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Coordinated decisions for transmission and generation expansion planning in electricity markets

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SUMMARY

This paper presents a new approach to coordinate the decisions of transmission and generation capacity expansion planning for a competitive electricity market in which only the generation sector is deregulated. The independent system operator (ISO) as transmission planner has a regulatory role in the strategic behavior of generation companies. To reach coordinated decisions, the model relies on an interactive and iterative process between generation expansion planning and transmission expansion planning. This repetitive process continues until reaching a converging point or fulfilling the stopping criterion assigned by the ISO. In order to consider random outages of network components as well as uncertainty of load and bid prices of generating units, the Monte Carlo simulation method is applied. The simulation results confirm the efficacy of the proposed model in the coordinated generation and transmission planning problem considering the uncertainties. Copyright © 2012 John Wiley & Sons, Ltd.

KEY WORDS: competitive electricity market; coordinated decisions between generation and transmission planning; mixed integer programming; Monte Carlo simulation; random outages and uncertainty; system reliability

1. INTRODUCTION

The liberalization and restructuring process worldwide have introduced new complexities to the transmission expansion planning (TEP) [1–5]. In new structure, generation companies (GenCos) freely decide about their investments, while the transmission planner is not directly involved in their decisions. Generation and transmission planning are dependent to each other. On the other hand, both of them required the confirmation of system planning center which may be the independent system operator (ISO) or in collaboration with the ISO. System planning center can provide collaboration between generation and transmission planning. In this paper, it is assumed that the ISO does collaboration between generation and transmission planning. It is also assumed that the ISO is responsible for transmission planning.

Since the fundamental objective of TEP is optimum expansion of the existing network in order to enhance competition level amongst all power market participants, the transmission planner needs to incorporate GenCos' strategic decisions in its planning process, which is, the main focus of this work. In this paper, a new pool-based model is proposed to coordinate TEP and decentralized generation investment planning in competitive markets. In this model, an interrelated tri-level optimization problem is utilized to achieve optimum decisions in expansion of generation capacity and transmission network. Monte Carlo simulation is used to consider random outages of network components as well as uncertainty of load and bid prices of generating units.

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The coordination between transmission and generation resource planning has been addressed previously. Roh, *et al*. presented an ISO model to provide investment signals for generation and merchant transmission planning where the market operator coordinates the generation and transmission companies' plans in the context of a joint energy and transmission auction market [6,7]. However, not considering of uncertainties in bid prices of generating units is one of the disadvantages of their proposed model. Kaymaz, *et al*. [8] modeled the generation expansion planning (GEP) as a Cournot competition game to study the interaction between competition and transmission congestion on power generation expansion. In [9], an innovative method is presented for simultaneous assessing of technical and economic benefits of transmission expansions in competitive electricity markets. In this model, Lerner index is used to model the strategic behavior of generating units. A flexible transmission expansion algorithm is proposed in [10], where the most flexible plan is defined as the plan with least adaption cost. Buygi, *et al*., in [11], proposed a market-based TEP approach that flatness of local price, in which the means lack of congestion, is supposed as a proper criterion for measuring the degree of competitiveness of the transmission network. In this work, GEP decisions have been considered as non-random uncertainty. In [12], a bilevel transmission expansion model is presented in which the upper level is modeled based on minimizing of transmission investment cost and the lower level is market clearing problem. In [13], a new scenario-based model is presented in order to make coordination between TEP and decentralized generation investment planning. In this work, considering the acceptable levels of transmission congestion and security, an incentive mechanism is used to trigger generation investments earlier than projected date. This can lead to postponement of some transmission plans and cost-saving over the horizon planning. Motamedi, *et al*. [14] presented a new framework for TEP considering GenCos' strategic behaviors and anticipation of their expansion patterns from the viewpoint of the transmission system planner. In this approach, an iterative solution algorithm based on agent-based models with Q-learning method and search-based optimization is utilized to determine the equilibrium point that is somehow complex and time-consuming. Deb and White, in [15], stated that it is necessary to be able to articulate the value of transmission projects in terms of more than just traditional reliability measures such as loss of load probability or MWh of unserved energy, by analyzing the potential benefits of transmission investment to be realized through reduced congestion costs (CCs) and greater competition among generating units. The paper also shortly discusses the reliability effects and the value of eliminating unserved energy.

GEP and TEP are strongly related to each other so that, the results of GEP decisions affect the optimum decisions of TEP and vice versa. In addition, as the variables of GEP and TEP decisions are integer and discrete, formulation of a single objective function which can simultaneously optimize these variables in a competitive market, is very difficult. The presented algorithm in this work includes three different optimization levels that are: maximization of social welfare (SW), maximizing the profit of generation investors and maximizing the transmission expansion criterion (maximizing the reduction in CC for one dollar investing in transmission expansion) so that maximization of the SW is a constraint for GenCos in order to optimize their investment decisions and in turn optimized decisions of GenCos are a constraint for transmission planner. Since solving this problem analytically is complex, an iterative solution approach is used.

In most previously presented model, the strategic decisions of GenCos are supposed as beneficial scenarios in the form of non-random uncertainties in transmission expansion, while in this paper, the optimum decisions of GenCos are made in interaction with transmission planning during the planning horizon. The ISO is responsible for providing and maintaining the acceptable level of network security and adequacy. Therefore, an incentive mechanism is utilized such that motivates generation units to investigate where to enhance system reliability level. This capacity revenue allows the ISO to set prices at acceptable levels and yet motivate GenCos to make proper investment decisions.

The main contribution of this paper is the presentation of an approach to coordinate generation and transmission planning and to prevent overinvestment in generation and transmission expansion. A generation expansion plan is profitable if a specific transmission expansion plan is done. If GEP and TEP are not coordinated, an undesired transmission expansion plan may be selected and may lead to reduction of generation investors' profits. On the other hand, transmission expansion reduces network congestion if the proposed generation expansion plans remain unchanged. If generation expansion plans

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change due to lack of coordination between GEP and TEP, the executed transmission expansion may not reduce the congestion and consequently may lead to unnecessary transmission investments.

The paper is organized as follows. Section 2 describes the proposed model and the solution methodology. Section 3 provides a formulation of planning problem and its solution algorithm in details. To show the effectiveness of the algorithm, a case study based on the modified IEEE 30-bus system has been developed in section 4. The results of the applied model on the case study have been reported and discussed. Finally, the conclusion drawn from the study is presented in section 5.

2. MODEL DESCRIPTION

As shown in Figure 1, in order to coordinate decisions in TEP and GEP, a tri-level optimization model is used. Three different optimization levels are:

- Maximizing SW, in which, in each scenario, the locational marginal prices (LMPs) are calculated considering generation and transmission expansion plans.
- Maximizing the profit of generation investors, in which, the optimum generation expansion plan is determined considering LMPs computed in level 1.
- Maximizing the transmission expansion criterion (maximizing reduction in CC or one dollar investing in transmission expansion), in which, the optimal transmission plan is determined considering the optimal generation plan determined in level 2.

An iterative method is used to solve the tri-level optimization problem. In this iterative method, first, the ISO calculates LMPs by solving the first level of optimization for different years in the planning horizon by considering available generating units and forecasted future load and future LMPs is conveyed to investors. Then, investors compute their optimum plans by solving the second level of optimization considering computed future LMPs and existing transmission network structure. The computed generation plans are proposed to the ISO for acceptance. The ISO checks the network reliability and security constraints. In the case of any violation in mentioned constraints, the ISO utilizes the policy of a capacity payment to increase the probability of generating units' installation that can result in network reliability improvement. After receiving the final plans of GenCos, the ISO as transmission planner determines the optimum transmission plan by solving the third level of optimization considering the proposed generation expansion plan. In continuation, the ISO calculates LMPs considering proposed generation expansion plans and computed transmission plan. Updated LMPs are given to generation investors to revise their investment plans. The revised generation plans are given to the ISO to compute the optimal transmission plans. This repetitive process will continue until the algorithm is converged to an equilibrium point in coordination generation and transmission planning, if there is, otherwise defined supportive stopping criterion is fulfilled. In the proposed model, in order to encourage GenCos to invest in places where this can lead to system risk reduction, it is assumed that, the ISO allots a part of the 'expected energy not supplied' (EENS) cost to GenCos through capacity payment.

In order to calculate prices, load duration curve (LDC) of various years is estimated by the ISO. This curve is divided into some constant load levels. In these calculations uncertainties in various parts of LDC are taken into account. Bid prices of generating units can be applied in two ways. In the first way in accordance with proposed generation expansion plans, equilibrium points of different parts of LDC are calculated for different years of planning horizon, and bids of equilibrium points are utilized for calculating of LMPs. However, in the second method, the ISO estimates probability density functions (pdfs) of bid prices of generating units considering information of generating units and their technology type, generation expansion plans and status of network structure for different parts of LDC in various years of planning horizon. Mean value of pdfs as market equilibrium points with an assumed standard deviation is utilized for calculating of LMPs. In this paper, the second method with pdfs of bid prices of generating units is utilized.

During the planning process, if generation expansion plans are less than demanded capacity for network adequacy, the ISO will estimate a bid pdf with a greater average value which results in market price growth. Higher prices can provide a proper incentive for investors in order to expand their plans in the next repetition of the proposed amendment process that in turn can fulfill the adequacy of the

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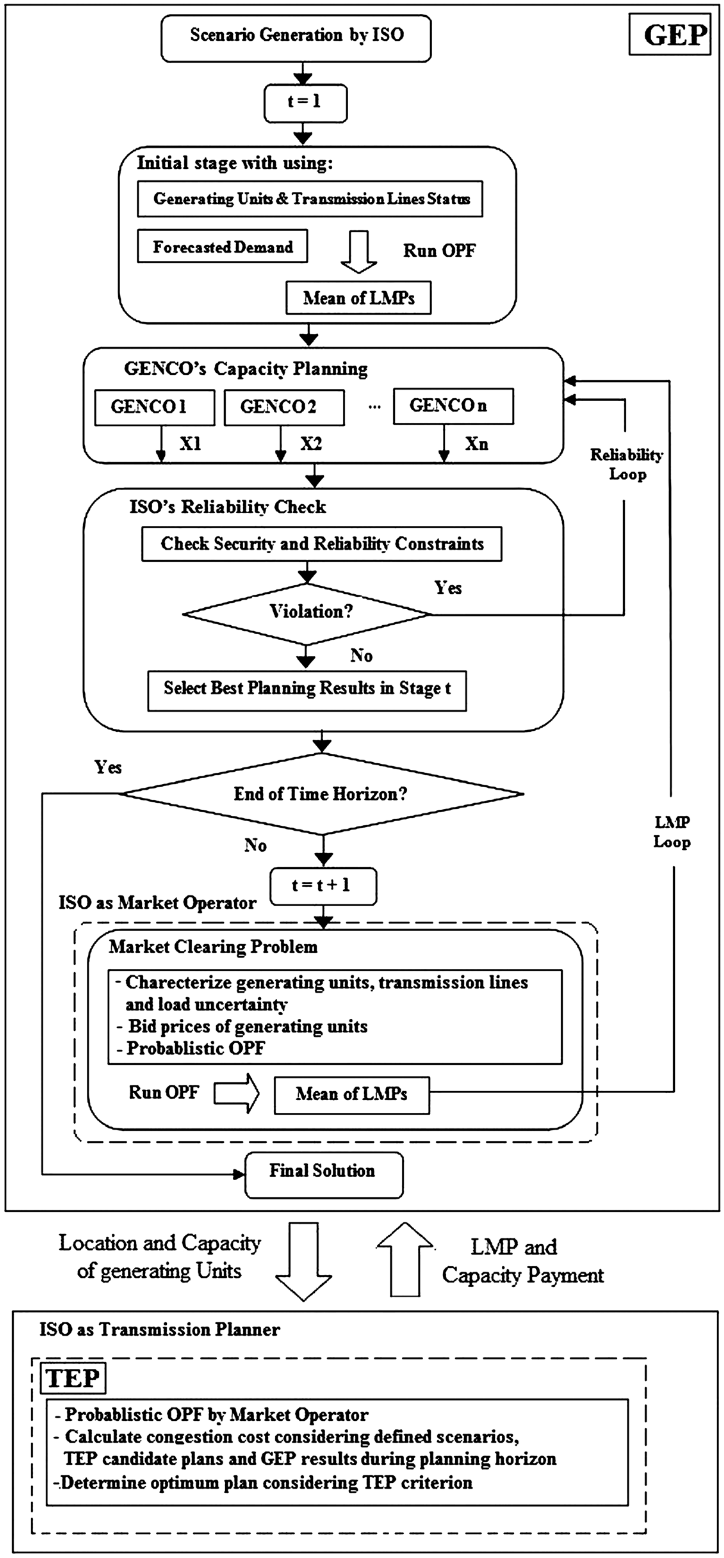

Figure 1. Proposed structure for coordination of GEP and TEP.

network capacity. In contrast, if the generation plans are more than network adequacy, The ISO will estimate a bid pdf with less average value which means lower market price. As a result, in planning amendment process, investors will withdraw low profitable plans.

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In order to model uncertainties in planning, Monte Carlo simulation considers a set of scenarios, defined by the ISO, based on the outage probability of generating units, transmission lines and uncertainties of load and bid prices of generating units during the planning horizon. The input data are defined as follows:

- For each generating unit and also for each transmission line, two states ‘available’ and ‘outage’ are considered. It is assumed that outages of the components are independent. A uniform pdf is assigned to each component. By sampling from the uniform pdf of each component, the status of each component is determined in each scenario.
- A normal pdf assigned to each load. The mean of the normal pdf assigned to a load is equal to its predicted mean at peak load. The standard deviation of each normal pdf is selected such that covers the related load uncertainty. By sampling from the normal pdf of each load, the value of each load is determined in each scenario.
- A normal pdf is assigned to each bid price. The mean and standard deviation of the normal pdf assigned to a bid price are selected so that the minimum obtained from sampling is more than its operation cost of the related unit with error probability less than 0.1%.

3. PROBLEM FORMULATION

In the proposed model, there are three different agents which are called market operator, GenCo and transmission planner. Each of the agents tries to optimize his objective based on mathematical optimization approaches. The SW maximizing as the aim of the ISO is a constraint for GenCos in order to optimize their planning decisions, and in turn optimizations of GenCos are constraints for transmission planner. The model is tri-level optimization problem to reach coordinated decisions for GEP and TEP. An iterative solution method is used to solve the problem.

Formulation of the problem has four steps; SW maximizing or market clearing problem by the market operator, GenCo’s generation capacity expansion, transmission expansion by transmission planner and checking stopping criterion.

3.1. Market clearing problem

This optimization problem is performed by the ISO to determine market clearing prices (LMPs) with respect to network information. LMP is the marginal cost of supplying the next increment of electric energy at a specific bus while considering generation marginal cost and physical aspects of the transmission system [16]. In this model, it is assumed that the outages of transmission lines are short term and are not informed to the GenCos. Then, generation investors will not change their strategies in the case of component outages. For bid of each generating unit, a normal pdf is assumed in which the mean value of bid prices of each generating unit is the bid of that generating unit in equilibrium point in normal condition of the network. It is obvious that in terms of long-term changes of network structure, bids will change. In the case, bid prices change according to related equilibrium point.

The objective of the optimal power flow (OPF) problem is to maximize the SW, and the decision variables are usually the consumption and production at each location. Market clearing prices are the other outputs of this problem. Solution of the optimum exploitation in year t for each bid price of generating units and assumed network scenarios of s can be done by running of the below mentioned DC OPF.

$$Max \quad SW(\mathbf{P}_G, \mathbf{P}_D) = \mathbf{C}_D^T\mathbf{P}_D - \mathbf{C}_G^T\mathbf{P}_G \tag{1}$$

$$\text{s.t.}\mathbf{B}_s\delta_s = \mathbf{P}_{G,s} - \mathbf{P}_{D,s} \ \forall s \tag{2}$$

$$-\mathrm{P}_l^{\max} \leq H_s\delta_s \leq \mathrm{P}_l^{\max} \ \forall s \tag{3}$$

$$\mathbf{P}_{G,s}^{\min} \leq \mathbf{P}_{G,s} \leq \mathbf{P}_{G,s}^{\max} \ \forall s \tag{4}$$

$$\mathbf{P}_{D,s}^{\min} \leq \mathbf{P}_{D,s} \leq \mathbf{P}_{D,s}^{\max} \ \forall s \tag{5}$$

In this problem, the capacities of the existing and the candidate units dispatched in vector of power generations are decision variables. The objective function (1) maximizes the SW. The first term of the

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objective function represents by multiplying the vector of load bids ($\boldsymbol{C}_D$) by the vector of active loads ($\boldsymbol{P}_D$). The second term of (1) represents the cost that is needed to operate generators which is calculated by multiplying the vector of generator bids ($\boldsymbol{C}_G$) by the vector of active power generations ($\boldsymbol{P}_G$). Constraint (2) shows the DC OPF equations. In each scenario s, $\boldsymbol{B}_s$ and δ_s represent the linearized Jacobian matrix and vector of bus angles, respectively. $\boldsymbol{P}_{G,\ s}$ and $\boldsymbol{P}_{D,\ s}$ stand for vector of active power generations and active loads, respectively, in assumed scenario s. Constraint (3) represents the line flow limits of the network. $\boldsymbol{H_s}$ represents for matrix of linearized line flows in assumed scenario s. $\boldsymbol{P}_l^{max}$ is vector of line limits. Constraints (4), (5) show generation limits and load limits, respectively.

For each of scenario determined from bid prices of generating units and all resulted scenarios from network component uncertainties, energy prices (LMPs) are calculated. It is assumed that the weights of proposed bid prices are identical. In each planning year, the mean of LMPs at different buses are computed during peak load for various scenarios obtained from bid prices of generating units and uncertainty network components.

3.2. Generation capacity expansion problem

Figure 1 shows that decisions of generation investor make based on an iterative process between the ISO as market operator and GenCos. It should be noted that in the optimization problem, the SW maximizing as the aim of the market operator or the ISO is a constraint for GenCos in order to optimize their planning decisions.

3.2.1. Formulation of the GENCO's planning. Under the market competitive environment, GEP problem is a maximization of each GenCo's total expected profit over the planning horizon while satisfying system adequacy constraints. A discount rate is used to convert revenues and expenses occurring at different times to their equivalent values at a common reference time (net present value). The discount rate is a factor that generating investors would require for holding their real assets based on inflation and system risk level. In this paper, it is assumed that the discount rate covers the system risk also. It is also assumed that the discount rate is constant over the planning time horizon and is flat across all generating units. The optimum decision problem for each GenCo h is formulated as follows:

$$\begin{aligned} Max \quad PF_h = [&\sum_{t=1}^{T}\sum_{d=1}^{Nd}\sum_{i\in EGht} DT_d \times \left(\lambda_{ihdt} \times P_{EG,ihdt} - OC_{ihdt}\right) \times \frac{1}{(1+r)^{t-1}} + \\ &+\sum_{t=1}^{T}\sum_{d=1}^{Nd}\sum_{j\in CGht} DT_d \times \left(\lambda_{jhdt} \times P_{CG,jhdt} - OC_{jhdt}\right) \times \frac{X_{jht}}{(1+r)^{t-1}} - \\ &-\sum_{t=1}^{T}\sum_{j\in CGht} IC_{jht} \times \frac{X_{jht}}{(1+r)^{t-1}} + \\ &+\sum_{t=1}^{T}\sum_{d=1}^{Nd}\sum_{j\in CGht} DT_d \times \left[\left(EPNS_{-jhdt} - EPNS_{jhdt}\right) \times \left(UEC - \lambda_{jhdt}\right) \times X_{jht}\right] \end{aligned} \tag{6}$$

$$\text{s.t.} ICAP_{jht} = \max\left(\sum_{d=1}^{N_d} P_{CG,jhdt} \times X_{jht}\right) \forall j \forall t \tag{7}$$

$$\sum_{j\in CGht} ICAP_{jht} \le MCI_{ht} \ \forall t \tag{8}$$

$$\sum_{j\in CGht} IC_{CG,jht} \times X_{jht} \le UCI_{ht} \ \forall t \tag{9}$$

$$TICAP_{h,t} = TICAP_{h,t-1} + \sum_{j\in CGht} ICAP_{jht} \ \forall t \tag{10}$$

$$0 \le P_{EG,ihdt} \le P_{EG,ih}^{\max} \ \forall d \forall t \tag{11}$$

$$0 \le P_{CG,jhdt} \le P_{CG,jh}^{\max} \ \forall d \forall t \tag{12}$$

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The objective function of the problem is presented as the sum of four terms in Equation (6), in which, the first two terms are the present value of operating profit of existing and candidate units, respectively. Energy prices of existing and candidate units are obtained from the market clearing problem in section 3.1. The third term represents the present value of the annual investment cost of candidate units, and finally the capacity payment paid to each candidate unit by the ISO for its contribution to system reliability is indicated by the fourth term. The decision variables are P_{EG}, P_{CG} and X. However, only X is submitted to the ISO. The decision variables P_{EG} and P_{CG} represent the amount of dispatched capacity for existing and candidate generating units, respectively. These variables are calculated in OPF for the defined scenarios. X is a binary variable that shows installation status of candidate units of different GenCos in each planning year. Values '1' and '0' stand for installed and uninstalled ones, respectively. To calculate the operating profits of the GenCos, the LDC is estimated for each year over the horizon planning that each of these curves is divided into multiple constant load blocks.

In this formulation, T and Nd are the number of planning years and subperiods in LDC. The duration of step d in LDC is shown by DT_d. i and j are indexes for the existing and candidate generating units, respectively. $EGht$ and $CGht$ are sets of the existing and candidate units of GenCo h in year t, respectively. r represents discount rate, and λ represents mean of nodal energy prices. The mean of nodal energy prices for the existing and candidate units are determined by considering network component outages as well as uncertainty in load and bid prices of the generating units in each subperiod of planning years during the planning horizon. Furthermore, generating operation cost and annual generation investment cost are represented by OC and IC in the planning horizon, respectively. UEC is the cost of expected unserved energy. For the purpose of long-term price forecasting, this cost will not be the same as the value of lost load (VOLL) because the duration of load blocks is too long to use VOLL. If VOLL is used as the cost of EENS, it may result in very high prices over long periods and potentially overestimate GenCos' expected revenues [9]. Hence, it is appropriate to use a value smaller than VOLL as UEC. On the other hand, EPNS_{-j} and EPNS_j are the amount of expected power not supplied (EPNS) before and after installation of each candidate generating unit, respectively. To calculate the amount of EPNS in each load block, it is assumed that each load can be modeled with a fix load which is never curtailed and an imaginary generator with the bid of load in the market clearing problem in section 3.1. The imaginary generator is dispatched before dispatching more expensive generators. In this study, the same bids are considered to all loads. Then, the amount of power dispatched by imaginary generator is equal to the amount of load curtailed and EPNS. The amount of the EENS in each stage is equal to EPNS multiplied by the duration of load block.

Every GenCo operates independently to maximize its own profit and there are no coupling constraints among the GenCos and the investment problem. Therefore, GEP is decomposed into several mixed-integer programs. Constraint (7) shows the amount of installed capacity (ICAP) of each candidate unit in year t. Constraint (8) expresses the maximum ICAP for the GenCos (MCI) in each planning year. This restriction is imposed to the GenCos by the ISO to prevent market power. Constraint (9) defines the investment budget limitations related to each GenCo. UCI is the maximum value specified for the capital investment of the GenCos in each planning year. This parameter defines the investment budget limitations related to each GenCo. GenCos estimate the amount of UCI parameter based on their predicted incomes. Constraint (10) preserves the installation status of generation units of each GenCo. TICAP is the total ICAP in each planning year. Constraints (11) and (12) are capacity limits of the existing and candidate generation units, respectively.

3.2.2. ISO's reliability check. When the GenCos have specified their generation investment plans, the plans are sent to the ISO for checking any violation in the security and reliability constraints of the system in any year of the planning horizon. The constraints that are checked by the ISO include: reserve margin and the EENS level. The details of these constraints are described as below:

The reserve margin level of generation in the system corresponding to peak loads in year t can be performed using (13). In this relation, MR_t^{min} and MR_t^{max} are the percentages of the minimum and maximum reserve margins in year t, respectively, and D_t is the average peak of the load. NG is the number of GenCos, and the value of subscript index d is equal to 1 that indicates the first load block of the LDC. This means that during computing the reserve margin in each year of the planning horizon, the peak annual demand is considered.

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$$\left(1+MR_t^{\min}\right)\times D_t \leq \sum_{h=1}^{NG}\left(\sum_{j\in EGht} P_{EG,idht}+\sum_{j\in CGht} P_{CG,jdht}\right) \leq \left(1+MR_t^{\max}\right)\times D_t \forall t \text{ and } d=1 \quad (13)$$

Constraint (14) is used to investigate the level of system risk in which $EENS_t^{max}$ represents the maximum of *EENS* in year t that admits the non-served load due to outages of generating units.

$$EENS_{dt} \leq EENS_t^{\max} \ \forall t \forall d \quad (14)$$

In this algorithm, an equivalent LDC (ELDC) is calculated considering candidate generating units and their outage probabilities. ELDC is a LDC considering the outage of generating units. In ELDC, the outage of a unit is modeled by the increase of load during the outage of that generating unit [17]. Surface under the curve is EENS.

If there is at least one violated constraint, it is assumed that the mean value of bid prices of generating units will increase based on a pre-specified multiplicative factor, and consequently, nodal energy prices (LMPs) will grow in the market environment. Then, the prices will be sent to the GenCos as a corrective signal for their plans revisions. This strategy represents the typical behavior of a power market where in the case of existing any limitation in available resources with respect to demands, the energy prices tend to raise. This iterative process between GenCos and the ISO continues until all constraints by the ISO are fulfilled.

3.3. *Transmission expansion problem*

Improving competition level in the market environment and reducing transmission-related market power should be considered in the transmission planning. CC is a proper criterion for measuring the competitiveness of electric markets [11,18]. So that, in this work, the impact of adding a candidate transmission line on congestion level reduction, with respect to its investment cost, is considered as a convenient index for TEP.

The CC is defined as the difference between SWs under two dispatching strategies with and without transmission line capacity limits [18] in the market clearing problem in section 3.1:

$$CC(t_h)=\left\{Max \quad SW\big|_{s.t.(2),(3),(4),(5)}\right\}-\left\{Max \quad SW\big|_{s.t.(2),(4),(5)}\right\} \quad (15)$$

Where t_h is the hourly time index.

Various criteria, such as transmission planner's knowledge of system congestion, projected future load growth, facilitating energy trade for economic, or reliability reasons could be considered to form set of potential new and reinforcement transmission expansion plans [10]. This set is denoted here by CTL. A plan $k\in$CTL is the set of lines specified by the sending and receiving end and its capacity.

TEP criterion (TEPC) is presented based on compromise between long-term investment costs and short-term CCs caused by transmission network limitations. The annual CCs are calculated on the LDC. Then, TEPC for candidate plan k (TEPC^k) is defined as follows:

$$TEPC^k=\frac{\Delta CC^k}{TIC^k}=\frac{CC-CC^k}{TIC^k} \quad (16)$$

In which, CC and CC^k are the total network CC before and after the addition of candidate plan k, respectively. TIC^k is the total investment cost for transmission lines installations of candidate plan k. For each set of candidate plans, the optimum TEPC is obtained as follows:

$$TEPC^*=\max_{k\in CTL}\left\{TEPC^k\right\} \quad (17)$$

Where TEPC* is the optimum plan from set of transmission expansion candidate plans.

3.4. *Convergence and stopping criterion*

The first stopping criterion is a solution that converges on model equilibrium point. If this criterion is not fulfilled, the model does not reach equilibrium point, supportive criterion is utilized. The supportive criterion is defined based on system costs (SCs) by the ISO. SCs are defined as the sum of operation costs, investment costs, capacity payments to GenCos and the average of total network CCs in

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GEP and TEP at the end of each iteration in the planning structure. If the percentage of SC changes is less than a certain value ($\in$), the supportive stopping criterion will be fulfilled. This criterion is defined as follows:

$$\frac{SC^{old} - SC^{new}}{SC^{old}} \leq \in \tag{18}$$

Where:

$$\begin{aligned} SC = & \sum_{h=1}^{NG}\sum_{t=1}^{T}\sum_{d=1}^{Nd}\sum_{j\in CGht}\frac{DT_d \times OC_{jhdt} \times X_{jht}}{(1+r)^{t-1}} + \\ & + \sum_{h=1}^{NG}\sum_{t=1}^{T}\sum_{j\in\{CGh\}}\frac{IC_{jht} \times X_{jht}}{(1+r)^{t-1}} + \\ & + \sum_{t=1}^{T}\sum_{d=1}^{Nd}\sum_{j\in CGht} DT_d \times \left[\left(EPNS_{-jhdt} - EPNS_{jhdt}\right) \times \left(UEC - \lambda_{jhdt}\right) \times X_{jht}\right] + \\ & + \sum_{t=1}^{T}\sum_{k\in CTL}\frac{TIC_t^k \times Y_t^k}{(1+r)^{t-1}} + \sum_{t=1}^{T}\sum_{d=1}^{Nd} CC_{dt} \end{aligned} \tag{19}$$

In Equation (19), CC_{dt} is CC at subperiod d in year t that is determined considering optimum decisions of generation and transmission expansion. TIC_t^k is transmission investment cost in year t and Y_t^k represents the status installation of candidate lines, 1 if installed, otherwise 0.

4. CASE STUDIES

The modified IEEE 30-bus system is used to analyze the effectiveness of the proposed model during 10-year planning horizon. This model has 41 existing transmission lines, 20 demand sides and seven existing generating units. The modified IEEE 30-bus system data and forecasted load for the 10-year planning horizon are given in the Appendix. Candidate generator and transmission line data are shown in Tables A.3 and A.4 in the Appendix A. Candidate generating units A1, A2, A3, A4 belong to GENCO A, and B1, B2, B3, B4, B5, B6, B7 belong to GENCO B. Generating units A4 and B6 (which have lower operating costs) and B1 are located remotely from the load, and remaining generating units are located at load buses. According to Table A.3, candidate generating units can have the different capacity, operating costs and locations except for outage rate. This assumption is intended to analyze the impact of generation unit location on generation capacity planning.

Two thousand random scenarios are generated using Monte Carlo simulation where each scenario represents outage statuses of the generating units and transmission lines as well as the load uncertainty. The average of peak demand at the initial year is 283.4 MW and the average of growth rate for peak load is 5% per year. The uncertainty in the forecasted peak load is assumed to be presented by the seven-stepped normal distribution shown in Figure 2, where the class intervals in the distribution have probabilities of $p_{-3}=0.006$, $p_{-2}=0.061$, $p_{-1}=0.242$, $p_0=0.382$, $p_{+1}=0.242$, $p_{+2}=0.061$ and $p_{+3}=0.006$. The standard deviation of this distribution is assumed to be 1% of the forecast peak load. The modified LDC is shown in Figure 3. The modified LDC is a LDC where load uncertainty is considered [17,19].

The discount rate is assumed to be equal to 5%. In each year, it is assumed that the accepted reserve margin level lies between 10 and 40% of average of peak load, and the maximum acceptable EENS is 3% of the average peak load of the system. It is also assumed that the capacity that can be installed by each GenCo (MCI) should not exceed 50% of its total capacity in each planning year. The maximum capital investment of each GenCo (UCI) is restricted to the cost of the most expensive unit in each planning year. Moreover, it is supposed that the supportive stopping criterion $\in$ is 1% and UEC is supposed that is equal to 250 \$/MWh. Bid prices of the existing and the candidate units supposed to have normal distribution functions with unit standard deviation. According to the characteristics of the

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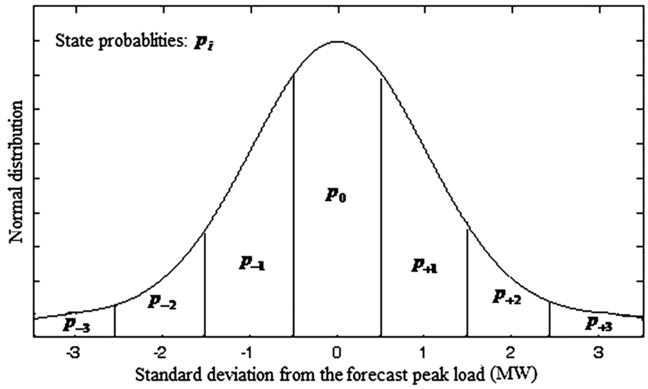

Figure 2. Seven-step approximation of the normal distribution.

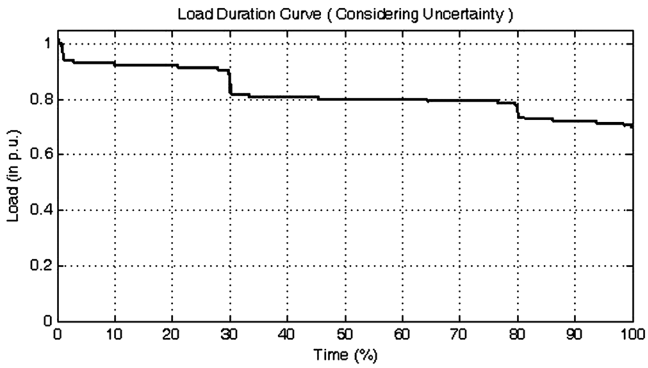

Figure 3. Modified load duration curve with uncertainty 1%.

normal distribution function, to have pragmatic random bid prices higher than the operating costs of generating units, the average amount of bid price function is supposed to be 6.6 \$/MWh more than the operating costs of generating units. One thousand scenarios are generated by using the defined bid prices of generating units.

The General Algebraic Modeling System (GAMS) and MATLAB are both applicable programs for solving the optimization problems. In order to attain optimized decisions in this method, the existed link between GAMS and MATLAB software has been utilized [20]. Simulation of the GenCos' planning optimization and the reliability check have been performed in GAMS and the optimal operation sub-problems in GEP and transmission planning are simulated in MATLAB software. GAMS provides a tool called SCENRED for scenario reduction processes [21,22].

Table I illustrates reduced scenarios and their weights, while outages of generating units, transmission lines, and load uncertainty are considered over the planning horizon. On the other hand, the numbers of scenarios attained from bid prices of generating units are reduced from 1000 down to 48. The weights of these scenarios are close to each other and approximately 0.02.

Four test cases are considered that are categorized into deterministic cases (cases 1 and 3) and stochastic cases (cases 2 and 4). Cases 1 and 2 are only based on GEP, while cases 3 and 4 are based on coordinated GEP and TEP. The results are listed in Table II.

Table I. Weight of each scenario after scenario reduction during horizon planning.

Scenario	1	2	3	4	5	6
Weight	0.018	0.016	0.020	0.004	0.024	0.022
Scenario	7	8	9	10	11	12
Weight	0.003	0.002	0.021	0.852	0.016	0.003

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Table II. Candidate generating units' and lines' installation status over 10-year planning horizon.

Year	Case 1	Case 2	Case 3		Case 4	
	GEP	GEP	GEP	TEP	GEP	TEP
1	A1, B1, B3	A3, B1, B3	-	T3	B4, B5	T3, T5
2	-	-	-	T5	-	-
3	A3, B7	A1, B5	B4	-	-	T1, T2
4	-	-	B3, B5	T1, T2, T4	A1	T4
5	-	A2, B7	A1	-	B3	
6	A4, B2	-	A3	-	A3	T8
7	B4	B4	B7	T8	B7	-
8	B5	-	B1	-	B1	-
9	-	B2	A2, B2	-	A2, B2	-
10	-	A4		-	-	-

In case 1, generating units A1, B1 and B3 are installed in planning year 1. The unit A1 is located at the load bus 4 with relatively lower SC and capacity payment. However, the units B1 and B3 are installed because of their higher revenue share from capacity payment. The A3 and B7 generating units are installed in planning year 3 with respect to the lower SC and their revenue from capacity payment. The A4 and B2 generating units with high investment cost, and B4 and B5 with high operation costs are installed in years 6, 7 and 8 when the capacity payment is sufficiently high following load growth. Due to high operation cost of the A2 generating unit and unfavorable location of the B6 generating unit, they are not installed. Note that the capacity payment is offered to each of the participants based on its capacity and location in the network and is zero before the installation of each candidate unit.

Considering outages of network components and load uncertainty in GEP, case 2, the A3, B1 and B3 generating units are installed in planning year 1 because of relatively lower SC and sufficiently large revenue from capacity payment. In planning year 3, the A1 and B5 generating units are located at the load buses 4 and 8, respectively. Also units A2 and B7 are installed because of their higher reliability level in planning year 5. The B4 generation unit is installed in planning year 7 to supply the load growth at bus 7. The B2 and A4 generating units with high investment cost are installed in the final planning years for saving the network risk level in acceptable range when the capacity payment is sufficiently large corresponding to the load growth.

Case 3 represents the results of generation and transmission expansion coordinated planning in deterministic condition. This algorithm has converged after three iterations. As it can be seen, with the installation of the lines T3 and T5 to mitigate congestion of transmission lines in planning years 1 and 2, generating unit B4 with minimum investment cost is installed to maintain the minimum reserve margin of the network in planning year 3. With the installation of the lines T1, T2, T4 and T8 in next planning years, the generating units B3, B5, A1, A3, B7, B1, A2 and B2 are installed to maintain the minimum reservation margin according to their low SC. The changes proposed in the following years are due to a modified power dispatch in comparison with the case 1.

Considering system uncertainties, the proposed algorithm for coordination of decision in generation and TEP, Case 4, has converged after four iterations. Due to high CC, transmission expansion is needed in the early years. The T5 and T3 candidate lines are installed in planning year 1. Considering uncertainty of load growth, candidate lines T1, T2 and T4 are installed in planning year 3. The installation of candidate lines T3 and T5 leads to installation of the generating units B4 and B5 based on lower SC and the amount of revenue from capacity payment in planning year 1. Consequently, with installation of candidate lines T1, T2, T4 and T8 in next planning years, the generating units A1, B3, A3, B7, B1, A2 and B2 are installed based on their lower SC to preserve the reserve margin. It should be mentioned that, in comparison with Case 2, the B6 generating unit is replaced with A4 generating unit due to its high investment cost and modified power dispatch in the final planning year.

Table III shows the amount of capacity payment offered and paid by the ISO to each candidate unit according to their share in the system EENS reduction in cases 2 and 4 during the planning horizon. As

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Table III. The amount of capacity payment offered and paid (highlighted numbers) to candidate units (Millions of $).

Case	Unit	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10
2	**A1**	8.88	0.70	4.02	-	-	-	-	-	-	-
	A2	4.94	0.72	3.22	1.28	8.85	-	-	-	-	-
	A3	16.8	-	-	-	-	-	-	-	-	-
	A4	19.2	1.10	5.57	1.98	10.6	2.70	12.7	10.1	13.8	17.4
	B1	18.9	-	-	-	-	-	-	-	-	-
	B2	19.6	1.14	5.57	1.54	8.53	3.38	16.2	15.6	27.7	
	B3	18.4	-	-	-	-	-	-	-	-	-
	B4	4.99	0.87	1.84	0.52	1.19	0.52	4.57	-	-	-
	B5	4.82	0.73	4.19	-	-	-	-	-	-	-
	B6	1.31	0.44	5.34	2.36	0.51	0.15	0.21	0.23	0.30	0.31
	B7	10.5	0.84	5.34	2.45	10.3	-	-	-	-	-
4	**A1**	3.18	0.82	0.84	1.31	-	-	-	-	-	-
	A2	3.31	0.91	1.03	1.33	2.63	1.19	2.43	1.05	1.28	-
	A3	3.38	1.51	1.72	2.64	3.01	2.99	-	-	-	-
	A4	4.48	2.15	2.03	2.99	3.24	3.24	2.71	1.21	1.91	2.22
	B1	4.43	2.08	2.01	2.94	3.17	3.24	4.09	2.84	-	-
	B2	4.45	2.08	2.08	3.03	3.34	3.29	4.13	2.91	2.59	-
	B3	3.20	1.10	1.29	1.99	2.03	-	-	-	-	-
	B4	3.31	-	-	-	-	-	-	-	-	-
	B5	3.24	-	-	-	-	-	-	-	-	-
	B6	4.48	2.15	2.14	3.26	3.76	3.50	3.69	2.61	2.63	2.22
	B7	4.27	1.73	1.54	2.17	2.31	2.48	3.43	-	-	-

it can be seen, considering coordinated generation and TEP has lead to a reduction in capacity payment, because the transmission network expansion can reduce the system EENS level.

Table IV compares GenCos' profits and the amounts of SCs in case 4 during the convergence process. It should be mentioned that in the first iteration, GenCos decisions are made based on existing transmission network. In next iterations, the profits of GenCos considerably change due to changes done on the transmission network. The identical results in third and fourth iteration show that the coordination between transmission and generation expansion has led to its equilibrium point. The results of the first up to third iterations depict that transmission expansion has increased the profit of GenCo A since existing generating units take the advantage of transmission capacity expansion. On the contrary, the profit of GenCo B is decreased because GenCo B has fewer investment opportunities after transmission expansion. Table IV shows that reaching to equilibrium point can result in a considerable saving in the SC. Although the SC value has been reduced from iteration 1 up to 3, it does not necessarily lead to the SC reduction in successive iterations. Since coordination between generation and transmission expansion avoids unnecessary investment, the SC should have a low value at the equilibrium, but since in coordination process objective functions of the ISO, GenCos and transmission planner are optimized not the SC, the SC does not reduce in successive iterations necessarily.

Table IV. Financial results in case 4 during the convergence process (Millions of $).

Iteration	System cost	Profit	
		GenCo B	GenCo A
1	323.12	120	219
2	259.79	230	154
3	229.89	253	170
4	229.89	253	170

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5. CONCLUSION

In this paper, a new formulation was proposed in order to achieve coordinated decisions in GEP and TEP in a competitive electricity market. This approach was based on an iterative algorithm to make adaptive GEP and TEP decisions. Stopping point of algorithm is reached in the case of convergence or fulfilling the supportive stopping criterion. In this approach, outages of generating units and transmission lines as well as the uncertainties of load and bid prices of generating units were considered and simulated using Monte Carlo simulation. The results of this study showed that utilizing of GEP and TEP information in an interactive and iterative process can increase the speed of convergence in comparison with other power system planning approaches. In this method, an appropriate incentive was introduced for GENCOs based on their role in enhancement of the system reliability level. The merit of this approach was the achievement of coordinated decisions as reliable as possible. Numerical results confirmed the effectiveness of the proposed model in achieving coordinated decisions in generation and TEP.

6. LISTS OF SYMBOLS AND ABBREVIATIONS

t	Index for year;
h	Index of GenCo;
i	Index for existing unit;
j	Index for candidate unit;
k	Index of candidate line;
d	Index for subperiod;
s	Index for scenario;
EG	Subscript index for the existing generating units;
CG	Subscript index for the candidate generating units;
T	Number of years in the planning horizon;
NG	Number of GenCos;
Nd	Number of subperiod in load duration curve;
EGh	Set of the existing generating units in GenCo h;
CGh	Set of the candidate generating units in GenCo h;
CTL	Set of candidate transmission lines;
DT_d	Duration of step d in load duration curve [%];
D_t	Average peak of load in year t [MW];
λ	Mean of nodal energy prices [$/MWh];
r	Discount rate [%];
OC	Operating cost of generating unit [$/h];
IC	Annual generation investment cost [$/yr];
UEC	Cost of the expected unserved energy [$/MWh];
P_{EG}	Dispatched capacity of the existing generating units [MW];
P_{CG}	Dispatched capacity of the candidate generating units [MW];
P_{EG}^{max}	Maximum capacity of the existing generating units [MW];
P_{CG}^{max}	Maximum capacity of the candidate generating units [MW];
MR_t^{min}	Minimum reserve margins in year t [%];
MR_t^{max}	Maximum reserve margins in year t [%];
ICAP	Installation capacity of each candidate unit in year t [MW];
TICAP	Total installed capacity in each planning year [MW];
MCI	Maximum installed capacity for each GenCo in each year [MW];
UCI	Maximum capital investment for each GenCo in each year [$/yr];
SW	Social welfare [$/h];
SC	System cost [$];
CC	Total congestion cost [$];
CC^k	Total congestion cost after adding of candidate line k [$];

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TIC^k	Total investment cost for transmission lines installation of candidate plan k [$];
TIC_t^k	Transmission investment cost in year t [$/yr];
X	Installation status of generating units, 1 if installed, otherwise 0;
Y	Installation status of candidate lines, 1 if installed, otherwise 0;
$EPNS_{-j}$ and $EPNS_j$	Expected power not supplied before and after installation of each candidate unit [MW];
$EENS_{dt}$	Expected energy not supplied at subperiod d in year t [MWh];
$EENS_t^{max}$	Maximum expected energy not supplied in year t [MWh];
$\mathbf{H}$	Matrix of linearized line flows;
$\mathbf{B}$	Linearized Jacobian matrix;
δ	Vector of bus angles;
$\mathbf{P}_G$	Vector of active power generations;
$\mathbf{P}_D$	Vector of active loads;
$\mathbf{P}_l^{max}$	Vector of transmission lines limits;
$\mathbf{C}_G$	Vector of generator bids;
$\mathbf{C}_D$	Vector of load bids;

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APPENDIX

A. CASE STUDY DATA FOR THE MODIFIED IEEE 30-BUS SYSTEM

Table A.1. Load blocks in base year.

Subperiod	1	2	3	4
Duration (%)	1	29	50	20
Load (MW)	283.4	260.73	226.72	204.05

Table A.2. Load characteristics.

ID	Bus	Pdf of Loads (MW)	Bid ($/MWh)	FOR (%)
1	2	$N \sim (22.672, 0.01)$	75	0.01
2	3	$N \sim (2.834, 0.01)$	75	0.01
3	4	$N \sim (56.680, 0.01)$	75	0.01
4	5	$N \sim (34.008, 0.01)$	75	0.01
5	7	$N \sim (22.672, 0.01)$	75	0.01
6	8	$N \sim (28.340, 0.01)$	75	0.01
7	10	$N \sim (19.838, 0.01)$	75	0.01
8	12	$N \sim (22.672, 0.01)$	75	0.01
9	14	$N \sim (5.668, 0.01)$	75	0.01
10	15	$N \sim (8.502, 0.01)$	75	0.01
11	16	$N \sim (2.834, 0.01)$	75	0.01
12	17	$N \sim (8.502, 0.01)$	75	0.01
13	18	$N \sim (2.834, 0.01)$	75	0.01
14	19	$N \sim (5.668, 0.01)$	75	0.01
15	20	$N \sim (2.834, 0.01)$	75	0.01
16	21	$N \sim (17.004, 0.01)$	75	0.01
17	23	$N \sim (2.834, 0.01)$	75	0.01
18	24	$N \sim (5.668, 0.01)$	75	0.01
19	26	$N \sim (5.668, 0.01)$	75	0.01
20	30	$N \sim (5.668, 0.01)$	75	0.01

Table A.3. generators data of the 30-bus system.

Unit	Bus	Capacity (MW)	Operating Cost ($/MWh)	Bid ($/MWh)	FOR (%)	Investment Cost (Thousand $/MW/year)
AE1	1	100	12.58	$N \sim (19.18,1)$	2	Existing
AE2	2	80	21.32	$N \sim (27.92,1)$	2	Existing
AE3	24	20	46.66	$N \sim (53.26,1)$	2	Existing
AE4	30	20	59.18	$N \sim (65.78,1)$	2	Existing
A1	4	10	46.66	$N \sim (46.66,1)$	2	50
A2	7	10	44.12	$N \sim (44.12,1)$	2	70
A3	23	20	21.32	$N \sim (21.32,1)$	2	80
A4	25	20	15.38	$N \sim (15.38,1)$	2	150
BE1	5	50	15.38	$N \sim (21.98,1)$	2	Existing
BE2	8	50	15.42	$N \sim (22.02,1)$	2	Existing
BE3	11	20	44.12	$N \sim (50.72,1)$	2	Existing
B1	13	20	24.15	$N \sim (24.15,1)$	2	100
B2	15	20	22.56	$N \sim (22.56,1)$	2	120
B3	17	10	22.56	$N \sim (22.56,1)$	2	80
B4	7	10	46.66	$N \sim (46.66,1)$	2	30
B5	8	10	46.66	$N \sim (46.66,1)$	2	40
B6	9	20	15.38	$N \sim (15.38,1)$	2	130
B7	4	20	44.12	$N \sim (44.12,1)$	2	60

Table A.4. Candidate transmission lines data of the 30-bus system.

Line	From	To	Capacity (MW)	X (p.u)	FOR (%)	Investment Cost (Thousand $/MW/year)
T1	1	2	30	0.0575	0.1	10
T2	1	3	30	0.1852	0.1	25
T3	2	4	30	0.1737	0.1	15
T4	3	4	30	0.0379	0.1	10
T5	9	10	30	0.11	0.1	14
T6	12	13	65	0.14	0.1	9
T7	9	11	30	0.208	0.1	8
T8	4	12	65	0.256	0.1	5

Table A.5. Transmission line characteristics.

ID	From	To	Capacity (MW)	X (pu)	FOR (%)	ID	From	To	Capacity (MW)	X (pu)	FOR (%)
1	1	2	30	0.0575	0.1	**22**	15	18	16	0.2185	0.1
2	1	3	30	0.1852	0.1	**23**	18	19	16	0.1292	0.1
3	2	4	30	0.1737	0.1	**24**	19	20	32	0.068	0.1
4	3	4	30	0.0379	0.1	**25**	10	20	32	0.209	0.1
5	2	5	30	0.1983	0.1	**26**	10	17	32	0.0845	0.1
6	2	6	30	0.1763	0.1	**27**	10	21	30	0.0749	0.1
7	4	6	30	0.0414	0.1	**28**	10	22	30	0.1499	0.1
8	5	7	30	0.0116	0.1	**29**	21	22	30	0.0236	0.1
9	6	7	30	0.082	0.1	**30**	15	23	16	0.202	0.1
10	6	8	30	0.042	0.1	**31**	22	24	30	0.179	0.1
11	6	9	30	0.208	0.1	**32**	23	24	16	0.27	0.1
12	6	10	30	0.556	0.1	**33**	24	25	30	0.3292	0.1
13	9	11	30	0.208	0.1	**34**	25	26	30	0.38	0.1
14	9	10	30	0.11	0.1	**35**	25	27	30	0.2087	0.1
15	4	12	65	0.256	0.1	**36**	27	28	30	0.396	0.1
16	12	13	65	0.14	0.1	**37**	27	29	30	0.4153	0.1
17	12	14	32	0.2559	0.1	**38**	27	30	30	0.6027	0.1
18	12	15	32	0.1304	0.1	**39**	29	30	30	0.4533	0.1
19	12	16	32	0.1987	0.1	**40**	8	28	30	0.2	0.1
20	14	15	16	0.1997	0.1	**41**	6	28	30	0.0599	0.1
21	16	16	16	0.1932	0.1						

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