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Optimal Long-Term Generation-transmission Planning in the Context of Multiple TSOs

Yaser Tohidi

Optimal Long-Term Generation-transmission Planning in the Context of Multiple TSOs

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SETS Joint Doctorate

The Erasmus Mundus Joint Doctorate in **Sustainable Energy Technologies and Strategies**, SETS Joint Doctorate, is an international programme run by six institutions in cooperation:

- Comillas Pontifical University, Madrid, Spain
- Delft University of Technology, Delft, the Netherlands
- Florence School of Regulation, Florence, Italy
- Johns Hopkins University, Baltimore, USA
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The Degree Certificates are giving reference to the joint programme. The doctoral candidates are jointly supervised, and must pass a joint examination procedure set up by the three institutions issuing the degrees.

This Thesis is a part of the examination for the doctoral degree.

The invested degrees are official in Spain, the Netherlands and Sweden respectively.

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Akademisk avhandling som med tillstånd av Kungl Tekniska högskolan framlägges till offentlig granskning för avläggande av teknologie doctorexamen i electrotekniska system sal F3, torsdagen den 1:e december 2016, kl. 09:00 i Kungl Tekniska högskolan, Stockholm.

Tryck: Universitetsservice US AB

Abstract in English Language

Author: Yaser Tohidi
Affiliation: Institute for Research in Technology, Comillas Pontifical University
Title: Optimal Long-Term generation-transmission planning in the context of multiple TSOs
Language: English
Keywords: Transmission-generation expansion planning, game theory, mathematical programming

Power system transmission is undergoing rapid changes by the advent of renewable resources of energy, distributed generation, market integration, etc. Transmission planning is, nowadays, about building more inter-connections between adjacent regions or connecting off-shore wind farms to the grid or augmenting the network to support new path flows of energy and is still almost entirely the responsibility of regulated transmission system operator (TSO). Moreover, a well-developed transmission planning includes anticipating the generation investment decisions made by profit-maximizing generation companies (Gencos).

Ensuring sustainable development of the power system necessitates coordination between TSO transmission investment with Gencos generation investments. Moreover, coordination between inter-connected TSOs in planning the network is also required in order to hunter the economic benefits of a robust and efficiently planned multi-area power system.

Driven by the need for more coordination of the long-term planning of the inter-connected power systems, this thesis aims to develop models to be used in analysis of the multi-TSO multi-Genco transmission and generation planning and suggest mechanisms and coordination approaches for the better functioning of the power system. This includes mathematical models for transmission planning in the context of multiple TSOs and generation-transmission investment planning based on the game theory concepts in applied mathematics and evaluating mechanisms and approaches.

Abstract in Spanish Language

Autor: Yaser Tohidi
Afiliación: Institute for Research in Technology, Comillas Pontifical University
Título: Planificación a largo plazo de transmisión de generación óptima en el contexto de múltiples TSOs
Lingua: Ingles
Palabras claves: planificación de expansión de transmisión-generación, la teoría de juegos, programación matemática

La transmisión del sistema de electerico está experimentando cambios rápidos por el advenimiento de los recursos de energías renovables, generación distribuida, la integración del mercado, etc. planificación de transmisión es, hoy en día, sobre la construcción de más interconexiones entre regiones adyacentes o conectar off-shore parques eólicos a la red o aumentar la red para apoyar la nueva ruta de los flujos de energía y sigue siendo casi en su totalidad la responsabilidad del operador del sistema de transmisión regulada (TSO). Por otra parte, una planificación de la transmisión bien desarrollado incluye anticipar las decisiones de inversión de generación realizadas por las empresas de generación que maximizan las ganancias (Gencos).

Asegurar el desarrollo sostenible del sistema de energía requiere una coordinación entre la inversión en transmisión por TSO con inversiones en generación por Gencos. Por otra parte, también es necesaria la coordinación entre los TSOs interconectada en la planificación de la red con para obtener de los beneficios económicos de un sistema de energía de múltiples área sólida y planificada de manera eficiente.

Impulsado por la necesidad de una mayor coordinación de la planificación a largo plazo de los sistemas de energía interconectados, esta tesis tiene como objetivo desarrollar modelos para ser utilizados en el análisis de la transmisión y generación de planificación multi-TSO multi-Genco y sugerir mecanismos y métodos de coordinación para el mejor funcionamiento del sistema de energía.

Esto incluye los modelos matemáticos para la planificación de la transmisión en el contexto de múltiples TSOs y la planificación de las inversiones de transmisión de generación en base a los conceptos de la teoría de juegos en matemáticas aplicadas y la evaluación de los mecanismos y enfoques.

Abstract in Swedish Language

Författare:: Yaser Tohidi
Aansluiting: Institute for Research in Technology, Comillas Pontifical University
Titel: Optimal långsiktigt elnät-generering planering i kontext av flera TSOs
Språk: Engelska
Nyckelord: Elnät-generering planering, spelteori , matematisk programmering

Elnäten genomgår snabba förändringar genom tillkomsten av förnybara energikällor, distribuerad generering, marknadsintegration, etc. utbyggnadsplanering för elnäten numera om att bygga fler anslutningar mellan angränsande regioner eller ansluter offshore-vindkraftverk till elnätet eller utöka nätverket för att stödja ny väg flöden av energi och är fortfarande nästan helt och hållet ansvarig för reglerad systemansvariga (TSO). Dessutom har en väl utvecklad transmission planering förutse generinginvesteringsbeslut som gjorts av vinstmaximerande generation företag (Gencos).

Garantera en hållbar utveckling av kraftsystemet kräver samordning mellan TSO investeringar i elnätkapacitet med Gencos produktionsinvesteringar. Dessutom är samordningen mellan sammankopplade systemansvariga i planeringen av nätverket också krävs för att skaffa de ekonomiska fördelarna med en robust och effektivt planerade multi-området kraftsystemet.

Driven av behovet av mer samordning av den långsiktiga planeringen av sammankopplade kraftsystem, syftar denna avhandling att utveckla modeller som kan användas vid analys av flera TSOs flera Gencos elnät-generering planering och föreslå mekanismer och samordnings metoder för en bättre fungerande kraftsystemet. Detta inkluderar matematiska modeller för elnät planering i kontext av flera TSO och elnät och generering planering baserad på spelteori begrepp i tillämpad matematik och utvärdera mekanismer och metoder.

Abstract in Dutch Language

Auteur: Yaser Tohidi
Aansluiting: Institute for Research in Technology, Comillas Pontifical University
Titel: Optimale langetermijnplanning van generatie-transmissie planning in het kader van meerdere TSOs
Taal: Engels
Trefwoorden: Transmissie-generatie uitbreiding planning, speltheorie, wiskundige programmering

Elektriciteitsnet ondergaat snelle veranderingen door de komst van hernieuwbare energie, decentrale opwekking, marktintegratie, etc. Transmissie planning wordt tegenwoordig over het bouwen van meer onderlinge verbindingen tussen aangrenzende regio's of het aansluiten van offshore windmolenparken op het net of het vergroten van het netwerk om nieuwe weg te ondersteunen stroomt energie en is nog steeds bijna volledig onder de verantwoordelijkheid van de gereglementeerde transmissienetbeheerder (TSO). Bovendien is een goed ontwikkelde transmissie planning omvat anticiperen op de productie investeringen beslissingen van winstmaximaliserende productiebedrijven (Gencos).

Zorgen voor duurzame ontwikkeling van het energiesysteem vereist coördinatie tussen TSO transmissie investering met generatie investeringen van Gencos. Bovendien is de coördinatie tussen de onderling verbonden TSOs in de planning van het netwerk ook vereist om verkrijgen de economische voordelen van een robuuste en efficiënte geplande multi-zone energie systeem.

Gedreven door de behoefte aan meer coördinatie van de langetermijnplanning van de onderling verbonden energiesystemen, dit proefschrift is bedoeld om modellen te worden gebruikt bij de analyse van de multi-TSO multi-Genco transmissie-generatie planning te ontwikkelen en suggereren mechanismen en coördinatie benaderingen voor een betere werking van het elektriciteitssysteem. Dit geldt ook voor wiskundige modellen voor transmissie planning in het kader van meerdere TSOs en generatie-transmissie planning op basis van de speltheorie concepten in

de toegepaste wiskunde en evalueren van mechanismen en methoden.

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Contents

List of Figures

List of Tables

Abbreviations

TSO Transmission System Operator

Genco Generation company

EU European Union

ENTSO-E Transmission System Operators for Electricity

TYNDP Ten-Year Network Development Plan

TEP Transmission Expansion Planning

GEP Generation Expansion planning

TP Transmission Planner

NE Nash Equilibrium

WNE Worst-Nash Equilibrium

MPEC Mathematical Program with Equilibrium Constraints

LP Linear Programming

KKT Karush-Kuhn-Tucker

SOS Special Ordered Sets

SOS1 Special Ordered Sets of Type 1

SOS2 Special Ordered Sets of Type 2

MILP Mixed Integer Linear Program

MIBLP Mixed Integer Bilevel Linear Program

MBA Moore-Bard Algorithm

P-MBA Parallelized Moore-Bard Algorithm

LOLE Loss of Load Expectation

LOLP Loss of Load Probability

EENS Expected Energy Not Served

The only knowledge that can truly orient action is knowledge that frees itself from mere human interests and is based in ideas-in other words knowledge that has taken a theoretical attitude.

JURGEN HABERMAS, KNOWLEDGE AND HUMAN INTERESTS

Chapter 1

Introduction

This chapter motivates the topic of this dissertation, defines the scope, and presents the scientific contributions.

1.1 Background

In liberalised electricity markets, transmission system operators (TSOs) were formed to provide access for all market participants for trading electrical energy and operate the system within an acceptable reliability level. However, transmission grids have limited transmission capacity. Transmission planning is one of the responsibilities of TSOs and it includes finding best technology to invest in, best time for investment, best capacity and best location for investment. TSOs continuously plan for their future transmission capacity in order to keep the electricity network and electricity markets well-functioning.

In vertically integrated power systems, the transmission planning problem can be formulated as an optimisation problem which minimizes (maximizes) the social cost (welfare) subject to a set of technical constraints. In these systems, transmission expansion is planned with generation expansion and both of these tasks are in hand of one entity. However, in liberalised power systems, different entities with different objectives are planning the system. Transmission planning is modified by adding the social welfare to the objective function of the transmission planning problem, [1–4], while generation planning is done by generation companies (Gencos) maximizing their profit [5–8].

Moreover, cross-border trading is a current and ongoing issue in different active markets in Europe. TSOs have found out that there is an opportunity in cross-border trades originated by diversity of generating capacities and complementary generation sources located in different places, [9]. Diversity of generating capacities means it might happen that a region with low generating capacity is adjacent to a region with high generating capacity. Also, difference between peak load days in these areas make a good opportunity for generating units to participate in power markets of each other. Realisation of these benefits is limited by the capacity of transmission grids. An economically efficient trading between different multi-national markets needs more multi-national transmission planning.

1.1.1 Situation in Europe

In Europe, there is a target for the European Integrated Electricity Market [10]. One of the key components for achieving this target is the future transmission system. Moreover, the European union (EU) has set a goal of reducing greenhouse gas emissions by 80-95% in 2050 as compared to 1990 levels [11] and creation of a well-integrated Internal Energy Market [12]. This requires both a significant change in generation mix and large investment in transmission lines, especially the cross-border ones. Investment in transmission system is needed not only for connecting the national networks to have a well-integrated energy market, but also because renewable sources, either onshore or offshore, are often located further away from major centers of consumptions (reference [10] identified that 80% of all existing and expected bottlenecks in the network are related to renewable integration).

There are several recent studies that use a pan-European welfare maximization approach to determine the optimal network investment plans to support such an integrated electricity sector [13]. However, a pan-European approach causes looser and winners in TSOs. Note that the transmission system in EU is run by different TSOs with different nationalities, ownerships, and internal policies and network expansion is still done by national authorities in Europe. This makes the transmission planning for the European Integrated Electricity Market difficult [14]. In fact, each TSO tries to act strategically in order to maximise his social welfare and they are reluctant to act in a cooperative solution. The arising reluctance against a pan-European plan results to under-efficient plans because national governments, regulators, or TSOs in charge of a network area might block the expansion which does not give profit to its immediate TSO where the line locates. On the other hand, it might result to an expansion which adversely affect other TSOs. Generally speaking, resolving this issue requires cooperation and coordination between TSOs. Examples of this inter-TSO cooperation and coordination are re-allocation of rents for the North and Baltic Seas offshore connectors [15] and Inter-TSO compensation mechanism in Europe [16]. With the same goal, European Network of Transmission System Operators for Electricity (ENTSO-E), the TSO's trade association (The European Network of Transmission System Operators for Electricity represents all electric TSOs in the EU and others connected to their networks, for all regions, and for all their technical and market issues.), publishes a European Ten-Year Network Development Plan (TYNDP) which lists transmission expansion projects as planned by TSOs and also a list of "projects of common interest", i.e., the ones which are affecting two or more TSOs and are invested accordingly [17]. The costs of investment in grid expansion depending on the scenario lie between 100 and 400 billion €. However, the benefit for the European economy (up to 500 TWh of RES curtailment and 200 mega tons of CO2 emissions would be avoided annually), would largely exceed these costs in all cases.

1.1.2 Research Motivation

Current approach for grid planning at European level should be changed from a purely bottom-up process at national level towards a more centralised European approach. This is supported by the work carried out by ENTSO-E in the TYNDP which combines top-down planning elements with a bottom-up approach. In this dissertation, the effect of centralize planing on different players of the electricity market is analysed and some mechanisms and/or regulatory decisions in order to alleviate those effects are discussed.

1.2 Modeling Assumptions

1.2.1 Transmission Expansion Approach

In this research, we have implemented static transmission expansion planning (TEP) by assuming that expansions are installed at a certain point in the future as compared to dynamic TEP in which transmission network developments take place in multiple stages, [18]. Depending on the application of the static TEP, it can include grid topology change or merely transmission capacity expansion.

1.2.2 Generation Expansion Approach

Generation expansion capacity planning (GEP) in this research is modeled by adding the capacity of existing units. If GEP is done by strategic Gencos, it is decided based on the ownership of the related unit and the effect of the expansion of the unit on the related Gencos profit function. If GEP is done centrally, it is determined by its effect on the social cost (welfare) of the system.

1.2.3 Network Representation

Power system network and its physical laws are modeled as a DC power flow [19]. Doing so, operation constraints consist of power balance constraint, capacity of lines limits, and generation capacity limits. Equation (1.1) models the energy balance constraint. Transmission capacity limits are modeled in (1.3) and (1.4). Generation capacity constraints considered in (1.2).

$$\sum_g p_g = \sum_n D_n \tag{1.1}$$

$$0 \leq p_g \leq \hat{P}_g \ \forall g \tag{1.2}$$

$$\sum_n H_{nl}(p_{g,g\leftarrow n} - D_n) \leq F_l \ \forall l \tag{1.3}$$

$$\sum_n H_{nl}(p_{g,g\leftarrow n} - D_n) \geq -F_l \ \forall l \tag{1.4}$$

This formulation is suitable for the cases that transmission expansion is modeled as adding capacity to the existing lines. If new lines (corridors) are to be analysed for investments, the set of formulations should change to the following:

$$D_n = \sum_{g,g\leftarrow n} p_g - \sum_{h\in H} A_{nh} f_h \ \forall n \tag{1.5}$$

$$0 \leq p_g \leq \hat{P}_g \ \forall g \tag{1.6}$$

$$f_h = \frac{1}{x_h} \sum_{n\in N} A_{nh}\delta_n \ \forall h \tag{1.7}$$

$$-\bar{f}_h \leq f_h \leq \bar{f}_h \ \forall h \tag{1.8}$$

The details of how transmission expansion is modeled in these two cases is discussed in the related sections.

1.3 List of Publications

The following articles are appended and form part of this thesis:

[P1]: Y. Tohidi and M. R. Hesamzadeh, ”Multi-national Transmission Planning Using Joint and Disjoint Solutions,” 10th International Conference on the European Energy Market, Stockholm, Sweden, 28-30 May 2013

[P2]: Y. Tohidi and M. R. Hesamzadeh, ”Free Riding Effect in Multi-national Transmission Expansion Planning,” IEEE ISGT Europe 2013 Conference, Copenhagen, Denmark, 6-9 October 2013.

[P3]: Y. Tohidi and M. R. Hesamzadeh, ”Multi-regional Transmission Planning under Interdependent Wind Uncertainty,” IEEE International Energy Conference, Dubrovnik, Croatia, 13-16 May 2014.

[P4]: Y. Tohidi and M. R. Hesamzadeh, ”Multi-regional Transmission Planning as a Non-cooperative Decision-making,” Power Systems, IEEE Transaction on, vol. 29, no. 6, pp. 2662-2671.

[P5]: Y. Tohidi, M. R. Hesamzadeh, and K. Ostman, ”Reactive Coordination of Transmission-generation Investment,” 12th International Conference on the European Energy Market, Lisbon, Portugal, 19-22 May 2015

[P6]: Y. Tohidi and M. R. Hesamzadeh, ”A Mathematical Model for Strategic Generation Expansion Planning,” PES General Meeting, 2016 IEEE, USA, July, 2016.

[P7]: Y. Tohidi, L. Olmos, M. Rivier, and M. R. Hesamzadeh, ”Coordination of Generation and Transmission Development through Generation Transmission Charges - A Game Theoretical Approach,” Power Systems, IEEE Transaction on, accepted, under publication.

[P8]: 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.

[P9]: Y. Tohidi and M. R. Hesamzadeh, ”Analyzing Nash Equilibria of Transmission Investment Game using Modified Benders and Branch-and-Bound Algorithms,” Power Systems, IEEE Transaction on, to be submitted.

[P10]: Y. Tohidi, M. R. Hesamzadeh, R. Baldick, and D. R. Biggar, ”Optimal Reconfiguration of Electricity Transmission Networks for Reducing Market Power Cost: A Nash-Equilibrium Approach,” Electric Power Systems Research, in review.

[P10]: Y. Tohidi and M. R. Hesamzadeh, ”Strategic Generation Investment Considering Oligopolistic Day-ahead Market: A Two-stage EPEC Approach,” Sustainable Energy, IEEE Transaction on, to be submitted.

During the following parts of the thesis, the symbol $\mapsto$ is used where a publication that is part of this thesis is discussed.

1.4 Thesis outline

The dissertation is divided in three chapters as follows:

Chapter 2 This chapter presents some mathematical principles on game theory, optimization, and uncertainty modeling used in the following chapters.

Chapter 3 This chapter discusses horizontal coordination of multi-TSO transmission planning considering uncertainty of wind, solar, demand, and generation failure rates. The developed model is simulated on the three-area IEEE-RTS96.

Chapter 4 This chapter discussed vertical coordination of transmission and generation investment planning. A mixed-integer bilevel programming model is developed and a solution methodology for the developed model is proposed. The developed model is simulated on different case studies and the discussion is provided.

Chapter 5 This chapter proposes a way to coordinate generation and transmission expansion through transmission charges derived based on the marginal effect of generation expansion on transmission expansion cost. An iterative algorithm is foreseen to implement this coordination. The proposed coordination algorithm is simulated on a 2-node illustrative example and the IEEE-RTS96.

Chapter 6 This chapter presents the concluding remarks and some directions for the future works in line with the research done in this thesis.

Chapter 2

Mathematical Principles and Applications

In this chapter, the required mathematical knowledge to be able to follow the rest of the sections is provided.

2.1 Introduction

This chapter reviews the mathematical applications used in this research. Section 2.2 introduce the game theory as a tool to deal with problems consisting of several strategic players. Game theory applications are used in this thesis in order to solve the problems when there are strategic players in different levels. Section 2.3 gives a brief introduction to optimization theory. The content of this section provides the mathematical background for the optimization models developed in Chapters 3 and 4. Section 2.4 discusses how the uncertainty is dealt with in this research.

2.2 Game Theory

In this section, we discuss the concepts of game theory which is used in this research. By these concepts, we can analyse the outcome of strategic interaction of several decision makers or players. Assumptions are: 1- each player is assumed to know the strategies of the other players and they all aware of this knowledge that each one has, 2- it is not allowed that players cooperate, 3- once a decision is acquired, it can not be changed.

2.2.1 Simultaneous Games

There are many real-world situations where several players interact simultaneously without the knowledge of the actions chosen by other players. In power markets, on-off decisions for power plants selling power to the market, investment decisions of strategic Gencos, and transmission expansion decisions of interacting transmission planners (TPs) are examples of these situations [20–24].

Therefore, there are some strategic players interacting with each other to reach a solution, i.e., an equilibrium point where all players are better-off not leaving that point. Game theory offers a framework to mathematically formulate strategic interaction between several economic players, where each player seeks to maximize its own payoff, and to find the equilibrium point. This framework is finding the Nash equilibrium point (NE). The Nash equilibrium was named after John Forbes Nash, Jr., [25]. Nash equilibrium is formulated below:

Definition 1 *Vector* $(v_1^*, ..., v_z^*, ..., v_{card(Z)}^*)$ *is the Nash equilibrium of the game between non-cooperative players if and only if*

$$\Pi_z(v_z^* | v_{-z}^*) \leq \Pi_z(v_z | v_{-z}^*) \;\; \forall z, v_z \tag{2.1}$$

Where z *is the set of players and* v_z *is the vector of decisions for player* z*.*

However, in real problems, e.g., investment in generation or transmission capacity, the decision variables are discrete. This makes finding the equilibrium solution difficult. In these cases, the NE can be found by exploring the entire solution space using brute-force methods. But this technique is computationally burdensome in large scale problems. Relaxing the binary decision variables can solve this problem but the NE found might be far from the result of the game when decisions are discrete. Reference [26] provides a compromise between relaxing the binary decision variables and finding the exact outcome of the game. In so far as finding the NE is important, multiple NE is problematic because it obscures the final solution of the game. Reference [27] provides a model to find the extremal Nash equilibria. Extremal-Nash equilibrium is discussed in Section 2.2.2. In order to eliminate the NE which are not self-enforcing, i.e., are not stable against slight perturbations in the strategies or payoffs, the concepts of perfect (proper) equilibria, [28], and essential equilibria, [29], are introduced. In the literature, there are many studies on the selection of one NE [30–32]. These studies are interested on the single outcome of the game. An example of this type of problems are coordination of transmission-generation planning [33]. More about this can be found in [34] and [35]. Besides, there can be a case that no NE exists, i.e., there is no outcome where no player is better-off by a deviation [36].

2.2.2 Discussion on Extremal-Nash Equilibria

The strategic games might have more than one NE outcome. The worst-case NE with respect to the social cost first introduced by Gairing et al. [37]. Fischer [38] further extended the work by Gairng et al. To the authors' best knowledge, the work in [39] is the first which employs the concept of worst-Nash equilibrium (WNE) for electricity market analysis. Reference [40] presents an application of the WNE concept. The WNE models a pessimistic view for electricity market analysis. In [27], authors extended the work and modeled both pessimistic and optimistic views by introducing the concept of extremal-Nash equilibria with respect to the social cost. An application of the Nash equilibria band for merger analysis in electricity markets is shown in [31]. The notion of WNE is defined and mathematically formulated as following:

Definition 2 *Suppose V^* is the set of all Nash equilibria of the game between non-cooperative transmission planners and*

$$SC = \sum_{z \in Z} SC_z \tag{2.2}$$

Vector v^{w*} is the WNE of this game if and only if

$$v^{w*} \in arg\ Max_{v^* \in V^*} SC(v^*) \tag{2.3}$$

2.2.3 Sequential Games

If a player is able to move before his rival, we have a Stackelberg game, [41]. The Stackelberg game can be written as a Mathematical Program under Equilibrium Constraints (MPEC), [42–45]. These type of problems are discussed in the next section.

2.3 Optimization

In mathematics, optimization is the selection of 'best approach' from some set of available alternatives and an optimization problem corresponds to the mathematical formulation of optimization. To formulate an optimization problem, one has to decide the criteria for selection, e.g., minimization of the cost, and set the variables affecting the criteria. In this thesis, the optimization problems are linear or mixed integer linear.

2.3.1 Linear Programming

Linear optimization problems (linear programming or LP) have the general form of:

$$\underset{x}{Maximize}\ c^T x \tag{2.4a}$$

$$Subject\ to$$

$$Ax \leqq b \tag{2.4b}$$

$$x \geqq 0 \tag{2.4c}$$

where x represents the vector of variables, c is the vector of coefficients of variables in the objective function, b is the vector of coefficients of the right hand side of the constraints, A is a (known) matrix of coefficients of variables in the constraints, and $(\cdot)^{\mathrm{T}}$ is the matrix transpose. Note that equalities can be transformed to inequalities using a slack variable. Linear optimization problems are convex and can be efficiently solved using solvers such as Simplex [46].

Every LP, referred to as a primal problem, can be converted into a dual problem as follows:

$$\underset{y}{Minimize}\ b^T y \tag{2.5a}$$

$$Subject\ to$$

$$A^T y \geqq c \tag{2.5b}$$

$$y \geqq 0 \tag{2.5c}$$

The dual problem provides an upper bound to the optimal value of the primal problem. The strong duality theorem states that if the primal has an optimal solution, x^*, then the dual also has an optimal solution, y^*, and $c^T x^* = b^T y^*$, [47].

Karush-Kuhn-Tucker (KKT) conditions are both necessary and sufficient conditions for LPs. In other words, the point which satisfies these conditions is the optimum point of the related LP, [47]. In order to derive the KKT conditions, the Lagrangian of the LP must be written:

$$\mathscr{L} = -c^T x + y^T (Ax - b) - z^T (x) \tag{2.6}$$

where y and z are the associated vectors of Lagrange multipliers of (2.4b) and (2.4c). The KKT conditions of (2.4) are:

$$
\begin{aligned}
& stationary\ condition: \\
& \nabla_x \mathscr{L} = -c + A^T y - z = 0 && (2.7a) \\
& primal\ feasibility\ conditions: \\
& Ax \leqq b && (2.7b) \\
& x \geqq 0 && (2.7c) \\
& dual\ feasibility\ conditions: \\
& y, z \geqq 0 && (2.7d) \\
& complementarity\ conditions: \\
& (Ax - b).y = 0 && (2.7e) \\
& z.x = 0 && (2.7f)
\end{aligned}
$$

where $(.)$ is the entrywise product.

Stationary condition states that the gradient of Lagrangian is zero at the optimal solution. Primal feasibility conditions makes sure that the optimal solution is a feasible point, i.e., satisfies (2.4b) and (2.4c). Dual feasibility together with complementarity constraints state that the Lagrange multipliers are nonzero only if the inequality constraints are active.

The complementary slackness conditions are the only nonlinear terms in equivalent KKT conditions. The complementary slackness conditions have the general form of $XY = 0, X \geq 0, Y \geq 0$. The following technique is employed for linearising the complementary slackness conditions.

Disjunctive Approach

If X and Y are positive variables in an optimisation problem and if b is a binary variable, the nonlinear constraint $XY = 0$ can be written as $Xb + Y(1-b) = 0$. This can, in turn, be expressed as a pair of linear constraints: $0 \leq X \leq M(1-b)$ and $0 \leq Y \leq Mb$, where M is a large enough number.

Strong Duality

If we do not consider complementarity constraints and find a point which satisfies stationary condition, primal feasibility, and dual feasibility conditions, this point is a feasible point both in primal problem and dual problem because (2.5b) and

(2.7a) are equivalent. Among these feasible points for primal and dual, there is just one point which is optimal for both problems and by strong duality theorem, we know that at this point $c^T x = b^T y$. Therefore, using the strong duality theorem, the complementarity constraints can be replaced by strong duality condition [48] and the primal problem (2.4) can be replaced by the following.

$$-c + A^T y - z = 0 \tag{2.8a}$$

$$Ax \leqq b \tag{2.8b}$$

$$x \geqq 0 \tag{2.8c}$$

$$y, z \geq 0 \tag{2.8d}$$

$$c^T x = b^T y \tag{2.8e}$$

2.3.2 Mixed Integer Linear Programming

A mixed integer linear program (MILP) can be expressed as:

$$\underset{x}{Maximize}\ c^T x \tag{2.9a}$$

$$Subject\ to$$

$$Ax \leqq b \tag{2.9b}$$

$$x_i \geqq 0 \quad \forall i \in \{1, 2, ..., m\} \tag{2.9c}$$

$$x \in \mathbb{Z}^{n-m} \quad \forall i \in \{m+1, m+2, ..., n\} \tag{2.9d}$$

It includes both continuous and discrete variables. All state-of-the-art MILP solvers are based on the branch-and-bound algorithm [49]. In this research, we have these type of optimization problems which we solve by using the available commercial solvers, e.g., CPLEX.

2.3.3 Mathematical Program with Equilibrium Constraints (MPEC)

Mathematical programming with equilibrium constraints (MPEC) are optimization problems where the constraints include complementarities. MPEC is related to the

Stackelberg game. Consider the leader-follower game formulated below:

$$\underset{x'}{Minimize}\ f(x,x') \tag{2.10a}$$

$$Subject\ to$$

$$x' \geqq 0 \tag{2.10b}$$

$$\underset{x}{Maximize}\ c^T x \tag{2.10c}$$

$$Subject\ to$$

$$Ax \leqq b + x' \tag{2.10d}$$

$$x \geqq 0 \tag{2.10e}$$

The leader minimizes f deciding on x' and the follower maximizes $c^T x$ deciding on x. As discussed in Section 2.3.1, lower level problem in (2.10) can be replaced by its KKT conditions as follows:

$$\underset{x'}{Minimize}\ f(x,x') \tag{2.11a}$$

$$Subject\ to$$

$$x' \geqq 0 \tag{2.11b}$$

$$-c + A^T y - z = 0 \tag{2.11c}$$

$$Ax \leqq b + x' \tag{2.11d}$$

$$x \geqq 0 \tag{2.11e}$$

$$y, z \geqq 0 \tag{2.11f}$$

$$(Ax - b - x').y = 0 \tag{2.11g}$$

$$z.x = 0 \tag{2.11h}$$

Complementarity constraints of (2.11g) and (2.11h) categorized this problem as an MPEC.

2.3.4 Mixed Integer Bilevel Programming

Another type of optimization problems that we face in this research are mixed integer bilevel problems (MIBLP). These type of problems can be expressed as:

$$\underset{x_1}{Minimize}\ F(x_1, y_1, y_2) \tag{2.12a}$$

$$Subject\ to$$

$$\underset{(y_1,y_2)\in Y(x_1)}{Minimize}\ f(x_1, y_1, y_2) \tag{2.12b}$$

$$Subject\ to$$

$$y_2 \in \mathbb{R}_+^{n_2} \tag{2.12c}$$

$$x_1 \in \{0,1\}^{n_1}, y_1 \in \{0,1\}^{n_2} \tag{2.12d}$$

where F and f are linear functions of their arguments and $Y(x_1)$ is the feasible set of the lower-level problem.

We employ the solution algorithm proposed in [50] to solve the MIBLP in (5.13). We have the following definitions and theorem for (2.12).

Definition 3 *The F_r^C is the optimal solution of (2.12) for subproblem r when (2.12d) is replaced by* $0 \leq x_1, y_1 \leq 1$.

Definition 4 *The F_r^H is the high point solution of (2.12) for subproblem r when (2.12d) is replaced by* $0 \leq x_1, y_1 \leq 1$ *and the objective function of the lower level* (2.12*b) is removed from the formulation.*

Theorem 1 *If along the path to subproblem r in the search tree, there are no restrictions on the binary variables controlled by the lower level, then the high point solution F_r^H is a lower bound on the solution of the MIBLP of subproblem r.*

Proof 1 *See [50].*

Accordingly, the Moore-Bard Algorithm (MBA) has the following steps.

Step 0 Set $r \leftarrow 0$, $\bar{F} = \infty$ and set no bounds on either x_1 or y_1.

Step 1 Find F_r^H. If high point problem (Definition 4) is infeasible or $F_r^H \geq \bar{F}$, go to Step 6.

Step 2 Find F_r^C. If relaxed MIBLP (Definition 3) is infeasible, go to Step 6. Otherwise label the solution (x_1^r, y_1^r).

Step 3 If (x_1^r, y_1^r) are all 0 or 1, go to Step 4. Otherwise, select an element of vector x_1^r which is fractional-valued and branch the search tree in subproblem r by putting bounds on the selected variable. Put $r \leftarrow r+1$ and go to Step 1.

Step 4 Fix x_1 at x_1^r, solve the follower subproblem to obtain $(x_1^r, \hat{y}_1^r)$ and compute the leader objective function F. Put $\bar{F} = Min\{\bar{F}, F\}$.

Step 5 If all of the binary variables are bounded, go to Step 6. Otherwise, select a binary variable not bounded and place a new bound on it. Put $r \leftarrow r+1$ and go to Step 1.

Step 6 If no live node exists, go to Step 7. Otherwise, branch to the newest live node. Put $r \leftarrow r+1$ and go to Step 1.

Step 7 If $\bar{F} = \infty$, there is no feasible solution. Otherwise, report $(x_1^r, \hat{y}_1^r, y_2^r)$ as the final solution with the value $\bar{F}$.

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 0P Select M binary variables of vector x_1.

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

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

Step 3P Run Step 0 to Step 7 on each core to solve the 2^M MIBLPs resulting in Step 0P to Step 2P.

Step 4P Use the optimal solutions in Step 3P and continue with the rest of binary variables.

Moreover, two heuristic versions explained in [50] can be considered. In heuristic technique A, Step 4 of the MBA will be replaced by Step 4A below:

Step 4A Fix x_1 at x_1^r, solve the follower subproblem to obtain $(x_1^r, \hat{y}_1^r)$ and compute the leader objective function F. If $\bar{F} > F$, put $\bar{F} \leftarrow F$ and go to Step 5; otherwise go to Step 6.

For heuristic technique B, we replace Step 4 of MBA with Step 4B below:

Step 4B Fix x_1 at x_1^r, solve the follower subproblem to obtain $(x_1^r, \hat{y}_1^r)$ and compute the leader objective function F. Put $\bar{F} = Min\{\bar{F}, F\}$. If $\hat{y}_1^r = y_1^r$, go to Step 6; otherwise go to Step 5.

These heuristic techniques reduce the size of decision tree by removing sections of the tree in which having the optimal point is unlikely.

2.4 Uncertainty Modeling

The approaches for modelling uncertainty in transmission planning problem can be categorised as probabilistic and scenario-based approaches. Probabilistic approaches are discussed in [51] and [52]. Accuracy of probabilistic approaches costs computational burden to the transmission planning problem. Scenario-based approaches proposed in [53] and [54] to tackle the computational burden of probabilistic approaches.

Availability of a conventional power plant, production level of an intermittent generator, and demand level are three main sources of uncertainties. The availability of conventional power plants are modelled using a three-state Markov process as depicted in Fig. 2.1. Three states of normal, forced-outage, and planned-outage are considered in this model, [55]. The transition probability matrix of each conventional generating unit can be calculated using its historical data.

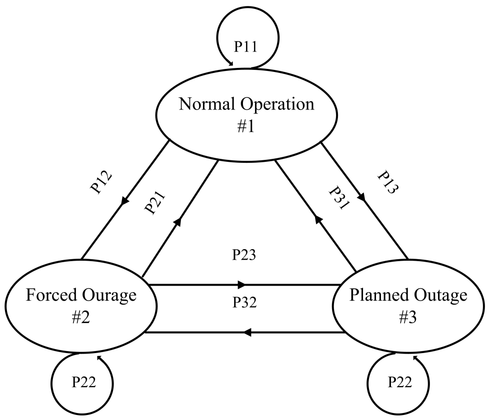

Figure 2.1: The three-state Markov model for a conventional generating unit

The stochastic behaviours of renewable units are not procedural and are based on the probabilistic distributions of their related resources. The available capacity of a hydro unit is represented by a log-normal distribution function, [56].

The wind speed is modelled using a Weibull distribution function, [57]. The wind speed is converted to power generation using the production curve in Fig. 2.2.

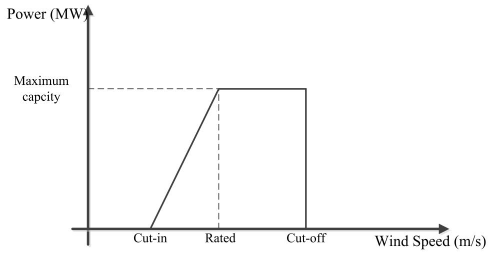

Figure 2.2: The production curve of a wind power unit

The sunshine probability function for modelling solar units follows a beta distribution, [58]. Seasonal Autoregressive Integrated Moving Average (SARIMA) model is used for load forecasting in this paper, [59].

To model these uncertainties, a large number of initial scenarios is generated and then reduced. The scenario generation and scenario reduction are discussed here. Using a random number generator and explained models above a large number of initial scenarios are generated. After generating the initial scenarios, they are reduced to the desired number of retained scenarios (S). During the reduction step, the weights of the removed scenarios are added to the remaining scenarios according to their distances to the remaining scenarios. This results in different probabilities for different scenarios considered in our model. Fast backward, fast forward, and fast forward/backward methods are the main algorithms used in the literature for scenario reduction [60]. In general, these methods are different in the accuracy of results and computational time. The fast backward method is the fastest one, while the results of the other two methods are more accurate but at the expense of higher computational time.

Fig. 2.3 shows the flowchart of scenario-based modelling of each slot in horizon year of planning. The number of retained scenarios (S) for each slot is determined based on a stopping criterion, σ_{fixed}, which is calculated as the maximum estimated standard deviation of loss of load expectation (LOLE), [61]. The formulation of the deviation index, σ, is as follow:

$$\sigma = \frac{1}{S}\sqrt{\sum_{s\in S}\frac{(LOLE_s - \overline{LOLE})^2}{S-1}} \tag{2.13}$$

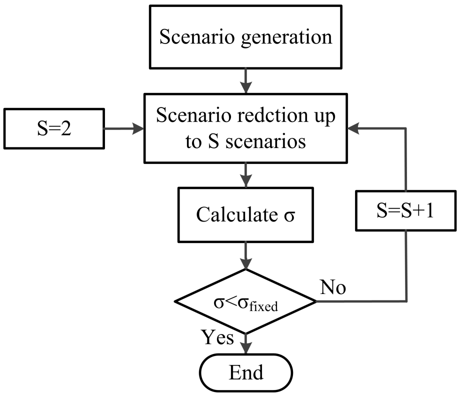

Figure 2.3: The flowchart of scenario-based modelling of each slot in horizon year of planning

The typical values for σ_{fixed} are 0.05 and 0.01 [61] and here it is assumed to be $\sigma_{fixed} = 0.05$. The initial number of retained scenarios is two, $S = 2$, for which the deviation is definable. The number of retained scenarios are increased up to the point that stopping criterion is met.

As stated above and presented in (2.13), the Loss of Load Expectation (LOLE) index is adopted for calculating σ. In (2.13), 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 calculated using the power flow simulation. The $\overline{LOLE}$ is the weighted average of curtailed loads in the set of retained scenarios. Note that the final set of retained scenarios and their related weights are calculated for the base case system. The LOLE index models the amount of curtailed load while this is not modelled in loss of load probability (LOLP) index. Moreover, the calculation based on the LOLE index is less time-consuming as compared to expected energy not served (EENS) index, [55].

The retained scenarios are a subset of initial ones that is closest to the initial probability distribution measured by the introduced probabilistic metric. In other words, presented scenario-based approach in Fig. 2.3 models the stochastic behaviour of the system in the planning problem while making a compromise between the computational issue and the accuracy of analysis.

Chapter 3

Horizontal Coordination

In this chapter, the main findings of $\mapsto$ [P4] are presented. This paper is written for comparing the non-cooperative transmission planning of multiple TSOs with the cooperative solution.

3.1 Introduction

Electricity transmission network connects the electricity producers and consumers for reliable transmission of electricity from producers to consumers. The design of an electricity transmission network is about finding a network design which delivers the optimal configuration, reliability, and capacity. Over the last two decades, implementation of liberalised electricity markets and huge penetration of renewable generation sources have raised new challenges in transmission planning problem.

One of these new challenges arising in the areas consisting of inter-connected networks si the following: How should different transmission planners design their interconnected transmission networks? There are two approaches for transmission planning when more than one transmission planner are involved: (a) cooperative approach, and (b) noncooperative approach. In the cooperative transmission planning, all transmission planners work together for the highest overall social welfare. The solution of cooperative transmission planning might not maximise the social welfare of each transmission planner involved. There would be some winners and losers in transmission planning solution which might cause disincentive for losers to continue. On the other hand, in the non-cooperative approach, each transmission planner maximises his own social welfare taking into account the planning decisions of other transmission planners. As an example, Nordic electricity sector has a long tradition of cooperation. Nordic countries cooperate to develop their grids regardless of national borders, [9]. But in the European market, the development of cross-border transmission lines did not keep the pace with the development of other electricity sectors, [10]. As the power transfers between transmission regions are increasing, a European-wide transmission planning is required, [14].

The multi-regional transmission planning, is the focus of this chapter. First, we derives the mathematical model for non-cooperative transmission planning based on the game theory concepts in applied mathematics. The initial derived models are non-linear mixed-integer programming problems. Different mathematical techniques are employed to derive the equivalent mixed-integer optimisation problems. This is discussed in detail in Section 3.2.1. Then, the co-operative transmission planning is formulated in Section 3.2.2 and used as the benchmark. In the assumed cooperative model, all the transmission planners cooperate to reach to the maximum social welfare for the whole region. For comparing the derived models, they are simulated on the Three-Region IEEE RTS-96 example system. The results and discussions are collected in Section 3.3. Concluding remarks are drawn in Section **??**.

3.2 Formulation

3.2.1 Non-cooperative Transmission Planning

We assume a transmission network which is divided into different interconnected regions. Each region is controlled by a social-welfare (social cost) maximising (minimising) transmission planner. An electricity market operator runs a bid-based security-constrained economic dispatch for all interconnected regions. The mathematical formulation of multi-regional transmission planning is developed in this section.

As formulated below, in the non-cooperative transmission planning, each regional transmission planner minimises his own region social cost using his inter-region and intra-region planning decisions given the planning decisions of other transmission planners. This is formulated in (3.1)-(3.10).

$$Minimise \;\; SC_z(v_z|v_{-z}) = \sum_{k\in K_z} u_{zk}c'_k \frac{r(1+r)^{T_k}}{(1+r)^{T_k}-1} \tag{3.1}$$

$$+\sum_{s\in S}\sum_{g\in G_z} w_s c_g p_{sg} \tag{3.2}$$

Subject to:

$$u_{zk} \in \{0,1\} \tag{3.3}$$

$$Minimise \;\; \sum_{z\in Z}\sum_{s\in S}\sum_{g\in G_z} w_s c_g p_{sg} \tag{3.4}$$

Subject to:

$$p_{sg} \leq \bar{p}_{sg} \;\; \forall z \in Z, \forall s \in S, \forall g \in G_z \Leftrightarrow \tau_{sg} \tag{3.5}$$

$$-\bar{f}_h \leq f_{sh} \leq \bar{f}_h$$
$$\forall z \in Z, \forall s \in S, \forall h \in H_z \Leftrightarrow (\lambda^+_{sh}, \lambda^-_{sh}) \tag{3.6}$$

$$-\bar{f}'_k u_{zk} \leq f'_{sk} \leq \bar{f}'_k u_{zk}$$
$$\forall z \in Z, \forall s \in S, \forall k \in K_z \Leftrightarrow (\lambda'^+_{sk}, \lambda'^-_{sk}) \tag{3.7}$$

$$f_{sh} = \frac{1}{x_h}\sum_{n\in N} A_{nh}\delta_{sn}$$
$$\forall z \in Z, \forall s \in S, \forall h \in H_z \Leftrightarrow \vartheta_{sh} \tag{3.8}$$

$$f'_{sk} = u_{zk}\frac{1}{x'_k}(\delta_{si}-\delta_{sj})$$
$$k \leftarrow (i,j), \forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.9}$$

$$D_{sn} = \sum_{g\in G_{z,n}} p_{sg} - \sum_{h\in H} A_{nh}f_{sh} \tag{3.10}$$
$$-\sum_{k\in K_z, i_k=n} f'_{sk} + \sum_{k\in K_z, j_k=n} f'_{sk}$$
$$\forall z \in Z, \forall s \in S, \forall n \in N_z \Leftrightarrow \eta_{sn}$$

The optimisation problem (3.1)-(3.10) has a bilevel structure. At the first level, the transmission planner z minimises his own region social cost (SC_z) using his planning vector (v_z) given the transmission planning decisions made in all other regions (v_{-z}). Note that the planning vector v_z consists of $u_{zk}, \forall k \in K_z$. Terms (3.1) and (3.2) represent the transmission investment and the operation cost for the transmission planner z. For effective modelling of the investment cost in the planning horizon, it is replaced with the correlated annual equivalent value as stated in (3.1). It should be noted that each transmission planner has both intra-region and inter-region options for expanding its future transmission capacity and the concept of cost sharing for inter-region lines is not modelled in this study. In other words, it is assumed that the decision and investment cost of each inter-region line is related to one transmission planner responsible in the area that the line is located.

At the second level, the system operator receives all transmission planning decisions in all regions and all marginal costs from generators. The system operator dispatches the market using this information. The lost load is modelled as the production of a generator connected to load node with marginal cost equals to value of lost load ($c_g = VoLL_n$). The generation capacity limit is modelled in inequality (3.5). The inequalities (3.6) and (3.7) model the limited transmission capacity for exiting and candidate lines. The power flow through existing and candidate lines are calculated in equations (3.8) and (3.9). The energy balance constraint at each node is formulated in (3.10).

The nonlinearity in constraint (3.9) is replaced by two linear inequalities expressed in disjunctive form using a large enough M as formulated in (3.11). The constant M should be selected carefully to avoid numerical ill-conditioning, [62].

$$\begin{aligned} & -M(1-u_{zk}) \leq f'_{sk} - \frac{1}{x'_k}(\delta_{si} - \delta_{sj}) \leq M(1-u_{zk}) \\ & k \leftarrow (i,j), \forall z \in Z, \forall s \in S, \forall k \in K_z \Leftrightarrow \mu^+_{sk}, \mu^-_{sk} \end{aligned} \tag{3.11}$$

The interaction between non-cooperative transmission planners can be modelled as a multiple-leaders single-follower game in applied mathematics, [63]. The follower is the electricity market operator. The leaders of this game are different non-cooperative transmission planners. We assume a game with complete information. In the games with complete information, every player knows the pay-offs and strategies available to other players. Suppose $CSet(v_z)$ represents the set of constraints (3.4)-(3.10). The V_z is the set of all planning vectors available for transmission planner z. The non-cooperative transmission planners compete to have the lowest social cost for their own region. They are of equal status. This can be modelled as a static simultaneous-move game.

To derive an explicit formulation for $CSet_z$, the optimisation problem (3.4)-(3.10) is replaced by its equivalent Karush-Kuhn-Tucker (KKT) optimality conditions. The complementary slackness conditions are the only nonlinear terms in equivalent KKT conditions. The complementary slackness conditions have the general form of $XY = 0, X \geq 0, Y \geq 0$. The disjunctive approach as discussed in Section 2.3.1 is employed for linearising the complementary slackness conditions.

Also, to tackle the multiple Nash equilibria problem, the notion of the worst-Nash equilibrium as defined in Section 2.2.2 is used.

The non-cooperative transmission planning can now be formulated as a mixed-integer linear programming problem.

$$\textit{Maximise } \sum_{z\in Z} SC_z = \sum_{z\in Z}\sum_{k\in K_z} u_{zk} c'_k \frac{r(1+r)^{T_k}}{(1+r)^{T_k}-1} \tag{3.12}$$

$$+\sum_{z\in Z}\sum_{s\in S}\sum_{g\in G_z} w_s c_g p_{sg} \tag{3.13}$$

s.t.

$$u_{zk} \in \{0,1\} \tag{3.14}$$

Primal feasibility conditions:

$$(3.5)-(3.10) \tag{3.15}$$

Stationary conditions:

$$\partial Ł/\partial p_{sg} = w_s c_g + \eta_{sn} + \tau_{sg} = 0$$

$$g \leftarrow n, \forall z \in Z, \forall s \in S, \forall g \in G_z \tag{3.16}$$

$$\partial Ł/\partial f_{sh} = \sum_{n\in N} \eta_{sn} A_{nh} + \lambda^+_{sh} - \lambda^-_{sh} + \vartheta_{sh} = 0$$

$$\forall z \in Z, \forall s \in S, \forall h \in H_z \tag{3.17}$$

$$\partial Ł/\partial f'_{sk} = \eta_{sn} + \lambda'^+_{sk} - \lambda'^-_{sk} + \mu^+_{sk} - \mu^-_{sk} = 0$$

$$\forall z \in Z, \forall s \in S, \forall k \in K_z, i_k = n \tag{3.18}$$

$$\partial Ł/\partial f'_{sk} = \eta_{sn} - \lambda'^+_{sk} + \lambda'^-_{sk} - \mu^+_{sk} + \mu^-_{sk} = 0$$

$$\forall z \in Z, \forall s \in S, \forall k \in K_z, j_k = n \tag{3.19}$$

$$\partial Ł/\partial \delta_{sn} = \sum_{h\in H} A_{nh} \vartheta sh + \frac{1}{x_h} \sum_{k\in K, i_k=n} \mu^+_{sk}\frac{1}{x'_k} - \mu^-_{sk}\frac{1}{x'_k}$$

$$\sum_{k\in K, j_k=n} \mu^-_{sk}\frac{1}{x'_k} - \mu^+_{sk}\frac{1}{x'_k} = 0 \ \ \forall n \in N, \forall s \in S \tag{3.20}$$

Complementary slackness conditions:

$$\alpha_{sg} + \alpha''_{sg} = \frac{\tau_{sg} + (\bar{p}_{sg} - p_{sg})}{2} \ \ \forall z \in Z, \forall s \in S, \forall g \in G_z \tag{3.21}$$

$$\alpha_{sg} - \alpha''_{sg} = \frac{\tau_{sg} - (\bar{p}_{sg} - p_{sg})}{2} \ \ \forall z \in Z, \forall s \in S, \forall g \in G_z \tag{3.22}$$

$$\beta_{sh} + \beta''_{sh} = \frac{\lambda^+_{sh} + (\bar{f}_h - f_{sh})}{2} \quad \forall z \in Z, \forall s \in S, \forall h \in H_z \tag{3.23}$$

$$\beta_{sh} - \beta''_{sh} = \frac{\lambda^+_{sh} - (\bar{f}_h - f_{sh})}{2} \quad \forall z \in Z, \forall s \in S, \forall h \in H_z \tag{3.24}$$

$$\gamma_{sh} + \gamma''_{sh} = \frac{\lambda^-_{sh} + (\bar{f}_{sh} + f_h)}{2} \quad \forall z \in Z, \forall s \in S, \forall h \in H_z \tag{3.25}$$

$$\gamma_{sh} - \gamma''_{sh} = \frac{\lambda^-_{sh} - (\bar{f}_{sh} + f_h)}{2} \quad \forall z \in Z, \forall s \in S, \forall h \in H_z \tag{3.26}$$

$$\xi_{sk} + \xi''_{sk} = \frac{\lambda'^+_{sk} + (\bar{f}'_k u_k - f'_{sk})}{2} \quad \forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.27}$$

$$\xi_{sk} - \xi''_{sk} = \frac{\lambda'^+_{sk} - (\bar{f}'_k u_k - f'_{sk})}{2} \quad \forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.28}$$

$$\varpi_{sk} + \varpi''_{sk} = \frac{\lambda'^-_{sk} + (f'_{sk} + \bar{f}'_k u_{zk})}{2} = 0$$
$$\forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.29}$$

$$\varpi_{sk} - \varpi''_{sk} = \frac{\lambda'^-_{sk} - (f'_{sk} + \bar{f}'_k u_{zk})}{2} = 0$$
$$\forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.30}$$

$$\rho_{sk} + \rho''_{sk} = \frac{\mu^+_{sk} + (M(1-u_{zk}) - (f'_{sk} - \frac{1}{x'_k}(\delta_{si} - \delta_{sj})))}{2}$$
$$k \leftarrow (i,j), \forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.31}$$

$$\rho_{sk} - \rho''_{sk} = \frac{\mu^+_{sk} - (M(1-u_{zk}) - (f'_{sk} - \frac{1}{x'_k}(\delta_{si} - \delta_{sj})))}{2}$$
$$k \leftarrow (i,j), \forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.32}$$

$$\zeta_{sk} + \zeta''_{sk} = \frac{\mu^-_{sk} + (f'_{sk} - \frac{1}{x'_k}(\delta_{si} - \delta_{sj}) - M(1-u_{zk}))}{2}$$
$$k \leftarrow (i,j), \forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.33}$$

$$\zeta_{sk} - \zeta''_{sk} = \frac{\mu^-_{sk} - (f'_{sk} - \frac{1}{x'_k}(\delta_{si} - \delta_{sj}) - M(1-u_{zk}))}{2}$$
$$k \leftarrow (i,j), \forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.34}$$

Dual feasibility conditions:

$$\tau_{sg}, \lambda^+_{sh}, \lambda^-_{sh}, \lambda'^+_{sk}, \lambda'^-_{sk}, \mu^+_{sk}, \mu^-_{sk} \geq 0$$
$$\forall z \in Z, \forall s \in S, \forall g \in G_z, \forall h \in H_z, \forall k \in K_z \tag{3.35}$$

and finally, Nash equilibrium constraint:

$$SC_z(v_z|v_{-z}) \leq SC_z(v_z^m|v_{-z}) \forall v_z^m \in V_z \forall z \in Z \tag{3.36}$$

3.2.2 Cooperative Transmission Planning

In the cooperative transmission planning, all involved transmission planners co-operate for expanding the transmission capacity of the system. They act as if they are merged into one single transmission planner who is responsible for all interconnected regions. The cooperative transmission planning is formulated as an optimisation problem set out in (3.37)-(3.44).

$$Min \ \ SC = \sum_{z \in Z} \sum_{k \in K_z} u_{zk} c'_k \frac{r(1+r)^{T_k}}{(1+r)^{T_k} - 1} \tag{3.37}$$

$$+ \sum_{z \in Z} \sum_{s \in S} \sum_{g \in G_z} w_s c_g p_{sg} \tag{3.38}$$

$$s.t.$$

$$p_{sg} \leq \bar{p}_{sg} \ \ \forall z \in Z, \forall s \in S, \forall g \in G_z \tag{3.39}$$

$$-\bar{f}_h \leq f_{sh} \leq \bar{f}_h \ \ \forall z \in Z, \forall s \in S, \forall h \in H_z \tag{3.40}$$

$$-\bar{f}'_k u_{zk} \leq f'_{sk} \leq \bar{f}'_k u_{zk} \ \ \forall z \in Z, \forall s \in S, \forall k \in K_z \tag{3.41}$$

$$f_{sh} = \frac{1}{x_h} \sum_{n \in N} A_{nh} \delta_{sn} \ \ \forall z \in Z, \forall s \in S, \forall h \in H_z \tag{3.42}$$

$$f'_{sk} = u_{zk} \frac{1}{x'_k} (\delta_{si} - \delta_{sj}) \ \ k \leftarrow (i,j), \forall z \in Z,$$

$$\forall s \in S, \forall k \in K_z \tag{3.43}$$

$$D_{sn} = \sum_{g \in G_{z,n}} p_{sg} - \sum_{h \in H} A_{nh} f_{sh} \tag{3.44}$$

$$- \sum_{k \in K_z, i_k = n} f'_{sk} + \sum_{k \in K_z, j_k = n} f'_{sk}$$

$$\forall z \in Z, \forall s \in S, \forall n \in N_z$$

In the optimisation problem (3.37)-(3.44), term (3.37) represents the total transmission investment cost and term (3.38) represents the total operation cost. The generation capacity limit is modelled in inequality (3.39). The inequalities (3.40) and (3.41) model the limited transmission capacity for exiting and candidate lines. The power flow through existing and candidate lines are calculated in equations

(3.42) and (3.43). The energy balance constraint at each node is formulated in (3.44).

The optimisation problem (3.37)-(3.44) is a mixed-integer nonlinear programming problem. The nonlinearity comes from constraint (3.43). This constraint is replaced by two linear inequalities expressed in disjunctive form using a large enough M as formulated in (3.45). The constant M should be selected carefully to avoid numerical ill-conditioning, [62].

$$-M(1-u_k) \leq f'_{sk} - \frac{1}{x'_k}(\delta_{si} - \delta_{sj}) \leq M(1-u_k) \tag{3.45}$$

Replacing (3.43) with (3.45), the optimisation problem in (3.37)-(3.44) is now a mixed-integer linear programming problem.

3.3 Results and Discussion

To examine the proposed formulations, the Three-region IEEE RTS-96 example system is carefully modified and used as a case study, [64]. Both cooperative transmission planning and non-cooperative transmission planning are applied to the modified Three-region IEEE RTS-96 example system and studied in detail. In order to reduce the computational effort of the problem, the transmission network of the Three-region IEEE RTS-96 example system is reduced in a way that the lines with less than 0.5 capacity factor in status-quo system are removed from the system. The optimisation problems are solved using the CPLEX solver in the GAMS platform, [65]. Uncertainty modelling is carried out using both R and Matlab softwares. The code is run on an Intel(R) Core(TM) i7-3720QM @ 2.60 GHz processor with 8 GB RAM. The simulation time for the cooperative transmission planing is 0.17 hour and for non-cooperative transmission planning is 0.84 hour.

Region 1, Region 2, and Region 3 of the Three-region IEEE RTS-96 example system have the same configuration. There are three independent transmission planners TP1, TP2, and TP3, responsible for planning decisions of Region 1, Region 2, and Region 3, respectively. Each transmission planner has intra-region and inter-region options for expanding its future transmission capacity. Existing and candidate inter-region lines are depicted in Fig. 3.1.

Table 3.1 presents the characteristics of candidate lines for each transmission planner. For all candidate lines, life time is assumed to be 30 years. As seen, the first five candidate lines are inter-region lines and the last four are intra-region ones.

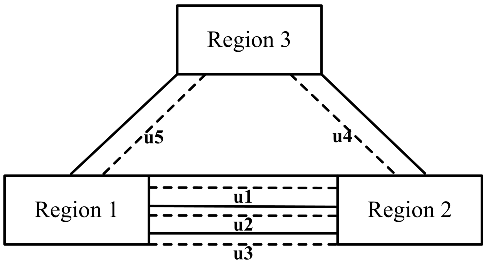

Figure 3.1: The Three-Region IEEE RTS-96 example system

Table 3.1: The characteristics of candidate lines, TCap: Transmission Capacity, EC: Expansion Cost

Owner	From-To (Name)	TCap (MW)	X (Ω)	EC ($)	Type
TP1	113-215 (u1)	50	0.075	2000	Inter-region
TP2	123-217 (u2)	50	0.074	2000	Inter-region
TP2	107-203 (u3)	50	0.161	2000	Inter-region
TP3	223-318 (u4)	100	0.075	2000	Inter-region
TP3	323-121 (u5)	100	0.075	2000	Inter-region
TP1	114-124 (u6)	75	0.075	1000	Intra-region
TP2	214-224 (u7)	75	0.075	1000	Intra-region
TP2	211-220 (u8)	75	0.075	1000	Intra-region
TP3	311-320 (u9)	75	0.075	1000	Intra-region

Note that existing inter-region lines have the same characteristics as their parallel candidate lines.

Table 3.2 presents the data for scenario-based modelling of conventional and renewable generating units in Region 1. Generating units in Region 2 and Region 3 have the same location and uncertainty parameters.

The horizon year of planning is divided into 52 slots each representing a week. The weekly demand is multiplied by 1, 0.5, and 1.5 factors are used in Region 1, Region 2, and Region 3, respectively. For each week, enough number of scenarios are generated and then reduced to represent the uncertainties in the generation sector.

The cooperative transmission planning results in $(1,0,1,1,1,1,1,0,1)$ for expanding the transmission capacity of three regions. The overall social cost of the system with the cooperative transmission planning approach is $\$2,032,458$. The non-cooperative approach results in different solution with the overall social cost

Table 3.2: The generating units in Region 1; location and uncertainty parameters

Unit	Type	Bus No.	Uncertainty Parameters
Conventional	CT/CCT	1,2,7, 13,15,16, 23	P11=0.90 P12=0.06 P13=0.04 P22=0.06 P21=0.90 P23=0.04 P33=0.03 P31=0.95 P32=0.02
	Nuclear	18,21	P11=0.95 P12=0.01 P13=0.09 P22=0.01 P21=0.01 P23=0.98 P33=0.50 P31=0.50 P32=0.00
Renewable	Hydro	22	μ=3.23 σ=0.5
	Wind	15	k=2.6428 λ=9.0927 cut-in=3 rated=14 cut-off=25
	Solar	1	α=2.45 β=2.36

Table 3.3: Operation Cost (OC) and Investment Cost (IC) ($) for status quo transmission system and transmission system expanded using cooperative and non-cooperative solutions

Region	Status quo	Cooperative	Non-cooperative
All-three	IC = 0 OC = $2,425,029$ Total = $2,425,029$	IC=718 OC=$2,031,740$ Total=$2,032,458$	IC=588 OC=$2,362,616$ Total=$2,363,204$
Region 1	IC = 0 OC = $693,085$ Total = $693,085$	IC=196 OC=$692,583$ Total=$692,779$	IC=196 OC=$785,170$ Total=$785,366$
Region 2	IC = 0 OC = $323,331$ Total = $323,331$	IC=196 OC=$369,522$ Total=$369,718$	IC=66 OC=$369,522$ Total=$369,588$
Region 3	IC = 0 OC = $1,408,613$ Total = $1,408,613$	IC=326 OC=$969,605$ Total=$969,931$	IC=326 OC=$1,207,336$ Total=$1,207,662$

of $\$2,363,204$. The TP1 expands his transmission system by building $u1$ and $u6$. The TP2 finds it non-profitable to expand his inter-region lines and just expands one of his intra-region lines $u7$. Finally, TP3 confirms lines $u4$, $u5$, and $u9$. The three regions will be expanded as $(1,0,0,1,1,1,1,0,1)$ vector. The operation cost and investment cost for status quo transmission system and transmission system expanded using cooperative and non-cooperative solutions are set out in Table 3.3. The line $u3$ is invested in the cooperative approach while it is not invested in non-cooperative approach.

The cooperative transmission expansion results in $\$393,289$ reduction in overall operation cost of all three regions. However, operation cost in Region 2 increases in cooperative solution. This is while Region 2 has a share of 27% of total investment cost. Obviously, in the non-cooperative solution, the TP2 is not interested to invest in line u3. As a result, the operation cost of non-cooperative solution for all three regions is increased by $\$330,876$ as compared to the cooperative solution. The strategic decision of TP2 has increased the operation cost in Region 1 by $\$92,587$ and in Region 3 by $\$237,731$.

The developed mathematical formulations for multi-regional transmission planning can be used (1) to quantify the economic benefit of compensation mechanisms and (2) to analyse the free riding effect. These applications of the developed mathematical formulations are further discussed here.

(1) The economic benefit of compensation mechanisms: The compensation mechanism is a system of payments to different regional-transmission planners to incentivise them for more cooperation. Suppose SC_0 is the social cost of non-cooperative solution without compensation and SC is the social cost of non-cooperative solution with compensation mechanism. $\Delta SC = SC - SC_0$ can be defined as the economic benefit of compensation mechanism. Accordingly, the compensation mechanism with the highest (ΔSC) is the economically efficient one.

As an example, a system of payments between TP1, TP2, and TP3 is proposed in Table 3.4.

The solutions of optimisation problem (3.12)-(3.36) for three different values of α are set out in Table 3.5.

In Table 3.6, the measure ΔSC is calculated for different values of $\alpha(\$/MWh)$. The compensation mechanism with $\alpha = 0.06\$/MWh$ has the highest ΔSC measure. This compensation mechanism incentivises TP2 to invest in line u3 in the non-cooperative planning.

(2) The economic analysis of the free riding effect: As it is shown in Table 3.3, the investment by TP2 in line u3 does not have any impact on Region 2 operation cost while it reduces the operation costs in Region 1 and Region 3. Although

Table 3.4: Compensation mechanism, α: Design parameter, f_{12}^{u1}: Power flow from Region 1 to Region 2 on line u1

Contract	Party	Counter Party	Payment from Party to Counter Party
C1	TP2	TP1	$\alpha Max\{0, f_{12}^{u1}\}$
C2	TP1	TP2	$\alpha Max\{0, f_{21}^{u2}\}$
C3	TP1	TP2	$\alpha Max\{0, f_{21}^{u3}\}$
C4	TP2	TP3	$\alpha Max\{0, f_{32}^{u4}\}$
C5	TP1	TP3	$\alpha Max\{0, f_{31}^{u5}\}$

Table 3.5: Non-cooperative solution with three different values for α

α	Non-cooperative solution
0.02	$(1,0,0,1,1,1,1,0,1)$
0.04	$(1,0,0,1,1,1,1,0,1)$
0.06	$(1,0,1,1,1,1,1,0,1)$

Table 3.6: The costs (\$) of non-cooperative solutions with different compensation mechanisms (α is in \$/MWh)

Region	$\alpha = 0.02$	$\alpha = 0.04$	$\alpha = 0.06$
All-three	IC=588 OC=2,362,616 Total=2,363,204	IC=588 OC=2,362,616 Total=2,363,204	IC=718 OC=2,031,740 Total=2,032,458
Region 1	IC=196 OC=785,652 Total=785,848	IC=196 OC=786,208 Total=786,404	IC=196 OC=673,183 Total=673,379
Region 2	IC=66 OC=368,817 Total=368,883	IC=66 OC=368,040 Total=368,106	IC=196 OC=150,674 Total=150,870
Region 3	IC=326 OC=1,208,147 Total=1,208,473	IC=326 OC=1,208,368 Total=1,208,694	IC=326 OC=1,207,883 Total=1,208,209
ΔSC	0	0	330746

line u3 connects Region 1 and Region 2, but investment in this line reduces the operation cost of Region 3. This is free-riding effect. In other words, the capacity investment in inter-region lines in an interconnected network not only affects the pay-offs of adjacent regions but also the pay-off of the third region. The developed mathematical formulations for multi-regional transmission planning can help the transmission planners in better understanding of this effect in their inter-connected network.

Chapter 4

Vertical Coordination

In this chapter, the main findings of $\mapsto$ [P8] are presented. This paper propose an approach for sequential coordination of transmission and generation investment planning considering both proactive and reactive approaches. The models are proposed as mixed-integer bilinear problems.

4.1 Introduction

Efficient investments in generation and transmission sectors are vital for the development of electricity industry. In a vertically-integrated electricity industry, a single entity is responsible for the operation of and investment in the electricity sector [18, 66–69]. 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 [70].

The coordination issue has been studied both in engineering and economics literature. References [6, 71, 72] 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 [73] discusses the benefit of proactive coordination in providing transmission capacity for integrating renewable generations. However, authors in [73] do not address the optimal capacity and location of new transmission investments specially when Gencos are strategic investors. References [6] and [71] 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 [74] 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 [7], 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 [8] 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 [75] 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 [75] explicitly address the multiple Nash equilibria issue in [76], 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 [75] leads to a large number of constraints and binary variables in large-scale networks specially when uncertainty is considered [77]. Accordingly, the computational issue needs to be alleviated by proper tuning of the disjunctive parameters and employing a suitable decomposition technique [78, 79].

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. Therefore, in this chapter we 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 [50] 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 this chapter is organized as follows. The efficient coordination is modeled in Section 4.2. The mathematical models for sequential coordination are derived in Section 4.3. In Section 4.4, an assumption made in the developed models is refined. The Illustrative 3-bus and 6-bus example systems are comprehensively discussed in Section 4.5. The modified IEEE-RTS96 and IEEE 118-bus test systems are studied in Section 4.6. Section **??** concludes the chapter.

4.2 The Efficient Coordination (MILP Model)

In the efficient coordination model used as the benchmark in this chapter, we assume an electric utility owning both transmission and generation assets. The electric utility minimizes the social cost of the system in the horizon year (4.1) as follows:

$$Minimize \sum_{l} \overline{C}_l \hat{f}_l + \sum_{g} \{ \underline{C}_g \hat{p}_g + \sum_{h,s} W_{hs} C_g p_{hsg} \} \tag{4.1}$$

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 (4.2) and (4.3). The generating units which are not considered for expansion are modeled by setting their additional generation capacities to zero.

$$\hat{p}_g = \sum_{k} A_k \beta_{gk} P_g \ \forall g \in \hat{U} \tag{4.2}$$

$$\hat{f}_l = \sum_{k} A_k \alpha_{lk} F_l \ \forall l \tag{4.3}$$

$$\alpha_{lk} \in \{0,1\}, \beta_{gk} \in \{0,1\} \in \mathbb{R} \tag{4.4}$$

As seen in (4.2), 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, $W_{hs} = \acute{W}_s \times \grave{W}_h$.

4.2.1 System Operation Constraints

System operation constraints consists of power balance constraint, capacity of lines limits, and generation capacity limits. Equation (4.5) models the energy balance constraint. Transmission capacity limits are modeled in (4.7) and (4.8). Generation capacity constraints for conventional units are considered in (4.6). Also, at each node, the lost load is modeled as a fictitious generator with a marginal cost equals to the value of lost load at that node.

$$\sum_g p_{hsg} = \sum_n D_{sn} \ \forall h,s \tag{4.5}$$

$$0 \leq p_{hsg} \leq \hat{P}_g + \hat{p}_g \ \forall h,s,g \in \hat{U} \tag{4.6}$$

$$\sum_n H_{nl}(p_{hsg,g \leftarrow n} - D_{sn}) \leq F_l + \hat{f}_l \ \forall h,s,l \tag{4.7}$$

$$\sum_n H_{nl}(p_{hsg,g \leftarrow n} - D_{sn}) \geq -F_l - \hat{f}_l \ \forall h,s,l \tag{4.8}$$

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

4.2.2 Hydro Units Constraints

Hydro generation units are subject to limited reservoir storage capacity and environmental consideration. This results to limited discharged energy for hydro units in different hydrologic seasons in addition to their limited capacity, [80, 80, 81]. Fossil-fueled units with specific fuel contracts are also intrinsically energy limited. In this chapter, different hydrologic seasons, h with their related probabilities, $\grave{W}_h$, are considered in order to model energy limits for hydro units represented in (4.10). Capacity limit of these units are modeled by (4.9).

$$0 \leq p_{hsg} \leq \grave{P}_g \ \forall h,s,g \in \grave{U} \tag{4.9}$$

$$\sum_s \acute{W}_s p_{hsg} \leq \overline{E}_{h,g} \ \forall h,g \in \grave{U} \tag{4.10}$$

4.2.3 Wind Units Constraints

Nowadays, wind units as an efficient renewable source are becoming widely integrated into the power systems. However, the production power of wind turbines depends on the speed of wind blowing which has an uncertain behavior. The Weibull distribution have been widely used to model the uncertainty of wind speed

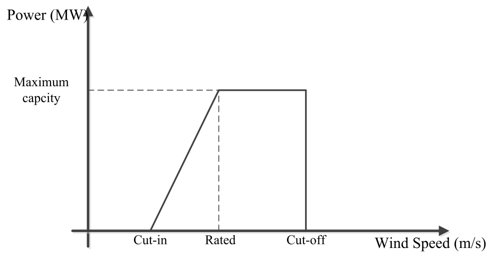

Figure 4.1: Production curve of a wind power unit.

[82], [83]. The shape parameter and scale parameter of the Weibull distribution can be derived from the historical data on mean and standard deviation of wind speed [84]. Then, the wind speed is converted to power generation using the production curve in Fig. 4.1.

The techniques for the uncertainty modeling of wind units has been developed extensively [85], [86]. These techniques can be categorized in two major methods; analytical methods [85] and Monte Carlo simulation techniques [87], [88], [89]. Since we develop linear models to analyze coordination issue between generation and transmission planning problems, the Monte Carlo approach is used in this chapter for uncertainty modeling of wind turbines. Doing so, wind turbines uncertainty is modeled through several scenarios, represented by index s, with their associated probabilities $\acute{W}_s$. Thus, wind units are subject to the capacity limit which has the s subscript, $\acute{P}_{sg}$. This is presented in (4.11).

$$0 \leq p_{hsg} \leq \acute{P}_{sg} \; \forall h, s, g \in \acute{U} \tag{4.11}$$

All in all, the optimization problem for efficient coordination of transmission and generation planning modeled through (4.1)-(4.11) is a MILP with $\Psi_U = \{\beta_{gk}, \alpha_{lk}, \hat{f}_l, \hat{p}_g, p_{hsg}\}$ is the set of decision variables which can be solve by available commercial softwares.

4.3 The Sequential Coordination

The interaction between regulated Transco and strategic Gencos is modeled using the leader-followers game in applied mathematics [41]. We focus on proactive Transco and reactive Transco for sequential coordination.

4.3.1 The Proactive Coordination (MIBLP Model)

The proactive Transco anticipates and influences 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. 4.2 and modeled in the following three steps.

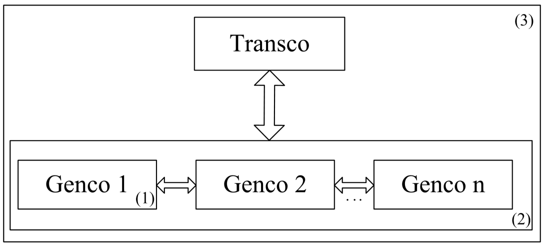

Figure 4.2: The proactive approach for generation-transmission investment game

Box 1: Each strategic Genco invests in additional generation capacity $(\beta_{gk}, \hat{p}_g)$ given the decisions of other rival Gencos $(\beta_{-g,k}, \hat{p}_{-g})$ and regulated Transco $(\alpha_{l,k}, \hat{f}_l)$. This is done through bilevel optimization problem (5.2).

$$\underset{\beta_{gk},\hat{p}_g:g\in G_z}{Maximize} \sum_{\substack{g\in G_z \\ g\leftarrow n}} \{-\underline{C}_g \hat{p}_g + \sum_{h,s} W_{hs}(\eta_{hsn} - C_g) p_{hsg}\} \tag{4.12a}$$

$$Subject\ to\ \ \hat{p}_g = \sum_k A_k \beta_{gk} P_g\ \forall g \in G_z \tag{4.12b}$$

$$\beta_{gk} \in \{0,1\} \tag{4.12c}$$

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

$$arg\underset{p_{sg}}{Minimize} \sum_{h,s,g} W_{hs} C_g p_{hsg} \tag{4.12d}$$

$$Subject\ to$$

$$\sum_g p_{hsg} = \sum_n D_{sn}\ :(\eta_{hs}^{sys})\ \forall h,s \tag{4.12e}$$

$$0 \le p_{hsg} \le P_g + \hat{p}_g\ :(\underline{\lambda}_{hsg}, \bar{\lambda}_{hsg})\ \forall h,s,g \in \hat{U} \tag{4.12f}$$

$$0 \le p_{hsg} \le \acute{P}_{sg}\ :(\underline{\rho}_{sg}, \bar{\rho}_{hsg})\ \forall h,s,g \in \acute{U} \tag{4.12g}$$

$$0 \le p_{hsg} \le \grave{P}_g\ :(\underline{\rho}_{hsg}, \bar{\rho}_{hsg})\ \forall h,s,g \in \grave{U} \tag{4.12h}$$

$$\sum_s \acute{W}_s p_{hsg} \leq \overline{E}_{h,g} \ : (\varpi_{hg}) \ \forall h, g \in \grave{U} \tag{4.12i}$$

$$\sum_n H_{nl}(p_{hsg,g\leftarrow n} - D_{sn}) \leq F_l + \hat{f}_l \ : (\bar{\mu}_{hsl})$$
$$\forall h, s, l \tag{4.12j}$$

$$\sum_n H_{nl}(p_{hsg,g\leftarrow n} - D_{sn}) \geq -F_l - \hat{f}_l \ : (\underline{\mu}_{hsl})$$
$$\forall h, s, l \tag{4.12k}$$

In optimization problem (5.2b)-(4.12k), we assume that the power generation of units is found by an economic dispatch that minimizes the total operation cost of generation subject to energy-balance constraint and generation and network capacity limits. Since (5.2b)-(4.12k) is a linear program, the Karush-Kuhn-Tucker (KKT) conditions are both necessary and sufficient [48]. The stationary, strong duality and dual feasibility conditions of (5.2b)-(4.12k) are derived in (4.13a)-(4.13c), (5.6d) and (5.6e), respectively.

$$W_{hs}C_g - \eta_{hs}^{sys} + \bar{\lambda}_{hsg} - \underline{\lambda}_{hsg} - \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0$$
$$g \leftarrow n, \forall h, s, g \in \hat{U} \tag{4.13a}$$

$$W_{hs}C_g - \eta_{hs}^{sys} + \bar{\rho}_{hsg} - \underline{\rho}_{hsg} - \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0$$
$$g \leftarrow n, \forall h, s, g \in \acute{U} \tag{4.13b}$$

$$W_{hs}C_g - \eta_{hs}^{sys} + \bar{\rho}_{hsg} - \underline{\rho}_{hsg} + \acute{W}_s \varpi_{hg}$$
$$- \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \ \ g \leftarrow n, \forall h, s, g \in \grave{U} \tag{4.13c}$$

$$\sum_{h,s,g} W_{hs}C_g p_{hsg} = \sum_{h,s,n} \eta_{hs}^{sys} D_{sn} - \sum_{h,s,g\in\acute{U}} \bar{\rho}_{hsg}\acute{P}_{sg}$$
$$- \sum_{h,s,g\in\hat{U}} \bar{\lambda}_{hsg}(P_g + \hat{p}_g) - \sum_{h,g\in\grave{U}} \{\varpi_{h,g}\overline{E}_{h,g} + \sum_s \bar{\rho}_{hsg}\grave{P}_g\}$$
$$+ \sum_{h,s,l} \{ \left((\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) \sum_n H_{nl} D_{sn} \right)$$
$$- (\underline{\mu}_{hsl} + \bar{\mu}_{hsl})(F_l + \hat{f}_l) \} \tag{4.13d}$$

$$\bar{\lambda}_{hsg}, \underline{\lambda}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \varpi_{hg},$$
$$\underline{\mu}_{hsl}, \bar{\mu}_{hsl} \geq 0 \ \ \forall h, s, g, l \tag{4.13e}$$

There are two bilinear terms in optimization problem (5.2) when inner problem is replaced by (4.13a), (5.6d) and (5.6e) and primal feasibility conditions (4.12e)-(4.12k). These are (A) the bilinear term $\eta_{hsn}p_{hsg}$ 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 $\eta_{hsn}=(1/W_{hs})[\eta_{hs}^{sys}+\sum_l H_{nl}(\underline{\mu}_{hsl}-\bar{\mu}_{hsl})]$. Substituting η_{hsn} in stationary condition (4.13a) and using the complementary slackness conditions $\underline{\lambda}_{hsg}p_{hsg}=0$ and $\bar{\lambda}_{hsg}(p_{hsg}-P_g-\hat{p}_g)=0$, we have

$$\begin{aligned}W_{hs}(\eta_{hsn}-C_g)p_{hsg}&=\bar{\lambda}_{hsg}(P_g+\hat{p}_g)\overset{(4.2)}{=}\bar{\lambda}_{hsg}P_g\\+\sum_k A_k\beta_{gk}P_g\bar{\lambda}_{hsg}&=\bar{\lambda}_{hsg}P_g+\sum_k A_kP_gt_{hsgk}\end{aligned}\tag{4.14}$$

where in (5.8), the $t_{hsgk}=\beta_{gk}\bar{\lambda}_{hsg}$ and it can be replaced by the following inequalities: $-\overline{M}(1-\beta_{gk})\leq t_{hsgk}-\bar{\lambda}_{hsg}\leq\overline{M}(1-\beta_{gk})$, $-\overline{M}\beta_{gk}\leq t_{hsgk}\leq\overline{M}\beta_{gk}$. Therefore, the non-convex profit function (5.2a) is linearized. Also, the bilinear term $\bar{\lambda}_{hsg}\hat{p}_g$ can be replaced by $\sum_k A_kP_gt_{hsgk}$. The bilinear term $(\underline{\mu}_{hsl}+\bar{\mu}_{hsl})\hat{f}_l$ can be linearized in the similar way as

$$\begin{aligned}&(\underline{\mu}_{hsl}+\bar{\mu}_{hsl})\hat{f}_l\overset{(4.3)}{=}\sum_k A_k\alpha_{lk}F_l(\underline{\mu}_{hsl}+\bar{\mu}_{hsl})=\\&\sum_k A_kF_lr_{hslk}\end{aligned}\tag{4.15}$$

where in (4.15), $r_{hslk}=\alpha_{lk}(\underline{\mu}_{hsl}+\bar{\mu}_{hsl})$ and it can be replaced by the following inequalities: $-\overline{M}(1-\alpha_{lk})\leq r_{hslk}-(\underline{\mu}_{hsl}+\bar{\mu}_{hsl})\leq\overline{M}(1-\alpha_{lk})$, $-\overline{M}\alpha_{l,k}\leq r_{hslk}\leq\overline{M}\alpha_{l,k}$. This results in a MILP model for each strategic Genco.

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 [75], [27]. At the optimal solution $(\hat{p}_g)$ we have $\pi_z(\hat{p}_g)\geq\pi_z(\hat{p}_g^v)$ $v=1,2,..,Card\{V_z\}$. The set $\{\hat{p}_g^1,\hat{p}_g^2,...,\hat{p}_g^{Card\{V_z\}}\}$ is obtained by different combinations of binary variables β_{gk} from equation (4.2). 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 Nash equilibria of the strategic generation investment game. Note that the Nash equilibria of the generation investment game are found using a feasibility problem.

Box 3: The feasibility problem of generation investment game might have more than one Nash equilibrium. In this situation, we assume that the Transco is pessimistic [90]. 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 [91]. The mathematical model of a proactive and pessimistic Transco is set out in (5.13).

$$\underset{\Psi_T}{Minimize} \sum_l \overline{C}_l \hat{f}_l + \sum_g \{\underline{C}_g \hat{p}_g + \sum_{h,s} W_{hs} C_g p_{hsg}\} \tag{4.16a}$$

$$Subject\ to\ \ (4.3) \tag{4.16b}$$

$$\alpha_{lk} \in \{0,1\} \tag{4.16c}$$

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

$$argMaximize_{\Psi_G} \sum_g \{\underline{C}_g \hat{p}_g + \sum_{h,s} W_{hg} C_g p_{hsg}\} \tag{4.16d}$$

$$Subject\ to\ \ (4.2) \tag{4.16e}$$

$$\beta_{gk} \in \{0,1\}, p_{hsg} \in \mathbb{R} \tag{4.16f}$$

$$\eta_{hsn} = (1/W_{hs})[\eta_{hs}^{sys} + \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl})]$$

$$\forall h,s,n \tag{4.16g}$$

$$(4.12e) - (4.12k) \tag{4.16h}$$

$$W_{hs}C_g - \eta_{hs}^{sys} + \bar{\lambda}_{hsg} - \underline{\lambda}_{hsg}$$

$$- \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \ \ g \leftarrow n, \forall h,s,g \in \hat{U} \tag{4.16i}$$

$$W_{hs}C_g - \eta_{hs}^{sys} + \bar{\rho}_{hsg} - \underline{\rho}_{hsg}$$

$$- \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \ \ g \leftarrow n, \forall h,s,g \in \acute{U} \tag{4.16j}$$

$$W_{hs}C_g - \eta_{hs}^{sys} + \bar{\rho}_{hsg} - \underline{\rho}_{hsg} + \acute{W}_s \varpi_{hg}$$

$$- \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0$$

$$g \leftarrow n, \forall h,s,g \in \grave{U} \tag{4.16k}$$

$$\sum_{h,s,g} W_{hs}C_g p_{hsg} + \sum_{h,s,g \in \hat{U}} \{\bar{\lambda}_{hsg} P_g + \sum_k A_k P_g t_{hsgk}\}$$

$$
\begin{aligned}
&= \sum_{h,s,n} \eta^{sys}_{hs} D_{sn} - \sum_{h,s,g\in \acute{U}} \bar{\rho}_{hsg} \acute{P}_{sg} \\
&- \sum_{h,g\in \grave{U}} \{\varpi_{h,g} \overline{E}_{h,g} + \sum_{s} \bar{\rho}_{hsg} \grave{P}_g\} \\
&+ \sum_{h,s,l} \{ \left((\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) \sum_{n} H_{nl} D_{sn} \right) \\
&- (\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) F_l - \sum_{k} A_k F_l r_{hslk} \} && \text{(4.16l)} \\
&\bar{\lambda}_{hsg}, \underline{\lambda}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \varpi_{h,g}, \\
&\underline{\mu}_{hsl}, \bar{\mu}_{hsl} \geq 0 \;\; \forall s,g,l && \text{(4.16m)} \\
&-\overline{M}(1-\beta_{gk}) \leq t_{hsgk} - \bar{\lambda}_{sg} \leq \overline{M}(1-\beta_{gk}) \\
&\forall h,s,g \in \hat{U}, k && \text{(4.16n)} \\
&-\overline{M}\beta_{gk} \leq t_{hsgk} \leq \overline{M}\beta_{gk} \;\; \forall h,s,g \in \hat{U}, k && \text{(4.16o)} \\
&-\overline{M}(1-\alpha_{lk}) \leq r_{hslk} - (\underline{\mu}_{sl} + \bar{\mu}_{sl}) \leq \overline{M}(1-\alpha_{lk}) \\
&\forall h,s,l,k && \text{(4.16p)} \\
&-\overline{M}\alpha_{l,k} \leq r_{hslk} \leq \overline{M}\alpha_{l,k} \;\; \forall h,s,l,k && \text{(4.16q)} \\
&\pi_z = \sum_{g\in G_z} [-\underline{C}_g \hat{p}_g + \sum_{h,s} \{\bar{\lambda}_{hsg} P_g + \sum_{k} A_k P_g t_{hsgk}\}] \\
&\forall z && \text{(4.16r)} \\
&\pi_z \geq \pi^v_z \;\; \forall z, v \in V_z && \text{(4.16s)} \\
&\eta^{sys}_{hs}, \eta_{hsn}, \varpi_{hg}, \bar{\lambda}_{hsg}, \underline{\lambda}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \\
&\underline{\mu}_{hsl}, \bar{\mu}_{hsl}, t_{hsgk}, r_{hslk}, \pi_z, \pi^v_z \in \mathbb{R} && \text{(4.16t)}
\end{aligned}
$$

In optimization problem (5.13), constraints (4.16e)-(4.16t) find the Nash equilibrium(ria) of generation investment game. The MILP (5.13a)-(4.16t) finds the pessimistic Nash equilibrium which has highest social cost. Finally, proactive Transco minimizes transmission investment cost and social cost of pessimistic Nash equilibrium through (4.16a)-(4.16t). The optimization problem (5.13) is a MIBLP with $\Psi_T = \{\alpha_{lk}, \hat{f}_l\}$ and $\Psi_G = \{\beta_{gk}, \hat{p}_g, p_{hsg}, \eta^{sys}_{sh}, \eta_{hsn}, \varpi_{hg}, \bar{\lambda}_{hsg}, \underline{\lambda}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \underline{\mu}_{sl}, \bar{\mu}_{sl}, t_{sgk}, r_{slk}, \pi_z, \pi^v_z\}$. Both upper-level and lower-level optimization problems have binary variables (α_{lk} and β_{gk}). Section 2.3.4 deals with solving the MIBLP with binary variables in both levels.

4.3.2 The Reactive Coordination (MILP Model)

In reactive coordination, strategic Gencos are the leaders and regulated Transco is the follower. Fig. 4.3 illustrates this situation. The optimization problem of each

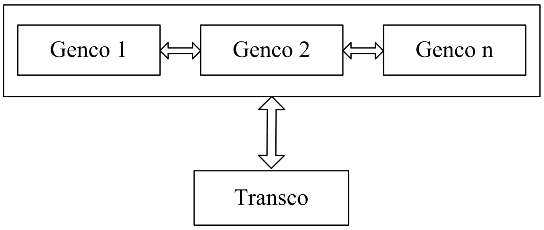

Figure 4.3: The reactive approach for generation-transmission investment game

Genco in Fig. 4.3 is derived in (4.17).

$$\underset{\hat{p}_g, g\in G_z}{Maximize} \sum_{\substack{g\in G_z \\ g\leftarrow n}} \{-\underline{C}_g \hat{p}_g + \sum_{h,s} W_{hs}(\eta_{hsn} - C_g) p_{hsg}\} \quad (4.17a)$$

$$Subject\ to\ \ (4.2) \quad (4.17b)$$

$$\beta_{gk} \in \{0,1\} \quad (4.17c)$$

$$\underset{\hat{f}_l, p_{hsg}}{Minimize} \sum_{l} \overline{C}_l \hat{f}_l + \sum_{h,s,g} W_{hs} C_g p_{hsg} \quad (4.17d)$$

$$Subject\ to\ \ \hat{f}_l \geq 0\ :(\gamma_l)\ \forall l \quad (4.17e)$$

$$(4.12e) - (4.12k) \quad (4.17f)$$

$$\hat{f}_l, p_{hsg} \in \mathbb{R} \quad (4.17g)$$

To preserve the convexity of the minimization problem (4.17d)-(4.17g), in the reactive formulation, we assume $\hat{f}_l$ is a continues variable [92]. This assumption allows us to replace the lower level with primal feasibility, dual feasibility and strong duality conditions. Similar to Box 1 in Fig. 4.2, the bilevel program (4.17) 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 (4.18).

$$\underset{\Psi_R}{Maximize} \sum_l \overline{C}_l \hat{f}_l + \sum_g \{\underline{C}_g \hat{p}_g + \sum_{h,s} W_{hs} C_g p_{hsg}\} \tag{4.18a}$$

$$Subject\ to \ \ \hat{f}_l \geq 0 \ \forall l \tag{4.18b}$$

$$\beta_{gk} \in \{0,1\}, \hat{f}_l, p_{hsg} \in \mathbb{R} \tag{4.18c}$$

$$\eta_{hsn} = (1/W_{hs})[\eta_{hs}^{sys} + \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl})]$$

$$\forall h,s,n \tag{4.18d}$$

$$(4.12e) - (4.12k), (4.2) \tag{4.18e}$$

$$W_{hs}C_g - \eta_{hs}^{sys} + \bar{\lambda}_{hsg} - \underline{\lambda}_{hsg}$$

$$- \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \ \ g \leftarrow n, \forall h,s,g \in \hat{U} \tag{4.18f}$$

$$W_{hs}C_g - \eta_{hs}^{sys} + \bar{\rho}_{hsg} - \underline{\rho}_{hsg}$$

$$- \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \ \ g \leftarrow n, \forall h,s,g \in \acute{U} \tag{4.18g}$$

$$W_{hs}C_g - \eta_{hs}^{sys} + \bar{\rho}_{hsg} - \underline{\rho}_{hsg} + \acute{W}_s \varpi_{hg}$$

$$- \sum_l H_{nl}(\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) = 0 \ \ g \leftarrow n, \forall h,s,g \in \grave{U} \tag{4.18h}$$

$$\overline{C}_l - \gamma_l - \sum_{h,s}(\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) = 0 \ \ \forall l \tag{4.18i}$$

$$\sum_l \overline{C}_l \hat{f}_l + \sum_{h,s,g} W_{hs} C_g p_{hsg}$$

$$+ \sum_{h,s,g \in \hat{U}} \{\bar{\lambda}_{hsg} P_g + \sum_k A_k P_g t_{hsgk}\}$$

$$= \sum_{h,s,n} \eta_{hs}^{sys} D_{sn} - \sum_{h,s,g \in \acute{U}} \bar{\rho}_{hsg} \acute{P}_{sg}$$

$$- \sum_{h,g \in \grave{U}} \{\varpi_{h,g} \overline{E}_{h,g} + \sum_s \bar{\rho}_{hsg} \grave{P}_g\}$$

$$+ \sum_{h,s,l} \{ \left((\underline{\mu}_{hsl} - \bar{\mu}_{hsl}) \sum_n H_{nl} D_{sn} \right)$$

$$- (\underline{\mu}_{hsl} + \bar{\mu}_{hsl}) F_l\} \tag{4.18j}$$

$$\bar{\lambda}_{hsg}, \underline{\lambda}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg},$$

$$\underline{\mu}_{hsl}, \bar{\mu}_{hsl}, \gamma_l \geq 0 \;\; \forall s, g, l \tag{4.18k}$$

$$-\overline{M}(1-\beta_{gk}) \leq t_{hsgk} - \bar{\lambda}_{sg} \leq \overline{M}(1-\beta_{gk})$$
$$\forall h, s, g \in \hat{U}, k \tag{4.18l}$$

$$-\overline{M}\beta_{gk} \leq t_{hsgk} \leq \overline{M}\beta_{gk} \;\; \forall h, s, g \in \hat{U}, k \tag{4.18m}$$

$$\pi_z = \sum_{g \in G_z} [-\underline{C}_g \hat{p}_g + \sum_{h,s} \{P_g \bar{\lambda}_{hsg} + \sum_k A_k P_g t_{hsgk}\}]$$
$$\forall z \tag{4.18n}$$

$$\pi_z \geq \pi_z^v \;\; \forall z, v \in V_z \tag{4.18o}$$

$$\eta_{hs}^{sys}, \eta_{hsn}, \varpi_{hg}, \bar{\lambda}_{hsg}, \underline{\lambda}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \varpi_{hg},$$
$$\underline{\mu}_{hsl}, \bar{\mu}_{hsl}, \gamma_l, t_{hsgk},$$
$$\pi_z, \pi_z^v \in \mathbb{R} \tag{4.18p}$$

Where $\Psi_R = \{\beta_{gk}, \hat{p}_g, \hat{f}_l, p_{hsg}, \eta_{hs}^{sys}, \eta_{hsn}, \varpi_{hg}, \bar{\lambda}_{hsg}, \underline{\lambda}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \bar{\rho}_{hsg}, \underline{\rho}_{hsg}, \underline{\mu}_{hsl}, \bar{\mu}_{hsl}, \gamma_l, t_{hsgk}, \pi_z, \pi_z^v\}$ is the set of decision variables considered. In optimization problem (4.18), constraints (4.18b)-(4.18p) finds the Nash equilibrium(ria) of generation-transmission investment game and objective function (4.18a) selects the pessimistic Nash equilibrium. The optimization problem (4.18) is a MILP which can be solved to global optimality.

4.4 Power Transfer Distribution Matrix

In this chapter, we consider transmission capacity upgrade [8], [2], [93], [94]. This helps us to focus better on coordination issue rather than making our mathematical models more complicated. Therefore, we used matrix H, power transfer distribution matrix, to model a linear relation between the power flows in the lines and the nodal power balances. However, elements of matrix H depend nonlinearly on line reactances, [19]. This means when line capacities change and consequently, the reactance of the lines changes, matrix H will change too and a new one should be calculated [95]. Thus, the problems formulated in Sections 4.2 and 4.3 have to be solved iteratively with the updated H until the stopping criteria is met. Stopping criteria can be the difference in the social cost of the system or the difference in the added capacities of the lines. We have considered the change in the added capacity of the lines as the stopping criteria, i.e., when the added capacities found in two consecutive iterations are less than the assumed tolerance for all of the lines, the convergence has been reached and the solution is a KKT point, [96].

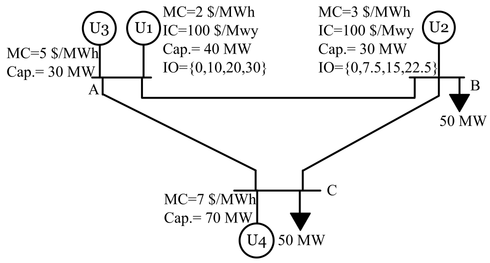

Figure 4.4: The 3-bus example system; MC: Marginal Cost, IC: Investment Cost, Cap.: Capacity, IO: Investment Options (in MW).

For updating matrix H when line capacities change, the law of parallel circuits is used, [93], [95], as follows:

$$X_l^* = \frac{F_l}{F_l + \hat{f}_l} X_l \tag{4.19}$$

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

In order to avoid large changes in the result between two consecutive iterations, thus invalidating the linear approximation, the added capacity for each line considered for updating matrix H is limited to half of the existing capacity of the related line. This limit can be reduced if convergence is not achieved, [97].

4.5 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.

4.5.1 The 3-bus Example System

The 3-bus example system is shown in Fig. 4.4. Table 4.1 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 2.3.4. The branch-and-bound tree of the MBA is presented in Fig. 4.5. This figure shows the process of searching the tree using the heuristic technique A.

Table 4.1: 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	20	200	0-10-20-30
3	B-C	0.02	15	200	0-7.5-15-22.5

The result of the proactive coordination with and without heuristic technique is the same. However, heuristic technique A (as shown in Fig. 4.5) 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.

The results for the status-quo system and the different cases of efficient coordination, reactive coordination and proactive coordination are presented in Table 4.2. For the rest of this chapter, 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 4.2. As reported, the RC has four Nash equilibria while the PC has just one Nash equilibrium. Please note that in this chapter, 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. 4.6. 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.

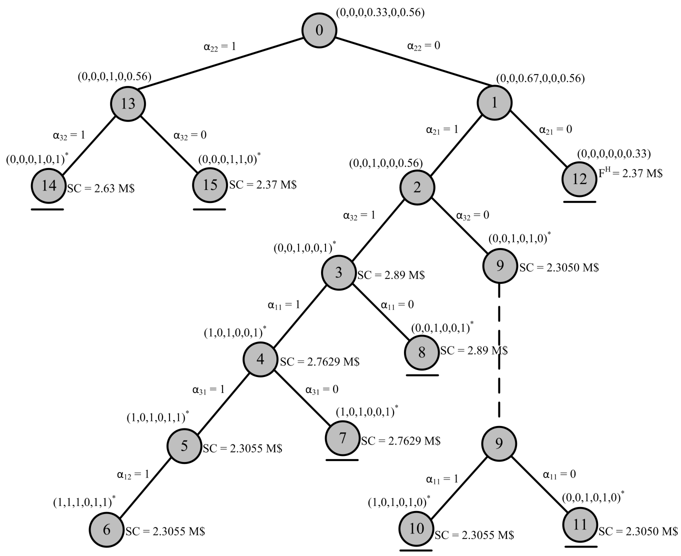

Figure 4.5: The branch-and-bound tree of the MBA for the 3-bus example system; (x,x,x,x,x,x)=(α_{11},α_{12},α_{21},α_{22},α_{31},α_{32}),$\alpha \in \{0,1\}$, SC: Social Cost.

Table 4.2: 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	CB
	U1	U2	*AB*	*AC*	*BC*	(M$)	(M$)
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**

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

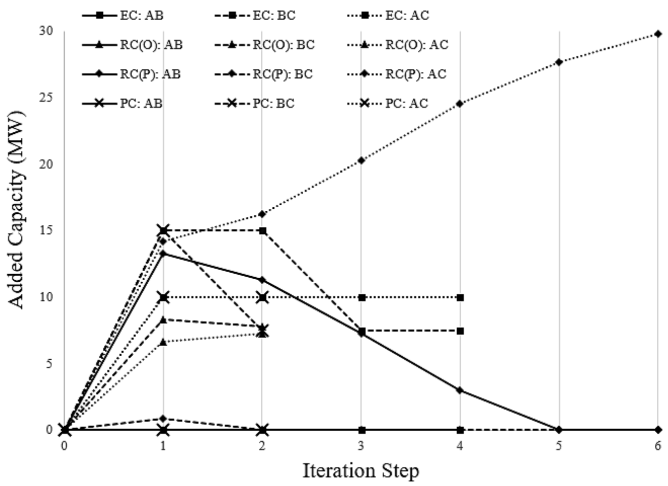

Figure 4.6: Development of added capacity to the lines during the iterations for the 3-bus example system.

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 4.2. 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 4.3. The RC has three Nash equilibria while the PC has only one Nash equilibirum. The changes in added capacity to the lines in each iteration of updating matrix H is presented in Fig. 4.7.

Table 4.3: 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	CB
	U1	U2	*AB*	*AC*	*BC*	(M$)	(M$)
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**

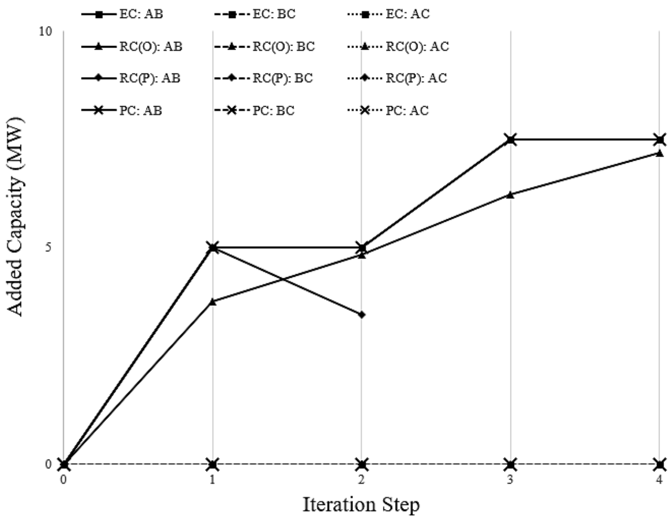

Figure 4.7: Development of added capacity to the lines during the iterations for the 3-bus example system with reduced generating capacity.

As seen from Table 4.3, in this round of simulation, the PC has less CB than the RC (opposite to the case in Table 4.2). 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 4.2, 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 4.3, 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.

4.6 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.

4.6.1 The Modified IEEE-RTS96

The IEEE-RTS96 has been modified for our study. The existing transmission capacities in [64] are reduced by a factor of 0.5. The $\overline{C}_l$ is proportional to the reactance of line l. The $\overline{C}_l$ 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 4.4. The generation expansion cost is 100 \$/MWy

Table 4.4: 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

for all Gencos. Weekly load levels in [64] 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 Table 3.2 of Section 3.3. 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 4.5: 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	GIC	TETC	TIC
	U1	U2	U3	(MW)	(M$)	(MW)	(M$)
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 4.5 and 4.6. As seen, the EC has a 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

Table 4.6: The Social Cost and Coordination Benefit of Different Coordination Approaches for the Modified IEEE-RTS96

	Profit (M$)			No. of	SC	CB
	U1	U2	U3	iterations	(M$)	(M$)
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**

Table 4.7: 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.

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 4.2. 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 4.7. 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.

4.6.2 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 [98] is multiplied by 0.5. The $\overline{C}_l$ is proportional to the reactance of line l. The $\overline{C}_l$ 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. The data for Gencos is presented in Table 4.8. 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

Table 4.8: 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

to bus 111 are considered as wind farms with the characteristics specified for the wind farm in Table 3.2 of Section 3.3. 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 4.9 and 4.10.

Table 4.9: The Generation-Transmission Planning for the Modified IEEE 118-bus Test System. (T)EGC: (Total) Expanded Generation Capacity, (T)ETC: (Total) Expanded Transmission Capacity, TIC: Transmission Investment Cost, GIC: Generation Investment Cost

	EGC (MW)			TEGC	GIC	TETC	TIC
	U1	U2	U3	(MW)	(M$)	(MW)	(M$)
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.

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 4.11. As seen, the P-MBA with 2, 4 and 8 cores cannot find any solution to the proactive model

Table 4.10: 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.

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 4.11: 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.

Chapter 5

Transmission Cost Allocation through Regulatory Charges

In this chapter, the main findings of $\mapsto$ [P7] are presented. The paper investigates the way by which a transmission charge can be used a signal to drive the coordination of generation and transmission expansion. The framework is built upon the idea that when agents make their decisions on generation expansion, they should consider the reaction of transmission expansion upon their decision by other agents.

5.1 Introduction

The expansion and operation of generation is in the hands of market agents (generation companies) in those systems where the electricity sector has been deregulated. Hence, due to the fact that both activities are in different hands (those of the transmission system operator and generation companies, respectively), achieving their efficient functioning requires that coordinating signals are sent to generators (and market agents in general) so that they take into account the existence of the network in the operation and investment decisions they make. Marginal electricity pricing theory provides a satisfactory solution to the coordination of generation and transmission operation in the form of Locational Marginal Prices (LMPs), or nodal prices, see [99]. Thus, LMPs, and other coordinating signals based on them, like wheeling transmission charges, have been employed to achieve an efficient coordination of generation and transmission operation under imperfect competition both in the short term, or operation time frame, see [72] and [100], and when computing the development of generation and transmission, see [75] and [101]. However, achieving an efficient coordination of the generation and transmission expansion requires that generation companies take into account, not only the impact that their operation and investment decisions shall have on the short term (operation) value of the transmission capacity, but also the overall impact that these decisions shall have on network investment costs. Note that efficient short term operation signals (LMPs or wheeling charges) are only able to recover a small fraction of the investment cost of a real transmission grid that is optimally adapted, as authors in [102] show. Consequently, additional transmission charges, sometimes called complementary charges, are needed to make generators internalize in their investment decisions the full transmission network development cost they cause.

Among the many methods to allocate network costs to users when computing network charges, Postage Stamp type methods apply the same charge per MW of generation capacity installed, or MWh of energy injected, regardless of the loading on the transmission system, the profile of each agent, or its location, [103]. Therefore, these methods do not make a distinction among transmission users based on their responsibility in the development of transmission system, [103]. There is a wide variety of Usage-based charging methods, [104, 105], resulting in widely different charges. They aim to allocate the fraction of the cost of each line not recovered from the application of energy prices according to the usage that agents make of this line. But the usage made of a line by each agent cannot be indisputably computed. Besides, network usage is nothing but a proxy to the benefits that agents obtain from network investments, which are the real driver behind these investments, see [106].

Allocation methods based on the responsibility of network users on grid investments can be deemed to result in efficient signals if appropriately implemented. Within this family of methods, we have considered in our analysis nodal charges (varying across network nodes), called regulatory transmission charges (RTCs), that are proportional to the marginal impact of a change in the generation capacity installed in each node on network development costs, or the marginal impact of generation capacity on the cost of transmission services. This type of methods have been largely discussed in [102, 107–110], and resemble in its conception philosophy the Investment Cost Related Pricing methodology applied in the UK, see [111].

This chapter is structured as follows. First, the problem representing the efficient planning of the system is formulated in Section 5.2.1, then, the strategic planning of the development of generation portfolios by SGPs is presented in Section 5.2.2, while the method applied to compute RTCs is addressed in Section 5.2.3 together with the algorithm implemented to compute the equilibrium investment strategies by SGPs and the network planner. Simulation results from the application of the considered RTCs in a 2-node illustrative example and the IEEE-RTS96 are discussed in Section 5.3. We conclude in Section **??**.

5.2 The Methodology

5.2.1 Efficient Planning of Generation and Transmission

At the beginning of this section, the formulation for efficient planning of generation and transmission is presented. This model is used as a benchmark to assess the efficiency of the results computed in a decentralized market context both when considering transmission charges paid by generators and when not considering them. Efficient planning means that one entity decides about the planning scheme of the system. This corresponds to the planning problem solved in vertically integrated power systems. The objective function of this model is to minimize the system social cost (this comprises both generation and network investment costs and operation ones).

$$\underset{\hat{p}_g, p_{gs}, \hat{f}_\ell \geq 0, \ell \in L_c}{\text{Minimize}} \quad sc = \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell + \sum_g \{\hat{p}_g EG_g + \sum_s W_s C_g p_{gs}\}. \tag{5.1a}$$

subject to:

$$\sum_n D_{ns} = \sum_g p_{gs}; \;\; \forall s. \tag{5.1b}$$

$$0 \leq p_{gs} \leq P_g + \hat{p}_g; \;\; \forall g, s. \tag{5.1c}$$

$$-(F_\ell + \hat{f}_\ell) \leq \sum_n H_{n\ell}(p_{\substack{gs \\ g \leftarrow n}} - D_{ns}) \leq (F_\ell + \hat{f}_\ell); \quad \forall l, s. \tag{5.1d}$$

As seen in this formulation, the operating constraints are the balance constraint between demand and supply (5.1b), capacity constraints of the generators (5.1c), and those of transmission lines (5.1d), all of which are written based on a DC power flow ($g \leftarrow n$ refers to the connection of unit g to node n). At each node, the lost load is modelled as a fictitious generator with its marginal cost equal to the value of lost load at that node. We assume that an increase in the capacity of a line does not change the topology of the network. This formulation is compatible with the idea proposed in this chapter for calculating RTCs, based on the marginal effect of increases in the generation capacity in each node on the cost of transmission reinforcements required. This is discussed in Section 5.2.3. This assumption is acceptable for meshed networks in analyses covering a relatively short-term horizon, where topological changes to the grid and additions to the capacity of existing lines are expected to be small.

The resulted model is linear optimization problem which can be solved by available commercial softwares.

5.2.2 SGPs Problem

Optimization Problem of One SGP

Each SGP maximizes its profit by deciding on its investment actions, $\hat{p}$, assuming that other SGPs' investment actions are given. As seen in (5.2a), the objective function of SGP includes the profits from selling power in the market (the first term) minus the investment cost, which includes RTCs paid by SGP (the second term). The interaction between SGP and the joint market is modelled as a leader-follower game, [112]. The leader is SGP and the follower is the joint market. This is a bilevel optimization problem as represented below:

$$\underset{\hat{p}_g \geq 0}{\text{Maximize}} \quad \sum_{g \in G_z} \{ \sum_{s,g \leftarrow n} W_s(\eta_{ns} - C_g) p_{gs} - \hat{p}_g(EG_g + RTC_g)\}. \tag{5.2a}$$

subject to

$$\underset{p_{gs} \geq 0}{\text{Minimize}} \quad \sum_{g,s} W_s C_g p_{gs}. \tag{5.2b}$$

$$\text{subject to} \quad (5.1b), (5.1c), (5.1d). \tag{5.2c}$$

where η_{ns} is the price of electricity at bus n in load level s, which is calculated through the Lagrange multipliers of the lower level problem as follows:

$$\eta_{ns} = (1/W_s)[\theta_s - \sum_{\ell} H_{n\ell}(\underline{\mu}_{\ell s} - \bar{\mu}_{\ell s})]; \;\; \forall n, s. \tag{5.3}$$

The price in expression (5.3) is calculated by partially differentiating the Lagrangian of the lower-level problem of the SGP with respect to demand, D_{ns}. It models the marginal impact of an increment of the demand at node n, load level s on the operation cost. Since the operation cost includes W_s as the duration of the related snapshot (operating situation), the whole term is divided by W_s.

We convert the lower level optimization problem to a mixed-integer linear programming problem using the Karush-Kuhn-Tucker approach, [113], and the strong duality, [114]. The dual problem of (5.2b)-(5.2c) is as follows:

$$\begin{aligned}
&\underset{\underline{\lambda}_{gs},\bar{\lambda}_{gs},\underline{\mu}_{\ell s},\bar{\mu}_{\ell s}\geq 0,\theta_s}{\text{Maximize}} \quad \sum_{n,s}\theta_s D_{ns} + \sum_{g,s}\bar{\lambda}_{gs}(P_g+\hat{p}_g)\\
&+\sum_{\ell,s}\{(\underline{\mu}_{\ell s}-\bar{\mu}_{\ell s})\sum_n H_{n\ell}D_{ns} - (\underline{\mu}_{\ell s}+\bar{\mu}_{\ell s})(F_\ell+\hat{f}_\ell)\}. \qquad (5.4a)\\
&\text{subject to:}\\
&W_sC_g - \theta_s + \bar{\lambda}_{gs} - \underline{\lambda}_{gs} - \sum_\ell H_{n\ell}(\underline{\mu}_{\ell s}-\bar{\mu}_{\ell s}) = 0;\\
&\quad g\leftarrow n, \forall g,s. \qquad (5.4b)
\end{aligned}$$

Since the problem in (5.2b)-(5.2c) is convex, strong duality holds and primal objective function at the optimal point is equal to the dual objective function:

$$\begin{aligned}
&\sum_{g,s}\{W_sC_gp_{gs} - \bar{\lambda}_{gs}(P_g+\hat{p}_g)\} = \sum_{n,s}\theta_s D_{ns}\\
&+\sum_{\ell,s}\{(\underline{\mu}_{\ell s}-\bar{\mu}_{\ell s})\sum_n H_{n\ell}D_{ns} - (\underline{\mu}_{\ell s}+\bar{\mu}_{\ell s})(F_\ell+\hat{f}_\ell)\}. \qquad (5.5)
\end{aligned}$$

Satisfying the strong duality condition (5.5) at the same time with the primal feasibility constraints (5.1b),(5.1c),(5.1d), and the dual constraint (5.4b), the optimal solution to both the primal and the dual problems is found. In this way, we can insert the short-term dispatch problem as equilibrium constraints to the SGP problem as follows.

$$\begin{aligned}
&\underset{\hat{p}_g\geq 0}{\text{Maximize}} \quad \sum_{g\in G_z}\{\sum_{s,g\leftarrow n} W_s(\eta_{ns}-C_g)p_{gs}\\
&\qquad\qquad - \hat{p}_g(EG_g+RTC_g)\}. \qquad (5.6a)\\
&\text{subject to } (5.1b),(5.1c),(5.1d) \qquad (5.6b)\\
&W_sC_g - \theta_s + \bar{\lambda}_{gs} - \underline{\lambda}_{gs} - \sum_\ell H_{n\ell}(\underline{\mu}_{\ell s}-\bar{\mu}_{\ell s}) = 0;\\
&g\leftarrow n, \forall g,s. \qquad (5.6c)\\
&\sum_{g,s}\{W_sC_gp_{gs} - \bar{\lambda}_{gs}(P_g+\hat{p}_g)\} = \sum_{n,s}\theta_s D_{ns}\\
&+\sum_{\ell,s}\{(\underline{\mu}_{\ell s}-\bar{\mu}_{\ell s})\sum_n H_{n\ell}D_{ns} - (\underline{\mu}_{\ell s}+\bar{\mu}_{\ell s})(F_\ell+\hat{f}_\ell)\}. \qquad (5.6d)\\
&\bar{\lambda}_{gs},\underline{\lambda}_{gs},\underline{\mu}_{\ell s},\bar{\mu}_{\ell s}\geq 0;\ \forall g,\ell,s. \qquad (5.6e)
\end{aligned}$$

Non-linearity in (5.6a) can be linearized by using stationary condition (5.6c) and the expression for price in (5.3),

$$W_s(\eta_{ns} - C_g)p_{gs} = (\bar{\lambda}_{gs} + \underline{\lambda}_{gs})p_{gs}. \tag{5.7}$$

and the fact that $\underline{\lambda}_{gs}$ is non-zero when the production is zero and $\bar{\lambda}_{gs}$ is non-zero when the production is equal to the maximum limit. Therefore,

$$W_s(\eta_{ns} - C_g)p_{gs} = \bar{\lambda}_{gs}(P_g + \hat{p}_g). \tag{5.8}$$

Right hand side of (5.8) is also seen in the strong duality condition equation, (5.6d).

The added capacity of generating units, $\hat{p}$, is in the discrete steps, although, it is clearly not continuous and cannot be discretized in very small steps. Therefore, $\hat{p}$ can be discretized using binary expansion $\hat{p}_g = \sum_{k\in K} a_k x_{gk} P_g$, where $a_k = \frac{1}{2^{Card(K)-k}}$ and $x_{gk} \in \{0,1\}$. Thus, the right-hand side of (5.8) is linearized using the disjunctive approach [115] and introducing a new variable t_{gks} as follows:

$$-M(1-x_{gk}) \le t_{gks} - \bar{\lambda}_{gs}P_g \le M(1-x_{gk}). \tag{5.9}$$

$$-Mx_{gk} \le t_{gks} \le Mx_{gk}. \tag{5.10}$$

This results to

$$\bar{\lambda}_{gs}(P_g + \hat{p}_g) = \bar{\lambda}_{gs}P_g + \sum_k t_{gks}a_k. \tag{5.11}$$

Therefore, the problem of each SGP can be written as a mathematical problem with equilibrium constraints (MPEC) as follows:

$$\begin{aligned}
&\underset{\hat{p}_g \ge 0}{\text{Minimize}}\;\; \pi_z = \sum_{g\in G_z}\{\sum_s\{\bar{\lambda}_{gs}P_g + \sum_k t_{gks}a_k\} \\
&\quad - \hat{p}_g(EG_g + RTC_g)\} && (5.12\text{a})\\
&\text{subject to}\;\; (5.1b),(5.1c),(5.1d) && (5.12\text{b})\\
&W_sC_g - \theta_s + \bar{\lambda}_{gs} - \underline{\lambda}_{gs} - \sum_\ell H_{n\ell}(\underline{\mu}_{\ell s} - \bar{\mu}_{\ell s}) = 0;\\
&g \leftarrow n, \forall g,s. && (5.12\text{c})\\
&\sum_{g,s}\{W_sC_gp_{gs} - \bar{\lambda}_{gs}P_g + \sum_k t_{gks}a_k\} = \sum_{n,s}\theta_s D_{ns}
\end{aligned}$$

$$+\sum_{\ell,s}\{(\underline{\mu}_{\ell s}-\bar{\mu}_{\ell s})\sum_{n}H_{n\ell}D_{ns}-(\underline{\mu}_{\ell s}+\bar{\mu}_{\ell s})(F_\ell+\hat{f}_\ell)\}. \quad (5.12d)$$

$$\bar{\lambda}_{gs},\underline{\lambda}_{gs},\underline{\mu}_{\ell s},\bar{\mu}_{\ell s}\geq 0;\ \ \forall g,\ell,s. \quad (5.12e)$$

$$\hat{p}_g=\sum_{k\in K}a_k x_{gk}P_g;\ \ \forall g. \quad (5.12f)$$

$$-M(1-x_{gk})\leq t_{gks}-\bar{\lambda}_{sg}P_g\leq M(1-x_{gk});\ \ \forall g,k,s. \quad (5.12g)$$

$$-Mx_{gk}\leq t_{gks}\leq Mx_{gk};\ \ \forall g,k,s. \quad (5.12h)$$

Interaction of SGPs

The Extremal-Nash Equilibrium (ENE) concept is employed for formulation the interaction of SGPs as a two-level optimization problem as follows:

$$\underset{\hat{p}_g\geq 0}{\text{Minimize}}\ \ sc=\sum_{g}\{\hat{p}_g EG_g+\sum_{s}W_s C_g p_{gs}\}. \quad (5.13a)$$

$$\text{subject to}\ \ (5.12b)-(5.12h) \quad (5.13b)$$

$$\pi_z=\sum_{g\in G_z}\{\sum_{s,g\leftarrow n}\{\bar{\lambda}_{gs}P_g+\sum_{k}t_{gks}a_k\}$$
$$-\hat{p}_g(EG_g+RTC_g)\};\ \ \forall z. \quad (5.13c)$$

$$\pi_z\geq\pi_z^v;\ \ \forall z,v\in V_z. \quad (5.13d)$$

Constraint (5.13d) is the Nash equilibrium constraint. Satisfying (5.13b)-(5.13d) gives all the Nash equilibria of the problem and the objective function of the problem (5.13a) makes sure that the Nash equilibrium with the lowest social cost (this includes generation investment and operation cost) will be selected. The optimization problem (5.13a)-(5.13d) is a mixed-integer linear program (MILP) which can be solved by available commercial softwares.

5.2.3 RTCs

Formulating RTCs

There are various ways to calculate RTCs. The goal of all these approaches is to allocate all or part of the transmission investment costs to the different users of the transmission system, [116]. In this chapter, these charges are calculated in a way that a) they are proportional to the marginal impact of generation investment $\hat{p}_g$ on transmission investment costs for a network that is optimally adapted to generation and load in the system and b) they recover the fraction α of transmission investment costs. Note that fraction α of the transmission investment cost is recovered through RTCs applied on new generation installed. RTCs provide locational signals to new generations in order to influence their decision to minimize the system social cost of the system. It is assumed that the rest of the transmission investment cost is recovered in other ways (e.g., from congestion rents, connection charges applied on demand, etc.) Therefore:

$$RTC_g = \beta \frac{\partial \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell}{\partial \hat{p}_g}. \tag{5.14}$$

$$\sum_g \hat{p}_g RTC_g = \alpha \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell. \tag{5.15}$$

Conditions a) and b) are reflected in (5.14) and (5.15), respectively. Note that, we have mainly studied the possibility of influencing strategic decision of SGPs through RTCs in order to drive a more efficient development of the system, rather than aiming to complete the recovery of the cost of transmission expansion through RTCs. In this respect, we have reported the results of using different αs in Section 5.3. α defines the portion of the transmission development cost recovered through RTCs applied on SGPs. It is assumed that the rest of the transmission expansion cost is recovered by fixed charges applied on the load and congestion rents, etc. Consequently, in order to be coherent with this assumption, parameter α should never be larger than one minus the fraction of the cost of network investments recovered from LMPs, which in real life systems normally is below 20%, see [102].

To calculate $\frac{\partial \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell}{\partial \hat{p}_g}$, one MW of generation capacity is added to the related generation unit and the transmission planning problem formulated below is solved.

$$\underset{\hat{f}_\ell \geq 0, \ell \in L_c}{\text{Minimize}} \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell + \sum_{g,s} W_s C_g p_{gs}. \tag{5.16a}$$

$$\text{subject to } (5.1b), (5.1c), (5.1d) \tag{5.16b}$$

Note that $\hat{p}_g$ is the result of SGPs' problem formulated in (5.13) and is given in (5.16). The problem above forms a linear problem which can be solved by available commercial softwares.

New transmission capacity built as resulting from (5.16) is marked $\hat{f}_l^*$. The partial derivative $\frac{\partial \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell}{\partial \hat{p}_g}$ is approximated by the difference in transmission investment costs of expansion schemes $\hat{f}^*_\ell$ and $\hat{f}_\ell$.

$$\frac{\partial \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell}{\partial \hat{p}_g} \approx \sum_{\ell \in L_c} \hat{f}^*_\ell EL_\ell - \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell. \tag{5.17}$$

Having the value for partial derivatives, β can be calculated by imposing the equality in (5.15). Equation (5.15) makes sure that the fraction α of the transmission investment costs is recovered through RTCs calculated per MW and multiplied by SGPs added capacities.

Coordination of Generation and Transmission Expansion Planning Using RTCs

In order to compute the equilibrium between SGPs, when subject to cost reflective RTCs, and the central planner's network investment decisions, the following iterative algorithm is proposed. Note that $\hat{P}_{g-final}$ is the final expanded capacity of generating units.

Step 0: RTCs are initialized (to zero) and all SGPs' new investment decisions are initialized to a value that cannot be adopted by investment decisions (e.g., sufficiently large number M)$\hat{P}_{g-final} = M$, that at least two iterations of the algorithm are run and coherence between RTCs computed (not the original value provided to them) and generation and transmission investments are ensured when convergence is achieved.

Step 1: SGPs' generation investment problems are solved considering last RTCs computed while ignoring the network capacity limits. Network capacity limits are ignored because the available capacity of network lines, as resulting from the network expansion plan that is consistent with generation investment decisions being computed in this step, has not been determined yet. This step aims to compute the generation investment decisions made by generation companies when only influenced by RTC signals (given that transmission lines may be reinforced in later steps of the algorithm).

Step 2: The central planner network investment problem is solved assuming generation investments computed in Step 1 as given. This aims to compute the network expansion plan best adapted to generation investments computed in Step 1. This network expansion plan shall, in turn, condition SGPs' investment decisions by setting network capacity limits considered by SGPs in the investment decisions (next Steps).

Step 3: Generation and Transmission investment decisions by SGPs and the network planner are refined taking this time into account a sensible estimate of the required capacity of network elements. This is undertaken in Steps 3 and 4 as follows (Finely tuned investments in generation and transmission capacity are employed to update RTCs in Step 5, if needed). In Step 3, SGPs investment decision problems are solved again, this time taking into account the network capacity limits computed in Step 2 together with RTCs. If the investment decisions by SGPs, $\hat{p}_{g-step3}$, do not change with respect to those computed in Step 3 in the previous iteration (i.e., if $\hat{p}_{g-step3} == \hat{P}_{g-final}$), convergence has been achieved and the algorithm ends. Otherwise, $\hat{P}_{g-final}$ is set to $\hat{p}_{g-step3}$, ($\hat{P}_{g-final} = \hat{p}_{g-step3}$).

Step 4: The central planner network investment problem, is solved considering generation investments computed in Step 3 ($\hat{P}_{g-final}$ or $\hat{p}_{g-step3}$, which are the same).

Step 5: RTCs are updated according to the network investments obtained in Step 4. Return to Step 1.

5.3 Case Study

To assess the developed approach on RTCs and coordination of generation and transmission investments, two case studies are analyzed in this section. First, a 2-node illustrative example representing two areas is studied. Second, the IEEE-RTS96, [64], is simulated and the computational performance of the proposed algorithm is tested. The CPLEX solver in GAMS is used to solve the optimization problems.

5.3.1 2-node Illustrative Example

The single-line diagram of the 2-node illustrative example is depicted in Fig. 5.1. Each node represents an area the generators of which are planned by a SGP, SGP1 and SGP2 for the nodes A and B, respectively. The weekly load profile in [64] with the peak load represented in Fig. 5.1 is considered for computing the operating cost of the system. A higher body decides about the expansion of the line between the two nodes, i.e., areas. As seen in the figure, there is a large load in node A and the unit in node B has lower (variable) production costs than the one in node A. Therefore, there is a great need for investment both on the generation and transmission sides.

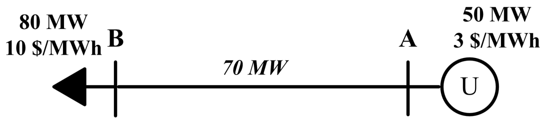

Figure 5.1: Single-line diagram of the 2-node illustrative example; OC: Operation Cost, Cap.: Capacity., IC: Investment Cost, IO: Investment Options (in MW applied only in decentralized planning)

The initial values considered for RTCs are zero. For the value of α (fraction of the transmission investment cost recovered through RTCs applied on new generations) equal to 0.4, the proposed algorithm achieves convergence, i.e., reaches a stable result after three iterations meaning the result in iteration #3 is the same as the one in iteration #2. The resulting generation and transmission investments in iteration #1 and iteration #2, as well as the system social cost, are compared with the result of the centralized (efficient) expansion planning in Table 5.1. The corresponding RTCs are reported in Table 5.2. In iteration #1, generation capacity is built in both nodes. However, the calculated RTC is zero for node A and is very high for node B (28261 $/MW) compared to its generation investment cost. Note that one MW increase of the generation investment in node B results in about one MW investment in the connection line while one MW investment in generating unit of node A does not affect the transmission investment. This would result in 59.66 M$ and 40.75 M$ profits for SGP1 and SGP2, respectively. However, as seen in the result of iteration #2, based on charges in iteration #1, SGP2 decreases its investment while SGP1 increases its investment. This result is consistent with the new RTCs computed in iteration #2, so SGPs do not change their actions and their final profits are 69.59 M$ and 40.63 M$ for SGP1 and SGP2, respectively. The energy not served (ENS) is the same for both iterations (17125 MWh), however, the final system social cost is 76.1 M$, which is 3.6% lower than the system social cost in iteration #1. This shows the effectiveness of the calculated RTCs to improve the efficiency of the system development and to make it closer to the efficient result of centralized expansion. Finally, U1 does not pay anything and U2 pays 0.24 M$ of the transmission investment costs.

Applying RTCs equal to zero, as corresponding to the first iteration of the proposed algorithm for the computation of RTCs, results in investments decided by the generation company located in the exporting node being well above the optimal level and, consequently, also investments in transmission capacity connecting both nodes being above the level that would result from the centralized joint expansion planning. When, in the second iteration of the algorithm, RTCs applied make the generation company U2 pay 40% of the cost of the transmission capacity required

Table 5.1: Generation and Transmission Expanded Capacities and the System Social Cost for Different Iterations ($\alpha = 0.4$) and the Centralized Planning of the 2-node Illustrative Example; EC: Expanded Capacity, SC: System Social Cost

Runs	Units EC (MW)		Lines EC (MW)	SC (M$)
	U1	U2	A-B	
Iteration #1	50	75	53	78.91
Iteration #2	100	25	3	76.1
Centralized Planning	150	30	0	74.64

Table 5.2: RTCs for the Different Iterations ($\alpha = 0.4$) of the 2-node Illustrative Example

Iteration #	Units RTCs ($/MW)	
	U1	U2
1	0	28261
2	0	4784

to export its power production to node A, U2 finds it profitable to decrease substantially its investments in generation capacity with respect to the first iteration, while investments by U1 (those in the importing node) increase substantially. Consequently, investments in transmission capacity decrease substantially as well. In this case, strategic generation investments by U1 and U2 and transmission capacity investments are closer to those resulting from the centralized expansion planning, i.e., the optimal ones. This results in a significant reduction in total system costs (about 2.81 M$) with respect to the first iteration of the algorithm (first row in Table 5.1), where RTCs equal to zero are applied. Convergence is achieved after this second iteration.

Changing parameter α determining the fraction of network investment costs paid by generation does not result in a reduction of the efficiency of system expansion (or the efficiency of the coordination between generation and transmission developments) with respect to the case where no RTCs are applied on generation. Values of α lower than 0.4 , i.e., 0.3, 0.2, and 0.1, result in infinite iterations between two states with the results similar to the two iterations reported in Table 5.1. In other words, with lower values of α, RTCs levied in iteration #1 on U2 are still large enough for SGP2 to reduce the capacity expansion of U2, but its RTC in iteration #2 is not large enough for SGP2 to keep its decision, and he goes back to investment decisions computed in the iteration #1.

5.3.2 The IEEE-RTS96

In this section, the cost allocation algorithm is simulated on the IEEE-RTS96. This system has 24 buses and 38 transmission lines. The technical information such as power flow input data, transmission line capacities, and the weekly load data for this system are given in [64]. The single line diagram of the network is depicted in Fig. 5.2. For our analysis, we have divided this system into two areas, the north and the south, shown in Fig. 5.2, according to the two voltage levels in this system. The south area in the picture has more load and the north area has more generating capacity. Transmission investments considered concern the connection lines between these two areas, each line with 0.05 M$/MW/year investment cost. The load level of the original IEEE-RTS96 is multiplied by a factor of 1.5, with 600 $/MWh being the value of lost load. SGPs and their generating units, which can be upgraded, are listed in Table 5.3. Investment options, as in the 2-node example, are zero, 0.25, 0.5, and 0.75 times the capacity of the generating units.

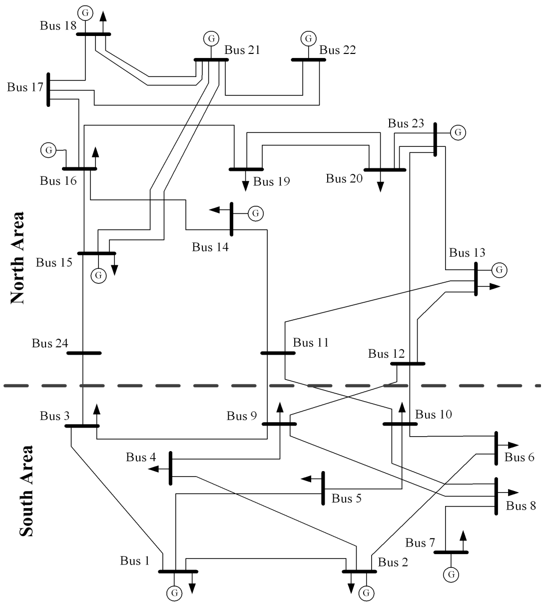

Figure 5.2: Single-line diagram of the the IEEE-RTS96.

Analogously to the 2-node example system, considering initial values of RTCs equal to zero and the value of α equal to 0.4, the algorithm achieves convergence in three iterations and after 47 minutes of running time. Most of the running time

Table 5.3: Characteristics of the Generating Units of SGPs of the IEEE-RTS96

SGP# (Unit#)	Capacity (MW)	Node	Fuel Cost ($/MWh)	Investment Cost M$/MW/year
SGP1 (U1)	76	3	10	0.02
SGP2 (U2)	76	7	10	0.02
SGP2 (U3)	197	12	5	0.05
SGP3 (U4)	155	20	6	0.05

Table 5.4: Generation Expanded Capacities and the System Social Cost for Different Iterations ($\alpha = 0.4$) and the Centralized Planning of the IEEE-RTS96; EC: Expanded Capacity, SC: System Social Cost

Runs	Units EC (MW)				SC (M$)
	U1	U2	U3	U4	
Iteration #1	57	38	49.25	116.25	285.28
Iteration #2	57	57	49.25	116.25	278.11
Centralized Planning	33.1	199.9	132.2	251.1	218.06

is devoted to solving the MIP problem of SGPs in steps 1 and 3 of the algorithm presented in Section 5.2.3. The results for generation and transmission investments as well as RTCs are reported in Tables 5.4 and 5.5, respectively. ENS amounts to 1574 MWh in iteration #1 and 1497 MWh in iteration #2. While the ENS increases by 5% in iteration #2, the System social cost decreases from 285.28 M$ in iteration #1 to 278.11 M$ in iteration #2. The decrease achieved in the system social cost is 7.17 M$, i.e., 2.5% of the system social cost. Having this result, we can calculate the transmission investment costs paid by each generation company in each area. From the total cost of transmission expansion, 0.2 M$ is paid by U1 and U2 in the area with higher load (the south area), and 7.57 M$ is paid by U3 and U4 in the area with higher generation (the north area). The fact that companies in the north area make larger payments is not only related to the larger generation investment taking place in the north area, but also because of the higher RTCs applied there compared to the south area.

An important observation here is that imposing RTCs calculated in iteration #1, SGP2 decides to increase the size of the new capacity built in U2. This is because of the effect of the strategic behavior of SGPs on investments. If SGP2 does not change its decision (or reduce the expanded capacity of U2), with the new RTCs, the other players change their actions and SGP2 is worse off. In other words, even though the RTC for U2 increases, the equilibrium of the stated problem lies in a

Table 5.5: RTCs for the Different Iterations ($\alpha = 0.4$) of the IEEE-RTS96

Iteration #	Units RTCs ($/MW)			
	U1	U2	U3	U4
1	1836.9	1797.7	34246.7	50647.5
2	1835	1700.1	34211.8	50595.9

Table 5.6: Generation Expanded Capacities and the System Social Cost for Different Iterations ($\alpha = 0.5$) and the Centralized Planning of the IEEE-RTS96; EC: Expanded Capacity, SC: System Social Cost

Runs	Units EC (MW)				SC (M$)
	U1	U2	U3	U4	
Iteration #1	57	38	49.25	116.25	285.28
Iteration #2	57	57	0	116.25	293.65
Centralized Planning	33.1	199.9	132.2	251.1	218.06

point where generation capacity built for U2 is larger. Then, the previous point of equilibrium in iteration #1 is not the Nash equilibrium anymore, meaning that at least one of the SGPs has an incentive to change its investment strategy assuming other SGPs do not change theirs. This example shows how the strategic behavior of SGPs might lead to results that are difficult to anticipate.

Next, we change the value of some input vectors to show that applying RTCs to generators might have a negative effect on the social welfare of the system. For this, we increase the value of α to 0.5. The new results are presented in Tables 5.6 and 5.7. As one can see, the system social cost increases by 8.37 M$ from iteration #1 to iteration #2. Then, in this case, RTCs are harmful. The reason for this is that, in iteration #2, as a result of transmission charges applied, SGP2 decides not to invest in U3 and, instead, increases its investment on U2 by 19 MW. Then, the total generation investment in the system decreases by 30.25 MW, and this results in an increase in the system social cost (U3 has the lowest fuel cost while U2 has the highest one). This result shows that RTCs can be ineffective when there is already under-investment in transmission capacity when not applying RTCs on generators ($RTCs = 0$).

The results of the model developed, when applied to some case studies, show that the theoretical effect of RTCs on the development of the system, increasing its efficiency, is contingent on the level of market power generators hold and are able to exercise. Not applying RTCs on generation turns out to result in larger generation investments than those decided by generation companies when they

Table 5.7: RTCs for the Different Iterations ($\alpha = 0.5$) of the IEEE-RTS96

Iteration #	Units RTCs ($/MW)			
	U1	U2	U3	U4
1	2296.1	2247.2	42808.4	63309.4
2	2667.8	2414.7	0	69252.7

are subject to network charges. Thus, when, in the absence of network charges, their profit maximization strategies lead generators in exporting areas to build more generation capacity than needed, as in the 2-node case-example discussed above, applying cost-reflective RTCs leads these generators to reduce their investments in new capacity and, consequently, drives a more efficient development of the system (affecting both generation and transmission expansion). However, when, in the absence of RTCs applied on generation, the strategic behavior of SGPs leads them to build a lower amount of cheap generation capacity (the most cost competitive generation exporting power to other areas of the system) than the optimal level of investments in this capacity, applying cost-reflective RTCs not only is unable to trigger more efficient generation investments (directing these investments towards better locations or driving the generation technology mix closer to the optimal one), but, instead, reduces the amount of investments in cost competitive generation further, thus reducing the overall efficiency of the development of the system and increasing system social costs (as it can be concluded from the numerical results computed for the IEEE-RTS96 system considering a value of parameter $\alpha = 0.5$). When agents behave competitively, i.e., under perfect competition assumptions, applying cost reflective RTCs always results in an increase in the efficiency of the development of the system.

Table 5.8 shows the output of the proposed algorithm, i.e., the number of iterations and the social cost of the system, for several values of α from 0 to 1. As seen, the only value of α for which RTCs applied increase the efficiency of system expansion (decrease the system social cost compared to $\alpha = 0$, i.e., $RTCs = 0$) is $\alpha = 0.4$. It can be concluded that the value of α, which is decided by the regulator, is an important factor and can affect the system development significantly. Having reliable information about the profit made by SGPs, the regulator can set the value of α accordingly to maximize the positive effects of RTCs.

Table 5.8: Comparing the Results for the Different Values of α for the IEEE-RTS96; SC: Social Cost

Value of α	Iteration #	SC (M$)
0	2	285.28
0.1	3	286.374
0.2	5	293.65
0.3	NA*	NA
0.4	3	278.11
0.5	3	293.65
0.6	NA	NA
0.7	4	286.374
0.8	4	296.589
0.9	4	296.593
1	3	296.589

* NA: Not Available (infinite iteration).

Chapter 6

Conslusion and Future Works

6.1 Concluding Remarks

In this thesis, first in Chapter 3, we discussed the multi-regional transmission planning problem. The non-cooperative model is developed and discussed. In this model, each regional transmission planner minimises his own region social cost using his inter-region and intra-region planning decisions given the planning decisions of other transmission planners. The cooperative solution which has the maximum social welfare for the whole region is considered as the benchmark in this study. In the cooperative solution, all involved transmission planners act as if they are merged into one single transmission planner responsible for the whole transmission network. The numerical results of this study show that without proper compensation mechanism, the non-cooperative transmission planning leads to inefficient results as compared to the cooperative solution.

Next, in Chapter 4, we proposed 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 IEEERTS96 and the modified IEEE 118-bus test systems. The numerical results clearly show the importance of sequence of investments in transmission and generation sectors.

Finally, in Chapter 5, we proposed and analysed an approach to impose transmission charges, named RTCS, in order to coordinate transmission expansion (coordinated by a central planner with the minimization of the social cost as the objective) with generation expansion (conducted by strategic generation planners, named SGPs, that maximize their profit). RTCs are calculated based on the marginal effect of generation investment on transmission expansion costs. An iterative algorithm is proposed to model the equilibrium between SGPs? investment decisions and the central planner's network investment decisions, where coordination takes place through RTCs. The algorithm is applied to compute the system development equilibrium in a 2-node illustrative example and the IEEE-RTS96. The results show that the theoretical effect of RTCs on the development of the system, increasing its efficiency, is contingent on the level of market power generators hold and are able to exercise. Therefore, RTCs should be designed carefully taking this into account. The strategic behavior of SGPs distorts also (among other things) the efficient coordination of generation and network expansion through RTCs. Measures to control and reduce the level of market power held and exercised by SGPs are needed also to achieve a better coordination of generation and transmission developments.

6.2 Future Works

The developed mathematical models in this thesis can be used by regulators for evaluating different incentive mechanisms for coordinating generation-transmission planning towards efficient results, e.g., other transmission charging methodologies based on network usage by generators, like Average Participations or Marginal Participations [117].

A limitation in the studies performed is the size of the system. The number of generation companies considered, that of potential investments to be undertaken by them, and the number of potential reinforcements to the network should be kept within certain limits to be able to solve the resulting problem. Parallelizing the models can adopt the large-scale problems to be solved by high performance computers consisting of several cores. Moreover, the numerical efficiency of the proposed models can be improved by parallelizing and increasing the number of computing cores and providing a platform for cores to communicate.

In order to model the interaction between system expansion planning strategies of different TSOs and Gencos, and their eventual coordination, we have adopted a simplified representation of the transmission and generation expansion planning problems, where scenarios formed by the different demand levels on the future evolution of the system and wind variability are being considered. Other uncertainties in power system, e.g., uncertainty in future emission reduction policies, needs to be included in the models. Considering uncertainty for long-term studies which consist of the decision about bulky investment options necessitate the risk factor to be included. Parallelizing the models and using high performance computers, the impact of uncertainty on coordination problem can be further analyzed.

As asserted in cost-benefit analysis (CBA) report by ENTSOE that "CBA aims at assessing transmission projects that affect transfer capabilities between TSOs as well as storage projects," considering new solutions at the same time with transmission expansion in renewable and market integration, e.g., investing on storage capacity in the form of heat-to-power units or growth of heat-pump consumers, is an interesting future work of the studies in this thesis.

Thus, integration of renewable resources requires a more integrated network in order to make complementary resources available. This is while renewable resources in the form of DERs are connected to distribution networks. This means for having an integrated and sustainable system, coordination between transmission and distribution planners is very important which is a good extension to the research in this thesis.

Many new comers in the market are expected in the near future both in the consumer side and in the producer side. Therefore, power system planners and regulatory bodies need to know if the result of this shift from a limited number of players in the market to many players does not hamper the function of electricity sector to keep the lights on. So, an interesting extension to the research in this thesis will be consideration of the competition between these many new players and finding the equilibrium of this situation.

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Complete List of Publications

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Y. Tohidi and M. R. Hesamzadeh, ”Multi-regional Transmission Planning as a Non-cooperative Decision-making,” Power Systems, IEEE Transaction on, vol. 29, no. 6, pp. 2662-2671.

Y. Tohidi, L. Olmos, M. Rivier, and M. R. Hesamzadeh, ”Coordination of Generation and Transmission Development through Generation Transmission Charges - A Game Theoretical Approach,” Power Systems, IEEE Transaction on, accepted, under publication.

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.

Peer-reviewed Conference Papers:

Y. Tohidi and M. R. Hesamzadeh, ”Multi-national Transmission Planning Using Joint and Disjoint Solutions,” EEM13, Sweden, May 2013.

Y. Tohidi and M. R. Hesamzadeh, ”Free Riding Effect in Multi-national Transmission Expansion Planning,” iSGT2013, Denmark, Oct. 2013.

Y. Tohidi and M. R. Hesamzadeh, ”Multi-regional Transmission Planning under Interdependent Wind Uncertainty,” ENERGYCON 2014, Croatia, May 2014.

Y. Tohidi, M. R. Hesamzadeh, and K. Ostman, ”Reactive Coordination of Transmission-generation Investment,” EEM15, Portugal, May 2015.

Y. Tohidi and M. R. Hesamzadeh, ”A Mathematical Model for Strategic Generation Expansion Planning,” PES General Meeting, 2016 IEEE, USA, July, 2016 (Best conference papers on Planning, Operation, & Electricity Markets).

Journal Articles Submitted/To be submitted:

Y. Tohidi, M. R. Hesamzadeh, and F. Regairaz, ”Analyzing Nash Equilibria of Transmission Investment Game using Modified Benders and Branch-and-Bound Algorithms,” Power Systems, IEEE Transaction on, to be submitted.

Y. Tohidi, M. R. Hesamzadeh, R. Baldick, and D. R. Biggar, ”Optimal Reconfiguration of Electricity Transmission Networks for Reducing Market Power Cost: A Nash-Equilibrium Approach,” Electric Power Systems Research, under review.

Y. Tohidi and M. R. Hesamzadeh, ”Strategic Generation Investment Considering Oligopolistic Day-ahead Market: A Two Stage EPEC Approach,” Sustainable Energy, IEEE Transaction on, to be submitted.

Other Publications:
”Transmission Grid Planning in Modern Electricity Markets” funded by Elforsk AB, Sweden.
”Market Price Signals and Regulated Frameworks for Coordination of Transmission Investments,” Technical Brochure by GIGRE working Group C5-18.

Curriculum Vitae

Yaser Tohidi was born in 1986 in Neyshabour, Iran. He entered the Department of Electrical and Computer Engineering in University of Tehran, Iran for B.Sc. studies in 2004. In 2008, he entered Sharif University of Technology as a graduate student and studied power systems engineering. During his M.Sc. under the supervision of Prof. Mahmood Fotuhi-Firuzabad, he wrote a thesis on optimum location and sizing of the generation units.

In 2012, he was selected as a PhD candidate of the Erasmus Mundus Joint Doctorate in Sustainable Energy Technologies and Strategies (SETS) and awarded an Erasmus Mundus Fellowship. This joint PhD program is offered by Comillas Pontifical University, KTH Royal Institute of Technology of Stockholm and Delft University of Technology.

In KTH, as his home university, he started his research on long?term generation?transmission planning in the context of multiple TSOs and Gencos under supervision of Prof. Mohammad Reza Hesamzadeh as my main supervisor and Prof. Lennart Soder as my co-supervisor. His research in KTH included different aspects of transmission and generation expansion planning in market environment, e.g., multi-TSO transmission planning of interconnections (simultaneous-move game) considering high share of renewables, modelling of proactive and reactive transmission expansion planning with strategic generation investments in different hierarchical levels (Stackelberg game), regulatory mechanism design of efficient transmission and generation planning.

He also visited Institute for Research in Technology in Comillas Pontificial University during his Ph.D. (Sep. 2014 - June 2015) where he studied cost allocation and transmission tariff design for planning of interconnecting power systems with Prof. Michel Rivier and Dr. Luis Olmos.

His research interests include regulation and economics of the power industry consisting of several players, generation and transmission expansion planning, strategic decision making, and mathematical optimizations.

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