A Transmission Planning Framework Considering Future Generation Expansions in Electricity Markets

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***Abstract*—This paper proposes a transmission planning framework in a market environment in which only the generation sector is deregulated. The proposed framework is based on modeling generation companies' (GenCos') strategic behavior and anticipating their expansion patterns from the viewpoint of a transmission system planner. The transmission expansion planning problem in this paper is modeled as a four-level optimization problem. A solution method based on agent-based systems and search-based optimization techniques is proposed to determine the optimal transmission expansion plan.**

***Index Terms*—Agent-based modeling, generation expansion, transmission planning.**

I. Introduction

MANY of today's electricity markets are "partially" deregulated, i.e., the generation sector is deregulated and competitive whereas the transmission sector has remained regulated. Transmission planning in such markets is complicated because GenCos freely decide about their investments, while the transmission planner is not directly involved in those decisions. Thus, considering the uncertainty in future generation expansions, the transmission planner needs to incorporate GenCos' strategic behavior in its planning process, which is the focus of this work.

In recent years, several studies have been reported in the literature on transmission planning in the context of deregulated electricity markets, such as [1]–[5]. In [1], a method to provide investment signals for generation and merchant transmission planning is proposed, where the market operator coordinates the proposals of private companies for generation and transmission expansion. A transmission expansion planning model in a pool electricity market, using a mixed integer linear programming formulation, is presented in [2]. A flexible transmission expansion planning method is proposed in [3], where the most flexible plan is defined as the plan with least adaption cost. In [4], a proactive transmission expansion planning approach is presented under which the GenCos could be induced by the transmission planner in their investment decisions. In [5], a bilevel transmission expansion model is presented in which the upper level is modeled as transmission investment cost minimization, and the lower level is market clearing problem. Further reviews of publications related to the transmission expansion planning can be found in [5]–[11].

The present work focuses on transmission planning in partially deregulated markets. Examples of such markets include Ontario's and Alberta's electricity markets. One of the main obligations of the transmission planner, usually the independent system operator (ISO), in such markets is to facilitate a fair and competitive market. The uncertainties in the generation sector, however, make this task challenging. The proposed transmission planning framework in the present paper takes into account uncertainties raised from short- and long-term strategic behavior of GenCos. The main contributions of this paper are: 1) A framework for transmission planning is proposed in which strategic behavior of GenCos and their possible post expansion reactions to the optimal transmission plan are taken into account. 2) An iterative solution algorithm based on agent-based systems and search-based optimization is proposed to solve the interrelated multilevel optimization problems. The advantage of the proposed solution algorithm is that it is able to handle the complexity of the formulated transmission planning problem based on a minimal set of assumptions with regard to GenCos' behavior.

The reminder of this paper is organized as follows: A background of the problem is presented in Section II. In Section III, the proposed framework and its solution algorithm are presented. Numerical results are provided in Section IV. Finally, Section V summarizes the main findings of this paper.

II. Background

Future generation expansion scenarios directly impact transmission planning. In a market environment, those scenarios depend on future electricity market prices. Market prices, on the other hand, are dependent upon GenCos' bidding strategies. Thus, four interdependent optimization problems need to be solved to optimally plan the transmission system, as follows: Problem A: GenCos' bidding strategy; Problem B: social welfare maximizing or market clearing problem; Problem C: GenCos' generation expansion; and Problem D: transmission expansion. These problems and their interdependency are shown in Fig. 1, and are discussed in more details in Section II-A. In this paper, the term *scenario* is used for the

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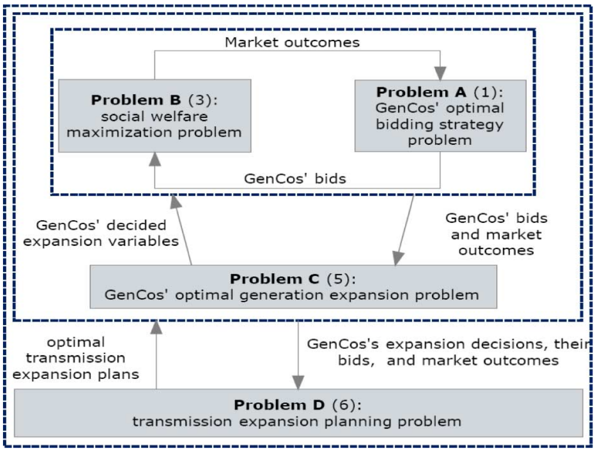

Fig. 1. Illustration of the interdependencies of problems A–D.

possible future generation expansion patterns. In addition, the term *plan* is used for the transmission expansion plans.

A. Problem A: Gencos' Optimal Bidding Strategy

Optimal bids of an independent GenCo is determined by solving the following generalized problem:

$$\max_{\boldsymbol{\zeta}} \pi(\boldsymbol{\zeta}), \text{ s.t. } \boldsymbol{\xi}(\boldsymbol{\zeta}) \tag{1}$$

where π is short-term GenCos' profit, $\boldsymbol{\zeta}$ represents the set of bidding variables, and generation operation constraints are denoted by $\boldsymbol{\xi}$. Bidding variables usually include production quantities and prices. In this paper, an agent-based modeling approach based on the Q-learning algorithm is employed to determine the GenCos' optimal bidding strategy. Demand-side bidding is not included in the strategic game.

B. Problem B: Market Clearing

Market clearing results, normally determined by the ISO, are found by solving an optimization problem, as follows:

$$\max_{\boldsymbol{\eta}} \triangle w(\boldsymbol{\eta}), \text{ s.t. } \boldsymbol{\kappa}(\boldsymbol{\eta}) \tag{2}$$

where $\boldsymbol{\eta}$ represents market variables, and the set of market operation constraints is denoted by $\boldsymbol{\kappa}$. The objective is to maximize the social welfare, $\triangle w$, and the decision variables, $\boldsymbol{\eta}$, are usually the consumption and production at each location. Market clearing prices are the other outputs of this problem.

In the present work, the following market model, which includes a DC representation of the network, is employed [2]:

$$\max \quad \triangle w = \left(\sum_{j=1}^{N_b} b_j PD_j - \sum_{i=1}^{N_g} a_i PG_i\right) \tag{3a}$$

$$\text{s. t.} \quad PG_j - PD_j - \sum_{k\in\phi_j} y_{jk}(\theta_j\theta_k) = 0$$
$$j = 1,2,\ldots,N_b \tag{3b}$$

$$-f_{jk}^{\max} \le y_{jk}(\theta_j\theta_k) \le f_{jk}^{\max}$$
$$j = 1,2,\ldots,N_b;\ \forall\, k \in \phi_j \tag{3c}$$

$$PG_i^{\min} \le PG_i \le PG_i^{\max}, \quad i = 1,2,\ldots,N_g \tag{3d}$$

$$0 \le PD_j \le PD_j^{\max}, \quad j = 1,2,\ldots,N_b \tag{3e}$$

where a_i and b_j represent the bid price of GenCo i and demand-side customer j, respectively. Power demand at bus j and power production of GenCo i are represented by PD_j and PG_i, respectively. In addition, the voltage phase angle at bus j is represented by θ_j, and admittance and power flow of line connecting buses j and k are represented by y_{jk} and f_{jk}, respectively. The DC power flow limitations are represented by(3b) and (3c), and power output of each producer is restricted by its physical constraints as in (3d). Moreover, power demand at each bus is restricted by (3e) to the size of the demand bid.

C. Problem C: Gencos' Optimal Expansion Problem

The generation expansion problem for an independent GenCo can generally be modeled as

$$\max_{\boldsymbol{\chi}} \Pi(\boldsymbol{\chi}), \text{ s.t. } \boldsymbol{\vartheta}(\boldsymbol{\chi}) \tag{4}$$

where Π is the GenCo's expansion objective, $\boldsymbol{\chi}$ represents generation expansion variables, and $\boldsymbol{\vartheta}$ is the set of generation investment constraints. The decision variables in this problem are usually the expansion capacity and investment year.

Various factors can be considered in formulating the expansion of a GenCo, such as revenue from selling energy, revenue from capacity markets, bilateral contracts, and portfolio diversification benefits. We have considered the revenue from energy sale and the cost of investment [1], as follows:

$$\begin{aligned}\max \quad \Pi_k = &\sum_{t=1}^{N_t}\sum_{d=1}^{N_d}(1+\gamma)^{-t}\left(D_d(\lambda_{kdt} - \mathrm{MC}_{kt}^e)PG_{kdt}^e\right)\\ &+\sum_{t=1}^{N_t}\sum_{d=1}^{N_d}(1+\gamma)^{-t}\ \left(D_d(\lambda_{kdt} - \mathrm{MC}_{kt}^c)PG_{kdt}^c\right)\\ &-\sum_{t=1}^{N_t}(1+\gamma)^{-t}\left(\mathrm{GIC}_k \times \sum_{\tau=1}^{t}\mathrm{EC}_{k\tau}\right)\end{aligned} \tag{5a}$$

$$\text{s. t.} \quad \mathrm{EC}_{k\tau} \ge 0, \quad \tau = 1,2,\ldots,N_t \tag{5b}$$

where the present value of profit from the existing and the candidate capacity of the GenCo at bus k are represented by the first and the second terms, respectively, and the present value of annualized capital cost is expressed by the third term in the objective function (5). γ and λ represent economic discount rate and nodal energy price, respectively. The duration of step d in load duration curve is shown by D_d. Superscript indices e and c stand for existing and candidate capacity, respectively. Furthermore, marginal cost of generation capacity and annual generation investment cost are represented by MC and GIC, respectively. The decision variables are the expansion capacity of the GenCo in each year of the planning horizon, $\mathrm{EC}_{k\tau}$, which can only take positive values. MC_{kt}^{c} is the marginal cost of each GenCo's candidate capacity which is assumed to be known by the transmission planner. The values of λ_{kdt}, PG_{kdt}^{e}, and PG_{kdt}^{c}, the locational marginal prices, the production quantities from the existing and the new candidate units, are the outputs of Problem B. The solution of Problem B in turn requires inputs from Problem A.

Although it is unlikely that an analytical model, such as the one formulated in (5), will capture the entire behavior of GenCos, this approach has been taken in several other publications such as [1] and [4], and should generally represent the business interests of a GenCo. However, the GenCo model of (5) can be customized/modified based on the observed behavior of GenCos in a practical situation. Adding different dimensions, such as spinning reserve and capacity payments, to the model of the GenCos expansion problem may result in a potentially better representation of GenCo behavior; however, this is balanced against the need for more parameter data and potentially a more difficult numerical problem to solve. Although variations in Problem C may result in a different set of likely generation expansion scenarios, it does not impact the overall transmission planning framework proposed in the present paper.

D. Problem D: Optimal Transmission Planning Problem

The transmission expansion planning problem can generally be represented as

$$\max_{\boldsymbol{\nu}} \quad \Phi(\boldsymbol{\nu}), \text{ s.t. } \boldsymbol{\mu}(\boldsymbol{\nu}) \tag{6}$$

where Φ represents transmission expansion objective, $\boldsymbol{\nu}$ is the set of transmission expansion variables, and $\boldsymbol{\mu}$ represents the planning constraints. Various planning objectives can be considered, such as maximizing the competition level in the market or maximizing the social welfare. The planning variables in this problem are usually line placements, timing of the investment, and line capacities. In this paper, Problem D is built on the interaction of Problems A, B, and C based on a predefined set of transmission plans.

E. Solving the Multilevel Optimization Problem

Solving the bilevel optimization problems A and B, i.e., finding the market equilibrium, has been widely addressed in the literature. A comprehensive review of different methods for computing electricity market equilibria and modeling gaming behavior of market players is presented in [12].

However, solving the four-level optimization problem (Problems A-D, illustrated in Fig. 1) is numerically difficult, given the interdependency of the problems. In the approach presented in Section III, the complexities of these interdependent problems are handled using an iterative solution algorithm based on agent-based systems and search-based optimization. This differs from the approach in [4], which is based on a sequential quadratic programming algorithm. In addition, the transmission planning paradigm presented in [4] is proactive, i.e., it aims to induce GenCos to follow the selected transmission plan. However, the planning paradigm in the present work aims at selecting an optimal plan based on anticipating the likely future generation expansion scenarios. This is motivated by the fact that implementing a transmission plan takes much longer than building new generation plants and thus, when planning transmission, it is necessary to reasonably anticipate what will happen in generation sector over the coming years.

III. Proposed Transmission Expansion Planning Framework and Solution Algorithm

The proposed framework consists of three main steps. The first step is called *generation expansion anticipation*, in which potential generation expansion scenarios in all buses are analyzed by the transmission planner. In order to determine the potential scenarios (i.e., solving Problem C), Problems A and B need to be solved. The second step, called *transmission expansion planning*, represents Problem D, which is solved based on the results of the first step. Finally, in the third step, referred to as *generation expansion re-evaluation*, assuming the decided transmission expansion plans are publicly announced and thus known by the GenCos, the transmission planner re-evaluates generation expansion scenarios to ensure the final transmission plan remains optimal in case GenCos react to the announced plan(s). In all the three steps, the strategic behavior of market players is modeled by the transmission planner using agent-based modeling.

Step 1: Generation Expansion Anticipation

In this step, starting from the first bus in system, $k = 1$, the possibility of generation expansion at each bus is studied by the transmission planner. Assuming that all generation capacity at a bus is owned by an individual GenCo, various factors that may influence this possibility at each bus, such as environmental restrictions or land or fuel limitations, are considered by the transmission planner. Buses with such limitations are eliminated from the study and profitability of generation expansion is evaluated for the rest of the buses, and consequently, generation expansion scenarios are determined. Known generation interconnection queues can also be incorporated into the generation expansion problem by adding them either to the system at the expected commissioning year for the finalized ones or to the set of generation expansion scenarios for those which only have shown interests. Following, the proposed iterative solution to the three-level optimization problem, i.e., Problems A, B, and C, is explained.

A. Proposed Algorithm for Solving Problems A, B, and C

To anticipate the capacity and year of generation expansion at each potential bus, the transmission planner formulates a profit-maximization problem from the viewpoint of a typical for-profit GenCo, Problem C, i.e., (5). This problem is solved for all potential expansion buses and a set of likely generation expansion scenarios, denoted by S, is determined. Each scenario $s \in S$ is specified by its capacity, year of commissioning, and the location. An expansion scenario s at year t takes into account all anticipated expansions prior to year t.

In order to solve Problem C with its interdependency with Problems A and B, an algorithm based on agent-based modeling [13] and search-based optimization [14] is utilized. The steps of

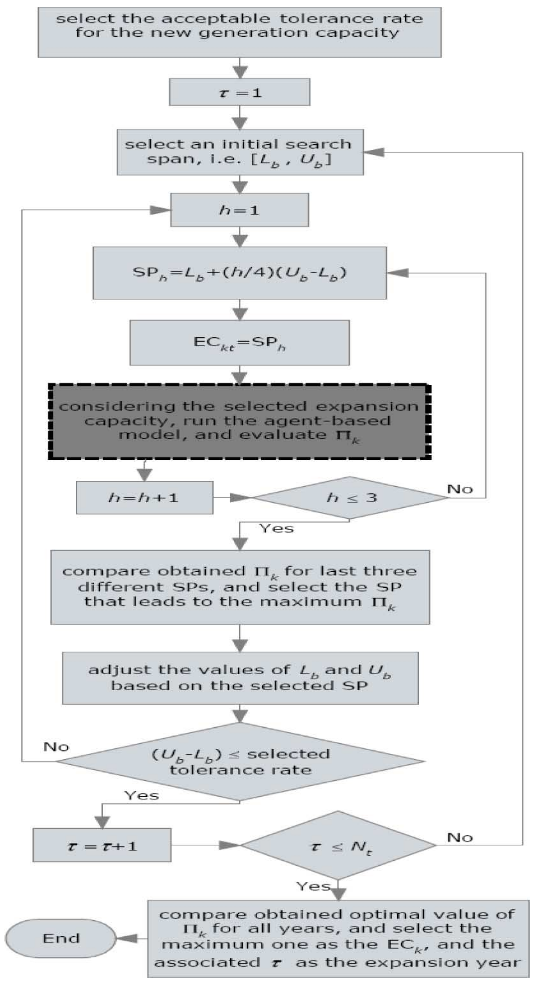

Fig. 2. Proposed iterative algorithm to solve problem A–C.

this algorithm are shown in Fig. 2. The search for optimal generation expansion capacity at bus k and year τ starts with a wide range of $[L_b, U_b]$ (the wideness of this range is dependent upon the system generation capacity and peak demand). This range is divided into four equal sections (this makes the convergence time shorter [14]) and each dividing point, h, is called a search points, denoted by SP_h, $h = 1, 2, 3$. The initial increments of capacity expansion are selected equal to each of the search point values, and Problems A and B are solved accordingly.

The bilevel optimization (Problems A and B) is handled using the agent-based modeling approach (presented using the dark block in Fig. 2). The advantage of this method compared to other market modeling techniques is its capability in handling market complexities with minimal assumptions regarding market players. Furthermore, the agent-based systems are able to find market equilibrium (equilibria) if it (they) exists [13].

Various learning methods may be used in agent-based systems, such as temporal difference learning, probably approximately correct learning and Q-learning [15]. Q-learning is a simple but powerful method which has been used in many applications including electricity market modeling, and is used in the present work. Each GenCo is modeled as a Q-learning agent. With a minimal set of assumptions, i.e., GenCos' marginal costs and their available capacity, the transmission planner models the market starting from a vague state in which none of the GenCos has an established bidding strategy.

In the Q-learning algorithm, the agent experiences a sequence of finite iterations, and at the nth iteration [15]:

1) receives its current state x_n;
2) selects and does an action a_n;
3) receives its next state z;
4) evaluates an immediate reward r_n; and
5) adjusts its Q_{n-1}-values using a learning factor $\Psi_n \in [0, 1]$ as follows:

$$Q_n(x,a) = \begin{cases} Q_n^*(x,a), & \text{if } x = x_n \text{ and } a = a_n \\ Q_{n-1}(x,a), & \text{otherwise} \end{cases} \quad (7a)$$

$$Q_n^*(x,a) = (1-\Psi_n)Q_{n-1}(x,a)\Psi_n[r_n + \varpi V_{n-1}(z)] \quad (7b)$$

$$V_{n-1}(z) = \max_b\{Q_{n-1}(z,b)\} \quad (7c)$$

where ϖ represents a discount rate for considering the future rewards. Equation (7c) implies the best strategy that the agent may take from state z, based on its past experiences. Each GenCo's action is its selected bid price. Moreover, the state of each iteration, x_n, is represented by the cleared nodal prices in that iteration. The reward that each GenCo receives in each iteration is also its profit, which is obtained by solving (3) (Problem B), and determining market clearing prices and quantities, considering the associated action and environment. The above procedure is repeated until the market reaches its equilibrium and thus, the GenCos reach their optimal bidding strategies. More details of the employed agent-based system are provided in [13] and [16]. The above algorithm is used to solve the bilevel optimization problem A–B.

To solve Problems A, B, and C, in the search-based algorithm, considering each search point, Problems A and B are solved using the agent-based algorithm, and consequently, the generation expansion profit associated to the search point is evaluated, as shown in Fig. 2. The solutions of the agent-based algorithm are transferred back to Problem C. These outcomes are used to evaluate Π_k, presented in (5), in each of these search points. The point with the highest value of Π_k is selected, and the next search is limited to the neighboring sections of that point. This procedure is repeated iteratively until the search range is narrow enough, based on a predefined tolerance (for example 25 MW), selected at the first block of Fig. 2. The above process is repeated for all planning years in the planning horizon. As shown in the bottom of Fig. 2, the expansion capacity $\mathrm{EC}_{k,t}$ that yields the highest value of Π_k is the optimal capacity expansion scenario for bus k. This procedure is repeated for all buses at which generation expansion is possible. This search technique is preferred to other alternatives (e.g., the Golden section search technique) because the search points can be restricted to factors of the desired capacity value (e.g., factors of 25 MW).

A contribution of this paper in this algorithm is linking the search-based and the agent-based approaches to solve Problems A-C. It is assumed in this work that for each GenCo, one generation expansion will be practically possible to be implemented over the planning period.

Step 2: Transmission Expansion Planning

The purpose of this step is to solve Problem D. The first task in this step is to construct a credible and tractable set of potential new and reinforcement transmission expansion plans, denoted here by P. 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 this set [3]. A plan $p \in P$ is specified by the sending and receiving end and its capacity.

For each pair of $(s \in S, p \in P)$, Problems A and B are solved in this step and market clearing quantities are determined. These quantities are then used to evaluate a set of transmission planning criteria, as explained later in this step.

To select the optimal plan, an approach based on the concept of minimizing maximum regret is used in this work. Consider a set of M planning criteria for which having a higher value would indicate a better plan according to the particular criterion. Referred to by $\mathrm{TPC}_{m,p,s}$ as the mth criterion based on plan p and scenario s, all of the planning criteria are evaluated for all plans and scenarios. For each scenario s, the highest value of the mth planning criterion is determined as

$$\mathrm{TPC}_{m,*,s} = \max_{p\in P}\{\mathrm{TPC}_{m,p,s}\}, \quad s \in S, \\ m = 1, \ldots, M. \tag{8}$$

Defining $\mathrm{TPC}_{m,*,s} - \mathrm{TPC}_{m,p,s}$ as "regret" for plan p under generation scenario s, the maximum regret (MR) of plan p across all scenarios $s \in S$ is defined as follows:

$$\mathrm{MR}_p = \max_{\{s\in S\}}\{\mathrm{TPC}_{m,*,s} - \mathrm{TPC}_{m,p,s}\}, \quad p \in P, \\ m = 1, \ldots, M. \tag{9}$$

Since more than one planning criterion is considered, the values of MR_p are normalized to their maximum value, as follows:

$$\mathrm{NMR}_p^{\mathrm{TPC}_{m,p,s}} = \frac{\mathrm{MR}_p}{\max_{\{p\in P\}}\{\mathrm{MR}_p\}}, \\ m = 1, \ldots, M \tag{10}$$

where $\mathrm{NMR}_p^{\mathrm{TPC}_{m,p,s}}$ is the normalized maximum regret of plan p based on the $\mathrm{TPC}_{m,p,s}$.

Choosing the "best" plan based on the values of NMR at this stage depends on the planner's preferences. Different multi-criteria optimization approaches, such as compromise programming, evolutionary programming, normal constraint method, and a single aggregate criterion, could be used to select the optimal plan. The single aggregate criterion has shown competitive results despite its simplicity, and is used in the present work. Thus, overall normalized maximum regret (ONMR) is defined for each plan, as follows:

$$\mathrm{ONMR}_p = \sum_{m=1}^{M} \alpha_m \mathrm{NMR}_p^{\mathrm{TPC}_{m,p,s}}, \\ \sum_{m=1}^{M} \alpha_m = 1 \text{ and } \alpha_m \geq 0. \tag{11}$$

ONMR_p is calculated as a weighted summation of normalized maximum regrets of plan p. In (11), the weighting factors for $\mathrm{TPC}_{m,p,s}$ are represented using α_m. Selecting the proper transmission planning criteria and associated weighting factors is highly dependent upon the system priorities, and the outcome of the proposed framework can change based on this selection. The system priorities are determined by the planner and expert knowledge based on the system analysis and studies. In fact, the choice of optimal transmission expansion plan is always affected by the planners concerns which are derived based on political and other practical considerations.

Different transmission planning criteria can be considered in this step. Examples of these criteria are system reliability, system security, system congestion cost, level of competition in the market, and sensitivity of the plan to generation expansion scenarios [3], [4], [17]. For this paper, two criteria are considered for selecting the optimal plan as described below, i.e., $M = 2$. However, the described procedure in this section is expandable to include any other planning criterion.

Improving competition level in the market and reducing transmission-related market power potentials should be considered in the transmission planning, given the ISO obligation in providing a level field for all market players [4]. Competition level can be quantified using different indices, such as Hirschman Herfindahl Index (HHI) and Lerner Index (LI) [18]. LI is employed in the present work to measure the system's competition level considering its ability to capture GenCos strategic bidding behavior. LI is defined as: $\mathrm{LI}_i = (\lambda_i - \mathrm{MC}_i)/\lambda_i$, where λ_i and MC_i are the market price received by GenCo i and marginal cost of GenCo i, respectively. A lower value of LI reflects a higher level of competition in the market. In this work, this index is averaged across all the GenCos in the market ($\bar{\mathrm{LI}}$). However, $\bar{\mathrm{LI}}$ does not take into account the cost of the plan. Thus, in order to involve the investment cost in the planning procedure [2], the following transmission planning criterion is used:

$$\mathrm{TPC}_{1,p,s} = \frac{\triangle\bar{\mathrm{LI}}_{p,s}}{\mathrm{TIC}_p} \\ = \frac{\bar{\mathrm{LI}}_s - \bar{\mathrm{LI}}_{p,s}}{\mathrm{TIC}_p}, \quad p \in P, \ s \in S \tag{12}$$

where $\bar{\mathrm{LI}}_s$ and $\bar{\mathrm{LI}}_{p,s}$ are the values of $\bar{\mathrm{LI}}$ before and after commissioning plan p in presence of generation expansion scenario s, respectively. TIC_p is the transmission investment cost of plan p. Observe that for two alternative transmission expansion plans, a higher value of TPC_1 indicates a higher return of the investment in terms of $\bar{\mathrm{LI}}$ for a given scenario s.

The second criterion, i.e., $\mathrm{TPC}_{2,p,s}$, is defined based on the reductions in congestions costs resulting from a transmission plan. Considering that reducing congestion cost results in increasing electricity market fairness and also indirectly improving the system reliability [17], [19], it is considered as a planning criterion in the present work. Congestion cost (CC) in a nodal pricing system is defined as: $\mathrm{CC} = \sum_{l=1}^{N_l} (\lambda_j - \lambda_k) f_{jk}$, where end buses of line l are denoted by j and k. The CC represents the congestion level in the system. To involve the investment cost in assessing the congestion relief resulting from a transmission plan, $\mathrm{TPC}_{2,p,s}$ is written as

$$\begin{aligned}\mathrm{TPC}_{2,p,s} &= \frac{\triangle \mathrm{CC}_{p,s}}{\mathrm{TIC}_p} \\ &= \frac{\mathrm{CC}_s - \mathrm{CC}_{p,s}}{\mathrm{TIC}_p}, \quad p \in P, \ s \in S. \qquad (13)\end{aligned}$$

The higher value of the above index means the more optimal the plan is in term of the congestion cost reduction, considering the investment cost.

Step 3: Generation Expansion Re-Anticipation

The objective of this step is to take into account possible reactions of GenCos to the announced plan, selected in Step 2. To do this, the selected line is included in the system and Step 1 is repeated again. If the new anticipated scenarios match the initial set, the selected plan is considered final. If not, Step 2 is repeated based on the new set of anticipated scenarios. If the selected plan remains the same as the previous iteration, the plan is considered final. If not, Step 3 is repeated again. No transmission plan is publicly announced to the market by the planner, unless it is determined as the final plan using the proposed framework, and the purpose of this step is to ensure the robustness of the final plan. This approach extends what is presented in [4] by incorporating into the current time horizon the impact that announcing a transmission plan may have on future generation expansions. This is a reasonable consideration, since time between transmission expansion announcements and commission of new lines is normally significantly greater than generation expansion planning.

The proposed planning framework models parts of uncertainties associated to future generation expansion in the system using the concept of minimizing the maximum regret of planning. But, other uncertainties such as demand levels uncertainties, forced outages of generation and transmission systems, future policy and regulation uncertainties, and economic inflation rates uncertainties are involved in the problem. These uncertainties can be modeled using available approaches such as in [2] and [4], but was not considered in this paper as the focus is presenting a framework that models the interactions between transmission and generation expansions.

The Transmission Economic Assessment Methodology (TEAM) in [20] presents a comprehensive framework for evaluating the value of a transmission upgrade from the viewpoint of various involved parties considering five key principals, namely, the benefit framework, the network representation, market prices, uncertainty, and alternative solutions. Evaluating the outcomes of the proposed planning framework using methods like TEAM can provide further quantitative and comparative insights to the planner and other parties impacted by the proposed upgrades.

IV. Simulation Results

The aims of the simulations considered in this section are: 1) to verify the practicality of the proposed framework using a test system; 2) to study the impact of the weighting factors of planning criteria, α_m, transmission planning investment cost of each plan, TIC_p, marginal cost of candidate capacities, MC^c, and also other transmission planning criterion, TPC, on the performance of the proposed framework.

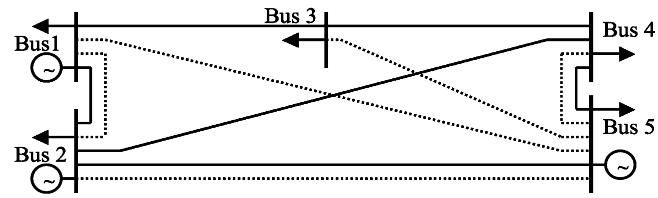

Fig. 3. Five-bus test system's single line diagram adapted from [13].

TABLE I
Transmission System Data

Line	Existing/ Candidate	Reactance (p.u.)	f_{jk}^{max} (MW)	Plan	Length (km)	Inv. Cost (10^5\$/km)
1-2	Existing	0.0064	150	-	-	-
	Candidate	0.0064	100	p_1	9	10
1-3	Existing	0.0281	150	-	-	-
1-5	Candidate	0.0304	100	p_2	12	20
2-4	Existing	0.0304	150	-	-	-
2-5	Existing	0.0297	150	-	-	-
	Candidate	0.0297	100	p_3	12	10
3-4	Existing	0.0180	150	-	-	-
3-5	Candidate	0.0304	100	p_4	6	20
4-5	Existing	0.0297	150	-	-	-
	Candidate	0.0297	100	p_5	8	10

The simulations are applied to the five-bus test system, illustrated in Fig. 3, which is a modified version of the test system in [13]. The supply-side in this system is composed of three 250-MW capacity GenCos, located at buses 1, 2, and 5, supplying the demand across all buses. The marginal costs of these GenCos are assumed to be 15, 12, and 20\$/MWh, respectively. The existing system is shown with solid lines, and the candidate transmission plans are shown using dashed lines. The transmission system data are presented in Table I.

A price cap of 200 \$/MWh is considered in the simulations. Yearly demand growth and discount rate are considered to be 3% and 5%, respectively. The values of the simulation parameters related to the agent-based algorithm are presented in [16]. The peak load of Buses 1 to 5 are considered to be 10, 50, 100, 100, and 250 MW, respectively. The load level, in each year under the planning horizon, in different buses is based on a load duration curve that has five steps of 95, 90, 80, 70, and 60%, where the associated duration of steps are 1, 7, 32, 40, and 20% of time of year, respectively. The generation investment cost, GIC, for all the buses is considered to be 10^4\$/MW/year. Number of planning years is considered to be 5. It is assumed that only a single new line or reinforcement of a single existing line is being decided by the transmission planner. However, the proposed framework provides a ranking for all plans and thus, more than one plan may be selected.

Each generator in the existing system is considered an independent GenCo. Candidate capacities' marginal costs at buses 1, 2, and 5 are assumed to be the same as the existing units' marginal costs. The marginal cost of the new candidate units at Buses 3 and 4 are assumed to be 17\$/MWh, which are subject to the yearly inflation rate (3.5%).

TABLE II
AVERAGE $\mathrm{TPC}_{m,p,s}$ FOR TRANSMISSION EXPANSION PLANS

Plan	$\mathrm{TPC}_{1,p,s}(10^{-6}/\$)$				$\mathrm{TPC}_{2,p,s}(10^{-3}/\mathrm{h})$			
	s_1	s_2	s_3	s_4	s_1	s_2	s_3	s_4
p_1	0.0016	0.0023	0.0024	0.0026	0.0597	0.0398	0.0383	0.0360
p_2	0.0023	0.0026	0.0009	0.0007	0.0083	-0.0046	-0.0015	-0.0027
p_3	**0.0236**	**0.0263**	0.0258	0.0257	0.5154	0.4352	**0.1816**	**0.1800**
p_4	0.0196	0.0251	**0.0261**	**0.0259**	0.4155	0.3520	0.0950	0.0944
p_5	0.0225	0.0199	0.0200	0.0203	**0.5794**	**0.4804**	0.1502	0.1472

A. Illustrative Example of the Proposed Framework

Initially the first step of the proposed framework (Problem C) is applied to this case study. To determine the anticipated generation expansion scenarios, Problems A, B, and C are solved using the proposed algorithm in Fig. 2. The tolerance rate in Fig. 2 is assumed to be 50 MW. It is observed that no generation addition is profitable at Buses 1 and 5, but a 100-MW capacity expansion at the end of first planning year is expected at Bus 2. Furthermore, adding 150 MW of new generation capacity at the end of the first planning year is expected at Buses 3 and 4. These new capacities at Buses 3 and 4 are owned by new GenCos, namely GenCo 3 and GenCo 4. Thus, the set of likely scenarios, i.e., S, is as follows:

- Scenario s_1: No generation expansion planning. This is to include a no-expansion scenario in the simulations.
- Scenario s_2: GenCo 2 expands its capacity by 100 MW.
- Scenario s_3: A new 150-MW GenCo at Bus 3.
- Scenario s_4: A new 150-MW GenCo at Bus 4.

Considering the above scenarios, different transmission expansion plans are assessed in the second step of the proposed framework. A large number of new/reinforcement transmission plans could be considered for this system. However, the load is mostly concentrated at Bus 5, and thus, the new plan should facilitate the transmission of power to this bus. Taking such facts into account, the set of potential transmission expansion plans is reduced to the ones presented in Table I.

Using (8)–(10), the values of planning criteria are evaluated, and their average values over the different load levels for different scenarios for the commissioning year are presented in Table II. Observe from Table II that according to the first criterion, plan p_3 is optimal in case scenarios s_1 and s_2 occur, and p_4 is optimal in case scenarios s_3 and s_4 happen in future. According to the second criterion, on the other hand, p_5 is the optimal plan for scenarios s_1 and s_2, whereas p_3 is the optimal plan for generation scenarios s_3 and s_4.

In order to select the "best" transmission expansion plan, the values of maximum regret, i.e., MR_p, normalized maximum regret, i.e., NMR_p, and overall normalized maximum regret, i.e., ONMR_p, are calculated for each plan using (9), (10), and (11), respectively. The values of ONMR_p are presented in Table III. These values are determined using $\alpha_1 = \alpha_2 = 0.5$. Observe from Table III that the value of ONMR_p is minimum for p_3, and therefore, this plan is considered as the optimal transmission expansion plan.

After Step 2, generation expansion re-anticipation step needs to be executed. Hence, considering p_3, generation expansion anticipation step in all buses is re-evaluated. This assessment results in the same scenarios at Buses 1 and 5. At Bus 2, however, it turns out that GenCo 2 is expected to expand its capacity by 150 MW instead of 100 MW. Furthermore, the expected expansion capacity at Buses 3 and 4 turns out to be 100 MW, instead of 150 MW. Based on the proposed framework, considering the new set of anticipated scenarios and discarding the selected plan from the system, Step 2 is performed again. It was observed that p_3 was still the optimal plan according to the selected planning criteria. Thus, p_3 is selected as the optimal transmission expansion plan.

TABLE III
ONMR_p FOR TRANSMISSION EXPANSION PLANS

Plan Name	p_1	p_2	p_3	p_4	p_5
ONMR_p	0.9312	1.0000	**0.0620**	0.2229	0.1557
Plan's Rank	4	5	1	3	2

B. Effect of α_m on the Selected Plan

The selected plan can change by varying the values of α_m. For example, for values of $0 \leq \alpha_1 \leq 0.15 (0.85 \leq \alpha_2 \leq 1)$, p_5 is selected as the best plan, instead of p_3, because the value of the normalized maximum regret of the second transmission planning criterion has its minimum value for p_5. Thus, increasing α_2 results in selecting p_5. This shows that optimal transmission expansion is dependent on the planer's preferences reflected in values of α_m.

C. Effect of Tic_p on the Selected Plan

The investment cost of each transmission plan is dependent upon length and technology of the plan. To examine the effect of this cost in the proposed framework, the investment cost of each of last three plans, p_3, p_4, and p_5, is varied individually. The selected plan is changed by a 10% increase in TIC_{p_3} (selecting p_5 instead of p_3), or by a 23% decrease in the TIC_{p_4} (selecting p_4 instead of p_3), or finally by 22% decrease in TIC_{p_5} (selecting p_5 instead of p_3). Thus, a high level of competition enhancement or the congestion cost diminishment solely cannot guarantee the selection of the associated plan. In the other hand, these developments are measured per investment cost in the proposed framework.

D. Effect of Mc_i on the Selected Plan

To verify the effect of the values of the candidate capacities' marginal costs on the selection of the optimal plan, the value of the marginal cost of candidate GenCo 3 is changed. It is observed that if this value is higher than GenCo 5's marginal cost, then no expansion is profitable at Bus 3. This results in selecting p_5 as the optimal plan instead of p_3. Thus, the optimal plan in the proposed framework is affected by the expected values for the candidate capacities' marginal costs. This is mainly because the transmission expansion planning problem (Problem D) is solved based on the generation expansion anticipation problem (Problem C), where Problem C is solved using the minimal transmission planner's information regarding the existing GenCos, including their marginal costs and their capacities, and also the expected transmission planner's values for the candidate capacities' marginal costs.

E. Other TPC Options

The proposed approach can utilize different transmission planning criteria. For example, if system reliability is to be directly included in the panning procedure as an independent criterion, different hierarchical level II reliability indices such as loss of load expectation (LOLE) and loss of load probability (LOLP), expected energy not supplied (EENS) and expected load curtailed (ELC) (all considering the composite evaluation of generation and transmission network) may be used to form a reliability criterion. For instance, the following can be used as a transmission planning criterion:

$$\begin{aligned}\mathrm{TPC}_{3,p,s} &= \frac{\triangle \mathrm{LOLP}_{p,s}}{\mathrm{TIC}_p}\\ &= \frac{\mathrm{LOLP}_s - \mathrm{LOLP}_{p,s}}{\mathrm{TIC}_p}, \quad p \in P, \ \ s \in S \quad (14)\end{aligned}$$

where LOLP_s and $\mathrm{LOLP}p, s$ are the values of LOLP before and after commissioning plan p in presence of generation expansion scenario s, respectively. Observe that for two alternative transmission expansion plans, a higher value of $\mathrm{TPC}_{3,p,s}$ indicates a higher return of the investment cost TIC in terms of LOLP for a given scenario s.

In addition, a planning criterion that maximizes the social welfare at the lowest investment costs can be defined as: $\mathrm{TPC}_{4,p,s} = \sum_{d=1}^{N_d} D_d \triangle w_{d,p,s} - \mathrm{ATIC}_p$, where $\triangle w$ represents the social welfare, and annual transmission investment cost of plan p is shown using ATIC_p.

In order to examine how the approach performs using a different planning criterion in the proposed framework, the transmission planning problem for the case system discussed in Section IV-A is resolved using $\mathrm{TPC}_{4,p,s}$ as the only planning criterion. The value for each plan is calculated considering a life span of 40 years. Again, in this case, a higher value of this criterion represents a more optimal transmission plan. Applying the min-max regret approach, the selected plan was found to be (p_3), which is the same plan found in Section IV-A, although in general, this would not be the case.

F. Convergence of the Proposed Framework

The bilevel problem (Problems A and B) is a nonconcave optimization problem [21]. The three-level problem (Problems A, B, and C) is also a nonconcave optimization problem [4]. Thus, there is no guarantee that a solution method can capture the optimal solution of this problem. However, computational experience can be used to evaluate effectiveness of a solution approach [21] and find a near-optimal solution.

The procedure described in the proposed framework easily converged to the optimal plan in our simulation results. It showed that the selected plan provides the most optimal performance considering the likely scenarios anticipated in either Step 1 or 3. However, due to the presence of Step 3 and the complicated nature of the problem, in the case in which there is a close competition between two or more candidate plans, a loop including these plans may be created in the solution procedure of the proposed framework. For such cases, the following approach is used to solve this problem.

In the proposed approach, a threshold is imposed to the number of iterations that the proposed framework is executed. If the number of iterations reaches the threshold without converging to the optimal solution, the candidate transmission expansion plans are ranked based on the likely set of scenarios in the last iteration. Ranking is done based on the explained min-max regret-based approach in Section III. Consequently, the first plan is taken out from the set of candidate transmission plans and the proposed framework is re-set and re-started again. In this way, the existing loop is expected to be removed from the solution procedure. This procedure is repeated until it converges to a plan. Considering the limited number of the candidate transmission plans, this framework is reasonable. Then the plan found is compared to the plan/plans which is/are taken out from the initial candidate set. Finally, the plan with the minimum overall normalized maximum regret is selected as the optimal transmission expansion plan.

In order to test this approach, the total cost of p_3 is assumed to increase to \$20 million, and α_1 is also assumed to increase to 0.7 (α_2 is 0.3). The imposed threshold for the number of iterations is assumed to be 20. For this case, simulation analysis results in a loop including p_4 and p_5. Applying the proposed approach results in taking p_5 out of the candidate set of the plans, and selecting p_4. Then, p_4 and p_5 are compared together, where p_4 shows a less overall normalized maximum regret and thus selected as the optimal expansion plan.

V. Conclusion

This paper presented a new transmission planning framework for partially deregulated electricity markets. The planning problem is modeled from the viewpoint of the transmission planner, as a four-level optimization problem. The interrelated Problems A (GenCos' bidding strategies), B (market clearing), and C (generation expansion) were solved by linking agent-based and search-based algorithms. Finally, Problem D (transmission planning) was linked to the first three problems through evaluating a predefined set of planning criteria. The proposed framework was applied to a five-bus test system, and the simulation results converged to the optimal transmission plan in all cases. When using such a framework, system planners need to be careful that the analytical models being used to represent GenCos capture reasonable behaviors. Solutions found from tools such as the one presented in this paper should not be applied blindly in actual planning exercises, but rather help planners gain more insight to expected behavior.

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