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Sequential Coordination of Transmission Expansion Planning with Strategic Generation Investments

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Abstract—This paper proposes mathematical models for sequential coordination of transmission expansion planning with strategic generation investments. The proactive and reactive coordinations are modeled and studied. The interaction between transmission company (Transco) and strategic generation companies (Gencos) is modeled using the sequential-move game. This is while the interaction between the strategic Gencos is modeled as a simultaneous-move game. In the proactive coordination, the Transco expands its future transmission capacities taking into account the strategic investments by Gencos. In the reactive coordination, strategic Gencos move first and expand their future generation capacities and then Transco expands the transmission capacity. The proactive coordination is modeled as a mixed-integer bilevel linear program (MIBLP) and the reactive coordination is modeled as a mixed-integer linear program (MILP). The MIBLP has binary variables in both upper and lower levels. The Moore-Bard algorithm is parallelized and used to solve the MIBLP. The mathematical models and the parallelized Moore-Bard algorithm are tested on 3-bus and 6-bus example systems and the modified IEEE-RTS96. Also, the IEEE 118-bus test system is studied using a heuristic version of the Moore-Bard algorithm.

Index Terms—Sequential coordination, Transmission expansion planning, Strategic generation investment.

NOMENCLATURE

Sets:

- G_z Set of generating units owned by Genco z
 - V_z Set of available investment options for Genco z
 - U Set of conventional units
 - I Set of wind power units
 - J Set of hydro power units
- Parameters (upper-case letters):**
- A_k Step size of the added capacity for binary variable k
 - C_g Fuel cost (\$/MWh) of unit g
 - $\bar{E}_{hg}$ Limit of produced energy (MWh) of hydro power unit g in hydro season h
 - D_{sn} Active load level (MW) at bus n in scenario s
 - F_l Capacity (MW) of line l
 - H_{nl} Matrix of power transfer distribution factors
 - P_g Capacity (MW) of conventional unit g
 - T_{sg} Capacity (MW) of wind unit g in scenario s
 - R_g Capacity (MW) of hydro power unit g
 - Y_h Probability of hydro season h in the horizon year of planning

- X_s Probability of scenario s in the horizon year of planning
- W_{hs} Probability of scenario s in hydro season h in the horizon year of planning
- $\bar{C}_l$ Expansion cost (\$/MWy) of line l
- $\underline{C}_g$ Expansion cost (\$/MWy) of unit g
- $\bar{M}$ Sufficiently large constant

Indices:

- g Index for generating units
- h Index for hydro seasons
- k Index for steps of added capacity
- l Index for transmission lines
- b Index for buses
- s Index for scenarios
- v Index for strategies
- z Index for Gencos

Variables (lower-case letters):

- $\hat{f}_l$ Expanded capacity (MW) of line l
- $\hat{p}_g$ Expanded capacity (MW) of unit g
- p_{hsg} Power generation (MW) of unit g in hydro season h in scenario s
- α_{lk} Binary variable of the added capacity for line l in step k
- β_{gk} Binary variable of the added capacity for unit g in step k
- π_z Profit (\$) of Genco z
- η_{hsn} Price of electricity (\$/MWh) at bus n in hydro season h in scenario s
- η_{hs}^{sys} Lagrange multiplier of power balance equation in hydro season h in scenario s (system price)
- $\bar{\mu}_{hsl}$ Lagrange multiplier of upper limit constraint on power flow of transmission line l in hydro season h in scenario s
- $\underline{\mu}_{hsl}$ Lagrange multiplier of lower limit constraint on power flow of transmission line l in hydro season h in scenario s
- $\bar{\lambda}_{hsg}$ Lagrange multiplier of upper limit constraint on conventional unit g in hydro season h in scenario s
- $\underline{\lambda}_{hsg}$ Lagrange multiplier of lower limit constraint on conventional unit g in hydro season h in scenario s
- $\bar{q}_{hsg}$ Lagrange multiplier of upper limit constraint on hydro power unit g in hydro season h in scenario s
- $\underline{q}_{hsg}$ Lagrange multiplier of lower limit constraint on

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	hydro power unit g in hydro season h in scenario s
$\bar{\rho}_{hsg}$	Lagrange multiplier of upper limit constraint on wind power unit g in hydro season h in scenario s
$\underline{\rho}_{hsg}$	Lagrange multiplier of lower limit constraint on capacity of wind unit g in hydro season h in scenario s
ϖ_{hg}	Lagrange multiplier of energy-limit constraint on hydro power unit g in hydro season h
γ_l	Lagrange multiplier of lower limit constraint on augmented capacity of transmission line l

I. INTRODUCTION

EFFICIENT investments in generation and transmission sectors are vital for the development of electricity industry. The investment costs for the projects of pan-European significance by 2030 amount to approximately €150 billion, of which €50 billion relates to subsea cables [1]. The US power sector will require \$2.1 trillion of new investments between 2014 and 2035 which include 579 GW of new generation capacities and 260000 km of new transmission lines [2]. In a vertically-integrated electricity industry, a single entity is responsible for the operation of and investment in the electricity sector [3]–[7]. However, in liberalized power markets, the generation investment decisions are made by profit-maximizing generation companies (Gencos). This is while the transmission expansion planning is still almost entirely the responsibility of regulated transmission company (Transco). This raises the important question about how these sunk investment decisions must be coordinated. The offshore transmission owner (OFTO) plan in Great Britain, the offshore grid development plan in Germany and optional firm access (OFA) plan in Australia are three practical plans aiming at coordinating transmission and generation capacities [8].

The coordination issue has been studied both in engineering and economics literature. References [9]–[11] distinguish two sequential approaches for coordinating transmission and generation investments. (1) Proactive approach: in this case, Transco announces its future plans for augmenting the network and then leaves Gencos the decision as to where to expand generation capacity. (2) Reactive approach: in this case, Gencos decide first and then Transco responds and plans the transmission system accordingly. Reference [12] discusses the benefit of proactive coordination in providing transmission capacity for integrating renewable generation. However, authors in [12] do not address the optimal capacity and location of new transmission investments specially when Gencos are strategic investors. References [9] and [10] propose mathematical models for reactive and proactive approaches. They show that proactive coordination results in more social welfare as compared to reactive coordination. However, their models cannot be solved efficiently. Moreover, the discrete nature of generation investments is ignored. Reference [13] solves the coordination problem iteratively using agent-based models and a search-based optimization technique. Agent-based models are mathematically intractable and hard to analyze. Moreover, there is no guarantee of finding the global

optimum in these iterative approaches. In [14], generation and transmission investment decisions are found through iterative interactions between Independent System Operator (ISO) and Gencos. In this paper, there is no sequence between ISO and Gencos decisions and the decisions are made simultaneously. Reference [15] models the proactive coordination in the context of strategic investments by Gencos. A modified genetics algorithm is proposed to find a good solution of the proposed model. Reference [16] models the proactive coordination but it does not address the multiple Nash equilibria issue. Also, it does not model the reactive coordination, and therefore, a comparative study on different coordination approaches can not be made. However, the same authors of [16] explicitly address the multiple Nash equilibria issue in [17], where they model the proactive coordination, defining the optimistic and pessimistic approaches in the same way as it is defined in our paper, and make a comparative study on different coordination approaches. Moreover, the disjunctive approach used in [16] leads to a large number of constraints and binary variables in large-scale networks specially when uncertainty is considered [18]. Accordingly, the computational issue needs to be alleviated by proper tuning of the disjunctive parameters and employing a suitable decomposition technique [19], [20].

Although the importance of sequential coordination is emphasized in the literature, there are as yet no mathematical models for proactive and reactive approaches which can consider the multiple Nash equilibria issue and can be solved efficiently. This paper contributes to the relevant literature in the following ways. (1) It derives a mixed-integer bilevel linear program (MIBLP) model for proactive coordination and a mixed-integer linear program (MILP) model for reactive coordination. We explicitly consider the multiple Nash equilibria issue in both MIBLP and MILP models. The horizon-year planning approach is assumed in our models. The concepts of sequential-move game and simultaneous-move game are employed in deriving MIBLP and MILP models. (2) The MIBLP model has binary variables in both levels. The parallelized version of Moore-Bard algorithm [21] is proposed and implemented to solve the MIBLP model. Also, two heuristic versions of Moore-Bard algorithm are used for dealing with large example systems.

The rest of the paper is organized as follows. The efficient coordination is modeled in Section II. The mathematical models for sequential coordination are derived in Section III. The solution algorithm for MIBLP model is detailed in Section IV. In Section V, an assumption made in the developed models is refined. In Section VI, uncertainty modeling is discussed. The illustrative 3-bus and 6-bus example systems are comprehensively discussed in Section VII. The modified IEEE-RTS96 and IEEE 118-bus test systems are studied in Section VIII. Section IX concludes the paper.

II. THE EFFICIENT COORDINATION (MILP MODEL)

The efficient coordination is used as the benchmark in our paper. In the efficient coordination, an electric utility owns both the transmission and generation assets. The electric utility

minimizes the social cost of the system in the horizon year as follows:

$$\text{Minimize } \sum_l \bar{C}_l \hat{f}_l + \sum_g \{C_g \hat{p}_g + \sum_{h,s} W_{hs} C_g p_{hsg}\} \quad (1)$$

The objective function consists of investment cost of the transmission expansion plus the investment cost and operation cost of the generation units. The additional generation and transmission capacities ($\hat{p}_g$ and $\hat{f}_l$) are modeled as discrete variables through binary expansions in (2) and (3). The generating units which are not considered for expansion are modeled by setting their additional generation capacities to zero.

$$\hat{p}_g = \sum_k A_k \beta_{gk} P_g \quad \forall g \in U \quad (2)$$

$$\hat{f}_l = \sum_k A_k \alpha_{lk} F_l \quad \forall l \quad (3)$$

$$\alpha_{lk} \in \{0, 1\}, \beta_{gk} \in \{0, 1\} \quad (4)$$

As formulated in (2), we assume generation expansion for conventional units. The horizon year of planning is modeled by different hydro seasons, h , and different scenarios, s , with their associated probabilities, $W_{hs} = X_s \times Y_h$.

A. The system operation constraints

The system operation constraints consist of power balance constraint, generation capacity limits and transmission capacity limits. Equation (5) models the energy balance constraint. Generation capacity constraints for conventional units are considered in (6). Transmission capacity limits are modeled in (7) and (8). Also, at each bus, the lost load is modeled as a fictitious generator with a marginal cost equals to the value of lost load at that bus.

$$\sum_g p_{hsg} = \sum_b D_{sb} \quad \forall h, s \quad (5)$$

$$0 \leq p_{hsg} \leq P_g + \hat{p}_g \quad \forall g \in U, \forall h, s \quad (6)$$

$$\sum_b H_{bl} (p_{hsg, g \leftarrow b} - D_{sb}) \leq F_l + \hat{f}_l \quad \forall h, s, l \quad (7)$$

$$\sum_b H_{bl} (p_{hsg, g \leftarrow b} - D_{sb}) \geq -F_l - \hat{f}_l \quad \forall h, s, l \quad (8)$$

$$p_{hsg} \in \mathbb{R} \quad (9)$$

Generation capacity constraints for wind and hydro power units are modeled in the following subsections.

B. The constraints of hydro power units

The hydro power units are energy-limited and their limited energy is different under different hydro seasons [22], [23]. In this paper, different hydro seasons, h , with their related probabilities, Y_h , are considered. The maximum capacity of the generator is modeled in (10). The energy limit constraint is presented in (11).

$$0 \leq p_{hsg} \leq R_g \quad \forall g \in J, \forall h, s \quad (10)$$

$$\sum_s X_s p_{hsg} \leq \bar{E}_{hg} \quad \forall g \in J, \forall h \quad (11)$$

Fig. 1: The production curve of a wind power unit.

Note that in this way, hydro uncertainty is roughly approximated by limiting the hydro maximum energy production under each hydro season. Hydro seasons duration (probability) and maximum energy limit are assumed to be derived from the historical data. This simplified modeling of hydro uncertainty in this paper is used in order to focus on the modeling of transmission and generation expansion coordination which is the main objective of this paper. References [24] and [25] specifically deal with hydro uncertainty in transmission expansion planning and generation expansion planning, respectively.

C. The constraints of wind power units

The wind power units are getting widely integrated into power systems. However, the generation capacity of wind turbines depends on the wind speed which is an uncertain parameter. The Weibull distribution has been used in our paper to model the uncertainty of wind speed [26], [27]. Note that other more appropriate approaches exist in literature for considering wind uncertainty [28]. However, our simplified wind uncertainty modeling is used in order to focus on the mathematical formulation of transmission and generation expansion coordination which is the primary goal of this paper. The shape parameter and the scale parameter of the Weibull distribution can be derived from the historical data of wind speed [29]. The wind speed is converted to generation capacity using the production curve in Fig. 1.

The techniques for the uncertainty modeling of wind power units have been developed extensively [30], [31]. These techniques can be categorized as analytical methods [30] and Monte Carlo techniques [32], [33], [34]. We use Monte Carlo technique for modeling uncertainty in wind speed. The wind generation capacity is modeled through several scenarios represented by index s , with their associated probabilities, X_s . These scenarios are derived using the scenario generation and reduction technique explained in Section VI. Accordingly, wind power units are subject to the capacity limit which has the s subscript, T_{sg} . This is presented in (12).

$$0 \leq p_{hsg} \leq T_{sg} \quad \forall g \in I, \forall h, s \quad (12)$$

Finally, the optimization problem (1)-(12) is a MILP with $\Psi_E = \{\beta_{gk}, \alpha_{lk}, \hat{f}_l, \hat{p}_g, p_{hsg}\}$ as the set of decision variables. This optimization problem can be solved to global optimality by available commercial softwares.

III. THE SEQUENTIAL COORDINATION

The interaction between regulated Transco and strategic Gencos is modeled using the leader-follower game in applied mathematics [35]. We focus on proactive Transco and reactive Transco for sequential coordination.

A. The proactive coordination (MIBLP model)

The proactive Transco anticipates the strategic generation investments. In this context, regulated Transco is the leader and strategic Gencos are the followers of the generation-transmission investment game. This set-up is illustrated in Fig. 2 and modeled in the following three steps.

Fig. 2: The proactive approach for generation-transmission investment game

Box 1: Each strategic Genco invests in additional generation capacity $(\beta_{gk}, \hat{p}_g)$ given the decisions of other rival Gencos $(\beta_{-gk}, \hat{p}_{-g})$ and regulated Transco $(\alpha_{lk}, \hat{f}_l)$. This is done through bilevel optimization problem (13).

$$\begin{aligned} & \underset{\beta_{gk}, \hat{p}_g: g \in G_z}{\text{Maximize}} \sum_{g \in G_z} \{-C_g \hat{p}_g + \sum_{h,s} W_{hs} (\eta_{hsb} - C_g) p_{hsg}\} \\ & \text{Subject to } \hat{p}_g = \sum_k A_k \beta_{gk} P_g \quad \forall g \in G_z \end{aligned} \quad (13a)$$

$$\beta_{gk} \in \{0, 1\} \quad (13b)$$

$$\text{where } \{\eta_{hsb}, p_{hsg}\} \in \quad (13c)$$

$$\underset{p_{hsg}}{\text{argMinimize}} \sum_{h,s,g} W_{hs} C_g p_{hsg} \quad (13d)$$

$$\begin{aligned} & \text{Subject to} \\ & \sum_g p_{hsg} = \sum_b D_{sb} : (\eta_{hs}^{sys}) \quad \forall h, s \end{aligned} \quad (13e)$$

$$0 \leq p_{hsg} \leq P_g + \hat{p}_g : (\lambda_{hsg}, \bar{\lambda}_{hsg}) \quad \forall g \in U, \forall h, s \quad (13f)$$

$$0 \leq p_{hsg} \leq T_{sg} : (\rho_{hsg}, \bar{\rho}_{hsg}) \quad \forall g \in I, \forall h, s \quad (13g)$$

$$0 \leq p_{hsg} \leq R_g : (\underline{\varrho}_{hsg}, \bar{\varrho}_{hsg}) \quad \forall g \in J, \forall h, s \quad (13h)$$

$$\sum_s X_s p_{hsg} \leq \bar{E}_{h,g} : (\varpi_{hg}) \quad \forall g \in J, \forall h \quad (13i)$$

$$\begin{aligned} & \sum_b H_{bl} (p_{hsg, g \leftarrow b} - D_{sb}) \leq F_l + \hat{f}_l : (\bar{\mu}_{hsl}) \\ & \forall h, s, l \end{aligned} \quad (13j)$$

$$\begin{aligned} & \sum_b H_{bl} (p_{hsg, g \leftarrow b} - D_{sb}) \geq -F_l - \hat{f}_l : (\underline{\mu}_{hsl}) \\ & \forall h, s, l \end{aligned} \quad (13k)$$

$$p_{hsg} \in \mathbb{R} \quad (13l)$$

In optimization problem (13d)-(13l), we assume that the power generation of units is found by an economic dispatch

that minimizes the total operation cost of generation subject to the energy-balance constraint and the generation and network capacity limits. Since (13d)-(13l) is a linear program, the Karush-Kuhn-Tucker (KKT) conditions are both necessary and sufficient [36]. The stationary, strong duality and dual feasibility conditions of (13d)-(13l) are derived in (14a)-(14c), (14d) and (14e),(14f), respectively.

$$\begin{aligned} & W_{hs} C_g - \eta_{hs}^{sys} + \bar{\lambda}_{hsg} - \lambda_{hsg} - \sum_l H_{bl} (\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \\ & g \leftarrow b, \forall g \in U, \forall h, s \end{aligned} \quad (14a)$$

$$\begin{aligned} & W_{hs} C_g - \eta_{hs}^{sys} + \bar{\rho}_{hsg} - \rho_{hsg} - \sum_l H_{bl} (\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \\ & g \leftarrow b, \forall g \in I, \forall h, s \end{aligned} \quad (14b)$$

$$\begin{aligned} & W_{hs} C_g - \eta_{hs}^{sys} + \bar{\varrho}_{hsg} - \varrho_{hsg} + X_s \varpi_{hg} \\ & - \sum_l H_{bl} (\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \quad g \leftarrow b, \forall g \in J, \forall h, s \end{aligned} \quad (14c)$$

$$\begin{aligned} & \sum_{h,s,g} W_{hs} C_g p_{hsg} = \sum_{h,s,b} \eta_{hs}^{sys} D_{sb} - \sum_{h,s,g \in I} \bar{\rho}_{hsg} T_{sg} \\ & - \sum_{h,s,g \in U} \bar{\lambda}_{hsg} (P_g + \hat{p}_g) - \sum_{h,g \in J} \{\varpi_{hg} \bar{E}_{hg} + \sum_s \bar{\varrho}_{hsg} R_g\} \\ & + \sum_{h,s,l} \left\{ (\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) \sum_b H_{bl} D_{sb} \right. \\ & \left. - (\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) (F_l + \hat{f}_l) \right\} \end{aligned} \quad (14d)$$

$$\begin{aligned} & \bar{\lambda}_{hsg}, \lambda_{hsg}, \bar{\varrho}_{hsg}, \varrho_{hsg}, \bar{\rho}_{hsg}, \rho_{hsg}, \varpi_{hg}, \underline{\mu}_{hsl}, \bar{\mu}_{hsl} \geq 0 \\ & \forall h, s, g, l \end{aligned} \quad (14e)$$

$$\begin{aligned} & \eta_{hs}^{sys}, \bar{\lambda}_{hsg}, \lambda_{hsg}, \bar{\varrho}_{hsg}, \varrho_{hsg}, \bar{\rho}_{hsg}, \rho_{hsg}, \varpi_{hg}, \\ & \underline{\mu}_{hsl}, \bar{\mu}_{hsl} \in \mathbb{R} \end{aligned} \quad (14f)$$

There are two bilinear terms in optimization problem (13) when inner problem is replaced by (14a)-(14f) and primal feasibility conditions (13e)-(13l). These are (A) the bilinear term $\eta_{hsb} p_{hsg}$ in the profit function and (B) the bilinear terms $\bar{\lambda}_{hsg} \hat{p}_g$ and $(\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) \hat{f}_l$ in the strong duality condition. The nodal price can be calculated as $\eta_{hsb} = (1/W_{hs}) [\eta_{hs}^{sys} + \sum_l H_{bl} (\underline{\mu}_{hsl} - \bar{\mu}_{hsl})]$. Substituting η_{hsb} in stationary condition (14a) and using the complementary slackness conditions $\lambda_{hsg} p_{hsg} = 0$ and $\bar{\lambda}_{hsg} (p_{hsg} - P_g - \hat{p}_g) = 0$, we have

$$\begin{aligned} & W_{hs} (\eta_{hsb} - C_g) p_{hsg} = \bar{\lambda}_{hsg} (P_g + \hat{p}_g) \stackrel{(2)}{=} \bar{\lambda}_{hsg} P_g \\ & + \sum_k A_k \beta_{gk} P_g \bar{\lambda}_{hsg} = \bar{\lambda}_{hsg} P_g + \sum_k A_k P_g t_{hsgk} \end{aligned} \quad (15)$$

where in (15), the $t_{hsgk} = \beta_{gk} \bar{\lambda}_{hsg}$ and it can be replaced by the following inequalities: $-\bar{M}(1 - \beta_{gk}) \leq t_{hsgk} - \bar{\lambda}_{hsg} \leq \bar{M}(1 - \beta_{gk})$, $-\bar{M}\beta_{gk} \leq t_{hsgk} \leq \bar{M}\beta_{gk}$. Therefore, the bilinear term in the profit function (13a) is linearized. Also, the bilinear term $\bar{\lambda}_{hsg} \hat{p}_g$ can be replaced by $\sum_k A_k P_g t_{hsgk}$. The bilinear term $(\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) \hat{f}_l$ can be linearized in the similar way as

$$\begin{aligned} & (\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) \hat{f}_l \stackrel{(3)}{=} \sum_k A_k \alpha_{lk} F_l (\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) = \\ & \sum_k A_k F_l r_{hslk} \end{aligned} \quad (16)$$

where in (16), $r_{hslk} = \alpha_{lk}(\mu_{hsl} + \bar{\mu}_{hsl})$ and it can be replaced by the following inequalities: $-\bar{M}(1 - \alpha_{lk}) \leq r_{hslk} - (\mu_{hsl} + \bar{\mu}_{hsl}) \leq \bar{M}(1 - \alpha_{lk})$, $-\bar{M}\alpha_{lk} \leq r_{hslk} \leq \bar{M}\alpha_{lk}$. The $\bar{M}$ is a sufficiently large constant the selection of which is discussed in Appendix A. The resulting problem for each strategic Genco is a MILP model.

Box 2: The Nash equilibrium of strategic generation investment game between Gencos can be found by solving Gencos problems simultaneously. However, since each Genco is modeled as a MILP, the KKT conditions do not exist. To overcome this issue, we use the fact that each Genco can select its optimal expansion capacity from a finite set of choices [16], [37]. At the optimal solution, $\hat{p}_g$, we have $\pi_z(\hat{p}_g) \geq \pi_z(\hat{p}_g^v)$ $v = 1, 2, \dots, \text{Card}\{V_z\}$. The set $\{\hat{p}_g^1, \hat{p}_g^2, \dots, \hat{p}_g^{\text{Card}\{V_z\}}\}$ is obtained by different combinations of binary variables β_{gk} from equation (2). Using the inequality above, the MILP model of each Genco is reformulated as a set of mixed-integer and linear constraints (MILCs). Solving the MILCs of all Gencos together, we can find all the Nash equilibria of the strategic generation investment game. Note that the Nash equilibria of the generation investment game are found solving a feasibility problem.

Box 3: The feasibility problem of the generation investment game might have more than one Nash equilibrium. In this situation, we assume that the Transco is pessimistic [38]. The pessimistic Transco selects the Nash equilibrium of generation investment game with the maximum social cost to the society. The pessimistic Transco plans its future transmission capacities such that it minimizes the maximum social cost to the society [39]. The mathematical model of a proactive and pessimistic Transco is set out in (17).

$$\text{Minimize}_{\Psi_T} \sum_l \bar{C}_l \hat{f}_l + \sum_g \{C_g \hat{p}_g + \sum_{h,s} W_{hs} C_g p_{hsg}\} \quad (17a)$$

$$\text{Subject to (3)} \quad (17b)$$

$$\alpha_{lk} \in \{0, 1\} \quad (17c)$$

$$\text{where } \{\hat{p}_g, p_{hsg}\} \in$$

$$\text{argMaximize}_{\Psi_G} \sum_g \{C_g \hat{p}_g + \sum_{h,s} W_{hs} C_g p_{hsg}\} \quad (17d)$$

$$\text{Subject to (2)} \quad (17e)$$

$$\beta_{gk} \in \{0, 1\}, p_{hsg} \in \mathbb{R} \quad (17f)$$

$$\eta_{hsb} = (1/W_{hs})[\eta_{hs}^{sys} + \sum_l H_{bl}(\mu_{hsl} - \bar{\mu}_{hsl})] \quad (17g)$$

$$\forall h, s, b \quad (17h)$$

$$\begin{aligned} W_{hs} C_g - \eta_{hs}^{sys} + \bar{\lambda}_{hsg} - \lambda_{hsg} \\ - \sum_l H_{bl}(\mu_{hsl} - \bar{\mu}_{hsl}) = 0 \quad g \leftarrow b, \forall g \in U, \forall h, s \end{aligned} \quad (17i)$$

$$\begin{aligned} W_{hs} C_g - \eta_{hs}^{sys} + \bar{\rho}_{hsg} - \rho_{hsg} \\ - \sum_l H_{bl}(\mu_{hsl} - \bar{\mu}_{hsl}) = 0 \quad g \leftarrow b, \forall g \in I, \forall h, s \end{aligned} \quad (17j)$$

$$W_{hs} C_g - \eta_{hs}^{sys} + \bar{q}_{hsg} - q_{hsg} + X_s \varpi_{hg}$$

$$\begin{aligned} - \sum_l H_{bl}(\mu_{hsl} - \bar{\mu}_{hsl}) = 0 \quad g \leftarrow b, \forall g \in J, \forall h, s \quad (17k) \\ \sum_{h,s,g} W_{hs} C_g p_{hsg} + \sum_{h,s,g \in U} \{\bar{\lambda}_{hsg} P_g + \sum_k A_k P_g t_{hsgk}\} \\ = \sum_{h,s,b} \eta_{hs}^{sys} D_{sb} - \sum_{h,s,g \in I} \bar{\rho}_{hsg} T_{sg} \\ - \sum_{h,g \in J} \{\varpi_{hg} \bar{E}_{hg} + \sum_s \bar{q}_{hsg} R_g\} \\ + \sum_{h,s,l} \left\{ (\mu_{hsl} - \bar{\mu}_{hsl}) \sum_b H_{bl} D_{sb} \right\} \\ - (\mu_{hsl} + \bar{\mu}_{hsl}) F_l - \sum_k A_k F_l r_{hslk} \end{aligned} \quad (17l)$$

$$\begin{aligned} \bar{\lambda}_{hsg}, \lambda_{hsg}, \bar{q}_{hsg}, q_{hsg}, \bar{\rho}_{hsg}, \rho_{hsg}, \varpi_{hg}, \mu_{hsl}, \bar{\mu}_{hsl} \geq 0 \\ \forall h, s, g, l \end{aligned} \quad (17m)$$

$$\begin{aligned} -\bar{M}(1 - \beta_{gk}) \leq t_{hsgk} - \bar{\lambda}_{hsg} \leq \bar{M}(1 - \beta_{gk}) \\ \forall g \in U, \forall h, s, k \end{aligned} \quad (17n)$$

$$-\bar{M}\beta_{gk} \leq t_{hsgk} \leq \bar{M}\beta_{gk} \quad \forall g \in U, \forall h, s, k \quad (17o)$$

$$\begin{aligned} -\bar{M}(1 - \alpha_{lk}) \leq r_{hslk} - (\mu_{hsl} + \bar{\mu}_{hsl}) \leq \bar{M}(1 - \alpha_{lk}) \\ \forall h, s, l, k \end{aligned} \quad (17p)$$

$$-\bar{M}\alpha_{lk} \leq r_{hslk} \leq \bar{M}\alpha_{lk} \quad \forall h, s, l, k \quad (17q)$$

$$\begin{aligned} \pi_z = \sum_{g \in G_z} [-C_g \hat{p}_g + \sum_{h,s} \{\bar{\lambda}_{hsg} P_g + \sum_k A_k P_g t_{hsgk}\}] \\ \forall z \end{aligned} \quad (17r)$$

$$\pi_z \geq \pi_z^v \quad \forall z, v \in V_z \quad (17s)$$

$$\begin{aligned} \eta_{hs}^{sys}, \eta_{hsn}, \varpi_{hg}, \bar{\lambda}_{hsg}, \lambda_{hsg}, \bar{q}_{hsg}, q_{hsg}, \bar{\rho}_{hsg}, \rho_{hsg}, \\ \mu_{hsl}, \bar{\mu}_{hsl}, t_{hsgk}, r_{hslk}, \pi_z, \pi_z^v \in \mathbb{R} \end{aligned} \quad (17t)$$

In optimization problem (17), constraints (17e)-(17t) find the Nash equilibrium(ria) of the generation investment game. The MILP (17d)-(17t) finds the pessimistic Nash equilibrium which has the highest social cost. Finally, the proactive Transco minimizes the transmission investment cost and social cost of the pessimistic Nash equilibrium through (17a)-(17t). The optimization problem (17) is a MIBLP with $\Psi_T = \{\alpha_{lk}, \hat{f}_l\}$ and $\Psi_G = \{\beta_{gk}, \hat{p}_g, p_{hsg}, \eta_{hs}^{sys}, \eta_{hsn}, \varpi_{hg}, \bar{\lambda}_{hsg}, \lambda_{hsg}, \bar{q}_{hsg}, q_{hsg}, \bar{\rho}_{hsg}, \rho_{hsg}, \mu_{hsl}, \bar{\mu}_{hsl}, t_{hsgk}, r_{hslk}, \pi_z, \pi_z^v\}$. Both the upper-level and the lower-level optimization problems have binary variables (α_{lk} and β_{gk}). Section IV deals with solving the MIBLP with binary variables in both levels.

B. The Reactive Coordination (MILP model)

In reactive coordination, strategic Gencos are the leaders and a regulated Transco is the follower. Fig. 3 illustrates this situation. The optimization problem of each Genco is shown in Fig. 3 and is derived in (18).

$$\begin{aligned} \text{Maximize}_{\hat{p}_g, g \in G_z} \sum_{g \in G_z} \{-C_g \hat{p}_g + \sum_{h,s} W_{hs} (\eta_{hsb} - C_g) p_{hsg}\} \\ g \leftarrow b \end{aligned} \quad (18a)$$

$$\text{Subject to (2)} \quad (18b)$$

Fig. 3: The reactive approach for generation-transmission investment game

$$\beta_{gk} \in \{0, 1\} \quad (18c)$$

$$\text{Minimize } \sum_l \bar{C}_l \hat{f}_l + \sum_{h,s,g} W_{hs} C_g p_{hsg} \quad (18d)$$

$$\text{Subject to } \hat{f}_l \geq 0 : (\gamma_l) \forall l \quad (18e)$$

$$(13e) - (13l) \quad (18f)$$

$$\hat{f}_l, p_{hsg} \in \mathbb{R} \quad (18g)$$

To preserve the convexity of the minimization problem (18d)-(18g), we assume $\hat{f}_l$ is a continues variable [40]. This assumption allows us to replace the lower level with the primal feasibility, dual feasibility and strong duality conditions. Similar to **Box 1** in Fig. 2, the bilevel program (18) is reformulated as a MILP. Using the fact that each Genco has a discrete set of investment options, the MILP model is transformed to a set of MILCs. The pessimistic and reactive Transco is modeled in (19).

$$\text{Maximize } \sum_l \bar{C}_l \hat{f}_l + \sum_g \{C_g \hat{p}_g + \sum_{h,s} W_{hs} C_g p_{hsg}\} \quad (19a)$$

$$\text{Subject to } \hat{f}_l \geq 0 \forall l \quad (19b)$$

$$\beta_{gk} \in \{0, 1\}, \hat{f}_l, p_{hsg} \in \mathbb{R} \quad (19c)$$

$$\eta_{hsb} = (1/W_{hs})[\eta_{hs}^{sys} + \sum_l H_{bl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl})] \quad (19d)$$

$$\forall h, s, b \quad (19e)$$

$$(13e) - (13l), (2) \quad (19f)$$

$$W_{hs} C_g - \eta_{hs}^{sys} + \bar{\lambda}_{hsg} - \lambda_{hsg} - \sum_l H_{bl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \quad g \leftarrow b, \forall g \in U, \forall h, s \quad (19f)$$

$$W_{hs} C_g - \eta_{hs}^{sys} + \bar{\rho}_{hsg} - \rho_{hsg} - \sum_l H_{bl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \quad g \leftarrow b, \forall g \in I, \forall h, s \quad (19g)$$

$$W_{hs} C_g - \eta_{hs}^{sys} + \bar{q}_{hsg} - q_{hsg} + X_s \varpi_{hg} - \sum_l H_{bl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \quad g \leftarrow b, \forall g \in J, \forall h, s \quad (19h)$$

$$\bar{C}_l - \gamma_l - \sum_{h,s} (\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) = 0 \quad \forall l \quad (19i)$$

$$\begin{aligned} & \sum_l \bar{C}_l \hat{f}_l + \sum_{h,s,g} W_{hs} C_g p_{hsg} \\ & + \sum_{h,s,g \in U} \{\bar{\lambda}_{hsg} P_g + \sum_k A_k P_g t_{hsgk}\} \\ & = \sum_{h,s,b} \eta_{hs}^{sys} D_{sb} - \sum_{h,s,g \in I} \bar{\rho}_{hsg} T_{sg} \end{aligned}$$

$$\begin{aligned} & - \sum_{h,g \in J} \{\varpi_{hg} \bar{E}_{hg} + \sum_s \bar{q}_{hsg} R_g\} \\ & + \sum_{h,s,l} \left\{ \left((\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) \sum_b H_{bl} D_{sb} \right) \right. \\ & \left. - (\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) F_l \right\} \quad (19j) \end{aligned}$$

$$\bar{\lambda}_{hsg}, \lambda_{hsg}, \bar{q}_{hsg}, q_{hsg}, \bar{\rho}_{hsg}, \rho_{hsg}, \underline{\mu}_{hsl}, \bar{\mu}_{hsl}, \gamma_l \geq 0 \quad (19k)$$

$$\forall h, s, g, l \quad (19k)$$

$$- \bar{M}(1 - \beta_{gk}) \leq t_{hsgk} - \bar{\lambda}_{hsg} \leq \bar{M}(1 - \beta_{gk}) \quad (19l)$$

$$\forall g \in U, \forall h, s, k \quad (19l)$$

$$- \bar{M} \beta_{gk} \leq t_{hsgk} \leq \bar{M} \beta_{gk} \quad \forall g \in U, \forall h, s, k \quad (19m)$$

$$\pi_z = \sum_{g \in G_z} [-C_g \hat{p}_g + \sum_{h,s} \{P_g \bar{\lambda}_{hsg} + \sum_k A_k P_g t_{hsgk}\}] \quad (19n)$$

$$\forall z \quad (19n)$$

$$\pi_z \geq \pi_z^v \quad \forall z, v \in V_z \quad (19o)$$

$$\eta_{hs}^{sys}, \eta_{hsn}, \varpi_{hg}, \bar{\lambda}_{hsg}, \lambda_{hsg}, \bar{q}_{hsg}, q_{hsg}, \bar{\rho}_{hsg}, \rho_{hsg}, \varpi_{hg}, \underline{\mu}_{hsl}, \bar{\mu}_{hsl}, \gamma_l, t_{hsgk}, \pi_z, \pi_z^v \in \mathbb{R} \quad (19p)$$

$\Psi_R = \{\beta_{gk}, \hat{p}_g, \hat{f}_l, p_{hsg}, \eta_{hs}^{sys}, \eta_{hsn}, \varpi_{hg}, \bar{\lambda}_{hsg}, \lambda_{hsg}, \bar{q}_{hsg}, q_{hsg}, \bar{\rho}_{hsg}, \rho_{hsg}, \underline{\mu}_{hsl}, \bar{\mu}_{hsl}, \gamma_l, t_{hsgk}, \pi_z, \pi_z^v\}$ is the set of decision variables considered. In optimization problem (19), constraints (19b)-(19p) finds the Nash equilibrium(ria) of generation-transmission investment game and objective function (19a) selects the pessimistic Nash equilibrium. The optimization problem (19) is a MILP which can be solved to global optimality by available commercial softwares.

IV. THE SOLUTION ALGORITHM FOR THE MIBLP MODEL

The optimization problem (17) is a MIBLP where all the variables of the upper-level problem are discrete. We employ the solution algorithm proposed in [21] to solve this MIBLP in (17). Implementing this algorithm, called Moore-Bard Algorithm (MBA) in this paper, we branch just on the binary variables of the upper-level problem in order to assure the optimality of the final result (please see Proposition 2 in [21]).

For MIBLPs with several binary variables, the computational burden of the MBA becomes excessive. The parallelized MBA (P-MBA) can reduce this computational burden. The P-MBA on 2^M cores has the following steps.

Step 0 Select M binary variables of vector x_1 .

Step 1 Form all 2^M combinations of the selected binary variables.

Step 2 Assign 2^M combinations to 2^M parallel cores.

Step 3 Run MBA on each core to solve the 2^M MIBLPs resulting in Step 0 to Step 2.

Step 4 Compare the results found in Step 3 and find the optimal solution.

Moreover, two heuristic versions explained in [21] can be considered. We have considered heuristic technique A and B, algorithm number 2 and 3 in [21], respectively. These heuristic techniques make the algorithm less enumerative and represents a trade-off between accuracy and computational effort [21]. We compare these techniques in Sections VII and VIII.

V. THE POWER TRANSFER DISTRIBUTION MATRIX

In this paper, transmission expansion is modeled as capacity upgrades [15], [41], [42], [43]. This helps us to focus better on coordination issue rather than making our mathematical models complicated. We use matrix H , power transfer distribution matrix, to model a linear relation between the power flows in the lines and the nodal power balances. However, the elements of matrix H depend nonlinearly on line reactances [44]. This means when line capacity changes, the reactance of the line changes, and a new matrix H should be calculated [45]. Thus, the optimization problems formulated in Sections II and III have to be solved iteratively with the updated H until the stopping criterion is met. The stopping criterion can be based on the social cost of the system or the added capacity to the lines. In this paper, we have considered the change in the added capacity to the lines as the stopping criterion. When the difference between added capacities in two consecutive iterations is less than the assumed tolerance, the convergence has been reached [46].

For updating matrix H when line capacities change, the law of parallel circuits is used [42], [45]. We have:

$$X_l^* = \frac{F_l}{F_l + \hat{f}_l} X_l \quad (20)$$

So, if the added capacity to the line, $\hat{f}_l$, is equal to the already installed capacity, F_l , the new reactance of the line, X_l^* , is half of the reactance before the capacity addition, X_l .

In order to avoid large differences between the results of two consecutive iterations, thus invalidating the linear approximation, the added capacity to each line is limited to half of the existing capacity of the related line. This limit can be reduced if convergence is not achieved [47].

VI. THE SCENARIO GENERATION AND REDUCTION ALGORITHM

We first generate a large number of scenarios based on the distribution function of the uncertain parameter(s). This is done for wind power units by using a random number generator and considering the Weibull distribution of wind speed and the production curve represented in Fig. 1. Then, the scenarios similar to each other are grouped and their weights are calculated based on the number of occurrence of these scenarios compared to the total number of generated scenarios. Since the planning problem is a complex combinatorial problem, the generated scenarios need to be reduced to alleviate the computational difficulties. During the reduction step, the weights of the removed scenarios are added to the remaining scenarios according to their distance to the remaining scenarios. Fast backward, fast forward and fast forward/backward methods are the main algorithms used in the literature for scenario reduction [48], [49]. In general, these methods are different in the accuracy of results and computational time. We have used the fast forward/backward method for the reduction phase.

Fig. 4 shows the flowchart of the scenario-based modeling used in our paper. The number of retained scenarios, S , is determined based on a stopping criterion, σ_{fixed} , which is

Fig. 4: The flowchart of the scenario-based modeling.

the maximum estimated standard deviation of the loss of load expectation (LOLE) [50].

The formulation of the deviation index, σ , is as follows:

$$\sigma = \frac{1}{S} \sqrt{\sum_{s \in S} \frac{(LOLE_s - \overline{LOLE})^2}{S-1}} \quad (21)$$

The σ_{fixed} is set at 0.05 in this paper. The initial number of retained scenarios is two ($S = 2$) for which the deviation index is definable. The number of retained scenarios are increased up to the point that the stopping criterion is met. The retained scenarios are a subset of initial ones which best present the underlying probability distribution function.

In (21), the $LOLE_s$ is the expected curtailed load in particular scenario s . This is calculated by multiplying the amount of curtailed load in scenario s by the weight of this scenario. The curtailed load is found using power flow simulation. The $\overline{LOLE}$ is the weighted average of curtailed loads in the set of retained scenarios.

The wind and demand scenarios can be derived using the proposed scenario generation and reduction algorithm. In this paper, the wind power scenarios are generated using the scenario generation and reduction algorithm. The demand level and hydro power energy are forecasted from historical data.

Note that the set of retained scenarios and their related weights are calculated for the status-quo system. These reduced scenarios are then used in the different coordination problems considered in Sections II and III.

VII. THE ILLUSTRATIVE EXAMPLE SYSTEMS

In this section, the 3-bus and 6-bus systems are simulated and the results of different coordination approaches are discussed. The convergence criterion for the iterations of updating matrix H is set to 1 MW change in the added capacity of the lines.

A. The 3-bus example system

The 3-bus example system is shown in Fig. 5. Table I provides the data for transmission lines. Gencos $U1$ and $U2$ make strategic investment decisions.

The proactive coordination problem is solved using the MBA introduced in Section IV. The branch-and-bound tree

Fig. 5: The 3-bus example system; MC: Marginal Cost, IC: Investment Cost, Cap.: Capacity, IO: Investment Options (in MW).

TABLE I: THE TRANSMISSION LINE DATA FOR THE 3-BUS EXAMPLE SYSTEM; IC: INVESTMENT COST, CAP.: CAPACITY, IO: INVESTMENT OPTIONS

Line No.	To-From	Reactance (Ω)	Cap. (MW)	IC (\$/Mw)	IO (MW)
1	A-B	0.02	5	200	0-2.5-5-7.5
2	A-C	0.02	20	200	0-10-20-30
3	B-C	0.02	15	200	0-7.5-15-22.5

of the MBA is presented in Fig. 6. This figure shows the process of searching the tree using the heuristic technique A. The result of the proactive coordination with and without heuristic technique is the same. However, heuristic technique A (as shown in Fig. 6) results in bounding in nodes 7, 8, 10, 11, 14 and 15. Nodes 7 and 8 are bounded because the social cost in these nodes are higher than the one found before in node 6. In a similar way, nodes 10, 11, 14 and 15 are bounded because of having higher social cost than the one in node 9. These bounds improve the computational efficiency of the MBA at the cost of sub-optimal solutions. Note that the bounding in node 12 happens in Step 1 of the original algorithm. The MBA with heuristic technique B works similar to the original algorithm. This means heuristic B is unable to improve the computational burden in this example. The MBA can find the optimal solution but with higher computational burden.

Fig. 6: The branch-and-bound tree of the MBA for the 3-bus example system; $(x, x, x, x, x, x) = (\alpha_{11}, \alpha_{12}, \alpha_{21}, \alpha_{22}, \alpha_{31}, \alpha_{32})$, $\alpha \in \{0, 1\}$, SC: Social Cost.

The results for the status-quo system and the different cases

TABLE II: THE GENERATION-TRANSMISSION PLANNING RESULTS FOR THE 3-BUS EXAMPLE SYSTEM FOR THE BOTH CASES OF OPTIMISTIC (O) AND PESSIMISTIC (P) TRANSCO; EGC: EXPANDED GENERATION CAPACITY, ETC: EXPANDED TRANSMISSION CAPACITY, SC: SOCIAL COST

	EGC (MW)		ETC (MW)			SC (M\$)	CB (M\$)
	U1	U2	AB	AC	BC		
SQ	-	-	-	-	-	3.15	-
EC	30	0	0	10	7.5	2.02	1.13
RC(1)	30	0	0	7.23	7.77	2.02(O)	1.13
RC(2)	20	7.5	6.78	29.28	0	2.16	0.99
RC(3)	10	15	0	28.62	0	2.29	0.86
RC(4)	0	22.5	0	29.8	0	2.42(P)	0.73
PC(1)	20	0	0	10	7.5	2.30	0.85

Fig. 7: Development of added capacity to the lines during the iterations for the 3-bus example system.

of efficient coordination, reactive coordination and proactive coordination are presented in Table II. For the rest of this paper, SQ, EC, RC and PC stand for status-quo system, efficient coordination mechanism, reactive coordination mechanism and proactive coordination mechanism. All Nash equilibria are reported in Table II. As reported, the RC has four Nash equilibria while the PC has just one Nash equilibrium. Please note that in this paper, we focus on the pessimistic Nash equilibrium in case of multiple Nash equilibria. The pessimistic Nash equilibrium (P) is the one with the highest social cost whereas optimistic Nash equilibrium (O) is the one with the lowest social cost. The case of being an optimistic or a pessimistic Transco depends on the electricity market in question and the experience of Transco about its market (similar to being a proactive or reactive Transco). The change in the added capacity of the lines in each iteration of updating matrix H is presented in Fig. 7. After 2 to 6 iterations, depending on the approach, the convergence is reached.

In the EC, the electric utility invests in 30 MW additional capacity for U1 and expands the transmission lines AC and BC by 10 MW and 7.5 MW, respectively. The expanded system has a social cost of 2.02 M\$ which is 36% less than the SQ social cost. In the case of RC, the strategic generation investment results in 22.5 MW investment in U2. This shows 7.5 MW under-investment in generation sector as compared to the EC. The added capacity of the lines in RC is 29.8 MW for line AC. The RC has a social cost of 2.42 M\$ which is 23%

TABLE III: THE GENERATION-TRANSMISSION PLANNING FOR THE 3-BUS EXAMPLE SYSTEM WITH REDUCED GENERATING CAPACITY FOR THE BOTH CASES OF OPTIMISTIC (O) AND PESSIMISTIC (P) TRANSCO; EGC: EXPANDED GENERATION CAPACITY, ETC: EXPANDED TRANSMISSION CAPACITY, SC: SOCIAL COST

	EGC (MW)		ETC (MW)			SC (M\$)	CB (M\$)
	U1	U2	AB	AC	BC		
SQ	-	-	-	-	-	4.86	-
EC	15	11.25	7.5	0	0	3.42	1.44
RC(1)	15	11.25	7.20	0	0	3.42(O)	1.44
RC(2)	15	0	0	0	0	3.81	1.05
RC(3)	10	3.75	3.44	0	0	3.93(P)	0.92
PC(1)	5	0	7.5	0	0	4.16	0.70

Fig. 8: Development of added capacity to the lines during the iterations for the 3-bus example system with reduced generating capacity.

less than the social cost in SQ and 20% higher than the social cost in EC. When the proactive Transco leads the game, lines AC and BC are invested for additional 10 MW and 7.5 MW, respectively. This incentivizes Genco U1 to invest 20 MW. The system social cost is 2.30 M\$ which is lower than the social cost in RC. From the regulator's perspective, it is interesting to see how much a specific coordination mechanism improves the economic welfare. First we define SC_1 and SC_2 as below.

- SC_1 : The system social cost when no coordination mechanism is applied.
- SC_2 : The system social cost when the coordination mechanism in question is applied.

Using SC_1 and SC_2 , the coordination benefit (CB) of a particular mechanism is defined as $CB = SC_1 - SC_2$. The CBs of EC, RC, and PC are set out in Table II. The EC has the highest CB (1.13 M\$), the PC has the second-best CB (0.85 M\$) and the RC has the third-best CB (0.73 M\$).

To analyze the coordination problem further, in the next round of simulations, we reduce the capacity of generating units and consequently their investment options to half (i.e., there is a lack of generating capacity in the system). The results are presented in Table III. The RC has three Nash equilibria while the PC has only one Nash equilibrium. The changes in added capacity to the lines in each iteration of updating matrix H is presented in Fig. 8.

As seen from Table III, in this round of simulation, the PC has less CB than the RC (opposite to the case in Table II).

This means if Transco waits for the decisions of Gencos and plans the transmission system accordingly, the social cost is less than the one resulting from the situation when Transco's decision leads Gencos' decisions.

The difference in the social costs of PC and RC is caused by the sequence of the game and the strategic behavior of Gencos. In Table II, the proactive Transco influences the decisions of strategic Gencos such that it leads the system to a better investment solution (as compared to the reactive Transco). However, in Table III, because of the high level of strategic behavior by Gencos, the proactive Transco is unable to guide the system towards a better solution as compared to the reactive one. This example clearly shows how the sequence of the game and the strategic behavior of Gencos can affect the final result. When there is a great need for generation expansion, strategic Gencos might use the situation to behave more strategically. In this situation, the proactive Transco might not be able to direct the generation investment decisions toward a solution with less social cost if that solution prevents Gencos from obtaining higher profits. To explain this situation further, we assume a game between two players, I and II, with payoffs presented in Fig. 9. If both players move simultaneously, the outcome is the Nash equilibrium of the game which is (M,C). Now consider a multilevel game in which the order of moves matters. If player I is the leader and player II is the follower, the outcome would be (U,L) and conversely, if player II is the leader and player I is the follower, the outcome would be (D,R). The payoff of player II is higher when he is the follower as compared to the case when he leads the game (similar to performance of proactive and reactive models).

		Player II		
		L	C	R
Player I	U	(5,7)	(2,2)	(1,3)
	M	(6,3)	(3,4)	(1,2)
	D	(4,6)	(1,3)	(3,5)

Fig. 9: The payoff matrix of a two-player game; (m,n) is the payoff for each player; m is the payoff for player I and n is the payoff for player II.

B. The 6-bus example system

To further analyze the different coordination approaches, the 6-bus example system shown in Fig. 10 is simulated [44]. The data for the lines is derived from [44]. The demand level in [44] is tripled in order to do the expansion planning analysis. Gencos U_2 and U_3 make strategic investment decisions with the investment options of 0.25Cap, 0.5Cap and 0.75Cap where Cap is defined in Fig. 10. U_1 is a hydro power unit with two hydro seasons of 788.4 KWh and 525.6 KWh with 0.6 and 0.4 probabilities, respectively. Also, it is assumed that there is a 50 MW wind farm connected to bus 5 with the stochastic parameters specified in Fig. 10. As in the 3-bus example system, the investment cost of transmission lines is

TABLE IV: THE GENERATION-TRANSMISSION PLANNING RESULTS FOR THE 6-BUS EXAMPLE SYSTEM FOR THE BOTH CASES OF OPTIMISTIC (O) AND PESSIMISTIC (P) TRANSCO; EGC: EXPANDED GENERATION CAPACITY, ETC: EXPANDED TRANSMISSION CAPACITY, SC: SOCIAL COST

	EGC (MW)		ETC (MW)			SC (M\$)	CB (M\$)
	U2	U3	1-2	1-5	2-3		
SQ	-	-	-	-	-	58.1	-
EC	112.5	135	60	40	0	17.6	40.5
RC(1)	112.5	45	76.93	0	0	20.8(O)	37.3
RC(2)	0	135	0	46.67	55	28.6	29.5
RC(3)	37.5	90	7.3	42.39	0	30.5(P)	27.6
PC(1)	37.5	135	60	40	0	23.3	34.8

200 \$/MWy with the investment options of 0, 0.5K, K and 1.5K where K is the existing capacity in MW.

Fig. 10: The 6-bus example system; MC: Marginal Cost, IC: Investment Cost, Cap.: Capacity, k: shape parameter, λ : scale parameter.

The results of different coordination approaches are presented in Table IV. The RC has three Nash equilibria while the PC has only one Nash equilibrium. The added capacity to each line in different iterations of updating matrix H is shown in Fig. 11.

In the EC, both U2 and U3 are invested up to 75% of their installed capacities (112.5 MW and 135 MW, respectively). Lines 1-2 and 1-5 are expanded 60 MW and 40 MW, respectively. This results in 70% reduction in the social cost as compared to the social cost in SQ. The RC leads to under-investment both in the transmission system and generation units and its social cost is 12.9 M\$ higher than the one in EC. However, PC has no under-investment in transmission system. Also, U3 has 45 MW more expanded capacity in PC as compared to RC. This results in 23.3 M\$ social cost under PC which is 7.2 M\$ lower than the social cost under RC. Therefore, as in the 3-bus example system in Table II, the PC is the desired coordination approach in this example system with CB of 34.8 M\$. Also, as in the 3-bus example system, the RC needs the highest number of iterations to reach convergence (11 iterations for RC(P) and 9 iterations for RC(O)). Both EC and PC reach convergence after 3 iterations. The lines 1-2, 1-5 and 2-3 are the only ones which are invested under different coordination approaches.

TABLE V: THE DATA OF GENCOS FOR THE MODIFIED IEEE-RTS96; CAP.: CAPACITY, IO: INVESTMENT OPTIONS

Genco	Bus	Marginal Cost (\$/MWh)	Cap. (MW)	IO (MW)
U1	2	10	76	0-19-38-57
U2	21	3	400	0-100-200-300
U3	13	5	197	0-49.25-98.5-147.75

VIII. NUMERICAL EXAMPLES

To examine the computational performance of the proposed formulations, the modified IEEE-RTS96 and the modified IEEE 118-bus test system are simulated. The MILP models are solved using the CPLEX solver in the GAMS platform. The MBA and P-MBA are coded by authors in GAMS for solving the MIBLP model. The lines which are invested under efficient coordination or reactive coordination are considered as expansion options in MIBLP model of proactive coordination. The convergence criterion for the iterations of updating matrix H is 10 MW change in the added capacity to the line. The simulation is carried out on a computer with 2.2 GHz processor and 16 GB of RAM.

A. The modified IEEE-RTS96

The IEEE-RTS96 has been modified for our study. The existing transmission capacities in [51] are reduced by a factor of 0.5. The $\bar{C}_l$ is proportional to the reactance of line l . The $\bar{C}_l$ for the line with the lowest reactance is set at 1000 \$/MWy. The additional capacity options for each line are 0, 0.5K, K and 1.5K where K is the existing capacity in MW. Three strategic Gencos (U1, U2 and U3) are assumed as shown in Table V. The generation expansion cost is 100 \$/MWy for all Gencos. Weekly load levels in [51] are considered for the horizon year of planning. The six 50-MW units connected to bus 22 are considered as wind farms with the characteristics specified for the wind farm in Fig. 10 of Section VII-B. The 350-MW unit connected to bus 23 is assumed to be a hydro power unit with two hydro seasons of 3 MWh and 2.2 MWh with 0.6 and 0.4 probabilities, respectively.

TABLE VI: THE GENERATION-TRANSMISSION PLANNING FOR THE MODIFIED IEEE-RTS96. (T)EGC: (TOTAL) EXPANDED GENERATION CAPACITY, (T)ETC: (TOTAL) EXPANDED TRANSMISSION CAPACITY, TIC: TRANSMISSION INVESTMENT COST, GIC: GENERATION INVESTMENT COST

	EGC (MW)			TEGC (MW)	GIC (M\$)	TETC (MW)	TIC (M\$)
	U1	U2	U3				
EC	0	300	147.75	447.75	0.045	1244	4.25
RC	38	0	98.5	136.5	0.014	1812	5.53
PC	57	300	98.5	455.5	0.045	548	2.21

The results of the generation-transmission planning are presented in Tables VI and VII. As seen, the EC has a

TABLE VII: THE SOCIAL COST AND COORDINATION BENEFIT OF DIFFERENT COORDINATION APPROACHES FOR THE MODIFIED IEEE-RTS96

	Profit (M\$)			No. of iterations	SC (M\$)	CB (M\$)
	U1	U2	U3			
SQ	2.56	5.41	1.73	-	133.7	-
EC	0	18.39	1.33	3	84.5	49.2
RC	0.93	17.36	2.26	13	98.03	35.67
PC	2.15	18.82	2.13	3	94.4	39.3

Fig. 11: Development of added capacity to the lines during different iterations for the 6-bus example system.

TABLE VIII: THE SIMULATION TIME OF THE P-MBA FOR SOLVING PROACTIVE COORDINATION PROBLEM OF THE MODIFIED IEEE-RTS96

Number of Cores	Run time (hours)
1	*
2	*
4	57
8	38

* Not found after three days of simulation.

TABLE IX: THE DATA OF GENCOS IN THE MODIFIED IEEE 118-BUS TEST SYSTEM; CAP.: CAPACITY, IO: INVESTMENT OPTIONS

Genco	Bus	Marginal Cost (\$/MWh)	Cap. (MW)	IO (MW)
U1	10	5	450	0-112.5-225-337.5
U2	66	15	392	0-98-196-294
U3	69	10	516.4	0-129.1-258.2-387.3

social cost of 84.5 M\$ which is 49.2 M\$ less than the social cost in SQ. The reactive Transco approach results in over-investment in transmission system (5.53-4.25=1.28 M\$) while the proactive Transco approach results in under-investment in transmission investment (2.21-4.25=-2.04 M\$). However, the RC has a lower investment in generation capacity as compared to the PC. This results in 35.67 M\$ CB in the case of RC and 39.3 M\$ CB under PC. Therefore, for the modified IEEE-RTS96, the PC is the preferred coordination approach. This result is analogous to the one for the 3-bus example system in Table II. In both of these systems, the proactive Transco can direct Gencos to a solution with lower social cost.

The MIBLP of the PC model is run on multiple cores using P-MBA. The simulation time is reported in Table VIII. The standard MBA (running on a single core) and P-MBA with 2 cores could not solve the proactive coordination problem after three days of simulation. However, the P-MBA with 4 and 8 cores solves the problem in 57 and 38 hours, respectively.

B. The modified IEEE 118-bus test system

The MIBLP model of the proactive coordination approach is a hard optimization problem for large case studies. Even the P-MBA might take a long time to find the optimal solution. In these situations, heuristic approaches help us to find a good feasible solution in less computational time.

In this section, the IEEE 118-bus test system is simulated under different approaches of coordination. For our study, the capacity of transmission lines in [52] is multiplied by 0.5. The $\bar{C}_l$ is proportional to the reactance of line l . The $\bar{C}_l$ for the line with the lowest reactance is set at 1000 \$/MWy. The additional capacity options for each line are 0, 0.5 K , K and

1.5 K where K is the existing capacity in MW. The data for Gencos is presented in Table IX. The generation investment cost is assumed to be 500 \$/MWy for all units. The marginal utility of demand is 100 \$/MWh. The 40-MW unit connected to bus 103 and the 36-MW unit connected to bus 111 are considered as wind farms with the characteristics specified for the wind farm in Fig. 10 of Section VII-B. The 477-MW unit connected to bus 80 is assumed to be a hydro power unit with two hydro seasons of 4.18 MWh and 3.5 MWh with 0.6 and 0.4 probabilities, respectively.

The results of different coordination approaches and the status-quo system are presented in Tables X and XI.

TABLE X: THE GENERATION-TRANSMISSION PLANNING FOR THE MODIFIED IEEE 118-BUS TEST SYSTEM. (TEGC: (TOTAL) EXPANDED GENERATION CAPACITY, (T)ETC: (TOTAL) EXPANDED TRANSMISSION CAPACITY, TIC: TRANSMISSION INVESTMENT COST, GIC: GENERATION INVESTMENT COST

	EGC (MW)			TEGC (MW)	GIC (M\$)	TETC (MW)	TIC (M\$)
	U1	U2	U3				
EC	112.5	98	0	210.5	0.105	1650	3.5
RC	112.5	0	129.1	241.6	0.121	1538	3.2
PC	*	*	*	*	*	*	*
PC (4A)	225	0	0	225	0.112	1284	1.9
PC (4B)	225	0	0	225	0.112	1284	1.9

* Not found after three days of simulation.

For this test system, the reactive Transco results in a small under-investment in transmission system (3.2 M\$ < 3.5 M\$) while assuming a proactive Transco, we observe a significant under-investment in transmission system (1.9 M\$ < 3.5 M\$). This incentives more generation expansion under RC as compared to PC. Accordingly, the social cost under RC (650.02 M\$) is less than the one under PC (734.42 M\$). Therefore, RC is the desired coordination mechanism in this example system.

TABLE XI: THE SOCIAL COST AND COORDINATION BENEFIT OF DIFFERENT COORDINATION APPROACHES FOR THE MODIFIED IEEE 118-BUS TEST SYSTEM; SC: SOCIAL COST

	Profit (M\$)			No. of iterations	SC (M\$)	CB (M\$)
	U1	U2	U3			
SQ	8.41	3.89	4.36	-	930.53	-
EC	4.77	0	3.45	5	578.32	352.21
RC	4.93	0	2.25	9	650.02	280.51
PC	*	*	*	*	*	*
PC (4A)	5.12	0	1.89	3	734.42	196.11
PC (4B)	5.12	0	1.89	3	734.42	196.11

* Not found after three days of simulation.

The simulation time of the MBA with heuristic techniques A and B and the P-MBA with different number of cores are reported in Table XII. As seen, the P-MBA with 2, 4 and 8 cores cannot find any solution to the proactive model after three days of simulation. However, heuristic techniques A and B can find the solution using 4 and 8 cores. The simulation time of the heuristic technique A is 51 and 38 hours using 4 and 8 cores, respectively. Similarly, by increasing the number of cores from 4 to 8, the simulation time of the heuristic technique B is reduced from 68 hours to 46 hours.

TABLE XII: THE SIMULATION TIME OF MBA WITH HEURISTIC TECHNIQUES A AND B AND THE P-MBA FOR THE MODIFIED IEEE 118-BUS TEST SYSTEM

Number of Cores	Algorithm	Run time (hours)
1	P-MBA	*
	Heuristic Technique A	*
	Heuristic Technique B	*
2	P-MBA	*
	Heuristic Technique A	*
	Heuristic Technique B	*
4	P-MBA	*
	Heuristic Technique A	51
	Heuristic Technique B	68
8	P-MBA	*
	Heuristic Technique A	38
	Heuristic Technique B	46

* Not found after three days of simulation.

Note that in this paper, we have implemented the algorithm developed in [21] to solve the proposed MIBLP model. The research on solution algorithms of MIBLP models is still in progress in mathematics literature [53]. Comparing different algorithms for solving the derived MIBLP in the paper can be considered as a future extension of the current work.

IX. CONCLUSION

This paper proposes mathematical models for coordinating the transmission expansion planning with the strategic generation investments. The proactive and reactive coordinations are modeled as MIBLP and MILP. These models are compared with MILP model of the efficient coordination. The parallelized Moore-Bard algorithm (P-MBA) is proposed to solve the MIBLP model with binary variables in both levels. For solving the MIBLP of proactive coordination in large case studies, two heuristic techniques have been also studied. The mathematical models have been simulated on the 3-bus and 6-bus example systems, the modified IEEE-RTS96 and the modified IEEE 118-bus test systems. The numerical results clearly show the importance

of sequence of investments in transmission and generation sectors. The developed mathematical models can be used by regulators for evaluating different incentive mechanisms for directing the results of sequential generation-transmission planning towards efficient coordination results. This paper can be extended in several ways. First, the numerical efficiency of P-MBA can be improved by increasing the number of computing cores in branch-and-bound algorithm and providing a platform for cores to communicate. Doing this, the impact of uncertainty on sequential coordination can be further analyzed. Second, future research might profitably examine the optimal design of transmission tariff for generation to improve the coordination of transmission and generation investment decisions. Third, the extension of mathematical models developed in our paper to consider strategic bidding of generators definitely adds another important layer to the coordination analysis.

APPENDIX

A. Determination of constant $\overline{M}$

The constant $\overline{M}$ can be found using either analytical or simulation techniques. References [54] and [55] derive suitably large constants for their problems analytically. In analytical techniques, the upper and lower bounds of all optimization variables are derived. Having found the bounds for the variables, appropriate values for the constants are easily determined. A disadvantage of the analytical approach is that finding the bounds on the variables becomes hard for large optimization problems. Alternatively, [56] and [57] rely on simulation techniques to find suitably large constants for their problems. In simulation techniques, these constants are varied over different ranges until the solution values are stable. This technique is suitable for large optimization problems and used in our paper. References [58] and [59] discuss this issue for their optimization problems.

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