KADİR HAS UNIVERSITY
GRADUATE SCHOOL OF SCIENCE AND ENGINEERING
PROGRAM OF INDUSTRIAL ENGINEERING

# CO-OPTIMIZATION MODELS OF GENERATION AND TRANSMISSION INVESTMENTS WITH MARKET-CLEARING EQUILIBRIUM

ZEKİ UYAN

MASTER'S THESIS

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Zeki Uyan M.S. Thesis 2018

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MASTER’S THESIS

Submitted to the Graduate School of Science and Engineering of Kadir Has University in partial fulfillment of the requirements for the degree of Master’s in the Program of Industrial Engineering

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# ACCEPTANCE AND APPROVAL

This work entitled **CO-OPTIMIZATION MODELS OF GENERATION AND TRANSMISSION INVESTMENTS WITH MARKET-CLEARING EQUILIBRIUM** prepared by **ZEKİ UYAN** has been judged to be successful at the defense exam held on **12.01.2018** and accepted by our jury as **MASTER OF SCIENCE THESIS.**

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CO-OPTIMIZATION MODELS OF GENERATION AND TRANSMISSION INVESTMENTS WITH MARKET-CLEARING EQUILIBRIUM

# ABSTRACT

Methods for co-optimizing transmission and generation investments, including bi-level or multi-level problems, consider trade-offs with market operations and interactions in electric power supply and demand. Under fairly general conditions, it is known that simultaneous solution of these multi-level models using complementarity problems can give more useful results than iterative optimization methods or single-level optimization of generation or transmission expansion alone. Hence, in this thesis, we provide mixed complementarity problem formulations for transmission and generation expansion models with electricity market-clearing models.

In this study, we have considered co-optimization models formulated as bi-level programming problems as well as single-level mixed complementarity problems. In the upper level of the bi-level problem, the system operator decides on the transmission expansion plans while anticipating the decisions in the lower level of the problem. The lower level problems present models of generation expansion and oligopolistic competition among power generators in the market, where we examine perfect competition models to Cournot game among generators. This model is essentially an economic equilibrium problem for electricity markets that is defined by the optimality conditions that examine system operator's and generators' expansion behavior along with supply-demand balance in the market. These models will be handful for planning generation/transmission expansions, and analyzing the relations between these expansions and the market outcomes. We have simulated market outcomes and expansion decisions in a 6-bus test system and a realistic Turkish electricity market under two different market structures (perfect competition and Nash-Cournot). Furthermore, four different scenarios considering carbon costs and feed-in-tariffs (FIT) for Turkish electricity market for December 2020 are simulated and results are examined. Scenario considering both carbon costs and FIT have provided relatively better results in terms of social welfare.

**Keywords:** Co-optimization, transmission/generation expansion planning, market-clearing, mixed complementarity problem, mathematical program with equilibrium constraints

ÜRETİM VE İLETİM YATIRIMLARI İLE PİYASA-TAKAS DENGESİ

ORTAK-ENİYİLEME MODELLERİ

# ÖZET

İletim ve üretim yatırımlarının ortak-eniyilemesi için kullanılan yöntemler (örn., iki- veya çok-seviyeli problemleri) piyasa operasyonlarıyla elektrik arzı ve talebi arasındaki ödeşmeyi de dikkate alır. Oldukça genel koşullar altında bu çok seviyeli modellerin tamamlama problemleri kullanılarak eş zamanlı çözümü, kademeli eniyileme yöntemlerine veya üretim ya da iletim yatırımının tek seviyeli eniyilemesine göre daha yararlı sonuçlar verebilir. Bu yüzden bu çalışmada piyasa-takas modeli içeren iletim ve üretim yatırımı modelleri için karışık tamamlama problemi formülasyonları geliştirilmiştir.

Bu çalışma, ortak-eniyileme modellerini tek-seviyeli karışık tamamlama ve iki-seviyeli programlama problemleri olarak ele almaktadır. İki-seviyeli problemin üst seviyesinde sistem yöneticisi, problemin alt seviyesindeki kararları da gözlemleyerek iletim yatırımı planları arasında karar vermektedir. Alt seviye problemler tam rekabet modellerinden Cournot oyunlarına kadar incelenen, üretim yatırımı modellerini ve piyasada üreticiler arasında oligopolistik rekabeti sergilemektedir. Bu model özünde elektrik piyasalarında, piyasadaki arz-talep dengesi ve sistem yöneticisi ile üreticilerin davranışlarını inceleyen eniyileme koşullarıyla tanımlanan bir ekonomik denge problemidir. Bu modeller üretim/iletim yatırımlarını planlamak ve bu yatırımlarla piyasa çıktılarını incelemek için kullanışlı olacaktır. Piyasa çıktıları ve yatırım kararları hem 6 –baralı bir test sistemi hem de Türkiye elektrik piyasası için ve iki farklı piyasa yapısı altında (Cournot ve tam rekabet) benzetilmiştir. Bunun yanısıra, Türkiye elektrik piyasası için karbon maliyetleri ile yenilenebilir destek mekanizmalarını dikkate alarak oluşturulmuş dört farklı senaryoya göre Aralık 2020 için piyasa benzetimi gerçekleştirilmiş ve sonuçlar sunulmuştur. Karbon maliyetleri ve yenilenebilir destek mekanizmalarını birlikte içeren senaryo, içermeyen senaryo veya güncel duruma göre sosyal refah açısından daha iyi sonuçlar vermiştir.

**Anahtar Sözcükler:** Ortak-eniyileme, iletim/üretim yatırım planlama, piyasa-takas, karışık tamamlama problem, denge kısıtlı matematiksel program

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**Indices:**

$f \in F$, set of generation firms

$i, j \in I$, set of buses (nodes)

$J_i \subset I$, set of buses connected to node *i*

$J_i^+ \subset I$, set of new buses connected to node *i* (for new transmission lines)

$I_f \subset I$, set of generators owned by firm *f* at bus *i*

$h \in H$, set of generation types

**Variables:**

$p_i$ electricity (nodal) price at node *i*

$x_{fi}$ generation by firm *f* at node *i* ($x_{fih}$ for generation type h)

$s_{fi}$ sales by firm *f* at node *i*

$\theta_i$ voltage angle of node *i*

$\Delta T_{ij}$ new transmission investment on generation *i* at node *j*

$\Delta K_{fi}$ new generation investment by firm *f* at node *i* ($\Delta K_{fih}$ for generation type h)

**Parameters:**

$\alpha_i$ non-price effects at node *i* for the linear inverse demand function (weather, socio-demographic factors, etc.)

$\beta_i$ constant price coefficient for the linear inverse demand function at node *i*

$c_{fi}$ operating cost of generation firm *f* at node *I* ($c_{fih}$ for generation type h)

$c_{fi}^{Gexp}$ investment cost of new generation capacity for firm *f* at node *I* ($c_{fih}^{Gexp}$ for generation type h)

$c_{ij}^{Texp}$ investment cost of new transmission capacity for transmission line connecting buses *i* and *j*

$K_{fi}^0$ initial available capacity of generation firm *f* at node *i* ($K_{fih}^0$ for generation type h)

$K_{fi}^{max-exp}$ generation firm *f*'s maximum investment level at node *I* ($K_{fih}^{max-exp}$ for generation type h)

$B_{ij}$ susceptance of transmission line connecting buses *i* and *j*

$T_{ij}^0$ upper level to the flow through transmission line connecting buses *i* and *j* before TSO's investment decisions.

$T_{ij}^{max-exp}$ maximum investment level for transmission line connecting buses $i$ and $j$.

# 1. INTRODUCTION

Investment and planning decisions of the private generation companies are led by economic considerations as a response to market outcomes in the organized electricity markets. Transmission system operator on the other hand, decides on the expansions of transmission lines. Obviously, expansion and planning in transmission, generation and market-clearing procedures are strongly related and influenced by a group of factors including electricity demand, fuel prices, hydrology, electricity price, technology development and institutional framework. Therefore, a necessity for the markets is integrating the models for transmission and generation expansions and market-clearing. Revealing the complicated market processes, such models could have an important role in the decision process in this context. For the upcoming expansion plans and their effects on the decisions in the market, the proposed model of this thesis may be very useful.

In the literature, there is a focus on multi-level programming problems to model these decisions using hierarchical decision making tools (e.g., equilibrium and mathematical programs with equilibrium constraints (MPECs and EPECs) among different agents (system operator, generators, consumers). However, solving these models can be very challenging and generally not computationally tractable (You et al., 2016).

In this study, we provide mixed complementarity problem formulations for transmission and generation expansion models with an electricity market clearing model. Even though studies about complementarity models of electricity markets have attracted much attention in the past decade, studies focusing on Turkish electricity market are very rare and this study also aims to contribute to the literature on Turkish electricity market.

Co-optimization can play a major role in facilitating simultaneous and integrated assessment of almost all the planning processes in the electricity market. There are two major cases we have focused on in this paper. In the first case, we state a centralized planner model where we have considered a welfare maximizing (or at least cost solution in perfectly competitive case) by considering the tight coordination between transmission and generation. In the second case, a bi-level model for a decentralized market environment is examined, since it expedites exploration of how generation investments and market-clearing decisions of generators respond to changes in transmission capacity and congestion. In this manner, policy makers and planners can identify transmission grid reinforcement that encourages generation investments that produce the highest welfare for power transmission and generation (Krishnan et al., 2016).

Our models depend on the study of Gabriel et al. (2012) as it is a very well established complementarity application based on the seminal study of Hobbs (2001). The models in these studies are the basis of our model and we converted them to co-optimization problems in search for a more efficient solution to investment problems. We solved two case studies to determine the expansion decisions of the generators and the transmission system operators as well as the social welfare. In the first small-scale case study, we used a "six bus network" with three generation companies on buses 1, 2 and 6 and three candidate lines presented in Figure 3.4. All of our data for the parameters of our first case study comes from Jin and Ryan (2014) as we found its 6-bus model easily applicable and well designed for our co-optimization problem. Every one of the eight transmission investment solutions are evaluated and our model obtain the equilibrium solution as well. In the second case study, we focused on a realistic Turkish electricity market. With a similar mathematical model and data from Turkish state agencies, we have solved our co-optimization models with market-clearing equilibrium for Turkish electricity system under different policy scenarios. In this case, we focus on a specific hour in December 2020 and all of our results represent the projections for that particular hour.

The contributions of this thesis are as follows:

i) We have developed mixed complementarity models (MCP) for transmission/generation investments with market-clearing equilibrium as a single-level problem and as an MPEC under Nash-Cournot and perfectly competitive market structures.
ii) We have applied these models on a 6-bus test system, where new transmission lines are modeled using binary decision variables and this requires the reformulation of the MPEC models by using Fortunuy-Amat et al. (1981) conversion method.
iii) For the Turkish market model, we have solved the MCP models for five realistic scenarios, where we have considered current investment plans, base, feed-in-tariffs (FIT), carbon cost, and both FIT and carbon cost scenarios.
iv) We have found that both FIT and carbon cost scenario provides relatively better results in terms of social welfare than any other scenario.

Hence, this thesis is planned as follows. First, in Chapter 2, a literature review is conducted including generation expansion problems with a risk analysis for generation expansion, transmission expansion problems and co-optimization of generation and transmission expansions using both old and new literature. Then, in Chapter 3, we have modeled and solved the 6-bus market-clearing model as a co-optimization problem for both perfect competition and Nash-Cournot market structures and evaluated the results as well. In Chapter 4, we have focused on Turkish electricity market based on the nine region structure provided by Turkish state transmission company and the data collected from Turkish state agencies. Using a similar mathematical model in Chapter 3, we have evaluated the Turkish system with five different scenarios and have shown the results in detail. We have also solved it for perfect competition and Nash-Cournot market structures under these five different scenarios differentiated by carbon costs and feed-in-tariffs (FIT). We have also evaluated the difference between current expansion plans and optimal expansion options. Finally, in Chapter 5, we have concluded by summarizing all of the efforts in this thesis so far.

# 2. LITERATURE REVIEW

The industry's former vertically integrated structure of transmission, generation, and distribution makes the traditional power system expansion planning problem assuming a centralized perspective. The decision deliberations in centralized planning are influenced by the system load balance, investment budget, and capacity limit constraints.

For this reason, in order to provide an efficient and reliable electricity supply network, the considerations must take into account both generation expansion and transmission to assure a supply of sufficient energy that meets future needs and a fully integrated electricity supply system with transmission.

Hirst (2000) points out that several dynamics extend beyond the normal growth in electricity demand, therefore, necessitates the need for new investment in generation and transmission capacity within the future two decades. According to Hirst (2000), one of the most significant approaches is the need to integrate the entire electricity market into a whole and also to focus on alternative electricity generation sources while considering the costs of investment. Suitable incentives for assuring reliability, grid monitoring, and establishing a functional electricity market offer both quantitative and qualitative requirements for generation and transmission expansion, particularly in an era trouble with increasing demands, shifting fuel prices, and new regulatory policies from environmental protection programs that affect grid expansion. A number of studies in the recent past reveal that the changing geographic patterns and need for sufficient energy require new investments in generation and transmission facilities (Hirst, 2000).

In her dissertation, Jin (2012) states that the intricacies experienced in decision making regarding the power system expansion planning problem commonly develop owing to the diversity of the existing power generation technologies, restructuring of the wholesale market, and the constant demand for reliable and adequate energy supply. On this regard, both operational scheduling and investment planning are long term compelling necessities for consideration on the account of the extended lives of a generation, transmission assets, and the scale of capital investment. The problem is further exacerbated by the composite and integrated aspects of the entire electricity supply system facilities including generation, distribution, transmission and fuel transportation. Other significant aspects also encompass environmental impact, the need for a reliable power grid, and siting facilities.

Jin and Ryan (2014) define the wholesale electricity market as separate generation companies (GENCOs), transmission owners (TRANSCOs), distribution companies (DISCOs) and load serving entities (LSEs). The independent system operator (ISO) is assigned the responsibility of assuring reliability, monitoring the grid, and establishing the electricity market for an area. Regional reliability councils together with the ISOs, who carry out reliability evaluation and transmission planning studies must as well weigh how GENCO's tactical expansion decisions may have an effect on transmission planning decisions, and how it will influence the performance of wholesale markets in reaction to generation and transmission expansions.

## 2.1 Generation Expansion Problems

The generation investment planning problem consists of determining the type of technology, size, location and time at which new generation units must be integrated to the system, over a given planning horizon, to satisfy the forecasted energy demand (Mejia Giraldo et al., 2010). Planners predominantly consider generation expansion as the only surety for sufficient energy that can meet future loads. However, the scenario should also involve the entire wholesale electricity supply system which allows for transmission and market clearing by ISO so as to provide a dependable and profitable electricity supply. Specifically, resource investment decisions need careful thoughts since they have massive implications on market outcome. For instance, transmission congestion arising out of an inadequate transmission capacity can give rise to heightened locational marginal prices (LMPs) or even load reduction in extreme cases. LSEs, at this point, can play a vital role in electricity distribution to retail customers because they are predominantly the buyers in the wholesale market. Instead of reducing costs, opting for possible profit increase may justify expansion decisions in restructured markets. The electricity market price settlement can be used to determine the likely profits for investors because the ISO can match the electricity supply bids by settling the LMPs and demanding offers with the objective of maximizing total market surplus of sellers and buyers. In a day-ahead market, this can be done on an hourly basis while in real-time market it can be done in every 5 minutes. Besides, investments in generation capacity will only be productive if the transmission capacity is sufficient enough to transfer the newly established power supply to the demand areas.

In recent times, many studies regarding restructured electricity markets tend to devise a single decision maker’s expansion decision that includes an ISO market clearing problem as a smaller sub-problem indicator. In the same perspective, Wu et al. (2006) provided a review of the transmission expansion planning methodologies about the conventional and market-based power generation system. Garcés et al. (2009) also modeled transmission expansion with a market equilibrium sub-problem. Su and Wu (2005) and Soleymani et al. (2008) similarly provide analysis of generation expansion models. Bi-level Programming (BLP) models, for example, are extensively employed to model particular GENCO’s capacity expansion decisions or bidding action plans while expecting the market settlement outcomes (Kazempour and Conejo, 2012; Ruiz and Conejo, 2009)

Based on a single level Cournot game study of multiple GENCOs making both the operational decision and capacity expansion, it became clear that diagonalization method iteratively provided answers to an equilibrium solution (Chuang et al., 2001). Murphy and Smeers (2005) showcased three models of finding solutions to a single level Cournot capacity game in different economic systems. The uniqueness and existence of the Cournot equilibrium solutions were likewise analyzed and validated based on the parameter assumptions on two types of candidate units and demand. Nanduri et al. (2009) suggested a two-tier multi-GENCO equilibrium problem for capacity expansion model. Wang et al. (2009) present the application of a co-evolutionary algorithm in the exploration of Nash equilibrium (NE) solution for the strategic multi-GENCO bi-level games for capacity expansion problem. Modeling as equilibrium problem with equilibrium constraints (EPEC) can be used as part of competitive decisions by various GENCOs to expand with the expectations of greater market results. Hu and Ralph (2007) discuss the presently two available algorithms using complementarity and diagonalization reformulations to provide a solution for the EPEC problem. Besides, Kazempour et al. (2013) and Ruiz et al. (2012) adopted both strong duality theory and linearization technique to redevelop an EPEC problem into a group of assorted integer linear constraints and solve it to its optimal requirement.

The planning model at times assumes a more complicated state, usually termed as a multi-level structure, every time both generation planning decisions and transmission accounts for the reciprocative actions among market players. In another study, a multi-GENCO equilibrium expansion planning model with the expectation of an ISO market clearing problem was studied, and the transmission expansion's outcome on the social welfare was equally assessed by carefully analyzing the different plans for transmission expansion (Sauma and Oren, 2006). Iterative diagonalization algorithm provided a solution to bi-level games for multiple candidates transmission expansion decisions. Generation and transmission planning problem was solved by Roh et al. (2009) through the formulation of an iterative course of action intended for simulating the interactions among TRANSCOs, GENCOs, and ISO by carefully analyzing transmission reliability, uncertainty, and profit from the market clearing decision. Propositions by Motamedi et al. (2010) holds that a transmission expansion framework should bear in mind the expansion reaction from decentralized GENCOs and should equally incorporate operational optimization in an electricity market that is restructured. The formulation of the problem assumed a four-level model and the approaches used were search-based plus agent-based system. Hesamzadeh et al. (2011) investigated a new model of augmentation planning problem including operational decisions and strategic generation expansion that fixed a tri-level program with the aid of a genetic algorithm. On a different account, Pozo et al. (2013) analyzed the essential features of transmission and generation with a tri-level model and switched it to a single level mixed integer linear programming problem. Table 2.1 compares the tri-level model in Jin and Ryan (2014) findings with the transmission expansion models and multi-level generation in other findings. A level is marked as "centralized" if decisions are determined by a single entity whereas if different individual decision makers make decisions, it is marked as "decentralized."

**Table 2.1 A Comparison Among Different Models ( Jin and Ryan, 2014)**

| | Sauma and Oren (2006) | Roh et al. (2009) | Motamedi et al. (2010) | Hesamzade et al. (2011) | Pozo et al. (2013) | Jin and Ryan (2014) | This study |
|---|---|---|---|---|---|---|---|
| Transmission Expansion | Centralized; Existing/new line expansion; Maximize net surplus | Decentralized; New line expansion; Maximize net profit | Centralized; Existing/new line expansion; Multi-criteria | Centralized; Existing line augmentation; Minimize operation and investment cost | Centralized; Existing/new line expansion; Minimizing operation and investment cost | Centralized; New line expansion; Maximize net surplus | Centralized; Existing/New line expansion; Maximize net surplus |
| Generation Expansion | Decentralized; Continous | Decentralized; Binary | Decentralized; Continuous | Decentralized; Binary | Decentralized; Continuous | Decentralized; Continuous | Decentralized; Continuous |
| Multi-Period Expansion | No | Yes | Yes | No | No | No | No |
| ISO's Market Problem | Maximize surplus | Minimize system cost, minimize loss of energy probability | Maximize Surplus | Minimze operating cost | Minimize operation cost | Maximize surplus | Maximize surplus |
| GENCO's Operational Problem | Strategic (Cournot) | Competitive | Strategic (pair of price and quantity) | Strategic (pair of price and quantity) | Competitive | Strategic (Cournot) | Competitive and Strategic (Cournot) |
| Operational Uncertainty | Yes | Yes | No | No | Yes | No | No |
| Solution Method | Optimization of Bi-level Games | Simulation of an Iterative Procedure | Search-based and Agent-based Method | Genetic Algorithm | Linearization and MILP Reformulation | Iterative algorithm with Optimization of Bi-level Games | Co-Optimization with Bi-level Model |

Power-specific generation expansion problems and general capacity expansion planning problems are facets that have both been examined for several decades, giving rise to a series of various algorithmic technique methods and optimization models for solving the problems. Many times the uncertainties in general capacity expansion difficulties have been tackled by the stochastic programming model. Studies have similarly been focused on rigorous optimization of generation capacity expansion with an aim of lessening cost variance within the bounds of possible scenarios. A multistage stochastic programming model for capacity expansion is illustrated by Ahmed et al. (2003) to have the potential for examining multiple heuristic methods for dealing with large problem instances through the introduction of a reformulation technique to lower computational difficulty. A fast approximation design founded on linear programming was introduced by Ahmed and Sahinidis (2003) to work out a multi-stage stochastic integer programming model of a capacity expansion planning problem.

Jin et al. (2011) devices a general expansion planning problem to establish the nature and number of power plants that can be set up annually throughout the extended planning horizon, taking into account uncertainties about the anticipated fuel prices and demands. The problems in generation expansion planning are influenced by nature, timing, and the number of power plant construction together with the prospective considerations of meeting the electricity demands within the duration of the power supply. The degree and kinds of uncertainties facing system planners in the past twenty years have increased owing to the rise of policies urging for renewable energy utilization, possible carbon emission regulations, and shifting fossil fuel prices. Accordingly, rethinking and reevaluating uncertainty can help devicing remarkable techniques for ameliorating the risks involved in generation expansion planning models.

Operational impacts must also be considered in generation planning decisions. The combination of different generating units remains the most gainful and resourceful in terms of production cost since electricity demand widely varies relative to seasonal, weekly or daily patterns. Furthermore, electricity supply is influenced by the availability of intermittent energy sources, fuel prices, and equipment availability. The uncertainties arising in future operational activities are usually consequences of various sources. Such a source is the increase in load (demand) which is a predominant cause of uncertainty in generation expansion planning. Throughout history, it is approximated through a mix of technological developments, forecasted economic circumstances, movement models or population expansion, and climate forecasts. Other rudiments that potentially determine the investment cost-efficiencies in various types of power plants include environmental concerns like emission penalties and other sustainability regulatory uncertainties. Greenhouse gas emissions restrictions, for instance, would have substantial costs on generation planning.

The planning of generation expansion entails two main costs including operational and investment costs. Operational costs rely on the quantity of produced electricity by each power plant in a given fiscal year and the costs of fuel linked with such generation. On the other hand, investment costs rely on the decisions defining the number and type of units each power plant can set up within the planned yearly schedules. Cost mitigations must encompass investments decisions made while considering future uncertainties that would, in turn, improve operational costs. Additionally, decisions on investments have to meet the expectations of extra requirements including financial budgets, meeting electricity demands, lessened carbon emissions, power generation dependability, energy resource limitations, and electricity generation in proportion to renewable energy utilization.

Free from external control and constraint of specific model formulation, problems in capacity expansion planning can introduce substantial computational challenges because of the number of the circumstances used to model the uncertainty, concerns about the system's scale, the existence of integer decision variables, and the counts of decision stages in the planning period. Hence, outstanding research has been committed to the expansion and improvement of decomposition techniques to address these problems more competently and with the long-term heuristic program for achieving the highly desired outcomes in tractable run-times.

Some of the commercial packages available for generation expansion planning in the electric power industry include Plexos (2009), Egeas (2009), and Pro-mod (2009). The majority of these packages are derived from deterministic models though Plexos supports two-stage stochastic programming as well. The utilizations of these packages are widely in the practice of estimating a stochastic programming model to deal with future uncertainties by addressing the various deterministic models on the basis of focusing on one of the particular generated future scenarios every single time. Rigorous optimization is estimated in an ad hoc manner by spotting the familiar aspects of the optimal plans for distinctly separate futures.

Jin et al. (2011) preferred to devise a two-stage stochastic programming model as a way of representing their generation expansion planning problem in favor of three important reasons. Foremost, the decision can be naturally segmented into distinct investment decisions that have to be adopted before uncertain quantities are witnessed. Uninterrupted operational variables that include cost realizations and recourse to demand must be adopted as well. Secondly, historical data availability for fitting models is essential for the uncertain variables. Third, including linear constraints to calculate Conditional Value-at-Risk, can control the risks of unacceptably high cost in a tractable manner.

Various closed loop advances to the generation capacity expansion problems have been proposed in the works of Murphy and Smeers (2005) and Kreps and Scheinkman (1983). Kreps and Scheinkman (1983) attempted to reconcile Cournot's and Betrand's theory by creating a two-stage game, where plants first simultaneously set capacity and second, capacity levels are made public for price competition. Their assumption is that when two matching plants and efficient rationing rules are used, their two-stage game produces Cournot outcomes. In Murphy and Smeers (2005), they present and evaluate three different models including a closed loop Cournot model, an open loop Cournot model, and open loop perfectly competitive model. Each of these models gives careful consideration to several loads periods with different demand curves and two plants, one with a base load technology (low operating cost, high capital cost) and the other with a peak load technology (high operating cost, low capital cost). Additionally, they reveal that the closed loop Cournot equilibrium productivity capabilities are classified between the open loop competitive solutions and open loop Cournot. Wogrin et al. (2013) differ with these models by looking at a variety of conjectural vibrations between Cournot and perfect competition. Their formal outcomes are for symmetric agents at the same time extending to asymmetric firms. Furthermore, in their model the considerations are on the basis of a constant second stage conjectural variation instead of a state in which the conjectural variation switches to Cournot whenever competing firms are at capacity.

On top of that, other works have formulated and addressed closed loop models of power generation expansion. Wogrin et al. (2013) find a closed loop Stackelberg-based model based on the works of  Ventosa et al. (2002) where in the first phase a leader firm make a decision of its capacity and in the second phase the others compete in quantities in a Cournot game. Centeno et al. (2003) reveal a two-stage model symbolizing the market equilibrium, where the initial stage is founded on a Cournot equilibrium in the midst of producers who can select continuous capacity investments and calculates a market equilibrium estimation for the total model horizon and the subsequent stage discretizes this solution singly for each year. García-Bertrand et al. (2008) explains a linear bi-level model that establishes the optimal investment decisions of given generation company taking into account uncertainty in competitor's decisions and in demand. Sakellaris (2010) employs the two-stage model in which plants pick their capacities under demand uncertainty before contending in prices and presents regulatory decisions. Kazempour et al. (2011) illustrates an example of a stochastic static closed loop model intended for generation capacity problem for a particular firm, where strategic production and investment decisions are in the upper limit for one target year in the future whereas the lower limit signifies market clearing.

Wogrin et al. (2013) propose closed loop and open models that extend to earlier approaches by including a generalized account of the market behavior through conjectural variations, particularly by equivalent conjectured price response. Wogrin et al. (2013) maintain that this aids in the representation of various forms of oligopoly, within the ranges of perfect competition to Cournot. Power market oligopoly models are as well suggested based on conjectural price responses (Day et al., 2002) and conjectural variations (Centeno et al., 2007), but solely for short-term markets where capacity is fixed.

In electricity markets, production decisions assumed by power producers are the consequences of a complex dynamic game within multi-settlement markets. Most of the time, bids in the form of supply purposes are in two or more consecutive markets at different times before operation, where the second and succeeding markets explain the commitments made in the previous markets. Conjectural Variation models can signify a form of dynamic game below normal as demonstrated in the theory of conjectural variations by Figuières et al. (2004). Other several authors have also proposed similar reinterpretations. For instance, Murphy and Smeers (2012) showcase how spot market Allaz-Vila game or the two stage forward contracting can be altered to one stage conjectural variations model. Accordingly, conjectural variations can be utilized to address very complex games in a computationally tractable manner. Perhaps, it is the main reason many econometric industrial organization studies approximate oligopolistic interactions using model specifications on the basis of constant conjectural variations assumptions (Perloff et al., 2007).

When it comes to a centralized planning of generation expansion, the main goal is to secure sufficient quantities of electric energy with the supply being reliable as possible. The economy of the present era determines the electricity market conditions; therefore, opening up markets is key and can assist in generation expansion especially by allowing new subjects in the market. Nonetheless, the state can still remain the chief regulator provided the shard goal of the system, the regulator, and the market operators are reliable and safe to drive the entire system. On this regard, to minimize on revenue and maximize on profits, the costs and savings are no more the points of discussion in generation expansion. Risk management is equally important and suitable risk evaluation factors can widely aid in solving generation expansion problems when included in all planning techniques. The aim is to satisfy the demands with minimal risks. Haubrich et al. (2001) considers planning methods in decongesting supply and finds out that the pre-existing models of planning the power system expansion can be combined with new models or modified to new conditions. Haubrich et al. (2001) insist the challenge of finding the best model is one of the key problems of long-term generation investment planning in market conditions. Besides, decisions made usually encounter expansion problems like future uncertainties, restructuring of the wholesale market, and the persistent need for reliable and sufficient energy.

### 2.1.1. Risk Analysis for Generation Expansion

Before making a decision for generation expansion, it is mandatory to carry out additional analysis, especially analysis of risks (REBIS-GIS, 2004). Furthermore, based on the regulatory policies of each country, there are needed permits and together with that, diverse studies which vary from country to country are as well undertaken, for instance, study on environmental impacts. On this regard, the whole expansion planning process must entail construction feasibility and justifiability. More detailed objectives concerning whether the costs of expansion are justifiable for plant construction can address the questions of the tolerable risks and uncertainty problems involved in generation expansion. The main risk elements and how they affect generation expansion are shown in the figure and discussed below (Zeljko, 2008).

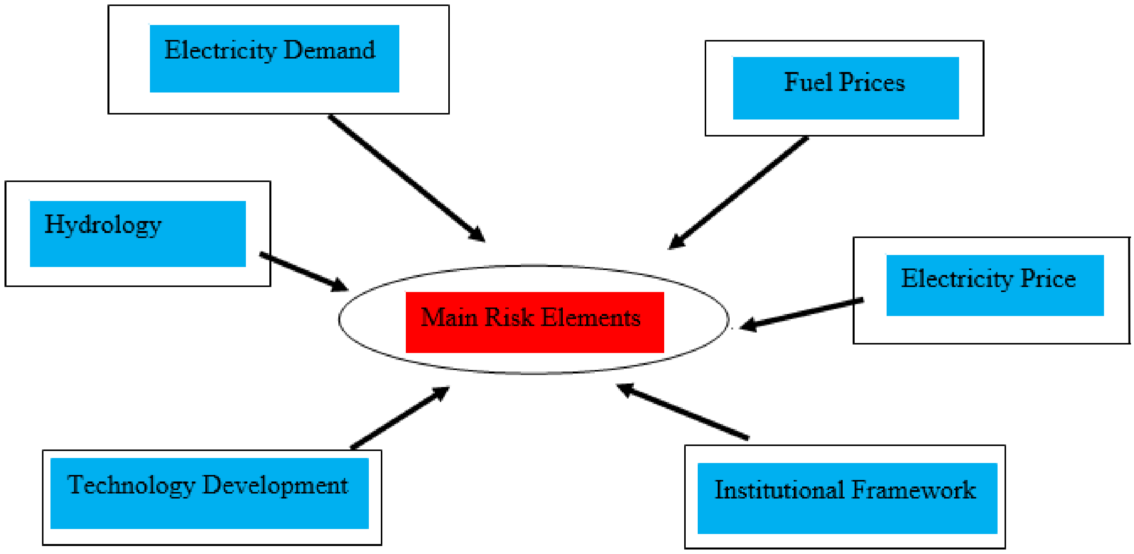


**Figure 2.1 Main Risk Factors**

#### 2.1.1.1 Fuel prices

Fuel prices can be a substantial factor when it comes to generation expansion risk levels. Notably, it can raise risk level regarding power plant operations and profitability. Nonetheless, fuel dynamics vary from one type of fuel to another. Some may stay constant; some may increase while others are influenced by other fuel types. In real markets, all sorts of combinations could be experienced thereby creating multiple uncertainties. Reduction of a fuel price of a newly established power plant, if a greater reduction in other fuel prices does not occur, determines the market position of the newly established power plant and vice versa (Zeljko, 2008).

#### 2.1.1.2 Electricity demand

Under normal circumstances, the trend of electricity consumption on a particular market does not follow or abide by the anticipations for a certain period. In a given year, the real consumption can be less or greater than the forecasted one. In such a scenario, if the real consumption is greater than what was initially forecasted then it decreases the risks of operations and profitability. On the contrary, if the estimated consumption is overrated then the risks of operations and profitability become higher (Zeljko, 2008).

#### 2.1.1.3 Hydrology

Hydrology plays a specific role in influencing risk levels of a potential power plant. The quantity of hydrology determining the risk level is reliant on the share of hydropower plants in the entire set up of all production units, not only in the grid system of a country where the plant is located but also the grid system of the entire potential market region. In the expansion planning process, hydrology is analyzed in three levels including low, medium and high and every level is ascribed to a probability factor. On average, hydrology is used in calculations and for determining future uncertainties for lifetime operations. Hydrology determines risk levels based on the annual hydrology dynamics and changes. For instance, when taking into account setting up new hydro plants, a wetter hydrology period means lower risk of capital return and greater production. Contrary, a wetter hydrology could also provide a false image that a potential power plant has a less significant market share since other hydro plants similarly increase their production (Zeljko, 2008). This would be particularly the case for a market that only consists of hydropower plants. In a mixed market, the impact is pretty different. In the regime of wetter hydrology, there is a growth of hydropower plant production thereby decreasing the shares and portfolio volume of other power producing plants.

#### 2.1.1.4 Electricity market price

The electricity market price has a considerable impact on the productivity, operations, efficiency, and continuity of a potential power plant. In durations when the capital and production costs are lower than electricity market prices the potential power plant has to increase feasible production and the risk level are lowered. In the vice versa, there is decreased production and risk levels are increased (Zeljko, 2008).

#### 2.1.1.5 Institutional framework

The institutional framework determines the stability, continuity, and future of the power plant in several ways. One way is particular for open markets whereby a section of consumers (eligible consumers) can select the energy supplier while the others (tariff consumers) are regulated. In such conditions, specific power plants can be contracted for the provision of public service obligation and obtain a regulated fixed price which makes some of the operations in the market difficult. The second way is on the basis of renewable energy administrative measures that influence power plants production and market status. The scenario is similar when there are mandatory quotas of renewable energy for suppliers, for instance, mandatory provision of green energy. The institutional framework also encompasses various environmental restrictions such as environmental protection legislations and multiple international protocols and conventions (Zeljko, 2008). All together, these measures can cause some generation technologies to be less competitive in the market, therefore, forcing them to reduce expansion and production or invest in expensive emission reduction technologies.

#### 2.1.1.6 Technology development

Technology development is as well as major risk factor attributed to the needs for constant technological improvements to cater for adequate electricity supply and reliability. As such, it is fundamental to evaluate technological development in the expansion planning process. Technological development is computed in two major directions. First is to increase efficiency levels of an existing power plant technology and second, to build a new competitive technology. Examples are the accelerated need in the recent times for renewable energy technologies to enhance efficiency and reliability in electricity supply as well as profitability (Zeljko, 2008).

Additionally, as Zeljko (2008) notes, one of the most significant rudiments for the feasibility study associated with the future power plant is the anticipated annual generation of the plant. For example, if the financial scheme of the plant expansion program is known, including grace period, loan repayment period, or interest rates, there is a possibility of defining monthly and annual expenditures for the capital costs. In a generation expansion scenario, for instance, the expansion costs can easily be established provided an assumed future fuel prices and operations, and maintenance costs are known. Eventually, it can address the decision-making problems since the anticipated revenue of the plant, yearly electricity demands, and electricity market price shall have been calculated. The loading order under load duration curve (LDC) is suitable enough for making comparisons and estimations of the anticipated yearly generation of the newly established power supply. For the estimation of the financial effects and the yearly generation capacity, several models can be used based on LDC estimated by Fourier coefficients (WASP model), or by a few bars with different height (MESSAGE model), or by cumulants (SPRA model).

However, Zeljko (2008) warns that these models are traditional and need to be used alongside some of the new models developed for different market situations. Besides that, Zeljko (2008) adds that the majority of the models all together are only suited for short-term generation expansion planning to optimize the operations of the existing plant. Zeljko (2008) emphasizes that even by using latest models like the PLEXOS, EMCAS, EGEAS or GTMax, uncertainties are still present. As a consequence, it is challenging to have the precise electricity supply demands and reliability projections for long periods, up to three decades, in advance. The factors highly influencing uncertainties and decision-making complexities are the variable costs for loading order (plant generation) calculation and the criterion for loading order calculation.

## 2.2 Transmission Expansion Problems

Within the context of an electric industry, transmission expansion planning (TEP) refers to the process of decision making by a Transmission System Operator (TSO) so as to establish the best way to reinforce and expand an existing grid transmission system. de Dios et al. (2007) present an industry viewpoint of their main decision making problem.

They propose that the TSO is the publicly governed entity in control of maintaining, operating, expanding and reinforcing the electricity transmission system within a given area of operation. In different European countries, TSOs are coordinated via ENTSO-E as pointed out by ENTSO-E (2013). In the United States, TSOs in most cases have much greater limited features than the TSOs in Europe, and are commonly known as Regional Transmission Organizations (RTOs).

According to Zerrahn and Huppmann (2014), deficiency of transmission capacity hinders the European electricity market from combining into an integral whole, and as such prevents maximum gains of completion. In their study, they examine the magnitude to which electricity transmission expansion encourages competition, welfare, and efficiency. The European Union in the mid-1990s began formulating plans and strategies for an integrated Internal Energy Market (IEM). The IEM unbundled the previously state-owned utilities and the electricity transmission grid allowed entry for new generators into the power market. Initially, the interconnectors between countries were set up for contingencies but not to smoothen the progress of cross-border trade. As such, what lacked were enough physical interconnector capacities to attain a fully integrated market. Through empirical investigations which identify persistent wholesale price spreads involving countries, strong pointers about incomplete integration in Europe are established (Böckers et al., 2013; Zachmann, 2008). This trend corresponds to a growing utilization of commercial transfer capacity and a reducing number of flows against the price differential, thus directing towards a more efficient use of interconnector capacity. Furthermore, it might prove profitable for them at insistently congesting lines to the nearby areas in order to cushion against the entry of competitors into their domestic market. They have used transmission grid expansion to mitigate the implications of small network capacities hindering competition.

The investigation of strategic generator reactions and actions in networks has been central in academic studies for many years. Neuhoff et al. (2005) underscore that the focus on this area has been compounding. In particular, diverse approaches involving how transmission constraints in bi-level models have been tackled are compared, and the authors recognize the primary challenges in providing a reasonable representation of interactions between strategic generation and getting rid of multiple markets.

Distinctively, two methods are available for integrating the transmission system operators (TSO) optimization programs contingent upon whether key players expect their impact on network operation or not (Hobbs et al., 2005). Typical instances include the exogenous assumption of rationing mechanisms if there happens to be a scarce transmission capacity (Willems, 2002), continued variation of an inelastic demand parameter (Boffa et al., 2010), and strategic actors handling transmission charges originating from TSO optimization as exogenous in their constraint sets (Tanaka, 2009). An in-between approach is chosen by Hobbs and Rijkers (2004) whereby generators hold conjectures regarding transmission price responses. Ehrenmann and Neuhoff (2009) and Cunningham et al. (2002) pursues the Stackelberg assumptions that clearly derive closed-form solutions and reaction functions under rigid assumptions for some unique cases. Then again, Ehrenmann and Neuhoff (2009) and Hobbs et al. (2000) suggest algorithm solutions on the basis of diagonalization approaches. Nevertheless, of all these methods, network expansion continues to be exogenous to the model and is restricted to a small number of scenarios in shifting line constraint sets.

Across the world, multiple scenarios of aging electrical transmission infrastructure are a common feature (MIT-Energy-Initiative, 2011). Hence, it is essential for the institutionalization of mathematical model tools to enhance TSOs effective decision making concerning updating and bettering the electricity transmission infrastructure. At times, these types of decisions have to be made under huge uncertainty owing to the uncertainties of both stochastic productions and demand growth in the regions of some generation plants. The uncertainties have both temporal and spatial proportions as production and demand facilities are situated at different geographical regions and the stochastic production and the demand are both temporally correlated (Baringo and Conejo, 2013). Moreover, Bouffard et al. (2005) note that uncertainty regarding failure of equipment as well affects the operation and hence the need for improvement or expansion of the transmission system.

According to de Dios et al. (2007), transmission planning decision making usually demands a planning horizon for about 10 years with reviews after every 2 years. The planning horizon can as well be lengthened or shortened contingent upon environmental policies or construction considerations. Usually, construction times for transmission facilities are much shorter and ranges from 6 months to 2 years. Thus, TEP is a medium term expansion problem with lesser uncertainty levels compared to that involved in the production investments. Nevertheless, employing year-by-year account of investment decisions may bring about a really complex and computationally intractable model. So as to ascertain tractability while maintaining the accuracy of the model as much as possible, one or few objective years are as a rule selected for the planning activities and yearly investment costs are also taken into account (Garcés et al., 2009; Jabr, 2013; Sauma and Oren, 2006). Still, to achieve effective and critical transmission investment plans, reasonable capturing of the effects of the uncertain factors on the outcomes of investment is paramount.

Garver (1970)'s study pioneers transmission expansion planning whereas applicable contributions on the basis of mathematical programming are owed to Pereira and his partners including Monticelli et al. (1982), Pereira and Pinto (1985), and Binato et al. (2001). Practical heuristics have also been advanced by Romero et al. (1996). In Villumsen and Philpott (2012) and de la Torre et al. (2008), stochastic programming is employed. Garcés et al. (2009) addresses precise modeling in a market environment decision making process while Sauma and Oren (2006) proposed an appealing game-theoretical approach.

In electricity transmission planning, emphasis should be on the basis of designing using design models that can assure operation under the worst plausible conditions (Ruiz and Conejo, 2015). Notably, the hourly and daily basis of electricity systems is typically minimizing anticipated costs of operations. This is primarily because, in most cases, the various sources of uncertainty that are existent in the system can be forecasted accurately in the short-term for example equipment availability or the level of demand among others. Thus, the likelihood of incidence of unexpected event, with high damage probability, is very minimal (Ruiz and Conejo, 2015). However, within the lifetime of the electricity infrastructure (three to five decades ahead) there is high uncertainty, therefore, fresh expansion planning decisions need to be made several years in advance and must be designed to perform effectively under extreme operating conditions (Ruiz and Conejo, 2015). This is to guarantee ease to cope with future uncertainties with practical reliability and economic consequences considerations.

To face this challenge, Ruiz and Conejo (2015) suggest solving uncertainty via plausible robust sets. Ruiz and Conejo (2015) maintain that these sets are intended to represent a series of potential worst-case scenarios for use in infrastructure planning. Accordingly, one of the robust optimization approaches as pointed out by Ruiz and Conejo (2015) pertains to Adaptive Robust Optimization (ARO). Bertsimas et al. (2011) explicates that ARO permits modeling decision making under uncertainty with recourse. In a scenario where there are transmission expansion problems, ARO encompasses three steps which include: investment decision making advanced on the basis of maximum social welfare; worst case uncertainty scenario within a plausible uncertainty set that highly regards the physics of the problem; and decisions making in operations to moderate the negative consequences to the realization of uncertainty so as to attain optimal social welfare. Unconventional robust techniques (Soyster, 1973) do not give room for managing the robustness level, for example, conservatism of the attained solution which is a huge shortcoming. Conversely, Bertsimas et al. (2011) brings in formulations that creates the possibility to manage the robustness level of the attained solutions which permits advancement of valuable and practical planning tools.

ARO has two significant advantages with regards to stochastic programming approaches that typically need a big number of scenarios to handle the concerned uncertainty (Gabrel et al., 2014). The first one, scenarios need not to be generated because scenario generation may involve crude estimations on the representation of uncertain parameters. Not requiring scenario generation is a great advantage. Rather, robust sets are employed in ARO models (Bertsimas and Brown, 2009) and such set construction is usually much simpler compared to generating scenarios. The second one, ARO model is generally a moderate size and does not expand with the number of scenarios thereby not necessarily needing computational tractability. A recent practical use of ARO model in transmission expansion planning is detailed in Jabr (2013).

Maurovich-Horvat et al. (2015) posit that transmission expansion demands the restructuring of the electric power industry. However, sometimes it is precipitated by the notion that the regulated corresponding conditions would not satisfy the accelerating demands for efficiency as pointed out by Hyman (2010). The functions of the industry such as distribution, retailing, and generation can be dealt with altogether by an investor-owned utility (IOU) with reliability and transmission planning under the guidance of a system operator (Maurovich-Horvat et al., 2015). Nonetheless, one of the main problems encountered in transmission expansion is due to the lack of adequate incentives to develop new technologies for the market when profits are controlled (Maurovich-Horvat et al., 2015). Similarly, because some areas are operated by a single IOU and prices are simply set administratively, it typically creates no need for either strategic analysis or risk analysis. As much as different post-restructuring market designs have emerged, there is still a general requirement for incumbent IOUs to rid their generation resources with distribution and transmission remaining regulated (Maurovich-Horvat et al., 2015). As a result, such kinds of scenarios have introduced imperfect competition and endogenous price formations which mandate strategic view of decision making in transmission expansion, especially in circumstances where complementarity-based equilibrium modeling is used (Hobbs and Helman, 2003). Besides, market-driven transmission expansion or investment has been proposed by various works. The decision making problems and expansion challenges are highly influenced by the delicate balance of achieving forecasted targets while not interfering with the industry (Hobbs and Helman, 2003). Example includes the transitions to a sustainable energy system that may rely on aspects such as technological advancements, supply demands, and uncertainties which creates the need for considering concomitant transmission expansion when coming up with measures to promote potential power plant investments (Kunz, 2013). Accordingly, key players in the market need an in-depth grasp of how market designs interrelate with strategic behavior in producing the desired outcomes.

Under regulation, traditional cost-effective methods could be used to estimate optimal transmission and generation investment (Hobbs, 1995). Nevertheless, with deregulation, generation and transmission investment are made different entities with discrete and many times conflicting incentives. For instance, regulated transmission system operators (TSOs) seek to capitalize on social welfare, while power firms are mainly interested in maximizing on profits. According to  Gabriel et al. (2012) and Ruiz and Conejo (2009), to manage such game-theoretic interactions, complementary modeling is suggested to determine Nash equilibria, that is, solutions from which there is no chance of unilateral incentive to deviate for any agent. Moreover, according to the linear complementarity approaches of Nash-Cournot competition in bilateral and poolco power markets as cited by Hobbs (2001), complementarity modeling is tractable for evaluating strategic behavior in deregulated power firms owing to its accommodation of the physical features of the grid system (Hobbs, 2001).

Bi-level problems are especially relevant for the analysis of the policies of strategic interactions which originate when a leading (dominant) agent influences equilibrium prices by expecting the decisions of others at the lower level (Maurovich-Horvat et al., 2015). In an effective manner, the leader's optimization problem is restrained by a set of equilibrium constraints and optimization problems at the lower level. If every lower-level is convex, then it might be substituted by its Karush-Kuhn-Tucker (KKT) situation, thereby re-devising the bi-level problem as a mathematical program with equilibrium constraints (MPEC) (Maurovich-Horvat et al., 2015). As Ruiz and Conejo (2009) illustrate on how to address the optimal offering strategy of a leading power firm, the endogeneity in the objective role of an MPEC might be managed by employing a strong duality to rebuild the problem as a mixed-integer linear program (MILP) and to handle complementarity conditions through disjunctive constraints. Alternatively, bi-linear expansions might manage the endogeneity in the MPEC's objective function.

Still within the aspects of bi-level framework, Wogrin et al. (2013) uses the framework of Kreps and Scheinkman (1983) to look into a two-stage duopoly where producers are responsible for investment decisions in the first stage and operational decisions in the second stage. As such, the resultant bi-level equilibrium (closed-loop) problem with equilibrium constraints produces similar result as an open-loop mixed-complementarity problem (MCP) for whichever conjectural variation in the cash market provided there is a single load period and cash market is as competitive as in the Cournot case at the least. This rationalizes a single-level estimation of the producers' bi-level problem. Wogrin et al. (2013) similarly demonstrates a counter-example where the installed capacity is in actual fact lower in the closed-loop (EPEC) model in relation to the open-loop (MCP) model when cash markets are almost entirely competitive, thus signifying that open-loop outcomes might not constantly generalize for numerous time periods. Proceeding to a tri-level model, Sauma and Oren (2006) and Sauma and Oren (2007) reveals a welfare-maximizing TSO at the upper level undertaking transmission investments, producers at the middle level undertaking capacity investments, and market clearing is done at the lower level. Therefore, this is to a greater extent a difficult problem to analyze than even an EPEC, and can neither be solved directly by Sauma and Oren (2006) nor Sauma and Oren (2007). Instead, they compare pre-set transmission investment suggestions from different planner's viewpoints. In opposition to Sauma and Oren (2006), Sauma and Oren (2007) centers on market power by the producers and observes that diverging aims for the TSO might bring about politically infeasible expansion plans.

In as much as transmission expansion has substantially remained under the direction of regulated TSOs, market-based models for transformation expansion have been suggested in the US and the UK. For instance, Hogan (1992) states a role for merchant investor (MI) who can construct new transmission lines inspired by the collection of congestion fees between grid nodes. Joskow and Tirole (2005) however hypothesizes that efficient outcomes are subverted under the MI if market power exists. In discussions pertaining the setting for merchant transmission investment in Europe, Kristiansen and Rosellon (2010) observes that financial transmission rights (FTRs) would be of benefit when handling externalities and availing hedging capabilities for investors. Still, inefficiencies have presented from empirical analyses of some markets for FTRs in the USA particularly in congested regions where there exists spot prices and divergent forward congestion fees/rents in their operations (Bartholomew et al., 2003).

A basic difficulty in power system planning is how to deal with the relations of participants' actions in deregulated markets. High costs makes this even more important. According to Pozo et al. (2017) some authors offered proactive or anticipative transmission investment plans to model together the relations between deregulated electricity market participants making expansion decisions driven by the markets. They also claim many studies have shown that by anticipating line investment to generation investment equilibrium and market outcomes; a Transmission Network Planner can increase social welfare. Still, proactive transmission investment decisions may cause suboptimal solutions when the generation expansion equilibrium problem have multiple solutions. They offer a methodology to study the potential effects of proactive investment planning on generation investment decisions. To solve their problem, they also offer an approach to derive EPEC solutions with ensured global optimality based on a column-and-row generation algorithm. Besides in a recent literature review on co-optimization in power systems (Olatujoye et al., 2017), it is claimed that co-optimization has great potential in determining high sunk costs and other decisions related to other infrastructures as certain types of decisions within planning are dependent.

## 2.3 Co-Optimization of Transmission and Generation Expansions

In competitive electricity markets, the strategic generation and transmission expansion decisions (investments) and the operational market clearing outcomes (bidding prices and quantities) influence each other. In the literature, there is a focus on multi-level programming problems to model these decisions using hierarchical decision making tools (e.g., equilibrium and mathematical programs with equilibrium constraints (MPECs and EPECs) among different agents (system operator, generators, consumers). However, solving these models can be very challenging and generally not computationally tractable. (You et al., 2016)

Methods for co-optimizing transmission and generation investments consider trade-offs with market operations and interactions in electric power supply, demand and as well as storage. Under fairly general conditions it is known that simultaneous solution of these multi-level models using complementarity problems can give useful results than iterative optimization methods or single-level optimization of generation or transmission expansion alone. (Liu et al., 2013) In this thesis, we provide mixed complementarity problem formulations for transmission and generation expansion models with an electricity market clearing model. Even though studies about complementarity models of electricity markets have attracted much attention in the past decade, studies focusing on Turkish electricity market are very rare and this study also aims to contribute to the literature on Turkish electricity markets.

Co-optimization can play a substantial role in facilitating simultaneous and integrated assessment of almost all the planning processes in the electricity market. There are two major cases we have focused on in this thesis. In the first case, we state a centralized planner model where we have considered a welfare maximizing (or at least cost solution in perfectly competitive case) by considering the tight coordination between transmission and generation. In the second case, a bi-level model for a decentralized market environment is examined, since it expedites exploration of how generation investments and market-clearing decisions of generators respond to changes in transmission capacity and congestion. In this manner, policy makers and planners can identify transmission grid reinforcement that encourages generation investments that produce the highest welfare for power transmission and generation. (Krishnan et al., 2016)

In a recent study held by Ziaee et al. (2018), they integrate the optimal transmission investment planning problem and the optimal placement of thyristor controlled series compensators (TCSCs) in a transmission network. The numerical results of the offered optimization model for the Garver's 6-bus and the IEEE 118-bus systems reveal the cost benefits and wind penetration of using the co-optimization. Meanwhile the so-called driven by renewable sources generation investment trend, forced by high renewable targets, is not followed by the same movement in the transmission investment planning. In this context, new methodes are needed to balance the costs. It gets even worse with contingencies where all calculations get more complex. So another study (Moreira et al., 2017) models a double stage min-max-min problem for co-optimizing the investment for the transmission lines and also renewable capacity considering the uncertainty of renewable generation. Transmission planning and expansion generally followed a "generation first" or "reactive" logic. When the world has figured the emergency of renewables, the deficiency in this approach was completely revealed as it ignores the interdependence between transmission and generation expansions. Ignoring the complementarity increases costs. Theoretically the solution for this is using a proactive transmission plan which anticipates how generation expansion responds by co-optimizing transmission and generation investments. Spyrou et al. (2017) consider and evaluate the potential of co-optimization by using a mixed-integer linear programming for a 24-bus representation of the U.S. Eastern Interconnection. They estimate cost savings from co-optimization and those savings end up being comparable to the amount of incremental transmission expansion.

# 3. A CO-OPTIMIZATION MODEL WITH MARKET EQUILIBRIUM

## 3.1 Mathematical Framework and Model Formulations

Economic theory suggests that, in a competitive market there will be a single price which brings demand and supply into balance, called equilibrium price. In its simplest form, the constant interaction of buyers and sellers enables a price to emerge over time. Equilibrium price is also called market-clearing price, because at this price the exact quantity that producers take to market will be bought by consumers, and there will be nothing ‘left over’. This is efficient, because there is neither an excess of supply and wasted output, nor a shortage – the market clears efficiently. This is a central feature of the price mechanism, and one of its significant benefits. Economic equilibrium problems are mainly application of these fundamental principles (EconomicsOnline, 2017).

In general, our model can be depicted as in Figure 3.1, using a bi-level structure where upper level problem is for the investment decisions and the lower level problem is the market-clearing equilibrium. The difference of our model is that the upper level problem includes the transmission investment decisions, whereas the lower level problem includes the generation investment decisions as well as the market-clearing equilibrium. This bi-level structure is usually seen in Stackelberg leader-follower games (Gabriel et al., 2012).

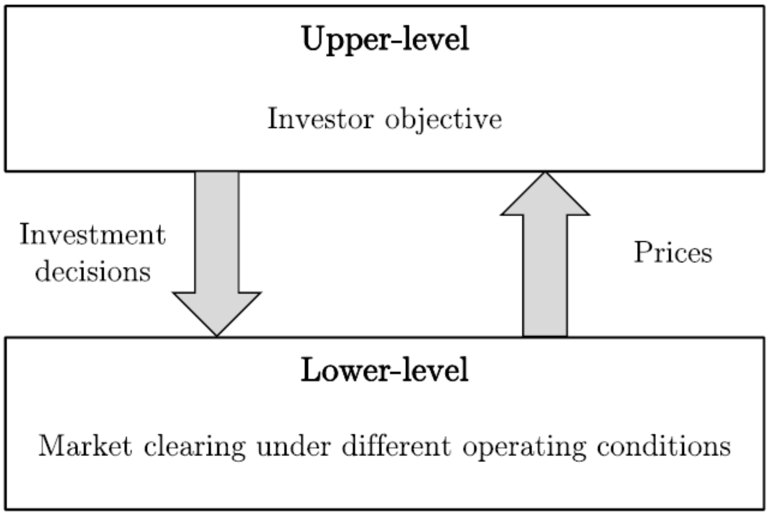


**Figure 3.1 Bi-level Model Structure (Baringo and Conejo, 2013)**

In this study, we have used several approaches and formulations to model this bi-level problem. The first is a complementarity problem (CP) formulation. Given the new paradigm for electricity markets, combining in some cases an old regulated structure and new deregulated markets with either imperfect or perfect competition, there is a need for robust models to aid decision-makers. This is where complementarity modeling comes into the picture. CP generalizes the linear programs (LP), (convex) quadratic programs (QP), and (convex) nonlinear programs (NLPs). This correspondence is made through the Karush-Kuhn-Tucker (KKT) optimality conditions for these problems. Indeed, the statement of these conditions is a special case of a CP (Gabriel et al., 2012).

The simultaneous (or interrelated) optimization problems of one or several interacting agents in the market can be represented by a CP framework. It has become an increasingly popular and important tool for formulating and solving electricity market models. We can define an equilibrium problem as the joint optimization of several decision-makers' problems and by bringing all the KKT conditions of these decision makers' problems together form a CP, as presented below in Figure 3.2.

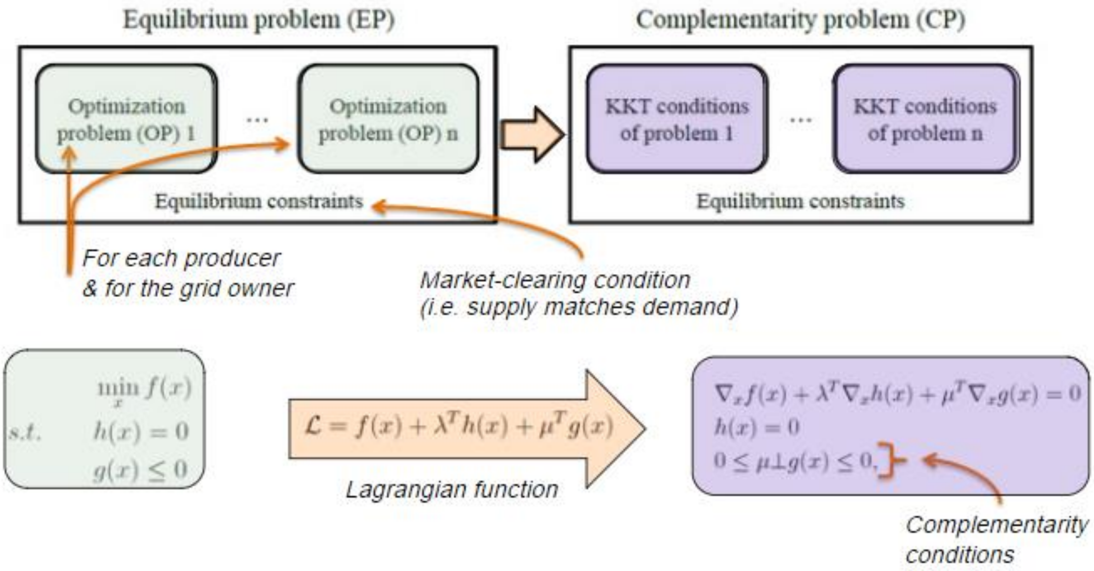


**Figure 3.2 Complementarity Problems (Virasjoki et al., 2016)**

In this CP framework, all decisions are simultaneously taken into account. Compared to the bi-level structure, there is no hierarchy in decision making (i.e., investors do not anticipate the outcomes of the market-clearing equilibrium). Complementarity conditions (i.e., variable-condition pairs), denoted as $0 \leq \mu \perp g(x) \geq 0$, states that either the condition is binding (i.e., $g(x) = 0$) or the variable is zero (i.e., $\mu = 0$) in the equilibrium solution.

The mixed complementarity problem (MCP) can be viewed as a generalization of the CP to the case of general and perhaps infinite lower and upper bounds rather than the non-negativity condition imposed in CP. As any practical application of an interior point or simplex method for linear programming must explicitly consider lower and upper variable bounds and free variables, MCP must also include them (Dirkse and Ferris, 1994).The formulations in Section 3.3, firstly present each agents (consumers, generators, system operator) problem individually and then, we form the MCP models (e.g., see equation (3.15) in Section 3.3).

Another formulation we have examined in Section 3.3 is the mathematical program with equilibrium constraints (MPEC) framework, which is depicted in Figure 3.3.

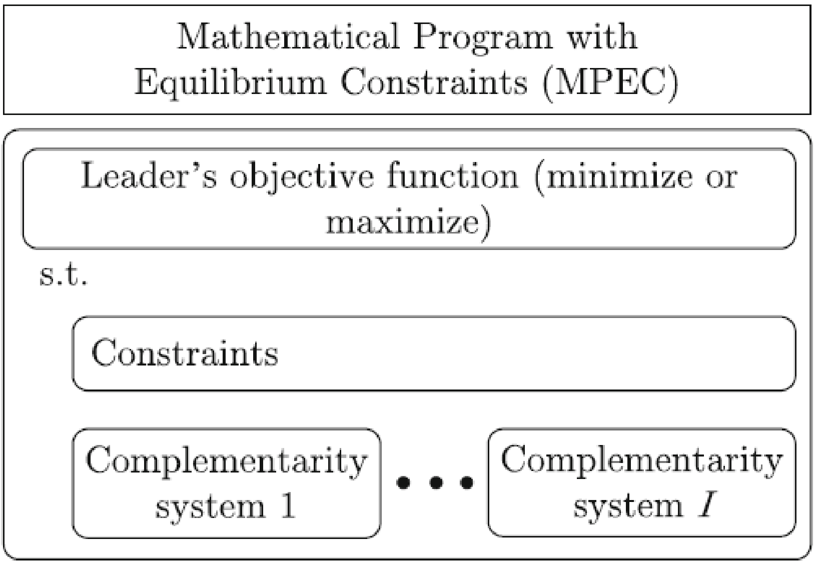


**Figure 3.3 MPEC Framework (Ruiz et al., 2014)**

In this framework, MPEC is an optimization problem whose constraints include other interrelated optimization or complementarity problems. MPEC is a recently grown field of research and is an extension of bi-level programming. The equilibrium constraints are normally manifested as a complementarity system. The concept of MPEC has its origins in the economic concept of Stackelberg games (Olsson, 2010). However, as Wogrin et al. (2013) mentioned, the bi-level equilibrium (closed-loop) or its reformulation as an MPEC model produces similar results as an MCP (open-loop) model under fairly general conditions. We provide both MPEC and MCP formulations for our models in Section 3.3.

For the MPEC model, if some of the agents' problems include binary decisions (e.g., to invest or not), then there is a further difficulty we have to consider. The MPEC and MCP models require continuous variables and introduction of binary variables would make these problems intractable, since there is no solution algorithm readily available for these type of problems with binary variables. One way to tackle these type of problems are to convert the complementarity conditions to a set of equivalent constraints by using Fortuny-Amat et al. (1981) method (e.g., by introducing new binary variables for variable-condition pairs in CP). This is also explained in Section 3.3.

## 3.2 Market Structures

In this study, we use perfect competition and Nash-Cournot market structures. Perfect competition is a market structure where the following five criteria are satisfied: All players sell a homogenous product; all players are price takers - they cannot control the market value of the product; all players have a relatively small market share; buyers have full information about the product and the prices charged by each player; and the industry is completely free to enter or exit (Investopedia, 2018). The main rationale in using perfectly competitive market structure is that it can be used as a benchmark to other market structures (e.g., the prices/sales can be compared), because this market structure provides the most efficient market outcomes.

On the other hand, Nash-Cournot model of oligopoly assumes that rival players produce a homogenous product, and each attempts to maximize profits by choosing how much to produce. All players choose output (quantity) simultaneously. The basic Cournot assumption is that each player chooses its quantity, considering the rivals' quantities as fixed values. The resulting equilibrium is a Nash-Cournot equilibrium in quantities where no player would have any incentive to deviate. If the oligopoly is symmetric, that is, all players have identical products and cost conditions, then to which the degree price exceeds marginal cost is inversely related to the number of players in the market. Thus, as the number of players increases, the equilibrium approaches what it would be under perfect competition (Khemani and Shapiro, 2002).

Besides Nash-Cournot structure, there are also other approaches available to model the competition in the electricity market, such as supply function equilibrium (SFE) or Bertrand competition. In SFE, each firm submit a bid function (i.e., the bid is a function of generation amount) rather than the marginal cost values as in Nash-Cournot model. However, the main drawback of SFE is its computational intractability and existence of multiple equilibria due to non-convexity. On the other hand, in Bertrand model, the competition is in selling prices rather than quantities as in Nash-Cournot model. But this usually leads to perfect competition solution where the prices are set to marginal cost of generation. Although, Nash-Cournot model is not as realistic as SFE, it is easy to compute solutions and it usually provides solutions that are close to long-run market behavior (Day et al., 2002).

## 3.3 Mathematical Model and Assumptions

This model is based on the works of Gabriel et al. (2012) as they apply a well-simplified complementarity application of the study of Hobbs (2001). Hobbs (2001) deals with a linear complementarity of Nash-Cournot market structure in a bilateral or pool type power markets and Gabriel et al. (2012) use a stochastic version of the original model solved with Benders decomposition algorithm. The models in these papers are the basis of our model and we rebuilt them as co-optimization problems in search for a more efficient solution to expansion problems by introducing investment decisions that would affect the capacity of generators and transmission lines. According to our model we can determine a basic perfectly competitive model and an oligopolistic model. The models that are detailed below can be converted to a perfectly competitive, open loop model where every player's problems are solved together. On the other hand, similar models where firms behave in an oligopolistic way can be built. The basic assumptions of the model are as follows:

- Market-clearing model is built for day-ahead markets and consider transmission constraints (balancing or real-time markets are not considered).
- Transmission/generation investments will be done for the "target year" in future (instead of a dynamic investment model for every year, picking a target year is a common practice in the literature).
- In compliance with the "target year" application, investment costs are discounted on an hourly basis.
- Potential generation investments are applicable for certain firms and buses and they have upper limits.
- Relatively, potential transmission line investments are also defined between certain buses and they are considered to have upper limits as they are constrained with a budget.

In this model, the generators can sell to all the consumers in the entire system and they use the system operator as a mediator. In this structure, while the system operator wants to optimize its transmission service income according to the network constraints of the entire system (DC load flow constraints that approximate the flow and voltage laws of Kirchhoff), generator companies (GenCOs) want to optimize their profits (according to the capacity, and generation-sales constraints). Besides, consumers can change their amount of consumption as a reaction to price levels (for optimizing their welfare levels). We first define each decision maker's problem individually and then form the overall equilibrium problem by concatenating each problem's optimality (KKT) conditions as an MCP. The equilibrium of this model is having the supply-demand equilibrium of every single bus (e.g., market-clearing conditions and nodal electricity price as dual variables of these conditions). This market-clearing model is valid for markets that have only bilateral agreements or only a power pool (PoolCO) who operates alone in the market (Hobbs, 2001).

The inverse demand function models the consumer behavior, i.e., the reaction of consumers to the change in prices, using (3.1). An equivalent formulation to this function can be consumer's benefit optimization model with a budget constraint. Every bus in the transmission system has its own linear inverse demand function (3.1) depending on the total sales of all the firms in that bus, where $f_{d,i}^{-1}$ denotes the inverse demand function at bus *i* (e.g., $price_i$) and $\sum_{f \in F} s_{fi}$ denotes the total sales of all firms at bus $i$. Both parameters $\alpha_i$ and $\beta_i$ are non-negative parameters. These parameters are calculated as in Şentürk-Eker (2017), also see section 4.3 of this thesis for details.

$$f_{d,i}^{-1}\left(\sum_{f \in F} s_{fi}\right) = price_i = \alpha_i - \beta_i \left(\sum_{f \in F} s_{fi}\right) \tag{3.1}$$

Generating firm *f*, is a price-taker in the perfectly competitive market and considers that the price in every single bus is an external parameter in the objective function. From the market's perspective, this price is a variable and is determined according to the balance of supply and demand in every single bus. All firms optimize their profits (sales revenue minus operating costs minus generation investment costs in (3.2)) according to the equivalence of total generation-sales (3.3), capacity constraints (3.4) and investment upper limits (3.5). As can be seen in (3.4), generation investments affect the capacity constraints. Dual variables are shown between parentheses next to the constraints. Finally, (3.6) shows the non-negativity constraints. Note that this problem is represented for a single firm $f$ only, where $f \in F$, but in the overall equilibrium problem, all firms' problems will be included.

$$\min_{s_{fi}, x_{fi}, \Delta K_{fi}} -\sum_{i \in I_f} \left( \alpha_i - \beta_i \left( \sum_{f \in F} s_{fi} \right) \right) s_{fi} + \sum_{i \in I_f} c_{fi} x_{fi} + \sum_{i \in I_f} c_{fi}^{Gexp} \Delta K_{fi} \qquad (3.2)$$

s.t.

$$\sum_{i \in I} s_{fi} - \sum_{i \in I_f} x_{fi} = 0 \;\; (\nu_f) \qquad (3.3)$$

$$x_{fi} \le K_{fi}^{0} + \Delta K_{fi} \quad (\mu_{fi}) \qquad i \in I_f \qquad (3.4)$$

$$\Delta K_{fi} \le K_{fi}^{max-exp} \quad (\delta_{fi}) \qquad i \in I_f \qquad (3.5)$$

$$s_{fi} \ge 0, \quad x_{fi} \ge 0, \quad \Delta K_{fi} \ge 0 \qquad i \in I_f \qquad (3.6)$$

The objective of the system operator is to effectively distribute the transmission system services considering network constraints and optimizing the revenue from these operations. System operator's revenue optimization in this manner, in fact, makes sure that firms cannot use their power to get more transmission right in this competitive market (Hobbs, 2001). In other words, the system operator works as a market arbitrager, where it benefits from price differences among nodes, for details see Gabriel et al. (2012). In this model, the system operator's behavior is modeled as a market player who approves that he cannot affect the price levels (even though, in the market model, price is an endogenous variable). Actually this model is like the "flowgate" market model offered by Chao and Peck (Gabriel et al., 2012; Hobbs, 2001). Furthermore, in this model, the system operator also decides on transmission line capacity investments ($\Delta T_{ij}$) in compatible with investment upper limits (3.10) and these affect the power flow limits (3.8) and (3.9). The objective function (3.7) denotes the revenue of the system operator, calculated as the price differences multiplied by the power flows $\sum_{i \in I} \sum_{j \in J_i} (p_i - p_j) B_{ij} (\theta_i - \theta_j) = \sum_{i \in I} p_i \sum_{j \in J_i} B_{ij} (\theta_i - \theta_j)$, minus the transmission expansion costs. Constraints (3.8) and (3.9) define the DC power flow limits (e.g., a DC power flow approximation is used, see Gabriel et al. (2012) for details) and upper and lower bounds of phase angle $\theta_i$ at bus $i$ is denoted by (3.11). The reference bus is denoted by (3.12) and (3.13) is the non-negativity constraints. This is a pretty standard representation for the system operator's problem, except that the transmission expansion decisions are also included in the problem.

$$\min_{\theta_i, \Delta T_{ij}} \sum_{i \in I} \left( -p_i \sum_{j \in J_i} B_{ij}(\theta_i - \theta_j) + \sum_{j \in J_i} c_{ij}^{Texp} \Delta T_{ij} \right) \tag{3.7}$$

s.t.

$$B_{ij}(\theta_i - \theta_j) \le T_{ij}^0 + \Delta T_{ij} \quad (\lambda_{ij}^+), \quad \forall\, i \in I, j \in J_i \tag{3.8}$$

$$-B_{ij}(\theta_i - \theta_j) \le T_{ij}^0 + \Delta T_{ij} \quad (\lambda_{ij}^-), \quad \forall\, i \in I, j \in J_i \tag{3.9}$$

$$\Delta T_{ij} \le T_{ij}^{max-exp} \quad (\gamma_{ij}), \quad \forall\, i \in I, j \in J_i \tag{3.10}$$

$$-\pi \le \theta_i \le \pi \quad (\varepsilon_i^{min}, \varepsilon_i^{max}), \quad \forall\, i \in I \tag{3.11}$$

$$\theta_i = 0 \quad (\xi), \;\; i = reference\ bus \tag{3.12}$$

$$\Delta T_{ij} \ge 0 \quad \forall\, i \in I, j \in J_i \tag{3.13}$$

Market clearing conditions are displayed by (3.14) and basically depend on the supply and demand balance on each bus. In the mixed complementarity problem, dual variable of this condition is the nodal electricity price ($p_i$).

$$\sum_{f \in F} x_{fi} - \sum_{f \in F} s_{fi} - \sum_{j \in J_i} B_{ij}(\theta_i - \theta_j) = 0 \;(p_i) \;\; \forall\, i \in I \tag{3.14}$$

Co-optimization model with market equilibrium consists of the first degree optimality conditions (KKT conditions) of generators' and system operator's problems along with market-clearing conditions and inverse demand functions It is formulated as an MCP in (3.15), where "⊥" reads as "perpendicular to" (i.e., either the variable is zero or the condition is equal to right hand side.)

MCP: Solve for $s_{fi}, x_{fi}, \Delta K_{fi}, \nu_f, \mu_{fi}, \delta_{fi}, \theta_i, \Delta T_{ij}, \lambda_k^+, \lambda_k^-, \gamma_{ij}, p_i, \varepsilon_i^{min}, \varepsilon_i^{max}, \xi$ so that:

$$
\begin{array}{rll}
s_{fi} \geq 0 \perp & -\alpha_i + \beta_i \left( \sum_{f \in F} s_{fi} \right) + p_i + \nu_f \geq 0 & \forall f \in F, i \in I \\
x_{fi} \geq 0 \perp & c_{fi} - p_i - \nu_f + \mu_{fi} \geq 0 & \forall f \in F, i \in I_f \\
\Delta K_{fi} \geq 0 \perp & c_{fi}^{Gexp} - \mu_{fi} + \delta_{fi} \geq 0 & \forall f \in F, i \in I_f \\
\nu_f \; free \perp & \sum_{i \in I} s_{fi} - \sum_{i \in I_f} x_{fi} = 0 & \forall f \in F \\
\mu_{fi} \geq 0 \perp & x_{fi} \leq (K_{fi}^0 + \Delta K_{fi}) & \forall f \in F, i \in I_f \\
\delta_{fi} \geq 0 \perp & \Delta K_{fi} \leq K_{fi}^{max-exp} & \forall f \in F, i \in I_f \\
\theta_i \geq 0 \perp & \begin{array}{l} \sum_{j \in J_i} B_{ij}(p_i - p_j) \\ + \sum_{j \in J_i} B_{ij}(\lambda_{ij}^+ - \lambda_{ji}^+) \\ - \sum_{j \in J_i} B_{ij}(\lambda_{ij}^- - \lambda_{ji}^-) \\ + \varepsilon_i^{max} - \varepsilon_i^{min} + \xi = 0 \end{array} & \forall\, i \in I, j \in J_i \\
\Delta T_{ij} \geq 0 \perp & c_{fi}^{Texp} - \lambda_{ij}^- - \lambda_{ij}^+ + \gamma_{ij} \geq 0 & \forall\, i \in I, j \in J_i \\
\lambda_{ij}^+ \geq 0 \perp & B_{ij}(\theta_i - \theta_j) \leq T_{ij}^0 + \Delta T_{ij} & \forall\, i \in I, j \in J_i \\
\lambda_{ij}^- \geq 0 \perp & -B_{ij}(\theta_i - \theta_j) \leq T_{ij}^0 + \Delta T_{ij} & \forall\, i \in I, j \in J_i \\
\gamma_{ij} \geq 0 \perp & \Delta T_{ij} \leq T_{ij}^{max-exp} & \forall\, i \in I, j \in J_i \\
\varepsilon_i^{max} \geq 0 \perp & \theta_i \leq \pi & \forall\, i \in I \\
\varepsilon_i^{min} \geq 0 \perp & -\theta_i \leq \pi & \forall\, i \in I \\
\xi \; free \perp & \theta_i = 0 & \begin{array}{c} i = reference \\ bus \end{array} \\
p_i \; free \perp & \sum_{f \in F} x_{fi} - \sum_{f \in F} s_{fi} - \sum_{j \in J_i} B_{ij}(\theta_i - \theta_j) = 0 & \forall\, i \in I
\end{array}
\tag{3.15}
$$

As non-negativity constraints and their dual variables are not mentioned in (3.15), variables with non-negativity constraints have their KKT conditions in " $\geq$ " form in (3.15). Different market structures can be modeled using this MCP (3.15) by modifying its first condition. Instead of the current perfectly competitive market structure, a Nash-Cournot market structure can be modeled by modifying the first condition as follows:

$$s_{fi} \geq 0 \perp \quad -\alpha_i + \beta_i\left(\sum_{f\in F} s_{fi}\right) + \beta_i s_{fi} + p_i + \nu_f \geq 0 \qquad \forall f \in F, i \in I$$

In this case, the generators are aware of the price-quantity relationship (demand function) in the market and they assume that they can influence the prices by modifying their sales (or generation) amounts. Another major assumption for the Cournot game is that they have assumed fixed values for other generators' sales (or generation). This usually results in higher prices for consumers.

As in Pozo et al. (2013), Jin and Ryan (2014) and Maurovich-Horvat et al. (2015), this model can be modeled hierarchically (as a bi or tri-level model), too. It can be formulated as a model where system operator can anticipate generation investments and market-clearing equilibrium. In this bi-level model, system operator's investment problem is in the upper level and generators' investments and market-clearing model is in the lower level. It can be modeled as an MPEC model, where the system operator tries to optimize the social welfare (generators' and consumer's surpluses minus all investment costs) with transmission investment constraints. As Wogrin et al. (2013) mentioned, the solution to this MPEC model (closed loop) is exactly equivalent to the MCP model (open loop) under fairly general conditions.

$$\begin{aligned} \min_{\Delta T_{ij}} \quad & -\sum_{i\in I}\left(\alpha_i\left(\sum_{f\in F} s_{fi}\right) - \frac{1}{2}\beta_i\left(\sum_{f\in F} s_{fi}\right)^2\right) \\ & + \sum_{i\in I_f} c_{fi}x_{fi} + \sum_{i\in I_f} c_{fi}^{Gexp}\Delta K_{fi} \\ & + \sum_{i\in I, j\in J_i} c_{ij}^{Texp}\Delta T_{ij} \end{aligned} \tag{3.16}$$

s.t.

$$\varDelta T_{ij} \leq T_{ij}^{max-exp} \qquad (\gamma_{ij}), \quad \forall\, i \in I, j \in J_i \tag{3.17}$$

$$\varDelta T_{ij} \geq 0 \qquad \forall\, i \in I, j \in J_i \tag{3.18}$$

MCP (3.15) excluding conditions for $\varDelta T_{ij}$ ve $\gamma_{ij}$ (3.19)

The MCP (3.15) conditions in (3.19) can be converted to constraints with Fortuny-Amat et al. (1981) method, which is commonly used for bi-level models (by introducing variables for each variable-condition pair and upper limits (M). But the disadvantage of this model is to have too many binary variables and new formulation is prone to calculation errors. For instance, if upper limits (M) are too loose, feasible region can expand or if they are too narrow, it can be infeasible. In the literature, these bounds (M) for primal and dual variables are determined by a trial-error approach.

For instance, let $a$ and $b$ be a variable-condition pair in the MCP in (3.19):

$$a \geq 0 \perp b \geq 0 \qquad (\text{or } a \geq 0, b \geq 0, a.b = 0) \tag{3.20}$$

It can be converted to a set of constraints by introducing the binary variable $u$ as follows:

$$a \leq Mu, b \leq M(1-u), a \geq 0, b \geq 0, u \in \{0,1\} \tag{3.21}$$

This reformulation in (3.21) converts the MPEC problem to a mixed integer non-linear program (MINLP) and it can be solved using MINLP solvers (e.g., ALPHAECP or DICOPT solvers in GAMS). For the MCP formulation, continuous and decreasing (monotonous) demand functions ($\beta_i > 0$) and strictly convex cost functions of generation companies are sufficient for a solution to exist and they also ensure the uniqueness of prices, sales and generation/transmission investment amounts. But for the MCP (3.19) converted by Fortuny-Amat et al. (1981) method, uniqueness and existence conditions cannot be guaranteed, since MPEC problem itself is a non-convex model. Hence, this problem, which is built by (3.21) reformulation, cannot guarantee a global or a local solution (only a stationary solution can be found, if it exists).

Despite these drawbacks, we have also converted the above problem into an MPEC problem in Appendix A. Moreover, this is required for a model with new candidate transmission lines, since these decisions can only be modeled by binary variables as follows (see Appendix A.2 for the complete model):

$$\min_{\Delta T_{ij}, z_{ij}} \quad -\sum_{i \in I} \left( \alpha_i \left( \sum_{f \in F} s_{fi} \right) - \frac{1}{2} \beta_i \left( \sum_{f \in F} s_{fi} \right)^2 \right) + \sum_{i \in I_f} c_{fi} x_{fi}$$

$$+ \sum_{i \in I_f} c_{fi}^{Gexp} \Delta K_{fi} + \sum_{i \in I, j \in J_i} c_{ij}^{Texp} \Delta T_{ij} + \sum_{i \in I, j \in J_i^+} c_{ij}^{Texp} z_{ij} T_{ij}^{L+}$$

$$\text{s.t.} \qquad \Delta T_{ij} \le T_{ij}^{max-exp} \qquad \forall\, i \in I, j \in J_i$$

$$\Delta T_{ij} \ge 0 \qquad \forall\, i \in I, j \in J_i$$

MCP (3.15) excluding conditions for $\Delta T_{ij}$ ve $\gamma_{ij}$ and following conditions modified:

$$\theta_i \ge 0 \perp \quad \begin{aligned} & \sum_{j \in J_i} B_{ij} \left( p_i - p_j \right) \\ & + \sum_{j \in J_i} B_{ij} \left( \lambda_{ij}^{+} - \lambda_{ji}^{+} \right) \\ & - \sum_{j \in J_i} B_{ij} \left( \lambda_{ij}^{-} - \lambda_{ji}^{-} \right) \\ & + \sum_{j \in J_i^+} z_{ij} B_{ij} \left( \lambda_{ij}^{L+} - \lambda_{ji}^{L+} \right) \\ & - \sum_{j \in J_i^+} z_{ij} B_{ij} \left( \lambda_{ij}^{L-} - \lambda_{ji}^{L-} \right) \\ & \quad + \varepsilon_i^{max} - \varepsilon_i^{min} + \xi = 0 \end{aligned} \qquad \forall\, i \in I \qquad (3.22)$$

$$\lambda_{ij}^{L+} \ge 0 \perp \quad z_{ij} B_{ij} \left( \theta_i - \theta_j \right) \le T_{ij}^{L+} \qquad \forall\, i \in I, j \in J_i^+$$

$$\lambda_{ij}^{L-} \ge 0 \perp \quad z_{ij} B_{ij} \left( \theta_i - \theta_j \right) \le T_{ij}^{L-} \qquad \forall\, i \in I, j \in J_i^+$$

$$z_{ij} \in \{0,1\} \qquad \forall\, i \in I, j \in J_i^+$$

where $J_i^+$ is the set of new candidate lines connecting node $i$ and $j$.

This model can be converted to a MINLP model by using Fortuny-Amat et al. (1981) conversion of complementarity conditions with extra binary variables. Due to large number of extra binary variables and bounds (M) on primal and dual variables, this method generally requires many trial-error iterations to get the optimal solution. In our case, we were able to set them large enough (10,000) to get the optimal solution.

### 3.4 Results and Discussions

We used a "six bus network" as in Figure 3.1 with three generation companies on buses 1, 2 and 6 and three candidate lines presented in Figure 3.1. All of our data for the parameters are from Jin and Ryan (2014)'s study. They use a tri-level model with arbitragers, but we use a simpler model with no arbitrager in the market. We called the three candidate lines A, B and C. Every one of the eight transmission investment solutions are evaluated using our compact model. We have enumerated all possible transmission options in order to show that our equilibrium solution is indeed the best solution. However, for larger models with many new transmission line expansions, enumeration may not be a feasible option.

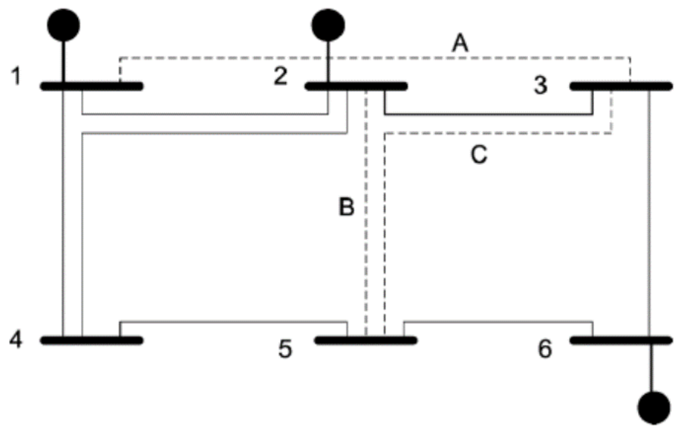


**Figure 3.4 Six Bus Test System**

## Table 3.1 Detailed Results under Perfect Competition

| **Transmission Line** | | None | A | B | C | AB | AC | BC | ABC |
|---|---|---|---|---|---|---|---|---|---|
| Total Surplus ($) | | 15638 | 17632.98 | 16886.18 | 14637.85 | 17736.36 | 17101.66 | 16575.65 | 17736.36 |
| Total Producer Surplus ($) | | 5447.48 | 6872.33 | 6181.52 | 5269.47 | 6961.16 | 6306.05 | 5874.60 | 6961.16 |
| Total Consumer Surplus ($) | | 7988.56 | 10432.74 | 9565.63 | 7129.99 | 10775.21 | 9213.08 | 8804.73 | 10775.21 |
| Total Transmission Rent ($) | | 2201.97 | 327.92 | 1139.03 | 2238.39 | 0 | 1582.54 | 1896.33 | 0 |
| Total Generation Investment Cost ($) | | 1367.75 | 1988.91 | 1723.92 | 1175.05 | 2045.46 | 1753.95 | 1594.48 | 2045.46 |
| Total Transmission Investment Cost ($) | | 0 | 400 | 400 | 400 | 800 | 800 | 800 | 1200 |
| Total Net Surplus ($) | | 14270.25 | 15244.07 | 14762.26 | 13062.80 | 14890.91 | 14457.71 | 14181.17 | 14490.91 |
| Generation Expansion level (MW) | 1 | 42.66 | 100.99 | 67.99 | 71.96 | 87.27 | 100.38 | 71.94 | 87.27 |
| | 2 | 72.60 | 97.90 | 92.31 | 21.28 | 117.27 | 70.30 | 73.78 | 117.27 |
| | 6 | 35.85 | 0 | 20.15 | 40.46 | 0 | 7.85 | 22.88 | 0 |
| Quantity Consumed (MW) | 1 | 54.67 | 47.38 | 51.50 | 51.01 | 49.09 | 47.45 | 51.01 | 49.09 |
| | 2 | 54.68 | 51.51 | 52.21 | 61.09 | 49.09 | 54.96 | 54.53 | 49.09 |
| | 3 | 44.95 | 66.39 | 52.46 | 43.31 | 69.09 | 59.91 | 51.58 | 69.09 |
| | 4 | 62.42 | 68.70 | 70.43 | 55.75 | 69.09 | 64.30 | 65.68 | 69.09 |
| | 5 | 58.34 | 68.36 | 69.93 | 48.76 | 69.09 | 61.83 | 63.24 | 69.09 |
| | 6 | 26.07 | 46.56 | 33.93 | 23.77 | 49.09 | 40.07 | 32,56 | 49.09 |
| Electricity Price ($/MWh) | 1 | 45.33 | 52.62 | 48.50 | 49.00 | 50.91 | 52.55 | 48,99 | 50.91 |
| | 2 | 45.33 | 48.49 | 47.79 | 38.91 | 50.91 | 45.04 | 45,47 | 50.91 |
| | 3 | 75.05 | 53.61 | 67.55 | 76.69 | 50.91 | 60.09 | 68.42 | 50.91 |
| | 4 | 57.58 | 51.30 | 49.57 | 64.25 | 50.91 | 55.70 | 54.32 | 50.91 |
| | 5 | 61.67 | 51.64 | 50.07 | 71.24 | 50.91 | 58.17 | 56.76 | 50.91 |
| | 6 | 73.93 | 53.44 | 66.08 | 76.23 | 50.91 | 59.93 | 67.44 | 50.91 |
| Flow (MW) | (1,2) | 22.38 | 5.67 | 51.22 | 54.17 | 11.64 | 8.74 | 55.20 | 9.13 |
| | (1,3) | 0 | 84.39 | 0 | 0 | 83.62 | **100** | 0 | 89.30 |
| | (1,4) | 45.61 | 43.56 | 45.27 | 46.78 | 22.92 | 24.19 | 45.73 | 19.76 |
| | (2,3) | **50** | **50** | **50** | **50** | 21.99 | **50** | **50** | 38.61 |
| | (2,4) | 40.31 | 52.06 | 14.92 | 14.35 | 19.91 | 24.08 | 12.09 | 17.95 |
| | (2,5) | 0 | 0 | 76.40 | 0 | 87.92 | 0 | 62.37 | 70.74 |
| | (3,5) | 0 | 0 | 0 | 34.86 | 0 | 68.27 | 6.81 | 27.84 |
| | (3,6) | 5.054 | 68 | -2.46 | -28.17 | 36.53 | 21.82 | -8.40 | 30.98 |
| | (4,5) | 23.50 | 26.91 | -10.24 | 5.39 | -26.265 | -16.03 | -7.86 | -31.38 |
| | (5,6) | -34.84 | -41,45 | -3.77 | -8.51 | -7.44 | -9.6 | -1.93 | -1,89 |

**Table 3.2 Detailed Results for Nash-Cournot Equilibrium**

| | | None | A | B | C | AB | AC | BC | ABC |
|---|---|---|---|---|---|---|---|---|---|
| Total Surplus ($) | | 14315.86 | 15102.88 | 14961.42 | 13539.05 | 15102.88 | 14990.92 | 14943.33 | 15102.88 |
| Total Producer Surplus ($) | | 7769.31 | 8887.30 | 8583.30 | 7076.26 | 8887.30 | 8623.07 | 8491.13 | 8887.30 |
| Total Consumer Surplus ($) | | 5488.50 | 6215.57 | 6064.32 | 4753.93 | 6215.57 | 5996.30 | 5949.77 | 6215.57 |
| Total Transmission Rent ($) | | 1511.48 | 785.93 | 1010.22 | 1912.32 | 785.93 | 1044.60 | 1140.04 | 785.93 |
| Total Generation Investment Cost ($) | | 916.87 | 1159.10 | 1102.97 | 716.71 | 1159.10 | 1101.65 | 1080.86 | 1159.10 |
| Total Transmission Investment Cost ($) | | 0 | 400 | 400 | 400 | 800 | 800 | 800 | 1200 |
| Total Net Surplus ($) | | 13398.99 | 13543.77 | 13458.45 | 12422.33 | 13143.77 | 13089.26 | 13062.47 | 12473.77 |
| Generation Expansion level (MW) | 1 | 27.45 | 40.36 | 36.25 | 24.20 | 40.36 | 44.50 | 36.37 | 40.36 |
| | 2 | 48.28 | 70.36 | 65.58 | 27.80 | 70.36 | 58.57 | 63.17 | 70.36 |
| | 6 | 26.60 | 8.66 | 14.12 | 32.78 | 8.66 | 11.84 | 14.24 | 8.66 |
| Quantity Consumed (MW) | 1 | 39.51 | 37.40 | 38.15 | 39.49 | 37.40 | 36.30 | 38.04 | 37.40 |
| | 2 | 41.52 | 37.40 | 38.30 | 45.26 | 37.40 | 39.79 | 38.74 | 37.40 |
| | 3 | 42.04 | 52.40 | 49.22 | 38.63 | 52.40 | 50.58 | 49.18 | 52.40 |
| | 4 | 51.47 | 52.40 | 52.93 | 45.75 | 52.40 | 51.59 | 51.98 | 52.40 |
| | 5 | 50.08 | 52.40 | 52.83 | 41.75 | 52.40 | 51.02 | 51.49 | 52.40 |
| | 6 | 27.71 | 37.40 | 34.52 | 23.90 | 37.40 | 35.62 | 34.37 | 37.40 |
| Electricity Price ($/MWh) | 1 | 60.49 | 62.60 | 61.85 | 60.51 | 62.60 | 63.70 | 61.97 | 62.60 |
| | 2 | 58.48 | 62.60 | 61.70 | 54.74 | 62.60 | 60.21 | 61.27 | 62.60 |
| | 3 | 77.96 | 67.60 | 70.78 | 81.37 | 67.60 | 69.42 | 70.83 | 62.60 |
| | 4 | 68.53 | 67.60 | 67.07 | 74.25 | 67.60 | 68.41 | 68.02 | 62.60 |
| | 5 | 69.92 | 67.60 | 67.17 | 78.25 | 67.60 | 68.98 | 68.51 | 62.60 |
| | 6 | 72.29 | 62.60 | 65.48 | 76.11 | 62.60 | 64.38 | 65.63 | 62.60 |
| Flow (MW) | (1,2) | 25.88 | 0.62 | 41.96 | 32.18 | 8.71 | 2.43 | 42.30 | 6.63 |
| | (1,3) | 0 | 50.81 | 0 | 0 | 57.08 | 67.93 | 0 | 61.77 |
| | (1,4) | 42.07 | 31.54 | 36.14 | 32.53 | 17.17 | 17.83 | 36.04 | 14.56 |
| | (2,3) | **50** | 42.88 | **50** | **50** | 11.50 | **50** | **50** | 25.23 |
| | (2,4) | 32.64 | 40.70 | 11 | 14.72 | 14.93 | 21.21 | 10.56 | 13.31 |
| | (2,5) | 0 | 0 | 58.24 | 0 | 65.26 | 55.28 | 56.17 | 51.05 |
| | (3,5) | 0 | 0 | 0 | 32.72 | 0 | 0 | 0.61 | 23.02 |
| | (3,6) | 7.96 | 41.29 | -0.78 | -21.36 | 16.18 | 12.07 | 0.21 | 11.59 |
| | (4,5) | 23.23 | 19.84 | -5.79 | 1.50 | -20.30 | -12.55 | -5.38 | -24.52 |
| | (5,6) | -26.85 | -32.56 | -0.38 | -7.53 | -7.44 | -8.30 | -0.09 | -2.85 |

It can be viewed on the detailed result tables that according to total net surplus values there is just one global optimum for both Nash-Cournot equilibrium and perfect competition equilibrium, which is "building transmission line A alone", as it has the highest total net surplus in both market structures. Here total surplus stands for the summation of consumer and producer surpluses.

On the other hand; when evaluated as a system with perfect competition, the system experiences congestion in all cases (depicted in bold font in “Flow” rows of Table 3.1 and Table 3.2) except for building A and B together and building all three new lines (A, B and C) together. For the sake of eliminating the congestion in the system, one can consider building A and B or A, B and C even though they bring lower net surplus values. But when it comes to Nash-Cournot equilibrium, building line A alone eliminates any congestion in the transmission system. Building A alone can still bring the best net surplus without any congestion in a market where system works as in Nash-Cournot equilibrium.

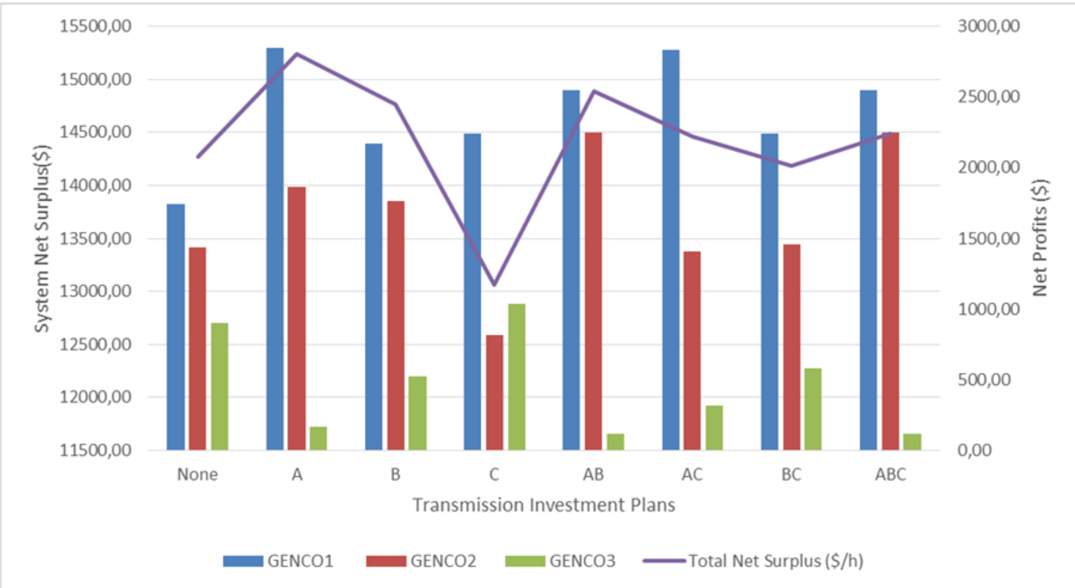


**Figure 3.5 Net Surplus And Genco’s Net Profits With Different Transmission Investment Plans For Perfect Competition**

Under perfect competition market structure, it is clear from Figure 3.5 that total surplus is the highest when only line A is built. When no new lines are added to the network, total surplus is the lowest and the second highest total surplus comes when lines A and B are built together. In terms of companies’ profits, they all get their highest profits under different investment plans, but total surplus reflects the well-being of both producers and consumers and its highest point is a better choice, since a market is not made up from producers only.

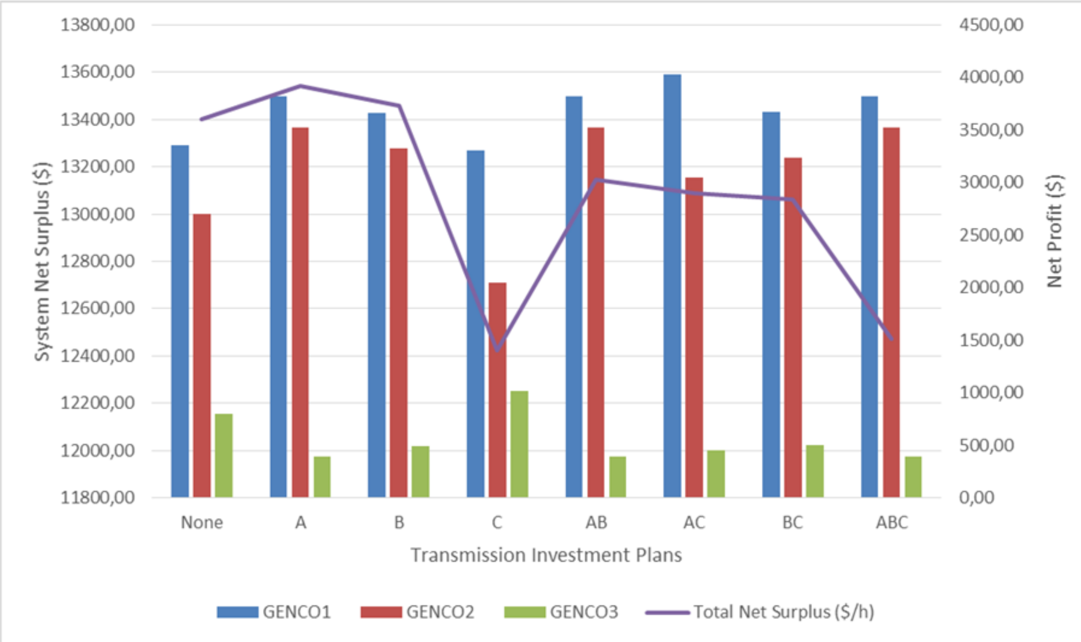


**Figure 3.6 Net Surplus And Genco's Net Profits With Different Transmission Investment Plans For Nash-Cournot Equilibrium**

In Figure 3.6; even though the market structure is different (Nash-Cournot) results are very similar. Despite profits and total surplus are not as low as in perfect competition case, still they are not the highest in "no new lines" option. The lowest total surplus comes with building line C only. The highest total surplus again happens when only line A is built, but the second highest total surplus comes when line B is built only this time. Once again, if it was up to generation companies, they would all choose different plans in order to maximize their profits.

# 4. A CO-OPTIMIZATION MODEL FOR TURKISH ELECTRICITY MARKET

## 4.1 Turkish Electricity Market and Generation Projections

In electricity markets, planning operations are considered seriously and it requires system operators to plan for constantly updated ambiguities in the market environment where new systems have to be integrated and policies to be implemented, including ambitious renewable energy targets. Therefore, both state and private actors continuously build new plants/lines and there is a risk of surplus in the long run. There are various projections for generation by both state agencies (TEİAŞ, Türkiye Elektrik İletim A.Ş. and/or EPDK, Enerji Piyasası Düzenleme Kurumu) and the private energy consulting companies.

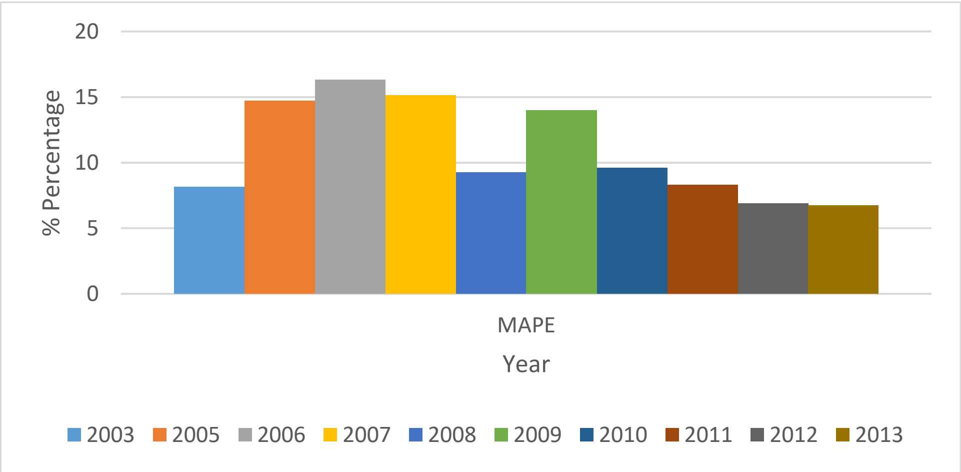


**Figure 4.1 Forecast Errors for Generation Capacities According to Projection Year (TEİAŞ, 2015)**

For instance in Figure 4.1, the capacity projection reports of Turkish State Transmission Company are compared with realised capacity data to see how much it has deviated in terms of percentages. When calculating this we used mean absolute percentage error (MAPE) method. Deviations vary between 7% and 16%.

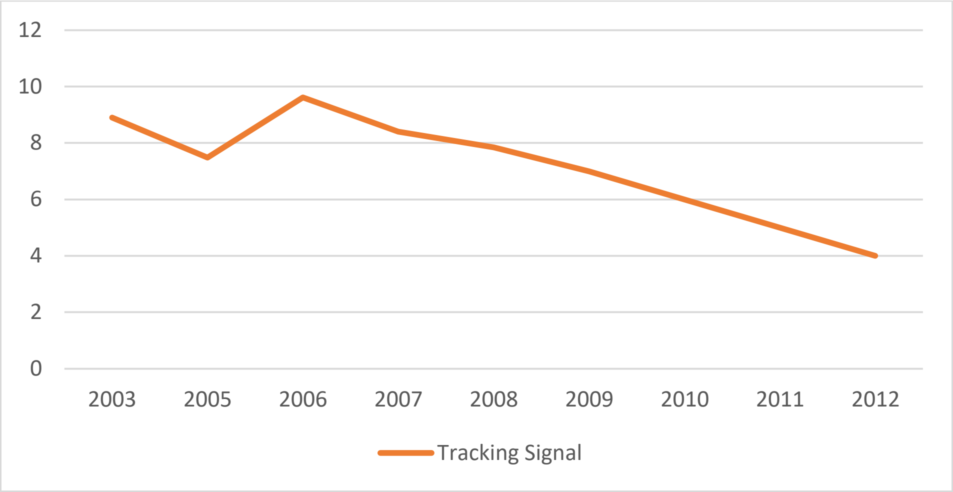


**Figure 4.2 Tracking Signal**

Exact same data are processed with tracking signal and the graph in Figure 4.2 appeared. Despite its decline over time, mean absolute deviation (MAD) was over the limit of 4 for all years. This shows that there is error (lower forecasts than realised values) or bias, but the situation tends to get better when time to projection year decreases (i.e., better forecasts for near future).

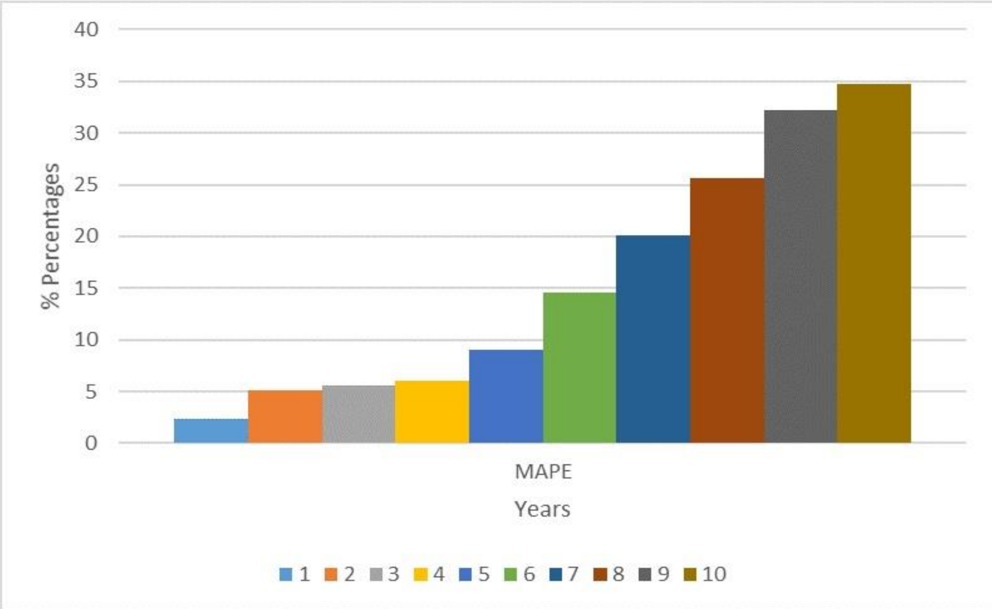


**Figure 4.3 Comparison of Capacity Projections By Time to Projection Year**

With the same dataset collected from the Turkish State Transmission Company (TEİAŞ), we have calculated the deviation (MAPE) between the projection year and the time of the realised data. The results are presented in Figure 4.3. Here, the difficulty in making projection appears in a more remarkable way. When capacity forecasts for next year (1-year) deviates 2.35% (lower) on average, capacity forecasts for ten (10) years later deviates around 34.77% (lower) on average. Hence it is obviously seen the error rapidly increases as the time to projection year increases.

## 4.2 Turkish Electricity Transmission System with Nine Buses

In this section, we present the nine regional control areas (9 buses) of Turkish system and data sources for this system. In Figure 4.4, Turkish electricity transmission system with 9 zones defined by load dispatch centers are presented with a simplified (i.e., abridged) transmission network. We approximated transmission network parameters (susceptance of the lines) from Şentürk-Eker (2017) using 2012 Turkish map of electrification and locations of generators from TEİAŞ and TETAŞ (Türkiye Elektrik Ticaret ve Taahhüt A.Ş.) reports.

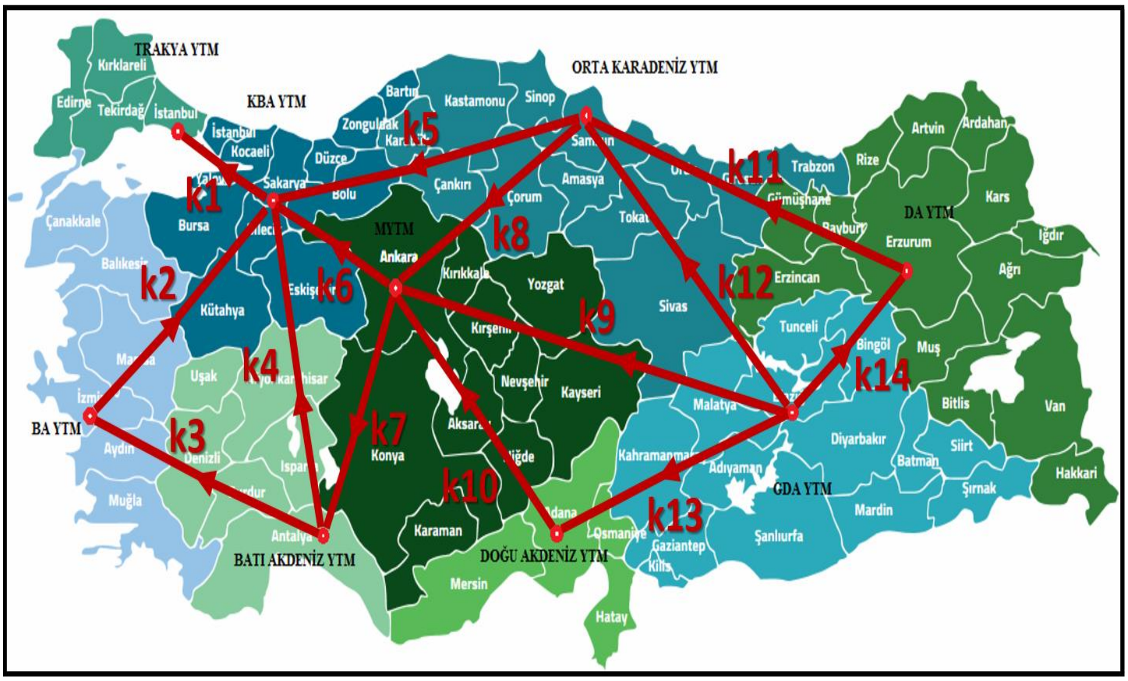


**Figure 4.4 The 9-Zone Turkish Electricity Transmission System**

In terms of the mathematical models, the main difference from previous chapter is that different generation technologies are modelled in this section, by using index *h*. For sake of brevity, these models are not presented in this section (see the model in Appendix A.2 for Turkish electricty market). For the Nash Cournot models, we have assumed that state-owned generation companies, namely, "affiliated partnerships of EÜAŞ" (denoted by f1) and EÜAŞ (denoted by f2), acts as a single entity. All data and definitions corresponding to indices of the model are defined properly in Appendix B.

### 4.3 Data and Assumptions

Operation, maintenance and fuel costs in the equilibrium models (in short, "operating cost"), generation and transmission expansion costs are from a report by International Energy Agency, Nuclear Energy Agency and Organisation for Economic Co-operation and Development Report (IEA-NEA-OECD, 2010). Median values for each generation technology's operating cost in this "Projected costs of generating electricity" report are used. Same costs have been assumed for some generation technologies as outlined in Table B.4. The operating cost values are in \$/MWh and converted to TL/MWh by using an exchange rate of 2.95 \$/TL for the end of 2015. Costs and assumptions for scenarios are related to December 2020 and are from TEİAŞ demand forecast report (TEİAŞ, 2017) along with IEA (2015) cost parameters.

When it comes to how we calculated capital costs in this thesis, there is another method we used. Mean overnight costs (p.37) and life times for generation technologies are (p.30) are used for generation expansion costs (IEA, 2015). They are discounted by using a 10% annual discount rate and life time of the related generation technology. Then, it is divided by 8760 hours of a year to get a hourly discounted cost for each technology. The calculation of the costs are based on the equivalence of the present value of the sum of discounted overnight costs. The electricity tariff is assumed not to change during the lifetime of the project, too (IEA, 2015). For transmission expansion, we considered several Turkish transmission expansion cases and calculated the cost of building one (1) km of a transmission line as 300,000 TL and it is annualized by using a 10% discount rate and 50 years of life time. Finally, similar to generation expansion costs, it is divided by 8760 hours, to have the hourly expansion cost per km. Multiplying this cost by the distance between nodes provides the transmission expansions costs per hour for each line in the system.

Data for the price-sensitive regional linear demand function parameters $(\alpha_i, \beta_i)$ for each bus in the network is calculated as in Şentürk-Eker (2017): Firstly, the model is solved with fixed demand values using 51,947 MW total demand projection in December 2020 from TEİAŞ (2017) and according to the share of each regional demand in the total annual consumption of Turkey. The optimal regional prices $(P^*)$ are obtained from this first model. By assuming a constant elasticity model $(P = AD^{-B})$ and a demand elasticity of $B = 0.1$, constant elasticity model parameter $A$ is computed, where $A = P^*(D^*)^{-B}$.

Using these $A$ parameters of the constant elasticity model in our framework, the optimal regional price $P^*$ and demand $D^*$ are re-calculated (i.e., the results of the fixed demand and constant elasticity model are the same). Finally, the constant elasticity model is linearized and the parameters of the linear and price-elastic inverse demand functions $(P = \alpha + \beta D)$ are calculated for each region as follows.

$$\beta = B\frac{P^*}{D^*}, \qquad \alpha = P^* + \beta D^*$$

We have focused on three policy issues, namely feed-in-tariffs (FIT), carbon costs and both of these policies together. To compare our results, we have also formed a base case without any of these policy issues. Finally, we have defined a current policy where no investments are allowed, but only nuclear (4480+4400 MW), solar (1000 MW) and wind (1000 MW) generation investments are fixed. This current policy will be useful for determining return on investment calculation. These scenarios, namely, current policy, scenario 1 (base), scenario 2 (FIT), scenario 3 (carbon cost) and scenario 4 (FIT and carbon cost) and their results for perfect competition (PC) and Nash-Cournot (NC) market structures are explained in the next subsections.

The MCP models are solved by using GAMS/ PATH solver on a personal computer with a 2.4 GHz processor and 4GB RAM. As this is a small-scale (but realistic) case study, the solution times are usually less than a second for all MCP models.

## 4.4 Analysis of the Current Policy

**Table 4.1 Welfare Results for Current Policy ( 1000TL/h)**

| | **Scenario 1** | | **Scenario 2** | | **Scenario 3** | | **Scenario 4** | |
|---|---|---|---|---|---|---|---|---|
| ***Market Structure*** | ***PC*** | ***NC*** | ***PC*** | ***NC*** | ***PC*** | ***NC*** | ***PC*** | ***NC*** |
| **Demand (1000 MW)** | 43.3 | 41.7 | 43.4 | 39.5 | 43.2 | 41.5 | 43.2 | 41.7 |
| **Total Surplus** | 4,699.9 | 4,699.0 | 6,830.1 | 6,821.4 | 7,203.0 | 7,201.5 | 10,625.3 | 10,623.9 |
| **Producer Surplus** | 3,802.7 | 3,809.5 | 6,088.3 | 6,115.8 | 5,879.3 | 5,888.8 | 9,301.5 | 9,310.1 |
| **Consumer Surplus** | 342.0 | 335.0 | 293.2 | 256.8 | 477.2 | 467.1 | 477.2 | 468.0 |
| **Revenue of TSO** | 555.3 | 554.6 | 448.6 | 448.8 | 846.6 | 845.6 | 846.6 | 845.9 |
| **Generation Expansion Costs** | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 |
| **Net Surplus** | 4,548.6 | 4,547.7 | 6,678.7 | 6,670.1 | 7,051.7 | 7,050.1 | 10,473.9 | 10,472.6 |
| **Feed-In-Tariff Cost** | | | 1,164.0 | 1,164.0 | | | 1,164.0 | 1,164.0 |
| **Carbon Cost** | | | | | 337.5 | 335.4 | 337.6 | 335.5 |
| **NETSURPLUS-FIT&CARBON COSTS** | | | **5,514.7** | **5,506.1** | **6,714.1** | **6,714.7** | **8,972.3** | **8,973.0** |

Using the parameters in Appendix B current policy is solved with fixed generation expansion plans and no transmission expansion under all scenarios (as some cost figures changes by each scenario). The summary results for the current policy can be viewed for all four scenarios in Table 4.1. Social welfare gets better for base scenario (Scenario 1) as well as FIT and Carbon Cost scenarios (Scenario 4). However, the nodal prices rise, whereas consumer welfare also increases.

## 4.5 Results for Scenario 1 (Base)

**Table 4.2 Results for Perfect Competition and Nash-Cournot Market Structures for Scenario 1 (TL/h)**

| | Perfect Competition (PC) | Nash-Cournot (NC) | % change (PC to NC) |
|---|---|---|---|
| **Total Surplus** | 5,679,162 | 5,641,272 | -1% |
| **Producer Surplus** | 4,432,508 | 4,429,885 | 0% |
| **Consumer Surplus** | 521,343 | 521,895 | 0% |
| **Revenue of Transmission** | 725,310 | 726,946 | 2% |
| **Generation Expansion Cost** | 278,449 | 282,946 | -1% |
| **Transmission Expansion Cost** | 146,000 | 146,000 | 0% |
| **Net Surplus** | 5,254,712 | 5,212,325 | -1% |

These results for scenario 1 (base) direct us to the conclusion that perfect competition and Nash-Cournot market structures give almost the same results even though perfect competition solution looks slightly better in terms of social welfare. Also producers may prefer perfect competition market structure as their profits are higher and their expansion costs gets a bit lower. However, consumer’s surplus and also the transmission operator revenues are slightly better off in Nash-Cournot structure. We can take these differences more seriously when it is considered they are all on an hourly basis.

**Table 4.3 Comparison Between Nash-Cournot and Perfect Competition for Scenario 1 (de la Torre et al., 2008; Sauma and Oren, 2006)**

| Nodes | Sales | Lerner Index |
|---|---|---|
| **TRAKYA** | -1% | 0% |
| **BATI ANADOLU** | 0% | 0% |
| **KUZEY BATI ANADOLU** | 2% | 0% |
| **ORTA ANADOLU** | -6% | 1% |
| **BATI AKDENİZ** | -2% | 0% |
| **ORTA KARADENİZ** | 38% | -2% |
| **DOĞU AKDENİZ** | 140% | -3% |
| **DOĞU ANADOLU** | -1% | 0% |
| **GÜNEY DOĞU ANADOLU** | -3% | 0% |

In Table 4.3 we can see a comparison based on sales data of both market structures and price-cost margin (a.k.a. Lerner Index). We took our inspiration on these methods from Sauma and Oren (2006) and de la Torre et al. (2008). Sales went down or remained still in seven regions, also prices remained same or went up just 1% in the same seven regions. Nash-Cournot structure seems as it did not make a substantial change in prices but in two regions prices went down around 2-3% and that caused a dramatic change in sales; 38% rise in one and 140% in the other. Obviously the sales in these regions are not important enough to make a large difference as producer surplus (e.g., total of all net profits) gets lower in Nash-Cournot market.

Rest of the results for scenario 1 can be seen in section 4.5 below and in Appendix C in details. All other scenarios are compared to the base scenario. However, welfare return on investment (ROI) measures are compared to the current policy (e.g., fixed generation expansion and no transmission expansion plan).

### 4.6 Results for All Scenarios

Four different scenarios were created to see the differences under different policies and regulations. First one is the base scenario with demand in December 2020 is assumed to be 51,471 MW (TEİAŞ, 2017). We have assumed the same capacity factors for December 2015. In this scenario, we have compared our equilibrium results to the current scheduled nuclear, solar and wind generation plants (i.e., Sinop and Mersin nuclear plants around 9000 MW, along with 1000 MW wind and solar generation expansion, a total of approximately 11,000 MW installed by 2020), but no transmission investment is assumed until 2020. Second scenario is the base scenario with current feed-in-tariffs (FIT). Current FIT are 7.3 US cent/kWh for hydro and wind, 10.5 US cent/kWh for geothermal and 13.3 US cent/kWh for biomass and solar. Third scenario is the base scenario with carbon costs included for some generation technologies. It may be assumed and collected as a tax as well. Fourth and the last scenario is the base scenario with FIT and carbon costs together (PC: Perfect Competition, NC: Nash-Cournot).

**Table 4.4 Welfare Results for All Scenarios (1000TL/h)**

| | **Scenario 1** | | **Scenario 2** | | **Scenario 3** | | **Scenario 4** | |
|---|---|---|---|---|---|---|---|---|
| ***Market Structure*** | ***PC*** | ***NC*** | ***PC*** | ***NC*** | ***PC*** | ***NC*** | ***PC*** | ***NC*** |
| **Demand (1000 MW)** | 46.94 | 48.33 | 46.52 | 42.63 | 45.40 | 49.21 | 46.63 | 49.93 |
| **Total Surplus** | 5,679.16 | 5,641.27 | 8,167.07 | 8,024.15 | 8,821.87 | 8,771.53 | 12,949.90 | 12,901.75 |
| **Producer Surplus** | 4,432.51 | 4,429.89 | 7,165.38 | 7,117.53 | 6,974.28 | 6,967.93 | 11,095.14 | 11,090.61 |
| **Consumer Surplus** | 521.34 | 521.90 | 413.65 | 331.82 | 738.72 | 741.84 | 744.10 | 748.46 |
| **Revenue of TSO** | 725.31 | 726.95 | 588.04 | 598.26 | 1,108.87 | 1,118.10 | 1,110.66 | 1,119.01 |
| **Generation Expansion Costs** | 278.45 | 282.95 | 399.10 | 307.26 | 283.79 | 299.42 | 405.05 | 423.18 |
| **Transmission Expansion Costs** | 146.00 | 146.00 | 146.00 | 146.00 | 146.00 | 146.00 | 146.00 | 146.00 |
| **Net Surplus** | 5,254.71 | 5,212.33 | 7,621.97 | 7,570.89 | 8,392.09 | 8,326.11 | 12,398.85 | 12,332.57 |
| **Feed-In-Tariff Cost** | | | 1,387.56 | 1,387.56 | | | 1,387.56 | 1,387.56 |
| **Carbon Cost** | | | | | 430.67 | 428.57 | 430.80 | 428.73 |
| **NETSURPLUS-FIT&CARBON COSTS** | | | **6,234.41** | **6,183.33** | **7,961.42** | **7,897.53** | **10,580.48** | **10,516.28** |
| **DIFFERENCE from CURRENT POLICY** | **706.15** | **664.62** | **719.68** | **677.25** | **1,247.27** | **1,182.84** | **1,608.18** | **1,543.24** |

All scenarios are found to be better than the current policy in terms of net surplus minus carbon and FIT costs. Carbon cost scenario alone (scenario 2) or together with FIT scenario (scenario 3) seems efficient, but in the Nash-Cournot market structure, carbon cost scenario has increased the share of conventional generation (nuclear plus all thermal technologies) substantially over renewable generation investments (hydro, geothermal, wind and solar (see Table C.5 for renewable versus conventional generation shares). Moreover, both of these scenarios have much higher electricity prices (see Table C.1). FIT policy (scenario 1) itself may increase some welfare measures, however, it has adverse effects on consumers surplus and transmission operator's revenues (see Table 4.4). Scenario 4 seems to be the best option in terms of social welfare again.

**Table 4.5 Welfare Return on Investment (ROI) for All Scenario's (TL)**

| | Scenario 1 | | Scenario 2 | | Scenario 3 | | Scenario 4 | |
|---|---|---|---|---|---|---|---|---|
| ***Market Structure*** | *PC* | *NC* | *PC* | *NC* | *PC* | *NC* | *PC* | *NC* |
| **Total Surplus** | 2.31 | 2.20 | **2.45** | **2.65** | **3.77** | **3.52** | **4.22** | **4.00** |
| **Producer Surplus** | 1.48 | 1.45 | **1.98** | **2.21** | **2.55** | **2.42** | **3.25** | **3.13** |
| **Consumer Surplus** | 0.42 | 0.44 | 0.22 | 0.17 | **0.61** | **0.62** | **0.48** | **0.49** |
| **Net Surplus** | 1.66 | 1.55 | **1.73** | **1.99** | **3.12** | **2.86** | **3.49** | **3.27** |
| **Revenue of Transmission** | 0.40 | 0.40 | 0.26 | 0.33 | **0.61** | **0.61** | **0.48** | **0.48** |

Here, we have presented welfare return on investments (e.g., welfare return on per TL investment) for all the scenarios this time. Transmission operators and consumers lose money in any cases and the best case for them is Scenario 3. Everyone else wins but they win the most in scenario 4.

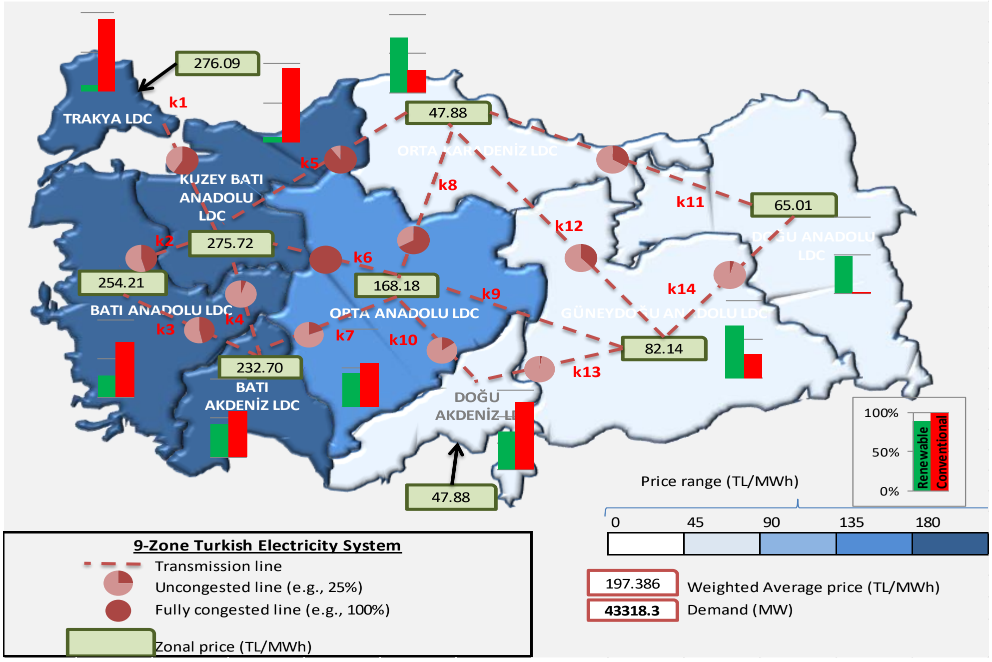


**Figure 4.5 Current Policy Perfect Competition Case on Turkish Map**

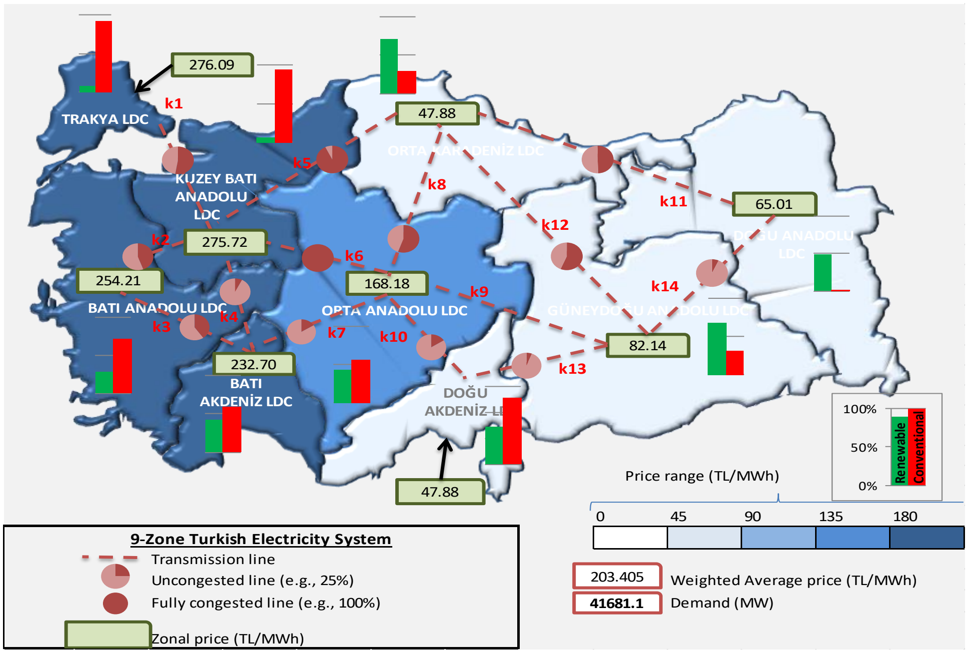


**Figure 4.6 Current Policy Nash-Cournot Case on Turkish Map**

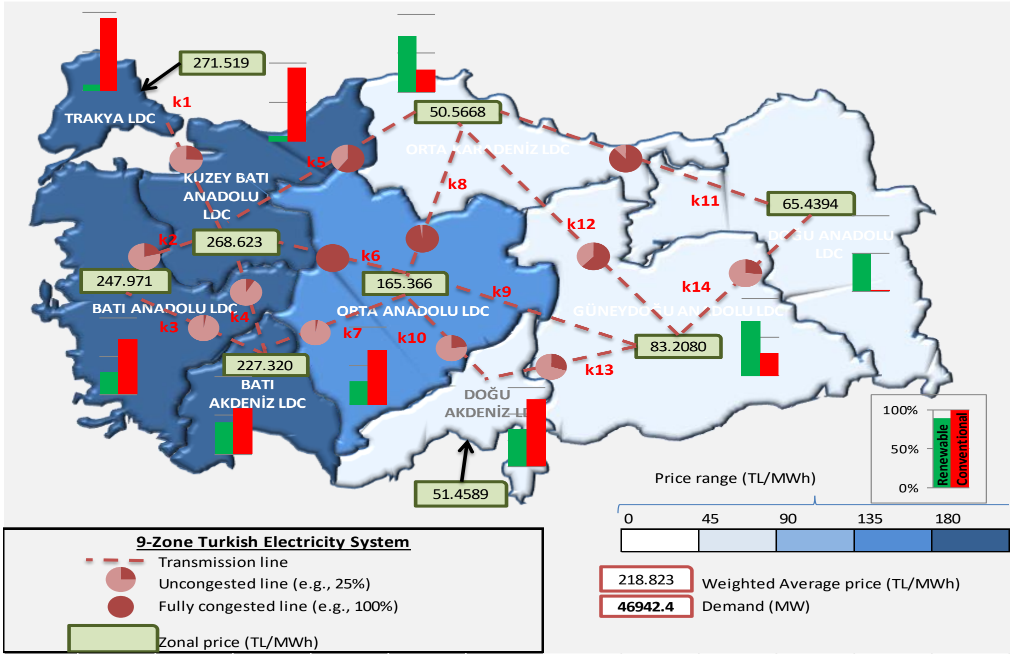


**Figure 4.7 Scenario 1 Perfect Competition Case on Turkish Map**

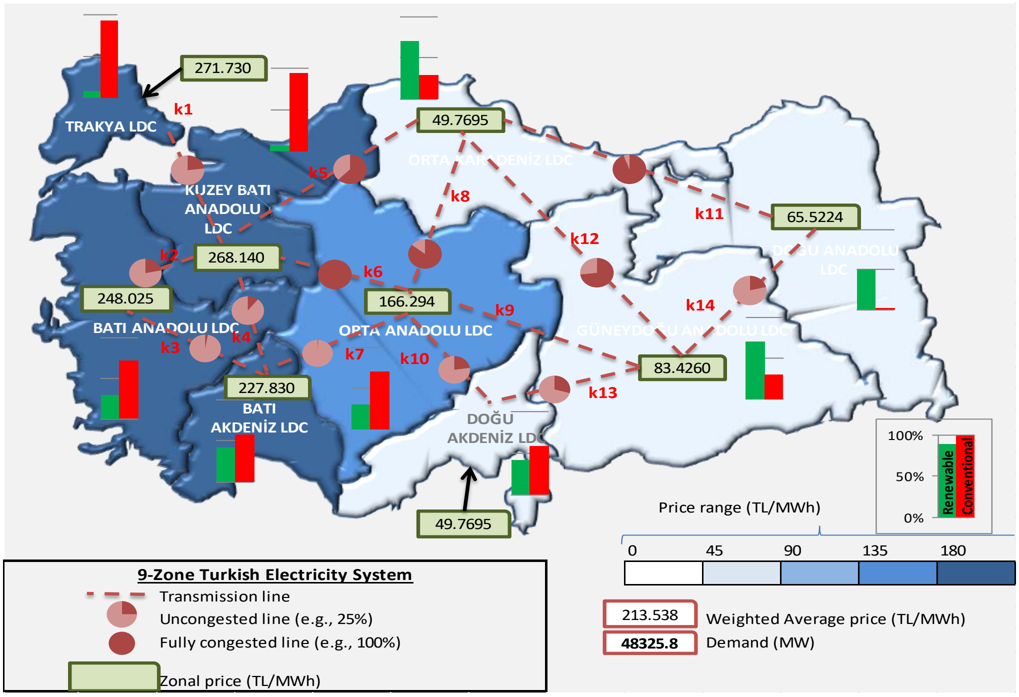


**Figure 4.8 Scenario 1 Nash-Cournot Case on Turkish Map**

On the maps for two market structures of scenario 1, there is only one congested line and western part of the country seems more congested and nodal prices are much higher. Nevertheless renewable energy usage are denser in the eastern regions.

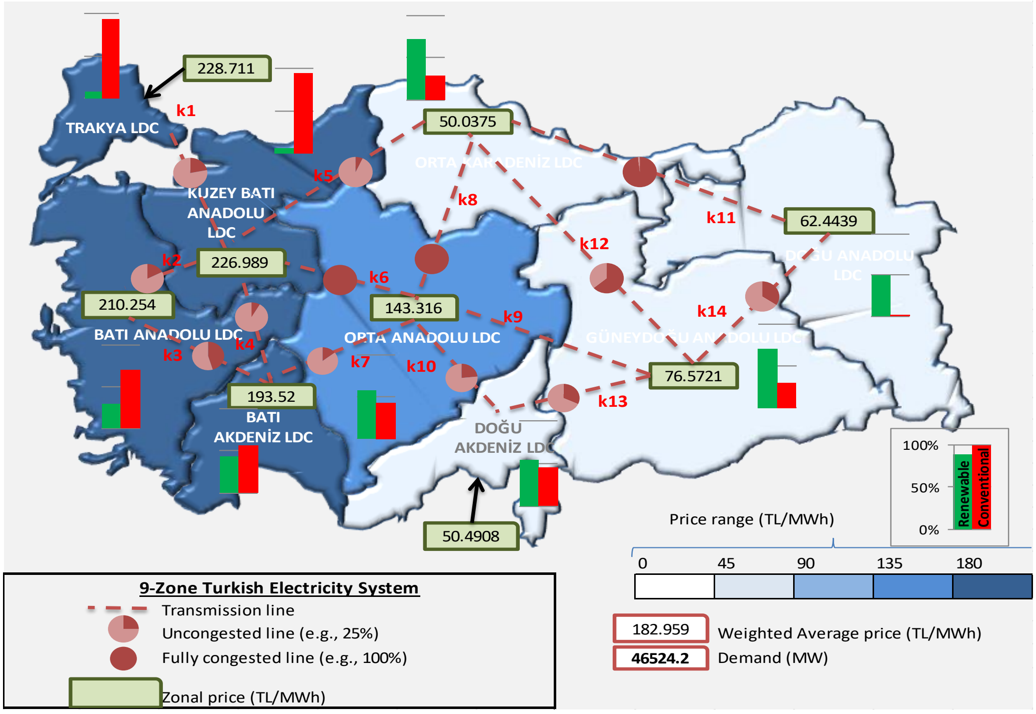


**Figure 4.9 Scenario 2 Perfect Competition Case on Turkish Map**

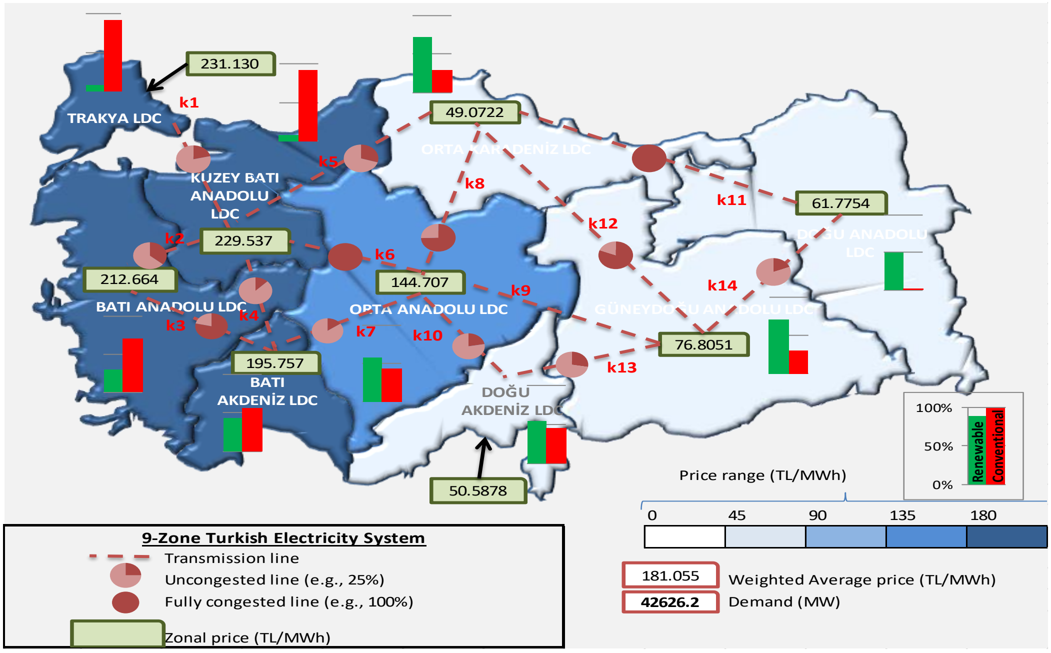


**Figure 4.10 Scenario 2 Nash-Cournot Case on Turkish Map**

On the maps for two market structures of scenario 2, there are two congestions, but at different lines (k6 and k8 in perfect competititon case and k6 and k11 in Nash Cournot case) and western part of the country still seems more congested and nodal prices are much higher. Renewable energy use due to investments are relatively more homogenous in this scenario.

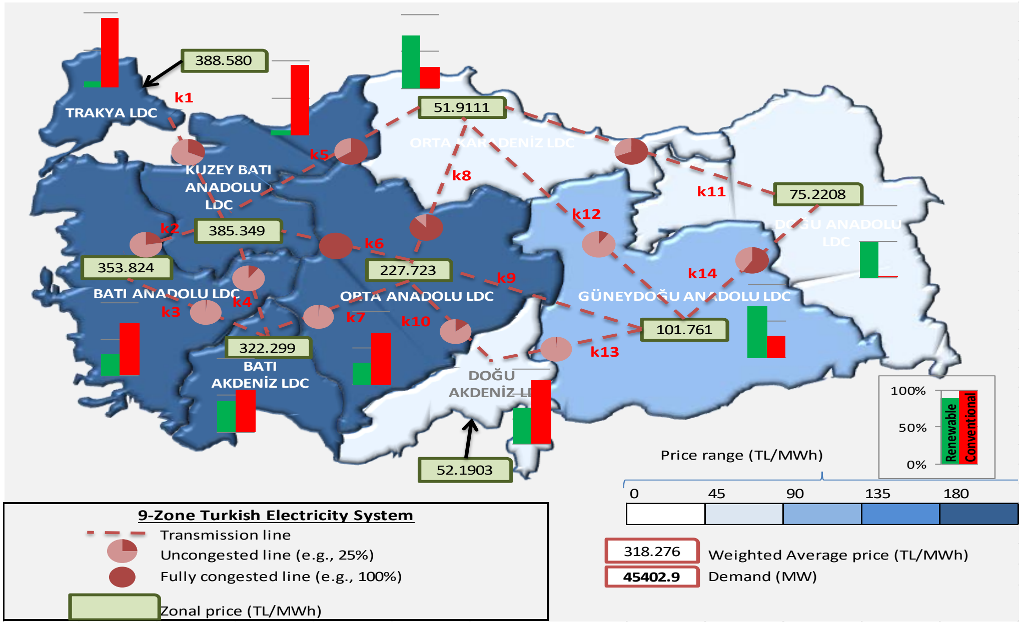


**Figure 4.11 Scenario 3 Perfect Competition Case on Turkish Map**

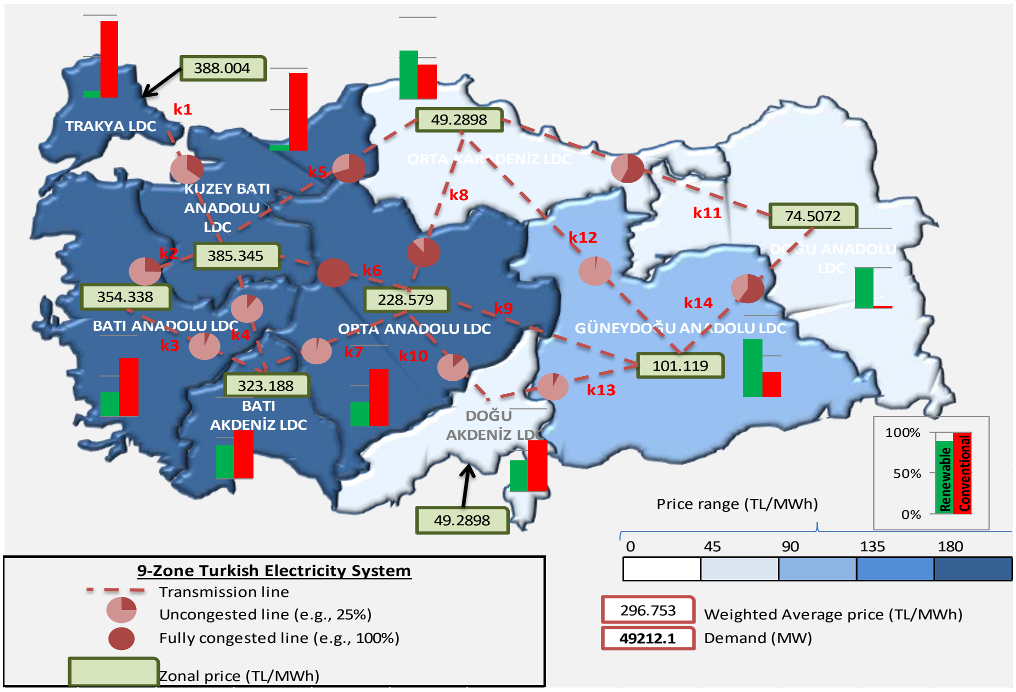


**Figure 4.12 Scenario 3 Nash-Cournot Case on Turkish Map**

On the maps for two market structures of scenario 3, there is only one congested line at the same line as in scenario 1 and western part of the country is congested and renewable usage and investment are simlar as in previous scenarios. On the other hand prices are higher, but “Güneydoğu Anadolu” gets a little bit higher than other eastern regions .

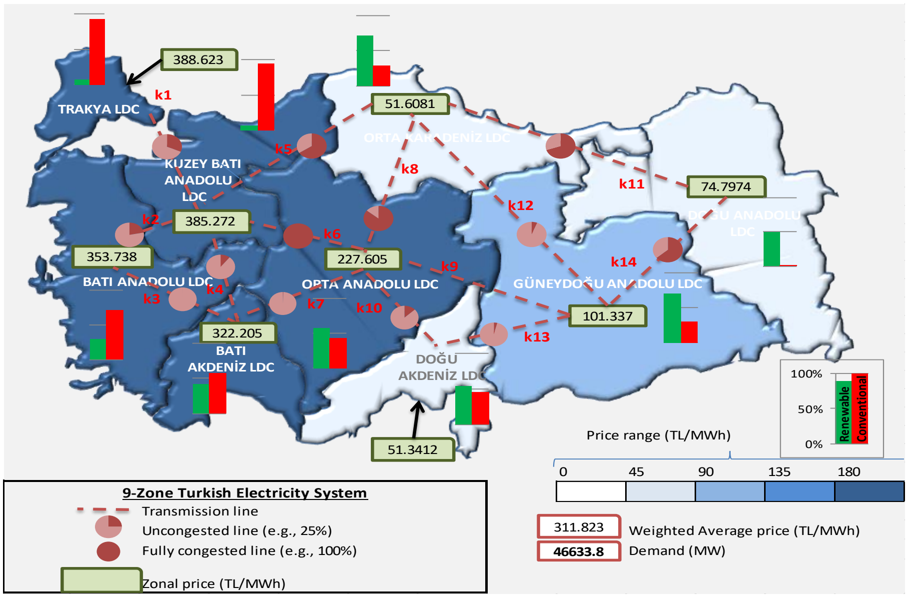


**Figure 4.13 Scenario 4 Perfect Competition Case on Turkish Map**

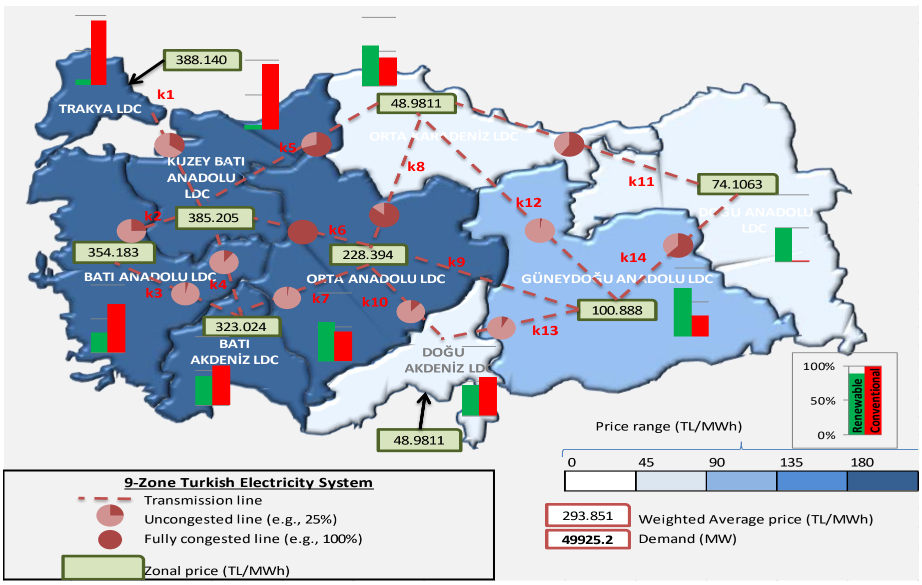


**Figure 4.14 Scenario 4 Nash-Cournot Case on Turkish Map**

Finally, as the maps for both market structures of scenario 4 are examined, there is only one congested line (k6), as similiar to scenario 1 and 3. The western part of the country, as expected, seems more congested with higher prices. Similar to scenario 3, “Güneydoğu Anadolu” gets a bit higher prices than other eastern regions. Renewable energy usage/investments are similar to scenario 2 and 3.

# 5. CONCLUSIONS

Co-optimization is mostly used for two important reasons. First, generation and transmission investments are often substitutes: loads can be met either with local resources or transmission of remote supplies. Second, generation and transmission investments complement each other. Building of new generation, including renewable sources, is affected by the availability of transmission, so that transmission expansions influence future patterns and mixes of generation investment. Consequently, cost-benefit calculations for transmission investment should consider not only fuel savings resulting from reduced transmission congestion, as is traditionally done in generation expansion studies, but also the capital cost savings from more efficient generation investments. By modeling relations between transmission and generation markets, co-optimization models promise solutions that are less expensive in total compared to decoupled optimization, i.e. transmission-only, generation-only, or iteration between the two (Krishnan et al., 2016).

The co-optimization approach promises economic, environmental, and resource utilization related benefits compared to a traditional decoupled approach to resource optimization. Building co-optimization models is also a data-intensive task requiring significant effort to collect, maintain and share data with the multiple parties who participate in regional planning processes while maintaining necessary information security and confidentiality.

In this study, we have considered co-optimization models formulated as bi-level programming problems as well as single-level mixed complementarity and MIQP problems. In the upper level of the bi-level problem, the system operator decides on the transmission expansion plans while anticipating the decisions in the lower level of the problem. The lower level problems present models of generation expansion and oligopolistic competition among power generators, where we examine perfect competition models to Cournot game among generators. This model is essentially an economic equilibrium problem for electricity markets that is defined by the optimality conditions that examine system operator's and generators' expansion behavior along with supply-demand balance in the market.

We first solved a relatively simple problem with a 6-bus test system with new candidate lines. Moreover, we have collected data from state companies of Turkey (TEİAŞ, TETAŞ, EPİAŞ) and many other sources to model the Turkish electricity system. Then, we solved this model based on a simplified 9-bus system obtained from TEİAŞ electrification map. We have created four different scenarios based on carbon costs and feed-in-tariffs (FIT). In GAMS software, an MCP model is solved using perfectly competitive and Nash-Cournot market structures. We also prepared summary maps showing the results for all scenarios. EXCEL-VBA is used for preparing these maps.

According to our results, social welfare mostly gets better when carbon costs and FIT are applied together in the models, however, radical changes in several regions may occur, such as prices may go up substantially. All scenarios are better than the current scheduled policy in terms of net surplus minus carbon and FIT costs. However, both of these scenarios have much higher electricity prices. FIT policy (scenario 1) itself may increase some welfare measures; however, it has adverse effects on consumers' surplus and transmission operator's revenues.

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Journal Article: The Effects of Demographic Characteristics of Logistics Firms on Their Performance and Job Satisfaction of Their Employees

3. International Conference on Energy and Thermal Engineering: İstanbul 2017, 25-28 April 2017, Yildiz Technical University, Istanbul, Turkey, ISBN: 978-605-9546-04-1

Proceeding: A Co-optimization Model of Generation and Transmission Investments with Market-Clearing Equilibrium in Electricity Market

**Projects:**

Title: Economical Equilibrium Models for Turkish Electricity Markets: Integration of market-clearing models and generation/transmission investment models

Sponsor: Tübitak (Turkish Scientific and Technological Research Council)

Position: Student Assistant with a monthly scholarship

# APPENDIX A: THE MATHEMATICAL MODEL

## A.1 Overall MPEC Model With New Candidate Lines

$$\min_{\Delta T_{ij}, z_{ij}} \quad -\sum_{i\in I}\left(\alpha_i\left(\sum_{f\in F} s_{fi}\right)-\frac{1}{2}\beta_i\left(\sum_{f\in F} s_{fi}\right)^2\right)+\sum_{i\in I_f} c_{fi}x_{fi} + \sum_{i\in I_f} c_{fi}^{Gexp}\Delta K_{fi} + \sum_{i\in I, j\in J_i} c_{ij}^{Texp}\Delta T_{ij} + \sum_{i\in I, j\in J_i^+} c_{ij}^{Texp} z_{ij} T_{ij}^{L+} \tag{A.1.1}$$

s.t.

$$\Delta T_{ij} \le T_{ij}^{max-exp} \qquad \forall\, i\in I, j\in J_i \tag{A.1.2}$$

$$\Delta T_{ij} \ge 0 \qquad \forall\, i\in I, j\in J_i \tag{A.1.3}$$

$$s_{fi}\ge 0 \perp \; -\alpha_i+\beta_i\left(\sum_{f\in F} s_{fi}\right)+p_i+\nu_f \ge 0 \qquad \forall f\in F, i\in I \tag{A.1.4}$$

$$x_{fi}\ge 0 \perp \; c_{fi}-p_i-\nu_f+\mu_{fi}\ge 0 \qquad \forall f\in F, i\in I_f \tag{A.1.5}$$

$$\Delta K_{fi}\ge 0 \perp \; c_{fi}^{Gexp}-\mu_{fi}+\delta_{fi}\ge 0 \qquad \forall f\in F, i\in I_f \tag{A.1.6}$$

$$\nu_f \; free \perp \; \sum_{i\in I} s_{fi}-\sum_{i\in I_f} x_{fi}=0 \qquad \forall f\in F \tag{A.1.7}$$

$$\mu_{fi}\ge 0 \perp \; x_{fi}\le (K_{fi}^0+\Delta K_{fi}) \qquad \forall f\in F, i\in I_f \tag{A.1.8}$$

$$\delta_{fi}\ge 0 \perp \; \Delta K_{fi}\le K_{fi}^{max-exp} \qquad \forall f\in F, i\in I_f \tag{A.1.9}$$

$$\begin{aligned} \theta_i \ge 0 \perp \; & \sum_{j\in J_i} B_{ij}(p_i-p_j) \\ & + \sum_{j\in J_i} B_{ij}(\lambda_{ij}^+-\lambda_{ji}^+) - \sum_{j\in J_i} B_{ij}(\lambda_{ij}^- - \lambda_{ji}^-) \\ & + \sum_{j\in J_i^+} z_{ij}B_{ij}(\lambda_{ij}^{L+}-\lambda_{ji}^{L+}) \\ & - \sum_{j\in J_i^+} z_{ij}B_{ij}(\lambda_{ij}^{L-}-\lambda_{ji}^{L-}) \\ & + \varepsilon_i^{max} - \varepsilon_i^{min} + \xi = 0 \end{aligned} \qquad \forall\, i\in I, j\in J_i \tag{A.1.10}$$

$$\Delta T_{ij}\ge 0 \perp \; c_{fi}^{Texp}-\lambda_{ij}^- - \lambda_{ij}^+ + \gamma_{ij}\ge 0 \qquad \forall\, i\in I, j\in J_i \tag{A.1.11}$$

$$\lambda_{ij}^+\ge 0 \perp \; B_{ij}(\theta_i-\theta_j)\le T_{ij}^0+\Delta T_{ij} \qquad \forall\, i\in I, j\in J_i \tag{A.1.12}$$

$$\lambda_{ij}^{-} \geq 0 \perp \quad -B_{ij}(\theta_i - \theta_j) \leq T_{ij}^0 + \Delta T_{ij} \qquad \forall\, i \in I, j \in J_i \qquad \text{(A.1.13)}$$

$$\lambda_{ij}^{L+} \geq 0 \perp \quad z_{ij}B_{ij}(\theta_i - \theta_j) \leq T_{ij}^{L+} \qquad \forall\, i \in I, j \in J_i^+ \qquad \text{(A.1.14)}$$

$$\lambda_{ij}^{L-} \geq 0 \perp \quad z_{ij}B_{ij}(\theta_i - \theta_j) \leq T_{ij}^{L-} \qquad \forall\, i \in I, j \in J_i^+ \qquad \text{(A.1.15)}$$

$$\varepsilon_i^{max} \geq 0 \perp \quad \theta_i \leq \pi \qquad \forall\, i \in I \qquad \text{(A.1.16)}$$

$$\varepsilon_i^{min} \geq 0 \perp \quad -\theta_i \leq \pi \qquad \forall\, i \in I \qquad \text{(A.1.17)}$$

$$\xi\ free \perp \quad \theta_i = 0 \qquad i = reference\ bus \qquad \text{(A.1.18)}$$

$$p_i\ free \perp \quad \sum_{f\in F} x_{fi} - \sum_{f\in F} s_{fi} - \sum_{j\in J_i} B_{ij}(\theta_i - \theta_j) = 0 \qquad \forall\, i \in I \qquad \text{(A.1.19)}$$

$$z_{ij} \in \{0,1\} \qquad \forall\, i \in I, j \in J_i^+ \qquad \text{(A.1.20)}$$

This model is for perfect competition market structure. For the Nash-Cournot market structure, the condition that corresponds to $s_{fi} \geq 0$ is modified as follows:

$$s_{fi} \geq 0 \perp \quad -\alpha_i + \beta_i\left(\sum_{f\in F} s_{fi}\right) + \beta_i s_{fi} + p_i + \nu_f \geq 0 \qquad \forall f \in F, i \in I \qquad \text{(A.1.21)}$$

In this condition, the term $+\beta_i s_{fi}$ is the marginal revenue for firm *f* at node *i*. It can be obtained from the partial derivative of the generation firm's objective function in (3.2) with respect to $s_{fi}$, i.e., the price-quantity relations in the demand function is known by the generation firm *f*.

## A.2 Overall MCP Model for Turkish Electricity Market

MCP: Solve for $s_{fi}, x_{fhi}, \Delta K_{fhi}, \nu_f, \mu_{fhi}, \delta_{fhi}, \theta_i, \Delta T_{ij}, \lambda_k^+, \lambda_k^-, \gamma_{ij}, p_i, \varepsilon_i^{min}, \varepsilon_i^{max}, \xi$ so that:

$$s_{fi} \geq 0 \perp \quad -\alpha_i + \beta_i\left(\sum_{f\in F} s_{fi}\right) + p_i + \nu_f \geq 0 \quad \forall f \in F, i \in I \tag{A.2.1}$$

$$x_{fhi} \geq 0 \perp \quad c_{fhi} - p_i - \nu_f + \mu_{fhi} \geq 0 \quad \forall f \in F, h \in H, i \in I_f \tag{A.2.2}$$

$$\Delta K_{fhi} \geq 0 \perp \quad c_{fhi}^{Gexp} - \mu_{fhi} + \delta_{fhi} \geq 0 \quad \forall f \in F, h \in H, i \in I_f \tag{A.2.3}$$

$$\nu_f \; free \perp \quad \sum_{i\in I} s_{fi} - \sum_{i\in I_f, h\in H} x_{fhi} = 0 \quad \forall f \in F, h \in H \tag{A.2.4}$$

$$\mu_{fhi} \geq 0 \perp \quad x_{fhi} \leq (K_{fhi}^0 + \Delta K_{fhi}) \quad \forall f \in F, h \in H, i \in I_f \tag{A.2.5}$$

$$\delta_{fhi} \geq 0 \perp \quad \Delta K_{fhi} \leq K_{fhi}^{max-exp} \quad \forall f \in F, h \in H, i \in I_f \tag{A.2.6}$$

$$\theta_i \geq 0 \perp \quad \begin{aligned} &\sum_{j\in J_i} B_{ij}(p_i - p_j) \\ &+ \sum_{j\in J_i} B_{ij}(\lambda_{ij}^+ - \lambda_{ji}^+) \\ &- \sum_{j\in J_i} B_{ij}(\lambda_{ij}^- - \lambda_{ji}^-) \\ &+ \varepsilon_i^{max} - \varepsilon_i^{min} + \xi = 0 \end{aligned} \quad \forall\, i \in I, j \in J_i \tag{A.2.7}$$

$$\Delta T_{ij} \geq 0 \perp \quad c_{ij}^{Texp} - \lambda_{ij}^- - \lambda_{ij}^+ + \gamma_{ij} \geq 0 \quad \forall\, i \in I, j \in J_i \tag{A.2.8}$$

$$\lambda_{ij}^+ \geq 0 \perp \quad B_{ij}(\theta_i - \theta_j) \leq T_{ij}^0 + \Delta T_{ij} \quad \forall\, i \in I, j \in J_i \tag{A.2.9}$$

$$\lambda_{ij}^- \geq 0 \perp \quad -B_{ij}(\theta_i - \theta_j) \leq T_{ij}^0 + \Delta T_{ij} \quad \forall\, i \in I, j \in J_i \tag{A.2.10}$$

$$\gamma_{ij} \geq 0 \perp \quad \Delta T_{ij} \leq T_{ij}^{max-exp} \quad \forall\, i \in I, j \in J_i \tag{A.2.11}$$

$$\varepsilon_i^{max} \geq 0 \perp \quad \theta_i \leq \pi \quad \forall\, i \in I \tag{A.2.12}$$

$$\varepsilon_i^{min} \geq 0 \perp \quad -\theta_i \leq \pi \quad \forall\, i \in I \tag{A.2.13}$$

$$\xi \; free \perp \quad \theta_i = 0 \quad i = reference\ bus \tag{A.2.14}$$

$$p_i \; free \perp \quad \begin{aligned} &\sum_{f\in F, h\in H} x_{fhi} - \sum_{f\in F} s_{fi} \\ &- \sum_{j\in J_i} B_{ij}(\theta_i - \theta_j) = 0 \end{aligned} \quad \forall\, i \in I \tag{A.2.15}$$

This model is for perfect competition market structure. For the Nash-Cournot market structure, the first condition is modified as follows:

$$s_{fi} \geq 0 \perp \quad -\alpha_i + \beta_i \left( \sum_{f \in F} s_{fi} \right) + \beta_i s_{fi} + p_i + \nu_f \geq 0 \qquad \forall f \in F, i \in I \qquad \text{(A.2.16)}$$

In this condition, the term $+\beta_i s_{fi}$ is the marginal revenue for firm *f* at node $i$. It can be obtained from the partial derivative of the generation firm's objective function in (3.2) with respect to $s_{fi}$, i.e., the price-quantity relations in the demand function is known by the generation firm *f*.

# APPENDIX B: DATA AND ASSUMPTIONS

## B.1 Parameters for the Turkish Electricity Market Model

**Table B.1 Plant Ownership Types and Model Index**

| Index | Plant Ownership Types |
|---|---|
| f1 | Affiliated Partnerships of EÜAŞ |
| f2 | EÜAŞ |
| f3 | Transfer of Operational Rights (TOR) |
| f4 | Autoproducers |
| f5 | Independent Power Producers (IPP) |
| f6 | Built-Operate-Transfer (BOT) |
| f7 | Built-Operate (BO) |

**Table B.2 Explanation for Nodes and Model Index**

| Index | Node Zones |
|---|---|
| n1 | TRAKYA |
| n2 | BATI ANADOLU |
| n3 | KUZEY BATI ANADOLU |
| n4 | ORTA ANADOLU |
| n5 | BATI AKDENİZ |
| n6 | ORTA KARADENİZ |
| n7 | DOĞU AKDENİZ |
| n8 | DOĞU ANADOLU |
| n9 | GÜNEY DOĞU ANADOLU |

**Table B.3 Generator Technology Types and Model Index**

| Index | Plant (technology) type |
|---|---|
| h1 | Lignite |
| h2 | Hydro (Run-of-river) |
| h3 | Hydro (Reservoir) |
| h4 | Natural Gas |
| h5 | Fuel Oil |
| h6 | Geothermal |
| h7 | Biomass |
| h8 | Asphaltite Coal |
| h9 | Imported Coal |
| h10 | LNG |
| h11 | NAFTA |
| h12 | Wind |
| h13 | Hard Coal |
| h14 | Solar |
| h15 | Nuclear |

**Table B.4 Cost Estimations for Each Generation Technology ($/MWh)**

| Plant Type | Operating Cost (IEA2010) | Carbon Cost | Feed-in-Tariff (FIT) |
|---|---|---|---|
| **h1** | 24.23 | 23.93 | - |
| **h2** | 6.09 | - | 73 |
| **h3** | 6.09 | - | 73 |
| **h4** | 65.6 | 11.49 | - |
| **h5** | 70.28 | 11.49 | - |
| **h6** | 30.92 | - | 105 |
| **h7** | 30.92 | 2.13 | 133 |
| **h8** | 24.23 | 23.93 | - |
| **h9** | 24.23 | 23.93 | - |
| **h10** | 65.6 | 11.49 | - |
| **h11** | 65.6 | 11.49 | - |
| **h12** | 21.92 | - | 73 |
| **h13** | 24.23 | 23.93 | - |
| **h14** | - | - | 133 |
| **h15** | 16.23 | - | - |

**Table B.5 Capacity Factors**

| h1 | h2 | h3 | h4 | h5 | h6 | h7 | h8 | h9 | h10 | h11 | h12 | h13 | h14 | h15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0.59 | 0.35 | 0.4 | 0.72 | 0.44 | 0.78 | 0.62 | 0.99 | 0.9 | 0.99 | 0.34 | 0.8 | 0.97 | 0.15 | 0.9 |

## Table B.6 Generation Capacities (MW)

| Firms | Plant Types | n1 | n2 | n3 | n4 | n5 | n6 | n7 | n8 | n9 |
|---|---|---|---|---|---|---|---|---|---|---|
| **f1** | **h1** | - | 25.96 | - | - | - | - | - | - | - |
| **f2** | **h1** | - | 188.80 | - | - | - | - | - | - | 1649.05 |
| **f2** | **h2** | - | 5.78 | - | 29.40 | 12.39 | 26.15 | 49.87 | 9.31 | 20.85 |
| **f2** | **h3** | - | 118.76 | - | 293.72 | 196.32 | 798.38 | 530.88 | 498.12 | 2589.99 |
| **f2** | **h4** | 1797.77 | 129.60 | 1031.04 | - | - | - | - | - | - |
| **f2** | **h5** | - | - | - | - | - | - | - | 22 | - |
| **f3** | **h1** | - | - | - | 365.80 | - | - | - | - | - |
| **f3** | **h2** | - | - | 5.99 | 6.83 | 20.99 | 0.64 | 3.96 | 17.21 | 28.34 |
| **f3** | **h3** | - | - | - | 6.72 | - | 2.21 | - | 19.24 | - |
| **f3** | **h6** | - | - | - | - | 11.70 | - | - | - | - |
| **f4** | **h4** | 0.43 | - | 3.74 | - | - | - | 1.44 | - | - |
| **f4** | **h5** | - | 1.49 | - | - | - | - | - | - | - |
| **f4** | **h7** | - | 9.42 | - | - | - | - | - | - | - |
| **f5** | **h1** | 3.19 | 1587.25 | 894.16 | 165.88 | 31.57 | 12.67 | 177 | 2.36 | 278.83 |
| **f5** | **h2** | - | 81.86 | 84.39 | 100.27 | 77.31 | 626.02 | 338.04 | 541.08 | 262.89 |
| **f5** | **h3** | - | - | 96 | 28.8 | 299.56 | 421.53 | 441.08 | 396.12 | 699.74 |
| **f5** | **h4** | 1595.95 | 1561.75 | 2502.28 | 170.19 | 1829.12 | 1389.50 | 925.17 | 5.45 | 447.78 |
| **f5** | **h5** | - | 170.19 | 7.92 | 21.93 | - | - | 111.94 | 13.16 | 129.78 |
| **f5** | **h6** | - | 413 | - | - | 70.71 | - | - | - | - |
| **f5** | **h7** | 27.23 | 27.27 | 46.85 | 49.65 | 6.17 | 6.84 | 21.04 | 7.77 | 11.03 |
| **f5** | **h8** | - | - | - | - | - | - | - | - | 400.95 |
| **f5** | **h9** | - | 1759.50 | 1422 | 1.395 | - | - | 1080 | - | 6.84 |
| **f5** | **h10** | - | - | - | 9.90 | 1.93 | - | - | - | - |
| **f5** | **h11** | - | - | - | - | - | - | 5.74 | - | - |
| **f5** | **h12** | 385.41 | 2037.35 | 156.80 | 232.88 | 145.76 | 63.2 | 532.77 | - | 82.40 |
| **f5** | **h13** | - | - | 291 | - | - | 82.46 | - | - | - |
| **f6** | **h2** | - | 3.71 | - | - | 7.28 | - | - | 7.735 | 5.99 |
| **f6** | **h3** | - | - | - | 40 | - | - | - | - | 268.80 |
| **f6** | **h4** | 857.66 | - | 186.05 | - | - | - | - | - | - |
| **f6** | **h12** | - | 13.92 | - | - | - | - | - | - | - |
| **f7** | **h4** | - | 1145.33 | 1723.01 | 588.53 | - | - | - | - | - |
| **f7** | **h9** | - | - | - | - | - | - | 1188 | - | - |

### Table B.7 Generation Expansion Limits (MW)

| Firms | Plant Types | n1 | n2 | n3 | n4 | n5 | n6 | n7 | n8 | n9 |
|---|---|---|---|---|---|---|---|---|---|---|
| **f2** | **h12** | - | - | - | 1000 | - | - | - | - | - |
| **f2** | **h14** | - | - | - | 1000 | - | - | - | - | - |
| **f2** | **h15** | - | - | - | - | - | 4480 | 4800 | - | - |
| **f5** | **h2** | - | 93.93 | 79.75 | 64.52 | 8.53 | 183.31 | - | - | - |
| **f5** | **h3** | - | - | - | - | - | - | 146.22 | 1917.53 | 889.60 |
| **f5** | **h4** | 3095.50 | 131 | 3474.50 | 747 | 171 | 154 | 64 | 153 | 567 |
| **f5** | **h6** | - | 345.21 | - | - | - | - | - | - | - |
| **f5** | **h7** | 15 | 25.15 | 12.50 | 95.90 | 1.511 | 21 | 4 | 2.80 | 16.85 |
| **f5** | **h12** | 185 | 75 | 158 | 230 | 25.20 | 75 | 120 | 129.50 | - |
| **f5** | **h13** | 1.19 | 700 | 51.04 | 802.03 | - | - | - | - | 72.07 |
| **f5** | **h14** | - | - | - | 87 | 110.40 | - | 848.88 | 100.80 | 43 |

### Table B.8 Inverse Demand Intercepts $(\alpha_i)$ for Each Scenario

| Node | Scenario 1 | Scenario 2 | Scenario 3 | Scenario 4 |
|---|---|---|---|---|
| **n1** | 297.32 | 250.13 | 426.49 | 426.49 |
| **n2** | 274.23 | 231.50 | 391.22 | 391.22 |
| **n3** | 297.32 | 250.13 | 426.49 | 426.49 |
| **n4** | 181.91 | 156.99 | 250.16 | 250.16 |
| **n5** | 251.15 | 212.87 | 355.96 | 355.96 |
| **n6** | 52.67 | 52.67 | 52.67 | 52.67 |
| **n7** | 52.67 | 52.67 | 52.67 | 52.67 |
| **n8** | 71.13 | 67.57 | 80.88 | 80.88 |
| **n9** | 89.59 | 82.47 | 109.09 | 109.09 |

**Table B.9 Inverse Demand Slopes ($\boldsymbol{\beta_i}$) for Each Scenario**

| Node | Scenario 1 | Scenario 2 | Scenario 3 | Scenario 4 |
|---|---|---|---|---|
| **n1** | 0.0033 | 0.0028 | 0.0047 | 0.0047 |
| **n2** | 0.0027 | 0.0023 | 0.0038 | 0.0038 |
| **n3** | 0.0021 | 0.0018 | 0.0030 | 0.0030 |
| **n4** | 0.0026 | 0.0023 | 0.0036 | 0.0036 |
| **n5** | 0.0108 | 0.0092 | 0.0153 | 0.0153 |
| **n6** | 0.0022 | 0.0022 | 0.0022 | 0.0022 |
| **n7** | 0.0012 | 0.0012 | 0.0012 | 0.0012 |
| **n8** | 0.0051 | 0.0049 | 0.0058 | 0.0058 |
| **n9** | 0.0016 | 0.0014 | 0.0019 | 0.0019 |

# APPENDIX C: DETAILED RESULTS ON TURKISH ELECTRICITY MARKET MODEL

## C.1. General Results

**Table C.1 Optimal Prices for Nodes and Scenarios (TL/MWh)**

| Scenarios | *Market Structure* | n1 | n2 | n3 | n4 | n5 | n6 | n7 | n8 | n9 | Weighted Average Prices |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Scenario 1** | ***PC*** | 271.52 | 247.97 | 268.62 | 165.37 | 227.32 | 50.57 | 51.46 | 65.44 | 83.21 | 218.82 |
| | ***NC*** | 271.73 | 248.03 | 268.14 | 166.29 | 227.83 | 49.77 | 49.77 | 65.52 | 83.43 | **213.54** |
| **Scenario 2** | ***PC*** | **228.71** | **210.25** | **226.99** | **143.32** | **193.52** | **50.04** | **50.49** | **62.44** | **76.57** | 182.96 |
| | ***NC*** | 231.13 | 212.66 | 229.54 | 144.71 | 195.76 | 49.07 | 50.59 | 61.78 | 76.81 | **181.06** |
| **Scenario 3** | ***PC*** | **388.58** | **353.82** | **385.35** | **227.72** | **322.30** | **51.91** | **52.19** | **75.22** | **101.76** | 318.28 |
| | ***NC*** | **388.00** | **354.34** | **385.35** | **228.58** | **323.19** | **49.29** | **49.29** | **74.51** | **101.12** | **296.75** |
| **Scenario 4** | ***PC*** | **388.62** | **353.74** | **385.27** | **227.61** | **322.21** | **51.61** | **51.34** | **74.80** | **101.34** | 311.82 |
| | ***NC*** | **388.14** | **354.18** | **385.21** | **228.39** | **323.02** | **48.98** | **48.98** | **74.11** | **100.89** | **293.85** |

Although, perfect competition is better in terms of welfare measures, demand weighted prices are slightly lower in all scenarios, due to increases in demand in nodes n6 to n9. But this increase is not substantial, hence, welfare measures (as expected) are better off for perfect competition case.

**Table C.2 Demands for Nodes and Scenarios (1000MW)**

| Scenarios | ***Market Structure*** | n1 | n2 | n3 | n4 | n5 | n6 | n7 | n8 | n9 | TOTAL DEMAND |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Scenario 1** | ***PC*** | 7.82 | 9.77 | 13.66 | 6.30 | 2.20 | 0.96 | 1.02 | 1.11 | 4.09 | 46.94 |
| | ***NC*** | 7.75 | 9.75 | **13.89** | 5.95 | 2.16 | **1.33** | **2.45** | 1.10 | 3.95 | **48.33** |
| **Scenario 2** | ***PC*** | 7.71 | 9.36 | 13.10 | 6.04 | 2.11 | 1.20 | 1.84 | 1.06 | 4.11 | 46.52 |
| | ***NC*** | 6.84 | 8.30 | 11.65 | 5.42 | 1.87 | **1.65** | 1.76 | **1.19** | 3.95 | 42.63 |
| **Scenario 3** | ***PC*** | 8.01 | 9.75 | 13.65 | 6.22 | 2.20 | 0.35 | 0.40 | 0.97 | 3.86 | 45.40 |
| | ***NC*** | **8.13** | 9.62 | **13.66** | 5.99 | 2.14 | **1.55** | **2.86** | **1.10** | **4.20** | **49.21** |
| **Scenario 4** | ***PC*** | 7.99 | 9.78 | 13.68 | 6.25 | 2.20 | 0.48 | 1.12 | 1.05 | 4.08 | 46.63 |
| | ***NC*** | **8.10** | 9.66 | 13.70 | 6.03 | 2.15 | **1.69** | **3.12** | **1.17** | **4.32** | **49.93** |

## Table C.3 Current Prices for Nodes and Scenarios (TL/MWh)

| Scenarios | *Market Structure* | n1 | n2 | n3 | n4 | n5 | n6 | n7 | n8 | n9 | WEIGHTED AVERAGE PRICE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Scenario 1** | ***PC*** | 276.09 | 254.21 | 275.72 | 168.18 | 232.70 | 47.88 | 47.88 | 65.01 | 82.14 | **197.39** |
| | ***NC*** | 276.70 | 253.94 | 275.10 | 168.83 | 232.75 | 48.73 | 48.73 | 65.71 | 82.69 | **203.40** |
| **Scenario 2** | ***PC*** | 232.25 | 214.61 | 231.99 | 145.09 | 197.23 | 47.88 | 47.88 | 61.73 | 75.58 | **168.59** |
| | ***NC*** | 233.02 | 215.44 | 232.61 | 146.41 | 198.25 | 48.81 | 48.81 | 62.72 | 76.62 | **174.26** |
| **Scenario 3** | ***PC*** | 396.02 | 362.55 | 395.38 | 231.25 | 329.73 | 47.88 | 47.88 | 74.07 | 100.27 | **276.76** |
| | ***NC*** | 396.37 | 362.45 | 394.83 | 232.18 | 330.01 | 48.64 | 48.64 | 74.89 | 101.13 | **285.73** |
| **Scenario 4** | ***PC*** | 396.02 | 362.55 | 395.38 | 231.25 | 329.73 | 47.88 | 47.88 | 74.07 | 100.27 | **276.76** |
| | ***NC*** | 396.34 | 362.47 | 394.86 | 232.15 | 330.02 | 48.53 | 48.53 | 74.79 | 101.05 | **284.54** |

## Table C.4 Current Demands for Nodes and Scenarios (1000MW)

| Scenarios | *Market Structure* | n1 | n2 | n3 | n4 | n5 | n6 | n7 | n8 | n9 | TOTAL DEMAND |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Scenario 1** | ***PC*** | 6.43 | 7.45 | 10.28 | 5.23 | 1.71 | 2.19 | 4.05 | 1.20 | 4.77 | **43.32** |
| | ***NC*** | 6.25 | 7.55 | 10.58 | 4.98 | 1.70 | 1.81 | 3.33 | 1.06 | 4.42 | **41.68** |
| **Scenario 2** | ***PC*** | 6.44 | 7.45 | 10.27 | 5.25 | 1.71 | 2.19 | 4.05 | 1.20 | 4.80 | **43.36** |
| | ***NC*** | 6.16 | 7.08 | 9.91 | 4.67 | 1.60 | 1.77 | 3.26 | 1.00 | 4.07 | **39.52** |
| **Scenario 3** | ***PC*** | 6.44 | 7.48 | 10.33 | 5.24 | 1.71 | 2.19 | 4.05 | 1.17 | 4.64 | **43.24** |
| | ***NC*** | 6.36 | 7.50 | 10.51 | 4.98 | 1.69 | 1.84 | 3.40 | 1.03 | 4.19 | **41.51** |
| **Scenario 4** | ***PC*** | 6.44 | 7.48 | 10.33 | 5.24 | 1.71 | 2.19 | 4.05 | 1.17 | 4.64 | **43.24** |
| | ***NC*** | 6.37 | 7.50 | 10.50 | 4.99 | 1.69 | 1.89 | 3.50 | 1.05 | 4.24 | **41.72** |

## Table C.5 Share of Renewable Plants According to Four Scenarios

| | **Scenario 1** | | **Scenario 2** | | **Scenario 3** | | **Scenario 4** | | **Current Policy** |
|---|---|---|---|---|---|---|---|---|---|
| ***Market Structure*** | ***PC*** | ***NC*** | ***PC*** | ***NC*** | ***PC*** | ***NC*** | ***PC*** | ***NC*** | ***PC or NC*** |
| **Renewable** | 41.9% | 41.2% | 43.7% | **46.1%** | 42.0% | **39.9%** | **43.5%** | **41.8%** | **42.6%** |
| **Conventional** | 58.1% | 58.8% | 56.3% | **53.9%** | 58.0% | **60.1%** | **56.5%** | **58.2%** | **57.4%** |

**Table C.6 Results for Perfect Competition and Nash-Cournot Market Structures for Scenario 2 (TL/h)**

| | Perfect Competition (PC) | Nash-Cournot (NC) | % change (PC to NC) |
|---|---|---|---|
| **Total Surplus** | 8,167,071 | 8,024,149 | -2% |
| **Producer Surplus** | 7,165,384 | 7,117,528 | -1% |
| **Consumer Surplus** | 413,646 | 331,819 | -20% |
| **Revenue of Transmission** | 588,040 | 598,262 | -23% |
| **Generation Expansion Cost** | 399,100 | 307,257 | -1% |
| **Transmission Expansion Cost** | 146,000 | 146,000 | 2% |
| **Net Surplus** | 7,621,971 | 7,570,892 | -2% |

**Table C.7 Comparison Between Nash-Cournot and Perfect Competition for Scenario 2 (de la Torre et al., 2008; Sauma and Oren, 2006)**

| Nodes | Sales | Lerner Index |
|---|---|---|
| **TRAKYA** | -11% | 1% |
| **BATI ANADOLU** | -11% | 1% |
| **KUZEY BATI ANADOLU** | -11% | 1% |
| **ORTA ANADOLU** | -10% | 1% |
| **BATI AKDENİZ** | -12% | 1% |
| **ORTA KARADENİZ** | 37% | -2% |
| **DOĞU AKDENİZ** | -4% | 0% |
| **DOĞU ANADOLU** | 13% | -1% |
| **GÜNEY DOĞU ANADOLU** | -4% | 0% |

**Table C.8 Results for Perfect Competition and Nash-Cournot Market Structures for Scenario 3 (TL/h)**

| | Perfect Competition (PC) | Nash-Cournot (NC) | % change (PC to NC) |
|---|---|---|---|
| **Total Surplus** | 8,821,872 | 8,771,529 | -1% |
| **Producer Surplus** | 6,974,284 | 6,967,925 | 0% |
| **Consumer Surplus** | 738,718 | 741,837 | 0% |
| **Revenue of Transmission** | 1,108,870 | 1,118,104 | 6% |
| **Generation Expansion Cost** | 283,785 | 299,424 | -1% |
| **Transmission Expansion Cost** | 146,000 | 146,000 | 1% |
| **Net Surplus** | 8,392,087 | 8,326,105 | -1% |

**Table C.9 Comparison Between Nash-Cournot and Perfect Competition for Scenario 3 (de la Torre et al., 2008; Sauma and Oren, 2006)**

| Nodes | Sales | Lerner Index |
|---|---|---|
| **TRAKYA** | 2% | 0% |
| **BATI ANADOLU** | -1% | 0% |
| **KUZEY BATI ANADOLU** | 0% | 0% |
| **ORTA ANADOLU** | -4% | 0% |
| **BATI AKDENİZ** | -3% | 0% |
| **ORTA KARADENİZ** | 347% | -5% |
| **DOĞU AKDENİZ** | 609% | -6% |
| **DOĞU ANADOLU** | 13% | -1% |
| **GÜNEY DOĞU ANADOLU** | 9% | -1% |

**Table C.10 Results for Perfect Competition and Nash-Cournot Market Structures for Scenario 4 (TL/h)**

| | Perfect Competition (PC) | Nash-Cournot (NC) | % change (PC to NC) |
|---|---|---|---|
| **Total Surplus** | 12,949,897 | 12,901,746 | 0% |
| **Producer Surplus** | 11,095,140 | 11,090,604 | 0% |
| **Consumer Surplus** | 744,097 | 748,455 | 1% |
| **Revenue of Transmission** | 1,110,659 | 1,119,005 | 4% |
| **Generation Expansion Cost** | 405,051 | 423,178 | -1% |
| **Transmission Expansion Cost** | 146,000 | 146,000 | 1% |
| **Net Surplus** | 12,398,846 | 12,332,568 | 0% |

**Table C.11 Comparison Between Nash-Cournot and Perfect Competition for Scenario 4 (de la Torre et al., 2008; Sauma and Oren, 2006)**

| Nodes | Sales | Lerner Index |
|---|---|---|
| **TRAKYA** | 1% | 0% |
| **BATI ANADOLU** | -1% | 0% |
| **KUZEY BATI ANADOLU** | 0% | 0% |
| **ORTA ANADOLU** | -3% | 0% |
| **BATI AKDENİZ** | -2% | 0% |
| **ORTA KARADENİZ** | 248% | -5% |
| **DOĞU AKDENİZ** | 178% | -5% |
| **DOĞU ANADOLU** | 11% | -1% |
| **GÜNEY DOĞU ANADOLU** | 6% | 0% |

## C.2. Investment Results

### Table C.12 Transmission Investments for All Scenarios (MW)

| Lines | Perfect Competition | Nash-Cournot |
|---|---|---|
| **k5 (n3-n6)** | 500 | 500 |

### Table C.13 Generation Investments for Scenario 1 (MW)

| Firms | Nodes | Plant Types | Perfect Competition | Nash-Cournot |
|---|---|---|---|---|
| **f2** | **n4** | WIND | 1000 | 1000 |
| **f2** | **n6** | NUCLEAR | - | 74.73 |
| **f2** | **n7** | NUCLEAR | - | 1599.24 |
| **f5** | **n1** | NATURAL GAS | 3095.50 | 3095.50 |
| **f5** | **n1** | BIOMASS | 15 | 15 |
| **f5** | **n1** | WIND | 185 | 185 |
| **f5** | **n1** | COAL | 1.19 | 1.19 |
| **f5** | **n2** | HYDRO(Run-of-river) | 93.93 | 93.93 |
| **f5** | **n2** | NATURAL GAS | 131 | 131 |
| **f5** | **n2** | GEOTHERMAL | 345.21 | 345.21 |
| **f5** | **n2** | BIOMASS | 25.15 | 25.15 |
| **f5** | **n2** | WIND | 75 | 75 |
| **f5** | **n2** | COAL | 700 | 700 |
| **f5** | **n3** | HYDRO(Run-of-river) | 79.75 | 79.75 |
| **f5** | **n3** | NATURAL GAS | 3474.50 | 3474.50 |
| **f5** | **n3** | BIOMASS | 12.50 | 12.50 |
| **f5** | **n3** | WIND | 158 | 158 |
| **f5** | **n3** | COAL | 51.04 | 51.04 |
| **f5** | **n4** | HYDRO(Run-of-river) | 64.52 | 64.52 |

## Table C.14 Generation Investments for Scenario 2 (MW)

| Firms | Nodes | Plant Types | Perfect Competition | Nash-Cournot |
|---|---|---|---|---|
| **f2** | **n4** | WIND | 1000.00 | 1000.00 |
| **f2** | **n6** | NUCLEAR | 1000.00 | 1000.00 |
| **f2** | **n7** | NUCLEAR | 3095.50 | 1908.96 |
| **f5** | **n1** | NATURAL GAS | 15.00 | 15.00 |
| **f5** | **n1** | BIOMASS | 185.00 | 185.00 |
| **f5** | **n1** | WIND | 1.19 | 1.19 |
| **f5** | **n1** | COAL | 93.93 | 93.93 |
| **f5** | **n2** | HYDRO(Run-of-river) | 345.21 | 345.21 |
| **f5** | **n2** | NATURAL GAS | 25.15 | 25.15 |
| **f5** | **n2** | GEOTHERMAL | 75.00 | 75.00 |
| **f5** | **n2** | BIOMASS | 700.00 | 700.00 |
| **f5** | **n2** | WIND | 79.75 | 79.75 |
| **f5** | **n2** | COAL | 3474.50 | |
| **f5** | **n3** | HYDRO(Run-of-river) | 12.50 | 12.50 |
| **f5** | **n3** | NATURAL GAS | 158.00 | 158.00 |
| **f5** | **n3** | BIOMASS | 51.04 | 51.04 |
| **f5** | **n3** | WIND | 64.52 | 64.52 |
| **f5** | **n3** | COAL | 95.90 | 95.90 |
| **f5** | **n4** | HYDRO(Run-of-river) | 230.00 | 230.00 |

## Table C.15 Generation Investments for Scenario 3 (MW)

| Firms | Nodes | Plant Types | Perfect Competition | Nash-Cournot |
|---|---|---|---|---|
| **f2** | **n4** | WIND | 1000 | 1000 |
| **f2** | **n6** | NUCLEAR | - | 1608.91 |
| **f2** | **n7** | NUCLEAR | - | 2854.30 |
| **f5** | **n1** | NATURAL GAS | 3095.50 | 3095.50 |
| **f5** | **n1** | BIOMASS | 15 | 15 |
| **f5** | **n1** | WIND | 185 | 185 |
| **f5** | **n1** | COAL | 1.19 | 1.19 |
| **f5** | **n2** | HYDRO(Run-of-river) | 93.93 | 93.93 |
| **f5** | **n2** | NATURAL GAS | 131 | 131 |
| **f5** | **n2** | GEOTHERMAL | 345.21 | 345.21 |
| **f5** | **n2** | BIOMASS | 25.15 | 25.15 |
| **f5** | **n2** | WIND | 75 | 75 |
| **f5** | **n2** | COAL | 700 | 700 |
| **f5** | **n3** | HYDRO(Run-of-river) | 79.75 | 79.75 |
| **f5** | **n3** | NATURAL GAS | 3474.50 | 3474.50 |
| **f5** | **n3** | BIOMASS | 12.50 | 12.50 |
| **f5** | **n3** | WIND | 158 | 158 |
| **f5** | **n3** | COAL | 51.04 | 51.04 |
| **f5** | **n4** | HYDRO(Run-of-river) | 64.52 | 64.52 |

## Table C.16 Generation Investments for Scenario 4 (MW)

| Firms | Nodes | Plant Types | Perfect Competition | Nash-Cournot |
|---|---|---|---|---|
| **f2** | **n4** | WIND | 1000 | 1000 |
| **f2** | **n6** | NUCLEAR | 1000 | 1000 |
| **f2** | **n7** | NUCLEAR | - | 1544.94 |
| **f5** | **n1** | NATURAL GAS | - | 2312.36 |
| **f5** | **n1** | BIOMASS | 3095.50 | 3095.50 |
| **f5** | **n1** | WIND | 15 | 15 |
| **f5** | **n1** | COAL | 185 | 185 |
| **f5** | **n2** | HYDRO(Run-of-river) | 1.19 | 1.19 |
| **f5** | **n2** | NATURAL GAS | 93.93 | 93.93 |
| **f5** | **n2** | GEOTHERMAL | 131 | 131 |
| **f5** | **n2** | BIOMASS | 345.21 | 345.21 |
| **f5** | **n2** | WIND | 25.15 | 25.15 |
| **f5** | **n2** | COAL | 75 | 75 |
| **f5** | **n3** | HYDRO(Run-of-river) | 700 | 700 |
| **f5** | **n3** | NATURAL GAS | 79.75 | 79.75 |
| **f5** | **n3** | BIOMASS | 3474.50 | 3474.50 |
| **f5** | **n3** | WIND | 12.50 | 12.50 |
| **f5** | **n3** | COAL | 158 | 158 |
| **f5** | **n4** | HYDRO(Run-of-river) | 51.04 | 51.04 |