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Energimyndighetens titel på projektet – engelska Long-term generation and transmission planning with several players	
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Nyckelord: 5-7 st Vertical coordination, Transmission expansion planning, Strategic generation investment, Game theory, Bi-level programming.	

Förord

Här ska stå vilka som har finansierat projekten samt andra som bidragit till ett lyckat projekt t ex referensgrupp.

[Klicka här och skriv]

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Sammanfattning

Investering i elöverföringssystemet har varit en komplicerad fråga för många skäl. Det är ett ämne som behöver både tekniska och ekonomiska kunskaper. Historiskt, ökning av utbud och efterfrågan i elsystem har varit den främsta drivkraften för nätutveckling. I dagens elindustri, har integreringen av varierande förnybar produktion och gränsöverskridande marknadsintegration lagt till en extra nivå av komplexitet till detta flerdimensionella problem. Därför kräver effektiv drift och planering av elsystem samordning mellan investeringar i elöverföringskapacitet och produktionsinvesteringar.

Samordning i utvekling av elsystem kan brett kategoriseras som; (I) Horisontell samordning: Hur kan investeringar i elöverföringssystemet i ett sammankopplat system samordnas? (II) Vertikal samordning: Hur kan investeringar i produktionssektorn och nätutveckling samordnas samtidigt göras med hänsyn till olika enheter i olika beslutsnivåer? Observera att på avreglerade elmarknader görs investeringsbeslut om produktion av vinstmaximerande elproduktionsföretag (Gencos). Detta är medan nätutvecklingen fortfarande är nästan helt och hållet ansvarig för reglerad överföringssystemetföretaget (Transco).

Vertikal samordning är i fokus för denna rapport. Den vertikala samordningen har studerats både i teknik och ekonomilitteratur. Två sekventiella metoder för att samordna investeringar i produktionssektorn och nätutveckling identifieras: (1) proaktiv strategi där Transco tillkännager sina framtidsplaner för nätutveckling och sedan beslutar Gencos om var produktionskapaciteten utvecklas. (2) Reaktiv strategi där Gencos beslutar först och sedan svarar Transco och planerar överföringssystemet i enlighet med detta.

I denna rapport föreslår vi matematiska modeller för sekventiell samordning av nätutveckling med strategiska produktionsinvesteringar. De proaktiva och reaktiva samordningarna modelleras och studeras. Interaktionen mellan Transco och Gencos modelleras med hjälp av sekventiell-stegspel och interaktionen mellan den strategiska Gencos modelleras som ett samtidigt-stegspel. De matematiska modeller härledda genomförs på olika fallstudier för att hitta en önskad samordning strategi.

Summary

Transmission investment has been a complex issue for many reasons. It is a topic, which needs both engineering and economic knowledge. Increase of demand and supply has been historically the main driver for investing in transmission capacity. In today’s electricity industry, the integration of intermittent renewable generation and cross-border market integration have added extra level of complexity to this multi-dimensional issue. Accordingly, the efficient operation and planning of power systems requires efficient coordination between transmission investment decisions and generation investment decisions.

The coordination issue can be broadly categorized as; (i) Horizontal coordination: How could the investment in transmission network of the inter-connected system

be coordinated? (ii) Vertical coordination: How could the investment in generation sector and the transmission expansion be coordinated while being done with different entities in different levels of decision making? Note that, 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).

Vertical coordination is the focus of this report. The vertical coordination issue has been studied both in engineering and economics literature. Two sequential approaches for coordinating transmission and generation investments are identified: (1) Proactive approach in which 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 where Gencos decide first and then Transco responds and plans the transmission system accordingly.

In this report, we propose mathematical models for sequential coordination of transmission expansion planning with strategic generation investments. The proactive and reactive coordinations are modelled and studied. The interaction between transmission company Transco and strategic generation companies Gencos is modelled using the sequential-move game. This is while the interaction between the strategic Gencos is modelled as a simultaneous-move game. The mathematical models derived are implemented on different case studies in order to find the desired coordination approach.

Introduction

Large investments in electric power systems are needed in many power markets in coming years for various reasons such as cross-border market integration, increase of demand, integration of new (often intermittent renewable) generation, or security of supply improvement. In Europe, ENTSO-E considers total investment costs for the portfolio of projects of pan-European significance amount to approximately €150 billion, by 2030, of which €50 billion relates to subsea cables [1]. In the United States, according to a report by the International Energy Agency (IEA) issued in May 2014, power sector investments over the 2014-2035 period amount $2.1 trillion, needed to build 579 GW of new generation capacities, 260,000 km of transmission lines and 1.3 million km of distribution lines. Concerning networks, the IEA underlines the necessity to deliver greater co-ordination between different grid operators in order to facilitate the integration of greater shares of variable renewables and optimize regional transmission investments [2]. The Edison Electric Institute (EEI) identified over 170 projects, totaling approximately $60.6 billion in transmission investments through 2024; of this total, interstate transmission projects represent $26.2 billion (43 %) [3].

In Europe, drivers for power system evolution are directly derived from EU energy policy goals, security of supply, internal electricity market integration, climate change mitigation and RES integration. By 2030, the net generating capacity is expected to grow from a slightly more than 900 GW today up to almost 1200 GW or even 1700 GW depending on the scenario considered [1].

- RES development is the major driver for grid development until 2030. The generation fleet will experience a major shift, with the replacement of much of the existing capacities with new ones, most likely located differently and farther from load centres, and involving high RES development. This transformation of the generation infrastructure is the major challenge for the high voltage grid, which must be adapted accordingly.
- Driven by RES development concentrated at a distance from load centres, and allowing for the required market integration, interconnection capacities should double on average by 2030.
- Other driver for investing on grids is the refurbishment of aging equipment.

In new economies, increase of consumption is the main driver: in India, the electricity sector is growing fast with the 9% domestic and industrial consumption growth and 22% agriculture consumption growth in 2012. In order to address this growing demand with more efficient resource allocation, India transformed from five fragmented and relatively small grids into one large power system over the last decade, finally fully integrated in January 2014, [4].

China has invested in electricity supply (mainly hydropower) aggressively due to the rapid load growth. But the energy resources are far away from the load centres. This required huge investment in transmission system e.g. ultra-high-voltage AC and DC projects [5].

In this context, the achievement of efficient power systems, from operational and planning perspectives, requires effective coordination of all players involved in this process, such as network owners and operators, generators, and regulatory authorities. From the planning perspective, two kinds of coordination are envisaged between transmission and generation expansion decisions in a multi-area connected power systems; (i) Horizontal coordination: How could the investment in transmission network of the inter-connected system be coordinated? (ii) Vertical coordination: How could the investment in generation sector and the transmission expansion be coordinated while being done with different entities in different levels of decision making?

Vertical coordination is the focus of this report. In practice, both generation and transmission investments involve substantial sunk investments. How should such sunk investments be vertically coordinated? Some generation and transmission investments can be easily coordinated. For example, if a generator requires a new transmission line to connect its remote generation plant to the network, the generator is generally required to pay for the new network assets. The first problem in vertical coordination, i.e., the coordination between investments of generation facilities and networks, is to determine if generation or network investment comes first. References [6], [7], and [8] distinguish two sequential approaches for coordination of transmission and generation investment. (1) Proactive approach: in this case the transmission investor announces its future plans for augmenting the network and then leaves the generation investors the decision as to where to expand generation capacity. (2) Reactive approach: in this case generation investors decide first and then the transmission investor responds and plans the transmission system accordingly. Note that, 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). Reference [9] is an explanatory work on coordination approaches. It focuses on the benefit of proactive coordination in providing transmission capacity for newly built renewable generations in a timely way because in proactive coordination, generation investments are predicted and responded. However, authors in [9] do not address the optimal capacity and location of new transmission investments especially when Gencos are strategic investors. In [10], 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.

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. In this report, we derive a mixed-integer bi-level 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. The MIBLP model has binary variables in both levels. The Moore-Bard algorithm [11] is implemented to solve the MIBLP model.

The rest of the report is organized as follows. First, the mathematical models for efficient planning, proactive coordination and reactive coordination are derived. Then, the algorithm for scenario selection is presented. Finally, the derived models are simulated on two case studies and concluding remarks are discussed. The content of this report is published in a journal paper in IEEE Transactions of Power Systems. The paper is attached to this report.

Efficient Coordination

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:

$$Minimize = \sum_l \bar{C}_l \sum_k A_k \alpha_{lk} F_l + \sum_g \{ \bar{\bar{C}}_g \sum_k A_k \beta_{gk} P_g + \sum_{h,s} W_{hs} C_g \, p_{hsg} \} \quad (1)$$

The objective function consists of investment cost of the transmission expansion plus the investment cost and operation cost of the generation units. The generation and transmission capacities ($\hat{p}_g$ and $\hat{f}_l$) are modeled through binary expansions in (2) and (3) and decided by the binary variables α_{lk} and β_{gk}. A_k is the step size of the added capacity for binary variable k. The generating units which are not considered for expansion are modeled by setting their additional generation capacities to zero.

$$\hat{p}_g = \sum_k (1 + A_k \beta_{gk}) P_g \quad (2)$$

$$\hat{f}_l = \sum_k (1 + A_k \alpha_{lk}) F_l \quad (3)$$

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, $W_{hs} = X_s \times Y_h$.

The system operation constraints

The system operation constraints consist of power balance constraint, generation capacity limits and transmission capacity limits. Equation (4) models the energy balance constraint. Generation capacity constraints for conventional units are considered in (5). Transmission capacity limits are modeled in (6). 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.

$$\sum_g p_{hsg} = \sum_b D_{sb} \quad (4)$$

$$0 \leq p_{hsg} \leq \hat{p}_g \quad (5)$$

$$-\hat{f}_l \leq \sum_g H_{bl}\left(p_{hsg,g\leftarrow b} - D_{sb}\right) \leq \hat{f}_l \quad (6)$$

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

The constraints of hydro power units

The hydro power units are energy-limited and their limited energy is different under different hydro seasons [12], [13]. In this paper, different hydro seasons, h, with their related probabilities, Y_h, are considered. The maximum capacity of the generator is modeled in (7). The energy limit constraint is presented in (8).

$$0 \leq p_{hsg} \leq \sum_k (1 + A_k \beta_{gk}) R_g \quad (7)$$

$$\sum_s X_s p_{hsg} \leq \sum_k (1 + A_k \beta_{gk}) \bar{E}_{hg} \quad (8)$$

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.

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 [14], [15]. Note that other more appropriate approaches exist in literature for considering wind uncertainty [16]. However, the simplified wind uncertainty modeling is used in this report in order to focus on the mathematical formulation of transmission and generation expansion coordination which is the primary goal of this research. The shape parameter and the scale parameter of the Weibull distribution can be derived from the historical data of wind speed [17]. The wind speed is converted to generation capacity using the production curve in Fig. 1.

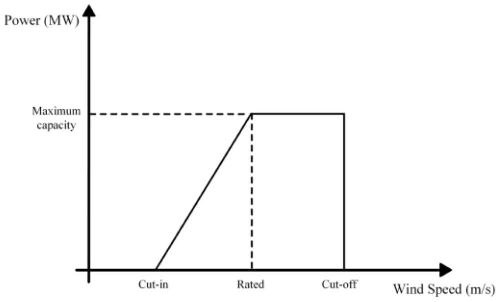

Fig.1 The production curve of a wind power unit.

The techniques for the uncertainty modeling of wind power units have been developed extensively [18], [19]. These techniques can be categorized as analytical methods [18] and Monte Carlo techniques [20], [21], [22]. 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 later in the report. Accordingly, the installed wind power units capacity has the s subscript,T_{sg}. This is presented in (9).

$$0 \leq p_{hsg} \leq \sum_k (1 + A_k \beta_{gk}) T_{sg} \quad (9)$$

Finally, the optimization problem (1)-(9) is a MILP with $\varphi = \{\beta_{gk}, \alpha_{lk}, \hat{f}_l, \hat{p}_g, p_{hsg}\}$ as the set of decision variables. This optimization problem can be solved to global optimality by available commercial softwares.

The Sequential Coordination

The interaction between regulated Transco and strategic Gencos is modeled using the leader-follower game in applied mathematics [23]. We focus on proactive Transco and reactive Transco for sequential coordination.

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.

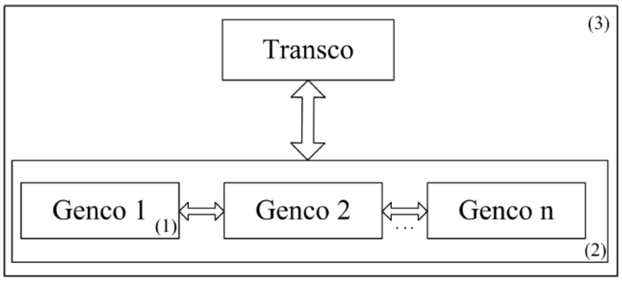

Fig. 2: The proactive approach for generation-transmission investment game.

Box1: Each strategic Genco invests in additional generation capacity β_{gk} given the decisions of other rival Gencos β_{-gk} and regulated Transco α_{lk}. This is done through bilevel optimization problem (10).

$$Maximize \sum_{g\in G_z, g\leftarrow b}\{-\bar{\bar{C}}_g \sum_k A_k\beta_{gk} P_g + \sum_{h,s} W_{hs}(\eta_{hsb} - C_g)\, p_{hsg}\} \quad (10.1)$$

subject to

$$\hat{p}_g = \sum_k (1 + A_k\beta_{gk})\, P_g \quad (10.2)$$

$$\beta_{gk} \in \{0,1\} \quad (10.3)$$

where $\{\eta_{hsb}, p_{hsg}\} \in$

$$argMinimize \sum_{h,s} W_{hs}C_g\, p_{hsg} \quad (10.4)$$

subject to

(4)-(9) (10.5)

In optimization problem (10.4)-(10.5), 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 (10.4)-(10.5) is a linear program, the Karush-Kuhn-Tucker (KKT) conditions are both necessary and sufficient [23]. Using the strong duality theorem and disjunctive constraints, the derived KKT conditions can be linearized. (Please refer to the published paper of this research for the detailed mathematical steps).

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 [24], [25]. At the optimal solution, $\hat{p}_g$, we have $\pi_z(\hat{p}_g) \geq \pi_z(\hat{p}_g^v), v = 1,2,\dots, Card\{V_z\}$. The set $\{\hat{p}_g^1, \hat{p}_g^2, \dots, \hat{p}_g^{Card\{V_z\}}\}$ 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 [26]. 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 [27]. The mathematical model of a proactive and pessimistic Transco is set out in (11).

$$Maximize = \sum_l \bar{C}_l \sum_k A_k \alpha_{lk} F_l + \sum_g \{\bar{\bar{C}}_g \sum_k A_k \beta_{gk} P_g + \sum_{h,s} W_{hs} C_g p_{hsg}\} \quad (11.1)$$

subject to

$$\hat{f}_l = \sum_k (1 + A_k \alpha_{lk}) F_l \quad (11.2)$$

$$\alpha_{lk} \in \{0,1\} \quad (11.3)$$

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

$$argMaximize = \sum_g \{\bar{\bar{C}}_g \sum_k A_k \beta_{gk} P_g + \sum_{h,s} W_{hs} C_g p_{hsg}\} \quad (11.4)$$

$$\hat{p}_g = \sum_k (1 + A_k \beta_{gk}) P_g \quad (11.5)$$

$$\beta_{gk} \in \{0,1\} \quad (11.6)$$

KKT conditions(linearized) (11.7)

$$\pi_z \geq \pi_z^v \quad (11.8)$$

In optimization problem (11), constraints (11.5)-(11.8) find the Nash equilibrium(ria) of the generation investment game. The MILP (11.4)-(11.8) 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 (11.1)-(11.8). The optimization problem (11) is a MIBLP where both the upper-level and the lower-level optimization problems have binary variables (α_{lk} and β_{gk}). We employ the solution algorithm proposed in [11] to solve this MIBLP in (11).

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.

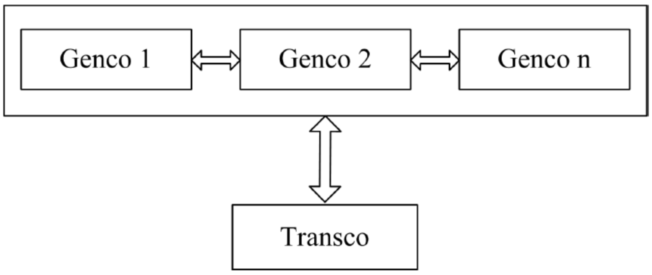

Fig. 3: The reactive approach for generation-transmission investment game.

The optimization problem of each Genco is derived in (12).

$$Maximize \sum_{g\in G_z, g\leftarrow b}\{-\bar{\bar{C}}_g \sum_k A_k \beta_{gk} P_g + \sum_{h,s} W_{hs}(\eta_{hsb} - C_g)\, p_{hsg}\} \quad (12.1)$$

subject to

$$\hat{p}_g = \sum_k (1 + A_k \beta_{gk}) P_g \quad (12.2)$$

$$\beta_{gk} \in \{0,1\} \quad (12.3)$$

where $\{\eta_{hsb}, p_{hsg}\} \in$

$$argMinimize \sum_l \bar{C}_l \sum_k A_k \alpha_{lk}\, F_l + \sum_{h,s} W_{hs} C_g\, p_{hsg} \quad (12.4)$$

subject to

$$0 \leq \alpha_{lk} \leq 1 \quad (12.5)$$

(4)-(9) (12.6)

To preserve the convexity of the minimization problem (12.4)-(12.6), we assume α_{lk} is a continues variable [28]. 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 (12) 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 (13).

$$Maximize \sum_l \bar{C}_l \sum_k A_k \alpha_{lk}\, F_l + \sum_g \{\bar{\bar{C}}_g \sum_k A_k \beta_{gk} P_g + \sum_{h,s} W_{hs} C_g\, p_{hsg}\} \quad (13.1)$$

subject to

$$\beta_{gk} \in \{0,1\} \quad (13.2)$$

KKT conditions(linearized) (13.3)

$$\pi_z \geq \pi_z^v \quad (13.4)$$

In optimization problem (13), constraints (13.2)-(13.4) finds the Nash equilibrium(ria) of generation-transmission investment game and objective function (13.1) selects the pessimistic Nash equilibrium. The optimization problem (13) is a MILP which can be solved to global optimality by available commercial softwares.

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 [29], [30]. 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.

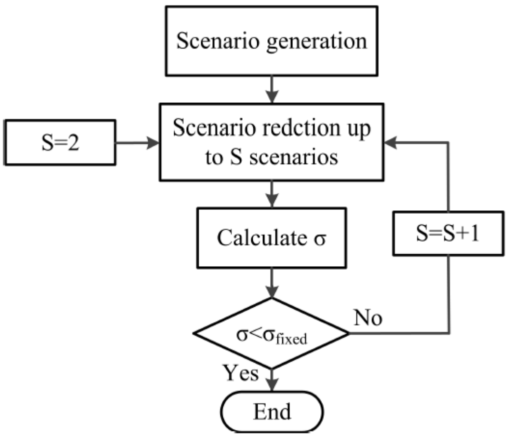

Fig. 4: The flowchart of the scenario-based modelling.

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 the maximum estimated standard deviation of the loss of load expectation (LOLE) [31].

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

$$\sigma = \frac{1}{S}\sqrt{\sum_{s\in S}\frac{(LOLE_s-\overline{LOLE})^2}{S-1}} \quad (14)$$

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 (14), the LOLEs 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 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 report, 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 previous sections.

Simulation Results

In this section, the 3-bus and 6-bus systems are simulated and the results of different coordination approaches are discussed.

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.

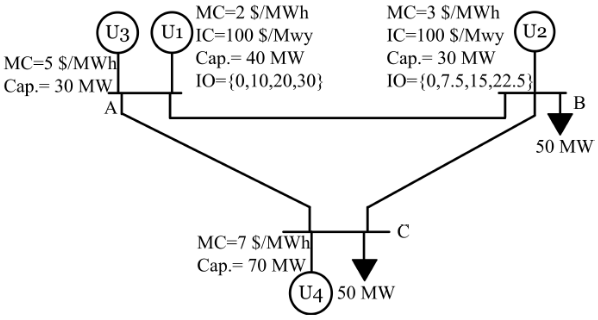

Fig. 5: The 3-bus example system; MC: Marginal Cost, IC: Investment Cost, Cap.: Capacity, IO: Investment Options (in MW).

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 ($/MWy)	IO (MW)
1	A-B	0.02	5	200	0-2.5-5-7.5

2	A-C	0.02	15	200	0-10-20-30
3	B-C	0.02	20	200	0-7.5-15-22.5

The results for the status-quo system and the different cases 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. The RC has four Nash equilibria while the PC has just one Nash equilibrium. Please note that in this report, 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 the 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).

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

Approach	EGC (MW)		ETC (MW)			SC (M$)	CB (M$)
	U1	U2	AB	AC	BC		
SQ	-	-	-	-	-	3.15	-
EC	30	0	0	10	5.5	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**

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% 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 SC1 and SC2 as below.

• SC1: The system social cost when no coordination mechanism is applied.

• SC2: The system social cost when the coordination mechanism in question is applied.

Using SC1 and SC2, the coordination benefit (CB) of a particular mechanism is defined as CB = SC1 − SC2. 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 equilibirum.

Table III: The Generation-Transmission Planning Results for the 3-Bus Example System with Reduced Generation Capacity for the Both Cases of Optimistic (O) and Pessimistic (P) Transco; EGC: Expanded Generation Capacity, ETC: Expanded Transmission Capacity, SC: Social Cost

Approach	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**

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 afterward, 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. 6. 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 the performance of the 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. 6: 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.

The 6-bus example system

To further analyze the different coordination approaches, the 6-bus example system shown in Fig. 10 is simulated [32]. The data for the lines is derived from [32]. The demand level in [32] is tripled in order to do the expansion planning analysis. Gencos U2 and U3 make strategic investment decisions with the investment options of 0.25Cap, 0.5Cap and 0.75Cap where Cap is defined in Fig. 10. U1 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. 7. As in the 3-bus example system, the investment cost of transmission lines is 200 $/MWy with the investment options of 0, 0.5K, K and 1.5K where K is the existing capacity in MW.

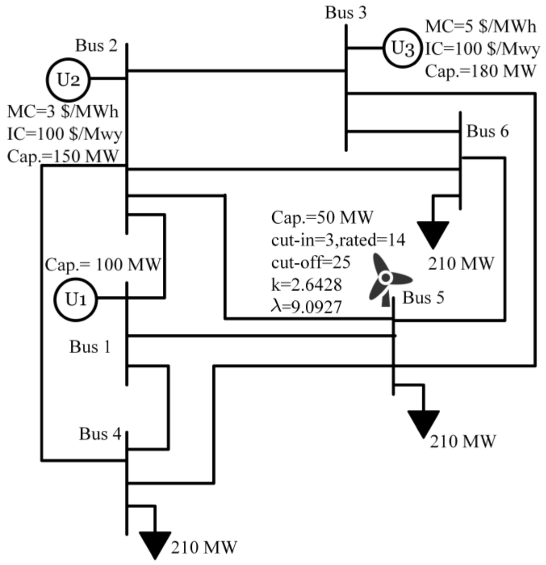

Fig. 7: The 6-bus example system; MC: Marginal Cost, IC: Investment Cost, Cap.: Capacity, k; shape parameter, λ: scale parameter.

The results of different coordination approaches are presented in Table IV. The RC has three Nash equilibira while the PC has only one Nash equilibrium. The lines 1-2, 1-5 and 2-3 are the only ones which are invested under different coordination approaches.

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

Approach	EGC (MW)		ETC (MW)			SC (M\$)	CB (M\$)
	U1	U2	1-2	1-5	2-3		
SQ	-	-	-	-	-	58.01	-
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**

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 underinvestment 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$. The lines 1-2, 1-5 and 2-3 are the only ones which are invested under different coordination approaches.

Conclusion

Transmission systems are experiencing great shifts in most parts of the world, mainly due to liberalization, market integration, and extensive development of renewable generation and distributed (embedded) generation. To this purpose local policies are less appropriate and improved coordination will be required, between adjacent systems and with generation.

This report presented key concepts of vertical coordination between transmission planners and strategic generation planners. The report 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 mathematical models have been simulated on the 3-bus and 6-bus example 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.

Future research might profitably examine other possible vertical coordination tools such as electricity market organisations and network tariffs schemes. Both of these tools can provide locational network signals for generation sitting. Other incentives can be provided by first connection cost which is charged to generators when they connect to the network. Moreover, the extension of mathematical models developed in our paper to consider strategic bidding of generators definitely adds another important layer to the coordination analysis.

Publications list

Y. Tohidi, M. R. Hesamzadeh, and F. Regairaz, "Sequential Coordination of Transmission Expansion Planning with Strategic Generation Investments," *Power Systems, IEEE Transaction on*, accepted, under publication.

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