sum_{h\in\Omega_j} d_{jht}^{\max}(s) : \alpha_{jt}^{\max}(s) \forall j \quad (15)$$

$$\sum_{h\in\Omega_j} d_{jht}(s) \ge d_{jt}^{\min}(s) : \rho_{jt}(s) \forall j \quad (16)$$

$$\theta_{nt}(s) \le \pi : \xi_{nt}^{\max}(s) \forall n \in \Omega^N \setminus n : slack \quad (17)$$

$$\theta_{nt}(s) \ge -\pi : \xi_{nt}^{\min}(s)\ \forall n \in \Omega^N \setminus n : slack \quad (18)$$

$$\theta_{nt}(s) = 0 : \chi_n(s) n : slack \quad (19)$$

$$g_{ibt}(s) \ge 0, \forall b, \forall i \quad (20)$$

$$gw_{yt}(s) \ge 0 \forall y \quad (21)$$

$$r_{jt}(s) \ge 0 \forall j \quad (22)$$

$$d_{jht}(s) \ge 0 \forall j, \forall h\} \forall t, \forall s \quad (23)$$

The upper-level problem is represented by (1)-(6), and the lower-level problems are shown by (7)-(23). The objective function (1) is the expected value of the social welfare minus the wind curtailment cost minus the transmission investment cost and risk. Due to uncertainties, expansion decisions involve risk. The criteria used for considering the degree of risk is the CVaR. According to the investor's degree of risk, in each scenario, S_w is obtained by (2). Constraint (3) imposes an upper bound on the investment cost. Constraints (4) indicate that existing lines are constructed, and constraints (5) and (6) are lines binary variables and S_w declaration respectively. The objective function of lower-level problems is represented by (7). Constraints (8) represent the power balance at each bus. Constraints (9) show the flow of each line. Constraints (10) and (11) impose line flow limits. Constraints (12), (13), and (14) represent the sizes of the blocks of the conventional and wind generating units and the demands, respectively. Constraints (15) and (16) enforce upper bounds on load-shedding and minimum demand, respectively. Constraints (17) and (18) enforce limits on the voltage angles at each bus. Constraint (19) is related to the voltage angle of the swing bus. Constraints (20)-(23) are the variables declaration.

3.2 MPEC

The bi-level problem (1)-(23) can be converted into an equivalent single-level stochastic MPEC [8]. The dual problem related to the lower-level problems (7)-(23) is:

$$\begin{aligned}\min \ & \sum_{k\in\Omega^L}\left(\phi_{kt}^{\max}(s)-\phi_{kt}^{\min}(s)\right)f_k^{\max}+\sum_{i\in\Omega^G}\sum_{b\in\Omega_i}\varphi_{ibt}^{g\max}(s)\,g_{ib}^{\max}\\ &+\sum_{y\in\Omega^{GW}}\varphi_{yt}^{gw\max}(s)\,P_{yt}^{w\max}(s)+\sum_{j\in\Omega^D}\sum_{h\in\Omega_j}\beta_{jht}^{\max}(s)\,d_{jht}^{\max}(s)\\ &+\sum_{j\in\Omega^D}\left(\alpha_{jt}^{\max}(s)\sum_{h\in\Omega_j}d_{jht}^{\max}(s)+\rho_{jt}(s)\,d_{jt}^{mim}(s)\right)\\ &+\sum_{n\in\Omega^N}\pi\left(\xi_{nt}^{\max}(s)-\xi_{nt}^{\min}(s)\right)\end{aligned} \tag{24}$$

subject to:

$$\lambda_{n(i)t}(s)+\varphi_{ibt}^{g\max}(s)\geq-\lambda_{Gib}\forall b,\forall i \tag{25}$$

$$\lambda_{n(y)t}(s)+\varphi_{yt}^{gw\max}(s)\geq 0\forall y \tag{26}$$

$$-\lambda_{n(j)t}(s)+\beta_{jht}^{\max}(s)+\rho_{jt}(s)\geq\lambda_{Djh}\ \forall h,\forall j \tag{27}$$

$$\lambda_{n(j)t}(w)+\alpha_{jt}^{\max}(w)\geq-c_j^U\forall\ j \tag{28}$$

$$-\lambda_{se(k)t}(w)+\lambda_{re(k)t}(s)+\phi_{kt}(s)+\phi_{kt}^{\max}(s)+\phi_{kt}^{\min}(s)=0\forall k \tag{29}$$

$$\begin{aligned}&-\sum_{k|se(k)=n}b_kx_k\phi_{kt}(s)+\sum_{k|re(k)=n}b_kx_k\phi_{kt}(s)+\xi_{nt}^{\max}(s)\\ &\qquad+\xi_{nt}^{\min}(s)=0\forall n\in\Omega^N\setminus n:slack\end{aligned} \tag{30}$$

$$-\sum_{k|se(k)=n}b_kx_k\phi_{kt}(s)+\sum_{k|re(k)=n}b_kx_k\phi_{kt}(s)+\chi_{nt}(s)=0\quad n:slack \tag{31}$$

$$\lambda_{nt}(s)\quad free\ \ \forall n \tag{32}$$

$$\phi_{kt}(s)\quad free\ \ \forall k \tag{33}$$

$$\phi_{kt}^{\max}(s)\geq 0\ \ \forall k \tag{34}$$

$$\phi_{kt}^{\min}(s)\leq 0\ \ \forall k \tag{35}$$

$$\varphi_{ibt}^{g\max}(s)\geq 0\ \ \forall b,\forall i \tag{36}$$

$$\varphi_{yt}^{gw\max}(s)\geq 0\ \ \forall y \tag{37}$$

$$\beta_{jht}^{\max}(s)\geq 0\ \ \forall h,\forall j \tag{38}$$

$$\alpha_{jt}^{\max}(s)\geq 0\ \ \forall j \tag{39}$$

$$\rho_{jt}(s)\leq 0\ \ \forall j \tag{40}$$

$$\xi_{nt}^{\max}(s)\geq 0\ \ \forall n \tag{41}$$

$$\xi_{nt}^{\min}(s)\leq 0\ \ \forall n \tag{42}$$

$$\chi_{nt}(s)\quad free\quad n:slack \tag{43}$$

According to strong duality theory, we have:

$$\begin{aligned}&\sum_{j\in\Omega^D}\sum_{h\in\Omega_j}\lambda_{Djh}d_{jht}(s)-\sum_{i\in\Omega^G}\sum_{b\in\Omega_i}\lambda_{Gib}g_{ibt}(s)-\sum_{j\in\Omega^D}c_j^U r_{jt}(s)\\ &=\sum_{k\in\Omega^L}\left(\phi_{kt}^{\max}(s)-\phi_{kt}^{\min}(s)\right)f_k^{\max}+\sum_{i\in\Omega^G}\sum_{b\in\Omega_i}\varphi_{ibt}^{g\max}(s)\,g_{ib}^{\max}\\ &+\sum_{y\in\Omega^{GW}}\varphi_{yt}^{gw\max}(s)\,P_{yt}^{w\max}(s)+\sum_{j\in\Omega^D}\sum_{h\in\Omega_j}\beta_{jht}^{\max}(s)\,d_{jht}^{\max}(s)\\ &+\sum_{j\in\Omega^D}\left(\alpha_{jt}^{\max}(s)\sum_{h\in\Omega_j}d_{jht}^{\max}(s)+\rho_{jt}(s)\,d_{jt}^{mim}(s)\right)\\ &+\sum_{n\in\Omega^N}\pi\left(\xi_{nt}^{\max}(s)-\xi_{nt}^{\min}(s)\right)\end{aligned} \tag{44}$$

The resulting single-level MINLP problem is:

$$\max.\ (1) \tag{45}$$

S.T.

$$(2)-(6) \tag{46}$$

$$(8)-(23) \tag{47}$$

$$(25)-(44) \tag{48}$$

3.3 MILP Problem

The single-level MINLP problem (45)-(48) can be converted into a MILP model by linearizing nonlinear terms [8], [29]. Nonlinear constraints (9), and constraints (10) and (11) can be written by (49)-(50).

$$-x_k f_k^{\max}\leq f_{kt}(s)\leq x_k f_k^{\max} \tag{49}$$

$$-(1-x_k)M\leq\frac{f_{kt}(s)}{b_k}-\left(\theta_{se(k)t}(s)-\theta_{re(k)t}(s)\right)\leq(1-x_k)M \tag{50}$$

Dual nonlinear constraints (30) and (31) can be represented by (51)-(54):

$$\begin{aligned}&-\sum_{k|se(k)=n}b_k\left(\phi_{kt}(s)-\phi_{kt}^{-}(s)\right)+\sum_{k|re(k)=n}b_k\left(\phi_{kt}(s)-\phi_{kt}^{-}(s)\right)\\ &\qquad+\xi_{nt}^{\max}(s)+\xi_{nt}^{\min}(s)=0\end{aligned} \tag{51}$$

$$\begin{aligned}&-\sum_{k|se(k)=n}b_k\left(\phi_{kt}(s)-\phi_{kt}^{-}(s)\right)+\sum_{k|re(k)=n}b_k\left(\phi_{kt}(s)-\phi_{kt}^{-}(s)\right)\\ &\qquad+\chi_{nt}(s)=0\end{aligned} \tag{52}$$

$$-x_k\Gamma^{\max}\leq\phi_{kt}(s)-\phi_{kt}^{-}(s)\leq x_k\Gamma^{\max} \tag{53}$$

$$-(1-x_k)\Gamma^{\max}\leq\phi_{kt}^{-}(s)\leq(1-x_k)\Gamma^{\max} \tag{54}$$

The disjunctive parameters M and $\Gamma^{\max}$ are sufficiently large constants. Based on simulations, it was concluded that 5000 is an appropriate value for these constants. Finally, the CRF is obtained by (55).

Table 1 Case studies.

Case No.		Fossil fuel power plants	Wind power plants	Wind power curtailment cost	Risk
Garver	RTS				
1		✓			
2	1	✓	✓		
3	2	✓	✓	✓	
4	3	✓	✓	✓	✓

$$CRF = \frac{ir(1+ir)^t}{(1+ir)^t - 1} \tag{55}$$

4 Case Studies

The model is analyzed using the classical Garver's six-bus test system and the IEEE 24-bus RTS. Table 1 shows the case studies.

In both case studies, the following assumptions are considered. A maximum of three transmission lines is considered in each corridor. The investment return period is assumed 25 years. The interest rate is 10%. The minimum of each demand is assumed to be 90% of the total demand bid. The cost of load-shedding is assumed to be ten times the bid price of the first block of each demand. Wind power producers offer at zero price and wind curtailment cost is equal to the highest price offered by the fossil generating units. In the last cases, α and β are considered equal to 0.2 and 0.8 respectively. The location and capacity of the power plants are known.

4.1 Case Study 1: Garver's Six-Bus Test System

4.1.1 Data

The model is analyzed using Garver's six-bus test system [30], shown by Fig. 3. This system comprises three generating units, six transmission lines, and five demands. Bus 6 is not initially connected to the system. The lines, generation units, and demand data are based on that provided in [8] and the demand factor equals 1.5. Two wind farms with a generation capacity of 500 MW are installed at buses 4 and 6. The load and wind scenarios are based on data of [31, 32]. According to [9] as depicted in Fig. 2, the load duration curve consists of five demand blocks. The load and wind uncertainties are defined by considering three demand levels and six wind intensities per each demand block of the load duration curve respectively. Therefore, the number of scenarios per demand block equals 18 and the total number of wind and load scenarios within the target year equals 90. In addition, the wind power intensity at bus 6 has been considered 10% more than at bus 4. In the first case, the two generating units installed at buses 4 and 6 are considered as the fossil fuel unit type. The blocks of power offered and the corresponding offer prices for these generating units are respectively 200, 150, and 150 MW and 70, 75, and

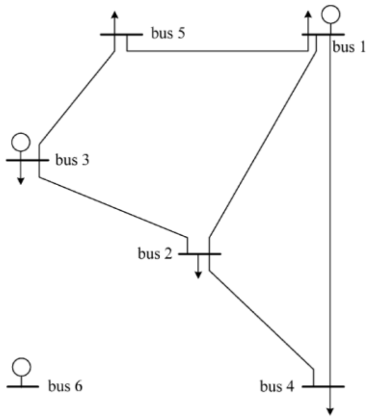

Fig. 3 Garver's six-bus test system [30].

80 €/MWh. Finally, the investment budget is limited to 30 M€. It is worth mentioning that in order to validate the simulation results, first the model of [8] was simulated, and then the proposed model of this paper is formed and simulated.

4.1.2 Results

Results are shown in Table 2. In the first case, where only the presence of fossil fuel production units is considered, a total of four transmission lines are installed. The investment cost, the expected social welfare, and the average and standard deviation of LMPs have the lowest amounts, and the expected energy consumption has the highest value compared to other cases. In the second case, the investment cost has increased by 29.92% compared to the first case, due to the increase in the number of transmission lines between rails 2 and 6. Also, the expected social welfare has increased by 54.23% compared to the first case, which is significant. The expected energy produced by fossil fuel units has decreased by 36.34% with respect to the first case, which is due to the presence of wind units. At the same time, in the presence of renewable resources, the average and standard deviation of LMPs have increased. The reason for the significant increase in the average and standard deviation of LMPs is the occurrence of load shedding due to the uncertainty of wind resources so that, the EENS cost has increased from 0 to 11.88 M€. In the third case, a new transmission line between bus 2 and bus 3 is added to the expansion plan for the second case, which is accompanied by an increase in investment cost of 15.38%. By applying the wind power curtailment cost, the energy produced by wind units has increased. In addition, the wind energy utilization factor has increased from 97.97% in the second case to 98.13% in this case. These increases are accompanied by a decrease in the energy production of fossil fuel units, which is environmentally important. In the fourth case, by considering the risk, the investment cost, the expected social welfare, and the expected wind power production have been reduced while the expected

Table 2 Results for case study 1.

Cases	1	2	3	4
Investment plan	2-6 (2) 3-5 (2)	2-6 (3) 3-5 (2)	2-3 2-6 (3) 3-5 (2)	2-6 (3) 3-5 (2)
Objective function [M€]	253.61	391.67	388.17	674
Investment cost [M€]	19.32	25.10	28.96	25.10
Expected social welfare [M€]	255.74	394.44	394.67	394.44
EENS cost [M€]	0	11.88	11.88	11.88
Expected producible energy of wind power [GWh]	–	2213.79	2213.79	2213.79
Expected energy produced by wind power [GWh]	–	2168.88	2172.39	2168.88
Expected energy produced by fossil fuel power plants [GWh]	6060.59	3857.95	3854.29	3857.80
CVaR [M€]	–	–	–	357.40
Average of LMPs [€/MWh]	70.17	100.3	100.04	100.30
Standard deviation of LMPs [€/MWh]	1.86	197.10	197.22	197.10
Expected energy consumption [GWh]	6060.59	6037.64	6037.48	6037.48
Wind energy utilization factor	–	97.97%	98.13%	97.97%

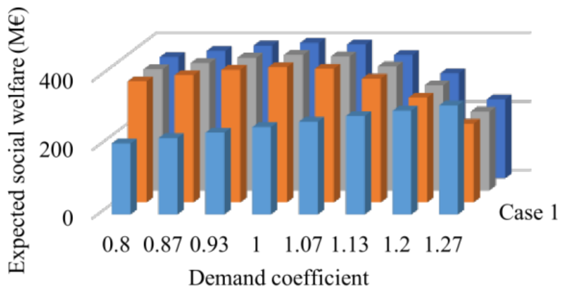

Fig. 4 Expected social welfare in terms of changes in the forecasted demand.

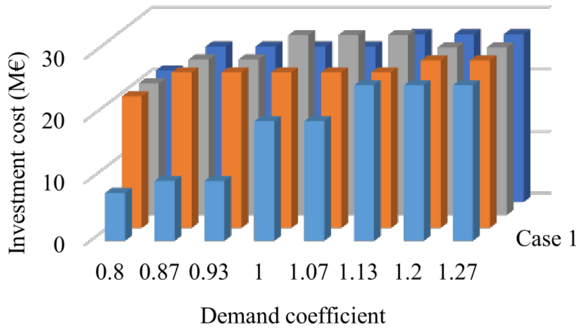

Fig. 5 Investment cost in terms of changes in the forecasted demand.

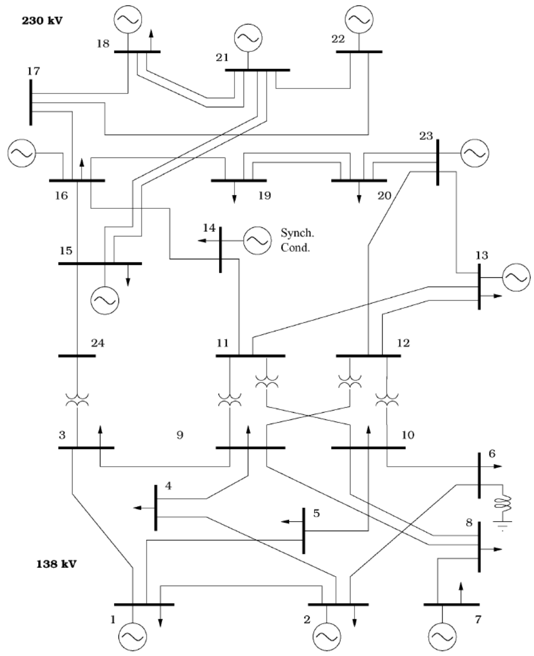

Fig. 6 IEEE 24-bus system [33].

energy produced by fossil fuel power plants has increased. Therefore, considering the risk has reduced the number of new lines and consequently reduced the investment cost compared to the third case. In this regard, the change in the expansion plan has been accompanied by a reduction in the use of uncertain wind resources and an increase in the use of thermal power plants.

4.1.3 Impact of Demand Uncertainty

Since one of the effective factors in the planning of the power systems is demand forecasting, so it is important to study changes in investment behavior and other decision variables caused by an error in the forecasting demand. Therefore, in most development planning models, the sensitivity of important system variables to changes in demand forecast coefficient is considered. Fig. 4 shows the changes in expected social welfare in terms of changes in the demand forecast coefficient in the four cases. It is observed that in the first case and the absence of wind production units, the expected social welfare increases with increasing the demand forecast coefficient. However, this trend is not observed in cases where wind production sources are present. Because with increasing demand, the load curtailment in these cases increases, and so reduces the expected social welfare.

Fig. 5 shows the changes in investment cost in terms of the demand forecast coefficient in the four cases. According to Fig. 5, in the first case, by increasing the forecasted demand, the investment in the transmission network has increased to meet the forecasted demand. In the next cases, the tendency to invest in transmission lines for greater use of renewable resources has increased. This is more evident in the third case. In the last case, considering the risk, the tendency to invest has decreased compared to the previous case.

Table 3 Prospective line data for case study 2.

From	To	Reactance [p.u.]	Capacity [MW]	Investment cost [10^3 €]
2	7	0.12	175	9622
3	4	0.12	175	10824
4	5	0.12	175	9622
5	7	0.14	175	10222
7	8	0.0614	175	10012

Table 4 Results for case study 2

Cases	1	2	3
Investment plan	6-10	6-10	6-10
	10-12	10-12	10-12
	12-13	14-16	12-13
	14-16	16-17	14-16
	16-17	4-5	16-17
	7-8 (2)	7-8 (2)	7-8 (2)
Objective function [M€]	1006.41	972.41	1678.34
Investment cost [M€]	39.87	39.91	39.87
Expected social welfare [M€]	1010.81	1003.56	1010.81
EENS cost [M€]	164.68	188.35	164.68
Expected producible energy of wind power [GWh]	5566.10	5566.10	5566.10
Expected energy produced by wind power [GWh]	5123.79	5298.57	5123.79
Expected energy produced by fossil fuel units [GWh]	54559.35	54255.05	54559.35
CVaR [M€]	–	–	895.19
Average of LMPs [€/MWh]	127.60	138.45	127.60
Standard deviation of LMPs [€/MWh]	166.49	193.95	166.49
Expected energy consumption [GWh]	59848.44	59746.59	59848.44
Wind energy utilization factor	92.05%	95.19%	92.05%

4.2 Case Study 2: IEEE RTS

4.2.1 Data

Fig. 6 depicts RTS [33]. Line 7-8 is not considered. Therefore, the transmission network comprises 33 corridors, 38 existing lines, and 5 new corridors.

The existing corridors, generating units, and demand data are based on that provided in [8], and the demand factor equals 1.5. The new corridors data are provided in Table 3. Two wind farms are considered at buses 4 and 7, with a capacity of 1200 MW. The investment budget is limited to 40 M€.

4.2.2 Results

Table 4 shows the results. In the first case, where the study was conducted in the presence of wind production units, as well as in the absence of wind curtailment costs, a total of 7 transmission lines were constructed for 39.87 M€. In the second case, where the wind curtailment cost is considered, the investment cost is slightly increased with respect to the first case, due to the change in the transmission line expansion plan. Also, the energy produced by wind and fossil production units has increased by 3.41% and decreased by 0.6%, respectively, compared to the first case. The increasing use of wind resources has led to an increase in the EENS cost by 14.37%, resulting in a higher average and standard deviation of LMPs. At the same time, consumer energy consumption has decreased slightly, which is in line with the 8.5% increase in the average of LMPs. Therefore, the inclusion of the wind curtailment cost has led to a change in the transmission network expansion plan, increasing the utilization factor of wind production resources from 92.05% to 95.19%, and reducing the energy production of fossil fuel resources. In the third case, where risk is considered, expansion plans have been changed. This change has been accompanied by a reduction in investment costs and a reduction in the use of wind power utilization. Instead, the energy produced by thermal power plants is increased compared to the second case. Therefore, it is concluded that considering the risk criterion has led to conservative decisions. This is accompanied by a decrease in the average and standard deviation of LMPs and the cost of EENS.

5 Conclusions

In order to study the impact of reducing wind production curtailment in the transmission network expansion and the operation of power systems in competitive electricity markets, a risk-constrained bi-level model under uncertainties is presented. The uncertainties discussed in this paper include wind production and demand forecasting. The considered problem was modeled as a stochastic MPEC and then converted to a MILP problem using dual theory. The results of the studies are summarized below:

- By considering the wind power curtailment cost, the transmission expansion plan changed in a way that has increased the use of wind resources and has decreased the energy produced by thermal power plants.

• Considering the risk has resulted in changes in expansion strategies, reducing investment cost and wind utilization, LMPs, EENS cost. On the other hand, this has increased the expected energy production of thermal power plants.

• The load shedding due to the uncertainty of wind resources has increased the EENS cost and so the average LMPs. It has also caused a sharp rise in the standard deviation of LMPs. In this regard, the use of energy storage resources will prevent sudden increases in electricity prices.

Although considering the wind curtailment cost, resulted in increasing the use of wind power, taking into account the risk, the wind power utilization decreases depending on the investor's willingness to risk. This is not environmentally desirable. In this regard, as future research, the presence of energy storage in wind farms can reduce the adverse effects of wind source uncertainties.

Intellectual Property

The authors confirm that they have given due consideration to the protection of intellectual property associated with this work and that there are no impediments to publication, including the timing of publication, with respect to intellectual property.

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R. Heydari: Research & investigation, Data curation, Software and simulation, Original draft preparation, Analysis. **T. Barforoushi:** Idea & conceptualization, Project administration, Supervision, Verification, Revise & editing.

Declaration of Competing Interest

The authors hereby confirm that the submitted manuscript is an original work and has not been published so far, is not under consideration for publication by any other journal and will not be submitted to any other journal until the decision will be made by this journal. All authors have approved the manuscript and agree with its submission to “Iranian Journal of Electrical and Electronic Engineering”.

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