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

MARKET-CLEARING SIMULATIONS AND ANALYSES FOR TURKISH ELECTRICITY MARKET

CANSU ŞENTÜRK EKER

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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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DECLARATION OF RESEARCH ETHICS /

METHODS OF DISSEMINATION

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ABSTRACT

In this thesis, current market structure of the Turkish electricity market, which uses a uniform pricing system, is analyzed and new market-clearing mechanisms (e.g., single or nodal pricing) are investigated for the market requirements. This has led to the development of different market-clearing models and market-price simulations that can be encountered in transition to a regional pricing model which provides market participants with greater transparency and simplicity in forecasting market outcomes. In the proposed models, Turkish electricity market has been analyzed by using nine regional control areas (zones) pre-specified by Turkish Electricity Transmission Company (TETC). Based on Energy Exchange İstanbul transparency platform and TETC reports, installed generation capacities are calculated for each region according to thirteen fuel types and seven different types of ownership. Different scenarios (e.g., seasonal peak, mid-peak and off-peak) and data sets (e.g., capacity and load factors for weekdays and weekends as well as price-elastic linear demand function parameters for each region) are formed and different pricing models are formulated using a mixed complementarity problem (MCP) framework. Operation, maintenance and fuel costs for each generation facility are obtained from international cost survey studies. The effects on social welfare and electricity price levels for the pricing models are examined in details using different market structures (e.g., perfectly competitive and Nash-Cournot). In MS EXCEL, regional maps containing nine control areas of the transmission network are created and the results obtained from GAMS software are summarized using macros (e.g., visual basic for applications –VBA codes).

In the literature, such models appear for different regions and countries, however, it is a major shortcoming for Turkish electricity market. Hence, the proposed models of this thesis will enable the analyses of decision-making process of market participants and their short/medium/long-term decisions, as well as future investment plans and their impact on the market.

Keywords: Turkish Electricity Market, Regional Pricing Model, Market-Clearing/Price Simulation Model, Economic Equilibrium Model

TÜRKİYE ELEKTRİK SİSTEMİ İÇİN PİYASA-TAKAS BENZETİMLERİ VE ANALİZLERİ

ÖZET

Bu çalışmada, halihazırda tek fiyat sistemini kullanan Türkiye elektrik piyasasının mevcut piyasa yapısı analiz edilerek, ihtiyaçlarına yönelik yeni piyasa-takas mekanizmaları (tek veya bara bazlı fiyatlandırma) araştırılmıştır. Böylelikle piyasa katılımcılarına daha fazla şeffaflık ve kolaylık tanıyan bölgesel fiyatlandırma modeline geçişte karşılaşılabilecek, ayrıca sistem sorunlarını analiz etmeye yardımcı olacak farklı piyasa-takas ve piyasa-fiyat benzeşim modelleri geliştirilmiştir. Önerilen modellerde Türkiye elektrik piyasası, Türkiye Elektrik İletim A.Ş (TEİAŞ) tarafından öngörülen dokuz bölgeli yük tevzi merkezi (YTM) kullanılarak analiz edilmiştir. Enerji Piyasaları İşletme A.Ş. (EPİAŞ) Şeffaflık Platformu ve TEİAŞ raporlarına dayanarak, on üç yakıt çeşidi ve yedi farklı santral çeşidi baz alınarak, kurulu güç kapasiteleri hesaplanmıştır. Farklı senaryo analizleri için (örn. mevsimsel pik, orta ve baz) veri setlerinin oluşturulmuş (örn. hafta içi ve haftasonuna göre değişen kapasite ve yük faktörleri ile varsayılan kısa dönem fiyat esnekliklerine göre her bölge için fiyat-esnek doğrusal talep fonksiyon parametreleri) ve farklı fiyat modelleri karışık tamamlama problemi olarak formüle edilmiştir. Her üretim tesisi için işletme, bakım ve yakıt masrafları uluslararası maliyet araştırması çalışmalarından elde edilmiştir. Bu fıyatlandırma modelleri için toplum refahı ve elektrik fiyat seviyeleri üzerindeki etkiler farklı piyasa yapıları (örn., tam rekabetçi ve Nash-Cournot) için detaylı olarak incelenmiştir. MS EXCEL'de, Türkiye elektrik iletim ağının dokuz yük tevzi merkezini içeren bölgesel haritalar oluşturulmuş ve GAMS programından elde edilen sonuçlar makrolar kullanılarak özetlenmiştir (örn., visual basic applications –VBA kodları).

Literatürde, bu tarz modeller farklı bölgeler ve ülkeler için ortaya çıkmaktadır, ancak Türkiye elektrik piyasası için önemli bir eksiklik olarak görülmektedir. Bu nedenle, bu tezin önerilen modelleri, hem geleceğe dönük yatırım planları açısından hem de bunların piyasaya etkileri ve piyasa oyuncularının karar verme süreçlerindeki sonuçları bakımından oldukça faydalı olabilecek ve piyasa oyuncularının kısa/orta/uzun vadeli

kararlarına yardımcı olabilecek analizleri sağlayabilecektir. Ayrıca bu modeller gelecek yatırım planları ve bunların piyasa etkileri konusunda yararlı olabilecektir.

Anahtar Sözcükler: Türkiye Elektrik Piyasası, Bölgesel Fiyatlandırma Modeli, Piyasa-Takas/Piyasa Fiyatı Benzeşim Modeli, Ekonomik Denge Modeli

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LIST OF SYMBOLS

Indices and Sets:

$f \in F$, index and set of generation firms

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

$h \in H$, index and set of generation types by fuel

$\phi_i \subset I$, set of nodes connected to node *i*

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

$k \in K,$ index and set of transmission lines

Variables:

p_i electricity (nodal) price at node *i*

x_{fih} generation by firm *f* and fuel type *h* at node *i*

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

y_i injection/withdrawals of power to/from node *i*

w_i wheeling fee at node *i*

Parameters:

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

β_i constant price coefficient for the linear inverse demand function at node *i*

c_{fih} operating cost of generation firm *f* and fuel type *h* at node *i*

K_{fih} capacity of generation firm *f* and fuel type *h* at node *i*

$PTDF_{ik}$ power transfer distribution factors, a linear response coefficient, translating net power injections/withdrawals at the nodes into flow on a transmission line *k* in the network

T_k upper level to the flow through transmission line *k*.

LIST OF ABBREVIATIONS

TETC (TEİAŞ)	Turkish Electricity Transmission Company (Türkiye Elektrik İletim A.Ş.)
EMRA (EPDK)	Energy Market Regulatory Authority (Enerji Piyasaları Düzenleme Kurumu)
EXIST (EPİAŞ)	Energy Exchange Istanbul (Enerji Piyasaları İşletme A.Ş.)
CA (RK)	Competition Authority (Rekabet Kurumu)
CAISO	California Independent System Operator
TEAM	Transmission Economic Assessment Methodology
DAM	Day-Ahead Market
IDM	Intraday Market
BPM	Balancing Power Market
LDC (YTM)	Load Dispatch Center (Yük Tevzi Merkezi)
MCP	Market Clearing Price
TSO	Transmission System Operator
TETCC (TETAŞ)	Turkish Electricity Trading and Contracting Company (Türkiye Elektrik Ticaret ve Taahhüt A.Ş.)
GDRE (YEGM)	General Directorate of Renewable Energy (Yenilenebilir Enerji Genel Müdürlüğü)
TL	Turkish Lira
MWh	Megawatt Hour
kWh	Kilowatt Hour
OECD	Organisation for Economic Co-operation and Development
EGC (EÜAŞ)	Electricity Generation Company (Elektrik Üretim A.Ş.)
MFSC (PMUM)	Market Financial Settlement Center (Piyasa Mali Uzlaştırma Merkezi)
MENR (ETKB)	Ministry of Energy and Natural Resources (Enerji ve Tabii Kaynaklar Bakanlığı)

1. INTRODUCTION

1.1 Overview of Turkish Electricity Market

In the liberalization and deregulation process of Turkish electricity market, electricity has become a commercial product that is bought and sold in a competitive market. In this market, the investment decisions of the transmission system operator, which aims to provide reliable and secure system operations, and the planning and investment decisions of the private generation companies are shaped by economic factors considering market outcomes (Awad et al., 2010). In the course of this restructuring, economic equilibrium models are useful, such that they can take into account new investment decisions, new price signals in the competitive market and the behaviour of other investors or generators underlying these signals as well as uncertainties related to supply-demand dynamics, such as capacity and load factors. Moreover, these models are helpful in forecasting and planning activities of interacting agents in the market. Despite market-clearing (or market price) simulation models for many regions and countries in the literature, there is no model that can be used for Turkish electricity market. Understanding the behaviour of private generation firms, analyses of market conditions and mitigation of market power requires such models to be employed by market monitoring regulatory agencies, i.e., Energy Market Regulatory Authority (EMRA), Energy Exchange Istanbul (EXIST), Competition Authority (CA). These models would be useful for short-, medium- and long-term decisions of all market agents.

Market-clearing models for Turkish electricity market under different load and capacity factors simulate the market outcomes, e.g., zonal (nodal) prices and generation amounts. These outcomes have been compared to currently used uniform price system for policy analyses. Depending on the different pricing models (single vs. zonal), the impacts on price-cost margins and social welfare measures are analysed. This study would be useful a) for market participants to plan their operations and long-term strategic investments, and b) for policy makers and regulatory agencies to understand market agents' strategic behaviour and interaction as well as to monitor and mitigate market power (Helman and Hobbs, 2010).

1.2 Objectives and Contribution of This Study

Since 2000, there have been many efforts in Turkish electricity sector to shift from a monopolistic market to a competitive market structure where the generation, transmission and distribution activities have been separated from each other. In this new competitive market structure, consumers are treated as customers, prices are to reflect the supply-demand balance instead of tariffs subject to cost-based regulation, and customers are free to choose their suppliers. As a result of these efforts, EXIST (also known as Enerji Piyasaları İşletme A.Ş. –EPİAŞ) has been launched in 2015. At this point, low prices for consumers and profitable investments for market participants are aimed. The system operator is also able to provide resources for high-cost infrastructure investments and opportunities for other participants to offer innovative services. In this context, decision making tools, i.e., economic equilibrium models, are needed to make forecasts and plans by taking into account price / outcome signals in the competitive market, other generators' behavior underlying this price signal, uncertainties related to supply / demand, and new generation / transmission capacity investment decisions.

Economic equilibrium models in electricity markets can provide many solutions for the market participants. Analyses based on historical data can be inadequate in electricity markets due to the peculiarities of electrical energy. Price signals are a very important input for medium / long-term generation / transmission investment decisions. Similarly, transmission / generation investments affect the prices and generation / consumption levels as they change the structure of the system. Therefore, it is clear that medium and long-term investment decisions and short-term market outputs interact with each other. In addition, economic equilibrium models are useful as an analysis tool for all participants in the electricity market, especially in market power analyses for supervisory and regulatory agencies (e.g., EMRA, CA); planning transmission investments for the system operator (TEİAŞ); and deciding on size and location of generation investments for investors.

1.3 Scope and Outline of the Thesis

Electricity markets have rapidly changed with the liberalization policy adopted around the world in the 1980s, causing privatization, liberalization and restructuring efforts in electricity markets. In this process, the idea that electricity supply is a public service has been completely abandoned. Thus, the generation, transmission, distribution, wholesale and retail sales stages of the sector were opened to competition. However, most of these supply chain stages in some countries could not have been opened to full competition, but rather become highly regulated (e.g., transmission and retail sales). Also organized trade markets (power exchange/pool) are established where electricity is bought and sold as a commercial product. Hence, electricity has now become a business activity in itself that is marketed. This process is slow because of economic constraints, the need for new constructions and legal regulations, and the fact that those who intend to operate the electricity market are faced with very high fixed costs. Despite completion of these stages in most countries, some countries are still at the beginning stage in the deregulation process (Ulusoy, 2012).

This thesis is organized as follows. Chapter 1 gives a brief overview of the electricity markets and objective/scope of this thesis. Chapter 2 presents the current literature on electricity market models and also includes a background on the Turkish electricity system and its restructuring process. Chapter 3 introduces the electricity market equilibrium and the formulation of the mathematical model from the perspective of each participating market agent under different market structures (e.g., perfectly competitive and Nash-Cournot). Chapter 4 presents the model for the nine regional control areas (zones) of the Turkish electricity system and analyses the results under different demand scenarios with the summary of the simulation results. The thesis concludes with Chapter 5, where conclusions, insights and recommendations for Turkish electricity market are summarized and directions for future research areas are presented.

2. LITERATURE REVIEW

2.1 Electricity Pricing Around the World

This section discusses studies related to approaches in our models for electricity markets. There are two main approaches to modeling electricity prices in the literature (Deng and Oren, 2006):

i) Fundamental Approach: An approach that determines market outcomes (prices and outputs) by considering the simulation of the system and market operations.

ii) Technical Approach: An approach that directly models the past behaviour of the market price with historical data and statistical analysis.

The fundamental approach offers more realistic system and network modeling with specific scenarios compared to technical approach, and even in case of many of the scenarios that need to be evaluated, there are now ways to handle computational issues using decomposition methods (Fuller and Chung, 2005). The technical approach is also useful, but we believe that analysis based on historical data in a newly deregulated market will not provide reliable results. Therefore, technical approach is not investigated in this thesis.

The fundamental approach in the literature, and especially interest in economic equilibrium problems that have modeled electricity markets for different market structures (perfectly competitive, oligopolistic, monopolistic or game theoretic structures), have increased considerably in the last two decades (Helman and Hobbs, 2010). The modeling of the transmission network (e.g., transmission network constraints that obey Kirchhoff's current and voltage laws) has also made these equilibrium models large-scale and complex. In addition, these equilibrium models provide market participants and system operators with insights into market design and market power issues through realistic market price simulations (Day et al., 2002; Hobbs, 2001; Jing-Yuan and Smeers, 1999; Smeers, 1997). Moreover, sufficiently detailed models are useful for short- / long-term price estimates and the replication of actual market outcomes / prices (Borenstein and Bushnell, 1999; Green and Newbery, 1992).

Ventosa et al. (2005) presents a detailed summary of market modeling trends. There are three main directions: optimization models, equilibrium models and simulation models. In optimization models, a firm's profit maximization or social welfare maximization approaches in a perfectly competitive market are considered. Ventosa et al. (2005) also examines optimization models in which the price is an external parameter or a function of the firm's demand. In addition, the equilibrium models include that the firm can influence the price with its own production decisions.

On the other hand, economic equilibrium models of this thesis are mainly used in three different ways in the determination of the electricity market policies:

a) First, large-scale but simplified models (e.g. addressing regional capacities with an abridged, i.e., reduced, transmission network) can provide basic price signals. Such research usually warns decision-makers about the need for market rules and helps them to watch the interaction between some elements of market design and market outcomes (Helman and Hobbs, 2010).

b) Secondly, such models can be used against market power by supervisory and regulatory agencies. For example, using highly detailed regional models, it is possible to analyze electricity market mergers, geographical market definitions, price-cost margins (Lerner index) and density indices (e.g., Herfindahl-Hirschman index - HHI) as market power measures.

c) Finally, market-clearing models can estimate short-term (hourly) electricity prices, e.g., see studies that replicate the prices on the New England market (Bushnell and Saravia, 2002) and in California market (Harvey and Hogan, 2001; Joskow and Khan, 2002).

In practice, the timing and size of the investments planned in the electricity market are determined by different market participants who interpret price signals according to their own interests. The high volatility of electricity prices, the capital intensive nature of generation and the long construction period required for new facilities raise the risk of investment. In the electricity market liberalization process, investors make new capacity investment decisions based on several inputs: price signals in the market, the behavior of other investors and/or producers underlying this price signal, uncertainties associated with supply-demand dynamics such as fuel costs and demand growth. Traditionally, prior to adopting a perfectly competitive market structure, transmission investments were made by the central planner (system operator, e.g., TEİAŞ in Turkish electricity system) according to production capacity and demand projections (Gómez-Expósito et al., 2008). However, in the process of restructuring and liberalization, generation investments can be made by independent market participants at any time, and demand can be shaped by market outputs. Instead of traditional cost minimization, factors such as economic and financial risks, expected return on investment and demand response affect the decision-making process for these investments. As a result, it is necessary to consider generation investments and market outputs rather than solely looking into traditional transmission investment planning at this new competitive environment.

In this context, one of the most important points for investors is to simulate the effects of various factors on the market price signal, as well as to understand the market operations and structure. Simulation by economic equilibrium models would play important roles in decision-making processes and in understanding complex market dynamics as well as in determining sales opportunities and alternatives;

- while it is possible to protect against price fluctuations in bilateral contracts, risks of especially intermittent generation facilities (such as wind, solar and hydro power plants) can not be eliminated.

- in spot market sales, it is not known that market prices can cover investment and operating costs at a reasonable risk level.

In this case, by making market simulations and price estimation studies; it is possible to examine

- project investment return within the desired time,

- operation cost recovery and
- the strategies needed to be hedge against any risks.

Accurate modeling of the market will allow analysis of various effects for many different and interacting factors. Market participants need to assess the course, opportunities and risks of the market, to examine the activities and behaviors of the competitors, to organize the growth opportunities through mergers, to determine where and how to take part in the electricity supply chain, and to determine market participation strategies. In this context, an equilibrium model that supports decision-making processes is important for understanding complex market dynamics.

In this thesis, a market-clearing model will be used: i) to examine the Turkish electricity market, ii) to simulate the interactions of the players and the market while taking into account the basic dynamics of the market, and iii) to predict the future outcomes and market conditions. This model also allows users to identify how they can influence the market conditions and other players' decisions, and as a result, analyze the decision making processes of the participants. Effects of other variables such as the effects of new regulations and legislations (e.g., the market development by supervisory and regulatory bodies), supply / demand dynamics, different type of costs (fuel costs, variable costs, fixed costs, emission costs/tax, etc.), price levels and reserve capacity costs can be evaluated. As a result, policy and market participants' decisions can be evaluated within an overall decision making process.

The price of electricity in the competitive electricity market has become the focal point of all participants in the market. In the liberalized electricity sector, producers and consumers need to come together on the market to determine electricity prices (Schweppe et al., 1988). Theoretically, the fully competitive electricity market generates the price signals needed for investments in new generation capacity. In the simplest case, if there is sufficient generation capacity to meet demand in a fully competitive market, the spot price of electricity is equal to the cost of generating from the marginal (last dispatched) power plant. However, another important input is the physical and operational characteristics of the electricity generation and transmission processes and the system itself (the continuous requirement of the instant generation-load balance, the physical power flows in the transmission lines that obeys Kirchhoff's laws and an economically no-storable product). Therefore, the price of electricity is different from other financial prices. Considering that electricity prices are important for strategic (e.g., generation / transmission investments), tactical (e.g., spot market proposals) and operational (e.g., system security) decisions in the market, electricity pricing models are also very important in this process.

Market-clearing models of this thesis, which can simulate market price and can also integrate investment analysis models, are still not prevalent in many countries and regions where electricity markets are deregulated. However, their use in literature is very wide-spread. These models generally include analyses of the effects such as market power, emissions, transmission constraints, uncertainties in generation, energy storage, demand response and uncertainty. Despite the research efforts that examines these issues individually or together, there are no studies that offer a solution approach in an integrated structure.

Transmission systems are costly infrastructure investments, and therefore investment planning requires a technical and economically rigorous work. Accordingly, there are many studies suggesting optimal transmission network planning models. These include methods such as linear programming (Villasana, 1984), integer programming (Alguacil et al., 2003; Romero and Monticelli, 1994) or Benders decomposition (Binato et al., 2001). Other studies used heuristics such as genetic algorithms and simulated annealing (Romero et al., 1996). Game theory models are also applied (Contreras and Wu, 1999; Sauma and Oren, 2006, 2007). In another model, the transmission model of the transmission investment was integrated using the full-fledged programming model (de la Torre et al., 2008). Similarly, Garcés et al. (2009) have formulated a bi-level model in which the transmission system planner in the upper level minimizes the transmission investment costs and the lower level performs the market clearing. This two-level model is transformed into an integer linear problem using the duality theory. In addition, multi-period models have been proposed to examine investments in electricity markets. Murphy and Smeers have proposed a two-stage generation capacity investment model with market operations in the second stage, whereas generation investment decisions are made in the first stage (Murphy and Smeers, 2005). Accordingly, the equilibrium problem in the first stage is solved together with the optimality conditions from the second stage. However, in this model, transmission constraints are not accounted for.

Beside these models, only Sauma and Oren (2006, 2007) have evaluated the economic impact of the transmission investments by foreseeing the strategic response of the oligopolistic generation company that is acting in the spot market. In both studies, the authors have formulated a tri-level model that examines how the market power applied by the generation company affects the equilibrium between generation and transmission investments and the evaluation of different transmission investment projects. This model is able to influence the transmission network planner's transmisison investments and subsequent spot market behavior as a result of the "proactive network planning" approach. This proactive model is also compared with an ideal integrated resource planner model and a reactive network planner model (Sauma and Oren, 2006). However, this method, which tries to find the equilibrium in an iterative process, does not solve the optimal network planning problem and only evaluates the effect of specifically determined transmission investment projects on social welfare. Similarly, Pozo et al. have dealt with a tri-level problem, but demand in the spot market model is assumed to be fixed and this model is reformulated as an optimization problem instead of an equilibrium problem (Pozo et al., 2013). In this case, the demand response is removed from all models and the market forces are not correctly represented. In CAISO (2004) and Sheffrin (2005), the authors have developed a model for the California Independent System Operator (CAISO), namely "Transmission Economic Assessment Methodology" (TEAM). In this model, transmission planning foresees a perfectly competitive market equilibrium, but ignores the potential strategic response of generation investments to transmission investments.

2.2 Turkish Electricity Market and Pricing Mechanisms

With the publication of the Electricity Market Law no. 4628 in 2001, the basis of the electricity market restructuring is announced in Turkey.

Figure 2.2 shows the ongoing liberalization process in Turkish electricity markets (see Turkish Electricity Transmission Company (2017) and Competition Authority (2015) reports for more information).

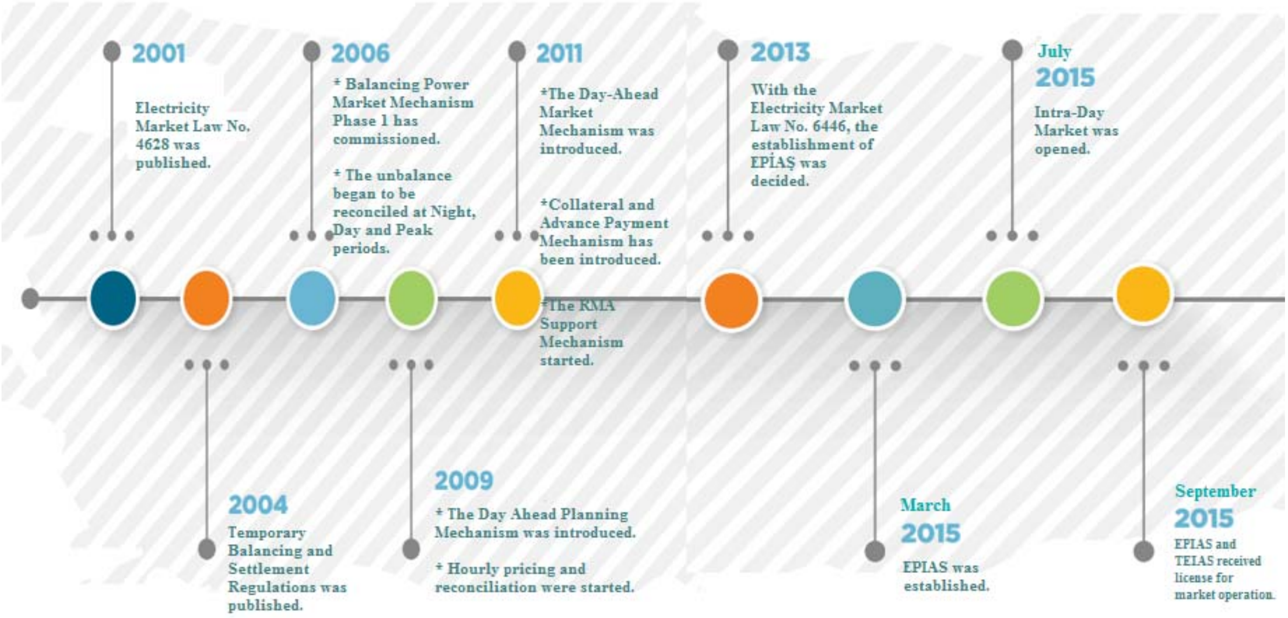


Figure 2.1 Liberalization Process of Electricity Market in Turkey (TEİAŞ, 2017)

In 2011, the Day-Ahead Market, advance payment and Renewable Energy Support mechanisms have been introduced in the market. Electricity Market Law No. 6446 has been published in 2013, and Intra-day market has started operations in 01 July 2015. The overall electricity market in Turkey can be summarized in Figure 2.2 and Figure 2.3 below.

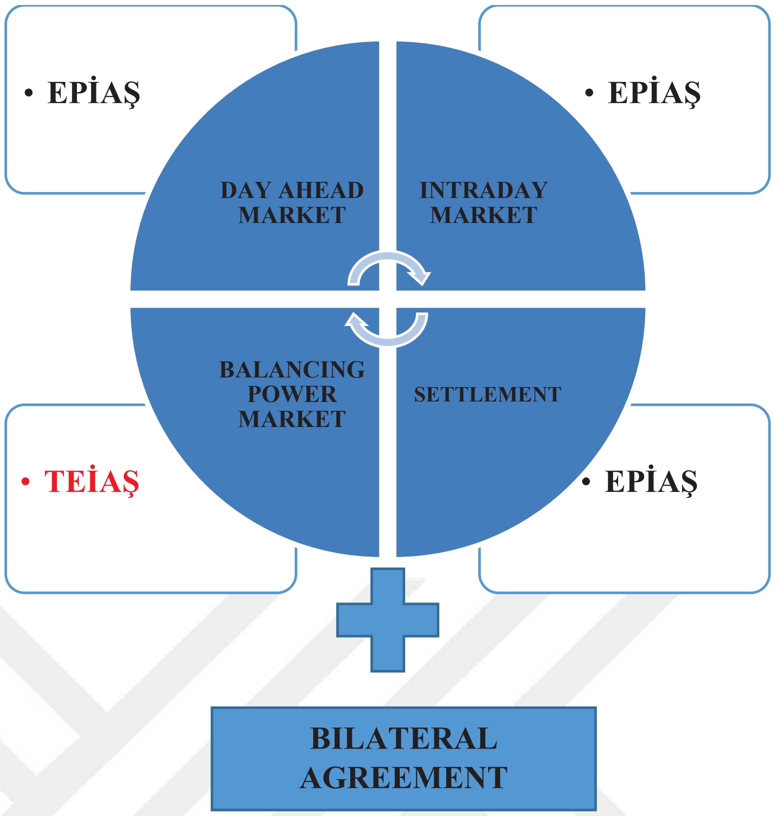


Figure 2.2 Electricity Market in Turkey (TEİAŞ, 2017)

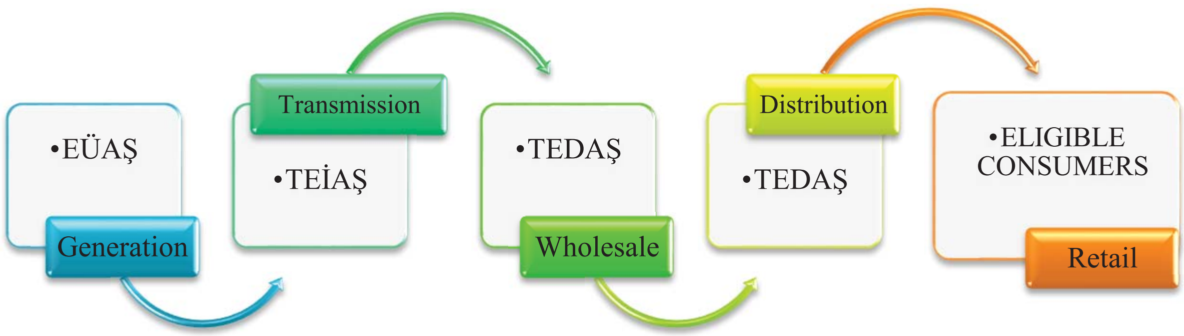
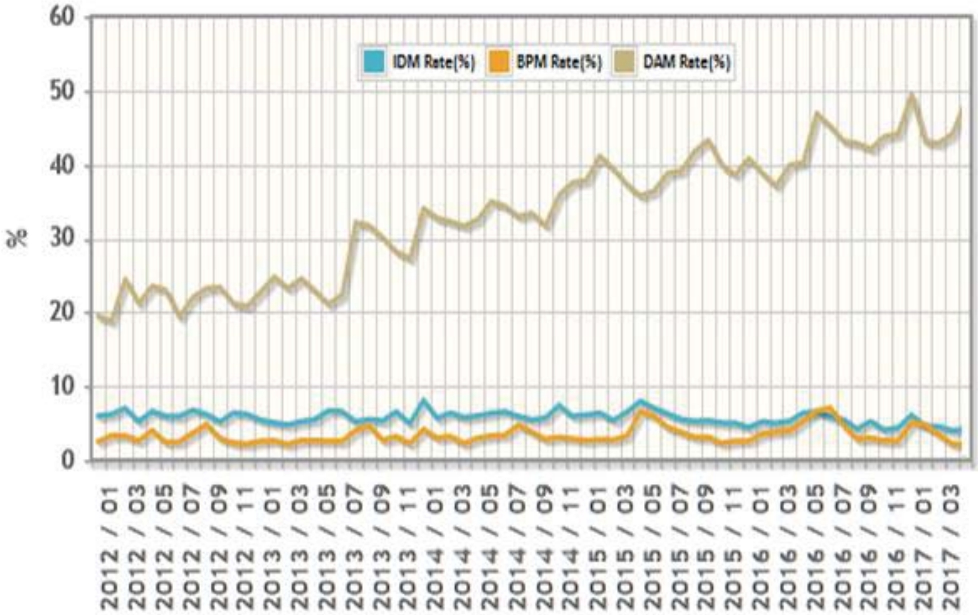


Figure 2.3 Electricity Supply Chain in Turkey (TEİAŞ, 2015)

The market activities were carried out by the Market Financial Settlement Center (MFSC) of TEİAŞ until the establishment of EPİAŞ and when it has started activities on 01.09.2015 about;

- Day Ahead Market (DAM),
- Intraday Market (IDM),
- Settlement.

On the other hand, the Balancing Power Market (BPM) activities have been carried out by TEİAŞ (TEİAŞ has both a transmission license and a Market Operation license.)



In Figure 2.4 above, it is observed that around 20% of the market participants involve in

Figure 2.4 IDM Rate (%), BPM Rate (%), DAM Rate (%) (TEİAŞ, 2017)

Day-Ahead Market (DAM) in 2012, whereas most of the market participants prefer bilateral agreements. As the market is managed more effectively and transparently in the following years, the rate of participation has increased to about 50%. It is also evident that more participants are trading on the DAM market. Around 4% of the participants appear to participate in Balancing Power Market (BPM). Similarly, the participation rate in Intraday Market (IDM) is as low as 5%.

2.2.1 Day-Ahead Market (DAM)

DAM operations are performed on a daily basis, on an hourly basis. Each day begins at 00:00 and ends at 00:00 the following day. Participants can offer hourly, block and / or flexible offers for a specific time period under DAM. Figure 2.5 shows processes of DAM.

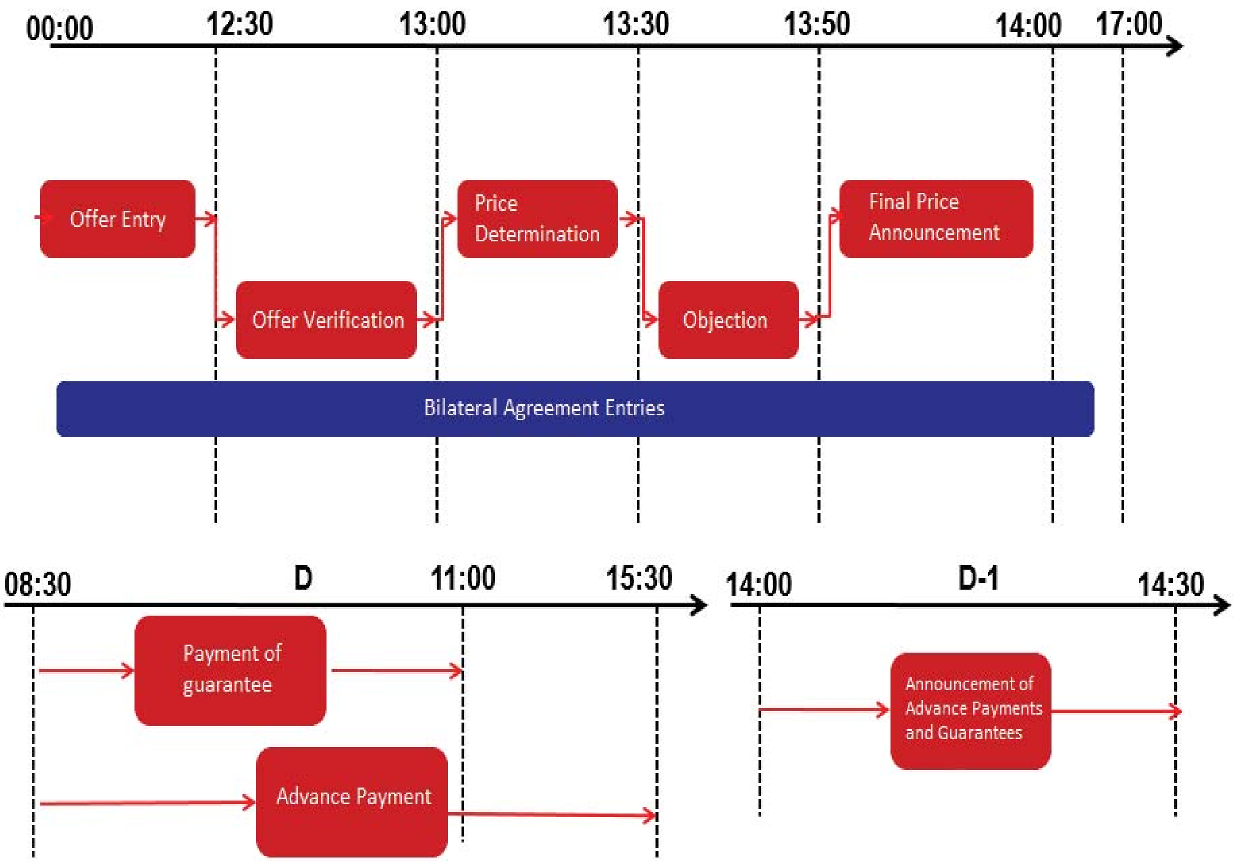


Figure 2.5 Processes of Day-Ahead Market (TEİAŞ, 2017)

There are two types of price in the electricity market.

- MCP (Market Clearing Price): We can refer to this price in the DAM at the point where the supply offers and demand bids intersects.
- SMP (System Marginal Price): Under BPM, the bid price, which corresponds to the net order volume according to the Energy Deficit Regulation Volume (EDRV) and Energy Surplus Regulation Volume (ESRV) instructions, is called SMP.

In other words, the price formed in DAM is called MCP and the price formed in the BPM (i.e., at the time of realization of the market) is called SMP. MCP is limited to 0 - 2000 TL / MWh and the arithmetic average of MCP in 2017 (first five months) was 158 TL / MWh.

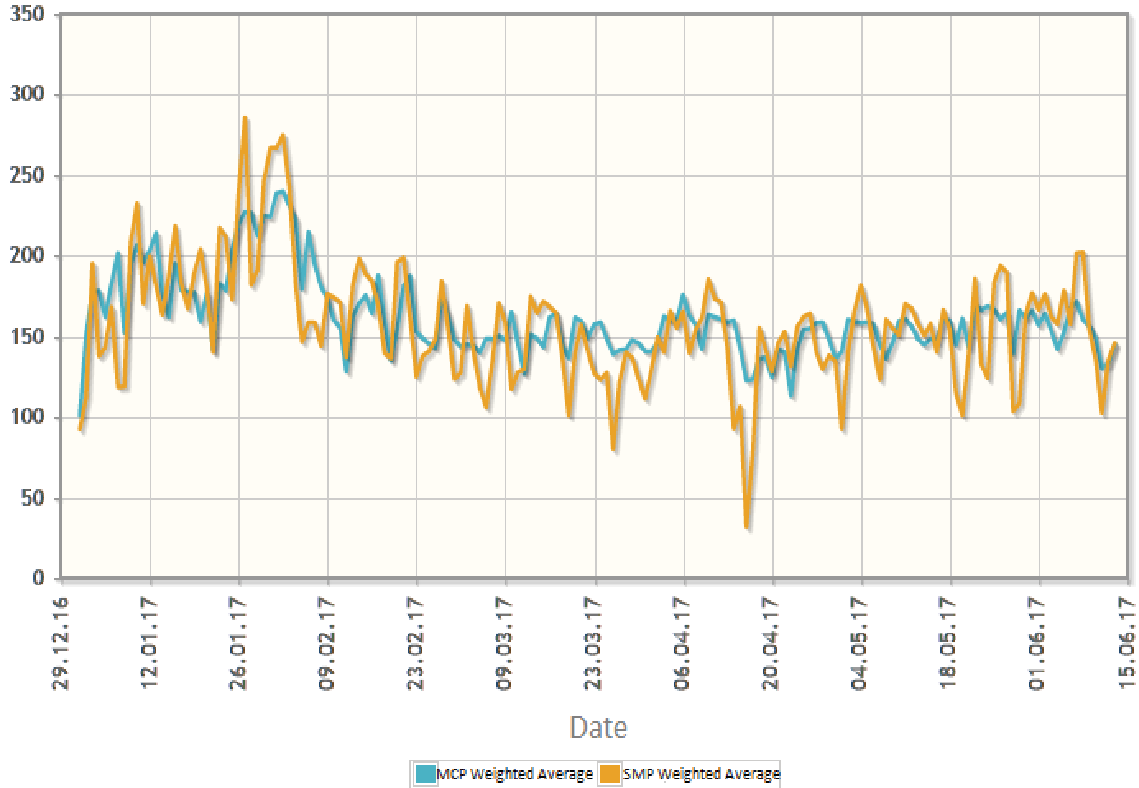


Figure 2.6 MCP and SMP Averages (TEİAŞ, 2017)

The highest MCP value was calculated as 1,899.99 TL / MWh in 2016 due to the disturbance of natural gas supply at 14:00 on 23 December 2016. In Figure 2.7 below, on 12.06.2017, the hourly transaction volume of the MCP is shown as TL and it is seen that the average transaction volume is between 2 and 5 million TL per hour.

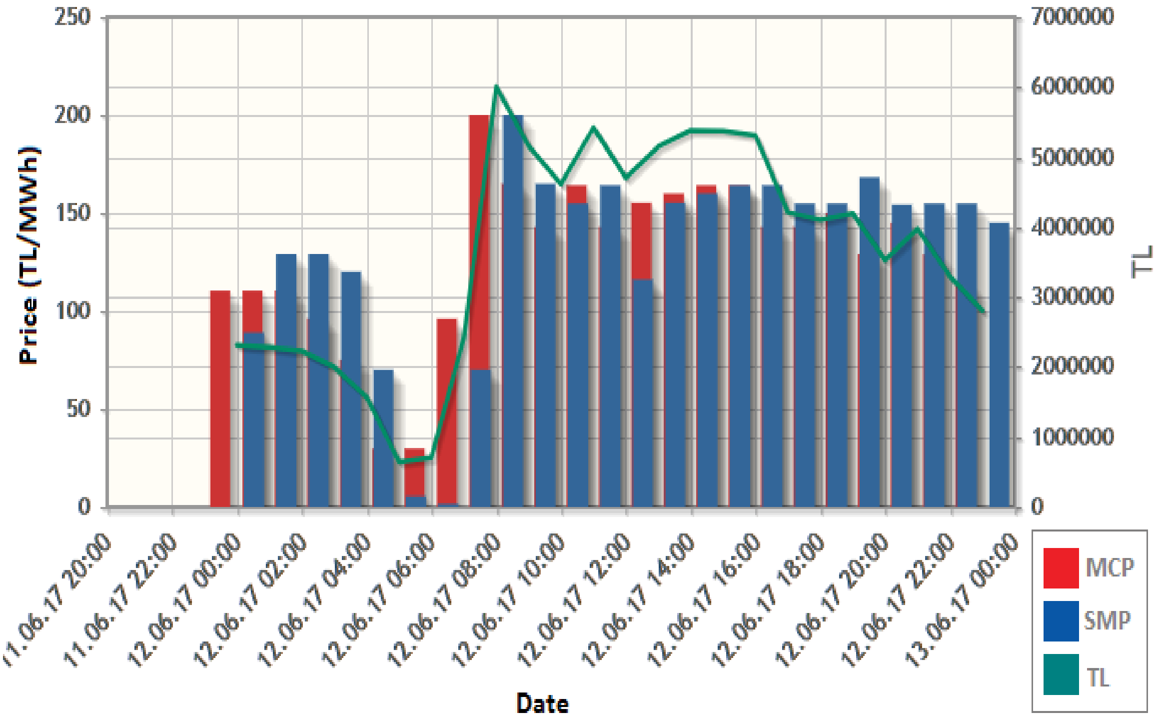


Figure 2.7 MCP – SMP and Transaction Volume (TL) (TEİAŞ, 2017)

2.2.2 Intraday Market (IDM)

On July 1, 2015, the Intra-Day Market has commenced its operations to enable participants with a more balanced and effective role in the electricity market. IDM serves as a bridge between DAM and BPM, which contributes greatly to the balancing and sustainability of the electricity market. For example, wind turbines have a large margin of error in wind forecasts which are performed a day ahead and IDM is an opportunity to reduce the imbalances in DAM. However, the introduction of IDM did not receive widespread market participation yet. The total market volume in IDM in 2016 has been below 1%. IDM is an ongoing market and bids can be entered up to 1.5 hours (90 minutes) before physical delivery to the market, and the offers can be updated, cancelled or made passive.

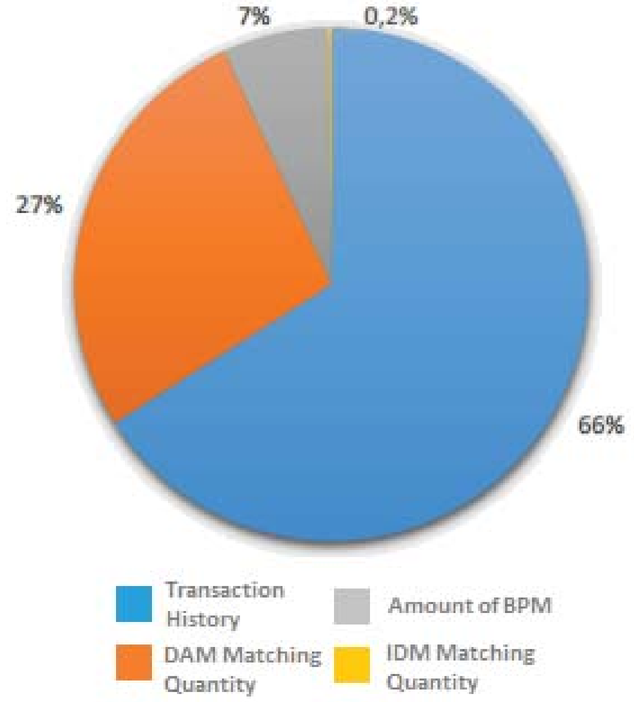


Figure 2.8 Distribution of Annual Market Volumes (TEİAŞ, 2017)

2.2.3 Balancing Power Market (BPM)

BPM is operated by TEİAŞ. Real-time balancing consists of ancillary services and balancing power market. Independent 15-minute balancing units capable of carrying or loading at least 10 MW of load are obliged to participate in BPM.

Even though DAM and the system operator (TEİAŞ's National Load Dispatch Center – NLDC) offers a balanced market of generation and consumption amounts a day ahead, there are real-time deviations. For example, if a plant is out of cycle due to a failure or if a large consumption plant is out of order, the balance is disrupted. In this case NLDC seeks to maintain system stability using bids submitted to BPM to achieve production and consumption (plus the losses) balance.

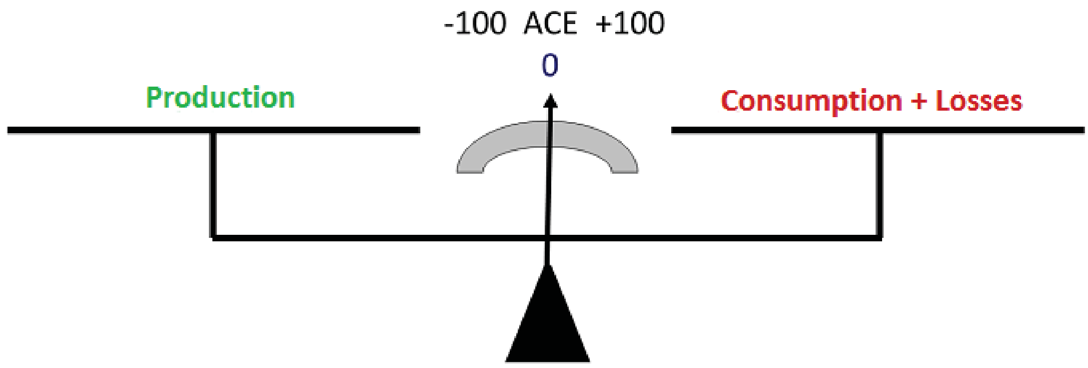


Figure 2.9 System Balance in BPM (TEİAŞ, 2017)

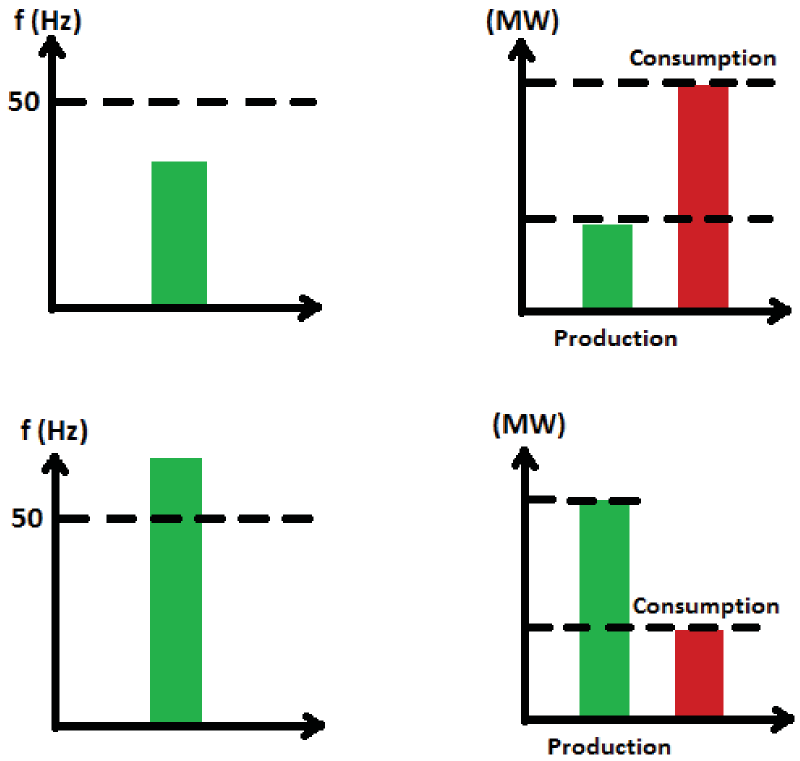


Figure 2.10 Frequency and MW Distribution According to Production and Consumption Amount (TEİAŞ, 2017)

According to the Electricity Market Grid Code, the main frequency of the alternate current (AC) system in Turkey is 50 Hz. If the frequency is below 50 Hz, it means that production is less than consumption. To correct this situation, it is necessary to increase production or reduce consumption. If the frequency is greater than 50 Hz, it means that production is greater than consumption. To correct this situation, it is necessary to reduce production.

2.2.4 Current State of the Electricity Market in Turkey

Based on data from EPİAŞ (2016a), average MCP has been 140.60 TL/MWh, increased by 1.8% compared to 2015, whereas installed capacity has increased by 4,910 MW and reached to 77,789 MW. Annual electricity generation has increased by 3.9% and reached to 272.5 TWh, and annual electricity consumption has increased by %4.25 and reached to 277.5 TWh. Due to a natural gas curtailment in December 2016, electricity generation from natural gas power stations has decreased and MCP has reached a record high values, e.g., 589 TL/MWh on Friday, December 23, and 1,899.99 TL/MWh at 14:00 in the same day.

Regarding the shares of electricity generation by energy source, generation from natural gas and LNG power stations declined by 6% to 32% and generation from hydropower stations declined by 1% to 25%. On the other hand, generation from import coal-fired power stations increased by 2% to 17%, generation from lignite power stations increased by 2% to 14% and generation from wind power stations increased by 2% to 6%

According to Republic of Turkey Ministry of Energy and Natural Resources Report (MENR, 2017), the gross electricity consumption in Turkey in 2015 was 265.7 billion kWh, while this figure has increased by 3.3% in 2016, reaching 278.3 billion kWh. The electricity output in 2016 has increased by 4.9% to 274.7 billion kWh when compared to the previous year (261.7 billion kWh). According to the highly probable scenario of an increase of 6.9% (to 392 TWh) in the base scenario, electricity consumption in the year 2023 is expected to increase by 5.5% to 357.4 TWh.

By the end of 2016, power plants have a total of 5,899 MW additional capacity added to the system, and as the end of 2016, installed capacity has increased to 78,497.4 MW. In 2016, 32.1% of the electricity generation has been obtained from natural gas, 33.9% from coal, 24.7% from hydropower, 5.7% from wind, 1.8% from geothermal and 1.8% from other sources. At the end of 2016, EÜAŞ has a share of 27.8% in installed capacity and 59% is owned by the private sector. The rest is composed of 8.3% of build-operate (BO) plants, 3.2% of build-operate-transfer (BOT) plants and 0.4% of unlicensed power plants.

The installed capacity of Turkish electricity system (with new power plants taken into account) has increased to 78,497.4 MW by the end of 2016. The distribution of the installed power by generation resources are 35.4% hydro, 29% natural gas, 22.1% coal, 6.1% wind, 0.9% geothermal and 7.4% other sources.

In addition, the number of electricity energy generation plants in Turkey have been 2,321. According to energy sources, number of existing plants is as follows:

- 597 hydro
- 39 coal
- 171 wind
- 31 geothermal
- 260 natural gas
- 1045 solar
- 178 other type of power plants

In summary, the electricity infrastructure in Turkey is strengthened and the electricity generation has increased in parallel with the increase in consumption in 2016. The connection of the electricity system with the European electricity system has also been strengthened. A long term agreement has been signed between TEİAŞ and ENTSO-E on April 15, 2015, which permanently connects Turkish and European electricity network systems.

3. MARKET-CLEARING EQUILIBRIUM MODEL

In this section, we have introduced the mathematical model proposed in this thesis and we have provided the details about this model.

3.1 Overview of the Model

Generally, this model is described by Gabriel et al. (2013a), and more generally by Hobbs (2001). This model is particularly useful because it allows modeling for different market structures (from monopolistic markets to perfectly competitive markets). Generally, this model can be summarized in the following Figure 3.1.

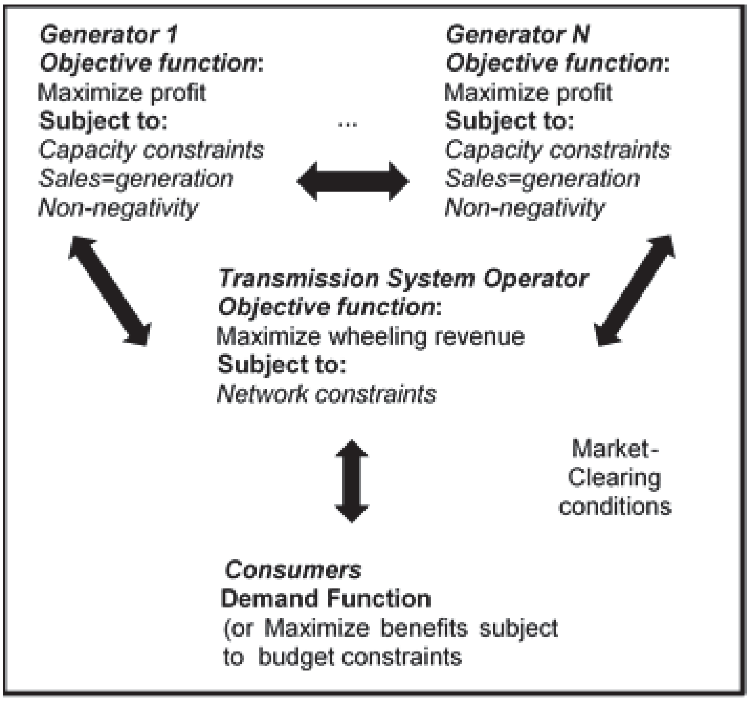


Figure 3.1 Sketch of the Market-Clearing Model

In this model, a system operator is mentioned where the generation firms in each bus or region can sell to all customers in the transmission network and pay for the transmission service to the system operator (due to system constraints). Within this structure, the system operator maximizes the transmission service revenue that the entire system obtains from network constraints (linearly constrained DC load flow constraints according to Kirchhoff's current and voltage laws), while generation firms seek to maximize their profits (according to capacity and sales/production equality constraints). In addition, consumers can change their consumption levels to optimize their own welfare levels by reacting to price levels. The equilibrium conditon for this model is that the transmission service requires a supply-demand balance for each bus or region (i.e., the market-clearing conditions and the dual for this condition as the transmission service fee, namely, the wheeling fee).

This market-clearing model is also valid for market structures where there are purely bilateral agreements or where a power pool (PoolCO) dominates (Hobbs, 2001; Metzler et al., 2003). Similarly, a hybrid model can be created by separating the sales quantities corresponding to PoolCO market or bilateral agreements.

3.2 Mathematical Model

According to this model, an elementary model of perfect and imperfect (oligopolistic) competition among generation firms, consumers and TSO is presented. Note that the model is for a single hour, but multiple hours can also be included into the model to represent longer time periods (e.g., week, month and year).

3.2.1 Consumers

The response of the consumers to price changes is formulated by a linear inverse demand function as in equation (3.1), where parameters α_i and β_i are positive. Each bus in the transmission network has its own linear inverse demand, depending on each generation firm's sales at this bus in the equilibrium solution.

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

3.2.2 Generator Firm *f*

Generating firm f is a price-taker (for the perfect competition model) and it views transmission wheeling fee (w_i) as an exogenous parameter in its objective function, even though from the market's point of view those prices are variable and are adjusted to balance supply and demand at each node. Each generator firm f maximizes its profit (revenues minus operating costs) subject to total sales equal total generation constraints and upper bounds on generation amounts.

$$\text{Max}_{x_{fih}, s_{fi}} \quad \sum_{i\in I_f} [p_i - w_i^*] s_{fi} - \sum_{i\in I_f}\sum_{h\in H} [c_{fih} - w_i^*]\, x_{fih} \qquad (3.2)$$

s.t

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

$$x_{fih} - K_{fih} \le 0 \quad (\mu_{fih}) \quad \forall\, i \in I_f, h \in H \qquad (3.4)$$

$$x_{fih} \ge 0 \qquad \forall\, i \in I_f, h \in H \qquad (3.5)$$

3.2.3 Transmission System Operator (TSO)

TSO's objective is to allocate transmission capacity to maximize the value that the market receives from network assets subject to network constraints. This can be shown to be equivalent to having the TSO choose values to maximize its revenue and a competitive market for transmission rights in which generators do not exercise market power (Hobbs, 2001). Moreover, TSO model is such that TSO's as a market agent can not affect the market price, although this price is a variable that is endogenous to the market. In other words, TSO auctions off the capacity of individual transmission components.

$$\mathrm{Max}_{y_i} \quad \sum_{i \in I} w_i^* y_i \tag{3.6}$$

s.t.

$$\sum_{i \in I} y_i = 0 \quad (\gamma) \tag{3.7}$$

$$\sum_{i \in I} PTDF_{ik} y_i \leq T_k \qquad (\lambda_k^+), \quad \forall\, k \in K \tag{3.8}$$

$$-\sum_{i \in I} PTDF_{ik} y_i \leq T_k \quad (\lambda_k^-), \quad \forall\, k \in K \tag{3.9}$$

Consistent with the linear DC approximation, flows through line k are modeled with power transfer distribution factors (PTDFs) which are derived based on Kirchhoff's current law (net flow into a node equals zero) and Kirchhoff's voltage law (net voltage drop around any loop in the network is zero). PTDF for node i on line k ($PTDF_{ik}$) describes the per megawatt (MW) impact (e.g., increase or decrease) in flow resulting from 1 MW of power injection at hub node (an arbitary node) and 1 MW of withdrawal at node i. Summation of such impacts over all nodes ($\sum_{i \in I} PTDF_{ik} y_i$) gives the total flow on line k.

TSO chooses y_i variables by naively assuming that it is a price taker for transmission services (i.e., wheeling fees, w_i, are exogenous in its problem, denoted by w_i^*). This is equivalent to a competitive market for transmission rights in which suppliers do not exercise market power. In this market setting, congestion (wheeling) charges are sufficient to ration the use of the transmission network. Note that y_i variables are not restricted (e.g., free) in sign. A positive (negative) y_i means that there is a net flow into (out of) node i from (to) hub node. Constraint (3.7) means that the net injections/withdrawals to/from all nodes sum up to zero.

3.2.4 Market-Clearing Conditions

The market- clearing conditions (3.10) depend on supply and demand balance at each bus i and, in the complementarity problem, these conditions are associated with the wheeling fees (w_i), which become endogenous in the overall model in the next section.

$$\sum_{f\in F}\sum_{h\in H} x_{fih} - \sum_{f\in F} s_{fi} - y_i = 0 \qquad (w_i), \qquad \forall\, i \in I \tag{3.10}$$

3.2.5 Overall Mixed Complementarity Problem (MCP)

The overall model can be formulated as a MCP by writing out the Karush-Kuhn-Tucker (i.e., first order optimality) conditions for the generator firms' (3.2 to 3.5) and TSO's (3.6-3.9) problems along with the inverse demand function (3.1) and the market clearing conditions (3.10). Note that equation (3.7) is not included in the overall MCP model (3.11) because it is jointly satisfied by equations (3.3) and (3.10), i.e., by summing equation (3.3) over all firms (*f*) and by summing equation (3.10) over all nodes (*i*), the result is $\sum_{i\in I} y_i = 0$. Hence, including this condition in the MCP may cause numerical problems due to redundancy. Also the non-negativity constraints (and their duals) are omitted from MCP (3.11) and therefore, the corresponding KKT conditions for the non-negative variables are in "≥" form.

MCP: Satisfying the following conditions $s_{fi}, x_{fih}, \nu_f, \mu_{fih}, y_i, \lambda_k^+, \lambda_k^-, w_i, p_i$

$$\begin{array}{lll}
s_{fi} \geq 0 \perp & -p_i + w_i + \nu_f \geq 0 & \forall\, f \in F, i \in I \\
x_{fih} \geq 0 \perp & c_{fih} - w_i - \nu_f + \mu_{fih} \geq 0 & \forall\, f \in F, i \in I_f, h \in H \\
\nu_f\ free \perp & \sum_{i\in I} s_{fi} - \sum_{i\in I_f}\sum_{h\in H} x_{fih} = 0 & \forall\, f \in F \\
\mu_{fih} \geq 0 \perp & x_{fih} - K_{fih} \leq 0 & \forall\, f \in F, i \in I_f, h \in H
\end{array} \tag{3.11}$$

$$y_i \; free \perp \quad -w_i + \sum_{k \in K} PTDF_{ik}(\lambda_k^+ - \lambda_k^-) = 0 \qquad \forall\, i \in I$$

$$\lambda_k^+ \geq 0 \perp \quad \sum_{i \in I} PTDF_{ik} y_i \leq T_k \qquad \forall\, k \in K$$

$$\lambda_k^- \geq 0 \perp \quad -\sum_{i \in I} PTDF_{ik} y_i \leq T_k \qquad \forall\, k \in K$$

$$w_i \; free \perp \quad \sum_{f \in F} s_{fi} - \sum_{f \in F} \sum_{h \in H} x_{fih} - y_i = 0 \qquad \forall\, i \in I$$

$$p_i = \alpha_i - \beta_i \left(\sum_{f \in F} s_{fi} \right) \qquad \forall\, i \in I$$

It can be easily verified that the MCP problem (3.11) has equal number of conditions and variables. Uniqueness and existence are desirable properties for MCP models that are used in policy analyses; since multiple solutions may make conclusions ambiguous). The uniqueness and existence of the solution of the MCP (3.11) can be verified easily. Continuous and decreasing demand curves (i.e., for the consumers, $\alpha_i > 0$ and $\beta_i > 0$) and strictly convex cost functions (i.e., given the cost function for generating firm as $C_{fih}(\cdot)$, Hessian of this function, $\frac{d^2 C_{fih}}{dx_{fih}^2}$, should be positive definite) are sufficient to ensure that a solution exists and that the quantities and prices are unique.

Different market structures can be modeled using MCP (3.11). In its current form, the market structure is a perfetcly competitive market. The Nash-Cournot market structure can be modeled by replacing the first equation by the following condition:

$$s_{fi} \geq 0 \perp \quad -p_i + \beta_i s_{fi} + w_i + \nu_f \geq 0 \qquad \forall\, f \in F, i \in I \tag{3.12}$$

In condition (3.12), the term $+\beta_i s_{fi}$ is the marginal revenue for firm f at node i. This marginal revenue term is derived from the partial derivative of the generation firm's objective function in (3.2) with respect to s_{fi}, i.e., when the generation firm is aware of the price-quantity relation of the linear inverse demand function.

3.3 Turkish Electricity Transmission System with Nine Regional Control Areas

In this section, the nine regional control areas (9-zone) of the Turkish system and data sources for this system are presented. In Figure 3.2, the 9-zone Turkish electricity transmission system separated by load dispatch centers are shown with a simplified (i.e., abridged) transmission system. All data for transmission system parameters (susceptance of the lines and PTDF values calculated from them) are approximated from a study by Çakır (2014) using 2012 Turkish electrification map, generator locations from TEİAŞ and TETAŞ reports. The demand data for each city (and hence the regions) is from GDRE (2013). Although very simplified, it is very useful and realistic for the purposes of this thesis.

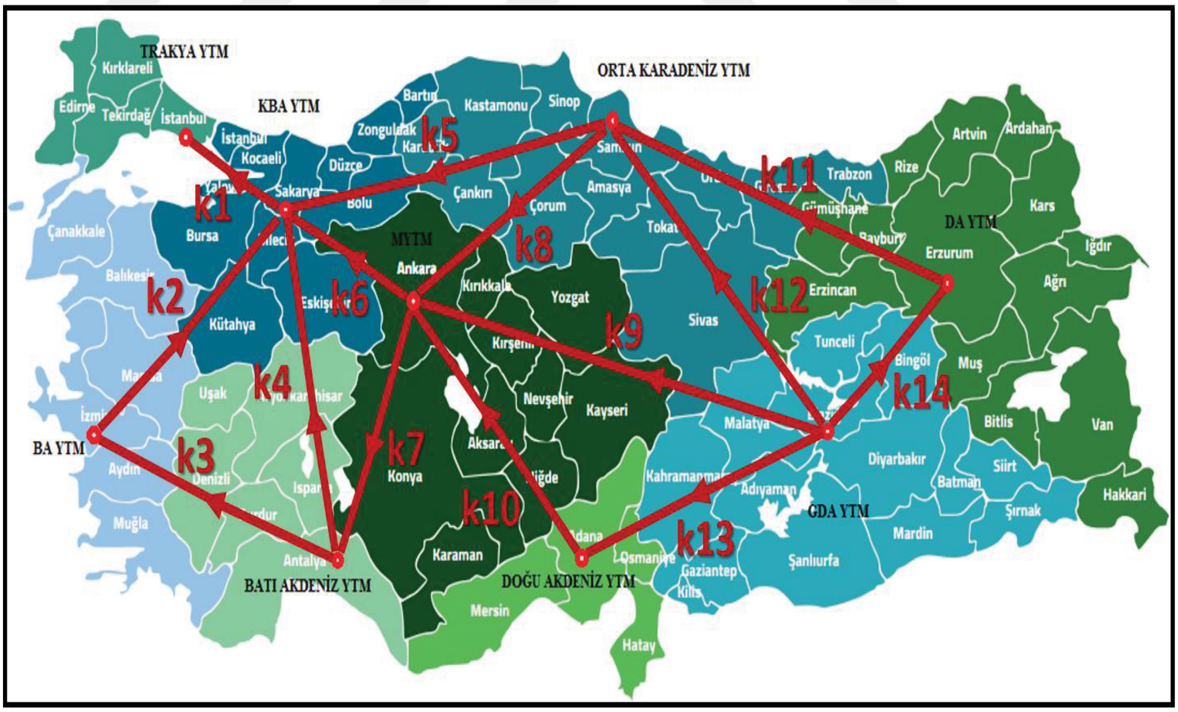


Figure 3.2 The 9-Zone Turkish Electricity Transmission System

3.3.1 Generation Capacities and Capacity Factors

Based on the current transparency platform of EPİAŞ (2016b) and TEİAŞ (2016) in 2016, installed power values are updated for each node according to thirteen generation types by fuel and seven different types of establishment (i.e., ownership). Figure 3.3 and 3.4 as well as Table 3.1 summarizes these data.

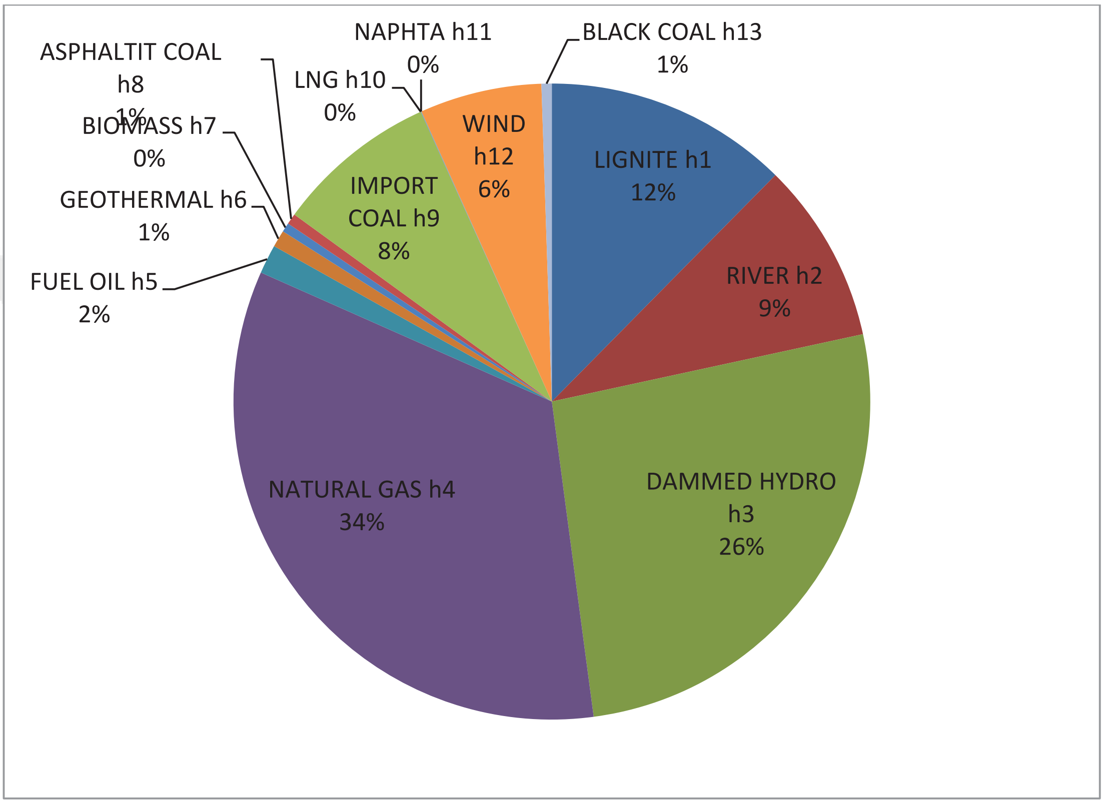


Figure 3.3 Installed Power Capacity by Fuel Type

Total Installed Capacity= 73,633.753 MW (EPİAŞ, 2016a)

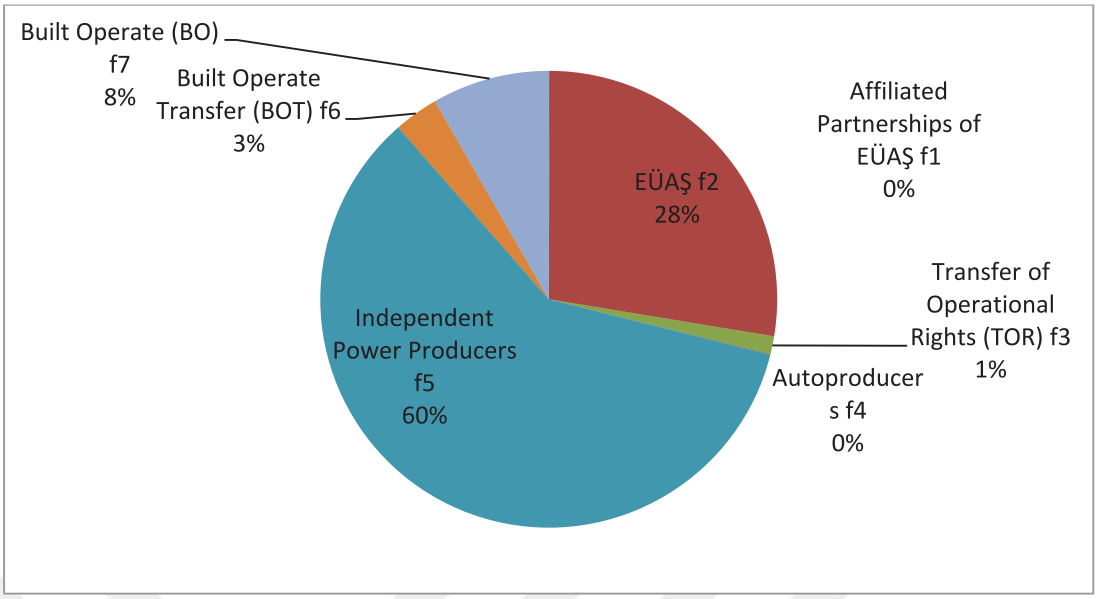


Figure 3.4 Installed Capacity by Establishment Type

Total Installed Capacity= 73,633.753 MW (EPİAŞ, 2016a)

Table 3.1 Installed Power Capacity by Fuel Types (EPİAŞ, 2016a)

Type of Fuel		***Installed Power Capacity (MW)***
LIGNITE	h1	9,122.904
RIVER	h2	6,783.692
DAMMED HYDRO	h3	19,364.915
NATURAL GAS	h4	24,849.713
FUEL OIL	h5	1,087.27
GEOTHERMAL	h6	635.148
BIOMASS	h7	344.013
ASPHALTIT COAL	h8	405
IMPORT COAL	h9	6,064.15
LNG	h10	11.95
NAPHTA	h11	16.872
WIND	h12	4,563.116
BLACK COAL	h13	385.01
TOTAL	=	**73,633.753**

With these installed power capacity values, fuel types and establishment type, each region's generation capacity values are determined from EPİAŞ (2016a), which states capacities and fuel/establishment type for each city. The capacity factors are calculated based on this information.

Hourly capacity factors for each fuel type are computed using the real time hourly generation data from transparency platform of EPİAŞ (2016b) using the following formulation:

$t = time\ (hour)$

$$Capacity\ Factor(t) = \frac{Real\ Time\ Generation(t)}{Installed\ Power}$$

$$Capacity\ Factor = Max\ [Capacity\ Factor\ (t)]\ , \qquad \forall t$$

The maximum values of all hourly capacity factors are calculated for the weekday and weekend and they are presented in Table 3.2.

Table 3.2. Maximum Values for Capacity Factors for Weekends and Weekdays in December 2015 (EPİAŞ, 2016b)

Type of Source		*Weekend*	*Weekday*
LIGNITE	h1	57%	59%
RIVER	h2	30%	35%
DAMMED HYDRO	h3	32%	40%
NATURAL GAS	h4	64%	72%
FUEL OIL	h5	45%	44%
GEOTHERMAL	h6	78%	78%
BIOMASS	h7	62%	62%
ASPHALTIT COAL	h8	67%	99%
IMPORT COAL	h9	89%	90%
LNG	h10	96%	99%
NAPHTA	h11	32%	34%
WIND	h12	43%	80%
BLACK COAL	h13	93%	97%

Note that the maximum capacity factors are higher in weekdays than weekends. Instead, average or median of the capacity factors can be used.

3.3.2 Load Factors

Figure 3.5 and 3.6 depict the demand by consumption type and region, respectively. The consumption type and level differs across regions. Specifically, share of industrial usage is almost half of the consumption (48.8%) in Orta Karadeniz and Kuzey Batı Anadolu regions, whereas share of household consumption is the highest in Doğu Anadolu region (36.0%). Share of the commercial usage is prevalent (45.8%) in Batı Akdeniz region. On the other hand, Orta Karadeniz and Doğu Anadolu are the regions with highest share of lighting usage (more than 5%). Share of agricultural watering is also the highest in Güneydoğu Anadolu and Orta Anadolu regions (around 5%). West regions of Turkey (Kuzey Batı Anadolu, Batı Anadolu and Trakya) have high consumption levels compared to northern and eastern regions (Orta Karadeniz, Doğu Anadolu).

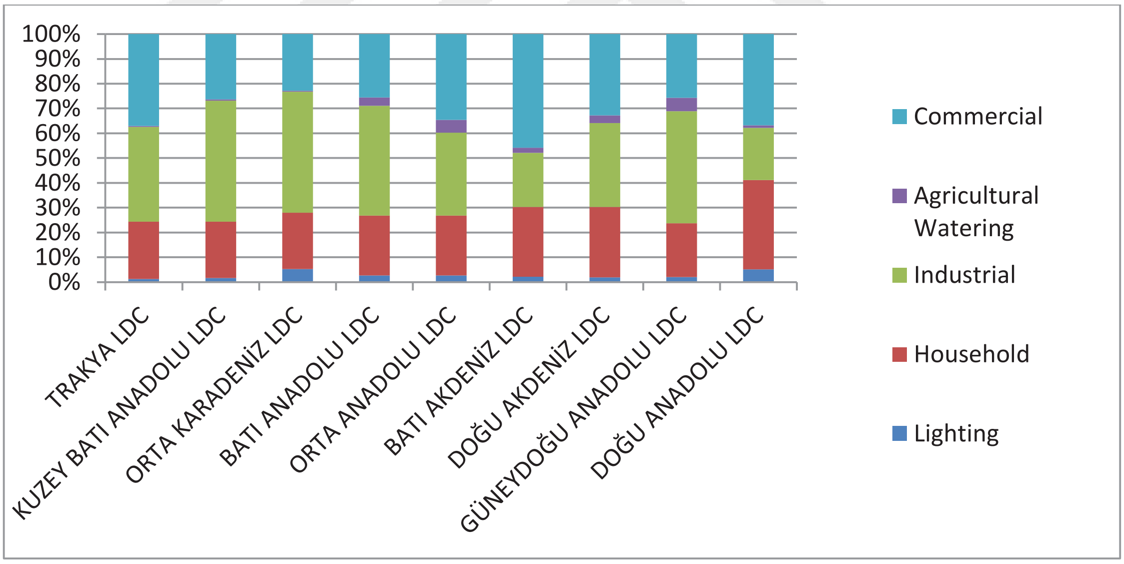


Figure 3.5 Demand by Consumption Type (EMRA, 2015)

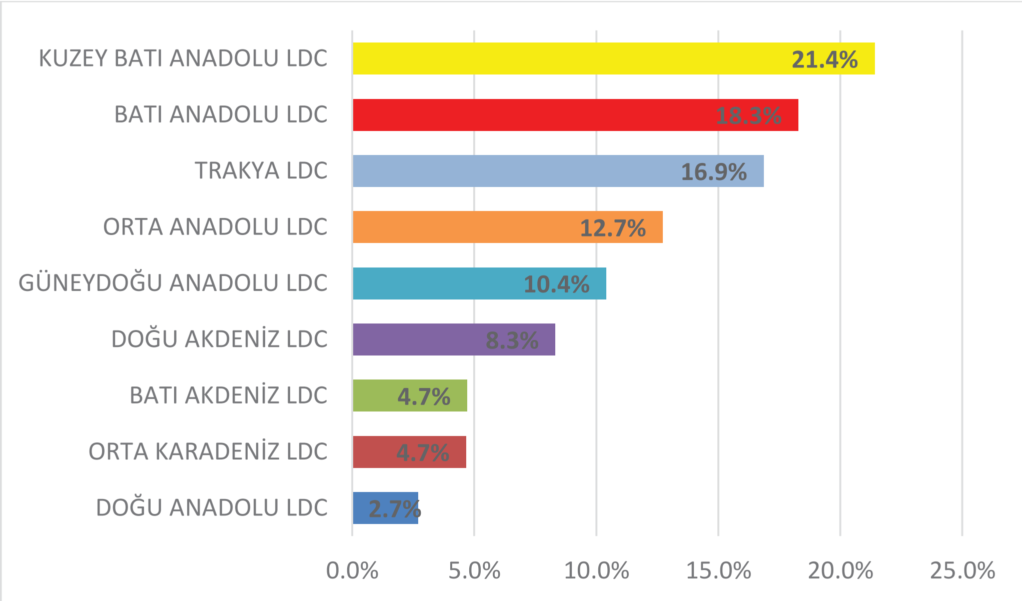


Figure 3.6 Percentage Share in Total Demand (EMRA, 2015)

Similar to capacity factor calculations, the demand (load) values for December 2015 are divided into two groups, weekday and weekend. In Figure 3.7, December 2015-hourly demand values are summarized with box-plots and histograms for weekends, weekdays and all days.

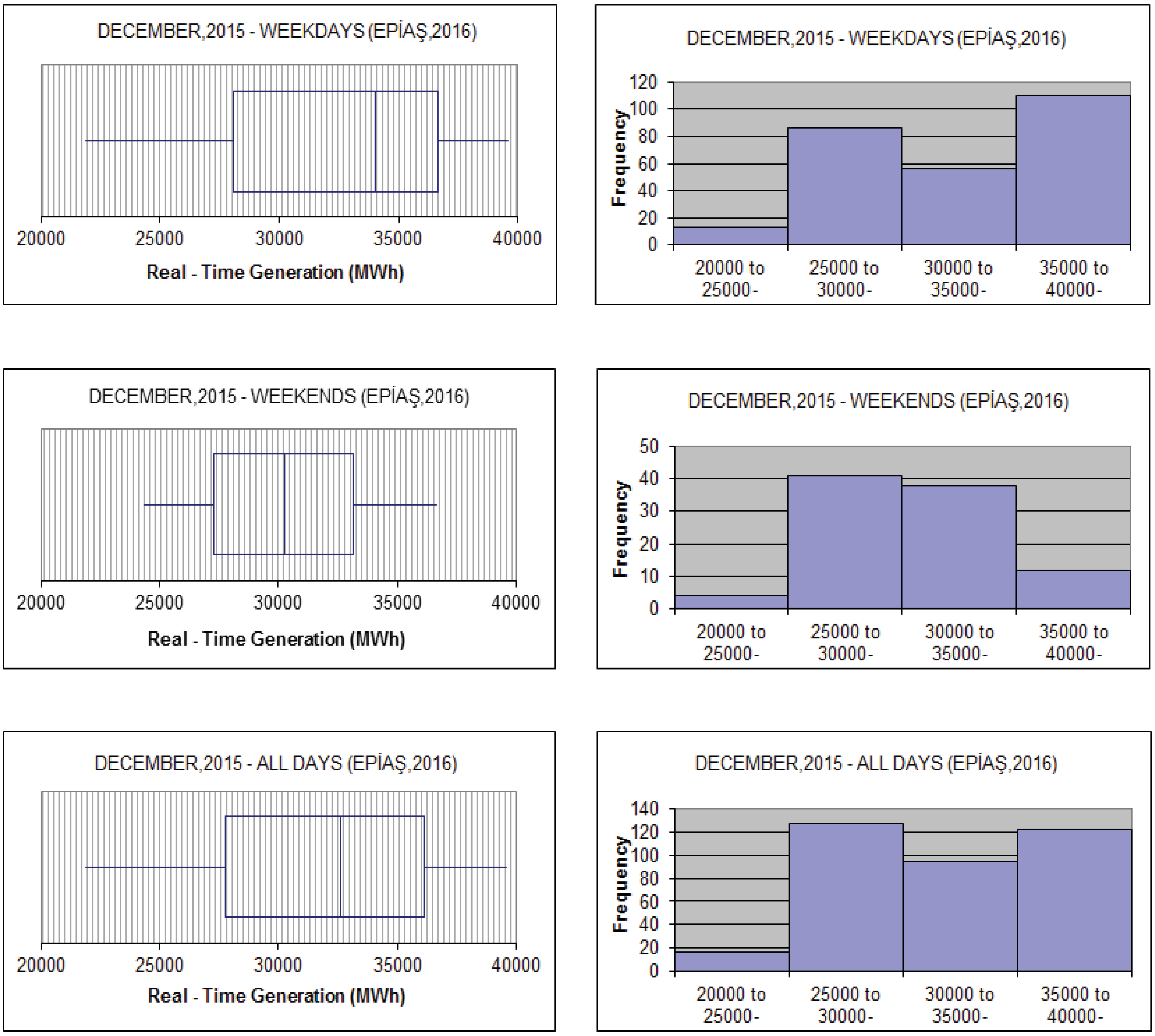


Figure 3.7 Box - Plots and Histograms Based on Real-Time Generation in December 2015

Using this summary information, we have introduced three separate demand scenarios (peak, mid-peak, off-peak) for weekdays and weekends. Note that the peak demand values and frequency are considerably higher than weekends. The peak demand scenario for hourly demand of the weekdays is set at 39000 MW, while the mid-peak average demand scenario is 36000 MW, while the off-peak demand scenario is set at 22000 MW. In the weekends, peak, mid-peak and off-peak demand scenario values are set at 36000 MW, 33000 MW and 27000 MW, respectively.

Alternatively, the averages of all hourly demand values in December 2015 are calculated and the maximum load factors are calculated by dividing the average demand value with the total demand value of each hour. Following the calculation of all load factors, the load factors are divided into three main groups.

$$\boldsymbol{Average\ MWh} = \frac{\sum_{1}^{t} Total\ MWh(t)}{t}$$

$$\boldsymbol{Load\ Factor(t)} = \frac{Total\ MWh(t)}{Average\ MWh}$$

$\boldsymbol{Peak} \leftrightarrow 1.30 \leq Load\ Factor \leq 1.10$

$\boldsymbol{Mid-Peak} \leftrightarrow 1.10 < Load\ Factor \leq 0.90$

$\boldsymbol{Off-Peak} \leftrightarrow 0.90 \leq Load\ Factor \leq 0.60$

The hourly demand values in December are ranked from maximum to minimum and the load-time duration curve of Figure 3.8 is obtained. This curve is divided by the three load factor groups.

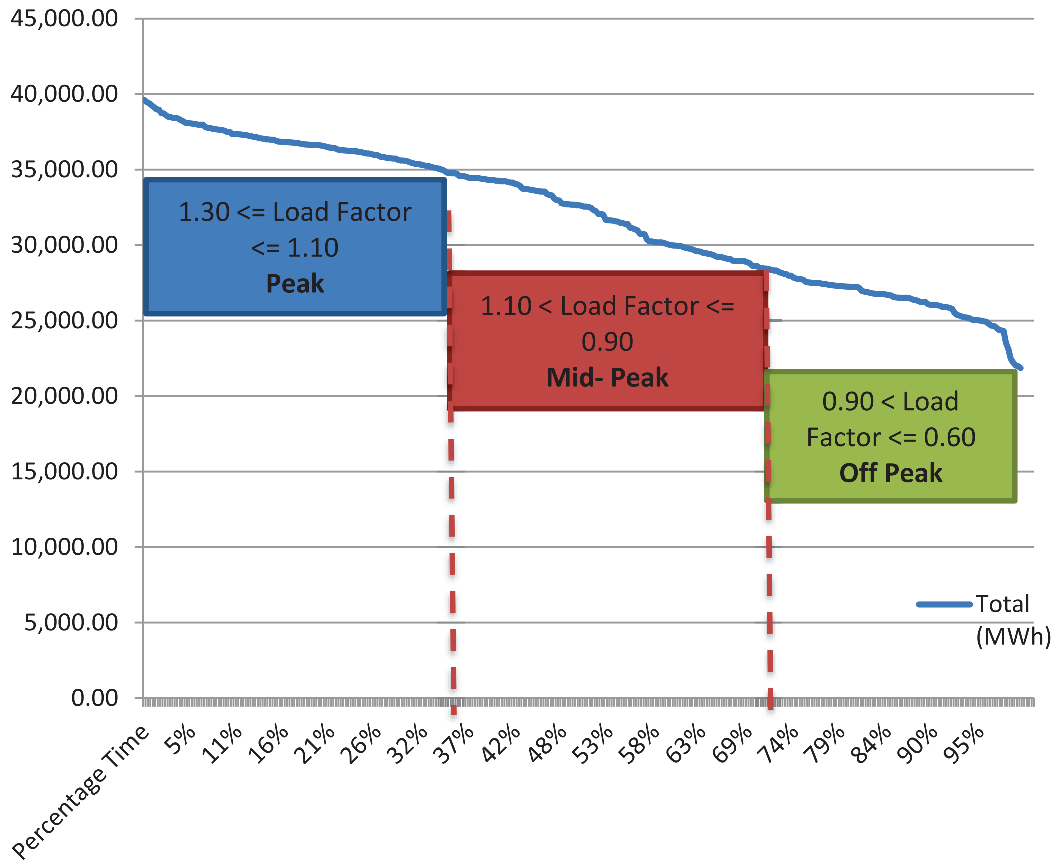


Figure 3.8 Load-Duration Curve for December 2015

Using these scenarios, the price-sensitive regional demand function parameters are calculated as follows: Firstly, the model is solved with fixed demand values (i.e., according to the share of each regional demand in the total annual consumption of Turkey) and the optimal regional prices (P^*) are calculated. 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.

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

3.3.3 Cost Parameters

In the equilibrium models, operation, maintenance and fuel costs (in short, "operating cost") are taken into account from a report by International Energy Agency, Nuclear Energy Agency and Organisation for Economic Co-operation and Development Report (IEA-NEA-OECD, 2010). The median values for each fuel type are used from this "Projected Costs of Generating Electricity" report. We have assumed same cost figures for some fuel types as outlined in Table 3.3.

Table 3.3 Operating Cost Estimations for Each Fuel Type

Fuel Type	Operating cost ($/MWh)
Lignite, Asphaltit Coal, Import Coal, Black Coal	24.23
River, Dammed Hydro	6.09
Natural Gas, LNG, Naphtha	65.60
Fuel Oil	70.28
Biomass, Geothermal	30.92
River, Dammed Hydro	6.09
Wind	21.92

The operating cost values are in $/MWh and converted to TL/MWh by using an exchange rate of 2.95 $/TL for December 2015.

4. OVERALL RESULTS FOR TURKISH ELECTRICITY MARKET

The MCP model is solved by using GAMS/ PATH solver on a personal computer with a 2.4 GHz processor and 8GB RAM. As this is a small-scale illustrative example, the solution times are less than a second for all MCP models. The data for the models and the results are summarized in the next section.

4.1 Market-Clearing Model Results

Based on all the information, regional and single pricing models were created through the GAMS program and the regional pricing model for the Turkish electricity market, which currently uses the single pricing system, was analyzed. Depending on the different pricing models created, the impacts on welfare measures and electricity price levels can be analyzed. Analyzes were made using different data sets, such as changes in capacity factors and demand functions depending on each scenario analysis.

In the GAMS program, social welfare maximization version of the original MCP is used with perfectly competitive and Nash-Cournot market structures. In this model, price levels are determined separately for each region; but if the capacity of any transmission line is not reached, there is a single price for each region. However, when the transmission capacity is reached for any line, regional prices are formed. According to each scenario, access to the capacity of the transmission lines does not only affect the regions it occupies but also all other regions, and the regions that interact with each other throughout the system.

The results for all scenarios are shown in the following summary maps (Figure 4.1, 4.2, 4.3, 4.4, 4.5 and Figure 4.6). These maps are prepared using EXCEL-VBA and can be updated according to different scenarios and GAMS solutions. In addition, detailed results according to different demand scenarios are summarized in Appendix A, B, C.

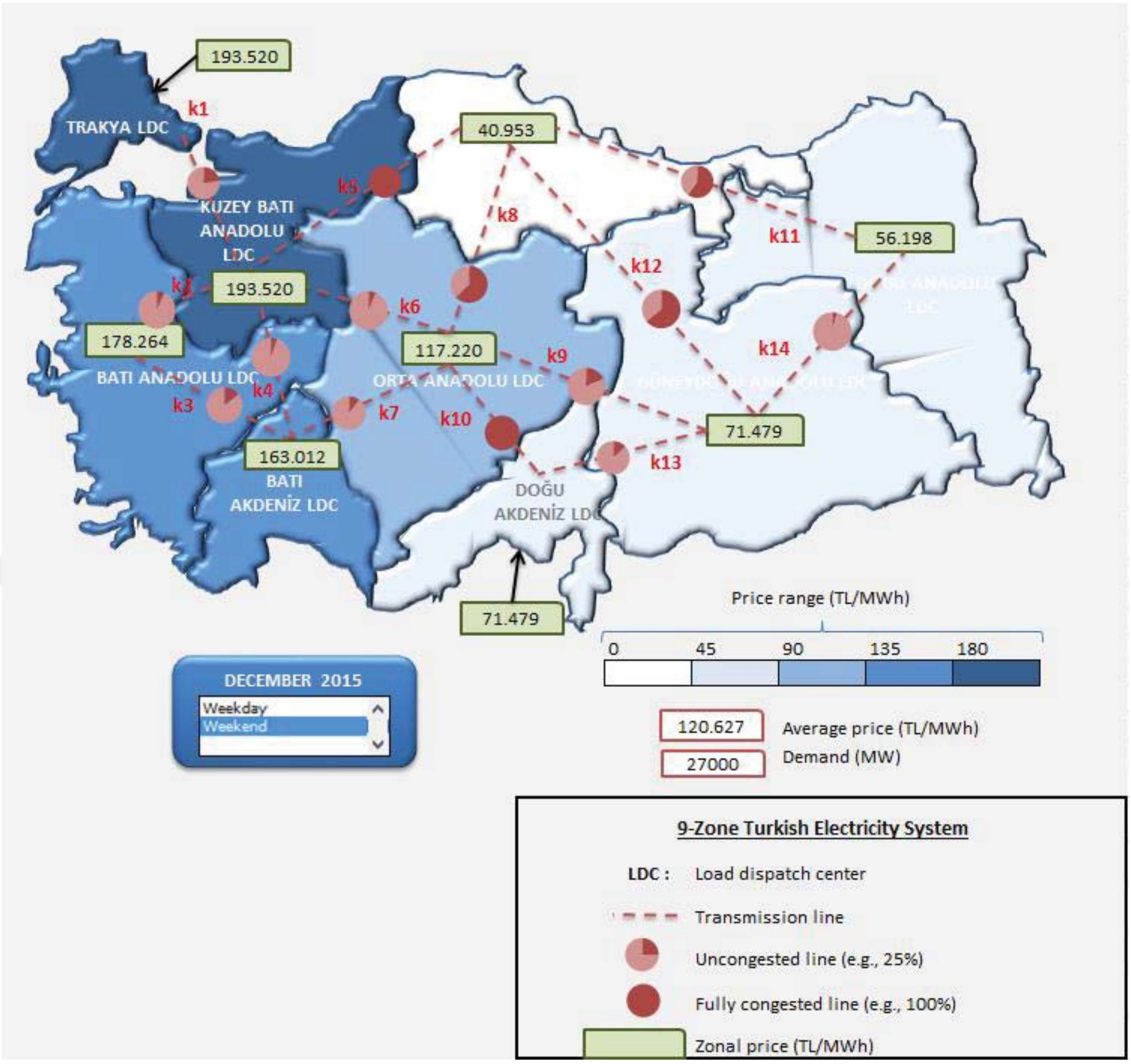


Figure 4.1 Simulation Results for Weekend, December 2015, Demand: 27000 MW

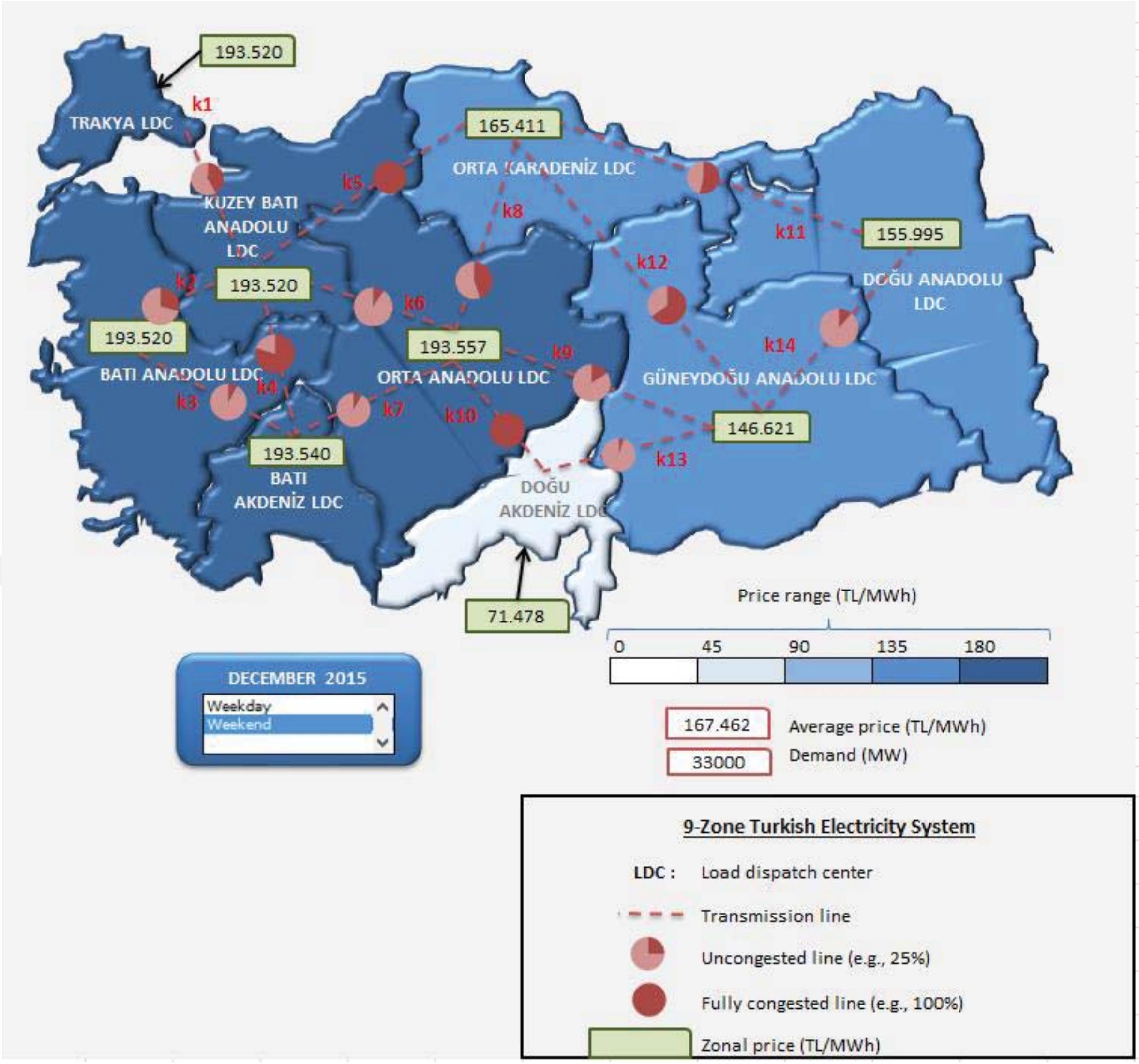


Figure 4.2 Simulation Results for Weekend, December 2015, Demand: 33000 MW

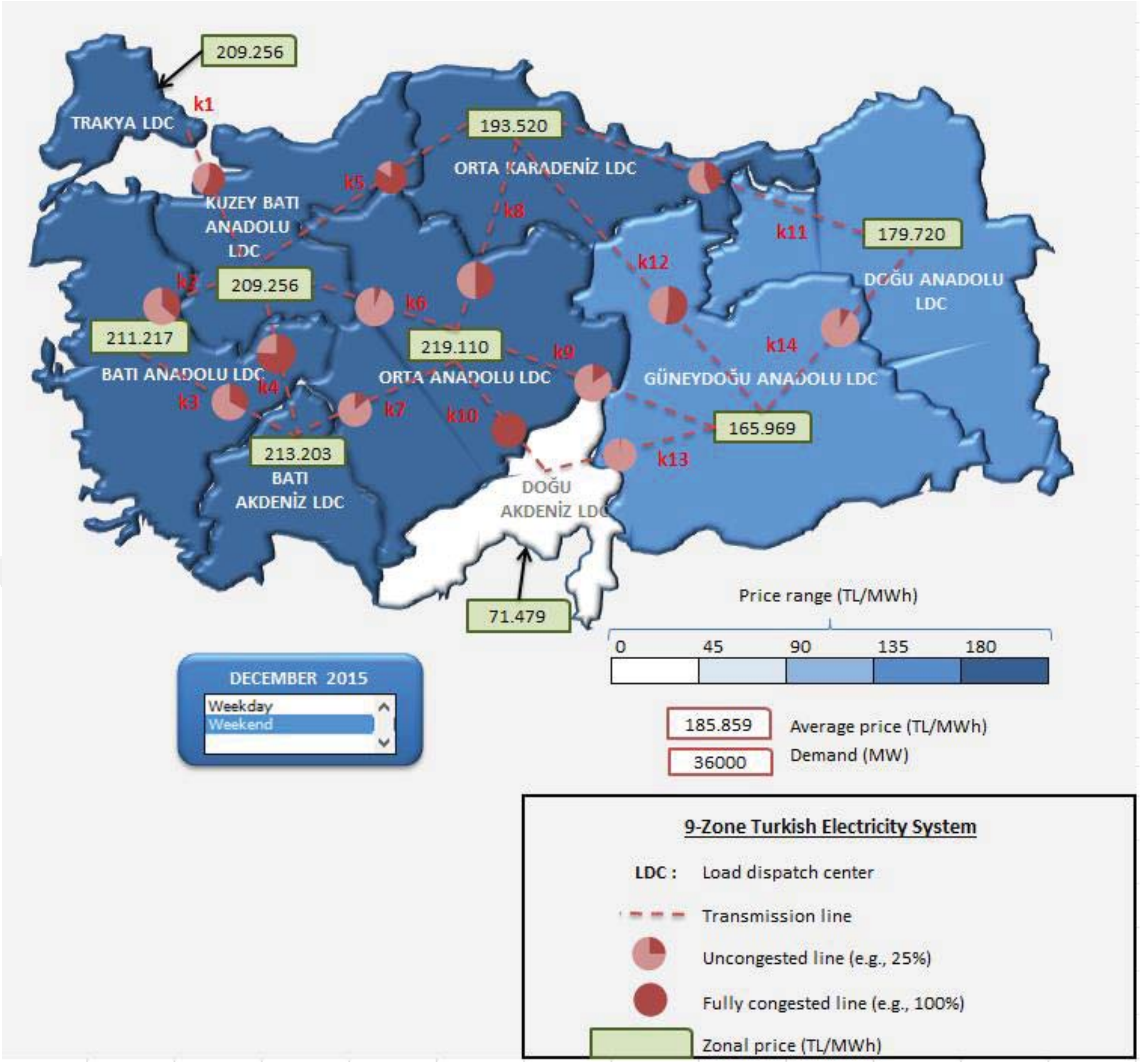


Figure 4.3 Simulation Results for Weekend, December 2015, Demand: 36000 MW

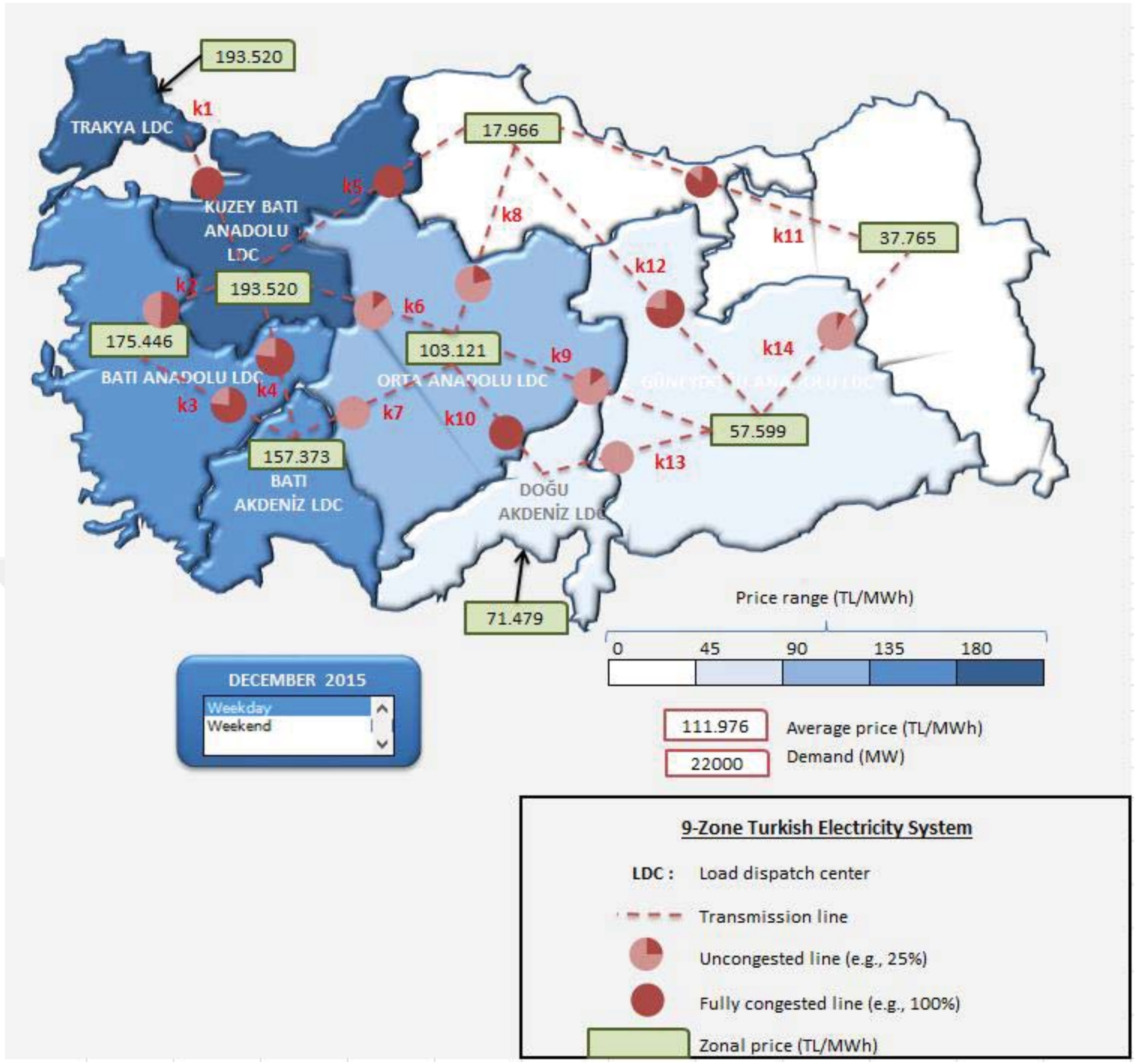


Figure 4.4 Simulation Results for Weekday, December 2015, Demand: 22000 MW

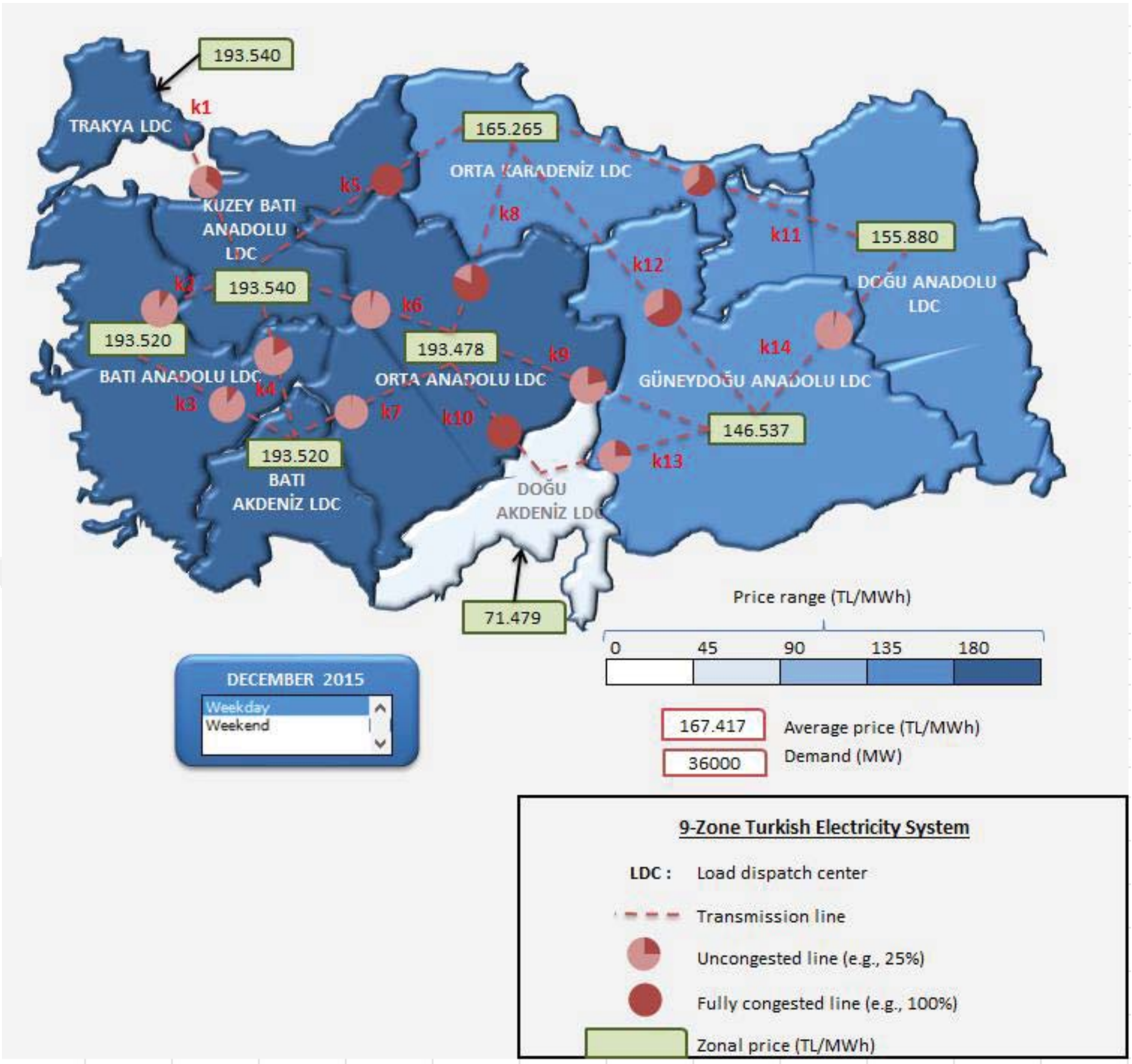


Figure 4.5 Simulation Results for Weekday, December 2015, Demand: 36000 MW

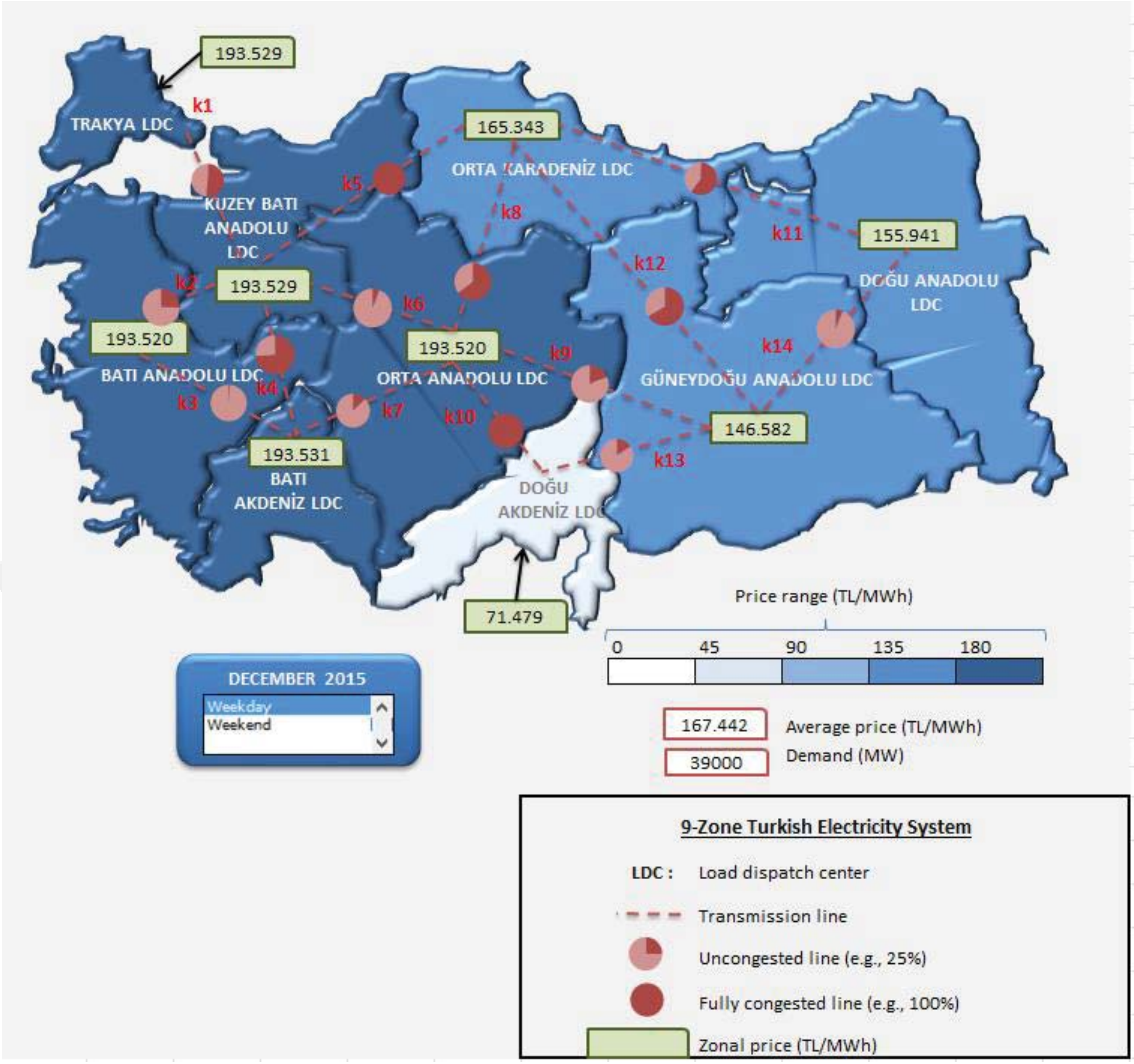


Figure 4.6 Simulation Results for Weekday, December 2015, Demand: 39000 MW

As expected, as the demand values increases for weekdays and weekend, the prices for all regions increases. Off-peak demand scenarios have the lowest prices. West regions, where the demand is considerably concentrated, have higher prices than eastern regions. Another interesting outcome of these simulations are that the weekend prices are higher than the weekday prices. This is due to the fact that the maximum capacity factors are higher for weekdays than weekends in our simulations (i.e., capacity factors are computed using real-time generation values, which are lower for weekends). In fact, production by fuel type is higher in weekdays and thus capacity factors are higher. This can be corrected using availability factors for each generation type with higher values during weekend.

In addition, we have also performed similar calculations for selected months in 2016, namely, February, May, August and November. The capacity factors and demand scenarios are presented in Appendix D.

Finally, we have calculated a weighted average price under different scenarios, and a single price for the whole system for a certain month is obtained. According to different demand scenarios, we have determined an average (weighted) single price for different months and compared them to actual (weighted) average MCP price values from EPİAŞ (2017) and error rates (mean absolute percent errors –MAPE) are computed for each month in the following Table 4.1. On average, the error rate (MAPE) is around 11.61%. The differences can be attributed mainly to differences between static cost estimates in this study and actual bids/offers in the market.

Table 4.1 Comparison of Simulated and Actual Weighted Average Prices (EPİAŞ, 2017)

Average Prices (TL / MWh)	**Actual Weighted**	**Simulated Weighted**	**MAPE (%)**
December 2015	168.448	158.004	6.20%
February 2016	108.961	113.295	3.98%
May 2016	122.436	115.076	6.01%
August 2016	168.414	127.677	24.19%
November 2016	154.862	127.466	17.69%

The following figures (Figure 4.7, 4.8, 4.9, 4.10, 4.11 and 4.12) depict the demands (total sales) and regional prices for each region on weekends and weekdays of December 2015. The demand values and prices are much lower in off-peak demand scenarios. On the other hand, for mid-peak and peak demand scenarios, they are very close to each other.

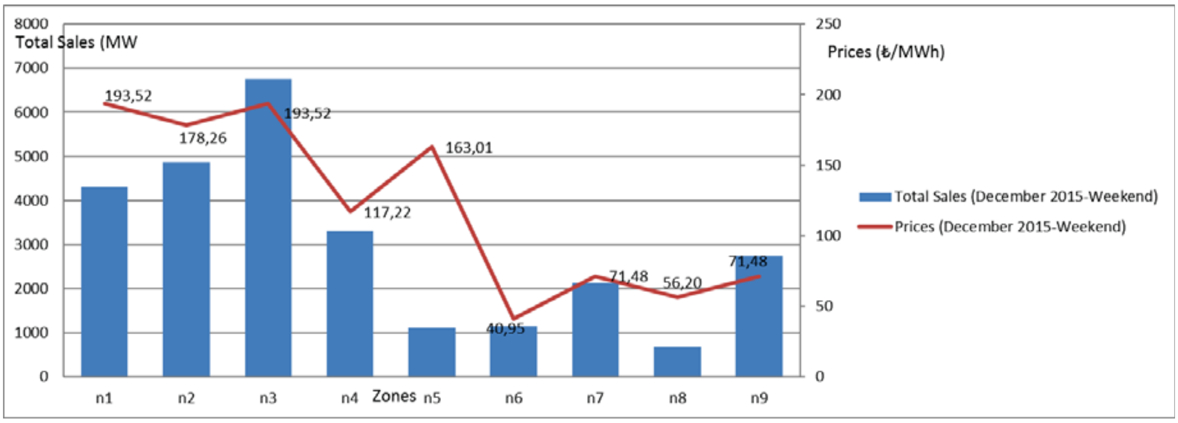


Figure 4.7 Total Sales and Prices for Weekend, December 2015, Demand: 27000 MW

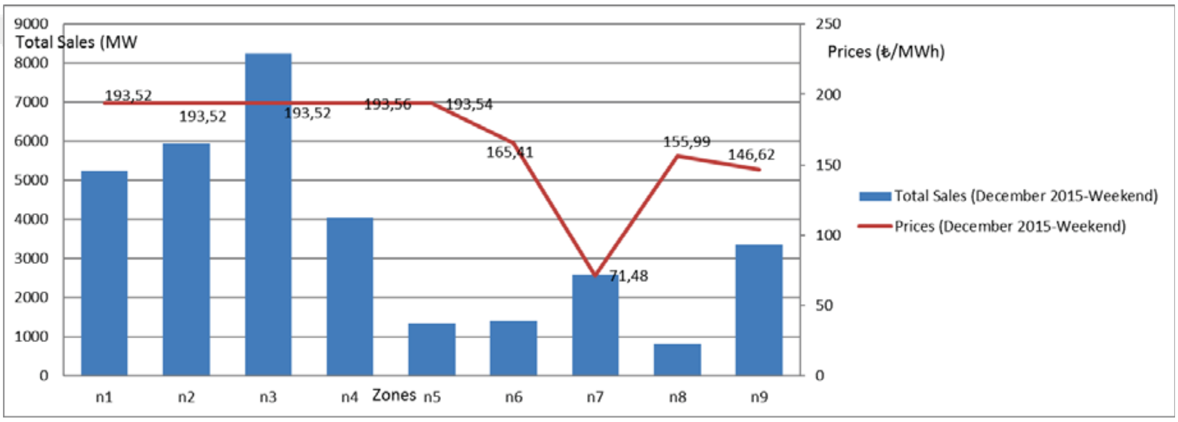


Figure 4.8 Total Sales and Prices for Weekend, December 2015, Demand: 33000 MW

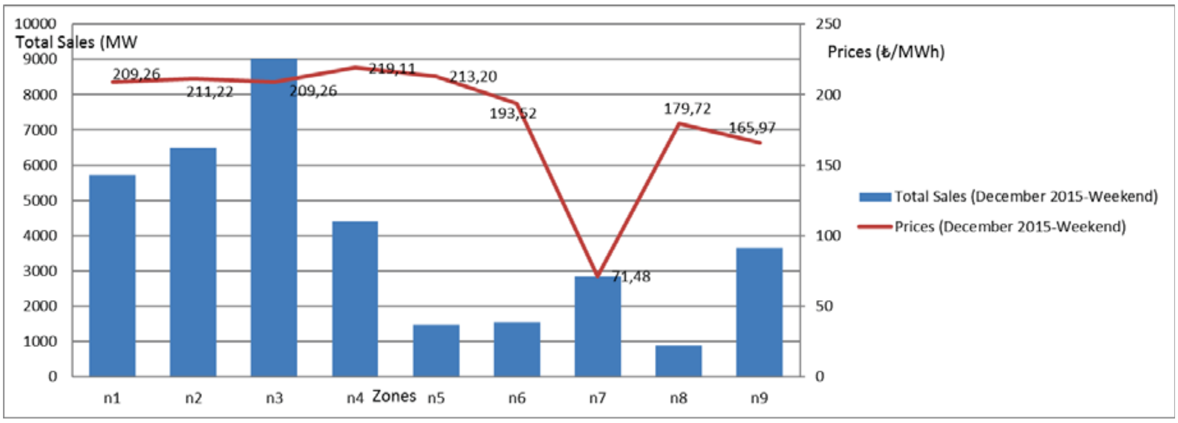


Figure 4.9 Total Sales and Prices for Weekend, December 2015, Demand: 36000 MW

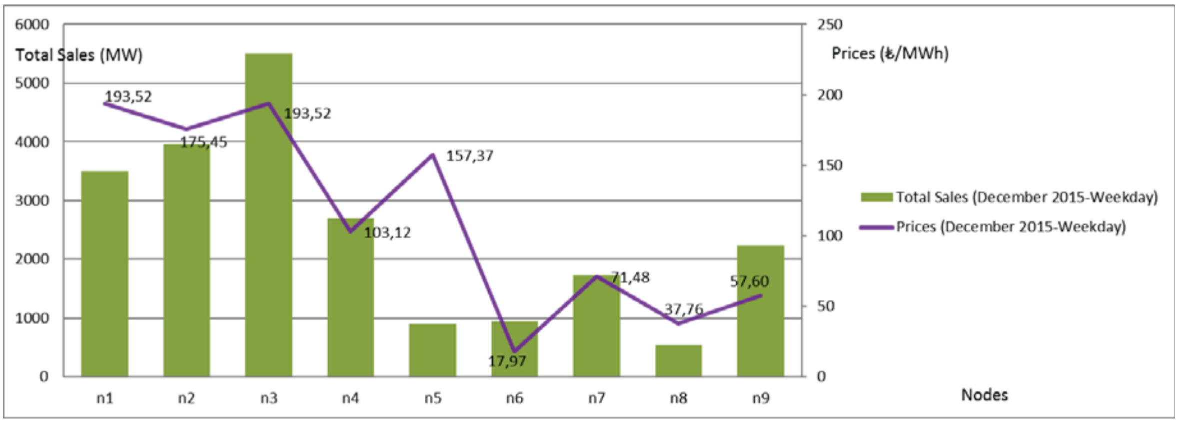


Figure 4.10 Total Sales and Prices for Weekday, December 2015, Demand: 22000 MW

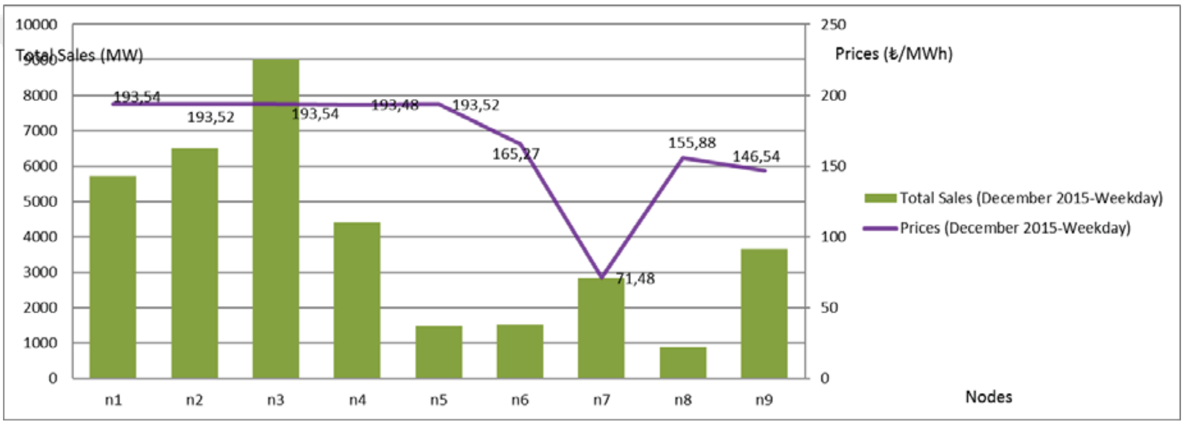


Figure 4.11 Total Sales and Prices for Weekday, December 2015, Demand: 36000 MW

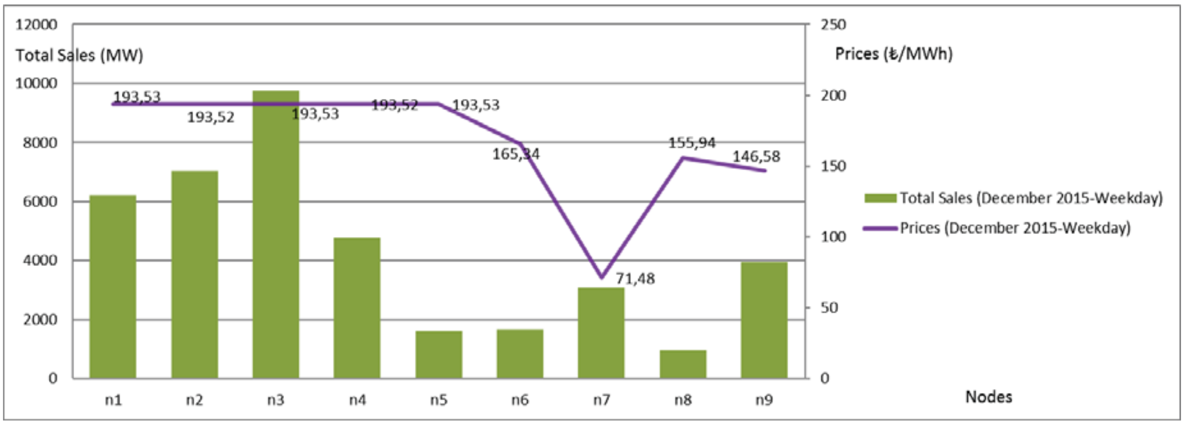


Figure 4.12 Total Sales and Prices for Weekday, December 2015, Demand: 39000 MW

4.2 Welfare Results

Based on the outcomes of the model, we have also calculated generation and profits by each establishment type and present them in Table 4.2 and Table 4.3. Note that the generation and profit are for a single hour for each scenario. The generation share and profits of IPP are the highest under all demand scenarios and they are followed by EÜAŞ.

Table 4.2 Generation of Each Establishment (MW) Under Different Demand Scenarios (December 2015)

TOTAL GENERATION (MWh)

	DEMAND AMOUNT / POWER PLANT	Affiliated Partnerships of EÜAŞ	EÜAŞ	Transfer of Operational Rights (TOR)	Autoproducers	Independent Power Producers (IPP)	Built-Operate-Transfer (BOT)	Built-Operate (BO)
DECEMBER WEEKDAY	**39000**	25.96	9846.57	489.646	13.6	23662.43	1391	3569
	36000	25.96	9846.57	489.646	13.6	21324.25	1391	2911
	22000	25.96	4759.18	489.646	13.6	14185.07	375.4	2151
DECEMBER WEEKEND	**36000**	25.08	8557.96	459.615	14.657	21493.08	1203	4247
	33000	25.08	8557.96	459.615	13.136	20135.26	1203	2605
	27000	25.08	7431.99	459.615	13.136	15662.63	1203	2203

Table 4.3 Profits of Each Establishment under Different Demand Scenarios (December 2015)

	DEMAND / POWER PLANTS	Affiliated Partnerships of EÜAŞ	EÜAŞ	Transfer of Operational Rights (TOR)	Autoproducers	Independent Power Producers (IPP)	Built-Operate-Transfer (BOT)	Built-Operate (BO)
		PROFITS (TL per hour)						
DECEMBER WEEKDAY	**39000**	3168.2	820551	62263.8	964.17	1861243	47165	15.80
	36000	3168.2	820276	62243.7	964.21	1861040	47161	33.90
	22000	2698.99	240453	19538.3	793.8	1253029	17592	0.00
DECEMBER WEEKEND	**36000**	3504.65	838154	69415.3	1195.2	1897298	57625	55505.367
	33000	3060.8	682118	58182.8	964.13	1548787	37479	19.164051
	27000	2678.17	253233	24319.1	820.36	1121363	17477	0.00

Producers', consumers' and total surpluses as well as TSO's revenues for each demand scenario are shown in Table 4.4.

Table 4.4 Surplus and Revenue Results for Each Demand Scenario (December 2015)

	DECEMBER WEEKDAY			***DECEMBER WEEKEND***		
Revenue	**DEMAND (MW)**					
(TL)	**39000**	**36000**	**22000**	**36000**	**33000**	**27000**
Producer Surplus	2795371.55	2794887.09	1534104.59	2922697.12	2330611.41	1419889.58
Consumer Surplus	345201.26	318665.37	157319.44	349836.68	292115.60	200233.09
Transmission Operators' Revenue	225347.94	225433.20	337937.44	242097.80	225274.01	320372.31
Total Surplus	3365920.75	3338985.66	2029361.46	3514631.60	2848001.02	1940494.98

4.3 Regional versus Single Prices

We have also computed the single prices (e.g., weighted average prices) for the perfectly competitive case and present the differences among regional prices and single price in Table 4.5 and 4.6.

Table 4.5 Nodal and Single Price Results for December Weekday (2015)

DEMAND/ LDC	22000			36000			39000		
	Nodal	Single	Difference (%)	Nodal	Single	Difference (%)	Nodal	Single	Difference (%)
Trakya LDC	193.52	**143.02**	-26.10%	193.54	**177.03**	-8.53%	193.53	**177**	-8.52%
Batı Anadolu LDC	175.45		-18.48%	193.52		-8.52%	193.52		-8.52%
Kuzey Batı Anadolu LDC	193.52		-26.10%	193.54		-8.53%	193.53		-8.52%
Orta Anadolu LDC	103.12		38.69%	193.48		-8.50%	193.52		-8.52%
Batı Akdeniz LDC	157.37		-9.12%	193.52		-8.52%	193.53		-8.52%
Orta Karadeniz LDC	17.97		696.06%	165.27		7.12%	165.34		7.07%
Doğu Akdeniz LDC	71.48		100.08%	71.48		147.66%	71.48		147.68%
Doğu Anadolu LDC	37.76		278.70%	155.88		13.57%	155.94		13.53%
Güneydoğu Anadolu LDC	57.6		148.29%	146.54		20.81%	146.58		20.78%

Table 4.6 Nodal and Single Price Results for December Weekend (2015)

DEMAND/ LDC	27000			33000			36000		
	Nodal	**Single**	**Difference (%)**	**Nodal**	**Single**	**Difference (%)**	**Nodal**	**Single**	**Difference (%)**
Trakya LDC	193.52	**148.32**	-23.35%	193.52	**177.04**	-8.51%	209.26	**194.35**	-7.12%
Batı Anadolu LDC	178.26		-16.79%	193.52		-8.51%	211.22		-7.99%
Kuzey Batı Anadolu LDC	193.52		-23.35%	193.52		-8.51%	209.26		-7.12%
Orta Anadolu LDC	117.22		26.54%	193.56		-8.53%	219.11		-11.30%
Batı Akdeniz LDC	163.01		-9.01%	193.54		-8.52%	213.20		-8.84%
Orta Karadeniz LDC	40.95		262.18%	165.41		7.03%	193.52		0.43%
Doğu Akdeniz LDC	71.48		107.51%	71.48		147.69%	71.48		171.90%
Doğu Anadolu LDC	56.20		163.93%	155.99		13.49%	179.72		8.14%
Güneydoğu Anadolu LDC	71.48		107.51%	146.62		20.75%	165.97		17.10%

4.4 Other Comparisons

We have computed the prices, total sales and welfare measures for each region with and without transmission line limits and compare the results in Appendices B and C for weekdays and weekends, respectively. We have also computed the prices, total sales for the Nash-Cournot market structure and calculated price-cost margins (PCMs), defined as the difference between Nash-Cournot market structure's price and perfect competition price divided by the perfect competition price. These results are also presented in Appendices B and C for weekdays and weekends, respectively. PCMs are summarized in Table 4.7 and 4.8 for weekday and weekend of December, 2015. Interestingly, PCMs are negative for some regions in red font (i.e., around 0.1% to 2.5% increases in prices in certain regions when market structure is changed from perfect competition to Nash-Cournot structure).

Table 4.7 PCM Results for December Weekday (2015)

	LDC / DEMAND	*22000*	*36000*	*39000*
PRICE (TL/MWh)	**Trakya LDC**	*1.0%*	*5.0%*	*5.0%*
	Batı Anadolu LDC	*0.9%*	4.2%	4.3%
	Kuzey Batı Anadolu LDC	*1.0%*	5.0%	5.0%
	Orta Anadolu LDC	*0.6%*	1.0%	1.7%
	Batı Akdeniz LDC	*0.9%*	3.4%	3.7%
	Orta Karadeniz LDC	*0.3%*	**-2.5%**	**-1.3%**
	Doğu Akdeniz LDC	*4.5%*	5.0%	5.0%
	Doğu Anadolu LDC	*1.4%*	**-1.4%**	**-0.4%**
	Güneydoğu Anadolu LDC	*1.9%*	**-0.1%**	0.7%

Table 4.8 PCM Results for December Weekend (2015)

	LDC / DEMAND	*27000*	*33000*	*36000*
PRICE (TL/MWh)	**Trakya LDC**	*1.0%*	*5.0%*	*5.0%*
	Batı Anadolu LDC	*1.0%*	4.2%	4.3%
	Kuzey Batı Anadolu LDC	*1.0%*	4.9%	5.0%
	Orta Anadolu LDC	*0.6%*	1.1%	1.7%
	Batı Akdeniz LDC	*0.9%*	3.4%	3.7%
	Orta Karadeniz LDC	*0.3%*	**-2.5%**	**-1.4%**
	Doğu Akdeniz LDC	*4.5%*	5.1%	5.0%
	Doğu Anadolu LDC	*1.4%*	**-1.4%**	**-0.4%**
	Güneydoğu Anadolu LDC	*1.9%*	**-0.1%**	0.7%

5. CONCLUSIONS AND FUTURE RESEARCH

In this thesis, it is aimed to create a market-clearing / market-price simulation model for the needs of Turkish electricity market. While Turkey's electricity consumption per capita today is around 2,700 kWh, it is observed that this value is about 9,000 kWh in OECD countries (World Bank, 2015). However, when Turkey's rapid growth and therefore the increase in its expenditures are evaluated, it is foreseen that the per capita electricity consumption may show a serious increase in parallel and that the electric market will develop rapidly as a natural result. In this context, one of the most important points for investors is to simulate the effects of a variety of factors (such as market power, transmission constraints, production uncertainties, demand response and uncertainty) on the market price signal beyond just dominating the market functioning. In addition to this, price signals are crucial in risk management of investments as well as the realization of these investments. Investors who are risk-averse can contract and manage their risks over long-term prices that can be estimated based on the price signal in the proposed models of this thesis.

Another important point in this context is that electricity generation is predominantly based on resources such as natural gas and therefore the current deficit in Turkey is increasing. Investments in domestic and renewable energy sources (wind, solar, geothermal, etc.) are needed to close this deficit. In order to manage the risk of these investments, it is important that price signals are estimated correctly. Market-clearing / market-price simulation models, which play important roles in decision-making processes, also play an important role in understanding complex market dynamics. In summary, the models that are developed in this thesis can enable market participants to analyze the market outcomes that can be useful both in terms of future investment plans as well as their effects on the market. This would also help market players in their short / medium / long term decisions. This study can be extended to include generation / transmission investments models, which is an important deficiency in the current literature and is not only specific to the Turkish market, but can also be adapted to electricity markets in other regions and / or countries.

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APPENDICES

In Appendix A and Appendix B, we have presented the detailed price, sales and welfare results for different demand scenarios and weekday / weekend in Tables. Appendix C displays monthly capacity factors for each generation type from December 2015 to December 2016 categorized as weekday and weekend. In Appendix D, we have provided the summary results for February, May, August and November 2016. Finally, in Appendix E, we have provided the GAMS, R and MS EXCEL VBA codes.

Appendix A

A.1 Electricity Price and Total Sales Results for All Scenarios (December 2015)

Table A.1 Detailed Electricity Price Results for All Scenarios (December 2015)

		PRICE (TL/MWh)								
	DEMAND (MW) / YTM	**Trakya LDC**	**Batı Anadolu LDC**	**Kuzey Batı Anadolu LDC**	**Orta Anadolu LDC**	**Batı Akdeniz LDC**	**Orta Karadeniz LDC**	**Doğu AkdenizL DC**	**Doğu Anadolu LDC**	**Güneydoğu Anadolu LDC**
WEEKDAY	**39000**	193.53	193.52	193.53	193.52	193.53	165.34	71.48	155.94	146.58
	36000	193.54	193.52	193.54	193.48	193.52	165.27	71.48	155.88	146.54
	22000	193.52	175.45	193.52	103.12	157.37	17.97	71.48	37.76	57.60
WEEKEND	**36000**	209.26	211.22	209.26	219.11	213.20	193.52	71.48	179.72	165.97
	33000	193.52	193.52	193.52	193.56	193.54	165.41	71.48	155.99	146.62
	27000	193.52	178.26	193.52	117.22	163.01	40.95	71.48	56.20	71.48

Table A.2 Detailed Total Sales Results for All Scenarios (December 2015)

TOTAL SALES (MWh)

	DEMAND (MW) / LDC	Trakya LDC	Batı Anadolu LDC	Kuzey Batı Anadolu LDC	Orta Anadolu LDC	Batı Akdeniz LDC	Orta Karadeniz LDC	Doğu AkdenizL DC	Doğu Anadolu LDC	Güneydoğu Anadolu LDC
WEEKDAY	**39000**	6204.85	7026.87	9749.6	4773.6	1599	1661	3069.1	959.4	3954
	36000	5727.72	6487.43	9001.9	4406.2	1476	1534	2833.1	885.6	3651
	22000	3500.09	3964.88	5499.3	2693.1	902	937.2	1731.6	541.2	2231
WEEKEND	**36000**	5728.34	6487.02	9000.3	4406.9	1475.9	1534	2833.1	885.6	3650
	33000	5250.14	5947.14	8248.9	4039.2	1352.9	1406	2597.3	811.8	3346
	27000	4295.67	4865.28	6749.9	3304.8	1106.9	1150	2124.8	664.2	2738

Appendix B

B.1 Comparative Results for Weekday Scenarios (December 2015)

Table B.1 Prices and Total Sales Comparison with / without Line Limits, Weekdays (December 2015)

	LDC / DEMAND	22000			36000			39000		
		No line limits	With line limits	Difference (%)	No line limits	With line limits	Difference (%)	No line limits	With line limits	Difference (%)
PRICE (TL/MWh)	Trakya LDC	168.9	193.52	**14.5%**	193.5	193.54	0.01%	193.5	193.53	0.00%
	Batı Anadolu LDC	168.9	175.45	**3.8%**	193.5	193.52	0.00%	193.5	193.52	0.00%
	Kuzey Batı Anadolu LDC	168.9	193.52	**14.5%**	193.5	193.54	0.01%	193.5	193.53	0.00%
	Orta Anadolu LDC	113.4	103.12	-9.09%	193.5	193.48	-0.02%	193.5	193.52	0.00%
	Batı Akdeniz LDC	168.9	157.37	-6.85%	193.5	193.52	0.00%	193.5	193.53	0.01%
	Orta Karadeniz LDC	19.76	17.97	-9.09%	181.8	165.27	-9.09%	181.9	165.34	-9.09%
	Doğu Akdeniz LDC	78.63	71.48	-9.09%	78.63	71.48	-9.09%	78.63	71.48	-9.09%
	Doğu Anadolu LDC	41.54	37.76	-9.09%	171.5	155.88	-9.09%	171.5	155.94	-9.09%
	Güneydoğu Anadolu LDC	63.36	57.6	-9.09%	161.2	146.54	-9.09%	161.2	146.58	-9.09%
TOTAL SALES (MW)	Trakya LDC	7,943	3,500	**-55.9%**	5,733	5,727	-0.10%	6,207	6,204	-0.05%
	Batı Anadolu LDC	5,431	3,964.	**-27%**	6,487	6,487	0.00%	7,026	7,026	0.00%
	Kuzey Batı Anadolu LDC	12,48	5,499	**-55.9%**	9,011	9,001	-0.10%	9,754	9,749	-0.05%
	Orta Anadolu LDC	0.00	2,693.1	0.00%	4,396	4,406	0.22%	4,773	4,773.6	0.00%
	Batı Akdeniz LDC	238.4	902.00	278.4%	1,476	1,476	0.00%	1,599	1,599.0	-0.05%
	Orta Karadeniz LDC	0.00	937.20	0.00%	0.00	1,533	0.00%	0.00	1.661,4	0.00%
	Doğu Akdeniz LDC	0.00	1,731.6	0.00%	0.00	2,833.1	0.00%	0.00	3,069.1	0.00%
	Doğu Anadolu LDC	0.00	541.20	0.00%	0.00	885.6	0.00%	0.00	959.4	0.00%
	Güneydoğu Anadolu LDC	0.00	2,230.8	0.00%	0.00	3,650.6	0.00%	0.00	3,954.2	0.00%

Table B.2 Welfare Comparisons With / Without Line Limits, Weekdays (December 2015)

DEMAND SCENARIO (MW)	*SOCIAL WELFARE MEASURES (TL)*	*Without line limits*	*With line limits*	*Difference (%)*
22000	**Consumer Payments**	4,408,646.50	3,146,231.60	-28.63%
	Transmission Operators' Revenue	0.00	337,937.40	100.00%
	Producer Surplus	3,095,933.50	1,534,104.60	-50.45%
	Consumer Surplus	514,299.80	157,311.60	-69.41%
	Total Surplus	3,610,233.30	2,029,353.60	**-43.79%**
36000	**Consumer Payments**	5,245,285.70	6,373,307.00	**21.51%**
	Transmission Operators' Revenue	0.00	225,433.20	100.00%
	Producer Surplus	3,737,019.70	2,794,887.10	-25.21%
	Consumer Surplus	262,321.90	318,665.30	**21.48%**
	Total Surplus	3,999,341.60	3,338,985.60	**-16.51%**
39000	**Consumer Payments**	5,682,192.10	6.904.025.40	**21.50%**
	Transmission Operators' Revenue	0.00	225,347.90	100.00%
	Producer Surplus	3,737,019.70	2,795,371.50	-25.20%
	Consumer Surplus	284,199.20	345,201.30	**21.46%**
	Total Surplus	4,021,218.90	3,365,920.80	**-16.30%**

Table B.3 Prices and Total Sales Comparison of Different Market Structures, Weekdays (December 2015) (Perfectly Competitive (PC) / Nash-Cournot (NC))

	LDC / DEMAND	*22000*			*36000*			*39000*		
		P.C.	**N.C.**	**Difference (%)**	**P.C.**	**N.C.**	**Difference (%)**	**P.C.**	**N.C.**	**Difference (%)**
PRICE (TL/MWh)	**Trakya LDC**	193.6	195.5	1.02%	193.5	203.2	4.99%	193.5	203.2	5.00%
	Batı Anadolu LDC	175.5	177.1	0.97%	193.5	201.7	4.21%	193.5	201.9	4.33%
	Kuzey Batı Anadolu LDC	193.5	195.5	1.02%	193.5	203.2	4.99%	193.5	203.2	5.00%
	Orta Anadolu LDC	103.1	103.7	0.59%	193.5	195.5	1.05%	193.5	196.7	1.68%
	Batı Akdeniz LDC	157.4	158.8	0.91%	193.5	200.1	3.42%	193.5	200.6	3.67%
	Orta Karadeniz LDC	17.97	18.03	0.34%	165.3	161.1	-2.53%	165.3	163.1	-1.34%
	Doğu Akdeniz LDC	71.48	74.7	4.50%	71.48	75.05	5.00%	71.48	75.05	5.00%
	Doğu Anadolu LDC	37.76	38.27	1.33%	155.9	153.7	-1.40%	155.9	155.3	-0.39%
	Güneydoğu Anadolu LDC	57.6	58.7	1.91%	146.5	146.3	-0.13%	146.5	147.5	0.68%
TOTAL SALES (MW)	**Trakya LDC**	3,500	3,143	-10.19%	5,727	2,866	-49.95%	6,204	3,103	-49.98%
	Batı Anadolu LDC	3,964	3,580	-9.68%	6,487	3,758	-42.07%	7,026	3,981	-43.34%
	Kuzey Batı Anadolu LDC	5,499	4,939	-10.19%	9,001	4,505	-49.95%	9,749	4,877	-49.98%
	Orta Anadolu LDC	2,693	2,534	-5.91%	4,406	3,942	-10.53%	4,773	3,972	-16.77%
	Batı Akdeniz LDC	902	820.3	-9.06%	1,476	971.4	-34.19%	1,599	1,012	-36.70%
	Orta Karadeniz LDC	937.2	904.9	-3.45%	1,533	1,921	25.29%	1,661	1,883	13.38%
	Doğu Akdeniz LDC	1,731	952.1	-45.02%	2,833	1,416	-50.00%	3,069	1,534	-50.00%
	Doğu Anadolu LDC	541.2	469	-13.33%	885.6	1,009	14.01%	959.4	996.7	3.89%
	Güneydoğu Anadolu LDC	2,230	1,805	-19.06%	3,650	3,697	1.28%	3,954	3,684	-6.83%

Table B.4 Welfare Comparison of Different Market Structures, Weekdays (December 2015) (Perfectly Competitive (PC) / Nash - Cournot (NC))

DEMAND (MW)	*SOCIAL WELFARES (TL)*	*P.C.*	*N.C.*	*Difference (%)*
22000	**Consumer Payments**	3,146,231.60	2,818,779.90	-10.41%
	Transmission Operators' Revenue	337,937.40	303,170.20	-10.29%
	Producer Surplus	1,534,104.60	1,598,937.90	4.23%
	Consumer Surplus	157,311.60	124,402.70	**-20.92%**
	Total Surplus	2,029,353.60	2,026,510.80	**-0.14%**
36000	**Consumer Payments**	6,373,307.00	4,333,234.10	-32.01%
	Transmission Operators' Revenue	225,433.20	244,399.80	8.41%
	Producer Surplus	2,794,887.10	2,886,195.10	3.27%
	Consumer Surplus	318,665.30	155,908.60	**-51.07%**
	Total Surplus	3,338,985.60	3,286,503.40	**-1.57%**
39000	**Consumer Payments**	6,904,025.40	4,531,396.00	-34.37%
	Transmission Operators' Revenue	225,347.90	241,340.10	7.10%
	Producer Surplus	2,795,371.50	2,914,354.00	4.26%
	Consumer Surplus	345,201.30	152,280.10	**-55.89%**
	Total Surplus	3,365,920.80	3,307,974.10	**-1.72%**

B.2 Comparative Results for Weekend Scenarios (December 2015)

Table B.5 Prices and Total Sales Comparison With / Without Line Limits, Weekends (December 2015)

		27000			*33000*			*36000*		
	LDC / DEMAND	**No line limits**	**With line limits**	**Difference (%)**	**No line limits**	**With line limits**	**Difference (%)**	**No line limits**	**With line limits**	**Difference (%)**
PRICE (TL/MWh)	**Trakya LDC**	181.2	193.52	6.79%	193.5	193.5	0.00%	203.51	209.25	2.82%
	Batı Anadolu LDC	181.2	178.26	-1.63%	193.5	193.5	0.00%	203.51	211.21	3.78%
	Kuzey Batı Anadolu LDC	181.2	193.52	6.79%	193.5	193.5	0.00%	203.51	209.25	2.82%
	Orta Anadolu LDC	128.9	117.22	-9.09%	193.5	193.5	0.02%	203.51	219.10	7.66%
	Batı Akdeniz LDC	179.3	163.01	-9.09%	193.5	193.5	0.01%	203.51	213.20	4.76%
	Orta Karadeniz LDC	45.05	40.95	-9.09%	181.9	165.4	-9.09%	203.51	193.52	-4.91%
	Doğu Akdeniz LDC	78.63	71.47	-9.09%	78.62	71.4	-9.09%	78.62	71.47	-9.09%
	Doğu Anadolu LDC	61.82	56.19	-9.09%	171.5	155.9	-9.09%	197.69	179.72	-9.09%
	Güneydoğu Anadolu LDC	78.63	71.47	-9.09%	161.3	146.6	-9.09%	182.56	165.97	-9.09%
TOTAL SALES (MW)	**Trakya LDC**	7,027	4295.6	-38.87%	5,250	5,250	0.00%	7299.5	5,728.3	-21.52%
	Batı Anadolu LDC	4,059	4865.2	19.84%	5,947	5,947	0.00%	8852.0	6,487.0	-26.72%
	Kuzey Batı Anadolu LDC	11,04	6749.9	-38.87%	8,248	8,248	0.00%	11468	9,000.2	-21.52%
	Orta Anadolu LDC	0.00	3304.7	0.00%	4,046	4,039	-0.19%	7541.5	4,405.9	-41.58%
	Batı Akdeniz LDC	0.00	1106.9	0.00%	1,354	1,353	-0.10%	2146.4	1,475.9	-31.24%
	Orta Karadeniz LDC	0.00	1150	0.00%	0.00	1,405	0.00%	741.3	1,533.5	106.86%
	Doğu Akdeniz LDC	0.00	2124.8	0.00%	0.00	2,597	0.00%	0.00	2,833	0.00%
	Doğu Anadolu LDC	0.00	664.19	0.00%	0.00	811.79	0.00%	0.00	885.58	0.00%
	Güneydoğu Anadolu LDC	0.00	2737.6	0.00%	0.00	3,345	0.00%	0.00	3,650	0.00%

Table B.6 Welfare Comparisons With / Without Line Limits, Weekends (December 2015)

DEMAND SCENARIO (MW)	*SOCIAL WELFARE MEASURES (TL)*	*Without line limits*	*With line limits*	*Difference (%)*
27000	**Consumer Payments**	4,010,143.57	4,004,661.79	-0.14%
	Transmission Operators' Revenue	0.00	320,372.31	100.00%
	Producer Surplus	2,868,272.69	1,419,889.58	-50.50%
	Consumer Surplus	316,213.42	200,233.09	-36.68%
	Total Surplus	3,184,486.11	1,940,494.98	-39.06%
33000	**Consumer Payments**	4,808,477.15	5,842,330.18	21.50%
	Transmission Operators' Revenue	0.00	225,274.01	100.00%
	Producer Surplus	3,140,587.75	2,330,611.41	-25.79%
	Consumer Surplus	240,520.08	292,116.49	21.45%
	Total Surplus	3,381,107.83	2,848,001.91	-15.77%
36000	**Consumer Payments**	7,743,804.29	6,996,538.71	-9.65%
	Transmission Operators' Revenue	0.00	242,097.80	100.00%
	Producer Surplus	3,520,962.00	2,922,697.12	-16.99%
	Consumer Surplus	555,966.58	349,826.94	-37.08%
	Total Surplus	4,076,928.58	3,514,621.86	-13.79%

Table B.7 Prices and Total Sales Comparison of Different Market Structures, Weekends (December 2015) (Perfectly Competitive (PC) / Nash-Cournot (NC)

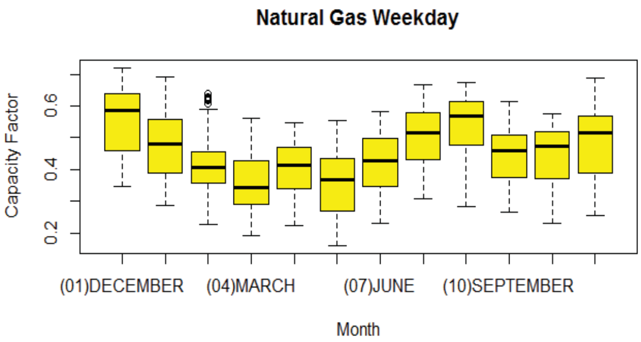
		27000			*33000*			*36000*		
	LDC / DEMAND	**P.C.**	**N.C.**	**Difference (%)**	**P.C.**	**N.C.**	**Difference (%)**	**P.C.**	**N.C.**	**Difference (%)**
PRICE (TL/MWh)	**Trakya LDC**	193.5	195.5	1.02%	193.5	203.2	4.99%	193.53	203.2	5.00%
	Batı Anadolu LDC	175.4	177.1	0.97%	193.5	201.7	4.21%	193.52	201.9	4.33%
	Kuzey Batı Anadolu LDC	193.5	195.4	1.02%	193.5	203.	4.99%	193.53	203.2	5.00%
	Orta Anadolu LDC	103.1	103.7	0.59%	193.4	195.5	1.05%	193.52	196.8	1.68%
	Batı Akdeniz LDC	157.37	158.8	0.91%	193.5	200.1	3.42%	193.53	200.6	3.67%
	Orta Karadeniz LDC	17.97	18.03	0.34%	165.3	161.1	-2.53%	165.34	163.1	-1.34%
	Doğu Akdeniz LDC	71.48	74.7	4.50%	71.48	75.1	5.00%	71.48	75.05	5.00%
	Doğu Anadolu LDC	37.76	38.27	1.33%	155.9	153.7	-1.40%	155.94	155.3	-0.39%
	Güneydoğu Anadolu LDC	57.6	58.7	1.91%	146.5	146.3	-0.13%	146.58	147.6	0.68%
TOTAL SALES (MW)	**Trakya LDC**	3,500	3,143.6	-10.19%	5,727	2,866	-49.95%	6,204	3,103	-49.98%
	Batı Anadolu LDC	3,964	3,580	-9.68%	6,487	3,758	-42.07%	7,026	3,981	-43.34%
	Kuzey Batı Anadolu LDC	5,499	4,939	-10.19%	9,001	4,505	-49.95%	9,749	4,877	-49.98%
	Orta Anadolu LDC	2,693	2,534	-5.91%	4,406	3,942	-10.53%	4,773	3,972	-16.77%
	Batı Akdeniz LDC	902	820.3	-9.06%	1,476	971.4	-34.19%	1,599	1,012	-36.70%
	Orta Karadeniz LDC	937.2	904.9	-3.45%	1,533	1,921	25.29%	1,661	1,883	13.38%
	Doğu Akdeniz LDC	1,731	952.1	-45.02%	2,833	1,416	-50.00%	3,069	1,534	-50.00%
	Doğu Anadolu LDC	541.2	469	-13.33%	885.6	1,009	14.01%	959.4	996.7	3.89%
	Güneydoğu Anadolu LDC	2,230	1,805	-19.06%	3,650	3,697	1.28%	3,954	3,684	-6.83%

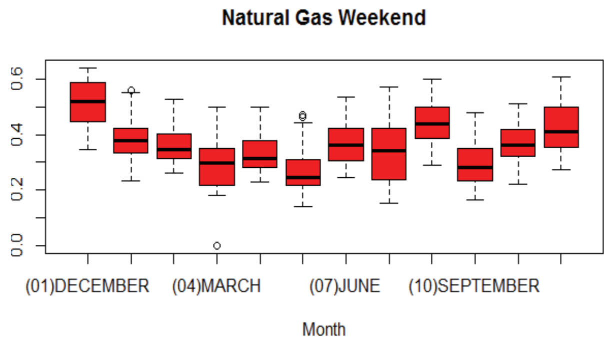
Table B.8 Welfare Comparisons of Different Market Structures, Weekends (December 2015) (Perfectly Competitive (PC) / Nash-Cournot (NC))

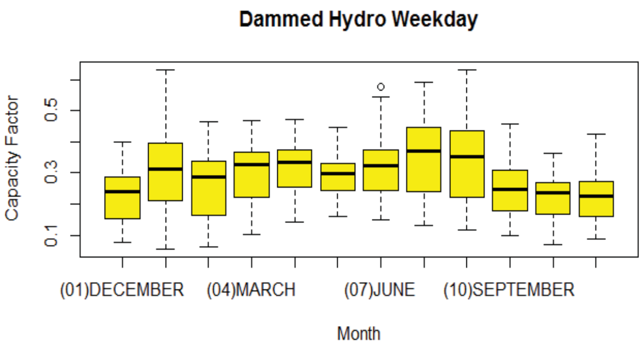
DEMAND SCENARIO (MW)	*SOCIAL WELFARE MEASURES (TL)*	*PC*	*NC*	*Difference (%)*
27000	**Consumer Payments**	4,004,661.79	2,693,718.15	-32.74%
	Transmission Operators' Revenue	320,372.31	312,926.57	-2.32%
	Producer Surplus	1,419,889.58	1,515,794.86	6.75%
	Consumer Surplus	200,233.09	86,033.16	-57.03%
	Total Surplus	1,940,494.98	1,914,754.59	-1.33%
33000	**Consumer Payments**	5,842,330.18	3,773,385.00	-35.41%
	Transmission Operators' Revenue	225,274.01	239,982.11	6.53%
	Producer Surplus	2,330,611.41	2,435,137.29	4.48%
	Consumer Surplus	292,116.49	123,059.11	-57.87%
	Total Surplus	2,848,001.91	2,798,178.51	-1.75%
36000	**Consumer Payments**	6,996,538.71	6,275,505.65	-10.31%
	Transmission Operators' Revenue	242,097.80	218,391.87	-9.79%
	Producer Surplus	2,922,697.12	2,967,253.55	1.52%
	Consumer Surplus	349,826.94	277,351.51	-20.72%
	Total Surplus	3,514,621.86	3,462,996.93	-1.47%

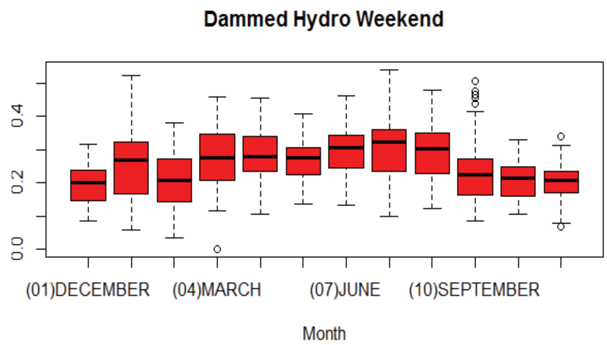
Appendix C

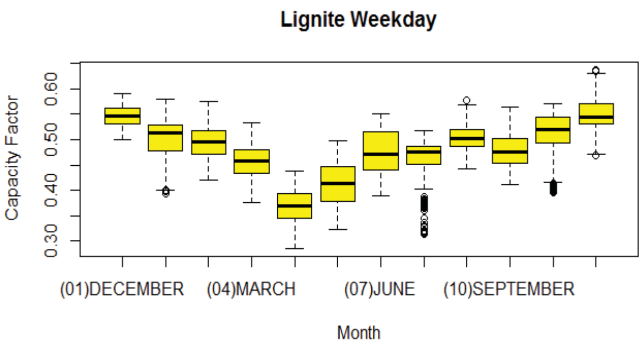
C.1 Box-plots for Capacity Factors of Different Generation Technologies (December 2015-November 2016, Weekday & Weekend)

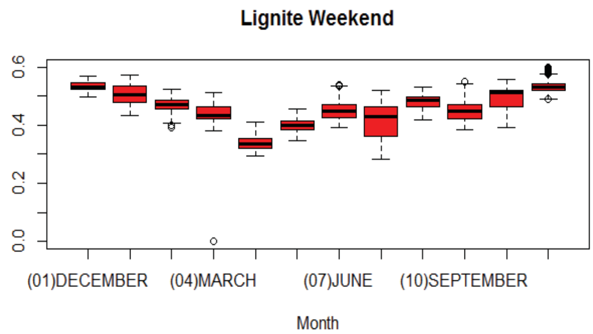


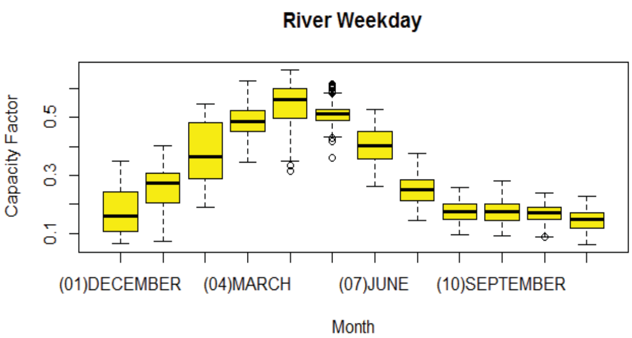


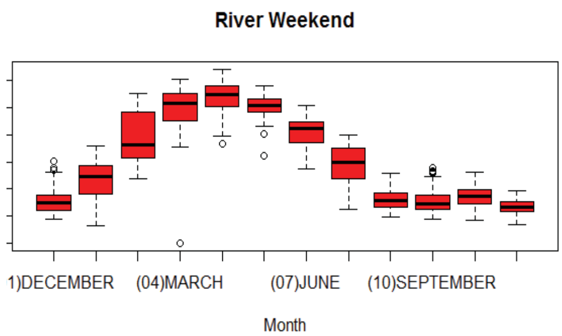


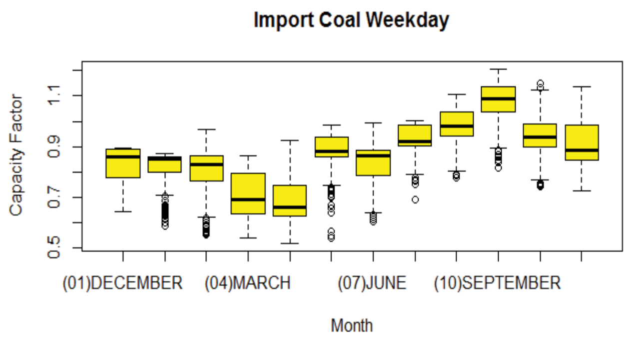


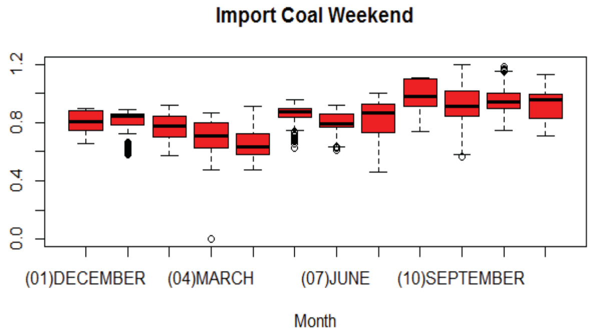


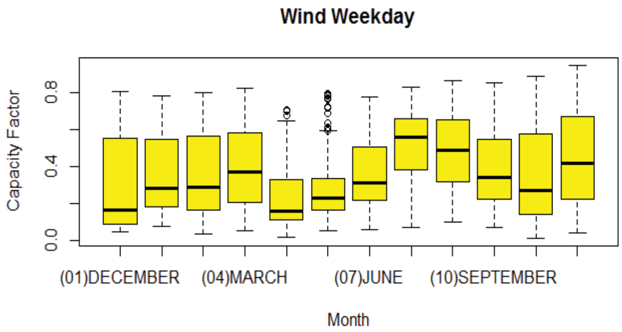


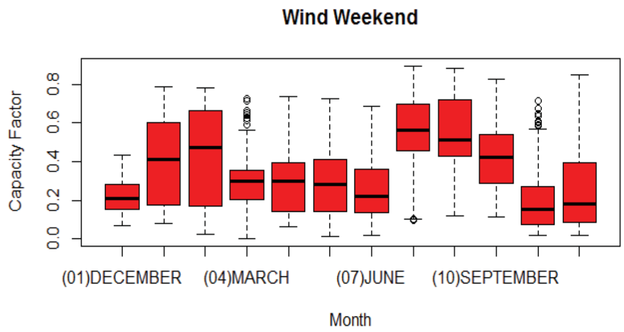


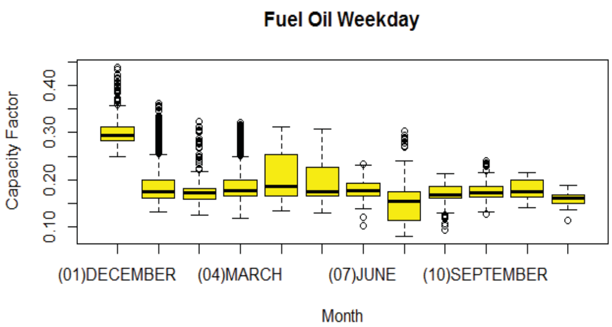


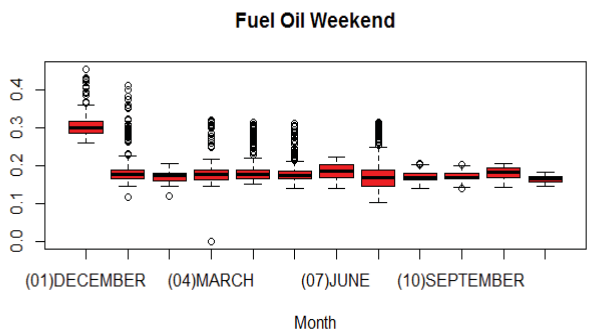

Import Coal Weekday
Capacity Factor
0.5
0.7
0.9
1.1
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

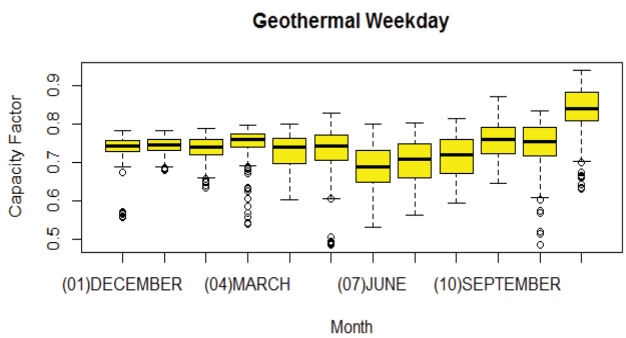

Import Coal Weekend
0.0
0.4
0.8
1.2
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

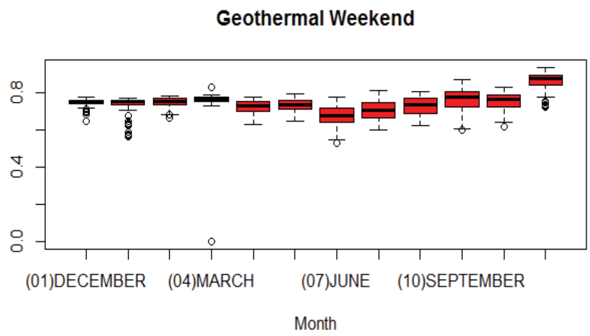

Wind Weekday
Capacity Factor
0.0
0.4
0.8
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

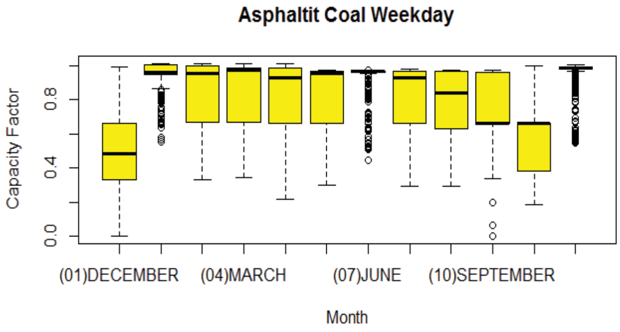

Wind Weekend
Capacity Factor
0.0
0.2
0.4
0.6
0.8
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

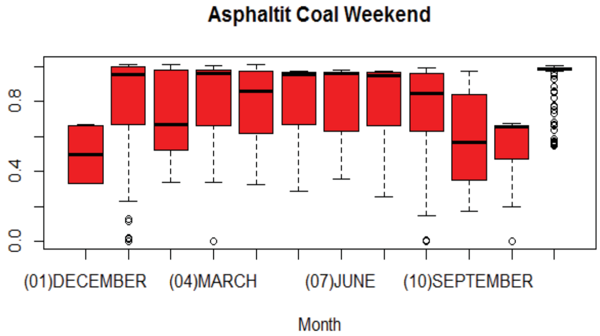

Fuel Oil Weekday
Capacity Factor
0.10
0.20
0.30
0.40
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

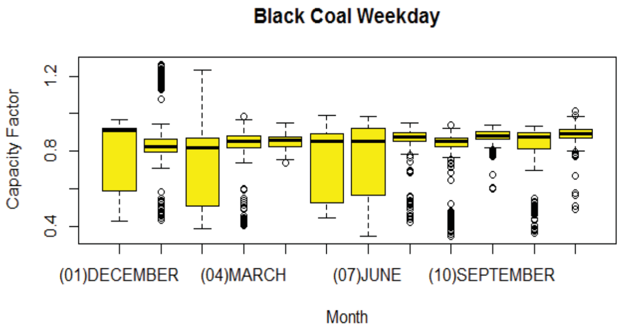

Fuel Oil Weekend
0.0
0.1
0.2
0.3
0.4
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

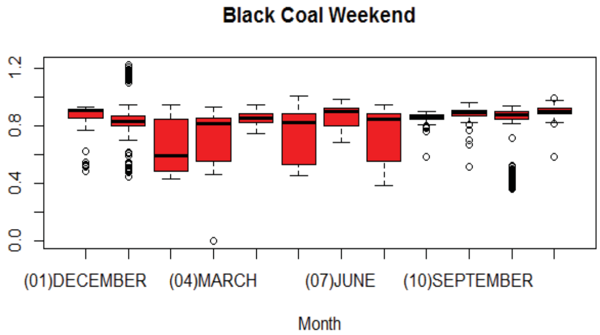

Geothermal Weekday
Capacity Factor
0.5
0.6
0.7
0.8
0.9
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

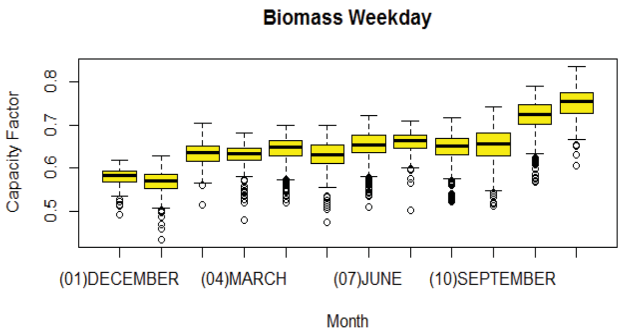

Geothermal Weekend
0.0
0.4
0.8
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

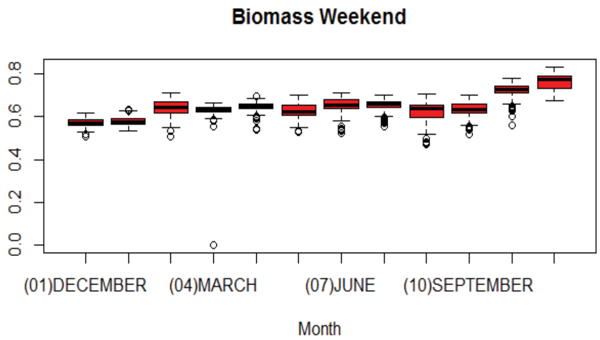

Asphaltit Coal Weekday
Capacity Factor
0.0
0.4
0.8
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

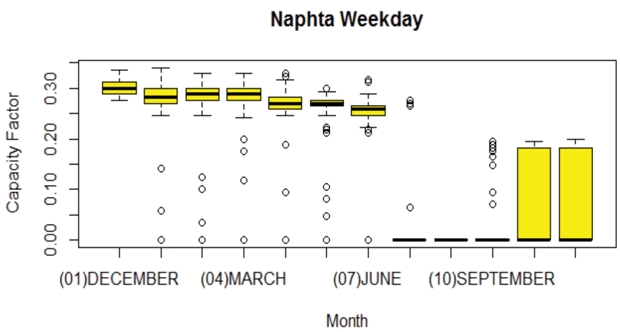

Asphaltit Coal Weekend
0.0
0.4
0.8
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

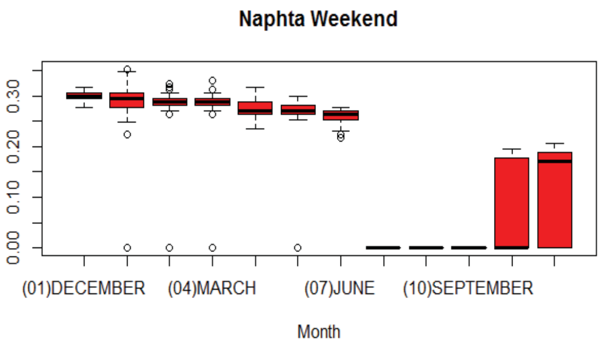

Black Coal Weekday
Capacity Factor
0.4
0.8
1.2
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month


Black Coal Weekend
0.0
0.4
0.8
1.2
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month


Biomass Weekday
Capacity Factor
0.5
0.6
0.7
0.8
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month


Biomass Weekend
0.0
0.2
0.4
0.6
0.8
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month


Naphta Weekday
Capacity Factor
0.00
0.10
0.20
0.30
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month


Naphta Weekend
0.00
0.10
0.20
0.30
(01)DECEMBER
(04)MARCH
(07)JUNE
(10)SEPTEMBER
Month

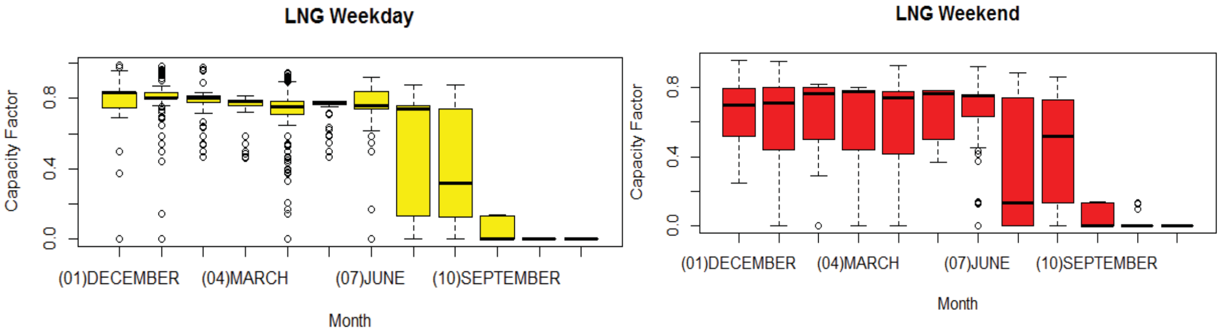


Figure C.1 Monthly Capacity Factors for Each Generation Source for Weekday and Weekend (December 2015 - November 2016)

Appendix D

D.1 Analyses for February, May, August and November 2016 (Weekday & Weekend)

Table D.1 Maximum Values for Capacity Factors for Weekends and Weekdays in February, May, August, November 2016 (EPİAŞ, 2017)

		FEBRUARY		MAY		AUGUST		NOVEMBER	
Type of Source		***Weekend***	***Weekday***	***Weekend***	***Weekday***	***Weekend***	***Weekday***	***Weekend***	***Weekday***
LIGNITE	h1	53%	57%	46%	50%	53%	58%	60%	64%
RIVER	h2	55%	55%	58%	62%	26%	26%	19%	23%
DAMMED HYDRO	h3	38%	47%	41%	45%	48%	63%	34%	43%
NATURAL GAS	h4	53%	64%	47%	56%	60%	67%	61%	69%
FUEL OIL	h5	21%	32%	31%	31%	20%	21%	18%	19%
GEOTHERMAL	h6	79%	79%	80%	83%	81%	82%	94%	94%
BIOMASS	h7	71%	70%	70%	70%	70%	72%	83%	84%
ASPHALTIT COAL	h8	101%	101%	98%	98%	99%	98%	100%	100%
IMPORT COAL	h9	92%	97%	96%	99%	111%	110%	113%	114%
LNG	h10	82%	98%	78%	78%	86%	88%	0%	0%
NAPHTA	h11	32%	33%	30%	30%	0%	0%	21%	20%
WIND	h12	78%	80%	72%	80%	88%	87%	85%	95%
BLACK COAL	h13	95%	124%	101%	99%	90%	94%	100%	102%

We have used the capacity values of each source at the end of 2015 to calculate these capacity factors, hence some values may be greater than 100% due to increases in capacity of a certain source within 2016.

Similar to section 3.3.2, we have introduced three (peak, mid-peak and off-peak) demand scenarios for each month as in the following table.

Table D.2 Demand Scenarios for Weekends and Weekdays in February, May, August and November 2016 (EPİAŞ, 2017)

	FEBRUARY		**MAY**		**AUGUST**		**NOVEMBER**	
Demand Scenarios (MW)	***Weekend***	***Weekday***	***Weekend***	***Weekday***	***Weekend***	***Weekday***	***Weekend***	***Weekday***
Off-Peak	27,000	28,000	26,000	26,500	30,000	31,500	26,500	27,000
Mid-Peak	29,000	32,000	28,000	30,000	33,000	35,000	27,000	32,000
Peak	30,000	33,500	30,000	33,500	37,000	41,000	31,000	34,500

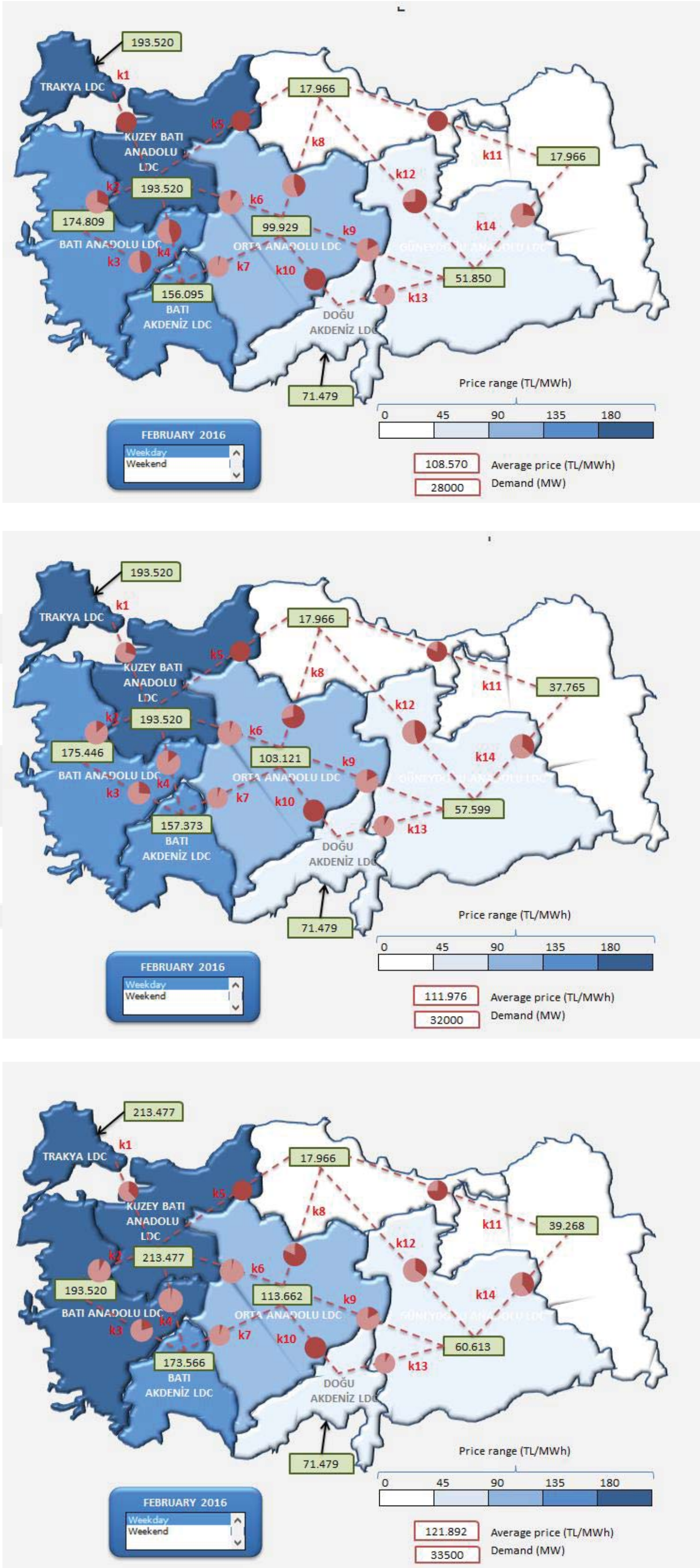


Figure D.1 Simulation Results for Weekday, February 2016 (Demand Scenarios: 28000 MW, 32000 MW and 33500 MW, respectively)

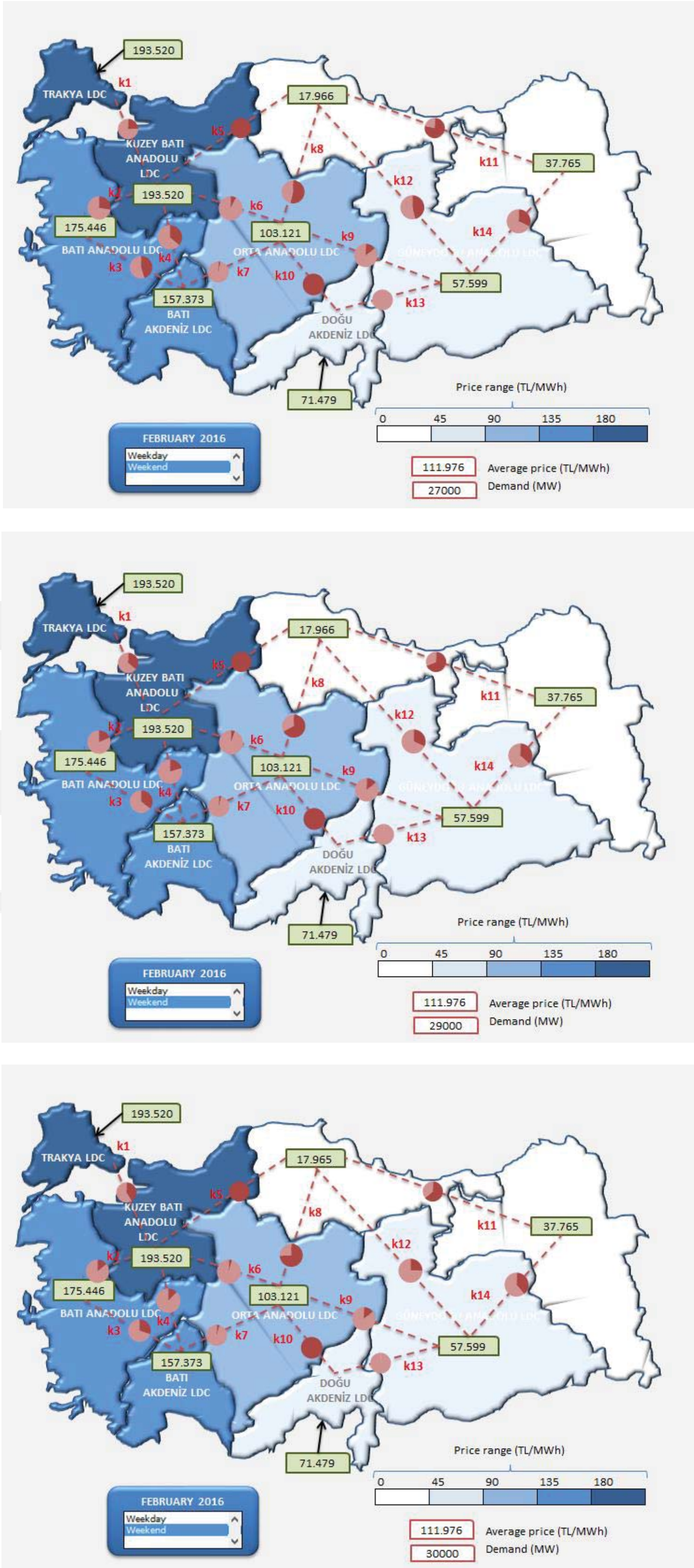


Figure D.2 Simulation Results for Weekend, February 2016 (Demand Scenarios: 27000 MW, 29000 MW and 30000 MW, respectively)

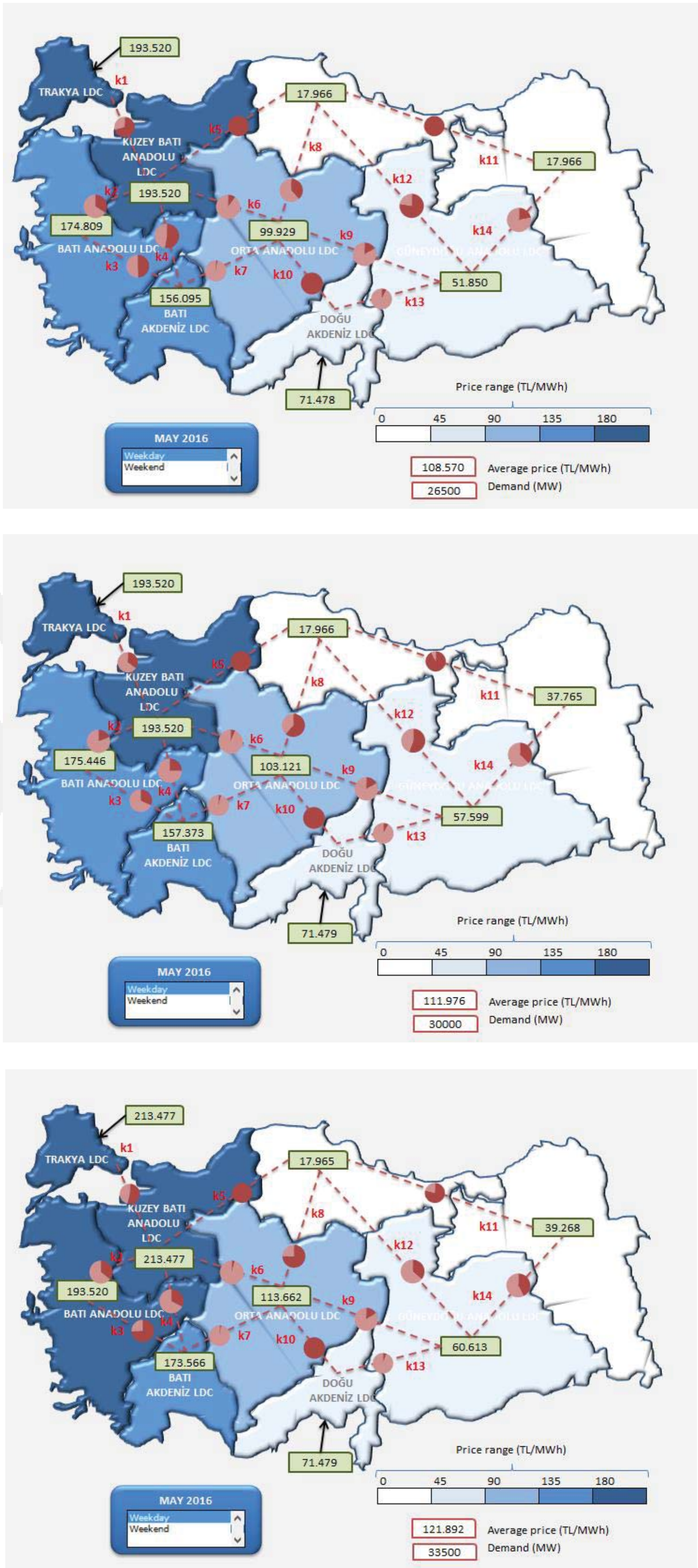


Figure D.3 Simulation Results for Weekday, May 2016 (Demand Scenarios: 26500 MW, 30000 MW and 33500 MW, respectively)

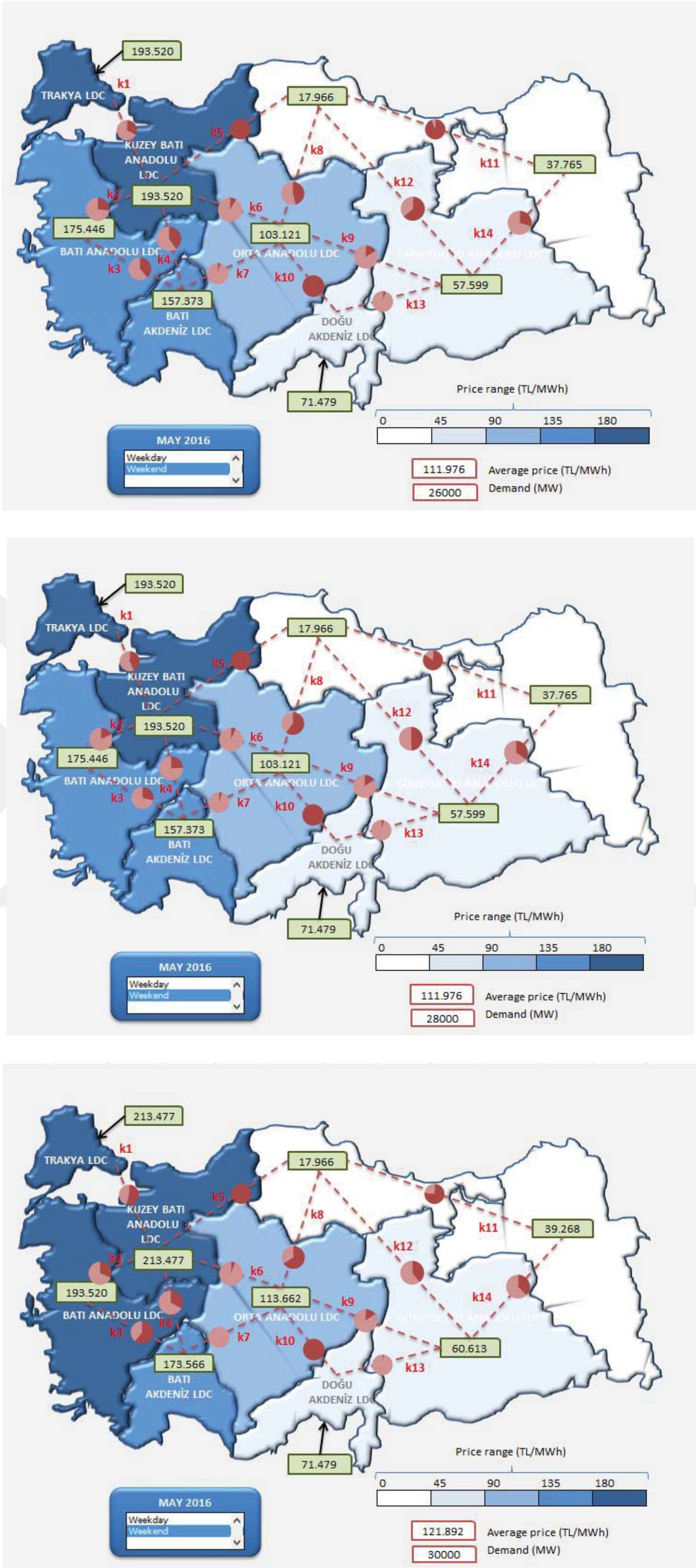


Figure D.4 Simulation Results for Weekend, May 2016 (Demand Scenarios: 26000 MW, 28000 MW and 30000 MW, respectively)

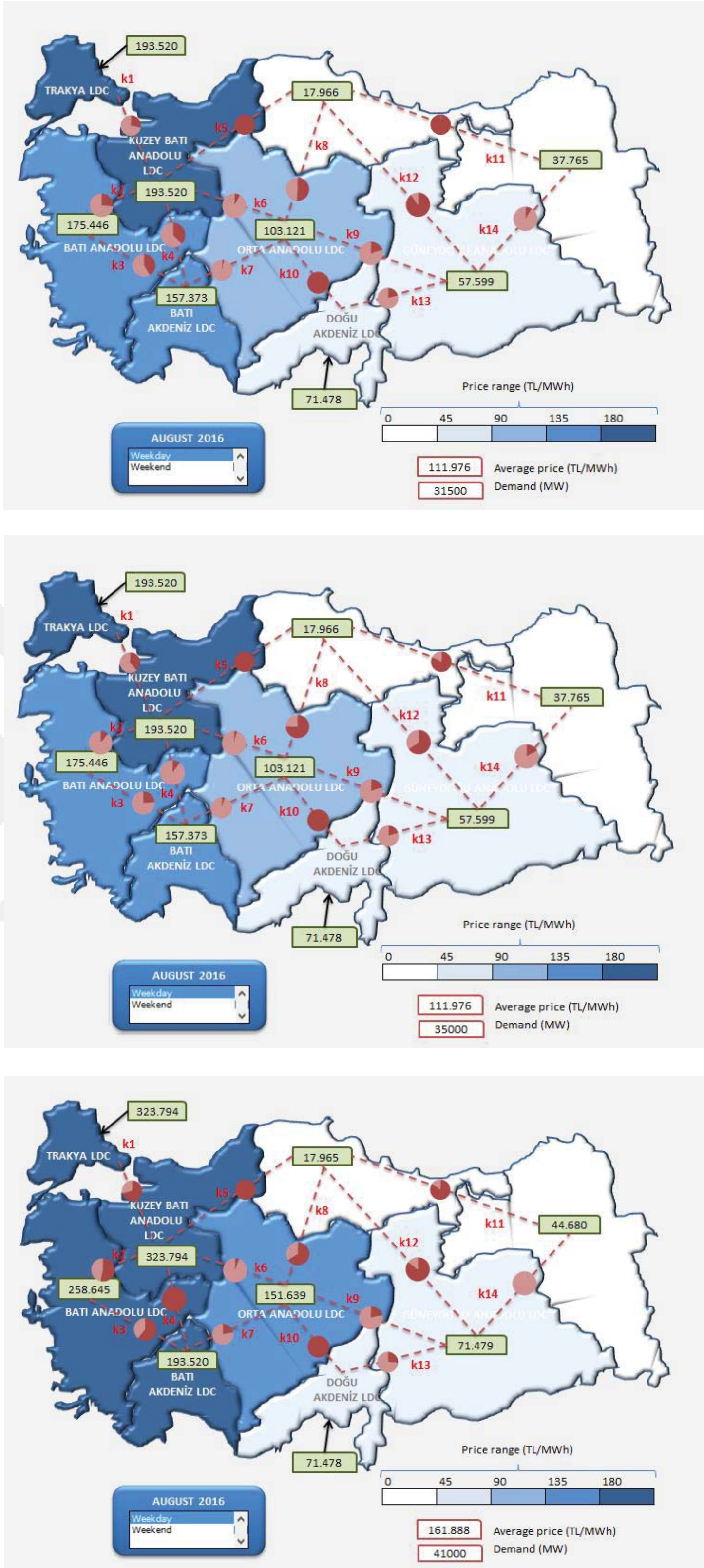
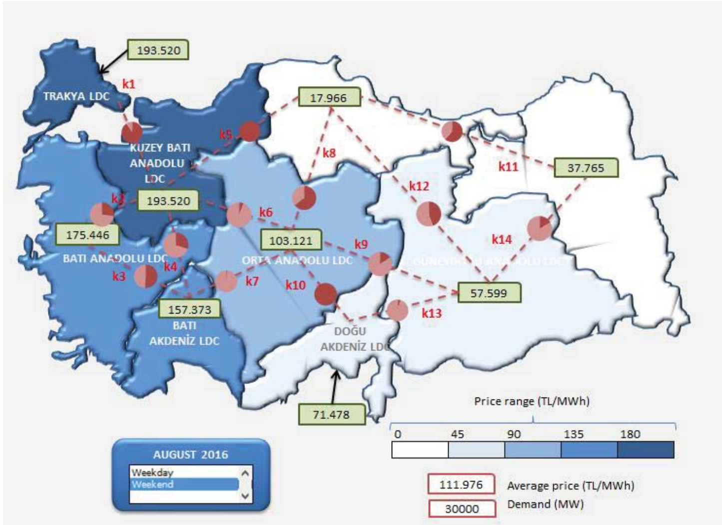
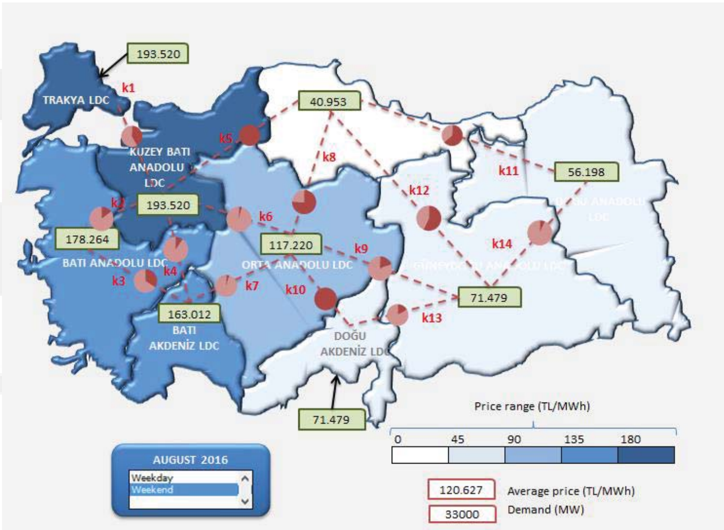


Figure D.5 Simulation Results for Weekday, August 2016 (Demand Scenarios: 31500 MW, 35000 MW and 41000 MW, respectively)





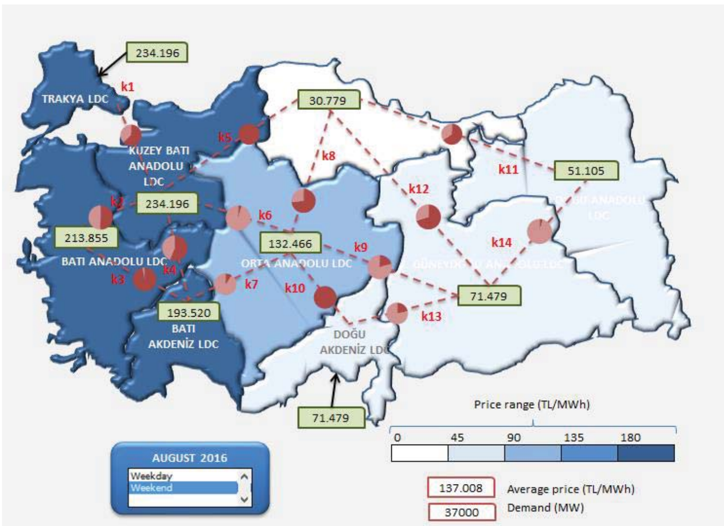


Figure D.6 Simulation Results for Weekend, August 2016 (Demand Scenarios: 30000 MW, 33000 MW and 37000 MW, respectively)

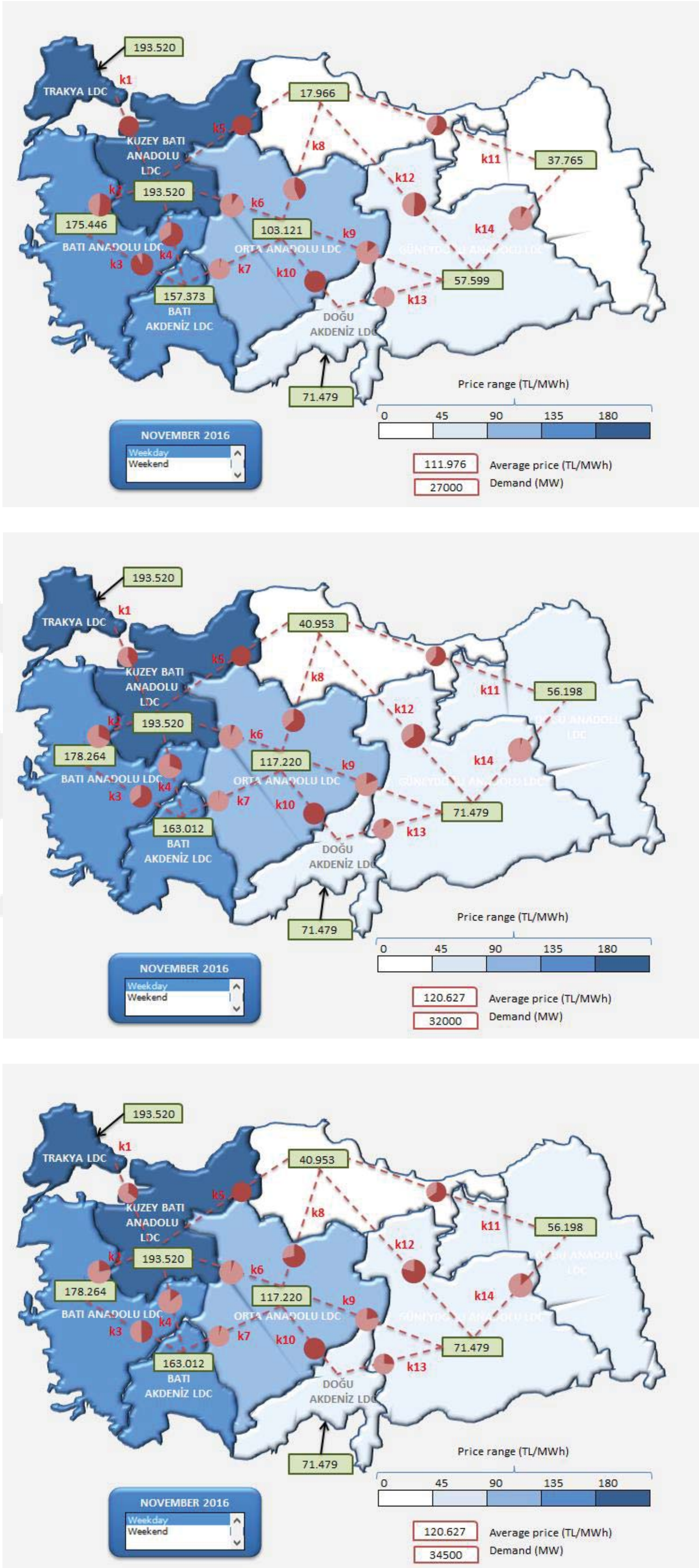


Figure D.7 Simulation Results for Weekday, November 2016 (Demand Scenarios: 27000 MW, 32000 MW and 34500 MW, respectively)

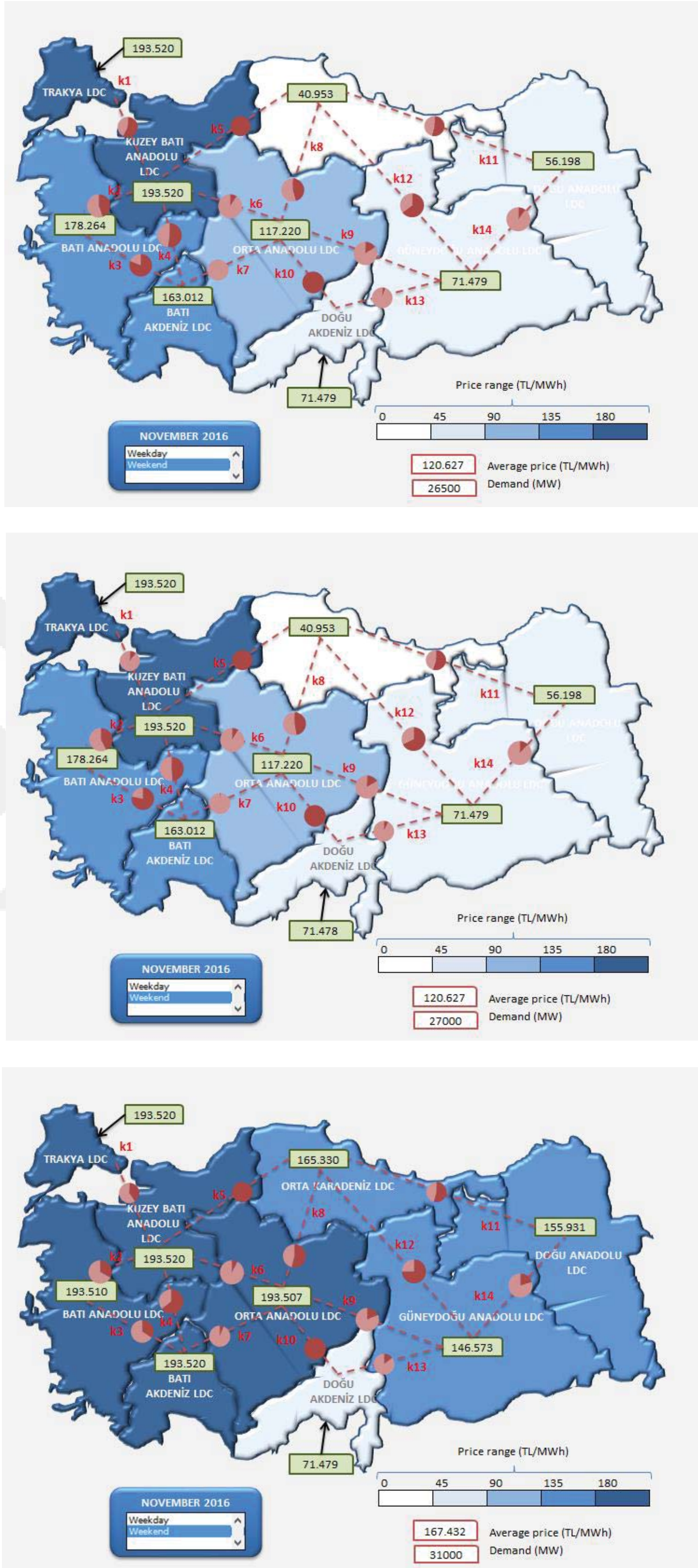


Figure D.8 Simulation Results for Weekend, November 2016 (Demand Scenarios: 26500 MW, 27000 MW and 31000 MW, respectively)

Appendix E

E.1 Gams Model

Overall GAMS model is available at:

https://www.eng.uwaterloo.ca/~ecelebi/CSE_Thesis_2017.html

E.2 R Codes

```
weekday <- read.csv2(file.choose(),header=TRUE)
View(weekday)
boxplot(weekday$cf.naturalgas~weekday$month, data= weekday, main=“Natural Gas
Weekday”,ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.river~weekday$month, data= weekday, main=“River Weekday”,
ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.lignite~weekday$month, data= weekday, main=“Lignite
Weekday”, ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.dammedhydro~weekday$month, data= weekday, main=“Dammed
Hydro Weekday ”, ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.importcoal~weekday$month, data= weekday, main=“Import Coal
Weekday”, ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.wind~weekday$month, data= weekday, main=“Wind Weekday”,
ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.fueloil~weekday$month, data= weekday, main=“Fuel Oil
Weekday”, ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.geo~weekday$month, data= weekday, main=“Geothermal
Weekday”, ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.asphaltit~weekday$month, data= weekday, main=“Asphaltit
Coal Weekday”, ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.black~weekday$month, data= weekday, main=“Black Coal
Weekday ”, ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.biomass~weekday$month, data= weekday, main=“Biomass Weekday
”, ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.naphta~weekday$month, data= weekday, main=“Naphta Weekday”,
ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
boxplot(weekday$cf.lng~ weekday$month, data= weekday, main=“LNG Weekday”,
ylab=“Capacity Factor”,xlab=“Month”, col=“yellow”)
weekend <- read.csv2(file.choose(),header=TRUE)
View(weekend)
```

```
boxplot(weekend$cf.naturalgas~weekend$month, data= weekend, main="Natural Gas
Weekend",ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.river~weekend$month, data= weekend, main="River Weekend",
ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.lignite~weekend$month, data= weekend, main="Lignite
Weekend", ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.dammedhydro~weekend$month, data= weekend, main="Dammed
Hydro Weekend", ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.importcoal~weekend$month, data= weekend, main="Import Coal
Weekend", ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.wind~weekend$month, data= weekend, main="Wind Weekend",
ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.fueloil~weekend$month, data= weekend, main="Fuel Oil
Weekend", ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.geo~weekend$month, data= weekend, main="Geothermal
Weekend", ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.asphaltit~weekend$month, data= weekend, main="Asphaltit
Coal Weekend", ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.black~weekend$month, data= weekend, main="Black Coal
Weekend ", ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.biomass~weekend$month, data= weekend, main="Biomass
Weekend", ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.naphta~weekend$month, data= weekend, main="Naphta Weekend",
ylab="Capacity Factor",xlab="Month", col="yellow")
boxplot(weekend$cf.lng~ weekend$month, data= weekend, main="LNG Weekend",
ylab="Capacity Factor",xlab="Month", col="yellow")
```

E.3 MS EXCEL – VBA Codes

```
Sub Shading
For i=3 to 11
Range("actReg").Value = Range("ShadingMacros!A"&i).Value
ActiveSheet.Shapes(Range("actReg").Value).Select
Selection.ShapeRange.Fill.ForeColor.RGB =
Range(Range("actRegCode").Value).Interior.Color
Next i
Range("A8").Select
End Sub
```