INTRADAY MARKETS AND POTENTIAL BENEFITS FOR TURKEY

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

ENGİN İLSEVEN

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF MASTER OF SCIENCE
IN
ELECTRICAL AND ELECTRONICS ENGINEERING

JANUARY 2014

Approval of the thesis:

INTRADAY MARKETS AND POTENTIAL BENEFITS FOR TURKEY

Submitted by **ENGİN İLSEVEN** in partial fulfillment of the requirements for the degree of **Master of Science in Electrical and Electronics Engineering Department, Middle East Technical University** by,

Prof. Dr. Canan Özgen ______________
Dean, Graduate School of **Natural and Applied Sciences**

Prof. Dr. Gönül Turhan Sayan ______________
Head of Department, **Electrical and Electronics Engineering**

Prof. Dr. Osman Sevaioğlu ______________
Supervisor, **Electrical and Electronics Engineering Dept., METU**

Examining Committee Members:

M.Sc. Abdülkadir Ongun ______________
Security of Supply Dept., MENR

Prof. Dr. Osman Sevaioğlu ______________
Electrical and Electronics Engineering Dept., METU

Prof. Dr. Mirzahan Hızal ______________
Electrical and Electronics Engineering Dept., METU

M.Sc. Budak Dilli ______________
Ret. General Director of Energy Affairs, MENR

Ph.D. Cem Şahin ______________
Energy Inst., TÜBİTAK MAM

Date: **31.01.2014**

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Last name : Engin İlseven

Signature :

ABSTRACT

INTRADAY MARKETS AND POTENTIAL BENEFITS FOR TURKEY

İlseven, Engin
M. Sc., Department of Electrical and Electronics Engineering
Supervisor: Prof. Dr. Osman Sevaioğlu

January 2014, 253 pages

In this thesis work; the characteristics, applications, logic, and potential benefits of intraday markets are investigated comprehensively. The properties of intraday markets are examined, and within this framework the applications of intraday markets in Europe and the mechanism that is going to be applied in Turkey are discussed. Also, considering the increasing importance of intraday markets, the logic behind these markets is examined. In this respect, the uncertainties which cause imbalances in the balancing market and result in financial losses for market participants are explained with the real data belonging to the Turkish system. The potential benefits of intraday trading opportunities are evaluated for Turkey, firstly from theoretical perspective with the utilization of synthetic intraday prices and different scenarios for intraday trading volumes. Then, two different models such as "Electricity Price

Model” and “Short Term Load Forecasting Model” are developed in order to perform more realistic analyses. “Electricity Price Model” is used to measure the potential benefits for wind generators at peak hours. In addition, “Short Term Load Forecasting Model” is utilized to manifest the opportunities for supplier companies, taking into account the trading strategies in the intraday market.

Key Words: Intraday Markets, Applications of Intraday Markets, Uncertainties in Power Systems, Energy Imbalances, Balancing Mechanism, Intraday Electricity Trading, Opportunities in Intraday Markets, Electricity Price Model, Short Term Load Forecasting Model

ÖZ

GÜN İÇİ PİYASALARI VE TÜRKİYE İÇİN MUHTEMEL FAYDALARI

İlseven, Engin
Yüksek Lisans, Elektrik ve Elektronik Mühendisliği Bölümü
Tez Yöneticisi: Prof. Dr. Osman Sevaioğlu

Ocak 2014, 253 sayfa

Bu tez çalışmasında; gün içi piyasalarının nitelikleri, uygulamaları, mantığı ve muhtemel faydaları kapsamlı bir şekilde araştırılmıştır. Gün içi piyasalarının özellikleri incelenmiş, ve bu kapsamda Avrupa'daki gün içi piyasaları uygulamaları ve Türkiye'de uygulanacak olan mekanizma tartışılmıştır. Ayrıca, gün içi piyasalarının artan önemi dikkate alındığında, bu piyasaların arkasında yatan mantık incelenmiştir. Bu bakımdan dengeleme piyasasında dengesizliklere neden olan ve piyasa katılımcıları için finansal kayba yol açan belirsizlikler Türkiye sistemine ait gerçek verilerle açıklanmıştır. Gün içi ticaret imkânlarının muhtemel faydaları, ilk olarak teorik perspektiften sentetik gün içi fiyatları ve gün içi ticaret hacimleri için farklı senaryoların kullanımı ile Türkiye için değerlendirilmiştir. Ardından, daha gerçekçi analizlerin yerine getirilmesi için "Elektrik Fiyat Modeli" ve "Kısa Dönemli

Yük Tahmin Modeli” olmak üzere iki farklı model geliştirilmiştir. “Elektrik Fiyat Modeli” puant saatlerde rüzgâr üreticileri için muhtemel faydaların ölçülmesi için kullanılmıştır. Ek olarak; “Kısa Dönemli Yük Tahmin Modeli”, gün içi piyasalarındaki ticaret stratejileri dikkate alınarak tedarik firmaları için fırsatların ortaya koyulması için kullanılmıştır.

Anahtar Kelimeler: Gün İçi Piyasaları, Gün İçi Piyasaları Uygulamaları, Güç Sistemlerindeki Belirsizlikler, Enerji Dengesizlikleri, Dengeleme Mekanizması, Gün İçi Elektrik Ticareti, Gün İçi Piyasalarında Fırsatlar, Elektrik Fiyat Modeli, Kısa Dönemli Yük Tahmin Modeli

ACKNOWLEDGEMENTS

First of all, I would like to thank my supervisor Prof. Dr. Osman Sevaioğlu for his guidance.

I would like to express my special thanks to my head of department Abdülkadir Ongun for his understanding, support and guidance. Also, I would like to thank my deputy general manager Barış Sanlı for teaching me extraordinary things related to “Electricity Price Model” and energy sector.

I am also thankful to Directorate General for Energy Affairs and all of my friends, specially to Özgür Sarhan and Murat Çiftçi, for helping me to carry out my thesis.

Furthermore, I wish to thank TÜBİTAK for giving me financial support with scholarship.

Finally, I would like to express my deepest gratitude to my family and my beloved wife Gizem; for their patience, permanent support and sincere love.

TABLE OF CONTENTS

LIST OF TABLES

TABLES

LIST OF FIGURES

FIGURES

LIST OF ABBREVIATIONS

ANN	Artificial Neural Network
AON	All-or-None Order
APE	Absolute Percentage Error
APX	Amsterdam Power Exchange
APX ID	APX Intraday
ATC	Available Transmission Capacity
BELPEX	Belgian Power Exchange
BELPEX CIM	BELPEX Continuous Intraday Market
BO	Build-Operate
BOT	Build-Operate-Transfer
CEPS	Czech Republic TSO
CMMF	Capacity Management Module Function
D	Delivery Day
D-1	One Day Before Delivery Day
DSİ	State Hydraulic Works
ELBAS	Electrical Balancing Adjustment System Intraday Market under Nord Pool
ELIA	Belgian TSO
ELSPOT	Electrical Spot Market Day-Ahead Market under Nord Pool
EPEX	European Power Exchange
EPEX ID	EPEX Intraday
EPİAŞ	Enerji Piyasaları İşletme A.Ş.

EPİAŞ ID	EPİAŞ Intraday
EU	European Union
EÜAŞ	Electricity Generation Company
FAK	Fill-and-Kill Order
FOK	Fill-or-Kill Order
GME	Italian Electricity Market
GME MI	GME Intraday
H	Delivery Hour
H-1	One Hour Before Delivery Hour
IOC	Immediate-or-Cancel Order
MAPE	Mean Absolute Percentage Error
MENR	Ministry of Energy and Natural Resources
MIBEL	Iberian Electricity Market
MIBEL ID	MIBEL Intraday
NLDC	National Load Dispatch Center
NTC	Net Transmission Capacity
OTC	Over-the-Counter
PTDF	Power Transfer Distribution Factor
PTF	Day-ahead Price
PTR	Physical Transmission Right
RES	Renewable Energy Systems
RTE	French TSO
SBDT	Zero Balance Correction Sum
SMF	System Marginal Price
SOBF	Shared Order Book Function
TEİAŞ	Electricity Transmission Company
TENNET	Dutch and German TSO
TERNA	Italian TSO
TETAŞ	Electricity Trade and Contracting Company
TOOR	Transfer of Operation Rights

TSO	Transmission System Operator
UIOLI	Use-It-or-Lose-It
UIOSI	Use-It-or-Sell-It
WAID	Weighted Average Intraday Market Price
XBID	Cross-Border Intraday

CHAPTER 1

INTRODUCTION

In the last couple of years, intraday electricity markets have emerged as a new structure under wholesale electricity markets. Depending on this prevalent development which is rapidly proceeding especially in Europe, this subject is found worthy to study comprehensively taking into account that Turkey has been experiencing structural changes in electricity sector and there hardly ever exists a study in the literature regarding this topic for Turkey. Therefore, the main idea of this thesis is designated as representing the characteristics, applications, logic and benefits of intraday markets for Turkey with analytical approach. In order to do so, 8 different chapters are organized within this thesis.

In Chapter 2, the general overview of electricity markets and the notions related to intraday markets are mentioned. The chapter begins with the structural mechanisms in electricity sector. In the second place, the macrostructure of wholesale electricity markets is presented. Then, the design of wholesale electricity markets based on trading timing is examined. Intraday market belongs to the classification of short term power markets, i.e. spot markets, based on its validity period. The main idea to present all this information is to show the big picture in electricity sector and then to indicate where exactly intraday markets place. In the remainder of the chapter the characteristics of spot markets, but mainly based on intraday markets are presented. These characteristics include participation, bidding philosophy, trading method, price range, timeline, trading products, bid and offer format, and cross-border congestion management.

In Chapter 3, the applications of intraday markets are investigated. The study in this chapter mainly based on the examination of characteristics mentioned in Chapter 2 on European countries. Not all European countries are reviewed; but only the ones with improved market structures are examined. The other countries are eliminated due to the simplicity or inexistence of intraday markets. After the selected European countries are researched, the intraday market plan of Turkey is analyzed considering the same characteristics. The intraday market in Turkey is expected to open in the year 2014 and it shows similar characteristics with the countries in the western and northern part of Europe. Both in Chapter 2 and Chapter 3, the main idea is to introduce intraday markets and show what characteristics they have. Taking into account the importance given to the intraday markets in Europe and the extended studies to benefit from these markets, two questions must be asked for Turkey at this stage: Why do all these countries implement intraday electricity markets willingly and diligently? What are the benefits of establishing these mechanisms?

In the rest of the thesis, the main idea is to find the answers of the above questions. In order to do so, firstly, In Chapter 4, the fundamental uncertainties in power systems and the importance of intraday markets for these uncertainties are covered. There are three main sources of uncertainties in power systems which are wind forecast errors, unplanned plant outages and load forecast errors. All of the uncertainties are examined for Turkey and it is endeavored to find the meaning of these uncertainties for Turkish power system and Turkish electricity market. Failure of plants and load forecast errors have long been dealt with by the system operators and these are conventional uncertainties. However, with the introduction of the technological developments, wind energy becomes a feasible investment option in the market; and considering the problematic characteristics of wind energy such as variability and uncertainty, these properties add new sources of uncertainty in power systems. Turkey is an energy importer country but also a developing one. Considering the installed capacity requirement in the electricity sector in the next couple of years and considering the already given wind generation licenses, the uncertainties in the system will surely increase.

Intraday markets cannot be considered without energy imbalances inasmuch as this is the main reason for their formation. Energy imbalances are in the nature of power sector and they are resulted from the uncertainties mentioned in the previous paragraph. Energy imbalances cause remarkable financial losses for market participants with the application of dual price mechanism in the balancing market. This implies that an unscheduled extra generation or deficit consumption from day-ahead program has to be settled at the price whichever is smaller among PTF and SMF. With the same logic, an unscheduled deficit generation or excess consumption from day-ahead program has to be settled at the price whichever price is greater among PTF and SMF. However, with the introduction of intraday markets, these imbalances or some part of these imbalances may be settled in the intraday time horizon with the own prices of market participants. Chapter 5 covers the aforementioned topics along with handling imbalances with intraday markets from theoretical perspective. For intraday trading, the price and volume data are required. For price data, synthetic weighted average intraday prices are formed based on PTF and SMF. For volume data, a number of scenarios are established with a couple of assumptions. However, both of these data regarding intraday analysis are based on static approaches.

Chapter 6 and Chapter 7 aims to make more scientific studies in order to manifest the potential benefits of intraday markets that will be initiated in Turkey. In order to do so, dynamic approaches for intraday price and volume are developed. However, two approaches cannot be used in the same studies but in the different studies. In Chapter 6, the dynamic approach is used to represent intraday trading with the utilization of the "Electricity Price Model". It is developed via advanced utilization of Microsoft Excel. It constitutes the marginal price curve in Turkish spot market. Based on the obtained data from the analyses in Chapter 4, a number of assumptions are derived for this study. The topic for application is chosen as the potential benefits of intraday market for wind generators at peak hours. Only peak hours are selected in order to simplify the study. In this model and the corresponding studies, the risk for wind generators as for the possibility of performing imbalances due to their variability and uncertainty is examined for the period of 2012-2013. Also, further studies are performed for the period of 2018-2019, taking into account the impending wind capacity increase in the Turkish electricity generation fleet.

In Chapter 7, the dynamic approach is used to represent intraday trading with the utilization of "Short Term Load Forecasting Model". The object of this model is to provide dynamic data for the decisions of supplier companies in the intraday time horizon. It is developed via ANN structure in MATLAB. It makes forecasts in the intraday time horizon for 24, 18, 12, 8, 4, and 2 hours prior to the delivery hour. The details of this model are presented in Appendix-B. Based on this data, the possible decisions of supplier companies in the intraday market are examined with synthetic intraday prices belonging to the year 2012. These decisions include performing active trading, moderate trading and no trading in the intraday market.

The results of the analyses for revealing the potential benefits of intraday markets are presented at the end of the relevant chapters and in Chapter 8, the conclusion chapter. It is concluded that although the intraday market is an auxiliary market connecting the day-ahead market to the balancing market, its importance cannot be underestimated. Its importance will flourish further as the uncertainty level in the power system will increase with the integration of more intermittent sources in a couple of years. However, it should be taken into consideration that intraday markets will earn market participants more profit providing that the forecasting tools perform with enough accuracy.

CHAPTER 2

GENERAL OVERVIEW OF ELECTRICITY MARKETS AND THE NOTIONS RELATED TO INTRADAY MARKETS

The aim of this chapter is to present the big picture in electricity markets and then the place of intraday markets among other trading mechanisms. In order to do so, this part is mainly composed of four sections. In the first section, the structure of electricity sector in terms of the level of competition in each segment is summarized under four parts. This is related to the concept of representing the big picture in electricity markets. Then, in the second section, the macrostructure of wholesale electricity markets and the characteristics of this structure are told under three parts. In the third section, the design of wholesale electricity markets based on trading timing is explained under two main parts such as long term markets and short term markets. In these parts, the types of electricity markets under wholesale market design are informed. Although intraday markets belong to classification of short term markets, also known as spot markets; the information related to the other markets is also given in order to provide an environment for comparison between intraday markets and the other ones along with the associated concepts of them. In the fourth section, the characteristics of spot markets but fundamentally specialized on those of intraday markets are submitted with respect to different topics such as participation, bidding philosophy, trading method, price range, timeline, trading products, bid and offer format and cross-border congestion management. In brief, the chapter gives general information about the aforementioned issues and intends to provide the reader with the proper knowledge for the following chapter in which intraday market will be examined in a detailed manner.

2.1 The Structure of Electricity Sector

Electricity sector is composed of five main activities. These can be counted as generation, wholesale trading, transmission, distribution and retail trading. Generation corresponds to electricity generation in electrical power plants utilizing different primary energy sources with different technologies. Wholesale trading refers to the sale of electricity to retail companies or eligible consumers. Wholesalers and retailers are also known under a different name, suppliers. Transmission and distribution are electricity services activities responsible for carrying electrical energy at different voltage levels. Retail trading implies buying electricity via wholesale trading and reselling to the customers who do not desire or are not eligible to make transactions in the wholesale market.

According to the structure and level of competition in each activity, typically four models exist in the general classification of electricity sector represented as the following titles:

- Vertically bundled monopoly model
- Single buyer model
- Wholesale competition model
- Retail competition model

The common point of all models is that transmission, distribution and system operation are not open to competition in that the first two are natural monopolies, i.e. the entrance of a second investor does not reduce overall welfare due to doubling of high infrastructure costs; and the last one is at a strategic point as it is the commander of the system and it can access all the information relevant to the system. Therefore, in the evaluation of the level of competition, transmission and distribution segments are excluded. The selection of any model is based on policy decisions and prevailing conditions in the past.

2.1.1 Vertically Bundled Monopoly Model

The first model is "Vertically Bundled Monopoly Model" in which only one company is generally responsible for the generation, transmission, distribution and sales of electricity. It has also another form in which generation and transmission are vertically bundled and distribution is separated. Since there is only one firm dealing with generation in both models, competition does not exist in this segment. This had been the leading model applied in the world prior to liberalization in the electricity sector [1]. The two possible choices for the vertically bundled monopoly model with the corresponding schematic diagram are shown in Figure 1.

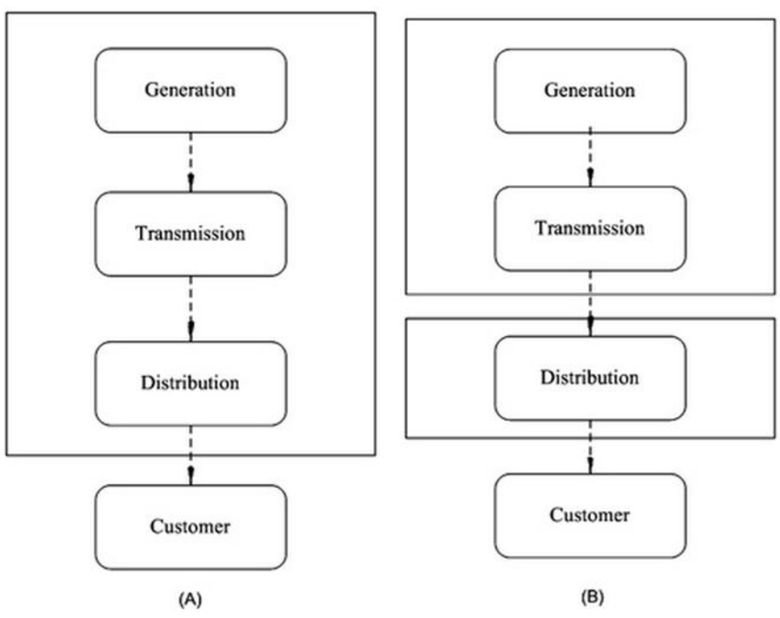


Figure 1: Vertically Integrated Monopoly Model [2]

2.1.2 Single Buyer Model

The second model is “Single Buyer Model”, also known as monopsony. It has mainly two different versions, but in each of them competition exists in the generation segment. The single buyer collects all the electrical energy from generators and sells it to the distribution companies. In other words, it has monopoly over the transmission network and sales to distributors. Any transaction between a generator and a distribution company or a customer is forbidden [1]. Typically, the single buyer model is the transition stage between vertically-bundled monopoly model and the wholesale competition model which will be covered in the next title. The schematic diagram of the single buyer model is presented in Figure 2.

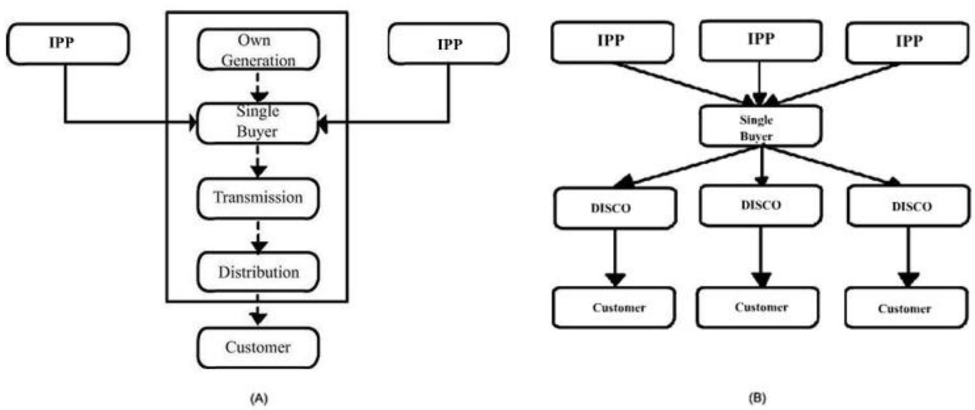


Figure 2: Single Buyer Model [2]

2.1.3 Wholesale Competition Model

The third model is “Wholesale Competition Model” in which competition exists in the generation and wholesale trading segments. The only section that is close to competition is retailing. An organized wholesale market is established to facilitate electricity trading between market participants. Besides, generators have the opportunity to sell directly to the distribution companies and eligible customers by making bilateral transactions [1]. The schematic diagram of this model is represented in Figure 3.

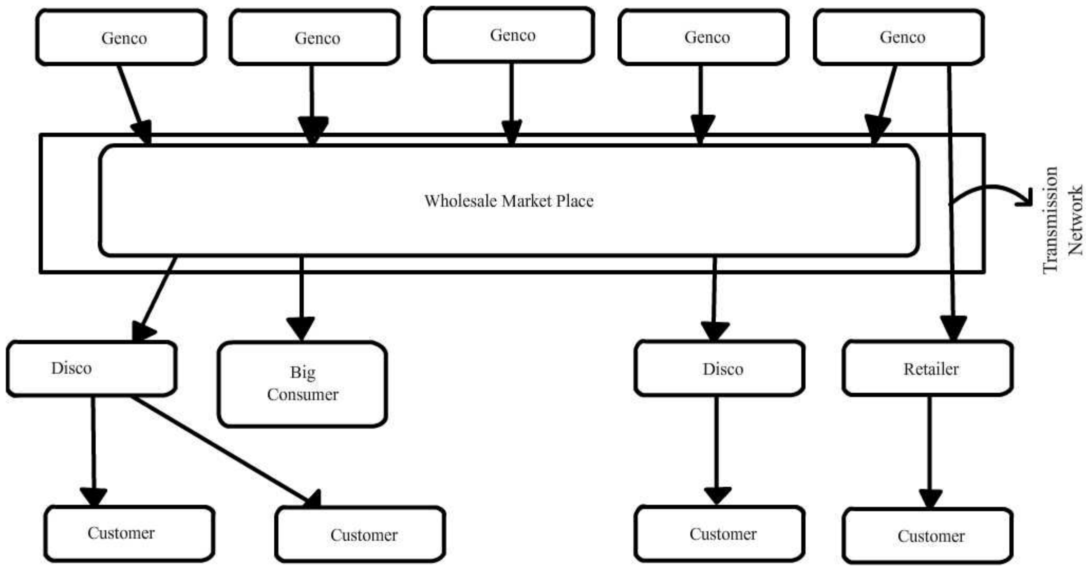


Figure 3: Wholesale Competition Model [2]

2.1.4 Retail Competition Model

The last model is "Retail Competition Model" in which all segments of the electricity sector are open to competition. All customers are able to choose their own supplier freely. Competition among retail companies urges them to sell electricity to customers at the least possible price and hence they force generation companies to lower their generation costs [1]. Although constitutional and structural changes and additional infrastructural support are needed for the application of this model, the energy price is not regulated and it is truly competitive thanks to its determination by supply and demand dynamics [2]. The schematic diagram of retail competition model is introduced in Figure 4.

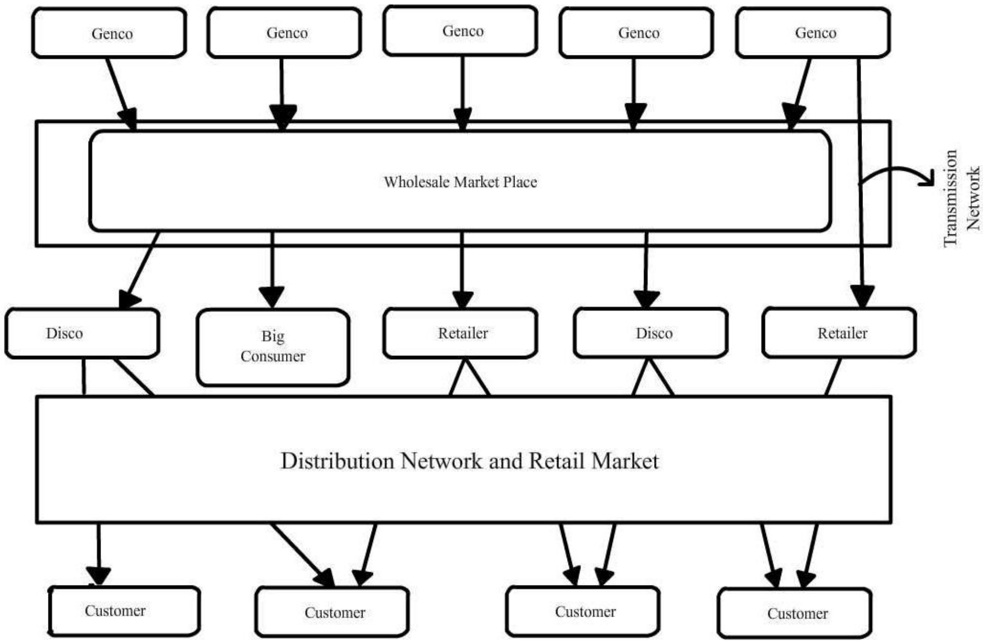


Figure 4: Retail Competition Model [2]

2.2 The Macrostructure of Wholesale Electricity Markets

In the previous part, the electricity sector and the structural mechanisms are discussed as a whole. In this part, the object is to present the mechanisms for wholesale electricity markets which deal with trading activities among generators, wholesale traders, retailers, distributers and big consumers.

Wholesale electricity markets can be classified into three models represented as follows:

- Bilateral agreements model
- Organized markets model
- Mixed market model

The first one is bilateral agreements model in which a market organization does not exist and the transactions are executed bilaterally. The second one is organized markets model in which a market organization exists and the trading is performed accordingly without direct interaction between supply and demand. Inside organized markets model, there are two possibilities such as pool model and power exchange model, depending on the degree of centralization. The last model is a combination of first and second one, which is called as mixed market model. Since the application of power exchange model is hardly ever without bilateral transactions among market participants, it will be narrated together with power exchange model.

2.2.1 Bilateral Agreements Model

The first wholesale market model is “Bilateral Agreements Model” in which trading activities are directly performed by the interaction between buyers and sellers or by means of brokers. The role of system operator is somewhat limited and its responsibility is to handle system security and balancing issues. Thus, it needs the knowledge of all the transactions between market participants [1].

Buyers and sellers can freely make a deal among themselves, specifying the terms according to their wishes. Therefore, this model has the advantage of providing flexibility to both sides. However, there are fundamental deficiencies regarding determination of price, liquidity and transaction costs. Due to the fact that a market in which a reference price is formed does not exist, the transaction price directly depends on the bargaining power of each side. Besides, liquidity cannot be maintained inasmuch as the agreements contain special terms and finding another side to agree with these terms is troublesome. Another issue is about high transaction costs owing to the additional burdens of the process of looking for a new customer or supplier, negotiations and signing a new contract [1]. In summary, this model does not form a transparent environment and thus it is thought and experienced to be an inefficient one.

2.2.2 Organized Markets Model

The second wholesale market model is "Organized Markets Model" which is split into two parts and one of them is "Pool Model". Many countries outside Europe have preferred to adopt this model. The prototype was implemented in the US regions of Pennsylvania, New Jersey and Maryland, known as PJM. The market design of PJM is copied by many countries including Canada, Australia, New Zealand and Russia [3].

In the pool model, there is a centralized organization through which the entire electricity has to be transacted. This centralized organization, the system operator, runs the electricity pool and manages the electric grid. The most distinctive characteristic of pool model is that bidding to the pool is compulsory. This makes the coordination of generation and transmission easier. The use of the power plants and the use of the grid are optimized at the same time by locational marginal pricing, a mechanism for using market-based prices to handle transmission congestion. In this procedure, electricity prices are determined at each injection and withdrawal point in such a way that they reflect the existing transmission system bottlenecks and generation cost structures in the whole system in an economical manner. The simultaneous optimization of the overall system means that the dispatch of power plants is organized centrally and in the framework of the daily and mandatory spot market [3].

Bilateral agreements among market participants are not permitted except purely financial long-term contracts which are mainly used for hedging risks. In other words, the generators have to sell all of their electricity to the pool and the consumers have to buy all of the electricity they need. Depending on the level of wholesale competition in the market, distribution companies and large consumers can be the buyers from the pool. Depending on the level of retail competition in the market; all end users, suppliers and retailers can be the buyers from the pool [1]. However, in general application only the supply side bids actively to the pool; the demand is estimated and then bid into the pool in an aggregated manner.

Apart from power exchanges, pool model is formed based on engineering principles rather than market principles. In the determination of market clearing price at each hour, it takes into account technical parameters and utilizes detailed multipart bids composed of several parts, which include operational cost and physical constraints of generators. If pool price is not able to cover the additional cost of generators regarding start-up cost, shutting down, loading constraint etc., giving side payments to these generators is required [1].

In brief, if the bids are guaranteed to accurately reflect the costs, this model principally secures efficient usage of all resources; but it is thought to be complex and difficult to understand.

2.2.3 Mixed Market Model

It is previously mentioned that “Organized Markets Model” is split into two parts and the first one, pool model, is narrated in the above section. The second part is “Power Exchange Model” and it will be recounted together with “Mixed Market Model” in that there hardly ever exists an exchange without bilateral transactions among market participants.

To start with the definition of an exchange, it is a marketplace which provides an environment for securities, commodities, derivatives and other financial instruments to be traded. Electrical power, gas, CO_2 and etc. can be counted as the objects of the exchange. As for an electrical power exchange, it can be a physical location or an electronic platform. The functions of exchanges are regarded as follows [4], [5]:

- Providing a platform for companies and other groups, i.e. for traders, to conduct businesses such as selling and buying electrical energy,

- Facilitating the trading of standardized products,
- Promoting market information, market participation and market liquidity,
- Maintaining easy, non-discriminatory access and new entry of market participants, low transaction costs and a secure environment,
- Greater transparency in price settling which reflects hourly market conditions,
- Giving accurate signals to market players for reliable reference prices and to provide a benchmark price for bilateral trading,
- Increasing security of supply by promoting available generation capacity and load management at peak times.

A power exchange is characterized by a decentralized organization of the market and decentralized decisions, which implies that the decisions for system operation and market operation are separated. It is the predominant application in European countries including Scandinavia and United Kingdom except Spain and Italy. Also, it is the application that is under operation in Turkey.

This model presents a number of trading options to market participants. Generators, distributors, suppliers and consumer are able to make bilateral transactions among themselves and these are supported by a sequence of closely connected but separate markets for generation, transmission and balancing activities. Trading is mainly based on bilateral agreements for medium and long term. Another option for trading is the spot market for short term agreements. Electricity generation companies dispatch their power plants independently and coordinate with the transmission system operator. Market participants can largely trade hourly electricity contracts for the following day. Participation to the exchanges is not mandatory, i.e. bypassing them is also possible [3].

Seen as the fundamental power market in power exchanges in terms of providing the reference price for other markets as will be mentioned in the following sections, in day-ahead markets, supply and demand curves are matched in every hour and the market clearing price is determined accordingly. However, differently from pool model, technical constraints are not taken into account and bidding structure is much easier. This removes the necessity for side payments in power exchange model [1]. The decentralized organization form under the exchange model ensures that market prices can drive decisions and generating companies can optimize the use of their power plants independently in all stages [3].

There are other differences of power exchange model that distinguishes it from the pool model. The participation to the power exchange is voluntary and the market participants can make bilateral transactions among themselves. Not only the generation companies but also wholesalers, distributers and large consumers are able to actively participate in the power exchange. Therefore, demand side participation to the market is possible unlike pool model [3].

The fact that market platforms can compete with each other is an advantage of exchange model over the pool model. However, there are possible problems due to lack of coordination of decentralized organization and this may lead to inefficiencies. The coordination of the markets for generation, transmission and balancing energy creates a central challenge for exchange models. Errors in the evaluation of issues related to generation, transmission and balancing services may cause inefficient dispatch of generation units, increasing electricity cost, reduced electricity security of supply [3].

In the following parts of this thesis, the mechanisms that will be mentioned are mainly related to the structure of “Power Exchange Model”.

2.3 The Design of Wholesale Electricity Markets Based On Trading Timing

In the last two parts, the structure of electricity sector was explained firstly and then the macrostructure focusing only on wholesale electricity markets was depicted. The object of this section is to represent information on wholesale electricity markets in which various trading opportunities are possible.

Theoretically, before a trade is realized in a market, an agreement between a buyer and a seller on the quality, quantity and the price of the goods is needed. In addition to all these, there are three important topics on which they have to compromise: the date of the delivery of the goods, the mode of the settlement, any conditions that might be attached to this transaction. According to the settlement of aforementioned issues, the type of the contract and thus the type of the market in which they come to an agreement are defined [6].

In liberalized electricity markets, the classification of submarkets can be done in a couple of ways. Here, the fact that trading between market participants typically takes place in a number of different timescales will be utilized to make a classification. In Figure 5, the overview of different timescales and the predominant trading activity in each are presented.

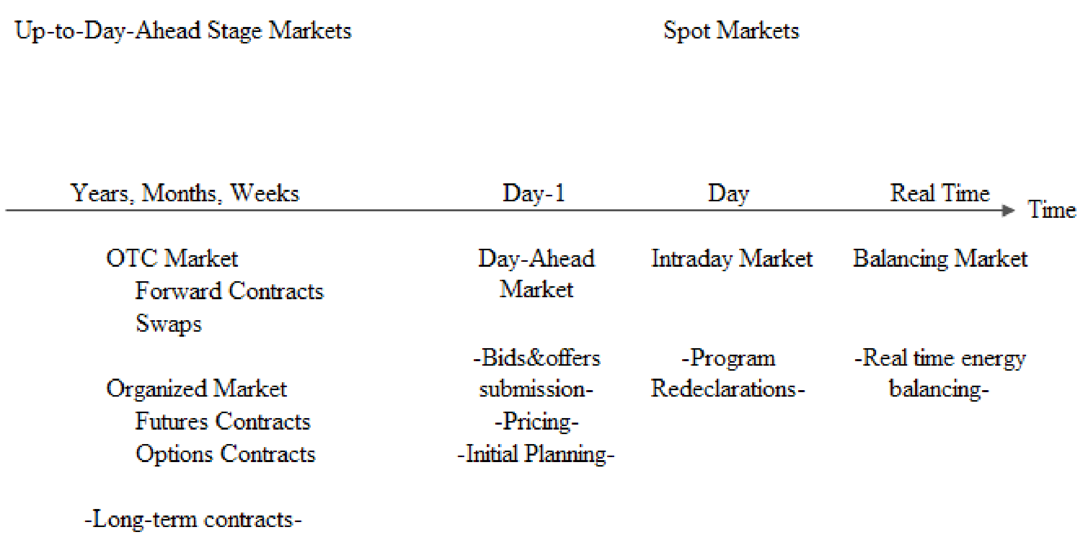


Figure 5: Timescale of Trading Activities [7]

These trading activities can be broadly split into two parts. The first one is up-to day-ahead stage markets, also known as long term markets, and the second one is spot markets, also known as short term markets. Intraday markets belong to the classification of short term markets. Nevertheless, in order to differentiate the characteristics of intraday markets from the other types, all submarkets related to the trading of electrical energy will be mentioned shortly.

2.3.1 Up-to Day-Ahead Stage Markets

In "Up-to Day-Ahead Stage" markets, typically, the highest volume of electrical energy is traded. They are also known under the name of long term markets.

Prices in liberalized electricity markets vary from trading period to trading period as a result of demand-supply interaction and transmission capacity. Market participants are exposed to the risks resulting from the variability of revenues and costs from selling and buying electricity. Long term instruments in the electricity market provide risk hedging from the volatility of prices [5]. With the utilization of these instruments, market participants typically aim to cover their physical positions, i.e. buyers make contracts to purchase electricity to cover their consumption at a reasonably certain price and sellers make contacts to sell electricity at a reasonable certain price. Also, in this period the majority of speculative trading takes place in that market participants take different views on the likely medium term evolution of electricity prices [8]. The contracts that are traded during this period can be classified as follows with respect to the trading place:

- Off-exchange markets (OTC markets)
- On-exchange markets (Organized markets)

2.3.1.1 Off-exchange Markets

“Off-exchange Markets” refers to the non-organized markets in which the transactions are conducted bilaterally. These markets are also known as Over-the-Counter (OTC) markets. For OTC markets, there does not exist a central exchange or a meeting place due to the fact that market players make transactions by using a telephone, a facsimile machine or an electronic network via a network of middlemen like brokers who is responsible for carrying inventories of transactions to facilitate purchase and sale orders of participants. There is a default risk in the OTC market which makes it a lot more risky than power exchanges. Considering EU electricity markets, OTC contracts are solely seen as financial instruments and 75% of electricity was traded through OTC market in 2009 [4].

There are mainly two types of long term contracts within OTC markets. These are forward contracts and swaps. The common point of the contracts executed in OTC markets is that the products are non-standardized, i.e. customized ones. In other words, a bilateral agreement on which market participants strike a deal involves mutually agreed characteristics upon price, quantity, date, and the payment and delivery of the asset that will only be realized in a future date [9]. Besides being non-standardized, these contracts are not anonymous, i.e. the buyer and the seller are explicitly known and therefore they are generally not listed on power exchanges.

The first kind of contract involved in off-exchange or OTC markets is “Forward Contracts” which are with an exercise date of more than one month ahead, typically quarter yearly, half yearly and yearly. In some power exchanges such as Nord Pool, their periods can be up to four years [10]. These contracts are not standardized and this enables their trading via OTC markets or bilaterally. The structure and terms are negotiated and determined by two parties involving in the transaction. One of the parties to a forward contract assumes a long position and agrees to buy electrical energy on a certain specified future date for a certain specified price. The other party assumes a short position and agrees to sell electrical energy on the same date for the same price. The specified price in a forward contract will be referred to as the delivery price [11]. The prices in the forward market correlate to the prices in the spot market prices because they represent today's expectation of the spot market price at the exercise date of the contract [12]. In forward contracts, there exists the clear intention for the physical delivery of the asset [9]. The forward contract has to be executed by both parties on the due date or on the specified maturity date by the delivery of electrical energy from the seller and by payment of money at the delivery price from the buyer, to each other [11].

"Swaps" are agreements to the future exchange of cash flows, i.e. the swap of price risks of two sides. They are generally executed in OTC markets and they are private agreements between two companies to exchange cash flows in the future according to a prearranged formula [11], [13]. One form of them is to compensate price fluctuations between two regions in which electricity prices are different. These are known as "Contracts for Differences" (CfDs). Their applications are common among different provinces in Baltic Region [10]. They are one form of forward contract and include a mechanism to stabilize the power costs to consumers and revenues to generators. These contracts are suggested due to the fact that the spot price fluctuates over a wide range and is difficult to forecast over a long period of time [14].

2.3.1.2 On-exchange Markets

The explanations in this section given until now are about the contracts traded on off-exchange markets up-to day-ahead stage. There is also another option, on-exchange markets, for the execution of transactions prior to day-ahead.

"On-exchange Markets", also known as "power exchanges", have no counter party risk, transparent prices and volumes, offer standardized products, and guarantee the anonymity of both parties at all times. There are mainly two types of contracts within organized markets. These are futures contracts and options contracts. The common point of the contracts executed in organized markets is that the products are standardized and anonymous.

A “Futures Contract” is a trading environment which is an agreement between two parties by which one is committed to buy or sell a given quantity of electrical energy at a given price at a future date. They are equivalent to the high standardized, exchange traded forward contracts, and are usually settled financially; in other words, could not contemplate the physical delivery of the energy negotiated in the contract [12]. The seller of a futures contract does not normally intend to deliver the actual commodity nor does the buyer intend to accept delivery; at some time prior to delivery specified in the contract, each of them have the opportunity to cancel out the obligation by an offsetting purchase or sell [14]. The only point of negotiation is the price. All terms and conditions are pre-specified by the exchange except price. The futures contract is settled every day and is rewritten at a new future price. As a consequence of that the daily change in price is debited or credited on the accounts of both buyer and seller. At the expiration of the contract the futures price always equals the current spot price. If both buyer and seller wait until expiration they will have paid and received the futures price agreed at the beginning [12]. They typically have daily and weekly exercise date. In some power exchanges, their period is limited up to 8 weeks and this time is relatively short when compared to forward contracts due to the preferences of market participants. Daily financial settlement of futures contracts requires market participants to have formidable financial structures in the long term. In forward contracts, there is not daily settlement and participants are not obliged to be under financial responsibility as in futures [10].

“Options Contracts” are generally executed in organized markets. These agreements give the right, not the obligation, to buy, call option, or to sell, put option, the electrical energy for a specified price within a specified date [11]. Options have to be purchased by paying a price known as optimum premium. The premium is market-determined and depends upon the time to expiration and expected future movements in the price of electrical energy. The premium is paid by the buyer of the option to the seller of the option. The holder has the right to exercise the option under the terms of the contract according to his convenience. When the right provided in the option is not exercised by the buyer of the option, the premium paid by him becomes a loss to the buyer and a gain to the seller [11].

2.3.2 Spot Markets

There are different definitions for spot market in the literature. Stoft defines the spot market as only real-time market, excluding the day-ahead and the intraday market [15]. However, the general tendency in the majority of the literature is to group trading activities starting from day-ahead until real time in spot markets. In dictionary, the term “spot market” is identified “cash market” or “physical market” and the most distinctive characteristic of spot markets is that the transactions are settled immediately or at short notice [16]. In electricity markets, this period can reach maximum one day after the transaction. Spot markets can be categorized as follows:

- Day-ahead market
- Intraday market
- Balancing market

In this headline, there will be not be any classification such as off-exchange and on-exchange markets. Typically, day-ahead and intraday markets are managed by the market operators and power exchanges while balancing markets are managed by the transmission system operator. In European experience, although the bulk volume of electrical energy in day-ahead and intraday time horizon is traded via organized institutions, it is possible to make OTC trading in the corresponding time horizon. However, this subject will not be mentioned due to the fairly low trading volume.

2.3.2.1 Day-ahead Market

A "Day-ahead Market" is the market in which purchase bids and sale offers of market participants are submitted and the market is cleared on the day before the actual delivery. In many of the liberalized electricity markets, day-ahead is seen as an important point of time at which market actors cover their positions in that they have contracted their own physical production and consumption and closed out any speculative positions they had created before. Generally, noon is defined as the deadline for submitting bids for power which will be delivered in the following day.

Typically a supplier in the market needs to evaluate how much energy it will need to meet its customer's demand the following day, and how much it is willing to pay for this volume hour by hour. Also, typically a generator needs to decide how much it can deliver and at what price hour by hour. These requirements are reflected through orders entered by buyers and sellers into a trading system [17]. As soon as the deadline for market participants to submit bids has passed, all purchase and sell orders are aggregated into two curves for each delivery hour; an aggregate demand curve and an aggregate supply curve. The information is fed into a specialist computer system which calculates the price based on an advanced algorithm. The system price for each hour is determined by the intersection of the aggregate supply and demand curves which are representing all bids and offers [18].

In the day-ahead, market participants have a significant amount of information on their generation and consumption plans. Generators have a reasonable perception of the power system and the likely schedule of their operation for the next day. Besides, suppliers have decent knowledge about temperature, cloud cover, precipitation and etc. that will affect the consumption of their customers. Although information for the next day exists before the day to estimate generation and consumption, it is not enough to make an exact estimation owing to the fact that there can be high error margin in forecasts. Situations both on the supply side and on the demand side are subject to change [8]. Therefore, there is another market for market participants to continue trading electrical energy for a longer time span, i.e. intraday markets.

2.3.2.2 Intraday Market

An “Intraday Market” is the market which opens after the day-ahead market is closed. It enables market participants to rearrange their positions in short term. This opportunity is provided owing to the fact that there is a long time span between the settling of contracts on the day-ahead market and physical delivery in real time [4].

Intraday markets cannot be evaluated regardless of day-ahead markets. Theoretically, they are the extension of day-ahead markets as well as mechanisms to be complementary and auxiliary for them. Intraday markets have emerged from the shortcoming of impossibility of making energy transactions in the intraday time horizon.

Following the closure of the day-ahead market, the market participants can continue to fine tune their positions in light of the updated information which brings along the possibility of affecting the their levels of generation, consumption and the overall position [8]. There are a number of reasons for market participants to fine tune their positions between the day before and the physical delivery time:

- They want to make sure to exploit all the profitable opportunities for more or less power generation. Just like in the supply side, the same logic is applicable for the demand side. According to conditions in the intraday horizon, it may be profitable for customers to consume more or less electricity. This concept is closely related to the term “arbitrage”.
- They want their contracted electrical energy position to match their expected physical electrical energy position. For the supply side, selling more or less than the expected generation; and for the demand side, consuming more or less than the expected consumption may face the participants to make

imbalances in the real time market, i.e. the balancing market. Considering this issue, they always have the risk of making imbalances that have to be settled in the balancing market at possible high prices for purchases and at possibly low prices for energy sales, both of which are undesirable.

The first topic mentioned above is related to the concept arbitraging. It aims to make more profit generally by undertaking the risk of losing some money. However, the second topic a lot more different from the first one inasmuch as the market participants whose solitary aim is to generate or consume electricity have the risk of being subjected to undesirable prices due to the imbalances they perform in the timespan from the closure of the day-ahead market until real time. In order to represent the possible effects of imbalances in the electricity market, a separate chapter in this thesis is constituted as presented in Chapter 5, which will point out the importance of intraday markets in handling these imbalances.

The main motive influencing the market participants to make intraday trading is the disruption of supply and demand balance. The factors affecting this balance in the intraday time horizon can be counted as follows [8]:

- Changes in wind forecasts
- Power station outages
- Changes in electricity load forecasts
- Changes in imports and exports

The aforementioned motives will be discussed profoundly in Chapter 4 through the analyses including the data reflecting the exact conditions in Turkey in order to take a picture of evaluating the needs for intraday markets which have not been established yet in Turkey as of January 2014.

Intraday markets are common among power exchanges in Europe. In power pools among different provinces in United States, there are not any markets with the name “intraday”. However, similar but not prevalent mechanisms exist under the name of “hour-ahead scheduling”. The main idea in those markets is similar, i.e. enabling late energy trades, changing schedules to shape generation as accurately as possible to meet demand for facilitating real time operation [19].

The applications of intraday markets in Europe, and the intraday market mechanism that is going to be in application for Turkey will be explained thoroughly in Chapter 3. The fundamental knowledge related to the characteristics of intraday markets will be presented in the next main title of this chapter.

2.3.2.3 Balancing Market

A “Balancing Market” is the market through which the system operators provide balancing the generation and consumption of electrical energy in real time. With the closure of the intraday market, if not exist day-ahead market, the trading activity of market participants stops, i.e. there is no trading activity for physical delivery including bilateral agreements. Market participants have already submitted their intended consumption or generation schedule for the next period by locations or in an aggregated manner and send this information to the system operator. The only trading activity that does not cease is the trading of imbalances, which exclusively affects the financial position of market participants, not their commitment to generate or consume electrical energy.

As it is well known, the generation and consumption of electricity have to be matched second by second. From the point of the system operator, ensuring the electricity security of supply in real time requires the trading activities to be finalized before the time of actual delivery. Otherwise, the job of the system operator would have been extremely difficult in terms of maintaining supply and demand balance [8].

Besides balancing supply and demand in real time; voltage control, frequency response, reactive power support etc. are performed in real time. After the spot market is closed, market participants can submit their bids and offers specifying the prices they need to increase their generation or decrease their consumption, or vice versa for a definite volume immediately.

While the day-ahead, if exists intraday market, and balancing markets are asynchronous in power exchanges; the markets for balancing energy are integrated to the pool. The bids and offers for day-ahead market are used to cover the demand for the following day as well as demand for system services concurrently. The pool model combines all those into a single market [3].

2.4 Characteristics of Spot Markets

In this section, the characteristics of spot markets mainly based only on day-ahead and intraday markets will be presented. Day-ahead is seen as an important point of time and the supply-demand balance is established by the closure of the day-ahead market. Intraday market is the extension of the day-ahead market and in some ways presents similar characteristics. The issues to be dealt with in this part will be as follows:

- Participation
- Bidding philosophy
- Trading methods
- Price range
- Timeline
- Trading products, bid and offer format
- Cross-border congestion management methods

2.4.1 Participation

Market participation in the spot markets can be mandatory or non-mandatory, i.e. voluntary. In power markets where pool model prevails, participation to the spot markets is generally mandatory. In power exchange structure, participation to the spot market mostly voluntary except balancing market. Although the general tendency is as mentioned, there can be some exceptions such as Spanish day-ahead market. In Spain, regulation favors participation to the exchange if generators want to take advantage of capacity payments [5]. Nevertheless, the general tendency in Europe in terms of market participation in the day-ahead and intraday markets is voluntary.

2.4.2 Bidding Philosophy

There are two possible bidding options in spot markets. The first one is “portfolio bidding”. It means that a generation company owning different power plants in a market area submits selling offers comprising all of its generation units. The second option is “unit bidding” which requires a generation company to submit the exact generation program of each generation facility separately. The general tendency in application is that compulsory market participation and unit bidding coexist, besides voluntary market participation and portfolio bidding coexist. Nevertheless, there is a Spanish power market example in Europe, in which voluntary market participation and unit bidding coexist for the day-ahead and intraday markets.

2.4.3 Trading Methods

There are two types of mechanisms existing for “Trading Methods” as follows:

- Auction-based trading
- Continuous bilateral trading

2.4.3.1 Auction-Based Trading

In "Auction-Based Trading", bids and offers for each delivery period are submitted by a specified deadline. Then, merit orders are compiled, i.e. bids are ranked in descending price order and offers are ranked in ascending price order. The market outcome is defined by the equilibrium market price. It is the price at which the cumulative quantity specified in the merit order of bids is equal to the cumulative quantity specified in the merit order of offers. Bids having a price lower than equilibrium price and offers having a price higher than equilibrium price are not accepted. [5].

There are a number of criteria for auctions that can be utilized in allocation and pricing mechanisms for electricity such as number of bidding sides, objective function, pricing rule, disclosure of bids and demand type. The first criterion, as for number of bidding sides, can be one-sided, in which only the bids of sellers or buyers are accepted, or two-sided in which bids are used by both the sellers and the buyers at the same time. The second criterion, objective function, can be based on cost minimization or consumer payment minimization. The third criterion concerns pricing rule which can be uniform pricing, pay-as-bid-pricing and Vickrey pricing. In uniform pricing, the price of the last accepted bid is paid for every all the generators of which bids are previously accepted, whereas each accepted generation unit takes their own bidding price in pay-as-bid pricing. In Vickrey pricing, the bidding price of the first rejected generation unit is paid to all generators. Uniform pricing is the most prevalent one compared to the others. The fourth criterion is about the way that the bids are handled such as whether to disclose them to all market participants or not. Depending on the aforementioned aspect, the type of the auction is named as open auction or sealed auction. The last classification is based on electricity demand type such as vertical and horizontal auctions. In the first one, daily demand is split into hourly or 30-minute markets; while in the latter one it is divided into a number of types like base, shoulder and peak demand and each of these is auctioned sequentially [20].

Considering the general tendency in the spot markets for Europe, the auctions for both day-ahead and intraday markets are generally one-sided, based on cost minimization, using uniform pricing, sealed and vertical.

2.4.3.2 Continuous Bilateral Trading

In "Continuous Bilateral Trading", bids and offers for a specified delivery period can be submitted at any time during the trading session. As soon as bids and offers are submitted, they are collected to the order book and each bid and offer is matched, if possible, with offers and bids that have already been submitted for the same delivery period, specifying compatible quantities and prices. The execution price of a transaction is generally the price specified in the bid and offer submitted earlier. If there are no matches, bids and offers are held and shown in the order book to be matched with bids and offers submitted later in the same trading session [5].

When auction-based trading and continuous bilateral trading are compared; the first one maximizes the value of transactions and facilitates efficient dispatching. Also, it gives a single equilibrium price reference and allows integrated congestion management which will be mentioned later. The latter one is analogous to financial markets trading, in which market participants can see and take actions before trading [5]. The majority of the intraday markets in Europe utilizes continuous bilateral trading mechanism.

2.4.4 Price Range

Depending on the trading method applied in the market, the floor price and cap price applications vary significantly. For example, in auction trading, buying bids and selling offers are collected and the price is determined by the intersection of bid and offer curves. Since the resulting market clearing price is valid for all the transactions until market clearing volume, the price range is generally not unlimited. However, in continuous bilateral trading, transactions are executed based on matching rules, i.e. if the price of a buying bid in the order book is greater than or equal to that of a selling offer, trading is completed. Market participants can freely define at which price they want to make a transaction and the resulting price does not have any effect on other transactions. Therefore, the price range in continuous bilateral trading is higher than that of in auction trading.

2.4.5 Timeline

Spot market includes the time period from day-ahead to real time. Typically, day-ahead market is closed by noon the day before the actual delivery. Following the closure of day-ahead market, intraday trading sessions are initialized. The beginnings and closures of intraday markets changes from country to country depending on the trading method and the requirements of market participants. It can reach up to 5 minutes prior to the delivery for continuous bilateral trading. The opening and closure of auction vary in countries in which auction trading prevails. However, the timespan between the closure of the market and the actual delivery is longer in auction trading.

2.4.6 Trading Products, Bid and Offer Format

The “Trading Products” are characterized by the delivery period of electricity. The typical delivery period is 60 minutes. However, half-hourly and 15-minute periods of delivery are possible in some power exchanges. Furthermore, block hours are also available as hourly energy for a predefined set of contiguous hours or a set defined by individual participants [5].

A bid can be defined as one or more quantity-price pairs, each specifying the maximum price at which the participant is willing to buy the corresponding quantity of electricity. An offer is one or more quantity-price pairs, each specifying the minimum price at which the participant is willing to sell the corresponding quantity of electricity. The “Bid and Offer Format” can be split into two parts such as simple and complex.

For simple bids and offers, they are submitted independently for each delivery period. They are step functions for each generation unit that offers a quantity of electricity in MWh at a certain price for a particular hour of the day [21]. The market equilibrium for a delivery period is determined independently from the market equilibrium for other delivery periods [5].

For complex bids and offers, they specify constraints covering more than one delivery period. The market equilibrium for different delivery products is interrelated. There are a number of types of complex bids and offers. In MIBEL, there are minimum revenue requirement, ramp constraint, indivisible bid and programmed stop constraints for generators. Complex bids and offers are generally utilized by thermal units except nuclear ones. They complement simple bids and unique for the whole day. They enable firms to determine a unit-specific minimum revenue requirement composed of a variable and a fixed component. The unit is dispatched only if the gross revenue obtained by the unit during the day covers fixed and the variable part of the complex bid day [21]. Also, in Nord Pool, EPEX, and APX, block bids and offers for a number of consecutive delivery periods for generators and consumers are possible. These can be standardized products or defined by the market participants [5].

When the simple and complex bids and offers are compared; the first one is simpler, more transparently determine the outcome of the market but imperfectly reflects the cost of generators and they have to bear some risk. However, adjustment markets may provide opportunities to modify their commitments. The latter one reflects actual cost of generators and the risk is reduced for them; but the computation is more complex and the determination of the market outcome is less transparent [5].

Besides simple and complex orders, another classification can be among market order and limit order. In market order, no limit price is specified. The order can be matched at the best available price. In limit order, a limit price is specified for buying or selling in the market by setting the maximum price to buy and minimum price to sell according to the wishes of market participants. The order can be matched at the limit price or better one. In the literature, limit orders can be included inside complex orders [22]. The advantage of limit order is that a participant can be sure of the execution at the limit price or better. However, there is no guarantee that the order will be executed [23].

The special execution of orders can be in four ways [22]:

- Fill-and-Kill Orders (FAK or IOC): If the limit order is not immediately executed in full or in part upon registration in the order book, the unexecuted part is immediately and automatically cancelled. This is also known as Immediate-or-Cancel (IOC) order in which unfilled portion of the orders are cancelled from the order book.
- Fill-or-Kill Orders (FOK): If the limit order is not immediately executed in full upon registration in the order book, the entire order is immediately and automatically cancelled. It refers to an immediate complete execution and if by any reason the whole quantity cannot be executed immediately, the order is removed from the order book. FOK orders does not allow partial filling.
- All-or-None Order (AON): If the limit order is not immediately executed in full upon registration in the order book, the entire order remains in the order book. An AON limit order will only be executed in full. The entire quantity must be executed for all specified hours.
- Iceberg: Markets participants specify their bids and offers as including an initial and a hidden quantity. Both the initial and the hidden quantity places in the order book, but the latter one is not visible. The order only becomes visible as soon as it can match with a counter order.

2.4.7 Cross-Border Congestion Management Methods

"Cross-Border Congestion Management Methods" become increasingly important as the regional market integrations spread and this requires efficient management of existing capacity.

Congestion occurs when the available transmission capacity does not suffice to satisfy the demand for transmission services. In other words, it depends on the demand for transmission services and the available transmission capacity. With the rise of the liberalization in the electricity sector, the need for transmission services has significantly increased. It can occur within a control area or between control areas, i.e. cross border.

The approaches for handling congestion are shown in Figure 6. There are two main approaches in order to handle congestion such as ex-post adjustment of market outcome and ex-ante congestion management. The first one, also known as congestion alleviation methods, includes re-dispatching and counter-trading which are performed following the occurrence or the prediction of congestion [24]. The latter one, which is superior in that it handles congestion prior to its occurrence and primarily discussed in the next pages, includes two significant approaches: Explicit allocation of physical transmission rights (PTRs) and implicit allocation of physical transmission rights and energy positions.

The right of cross-border transmission capacity is an important concept. The rights can be physical, which implies allowing for nomination of cross-border contracts in order to shift energy from one market to another; or they can be financial, which provides its owner the financial value of the capacity by utilizing the difference between the prices of energy among different market zones. The usage of physical transmission rights is prevalent across Europe and in this thesis it is emphasized accordingly.

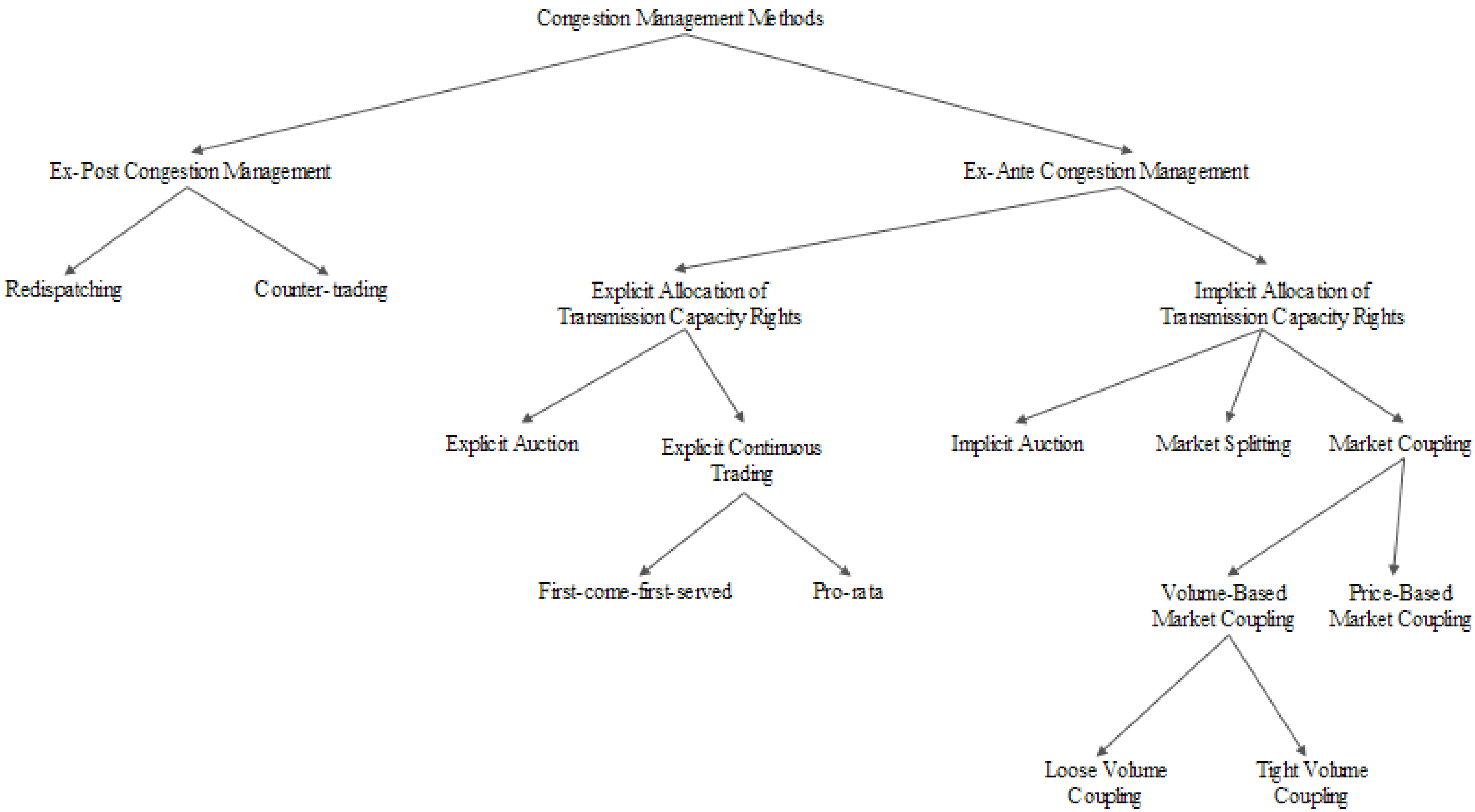


Figure 6: Congestion Management Methods

There several options for the determination of the physical transmission capacity to be allocated. The first one is interconnection-centric approach based on net transfer capacity (NTC) and available transfer capacity (ATC) concept. NTC is the maximum amount of total exchange capacity between two adjacent market areas. NTC takes into account technical uncertainties and security standards of network conditions. It can be determined weekly, monthly, quarterly or seasonally. ATC is a measure of the transfer capacity remaining in the transmission network; i.e. a part of NTC that remains available for further commercial activities. Depending on ATC, the allocation of physical transmission rights is performed [25]. This is the model that is under application in Europe right now. The second option for the determination of the physical transmission capacity to be allocated is flow-based approach grounding on power transfer distribution factors (PTDF). This is a matrix of which calculation is based on the influence of the bids on each of the borders simultaneously. It requires TSOs to jointly calculate the related matrix bilaterally and harmonize border capacities on their borders. The PTDF matrix and set for border capacities can be specified on daily, weekly, monthly or yearly basis. This method better utilizes the transmission capacities but needs very high level of collaboration and a centralized system which will decide the acceptation or rejection of bids [26]. The implementation of this model is under investigation in Europe in order to achieve a single electricity market.

It is previously mentioned that ex-ante congestion management is superior to ex-post adjustment of market outcome and it proposes two models. Now, these models will be introduced shortly based on the allocation methods of NTC.

2.4.7.1 Explicit Allocation of Physical Transmission Capacity Rights

With explicit allocation, the physical rights to use the transmission capacity on a cross-border line are given to market participants separately and independently from market places where energy transactions are executed. In other words, the allocation of the physical rights and energy trading are distinct; the first one does not include energy transactions. There are two options for explicit allocation: Market based and not market based.

Market based allocation depends on explicit auctions conducted by either TSOs or power exchanges. They are considered to be less efficient compared to the implicit ones inasmuch as the line capacity is auctioned independently from electricity prices. They suffer from the time difference between the capacity allocation and the wholesale energy market clearance. This results in as uncertainty for market participants since the rights for the utilization of transmission lines are purchased without knowing the price of electricity. The periods of explicit auctions are generally monthly and yearly [27]. However, the remaining capacity from daily, monthly and yearly auctions can be sold by the additional auctions in the intraday time horizon.

Not market based allocation depends on explicit continuous trading which comprises first-come-first-served and pro-rata allocation methods. First-come-first-serve method gives the first capacity reservation priority over the subsequent reservations. It requires TSOs to have a coordinated schedule for the allocation of NTCs via bilateral agreement on daily, weekly, monthly or yearly basis. In normal conditions, TSOs accept requests until NTC becomes full in both directions. Pro-rata allocation method requires TSOs to continue accepting requests even when demand surpasses available capacity. However, at the end of the trading session, they calculate the level of congestion and reduce each bid proportionally in order to eliminate congestion. The advantage of both first-come-first-serve and pro-rata capacity allocation methods is that they are easy to implement, well-suited for bilateral trading and does not require full harmonization of market areas. Nevertheless, they are not based on customers' willingness to pay for cross-border capacity; i.e. does not guarantee that the user paying most for the capacity will gain access [27].

As for explicit cross-border trading, the procedures for intraday allocation and nomination are separated into two phases. Generally, the one responsible for the allocation is the auction office for intraday trading, and the one responsible for nomination is the domestic TSOs.

In explicit allocation of PTRs, the utilization can be optional or obligatory. Optional rights allow the holder to use the right or not. They are subject to use-it-or-lose-it (UIOLI) or use-it-or-sell-it (UIOSI) conditions. UIOLI means that the previously allocated PTR, which has not been nominated during the scheduling phase, is not available to the owner and not being able to be returned to the original user any more. The aim of UIOLI principle is that the required capacity by the market participants is really needed for a physical delivery and not for a financial optimization [28]. Obligatory rights require the holder of the right to notify his schedule of the cross-border transfer. Otherwise, sanctions will be imposed depending on the legal framework, e.g. the non-nominated capacity can be handled as imbalances which would in return cause financial losses [25], [29]. On the other hand, UIOSI is applied in long term nominations, whereby the previously allocated capacity on yearly or monthly basis is returned to the original user and resold in the daily allocation. This principle is not applied in the intraday allocations and nominations [30], [31].

Explicit allocation of PTRs has three shortcomings. The first one is the non-rational use of transmission capacity. Power flowing is possible in the opposite direction rather than the market price would suggest. For example, between Germany and Denmark (W) border at which the capacity had been allocated explicitly, during 23% of the hours in 2005, the power flowed in the wrong direction, i.e. from high price area to low price area [32]. The second one is the underutilization of these capacities. Even it is accepted to be economically viable; all capacity cannot be used completely. Also, netting of the opposite flows generally is not possible. The third one is the wrong monetary valuation of the capacity. In general, the price paid for PTRs does not reflect the conditions in the energy market [33]. Therefore, implicit allocation of PTRs and energy positions is more preferable and projected mechanism than explicit allocations considering that good congestion management systems are responsible for ensuring power flows towards high price area [32].

2.4.7.2 Implicit Allocation of Physical Transmission Rights and Energy Positions

As for implicit allocation, the difference from explicit allocation is that the allocation of transmission capacity is implicitly included in the trading of electrical energy in a given power market. Implicit allocation of transmission rights can be through implicit auctions, market splitting and market coupling; the last of which is a kind of market splitting among different power exchanges.

In the first one, implicit auction, the capacity is used to support bidding into the market by participants located in a different price zone. The periods of implicit auctions are generally daily. However, the remaining or non-nominated capacity can be sold in the intraday time horizon. The efficiency of implicit auctions is widely accepted, but it requires a high level of coordination and harmonization. Furthermore, it is not easy for countries to make transition to this system owing to the differences that already exist across electricity markets [27].

In the second type of implicit capacity allocation method, market splitting, the capacity is used to support electricity flows between two price areas within the same organized market [5].

In the third type of implicit capacity allocation method, market coupling, the capacity is used to support electricity flow between different organized markets [5]. The only difference between market splitting and market coupling is the number of power exchanges controlling bidding areas through which cross-border lines may be congested. The difference between implicit auctions and market coupling is that market coupling comprises implicit auctioning; but continuous trading is also possible.

There are two options for market coupling. These can be volume-based and price-based. In volume-based market coupling, the coupling algorithm works with subset of market information in order to maintain simplicity. Also, it determines the flows between market zones. The clearing price in each zone is defined by the local algorithm. Inside volume-based market coupling, there are two ways for implementation such as tight and loose-volume based market coupling. Tight-volume based market coupling utilizes full information of bids and offers submitted in each market and fully replicates the individual matching rules. This property makes it similar to price-based market coupling; but the difference is that the prices in each market are determined locally. Energy flows will be identical but the prices can be slightly different compared to price-based coupling. In loose-volume based market coupling, the coupler does not completely replicate the local price determination. It does not own all bids and offers information and use an approximate version of the matching rules of each market [34]. In price-based market coupling, the coupling algorithm works with the full information regarding different markets. It determines the equilibrium prices in all participating market zones and flows among them [5].

Until now, approaches for congestion management have been presented and ex-ante congestion management including explicit allocation of physical transmission rights and implicit allocation of physical transmission rights and energy positions are stressed. Another classification for the utilization of physical transmission rights can be firm or non-firm. Firm rights cannot be cancelled or withdrawn once they are allocated. Conversely, for non-firm rights the usage depends on the holder’s ability to comply with the schedule [25].

2.4.7.3 Intraday Congestion Management Considering European Target Model

In this part, firstly the European target model for electricity markets will be mentioned. Then, the guidelines for handling the congestion management in the intraday time horizon will be examined.

The completion of the internal electricity market aims to constitute a single market for electricity in Europe and is strategic for three main aspects such as efficiency and competitiveness (well-functioning markets), sustainability (RES penetration) and electricity security of supply (adequacy). The benefits of wholesale electricity market integration can be summarized under four items [35]:

- Better use of cross-border capacity
- Greater liquidity in markets
- Greater price responsiveness to promote efficiency
- Easier entry into markets

All of these provide greater choice and better prices for electricity consumers. In order to obtain a well-functioning single electricity market, the harmonization of five important steps is required as shown in Figure 7.

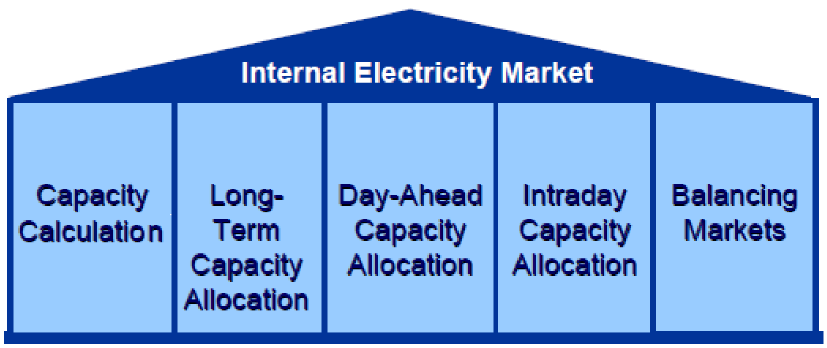


Figure 7: Well-Functioning Internal Electricity Market Prerequisites [35]

Capacity allocation congestion management framework seems to be the most critical area for the integration of intraday markets in Europe.

According to current legal framework in force, intraday congestion management shall be established in a coordinated way. Options for capacity allocation congestion management for intraday markets are as follows [36]:

- Explicit continuous trading
- Explicit auction

- Implicit auction
- Implicit continuous trading

The first one, explicit continuous trading, is viewed as not market based and not efficient. However, it is preferred as a starting point due to low cost and easy implementation. The second one, explicit auction is different from explicit continuous trading in terms of market based but it is not efficient, either. It poses big drawbacks such as high cost and high technical constraints that reduce flexibility [37]. The third one, implicit auction, is again market based, nevertheless it is not flexible and it has some governance challenges. The last one, implicit continuous trading is efficient but it is problematic due to the challenge of how scarce capacity would be valued [36], [38].

Intraday markets are auxiliary markets for day-ahead markets and serve as an adjustment market. The majority of the trading activities are completed by the end of the day-ahead markets. Therefore, it is highly unlikely that highly valued transmission capacity will be available in the intraday markets because it would already have been used until this time horizon. In this respect, continuous trading in intraday markets is a more natural and easy solution than auctioning providing that it presents the opportunity of giving quick reaction needed by market participants for the information that can change and may come at any time. Auction trading requires the necessary products that may be non-standardized, e.g. the ones to make up for variations in wind generation, hence cannot be easily adapted. When continuous and auction trading is compared, from the implementation view, the first one is quicker to execute, giving it an important advantage over auction trading [38]. Therefore, the intraday target model is defined as an evolution of implicit continuous trading that would reflect reliable capacity pricing for network congestion, and allow automatic matching of bids and appropriate block bids [36].

Until the target model is reached, an interim model would be used. This includes both explicit and implicit allocation methods. However, implicit auction proposed to be utilized under the condition that liquidity is sufficient in the intraday time horizon [36].

In order to achieve the aforementioned model for the intraday time horizon, there are some requirements and guidelines on cross border capacity allocation and congestion management represented as follows [36], [39], [40], [41], [38]:

- The target model needs compatibility and coordination among all the members. For cross border intraday electricity trading, different approaches in different regions are employed. In order to form a single electricity market and make cross border intraday trading possible, mechanisms in different regions must be in unison. An important step is to harmonize the gate closure hours for trans-zonal trading.
- In order to implement the target model[1] for intraday trading, implicit continuous allocation, i.e. continuous trading, must be applied and the required provisions must be set. Specific solutions can be developed for the intraday horizon at national or regional level in cases where appropriate and under the condition that they are compatible with the target model.
- As an interim measure, the direct explicit access to capacity can be allowed, but it must be in compliance with the framework guideline published by ACER [42]. Also, standard hourly products must be used; and for future trading, block bids must be allowed.
- Mechanisms must be such that market fragmentation shall be avoided in order to increase the liquidity. This means that there should not be several platforms in which capacity management and trading activities will be handled.

[1] In the European target model for electricity; long term (yearly and monthly) capacity allocation will be performed via explicit auctions, day-ahead capacity allocation will be performed via implicit auction through market coupling and intraday allocations are planned to be handled via implicit continuous trading as mentioned in this part.

- In order to match the bids, a single algorithm, the pan-European Shared Order Book Function must be used. A technology like ELBAS which includes Shared Order Book Function (SOBF) and Capacity Management Module Function (CMMF) in direct relation shall be used as shown in Figure 8. The CMMF is a matrix based PTDF, showing the amount of available transmission capacity from each zone to other zones. This matrix is fed by the information provided by the local TSOs. The SOBF collects information from power exchanges. They put all the orders on their own platforms to the local order book, which associates with SOBF. As long as CMMF signals that there is available capacity from one zone to another, orders can be matched across these zones and then the capacity matrix in the CMMF is updated with real time information to show the remaining available capacity.
- All trans-zonal capacity will be allocated through the pan-European platform mentioned in the previous article. All products will be matched in SOBF without discrimination between products.
- The allocated capacity must be firm, i.e. the use of intraday capacity is mandatory once it is allocated.

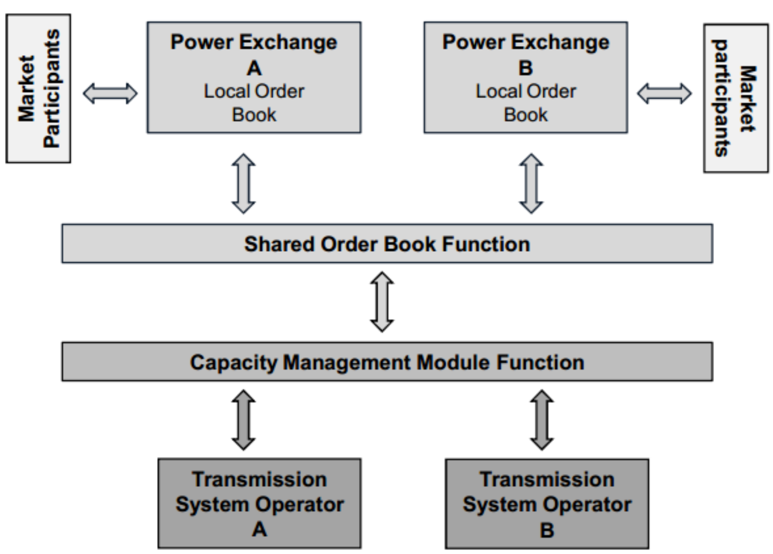


Figure 8: Functional Scheme of European Cross-Border Intraday Market [39]

CHAPTER 3

APPLICATIONS OF INTRADAY MARKETS

Until now, intraday markets have not received the same attention that of day-ahead markets in the literature. The trading volume in intraday markets is relatively low in almost in all power exchanges in Europe. Most of the electricity trading is realized by bilateral transactions and day-ahead markets. However, the developing structure of intraday markets, especially improved in the last couple of years should be studied in detail.

The object of this chapter is to present the applications and characteristics of the intraday markets, specifically in Europe, based on the information given in the previous chapter.

Firstly, the detailed examination of the intraday market structures among European countries in which this structure has been relatively improved will be presented. The countries that will be covered include the western, northern and southwestern part of Europe. The structures in the central-eastern and eastern part of Europe are not addressed in this thesis due to the simplicity, non-functionality or inexistence of intraday markets in those countries.

Secondly, the intraday market plan of Turkey will be told. As of January 2014, Turkey has not yet established an intraday market; however it is about to complete all the requirements for the establishment. The plan of Turkey will be handled with a similar manner compared to the selected European countries.

Thirdly, the results of the information represented in this chapter will be discussed.

3.1 Country Reports of Europe

In this part, applications of intraday markets among different countries in Europe will be presented in terms of participation, bidding philosophy, trading method, price range, timeline, volume, trading products, bid and offer format, and cross-border congestion management method in the intraday time horizon.

The part will start with the countries in northwestern part of Europe, Belgium and the Netherlands. The intraday markets in these countries are coupled, i.e. the cross border capacity is allocated implicitly. Therefore, the characteristics of intraday markets are close to each other. In the third and fourth headline, the intraday markets in Germany and France will be mentioned. The intraday markets of those two countries are also coupled and show similar characteristics. In the fifth headline, the intraday market in Denmark with also focusing the countries under NordPool will be covered. The common point of the previously mentioned intraday markets is continuous trading mechanism enabling immediate electricity trading. There is a different mechanism rather than continuous trading, auction trading, which is in application in Spain and Portugal, and Italy. The characteristics of intraday markets in these countries will be covered in the sixth and seventh headline.

3.1.1 Belgium

The market operator in Belgium is Belgian Power Exchange, BELPEX. It has been the market operator of power spot exchange since January 2006 [43]. It is a part of APX Group operating in United Kingdom [44]. The intraday trading platform in Belgium is BELPEX CIM based on ELBAS system technology used in Nordic countries. It has been in operation since March 2008 [45]. In order to guarantee anonymity and financial security, all the contracts concluded on the BELPEX Spot Market are cleared and settled by APX. APX handles cash management arising from the contracts concluded by the participants on the BELPEX Spot Market and guarantees the execution of the financial obligations.

- Participation:

BELPEX CIM is a non-mandatory market, i.e. the participation is optional as it is for the day-ahead market in Belgium. No physical characteristics of units are considered in order to participate in BELPEX CIM [22].

- Bidding Philosophy:

The bidding philosophy in BELPEX CIM is portfolio bidding [22].

- Trading Method:

The trading method in BELPEX CIM is continuous bilateral trading. Market participants immediately know whether their orders can match with other orders or not and the resulting clearing price. The order book is open and accessible for every intraday market participant [46].

- Price Range:

The floor price for orders is -99,999.90 €/MWh and the cap price is 99,999.90 €/MWh. Considering that in the day-ahead market the minimum and maximum order prices can be -3,000 €/MWh and 3,000 €/MWh respectively, the floor price and cap price in BELPEX CIM are relatively high. In other words, it can be interpreted that there are almost no price limits for electricity trading [47].

- Timeline:

BELPEX CIM opens at 14:00 D-1, which is two hours after the day-ahead market is cleared. Trading in BELPEX CIM continues until 5 minutes prior to delivery. It is open for 24 hours, 7 days and 365 days in a year [47].

➢ Volume:

The trading volume in BELPEX CIM was 0.16 TWh in 2009. It corresponds to 1.6% of the volume traded in the day-ahead market. The liquidity is low compared to the day-ahead market in which 13% of the total Belgian consumption is traded. The volume moved up to 0.28 TWh in 2010, 0.37 TWh in 2011 and 0.51 TWh in 2012 [45].

➢ Trading Products, Bid and Offer Format:

Bidding granularity of contracts in BELPEX CIM is one hour. The volume of minimum contract is 0.1 MWh. The price tick value is 0.10 €/MWh [47].

Block orders and limit orders exist in BELPEX CIM. For block orders, there are standardized contracts such as 24 pieces for 1-hour periods, 6 pieces for 4-hour periods[2], 2 pieces for 6-hour periods[3]. Furthermore, market participants can freely define block contracts. Block orders only subject to AON condition [45]. Hourly limit orders are with execution conditions IOC, FOK and AON [22].

➢ Cross-Border Congestion Management:

Intraday cross-border limits are defined according to ATC method. Intraday NTCs are calculated once in D-1 afternoon, following the closure of day-ahead market and prior to the beginning of intraday trading. The NTC value for a specific hour remains valid for all intraday capacity allocation gates applicable for that hour, and the corresponding value is not recalculated among each gate.

For cross-border intraday trading, Belgium has two direct options with its neighbors, which are the Netherlands and France.

Between Belgium and the Netherlands, BELPEX CIM is coupled with APX ID market and there is implicit continuous intraday trading based on ELBAS technology

---

[2] 4-hour periods cover hours 1-4, 5-8, 9-12, 13-16, 17-20, 21-24.

[3] 6-hour periods cover hours 9-14 and 15-20.

since February 2011. Also, over the Netherlands, there has been implicit intraday market coupling via NorNed[4] cable with Nord Pool Spot ELBAS market since March 2012 [43], [45]. Since the Dutch and Scandinavian intraday market participants markets are coupled and the Belgian and the Dutch intraday markets are coupled, BELPEX market participants can trade in intraday time horizon across a region of seven countries such as the Netherlands, Denmark, Norway, Sweden, Finland, Estonia and Germany [48].

With the Netherlands, the way of allocating capacity has been changed from a pro-rata allocation methodology into an implicit continuous intraday trading platform where market parties are able to obtain energy as well as transfer capacity in one single transaction. The trading platform continuously takes in account the remaining cross border transfer capacity. As far as there is available capacity, orders from foreign intraday markets become visible in each country [45]. The gate closure is one hour before real time for exchanges with the Netherlands [49].

Between Belgium and France, there has been an explicit continuous intraday trading based on pro-rata method since 2007 [33]. The joint office for the allocation is the French TSO, RTE [50]. The minimum capacity allocation volume is 1 MW and the products are on hourly basis. The capacity is provided free of charge [51]. The transferring of capacity usage rights and obligations are not possible. There are 12 gates for intraday capacity allocation, all of which are composed of two-hour periods and the gate closure is two hours before real time [49]. The participant loses the benefit of intraday capacities for non-nominated capacity; i.e. UIOLI principle. The nominations for international energy exchange, submission to TSOs in both countries Elia in Belgium and RTE in France one hour after the deadline for requests is required [51].

[4] NorNed cable is a 580 km, 450 kV, 700 MW HVDC cable connecting the Netherlands and Norway.

3.1.2 The Netherlands

The market operator in the Netherlands has been APX (Amsterdam Power Exchange) since 1999. The trading platform in the Netherlands is APX ID market. It has been in operation since September 2006. It has been coupled with BELPEX CIM since February 2011 and with ELBAS market since March 2013 [52].

- Participation:

The participation to APX ID market is non-mandatory. Participants of this market have the same prerequisites as in the day-ahead market. They use the intraday market to optimize their positions and to reduce risks associated with unexpected imbalance prices charged by the TSO, Tennet. Also, the intraday market is seen as an important tool for portfolio management [52]. No physical characteristics are considered in order to participate in APX ID market.

- Bidding Philosophy:

The bidding philosophy in APX ID market is portfolio based [22].

- Trading Method:

There is continuous bilateral trading in APX ID market. This market uses an anonymous open order book that is open and accessible for every intraday market participant. Concerning trades and market data, they are broadcasted in real time [22].

- Price Range:

Intraday prices differ from day-ahead prices in the floor and cap price definitions. The intraday cap price has an upper value set at 99,999.90 €/MWh, while the intraday floor price has a lower value set at -99,999.90 €/MWh. Considering that in the day-ahead market the minimum and maximum order prices can be -3,000 €/MWh and 3,000 €/MWh respectively, the floor price and cap price in APX ID market are relatively high. Also, there is no mandatory relation between ID and DA prices. [47].

- Timeline:

Formerly, the first prototype of APX ID market was not open in every day of the year and it was not a 7/24 market. Trading for the same day had started at 07:30 D until 18:00 D in weekdays and until 14:00 in weekends while trading for the next day had started at 12:00 D-1 until 18:00 D-1 [22].

As the requirements of the market participants change, the trading period in APX ID market was reconsidered. Today, the same timeline, the one belonging to BELPEX CIM, applies to APX ID market. It opens at 14:00 D-1, which is two hours after the day-ahead market is cleared. Trading continues until 5 minutes prior to delivery. It is open for 24 hours, 7 days and 365 days in a year [47].

- Volume:

The trading volume of APX ID market was 0.3 TWh in 2010, corresponding to 2.5% of the volume in the day-ahead market [22], [53].

- Trading Products, Bid and Offer Format:

The granularity of the contracts is one hour. As a distinctive characteristic, the intraday market offers to the opportunity to continuously trade power products, 96 pieces of 15 minutes intervals, 24 pieces of one-hour blocks and 12 hours of two-hour blocks [22]. The volume of minimum contract is 0.1 MWh. The price tick value is 0.10 €/MWh [47].

- Congestion Management:

In the matter of congestion management, intraday cross-border limits are defined according to ATC method. The calculation methodology is the same as in Belgium. Intraday NTCs are calculated once in D-1 afternoon, following the closure of day-ahead market and prior to the beginning of intraday trading. The NTC value for a specific hour remains valid for all intraday capacity allocation gates applicable for that hour, and the corresponding value is not recalculated among each gate.

For cross-border intraday trading, the Netherlands has three direct options with Norway, Germany and Belgium.

Between the Netherlands and Norway, there is the NorNed cable connecting each country. Through implicit continuous trading via ELBAS system, the market participants in Netherlands are able to make intraday transactions with Norway, Denmark, Sweden, Finland, Estonia, Belgium and Germany. ATC values are available starting from 21:00 D-1 in the ELBAS platform [54]. Trading is available until 90 minutes before the start of the delivery period [55]. Since implicit capacity allocation is applied, market parties do not have to nominate their cross border trades to the Dutch TSO.

Between the Netherlands and Germany, there has been explicit continuous cross-border trading since 2008. The ATCs for allocation is netted after the day-ahead allocation, hourly based, and the capacity is for free. Nominations must be performed one hour before the hour of usage. If the allocated capacity is not nominated, it will be handled as imbalance in Dutch system and will be imposed in the energy schedules in the German system [56].

3.1.3 Germany

The market operator in Germany is European Power Exchange, EPEX. Former German market operator, European Energy Exchange, EEX, was established in 2000. In 2008, German EEX merged with French market operator, Powernext, and became known as EPEX.

The trading platform for intraday trading in Germany is EPEX German ID market. It has been in operation since 2006. In this market, no physical characteristics of units are considered. In other words, the trading is simply energy.

- Participation:

The participation to EPEX German ID market is non-mandatory except for TSOs which are responsible for balancing wind turbines under feed-in-tariff mechanism in their regions [22]. Besides, no physical characteristics of units are considered in order to participate in this market.

- Bidding Philosophy:

The bidding philosophy in EPEX German ID market is portfolio bidding [22].

- Trading Method:

The trading method in EPEX German ID market is continuous bilateral trading. Compared to the auction mechanism in the day-ahead market, orders are executed as soon as they are matched. The order book is open and accessible for every intraday market participant.

- Price Range:

The floor price for orders is -9,999 €/MWh and the cap price for orders is 9,999 €/MWh. Although the minimum and maximum prices in the day-ahead market are at -3,000 €/MWh and 3,000 €/MWh, and there are thresholds at -150 €/MWh and 500 €/MWh in order to launch the second auction; no procedures exist to reconsider the clearing prices in case of rocketing up or down in the intraday market [57].

- Timeline:

EPEX German ID market opens at 15:00 D-1, which is 3 hours after the day-ahead market is cleared. Trading in EPEX German ID market continues until 45 minutes prior to delivery. It is open for 7 days and 24 hours [22].

- Volume:

The trading volume in EPEX German ID market was 5.6 TWh in 2009. It corresponds to 4.2% of the volume traded in the day-ahead market. The volume moved up to 16 TWh in 2011 by increasing 56% compared to 2010 [58]. After 2009, the volume in the intraday market significantly rose owing to the amended RES regime, which brought obligation to TSOs to decrease imbalances derived from the uncertainties of renewable energy generation.

- Trading Products, Bid and Offer Format:

Granularity of contracts in EPEX German ID market is 15 minutes and 1 hour. 15-minute products are unique for EPEX German ID market due to the requirements of market participants for more flexible contracts in order to accommodate high renewable energy production which can significantly vary within an hour. The volume of 15-minute products is 10% of total intraday trading volume, while the remaining belongs to one-hour products [59]. The volume of minimum contract is 0.1 MWh. The price tick value is 0.01 €/MWh [57].

Limit orders and block orders exist in EPEX German ID market. For block orders, there are two types of pre-defined standardized contracts, under the name of "base load" from hours 1 to 24 everyday and "peak load" from hours 9 to 20 on weekdays. Furthermore, market participants can freely define block contracts [57].

The limit orders can be executed in three different manners such as IOC, FOK and AON. Simple orders and pre-defined block orders can be executed by IOC and FOK conditions. They are partially executable by default. User-defined block orders are not partially executable; hence AON execution restriction is added by default. If IOC execution condition is added, user-defined block orders become market sweep orders and they will be executed immediately and as far as possible against respective simple orders [60].

- Congestion Management:

Intraday ATCs are defined as the amounts of day-ahead ATCs, which were not sold in the day-ahead auction and those that were sold but not nominated. Then, the intraday ATCs for the borders are announced to the intraday market platform.

Germany has eight options for cross-border trading; which are Denmark (W), Denmark (E), Czech Republic, Poland, Austria, Switzerland and France and the Netherlands.

Between Germany and Denmark (W)[5], there is explicit continuous intraday trading since June 2008. It starts from 18:00 D-1 until one hour prior to the delivery. Trading is two-sided as it is at other borders. Allocated capacities are netted before intraday allocation and made available for the opposite direction. Capacities allocation session ends one hour before delivery and allocated capacities must be nominated 45 minutes before the start of the trading hour. Non-nominated capacities are traded as imbalances in both area and settled according to the normal settlement rules in the two areas [61].

Between Germany and Denmark (E)[6], there is implicit continuous intraday trading since 2006. It is based on ELBAS technology via Kontek[7]. Trading is possible until 30 minutes prior to the delivery [62].

Between Germany and Czech Republic, and between Germany and Poland; there is explicit continuous intraday trading since December 2010. It is held in multiple sessions for hourly products. The day is divided into six sessions comprised of four-hour intervals. The preliminary offered capacity is published at 16:00 D-1 by Czech Republic TSO, CEPS. The offered capacity can be updated by H-2:30, where H is the first hour of intraday time interval. The nominations must be entered until H-1:30 [63]. The procedures for intraday allocation and nomination are separated into two phases. The one responsible for the allocation is the auction office for intraday trading, Czech Republic TSO CEPS; and for nomination are the domestic TSOs. The capacities are allocated free of charge.

[5] In Denmark, there are two geographical price zones. Denmark (W) represents the zone in the western part of Denmark.

[6] Denmark (E) represents the price zone in the eastern part of Denmark.

[7] Kontek is a 400 kV and 600 MW HVDC cable connecting Germany and Denmark (E).

Between Germany and Austria, cross-border intraday trading has been performed since 2012. On the grounds that there is no congestion between Germany and Austria, no capacity allocation procedure is applied [64].

Between Germany and Switzerland, there is implicit continuous intraday trading since June 2013 with the opening of the Swiss intraday market [65]. The hourly available intraday capacities are announced 21:00 D-1 on the capacity allocation platform. Allocations are terminated one hour prior to the hour of delivery [66].

Between Germany and France, there is implicit continuous intraday trading since December 2010 [53]. Once a certain amount of capacity is allocated in one direction, the same amount of capacity is added to the overall capacity to be allocated in the other direction accordingly. The hourly available intraday capacities are announced 21:00 D-1 on the capacity allocation platform and allocations are terminated one hour prior to the hour of delivery [66]. Also, there is a second option via explicit continuous trading for bilateral transactions. It is thought that implicit and explicit trading opportunities complement each other and response the required flexibility for different market needs [53].

3.1.4 France

The market operator in France has been EPEX since 2008. The duty was performed by Powernext from 2001 to 2008. The trading platform in France is EPEX French ID market. It has been in operation since 2007. Since both Germany and France spot markets are under the control of EPEX, the characteristics of intraday markets is quite similar at regional level.

- Participation:

Participation to EPEX French ID market is non-mandatory [22]. No physical characteristics of units are considered in order to participate in EPEX French ID market.

- Bidding Philosophy:

The bidding philosophy in EPEX French ID market is portfolio based [22].

- Trading Method:

There is continuous bilateral trading [22]. Compared to the auction mechanism in the day-ahead market, orders are executed as soon as they are matched. The order book is open and accessible for every intraday market participant.

- Price Range:

In the former application, the minimum price was 0.01 €/MWh and the maximum price was 3,000 €/MWh similar to the day-ahead market. However, following the intraday market coupling with Germany in 2010, the floor price for contracts price becomes -9,999 €/MWh and the cap price for contracts becomes 9,999 €/MWh. [67]. It should be noted that there is no mandatory relation between both day-ahead and intraday prices.

- Timeline:

EPEX French ID market starts at 15:00 D-1, which three hours after the day-ahead market is cleared and it lasts until 45 minutes prior to the delivery [67]. Trading can be executed for all hours of the same and the following day.

- Volume:

The trading volume in EPEX French ID market is 1.7 TWh in 2011 by increasing 70% compared to 2010 and it reached 2.2 TWh in 2012. It corresponds to 2% of the day-ahead market volume [59].

- Trading Products, Bid and Offer Format:

The granularity of contracts is one hour. The volume of minimum contract is 0.1 MWh. The price tick value is 0.10 €/MWh [67].

Block orders consist of six pieces of 4-hour blocks, base load from hours 1 to 24, peak load from 9 to 20 and user defined block orders linking several consecutive hours of their choice with a minimum of two consecutive hours of the day [22]. Limit orders exist with execution restrictions IOC, FOK, AON and Iceberg [67].

- Congestion Management:

Intraday ATCs are calculated as the remaining commercial capacity based on day-ahead NTCs after subtraction of net nominations. Simultaneous netting in the intraday time horizon is only applied on the borders at which the cross-border capacity is auctioned implicitly.

France has six options for cross-border intraday trading; which are Switzerland, Spain, UK, Italy, Belgium and Germany.

Between France and Switzerland, there has been implicit continuous trading based on first-come-first-served principle since June 2013. The price of the allocated capacity on intraday basis is set at zero 0 Euro under the present rules. The minimum bid and offers are 0.01 MW on hourly basis [68]. The hourly available intraday capacities are announced 21:00 D-1 on the capacity allocation platform. Allocations are terminated one hour prior to the hour of delivery [66].

Between France and UK, although the day-ahead markets will be coupled and the capacity allocation will be performed implicit auctions, the allocation methodology in the intraday time horizon will to continue be based on explicit auctions [69]. The cross-border capacity allocated in this method is subject to UIOLI principle. There are two gates for auctions; the first one closes at 19:30 D-1 and the second one at

08:50 D. The nominations must be completed at least three hours before delivery [22].

Between France and Italy, and between France and Spain; there has been explicit auction cross-border trading mechanism. The details will be given under the titles of Spain and Italy.

3.1.5 Denmark and Nordic Countries

The trading platform for intraday trading in Denmark is ELBAS, under Nord Pool Spot which is owned by the Nordic and Baltic TSOs. ELBAS market was first launched in Finland and Sweden in 1999, making it the world's first cross border intraday market [55]. In 2000, Denmark joined Nordic power market. ELBAS market started in operation in Denmark (W) in 2004 and in Denmark (E) in 2007 [53]. As of January 2014, NordPool is the joint operator of Denmark, Sweden, Norway, Finland and Estonia; and operates ELBAS market in those countries.

- Participation:

ELBAS is a non-mandatory market. Area declaration and balance agreement is required as in the day-ahead market, ELSPOT, with the difference that participants are only obliged to report the trades done on ELBAS to their local TSOs. Administration and settlement of cross-border trades are handled by Nord Pool Spot [22]. Besides, no physical characteristics of units are considered in order to participate in ELBAS market.

- Bidding Philosophy:

The bidding philosophy in ELBAS is portfolio based [22].

- Trading Method:

The trading method is continuous bilateral trading. Due to incessant nature of continuous markets, the results are matched according to time and price priority, and published immediately. The order book is open and accessible for every intraday market participant.

- Price Range:

All prices are Euro and negative prices are allowed in ELBAS since 2011 [70]. The minimum volume change is 0.1 MWh [55]. The lower and upper technical order price limits are defined as -200 €/MWh and 2,000 €/MWh in ELSPOT; however, the limits for the ELBAS market are not defined [71].

ELBAS does not have a procedure to reconsider the clearing in case prices are rocketing up and down. In addition, there is no mandatory relation between day-ahead and intraday bid prices [22].

- Timeline:

ELBAS starts at 14:00 D-1, 2 hours after ELSPOT is closed and finishes one hour prior to delivery in Denmark, Sweden, Finland, Estonia; two hours prior to delivery in Norway. It is possible to make intraday trading for 7 days and 24 hours [72].

- Volume:

Only major market participants make minor adjustments in ELBAS market. In the entire Nordic region, while the trading volume in ELBAS represents 0.5% what is traded in ELSPOT in 2009, the ratio increased to 1% as of 2012; showing that the liquidity is relatively low. The trading volume in ELBAS is 2.25 TWh in 2009, 2.1 TWh in 2010, 2.6 TWh in 2011 and 3.2 TWh in 2012 [55].

- Trading Products, Bid and Offer Format:

The trading products in ELBAS are hourly basis. There are two types of contracts such as hourly contracts and block contracts. In the first one, the market participants are free to choose any hour along with specifying the price and the volume of the trade they want. In the latter one, contracts can be defined for one hour or several consecutive hours, which can only be accepted according to AON condition [55].

- Congestion Management:

There are five price areas in Norway, four in Sweden, two in Denmark, one in Finland and one in Estonia [55]. Market members offer how much they want to sell and buy electrical energy and at what price. Prices are set based on a first-come-first-served principle where lowest sell price and highest buy price comes first, regardless of when an order is placed. Trading continues among buyers and sellers as far as transmission capacities between neighboring areas permit.

Intraday ATCs are used as cross border limits for every hour of operation with power flowing towards the higher price, while also respecting given capacity constraints. After ELSPOT gate closure time, TSOs allocate capacities on their grid to ELBAS, where usage is managed [22]. This is due to the fact that ELBAS uses a multi-area platform. Market participants are only obliged to report their trades to their local TSOs.

Among all of the Nordic Countries, there is market splitting and thus the method for cross-border trading is implicit continuous. Capacities are updated continuously according to the direction of a cross-border trade [55].

3.1.6 Spain and Portugal

The market operator in Spain and Portugal has been MIBEL (Iberian Power Exchange) since 2006, the year which the former market operator in Spain OMEL and in Portugal OMIP merged. The trading platform for intraday trading in Spain and Portugal is MIBEL ID market. It started its operation in Spain in 1998 under a different name and in Portugal with the introduction of the spot market in 2007 [73]. The particular design of Spanish intraday market is special and cannot be found in any other European power market.

- Participation:

As in the day-ahead market, participation to MIBEL ID market is voluntary. It should be noted that at the beginning stage of OMEL in Spain, participation to the both day-ahead and intraday markets were mandatory but later switched to voluntary mechanism [73]. In order to be able to participate to this market, agents must be participants in the corresponding day-ahead session or executed a bilateral contract with physical delivery or become available[8] for the corresponding session [22]. Besides, as distinct from the previous examples, the physical characteristics of units are taken into account.

- Bidding Philosophy:

The bidding philosophy is physical unit bidding. Intraday market in Spain and Portugal market is an adjustment market and if a given adjustment causes constraints in the system, that adjustment is cancelled. In fact, due to the application of up and down limitations obtained from day-ahead constraint solving process for each session of the intraday market; it is very odd that intraday constraints arise in the system [22].

- Trading method:

There is uniform-price auction trading, including implicit auctions for cross-border trading platform with Portugal. It is comprised of six consecutive intraday sessions.

[8] If they previously report unavailability and then become available, they can participate for the corresponding section in MIBEL ID.

➢ Price Range:

The pricing range of the products traded within the MIBEL ID is the same as the one observed in the day-ahead market, from 0 €/MWh up to 180.03 €/MWh [74]. As observed, negative prices are not allowed within both markets. As in the in the day-ahead market, there is no procedure to reconsider clearing within the MIBEL ID market sessions. Within this market, no mandatory relation exists between the day-ahead and the intraday bidding price [22].

➢ Timeline:

There are six sessions for intraday trading. Market participants can submit their bids and offers for a 45-minute period in each of the intraday market sessions except the first one, which lasts 105 minutes. Following each auction, the results are published in 45 minutes. From one session to another, the schedule horizon covers fewer hours; i.e. 28 hours for session 1, 24 hours for session 2, 20 hours for session 3, 17 hours for session 4, 13 hours for session 5, 9 hours for session 6. This means that following the closure of the day-ahead market, MIBEL ID market enables market participants to trade energy again a number of times, ranging from 2 to 7 times. The hourly distribution of the sessions in MIBEL ID is presented in Table 1 [75].

Table 1: Hourly Distribution of Sessions in MIBEL ID

Sessions	1	2	3	4	5	6
Opening	16:00 D-1	21:00 D-1	01:00 D	04:00 D	08:00 D	12:00 D
Closing	17:45 D-1	21:45 D-1	01:45 D	04:45 D	08:45 D	12:45 D
Results	18:30 D-1	22:30 D-1	02:30 D	05:30 D	09:30 D	13:30 D
Schedule Horizon	21-24 D-1 1-24 D	1-24 D	5-24 D	8-24 D	12-24 D	16-24 D

- Volume:

In relation to traded volumes of energy, for the last years, it has been observed that the MIBEL ID market sessions present low liquidity due to the fact that market agents only need intraday market sessions for small adjustments or to correct deviations. However, there has been slightly increasing interest for MIBEL ID market. The total traded energy in MIBEL ID market is 11.4 TWh in 2000, 20.5 TWh in 2005 and 35.3 TWh in 2010. These numbers correspond to 7%, 12% and 18% of the day-ahead market volume, respectively [75]. Total traded energy in the intraday market reached 52 TWh in 2012 [76].

- Trading Products, Bid and Offer Format:

The granularity of contracts is one hour. The volume of minimum contract is 0.1 MWh. The price tick value is 0.01 €/MWh.

There are only hourly products in MIBEL ID market, containing simple and complex bids, and conditions apply as in the day-ahead market. Complex bids have conditions including ramp rate constraints, minimum income constraints, indivisible bid, constraint and programmed stop [22].

- Congestion Management:

Spain has two options for cross-border intraday trading, with Portugal and France. As in the day-ahead market, the cross-border limits used in the MIBEL ID market are the ATCs.

Between Spain and Portugal, the cross-border capacity available at intraday market is implicitly allocated between Spain and Portugal through market splitting. In case of congestion between Spain and Portugal, market splitting is enforced by separating these countries into two price areas [22]. If congestion does not exist, both countries are treated as if one price area.

Between Spain and France, the ATCs are explicitly allocated at the interconnection in two intraday capacity auctions. Although the intraday market mechanism in France contains continuous trading, auction based cross border trading is utilized at this border in order to provide the harmonization with the intraday sessions of the Spanish intraday market. The usage principle applied to the capacity products sold on the intraday auctions is UIOLI. The first auction is completed at 16:30 D-1 covering the whole 24-hour period of the next day, the second auction is concluded at 11:30 D covering the last 10 hours from 14:00 to 24:00 D [77]. Nominations should be performed until 35 minutes prior to the beginning of the sessions in MIBEL ID [22].

3.1.7 Italy

The market operator in Italy is GME (Gestore dei Mercati Energetici), also known as IPEX (Italian Power Exchange). It was established in 2003. The trading platform for intraday trading in Italy is GME MI, started in operation in November 2009. GME acts as a central party in all transactions.

- Participation:

The participation to GME MI is non-mandatory [78]. However, the physical characteristics of units are taken into account.

- Bidding Philosophy:

The bidding philosophy in GME MI market is physical unit bidding [78].

- Trading Method:

GME MI is an auction based intraday market. Participants submit bids and offers in which they specify the quantity and the minimum and maximum price at which they are willing to sell and purchase. Bids and offers are accepted under the economic merit-order criterion and taking into account transmission capacity limits between the predefined zones. All the supply offers and the demand bids belonging to foreign virtual zones that are accepted and valued at the marginal clearing price of the zone to which they belong. This price is determined, for each hour, by the intersection of the demand and supply curves and is differentiated from zone to zone when transmission capacity limits are saturated. All sittings use the same price range used in the day-ahead market and as in the day-ahead market; there is no procedure to reconsider clearing [79].

- Price Range:

In contrast with the day-ahead market, accepted demand bids are valued at the zonal price, not at the national single price. Prices can be from 0 to 3,000 €/MWh [22].

- Timeline:

GME MI has four sessions: MI1, MI2, MI3, MI4; with a frequency similar to the one of continuous trading taking into account the variations of information about the status of power plants and consumption requirements. The first two sessions became operational in November 2009, third and fourth sessions in January 2011. The hourly distribution of sessions in the Italian intraday market is shown in Table 2.

Table 2: Hourly Distribution of Sessions in GME MI

Sessions	1	2	3	4
Opening	10:45 D-1	10:45 D-1	16:00 D-1	16:00 D-1
Closing	12:30 D-1	14:40 D-1	07:30 D	11:45 D
Results	13:00 D-1	15:10 D-1	08:00 D	12:15 D
Schedule Horizon	1-24 D	1-24 D	13-24 D	17-24 D

- Volume:

The trading volumes in GME MI were 14.6 TWh and 21.9 TWh in 2010 and 2011. It reached 25.1 TWh in 2012, increasing by 14.6% compared to the previous year. The market operator stresses that it reflects the need to adjust a long thermal generation market competing with renewable energy sources. The first session, MI1 is the most active session with 16 TWh trading volume. Then, there come MI2, MI3 and MI4 with 6.2, 1.7 and 1.2 TWh, respectively [80].

- Trading Products, Bid and Offer Format:

The granularity of contracts is one hour. The volume of minimum contract is 0.001 MWh. The price tick value is 0.01 €/MWh [78].

Since this is an auction market, limit orders with execution condition such as FAK, FOK, AON and Iceberg do not exist.

In GME MI, bids and offers could be simple and complex, i.e. multiple or balanced. Simple bids and offers consist of a quantity and price pair, in which the quantity is the maximum amount of electrical energy that the market participant would like to inject into or withdraw from the system. The price is the minimum selling price or the maximum purchasing price. Multiple bids and offers consist of multiple pairs of simple bids and offers which are the division of an overall volume offered in the market by the same market participant. Balanced bids and offers can only be submitted in the intraday market. They consist of at least one supply offer and one demand bid, referring to the same zone and to the same hour. Their overall quantities are balanced with the purchasing or selling price equal to zero. These bids and offers have the maximum priority in the intraday market [79].

- Congestion Management:

Italy is a net electricity importer country which actively uses its interconnection lines with neighbors. Approximate net transfer capacities are 2.650 MW with France, 4.240 MW with Switzerland, 220 MW with Austria, 630 MW with Slovenia and 500 MW with Greece; i.e. over 8.000 MW in total [81].

Management of congestions on Italian borders is carried out by CASC (Capacity Allocating Service Company S.A.), the Joint Auction Office in Luxemburg, on behalf of Terna, the Italian TSO, and neighboring TSOs [81]. All TSOs inform the remaining cross-border transmission capacity at their borders, remaining from the previous sessions [82].

For Italy, cross-border intraday trading has been possible with France, Switzerland and Slovenia since May 2012 and with Austria since June 2013. Trading with Greece is under investigation as of January 2014.

Explicit auction has been selected as an interim solution at all borders of Italy. The intraday market in Italy, GME MI, is not a continuous one, differently from the general tendency among Europe. Therefore, explicit auction is preferred over the other choices in order to maintain the harmonization between the cross-border transactions and GME MI.

Intraday capacity is allocated in the form of PTRs on intraday basis. The auction is with respect to the line capacity only. The auctions are closed and comprise single round. There is not any possibility to transfer or resale the allocated capacity based on UIOLI principle. Intraday auction payment is made according to the marginal price [82].

If the total capacity for which valid bids have been submitted is equal to or lower than offered capacity, the marginal price will be 0 €/MWh. The capacity holder is not obliged to use the capacity allocated in an intraday auction; the capacity price, however, must be paid at any rate once the capacity has been allocated [83].

There are two intraday auction sessions for cross-border intraday trading. The first one is cross-border intraday market 1, represented by XBID1. It is held in the period from 13:55 to 14:10 D-1, resulted within 30 minutes. The transactions are reflected in the second session of GME MI. XBID1 covers the hours from 1 to 24 D. Besides, the second possibility for cross-border intraday trading is XBID2. It is held in the period from 10:25 to 10:40 D, resulted in 30 minutes. The transactions are reflected in the fourth session of GME MI. XBID2 covers the hours from 17 to 24 D [83].

3.2 Turkey's Intraday Market Plan

In this chapter, applications and characteristics of intraday markets around Europe have been studied up to now. In this part, the intraday market plan of Turkey will be narrated.

The preparations for the establishment of an intraday market in Turkey started in June 2011. The required software for this market completed at the end of 2012. Throughout 2013, a number of developments regarding the software were performed. The intraday market is expected to become active within 2014 [84].

The trading platform will be Turkish electricity intraday market. Following the opening of Turkish Power Exchange, EPİAŞ; the platform will be possibly be named EPİAŞ ID market.

Similar to the study in the previous chapter, the characteristics of the intraday market in Turkey will be examined in terms of participation, bidding philosophy, trading method, price range, volume, timeline, trading products, bid and offer format, and cross-border congestion management in the intraday time horizon.

- Participation:

In participation, no physical characteristics of units will be considered. Also, participation to the intraday market will be voluntary as it is in the day-ahead market. However considering the application in Germany, in which the TSOs are obliged to use intraday market to balance wind turbines under feed-in-tariff mechanism in their regions; a similar mechanism can be applied. The renewable energy installed capacity is expected to increase in the near future and the feed-in-tariff mechanism is extended until 2020 as will be mentioned in Chapter 4. Taking into account that the balancing responsibility of wind turbines with purchase guarantee agreements belongs to Turkish TSO, it will be quite sensible to force the TSO to rearrange the generation program of these power plants with the incoming updated information.

- Bidding Philosophy:

The bidding philosophy in the intraday market will be portfolio based as it is in the day-ahead market. This is the predominant application among Europe. Market participants will be free to optimize their portfolios according to their generation programs.

- Trading Method:

The trading method will be continuous bilateral trading. The order book will be open and accessible for every intraday market participant.

This application is compatible with the majority of EU member states. Also, the target for the intraday trading in the single electricity market structure proposes the intraday transactions to be handled with continuous trading mechanism because the need to utilize the intraday market emerges suddenly in the intraday time horizon. Therefore, it would be illogical to keep the market participants wait some kind of intraday auctions.

- Price Range:

The floor price will 0 TL/MWh and the cap price will be unlimited. However, in the intraday market software, the market participants will have an option to determine the maximum price at which they can present bids and the minimum price at which they can present offers, which aims them to prevent from getting financial loss in case of mistyping.

- Timeline:

The opening of the intraday market will be 18:00 D-1, after four hours at which the results of day-ahead market are published. Contracts of D-1 and D can be executed starting from 18:00 D-1. Trading will be possible until two hours prior to the delivery. It is defined by the Turkish TSO due to technical reasons; however the closure of the market will be postponed until 1 hour or 45 minutes before delivery hour in the future, depending on the needs of market participants.

- Volume:

Considering the somewhat limited integration of wind energy in Turkey, the trading volume in the intraday market will be low as it is in the majority of the markets in Europe. However, with the increasing penetration of wind energy in the near future and the uncertainty of incoming water for run-of-river hydraulic power plants especially in the spring season will possibly enhance the liquidity in the intraday market.

- Trading Products, Bid and Offer Format:

The granularity of the trading products will be one hour. The incremental volume will be 0.1 MWh and the price tick is 0.01 TL/MWh.

Complex bids and offers will be composed of block and limit orders. There will be standardized block contracts such as base and peak. However, participants will be able to freely define their own contracts. The fact that block contracts will have to be matched completely and partial matching will not be allowed is an important property for these contracts. Block orders are automatically matched or kept in the order book according to AON condition.

Limit orders will have only one option for execution, IOC. There will be other options such as FOK, AON or Iceberg in the future. However, the market operator thinks that it will be confusing for market participants at the initial stage of the intraday market.

- Cross-Border Congestion Management:

Turkey has ten cross-border lines with seven of its neighboring countries, e.g. Bulgaria, Greece, Georgia, Azerbaijan, Iran, Syria and Iraq. The feasibility studies for the extension of interconnection capacities are undergoing.

As of January 2014, at Bulgaria and Greece border, total trading capacity is 550 MW in the direction of import and 400 MW in the direction of export for Turkey. These capacities are allocated on monthly basis utilizing explicit auctions. For other borders at which electricity trading activities exist, the capacity allocation is performed with non-market based procedures.

The cross-border trading capacity is not auctioned on daily and intraday basis. With the progress in the electricity market structures in both Turkey and its neighbors, the capacity will also be allocated in day-ahead, which is a step to utilize the capacities in a more efficient manner. In medium term, if market coupling opportunities with some of the European countries become an issue, utilizing implicit auctions will be evaluated as a more efficient mechanism and also a compatible one to the target structure of single electricity market in Europe. For intraday capacity allocation, there is a long way to construct market-based mechanisms inasmuch as many of the neighbors are far from establishing intraday markets except Bulgaria and Greece. Nevertheless, even with these countries, capacity allocation in the intraday time horizon is not probable in the short term.

3.3 Results of the Information Given In This Chapter

In this chapter, the applications and characteristics of intraday markets both in Europe and in Turkey are examined. The intraday market concept is an issue of which importance has gradually improved so far; but it will definitely be an even more important subject in the forthcoming years taking into account the developments in intraday trading mechanisms and market structures that are under progress.

Trading volumes in intraday markets are quite low compared to the day-ahead markets. In most of the European countries, the ratios are up to 5%, where continuous bilateral trading prevails and they can be over 5% in countries where auction trading mechanism exists. The common point is that the liquidity of intraday markets in Europe is not seen enough; but the volumes are increasing slightly. Anyway, there should not be expected high increases in the trading volume since intraday markets are some kind of transitional markets connecting the day-ahead markets and the balancing markets.

The fact that most of the power exchanges in Europe offer a variety of intraday products is an indication of significance esteemed to intraday markets. There is a great enthusiasm to serve better to the customers' needs and increase their trading volume in intraday market and provide them financially better transactions.

The structural mechanism of intraday markets among Europe and the impending mechanism in Turkey show two different architectures for intraday markets. The first one is observed in the countries within Belgium, the Netherlands, Germany, France, Denmark and Nordic countries, and will be observed in Turkey. In this mechanism, the physical characteristics of units are not taken into account. In other words, a generator or a consumer can make transactions to whatever extend they want. In these markets, the bidding philosophy is portfolio based and the trading method is continuous bilateral trading; hence there can be very low and high caps and floor prices. Since continuous trading exists, trading can last from 2 hours up to 5 minutes prior to the delivery hour.

The second architecture is observed in the countries within Spain, Portugal and Italy. Spain and Portugal can be evaluated as a whole because the mechanism treats such that there is only one intraday market price region if there is no congestion. In this mechanism, the physical characteristics of units are taken into consideration. Besides, in these markets, the bidding philosophy is unit bidding and the trading method is auction trading; hence the cap and floor price limits are similar to those in the day-ahead markets. Also, it should be stressed that these markets are the extensions of day-ahead markets in real terms taking into account that both day-ahead and intraday markets apply auction trading mechanism. Owing to the auction trading structure, there can be a number of sessions which introduces different timelines. This architecture has the disadvantage of giving market participants less flexibility to make transactions in defiance of the logic of the intraday trading, because the factors that create intraday markets contain different amount of uncertainty and variability, which will thoroughly be mentioned in the next chapter. In brief, the first architecture represented in the previous paragraph is more close to the projected structure designated by the EU member states.

As for cross-border congestion management, intraday markets no longer serve as distinct markets. High levels of collaboration have been established in the last couple of years and this relationship among European countries is progressively developing. There is a great eagerness among the member states to establish a single electricity market among Europe in order to maintain efficiency and competitiveness, sustainability and electricity security of supply. This plan also requires combining all intraday markets into a single intraday market platform. Actually, the majority of the interconnections use explicit continuous cross-border trading platform, but it should be underlined that this is an interim phase and the target model is continuous implicit cross-border trading in the intraday time horizon, in which capacity and energy transactions will be performed at the same time. This final mechanism is in operation among a couple of European countries.

With the establishment of the intraday market, Turkey will enter a new path. It follows the stages that the most of the European countries has been tracking just a couple of years from behind.

Up to this point, the issues regarding the different mechanisms for intraday markets have been informed. However the logic and benefits of intraday markets have not been investigated in real terms. Therefore, at this stage the following questions shall be asked: Why do all of these countries implement intraday electricity market mechanisms and what are the benefits of establishing these mechanisms?

In the following chapters of this thesis, the detailed analyses will be performed in order to find some answers to the above questions. The studies will cover the examination of uncertainties in power systems that create need for intraday markets, handling these imbalances with intraday markets from theoretical perspective, and the benefits for market participants with the utilization of different models and approaches. All of these issues and studies will be discussed specifically for Turkey.

CHAPTER 4

UNCERTAINTIES IN POWER SYSTEMS AND IMPORTANCE OF INTRADAY MARKETS

In contrast to other commodities, electricity has some specific characteristics that are difficult to deal with. These can be regarded as non-storability, the simultaneousness and equilibrium of electricity production and consumption, the necessity to be transferred from remote areas, potential network congestions and etc. [85]. When these physical constraints combine with economic interests, ensuring economically the most efficient way requires a multi stage power market framework which includes a forward market, a day-ahead market, an intraday market, a balancing market for the reliability of power systems [86].

If the conditions affecting the power systems such as the amount and locations of generation and consumption, power flows over transmission lines, whether there would be a failure in the system or not were exactly known much before real time, operation and management of them would be much easier. For the secure operation of system, the generation of each or a group of power plants is pre-determined and then sent to the system operator for every hour of the next day from day-ahead. Also, electricity load for the next day for each hour is predicted by the utilization of short-term load forecasting programs.

However, in real time, there occur imbalances in the power systems due to three main uncertainties. The first one is the indefinite characteristic of power plants with variable energy resources such as wind and solar, the second one is unpredictable power plant outages and the last one is demand uncertainty and load forecast errors; all of which show up between real time and day-ahead [87]. These imbalances result from the uncertainty of each of these characteristics in the intraday time horizon, in which market participants are not able to compensate their energy positions without intraday markets. Also, there is a fourth source of uncertainty, arbitrage opportunities, emerging after the day-ahead marker is closed; but it will not be covered in this thesis with only covering the factors arising from the needs of power systems.

In a study conducted by Weber, to what extend the uncertainties in the power systems have an influence on total uncertainty is investigated by measuring the required adjustment capacity. With the assumption that all three errors are normally distributed, Weber comes to the conclusion that in power systems with low wind capacity, the overall uncertainty is determined by the probability of failure in power plants and load forecast errors; both of which defined as conventional deviations. As wind installed capacity increases as shown in Figure 9, total uncertainty is dominated by wind energy uncertainty [88]. The flaw of this study is that there are not any exact or approximate values in the x-axis and y-axis. At which value the uncertainty due to wind prevails conventional deviations is obscure.

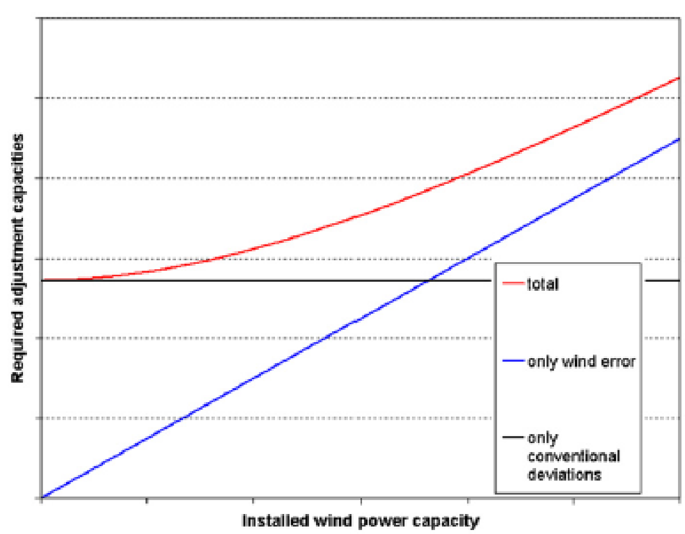


Figure 9: Required Reserve Capacity with respect to Uncertainties [88]

In this chapter, these three kinds of uncertainties that occur in intraday time horizon will be covered thoroughly in order to represent the progressively increasing importance of intraday markets in Turkey. First, the uncertainty arising from intermittent resources will be discussed for Turkey. In the second step; capacity utilization, failure of power plants and the latest situation in Turkey will be narrated. In the last step; short term load forecasting, its basics and current condition of load forecast errors in Turkey will be elucidated.

4.1 Analysis of the Characteristics of Wind Energy

The predominant subjects of this part will be variability and uncertainty, analyses for Turkey and capacity development of wind energy. Although in theory solar energy shows somewhat similar characteristics with wind energy, it will not be mentioned owing to the fact that the current increasing penetration of wind energy is much faster than that of solar energy in Turkey.

4.1.1 Variability and Uncertainty

Wind energy and also solar energy are generally referred as “variable energy resources” due to the fact that they are known to be variable and uncertain. Their controllability is limited. Their production is much less predictable than that of conventional energy technologies like coal and natural gas [89].

In power systems and system control variability and uncertainty are familiar concepts. Transmission system operators have already been dealing with these problems on account of instantly changing demand levels and failure of generating units. The aforementioned new resources add on present challenges of variability and uncertainty [89].

The term “variable” comes from the fact that the output power of these plants can show huge amount of variability in a short span of time. There are a number of examples showing the extent of the variability in the literature. The one examining the fluctuation of wind power output in California’s five regions with different installed capacities is presented in Figure 10. In Solano region, the output can fall from 100-150 MW to 0 MW in a few minutes. In other regions, the outputs can change frequently in variable quantities. In total shown with red line, the total output can vary from 0 MW to 1,000 MW and 200 MW rises and falls can be seen in an hour time.

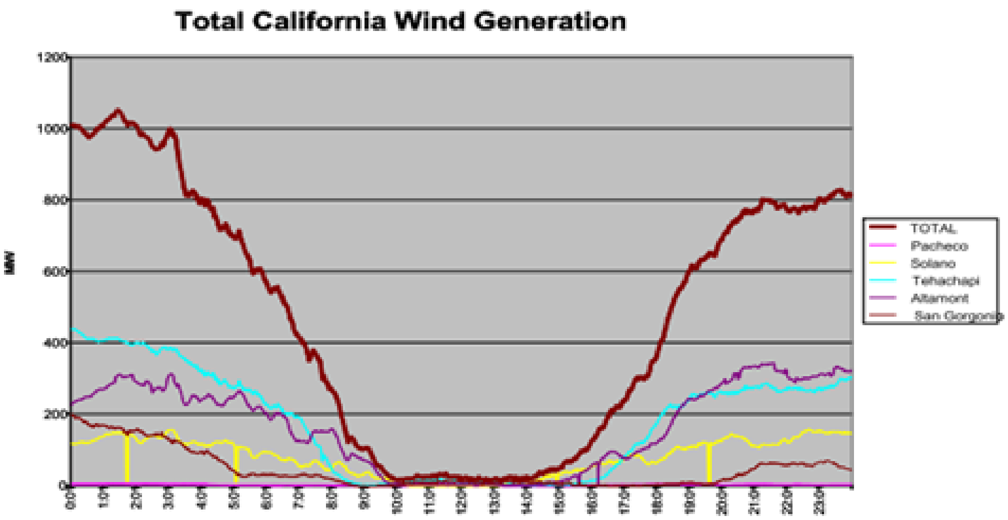


Figure 10: The Fluctuations of Wind Power Output in Five Different Regions of California [90]

The second example is the fluctuation of wind power output in two different regions and the total aggregated situation in Germany as presented in Figure 11. The first graph belongs to a single 225 kW wind turbine, the second one belongs to a group of wind farm of 72.7 MW and the last one belongs all the wind turbines of approximately 15 GW installed capacity. The output of the single wind turbine on the top shows dramatic changes in course of time, i.e. it can diminish from full capacity to 10% capacity factor just in a short period. As the number of wind turbines examined increases, the total output becomes smoother compared to a single wind turbine. If the output of all the wind turbines is examined, it becomes even smoother. However, as shown between December 24 and December 25, it is possible that the total capacity factor can diminish from 80% to 30% in several hours.

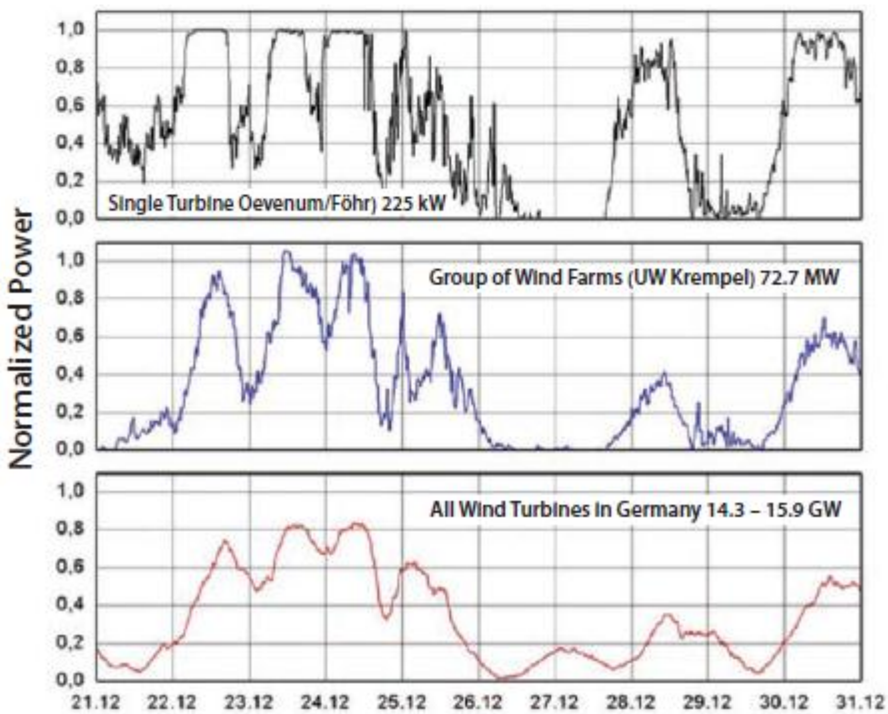


Figure 11: The Fluctuations of Wind Power Output in Germany [89]

Besides variability, wind energy has the problem of uncertainty. With what velocity the wind is blowing in a region completely depends on the meteorological conditions. In meteorological forecasts, the accuracy rate gets better significantly as real time approaches. Figure 12 shows that the relative forecast error for the aggregated wind production of all wind farms in Germany with blue line and in three transmission zones with different pointers on different forecast horizons. Throughout Germany, the forecast error is approximately 6% from day-ahead and it substantially reduces near delivery time [87]. It must be noted that the given forecast errors are relative to the total wind installed capacity not to the actual wind generation. Taking this point into consideration, the day-ahead forecast error is more than 20% of actual electricity production.

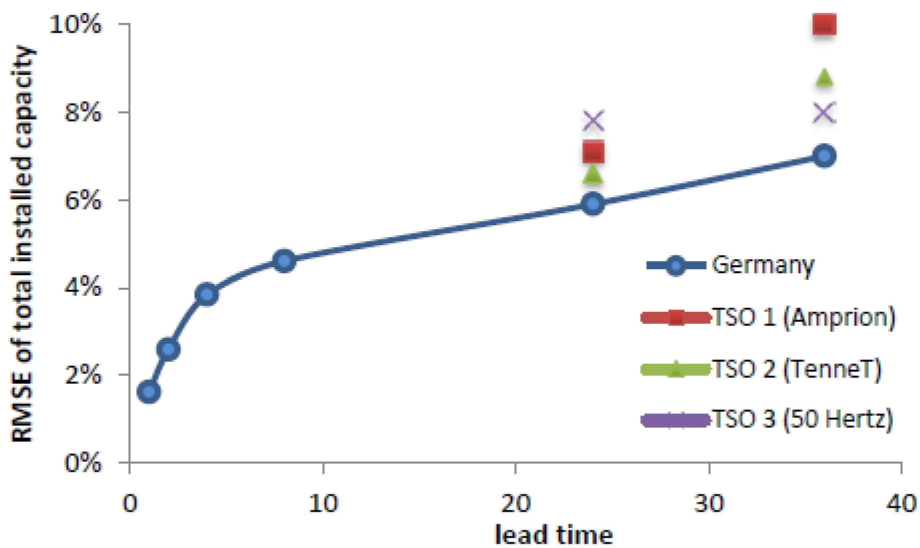


Figure 12: Relative Forecast Errors for Wind Generation in Germany and Three Transmission Zones on Different Forecast Horizons [87]

As mentioned above, there are mainly two problems caused by the utilization of wind energy: variability and uncertainty. These elements can jeopardize electricity security of supply. In order to prevent it, the electricity system operators must keep more reserve capacity and have more flexible generation capacity, in other words having facilities that are able to adjust their output power very swiftly and schemingly. Moreover, the additional start up and shut down costs of large fossil-fuel plants will emerge and the possible high frequency of start-ups and shut downs will increase the mechanical stress on these generation plants, causing higher maintenance costs and reduced life. The absence or very limited presence of variable energy sources for extended periods of time can result in serious operational troubles. In order to maintain reliability and system security standards under worst-case conditions, power systems must have enough primary and secondary reserve capacity; also demand response and storage if possible [89]. In brief, renewable energy technologies will require changes on how power systems and markets are planned, operated and controlled.

However, with the introduction of intraday electricity markets, the market participants with variable energy resources are able to make transactions after the day-ahead is closed and until near real time. This property is not only beneficial for them in terms of the reduction of their imbalances that would be handled in the balancing market, but also it prevents the aforementioned deficiencies that the system operator and the other market participants might have to bear.

4.1.2 Analysis of the Characteristics of Wind Energy in Turkey

In the previous part, it has been mentioned wind energy has fundamental problems such as variability and uncertainty. In this part, the aim is to investigate the characteristics of wind energy in Turkey and also investigate whether these characteristics force market participants to fall imbalances at possibly high prices in the balancing market.

There has been no study found in the literature focusing on the variability and uncertainty problem of wind energy in Turkey. Therefore, in this part, the required analyses will be performed with the data generated by the system operator.

To begin with, the average and maximum capacity factors vary significantly on monthly basis. These are shown in Figure 13 and Figure 14. The patterns belonging the year 2010 depart from those in 2011 and 2012 due to the fact that the total wind installed capacity at the beginning of 2010 was under 1,000 MW and relatively low. This is a sign of the clustering of wind generators in several regions that do not reflect the general condition of Turkey as a whole.

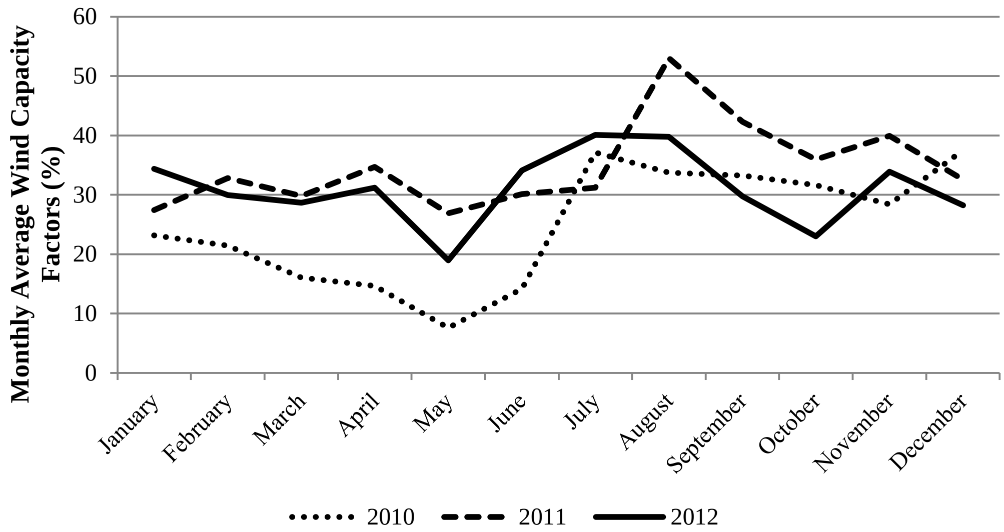


Figure 13: Monthly Average Wind Capacity Factor of All Wind Power Plants in Turkey from 2010 to 2012 [91]

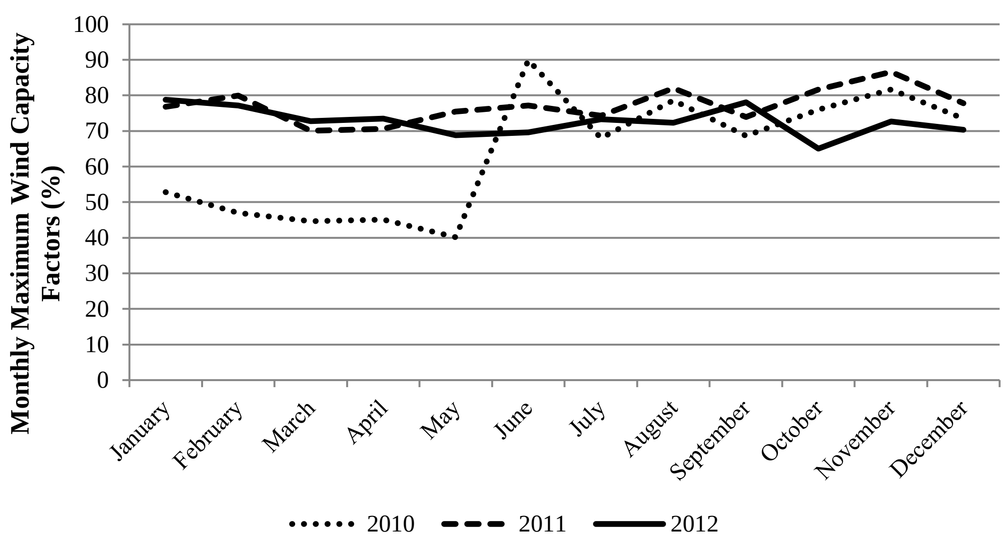


Figure 14: Monthly Maximum Wind Capacity Factor of All Wind Power Plants in Turkey from 2010 to 2012 [91]

When the figures are examined, the increasing generation in summer season and the tendency of decreasing generation in spring and fall seasons draw attention. The maximum monthly average wind utilization is in August 2011 with 53% and the minimum is in May 2012 with 19% if the year 2010 is neglected.

The abundance of wind energy in summer season coincides with the increasing electricity consumption in Turkey due to air conditioning effect. However, the variability and uncertainty of wind increase the risks for electricity security of supply and hampers the security of the power system. This also increases the risk for wind generators in terms of not being able to make the generation that they have programmed from day-ahead. It would end up with purchasing the energy that they are not able to generate at imbalance tariff from the balancing market. The evaluation on the variability of wind energy must be performed with the utilization of the wind generation data of all wind farms combined in Turkey. The maximum deviations in total wind generation are examined from 1 to 6-hour time span on monthly basis. The quarterly results for 2011 and 2012 are presented in Figure 15 and Figure 16.

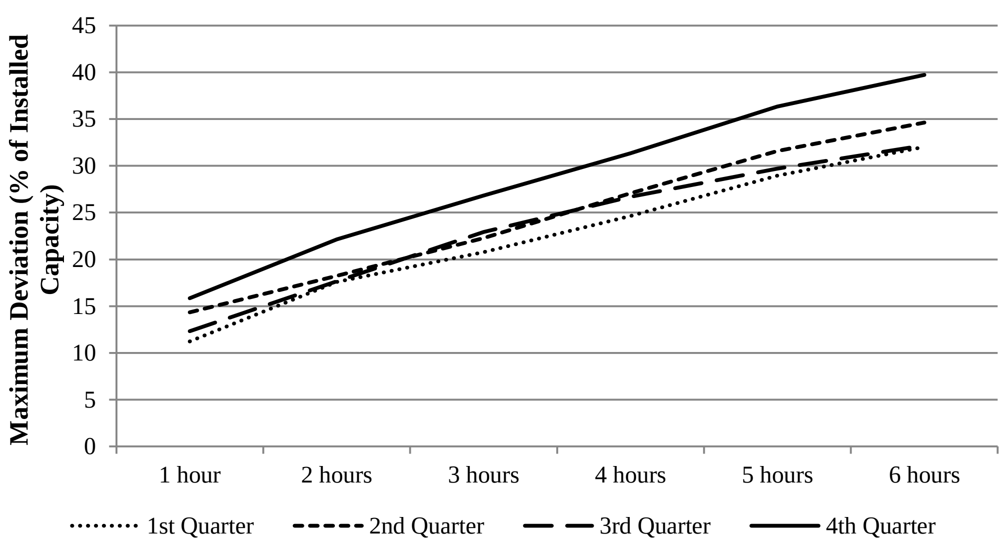


Figure 15: Maximum Average Quarterly Deviation in Total Wind Power Output in 2011 [91]

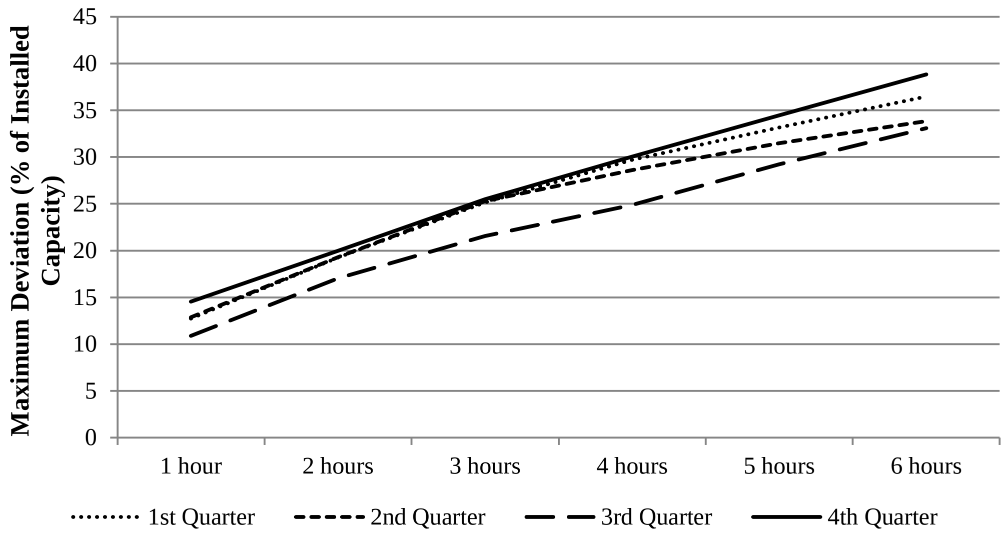


Figure 16: Maximum Average Quarterly Deviation in Total Wind Power Output With Respect To Total Wind Installed Capacity in 2012 [91]

The results show that the maximum deviation in wind power output of all wind farms in Turkey can reach 11-16% of the total wind installed capacity in one hour, 17-22% in two hours, 21-27% in three hours, 25-31% in four hours, 29-36% in five hours and 32-40% in six hours. The high ratio of deviation makes wind power forecasting extremely difficult. The situation might get extremely severe in case of high amounts of wind penetration.

The evaluation on the uncertainty of wind energy based on wind forecast data from day-ahead is not easy due to the fact that since the beginning of December 2011, the market participants in Turkey submit their bids and offers not unit based but portfolio based. However, prior to this period, in real time operation, they had to match their generation and consumption programs given in day-ahead. Utilizing the data concerning aggregated wind power plants, the hourly and maximum monthly deviations are presented in Figure 17 and Figure 18.

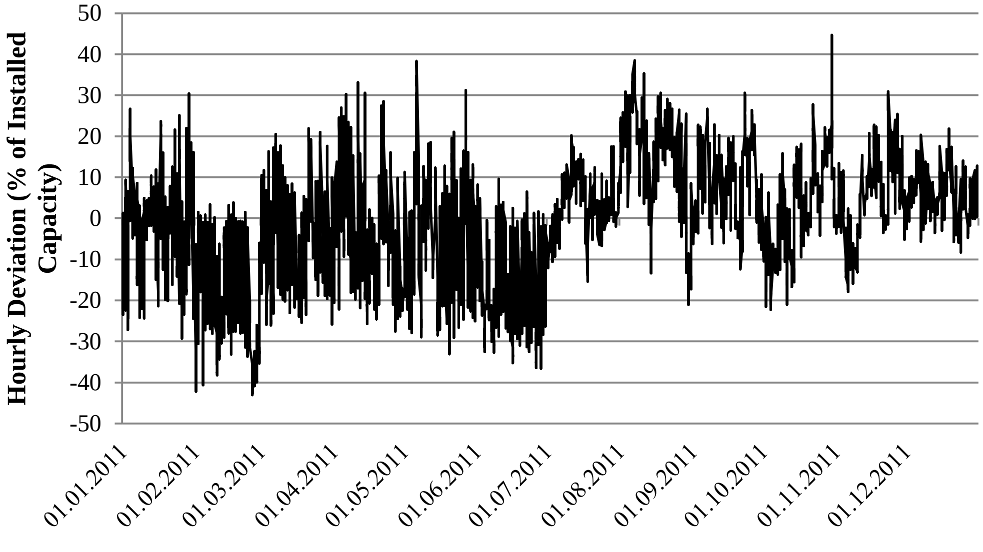


Figure 17: Hourly Deviation in Total Wind Generation Compared to Generation Program [91]

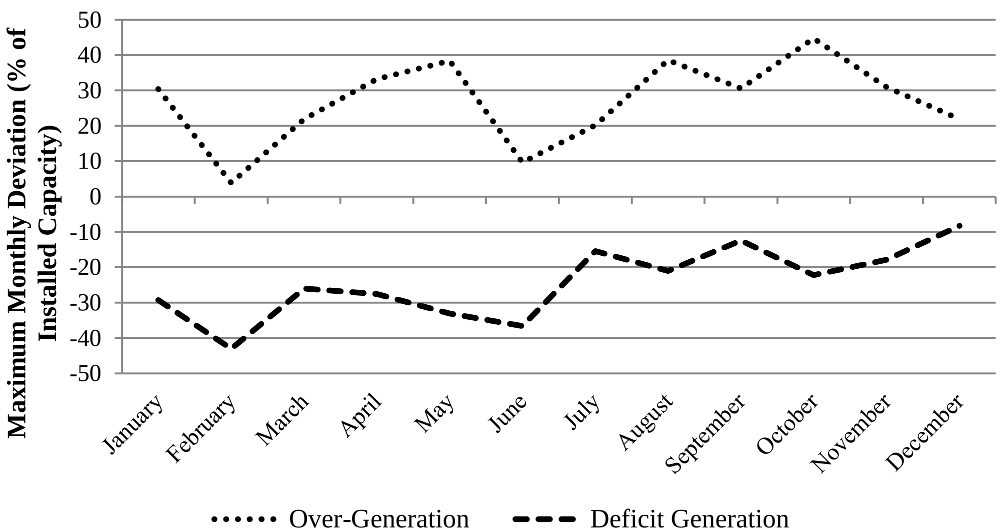


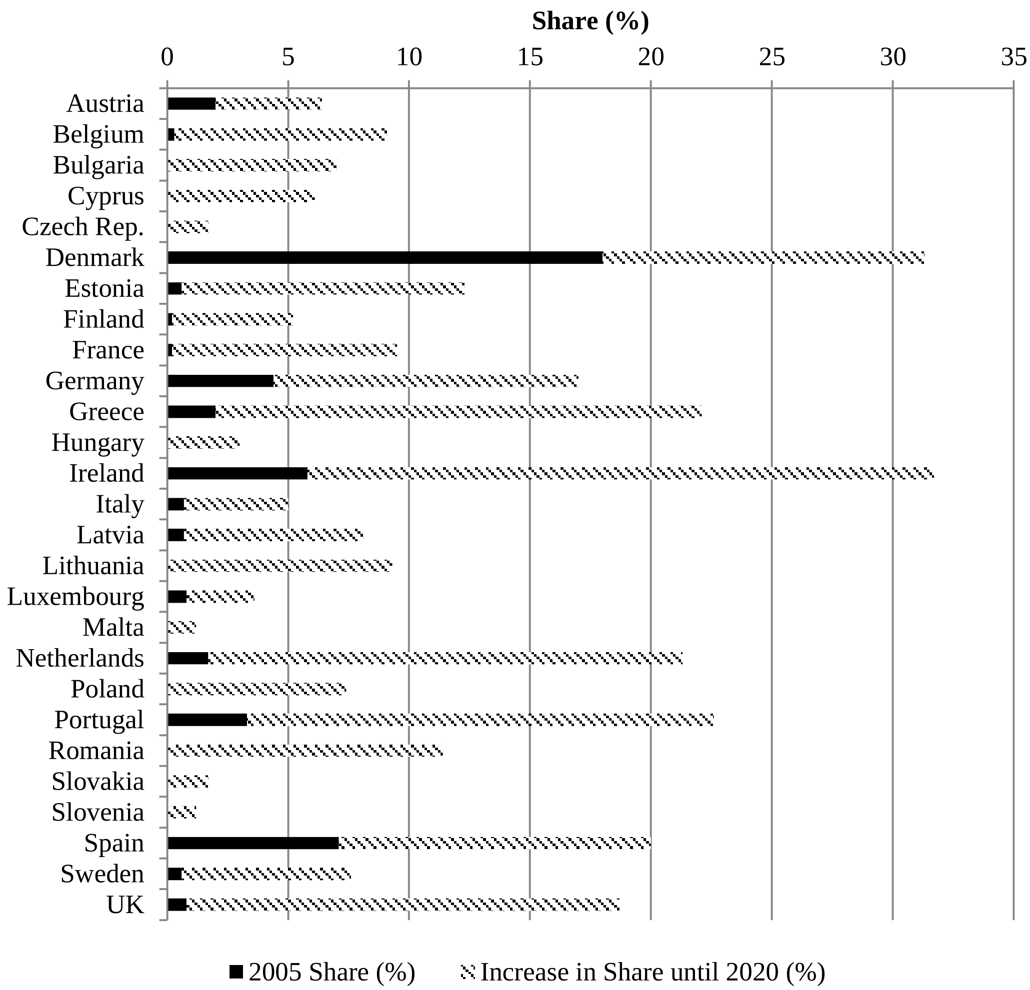
Figure 18: Maximum Deviation in Total Wind Generation Compared to Generation Program [91]

The randomly distributed pattern of wind generation forecast errors can be shown in Figure 17. At his point, it should again be noted that the deviations are represented in the form of percentage of wind installed capacity. In other words, the lines correspond to the wind forecast errors relative to the overall wind capacity. The severest deviation in over-generation direction is in October with 45% and that in deficit generation direction is in February with 43%. These results pose a great amount of risk for achieving correct wind generation forecasts and the danger of making imbalances in real time.

4.1.3 The Progress of Wind Power Sector and General Outlook from Capacity Development and Projection Perspective

In this section, the progress in the wind power sector will be discussed inasmuch as with the increasing wind power capacity, the variability and uncertainty problem will possibly deepen. The object is to present the acceleration and the future projections related to wind energy around the world, and to discuss whether increasing wind capacity will dominate the forecast errors in Turkish power system.

In Chapter 3, the applications of intraday markets in Europe have been presented. It has been stressed that these mechanisms have evolved earlier than those in Turkey. One of the main reasons for the early developed intraday market structures in Europe resulted from the targets of EU member states designated on renewable energy and expanding utilization. According to the European Renewables Directive of 2008, European Union Member States have defined 20% renewable target which aims that European Union as a whole shall obtain at least 20% of total energy consumption from renewable sources by 2020 [92]. In order to fulfil the aforementioned aim these states are increasing the deployment of renewable energy sources in the direction of the targets. The resulting effect of this policy is the widespread utilization of wind power in electricity sector. When the current electricity generation portfolio of European Union Member States with respect to primary energy sources and their projection for the year 2020 is examined, the expected rising share of wind energy is remarkable as shown in Figure 19.



.

Figure 19: EU Member States Projections for Wind Energy Production/Total Electricity Consumption Ratios in 2020 and Comparison with 2005 [93]

According to Figure 19, total wind installed capacity among the Member States in 2005 was about 40,400 MW and it has reached 108,000 MW in 2012 by increasing approximately 167%. The projected total wind capacity is about 213,000 MW in 2020. In other words, the European target is claimed two times of the capacity in

2012. Taking into account that the conventional errors like power plant failures and load forecast deviation represent a stable trend as mentioned in the previous sections, errors owing to wind will definitely enhance its share in total uncertainty by the enormously increasing wind capacity. This is an important proof of the requirements and the applications of new favorable mechanisms that have already initiated in Europe, enabling more wind power capacity especially with intraday electricity markets.

Before the progress of the wind sector in Turkey is examined, the capacity and consumption development must be mentioned firstly. Then, the necessity for wind energy in the future generation capacity will be discussed thoroughly.

By the end of 2012, the total installed capacity and annual consumption of Turkey reached 57,059 MW and 242.3 TWh, respectively [94]. Turkish electricity sector and the need for additional investments have flourished especially starting from 2000s. In this period, the majority of the generation capacity came from conventional resources; but for the last couple of years wind sector made great strides, reaching 2,261 MW installed capacity corresponding 4% of the total capacity [94]. The progress of total installed capacity, annual electricity generation and the share of wind energy are presented in Figure 20 and Figure 21. These figures prove that the electricity sector in Turkey has been undergoing a significant progress.

At this point, the sustainability of electricity demand increase gains importance. In order to foresee the future, MENR is responsible for preparing the electricity demand projection every two years according to the law. With regard to the realization of economic and population growth estimations, three scenarios are created as low demand, reference demand and high demand [95]. The electricity demand projection spanning from 2012 to 2023 is presented in Figure 22.

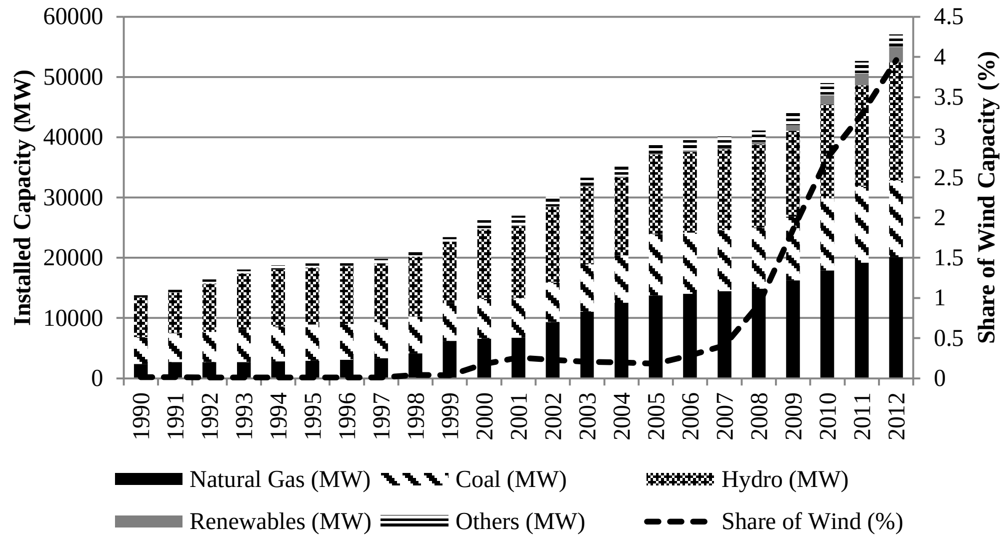


Figure 20: Development of Installed Capacity of Turkey by Primary Energy Resources and Share of Wind Energy [94]

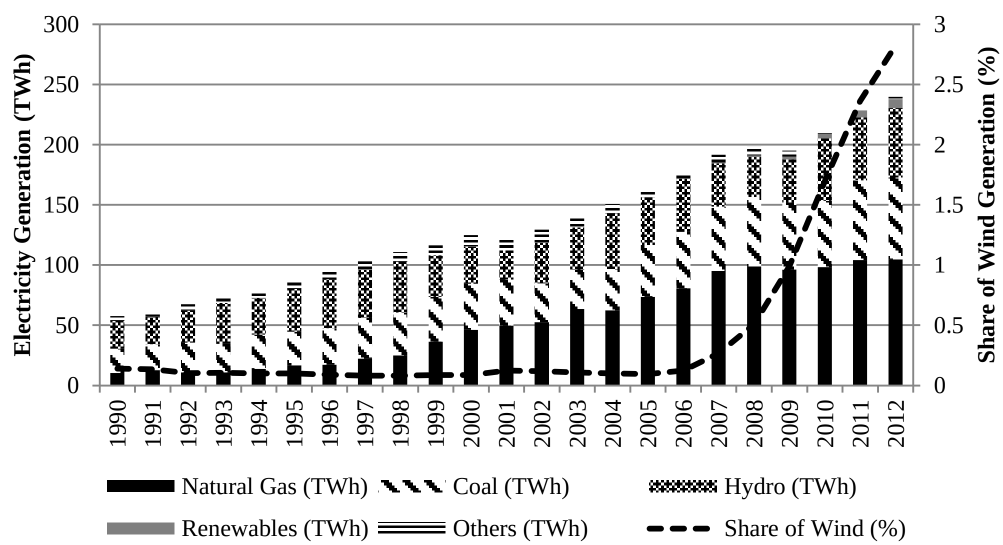


Figure 21: Development of Annual Electricity Generation of Turkey by Primary Energy Resources and Share of Wind Energy [94]

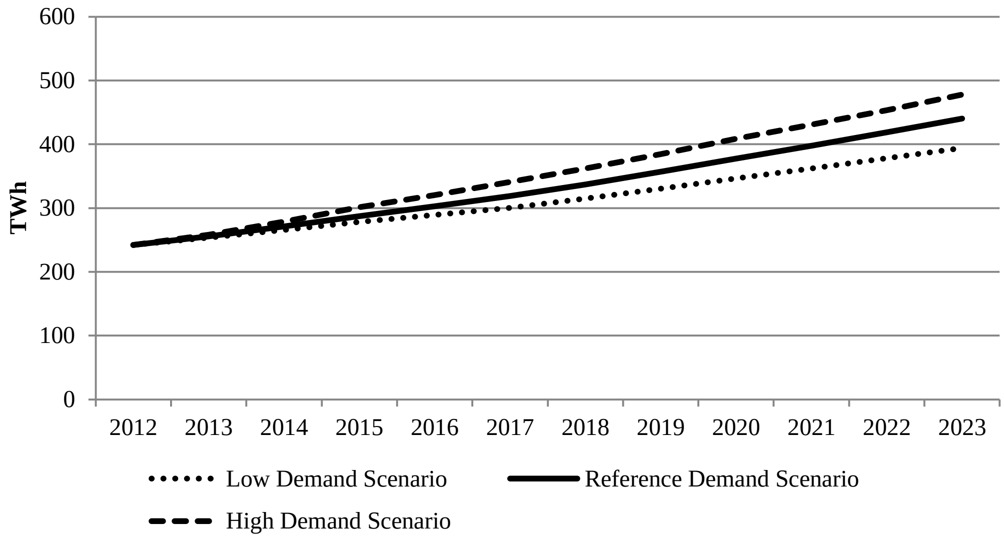


Figure 22: Electricity Demand Projection from 2012 to 2023 [95]

According to the reference demand scenario, the total electricity demand of Turkey in 2023 is estimated to be 440 TWh, corresponding yearly 5.6% and in overall 82% increase with respect to 2012. Taking into account these estimations, the acceleration recorded in electricity demand is expected to continue.

The biggest impediment in front of the sustainability of electricity demand stands out to be import dependency. In 2011, the total primary energy supply was 114.4 mtoe and 90.3 millions of it comes via import. Natural gas, oil and coal constitute a huge portion in primary energy supply fleet [96]. Concerning natural gas, despite the fact that the total production in Turkey can meet only 1.8% of the total demand in 2012, the share of it is 43.5% in electricity generation portfolio, ranking in the first place. Besides that, the share of import coal is 12.5%. In the provision of the sustainability of electricity demand increase, using more natural gas and import coal in electricity generation means increasing import bill for Turkey. In order to prevent this, giving priority to domestic resources and including renewable energy resources more in electricity generation fleet are aimed and it appears in 2010-2014 Strategic Plan of MENR [97].

The subject of increasing the share of renewable energy resources in total electricity generation fleet takes part in Electricity Market and Security of Supply Strategy Paper. In accordance with this paper, the aforementioned share is targeted to be at least 30% by 2023. Furthermore, enhancing total wind installed capacity to 20,000 MW, putting in use all the technically and economically available hydroelectric and geothermal potential, ensuring maximum utilization of country’s solar potential are other targets to be realized by 2023 [98].

However, it is highly probable that Turkey will not be able to utilize all its technical and economical hydroelectric capacity, which is evaluated as 144 TWh coinciding 36,000 MW hydraulic installed capacity Turkey, until 2023. The long periods of environmental impact assessment, increasing number of suits against both the owner of the plant and the Ministry are the main reasons behind the aforementioned delay [99].

As for nuclear energy, in the concept of decreasing import dependency Turkey has the target of generating 10% of total electricity production by 2023 from the nuclear power plant which have been under construction. However, the long periods of environmental impact assessment and choosing an independent consultant to audit the documents of the plant have already caused one year delay [100].

In the direction of predetermined targets, with the effects of the problems on including hydraulic and nuclear energy sources to the electricity generation fleet of Turkey, the most remarkable capacity increase on the basis of energy resources will be from “Variable Energy Resources”, mainly by wind in the next 10 years.

Considering Renewable Energy Potential Atlas of Turkey prepared in 2007, at least 5,000 MW wind capacity potential is available in the regions with annual average wind velocity 8.5 m/s and more. Furthermore, at least 48,000 MW wind power capacity is available in the regions having 7 m/s or more wind velocity [101]. As of July 2012, according to license progress report published by Energy Market Regulatory Authority, 4 wind projects with 65 MW are in the application phase, 9 wind projects with 409 MW are in the examination-evaluation phase, 34 wind projects with 1,717 MW are approved and 260 wind projects with 9,107 MW are given license [102]. The fact that over 9,000 MW wind project is has already been given license is a strong indication of imminent rise in total wind capacity in Turkey in medium term.

Wind energy, if it is available, is an indispensable source to produce electricity both in the world and in Turkey. Besides, its importance flourishes as the question on how the rise in the electricity consumption will be maintained sustainably considering the high import dependency is discussed more.

Wind energy will be one of the most valuable and most widely used energy sources in the near future. The high level of wind penetration in the power system will definitely deepen the problems arising from wind energy, such variability and uncertainty. In order to be able to overcome the obstacles, the mechanisms favoring the utilization wind energy such as the introduction of intraday markets will be even more critical.

4.2 Analysis of Installed Capacity and Power Plant Failures

It has already been shown that total uncertainty in electrical power systems is decided by the loss of generated power due to failure of power plants when wind penetration is low and load forecast errors are neglected. This characteristic makes it the second important uncertainty in power systems after wind. In this part, capacity utilization and the share of power plant failures on the total unavailable capacity will be examined and then some analyses on these failures will be performed.

4.2.1 Analysis of Installed Capacity

Turkey suffers from not being able to use its installed power capacity at high percentage. The availability factor was 70.8% even on 27 July 2012 when the hourly and daily electricity consumption reached all-time high as 39,045 MW and 799 million kWh respectively. In general, this factor oscillates between 55% and 75% throughout a year as shown in Figure 23.

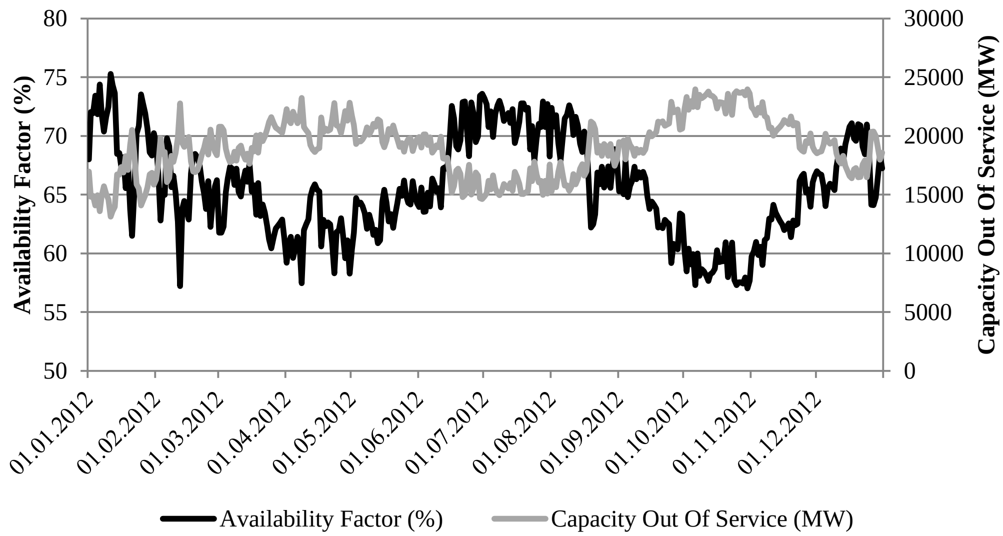


Figure 23: Availability Factor of All Generators and Daily Capacity Out of Service in 2012 [91]

The average available capacity was 36,195 MW and the average availability factor was 65.6% in 2012. In the same way, the capacity that is out of service shows a similar trend compared to that of availability factor. In 2012, the daily average capacity that was unable to be utilized was 19,001 MW as can be observed from the same figure.

When the factors having an influence on the capacity that is out of service are examined, there are five components that are rebuilding, maintenance, cold reserve, stand-by reserve, failure and non-utilizable capacity which is due to a number of reasons such as participation to secondary frequency control, low heating value of coal for coal fired power plants, too low or too high wind velocity for wind turbines, low water level for hydraulic power plants and etc. The bulk of the unavailable capacity is resulting from the non-utilizable capacity as shown in Figure 24.

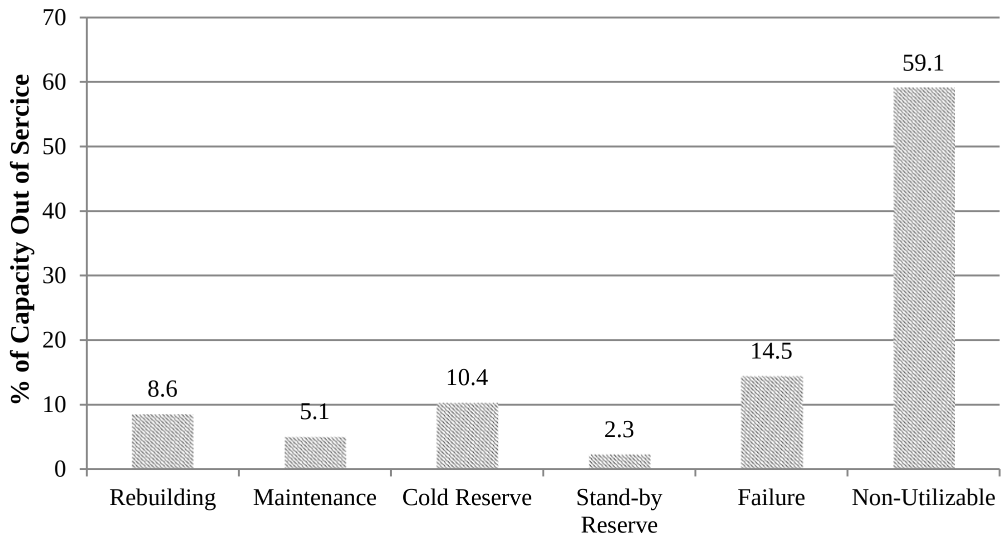


Figure 24: Breakdown of Unavailable Capacity [91]

Taking into account the aforementioned information, the daily average unavailable capacity from rebuilding is 1,627 MW, from maintenance 978 MW, from cold reserve 1,971 MW, from stand-by reserve 441 MW, from failure 2,758 MW and from non-utilizable capacity 11,227 MW.

After non-utilizable capacity, failure is the leading reason for the unavailability of the capacity with 14.5%. Taking into account that the majority of the non-utilizable capacity is not controllable and adjustable owing to the fact that coal rank, precipitation etc. are not controllable and abruptly emerging factors; failures show up as the most important driver on the unavailability of power plants in terms of the possible imbalances in the market and possible financial losses.

4.2.2 Analysis of Power Plant Failures

In Turkey, there were 900 power plant failures recorded in 2012, of which data belong to the aforementioned types of power plants in the previous page. The total installed capacity that broke down in this period was 168,206 MW which corresponds to 460 MW on daily basis. In other words, a power plant of 460 MW becomes out of service every day.

The majority of the failed capacity is in the group of thermal power plants as presented in Figure 25.

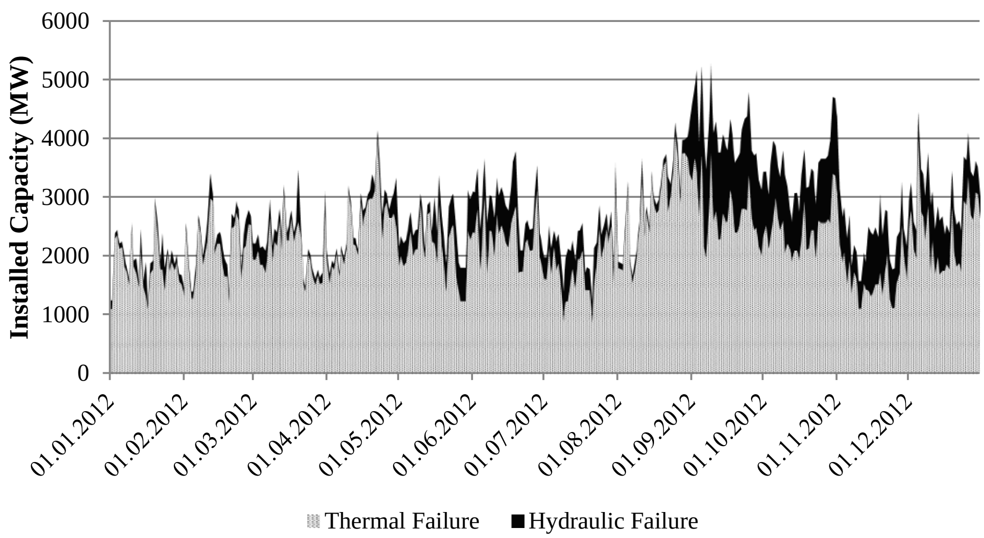


Figure 25: Breakdown of Failed Capacity [91]

From 2,758 MW of daily average unavailable capacity, 80.6% resulted from thermal and 19.4% from hydraulic power plants. Renewable power plants are not taken into account in this study.

When these failures are examined, it is concluded that most of them occur in summer and winter season in which extreme weather conditions exist. 79 and 90 power plant failures are recorded in July and August as well as 90 and 83 of them recorded in

January and December. The numbers for other months and failed capacity per failure are given in Figure 26.

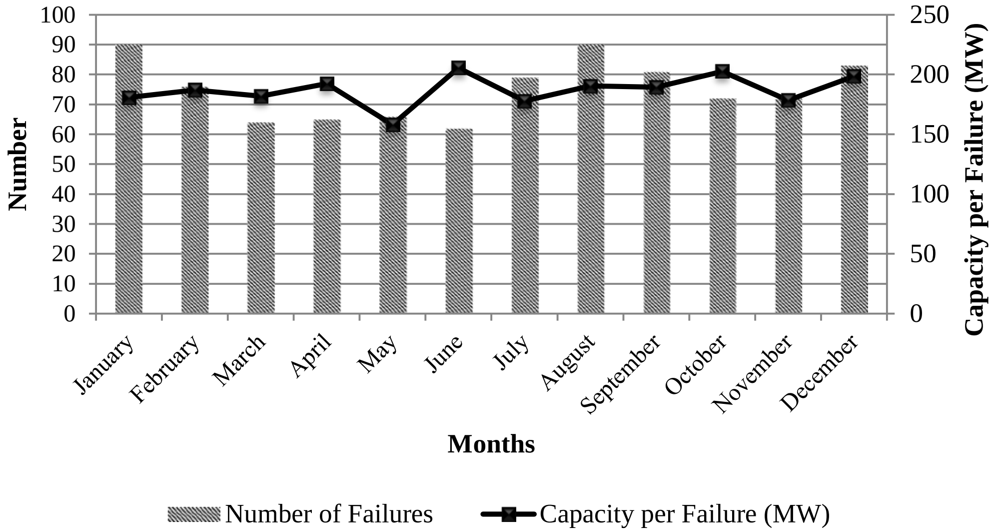


Figure 26: Number of Failures in 2012 on Monthly Basis [91]

When the failures are examined on hourly basis, the most prominent detail is that most of them occur at 0 am and 8 am as shown in Figure 27. These are the hours at which night ramp and morning ramp occurs in Turkish electricity daily load. This can be a proof of the fact that power plants are more prone to failures when they start up or shut down.

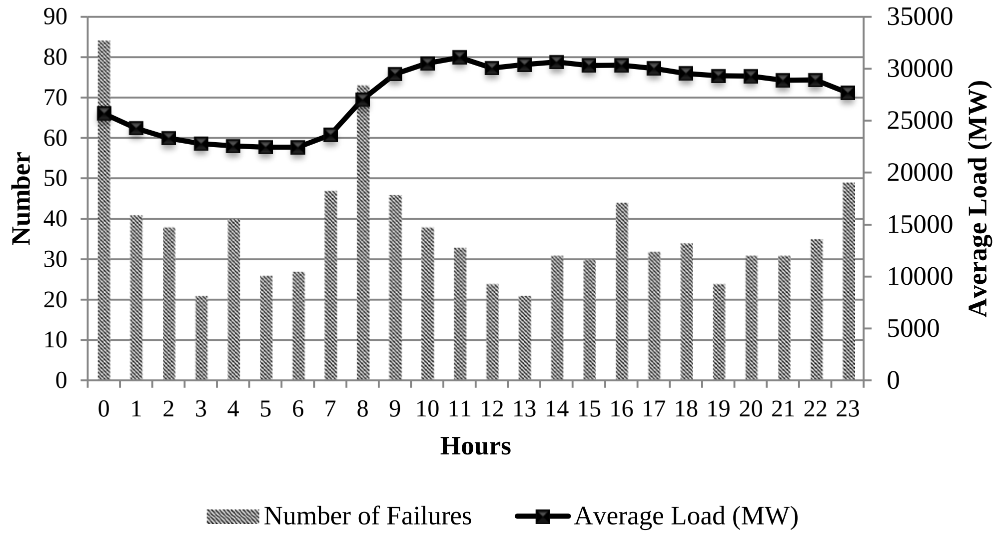


Figure 27: Number of Failures in 2012 on Hourly Basis [91]

Power plant failures have long been considered as a source of uncertainty in power systems. It constitutes the conventional uncertainties along with load forecast errors. In this part, it has been shown that a considerable amount of capacity fails while in operation and this situation poses risk for these power plants in that they would have to make imbalances in real time operation. In order to overcome these problems, intraday markets can offer important opportunities for the market participants whose power plants fail.

4.3 Analysis of Load Forecast Errors

The third main uncertainty in power systems is load forecast errors. It is a conventional type of uncertainty along with power plant failures, together having been existed for long years.

Load forecasts are centrally performed by NLDC under TEİAŞ. These forecasts are not the exact estimations of all suppliers regarding the following day. They are prepared in order to be prepared for system operation of the next day and to lead supplier companies while making short term forecasts. Supplier companies are assumed to regard the information given by NLDC and prepare their forecasts accordingly.

One of the parameters showing the accuracy of load forecasts is the percentage error, found by proportioning the hourly deviation from exact load to the exact load. In Turkey, load forecast errors show an oscillating pattern as shown in Figure 28, Figure 29 and Figure 30, which present hourly load forecast errors for 2010, 2011 and 2012. In these figures, y-axis is limited between -10% and +10% in order to provide a better display.

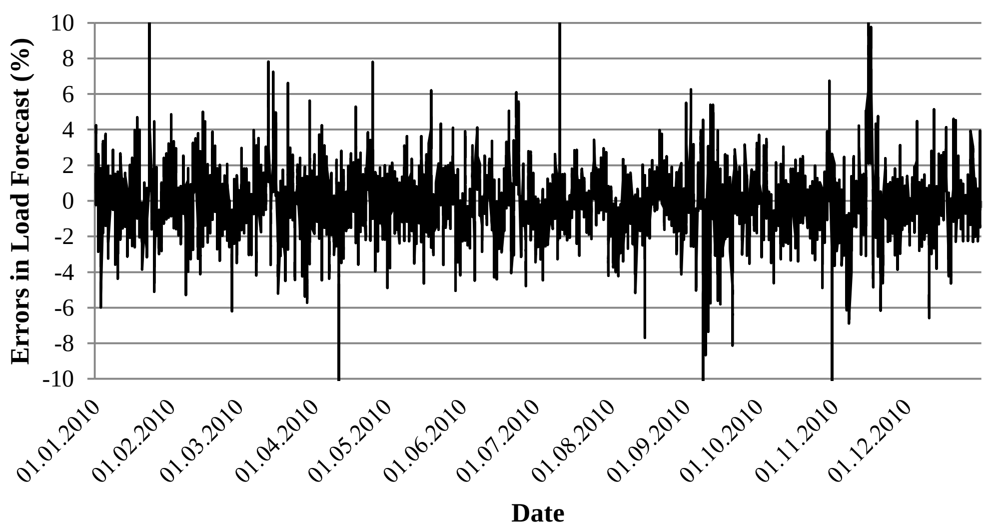


Figure 28: Hourly Load Forecast Errors in 2010 [103]

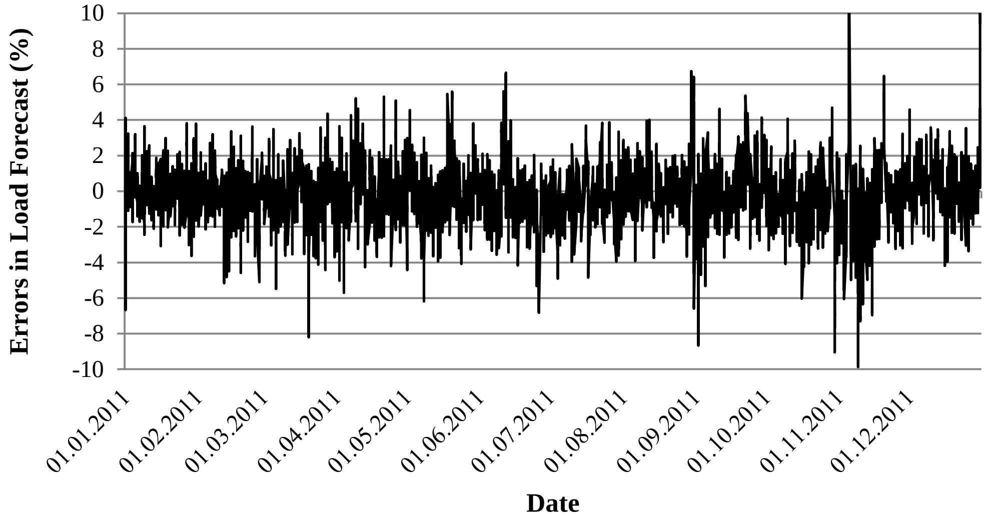


Figure 29: Hourly Load Forecast Errors in 2011 [103]

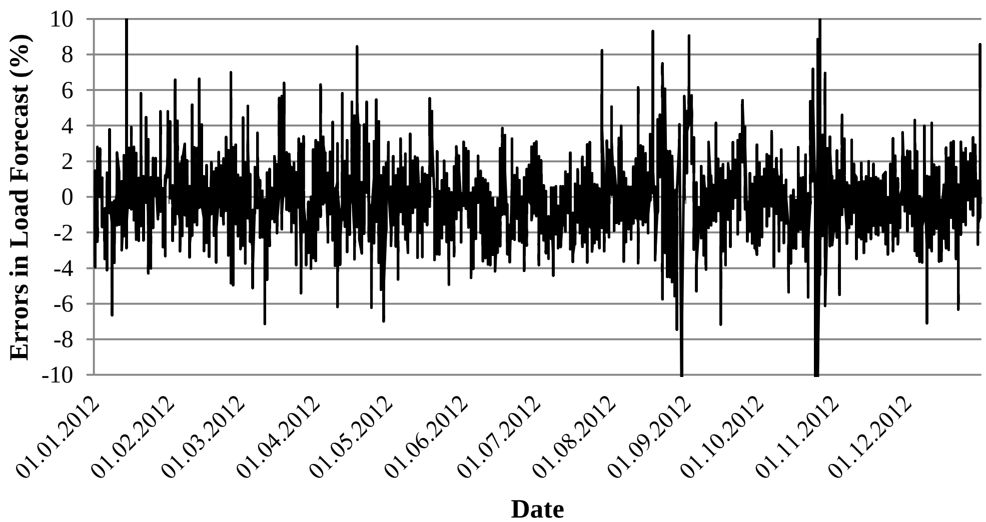


Figure 30: Hourly Load Forecast Errors in 2012 [103]

According to these figure, errors are in the range of -5% and +5% most of the time. However, at some points, errors beyond ±10% stand out. High forecast errors are generally associated with forced power outages, national holidays and unexpected weather conditions. For instance, on January 14, 2012 at 2:00 pm, the load forecast before the day is 30,900 MW for the relevant hour. Nevertheless, in İstanbul and İzmit region, where population and industrial activity are dense, power had to be cut owing to frequency shift on 380 kV transmission lines connecting Anatolian and European Side and the actual demand diminished to 23,244 MW resulting 24.8% error. Another example is for the eve of the Feast of the Sacrifice Holiday. On November 15, 2010, November 5, 2011, October 24, 2012, throughout the day, errors were up to 10%, 23% and -10% respectively. Also, on the eve of Ramadan Feast in 2010, 2011 and 2012, load forecast errors were remarkably elevated. The next example is for the Victory Day celebrated every year on August 30. For this time of the year, high load forecast errors were experienced for 2010, 2011 and 2012, ranging from -17% to 7%. The number of examples can be reproduced.

The number of hours at which absolute load forecast percentage of errors (APEs) are greater than 2.5%, 5% and 10% for the years 2010, 2011 and 2012 is shown in Table 3. A huge number of hours represent absolute percentage errors greater that 2.5%. Also, it must be stressed that although the performance of load forecasts improved in 2011, in 2012 it is degraded inferior to 2010.

Table 3: Distribution of Hours with respect to APE

Year	Number of Hours		
	APE>2.5%	APE>5%	APE>10%
2010	1214	163	10
2011	979	149	20
2012	1382	201	28

In addition to the above table, an extensive table summarizing electricity demand, total load forecast errors, and as a performance indicator mean absolute load forecast percentage error (MAPE) for the years 2010, 2011 and 2012 is given in Table 4.

Table 4: Pivot Table related to Electricity Demand and Load Forecast Errors

Year	Total Electricity Consumption (MWh)	Average Hourly Demand (MW)	Yearly Load Forecast Error (MW)	Average Hourly Forecast Error (MW)	MAPE (%)
2010	209,434,863	23,908	2,762,542	315	1.32
2011	229,334,830	26,180	2,838,466	324	1.24
2012	241,794,529	27,527	3,458,357	394	1.43

Electricity consumption and the amount of load forecast errors in Turkey showed continuous increase for the last three years. Average load forecast errors are 1.24% in 2011 and 1.43% and 2012, which is an evidence of the fact that load forecast errors do not show continuous progression and they are not on decreasing trend.

1.43% load forecast error does not seem high at the first glance. However, it corresponds to approximately 400 MWh energy imbalances in every hour of the year. Therefore, it can be asserted that supplier companies are suffering from the results of their load forecasts. However, in the intraday time horizon, it is highly possible that with the incoming updated information regarding system conditions, these errors would definitely diminish with the introduction of intraday markets.

CHAPTER 5

HANDLING IMBALANCES WITH INTRADAY MARKETS FROM THEORETICAL PERSPECTIVE

Intraday market mechanism cannot be thought without energy imbalances because they are the fundamental factor in the rise of intraday markets. In this chapter, energy imbalances and the benefits of handling these imbalances with the intraday markets will be investigated from theoretical perspective.

The chapter begins with the concept of energy imbalances and the balancing mechanism in Turkey, which tell about how the imbalances are punished by the dual price mechanism applied in the balancing market. Secondly, the analysis of hourly net energy imbalances in both positive and negative directions will be examined for 2012 and the potential benefits of intraday markets with handling these imbalances in the intraday market will be covered through different scenarios. The chapter ends with a conclusion part summarizing the important points obtained throughout the analyses performed.

5.1 Energy Imbalances and Balancing Mechanism

The instructions for balancing and settlement mechanism are described in Electricity Market Balancing and Settlement Regulations. In the corresponding regulation, in Article No.111, the amount of energy imbalance is calculated as formula (1).

$$EDM_{f,t,u} = \left(\sum_{b=1}^{k} (UEVM_{f,t,b,u} - UECM_{f,t,b,u}) \right) + UEIAM_{f,t,u}$$
$$+ \left(\sum_{p=1}^{l} \sum_{r=1}^{m} GOAM_{t,p,r,u} - \sum_{p=1}^{l} \sum_{r=1}^{n} GOSM_{t,p,r,u} \right) \tag{1}$$
$$+ \left(\sum_{d=1}^{h} \sum_{r=1}^{t2} KEYATM_{f,d,u,r} - \sum_{d=1}^{h} \sum_{r=1}^{t1} KEYALM_{f,d,u,r} \right)$$

In this formula,

$EDM_{f,t,\mathrm{u}}$: Amount of energy imbalance for ”f” balancing responsible party, “t” trade zone, “u” settlement period (MWh),

$UEVM_{f,t,b,u}$: Amount of injected to the system for ”f” balancing responsible party, “t” trade zone, “b” generation or consumption unit, “u” settlement period (MWh),

$UECM_{f,t,b,u}$: Amount of taken from the system for ”f” balancing responsible party, “t” trade zone, “b” generation or consumption unit, “u” settlement period (MWh),

$UEIAM_{f,t,u}$: Amount bilateral agreement for ”f” balancing responsible party, “t” trade zone, “u” settlement period (MWh),

$GOAM_{t,p,r,u}$: Amount of energy bought in the day-ahead market for “t” trade zone, “p” market participant, “r” bid, “u” settlement period (MWh),

$GOSM_{t,p,r,u}$: Amount of energy sold in the day-ahead market for “t” trade zone, “p” market participant, “r” offer, “u” settlement period (MWh),

k : Number of generation and consumption units for “u” settlement period, “t” trade zone, ”f” balancing responsible party,

l : Number of market participants registered under “f” balancing responsible party,

m : Number of realized bids submitted to the day-ahead market for “t” trade zone, “p” market participant, “u” settlement period,

n : Number of realized offers submitted to the day-ahead market for “t” trade zone, “p” market participant, “u” settlement period,

$KEYALM_{f,d,u,r}$: Amount of increased generation injected to the system following the orders of NLDC in the balancing market for ”f” balancing responsible party, “d” balancing unit, “u” settlement period (MWh),

h : Number of balancing units for “u” settlement period, “t” trade zone, “f” balancing responsible party,

$t1$: Number of realized offers submitted to the balancing market for “d” balancing unit, “u” settlement period,

$KEYATM_{f,d,u,r}$: Amount of reduced generation following the orders of NLDC in the balancing market for ”f” balancing responsible party, “d” balancing unit, “u” settlement period (MWh),

$t2$: Number of realized offers submitted to the balancing market for “d” balancing unit, “u” settlement period.

In these notions, “f” represents balancing responsible party, a group of market participants that handle imbalance in their group by compensating deficit or excess energy positions. The participation in these groups is not compulsory. “t” represents trade zone referring the price region formed due to transmission congestions with other regions. As of January 2014, whole Turkey is treated as one zone, and this application is not going to change in the near future. “u” represents settlement period of financial positions. Energy imbalances are settled on monthly basis; hence it refers to any single month.

According to (1), the amount of energy imbalance depends on the amount of real time generation and consumption, bilateral agreements, day-ahead transactions, increased or decreased generation in the balancing market.

With the introduction of the intraday market in Turkey, the market participants will be able to make transactions between day-ahead market and balancing market, which aims to diminish the volume of imbalances. The calculation of the amount of energy imbalance will be altered as formula (2).

$$\begin{aligned} EDM_{f,t,u} &= \left(\sum_{b=1}^{k} (UEVM_{f,t,b,u} - UECM_{f,t,b,u}) \right) + UEIAM_{f,t,u} \\ &+ \left(\sum_{p=1}^{l} \sum_{r=1}^{m} GOAM_{t,p,r,u} - \sum_{p=1}^{l} \sum_{r=1}^{n} GOSM_{t,p,r,u} \right) \\ &+ \left(\sum_{p=1}^{l} \sum_{r=1}^{x} GIAM_{t,p,r,u} - \sum_{p=1}^{l} \sum_{r=1}^{y} GISM_{t,p,r,u} \right) \\ &+ \left(\sum_{d=1}^{h} \sum_{r=1}^{t2} KEYATM_{f,d,u,r} - \sum_{d=1}^{h} \sum_{r=1}^{t1} KEYALM_{f,d,u,r} \right) \end{aligned} \tag{2}$$

In the above formula, in addition to the notions in (1),

$GIAM_{t,p,r,u}$: Amount of energy bought in the intraday market for “t” trade zone, “p” market participant, “r” bid, “u” settlement period (MWh),

$GISM_{t,p,r,u}$: Amount of energy sold in the intraday market for “t” trade zone, “p” market participant, “r” offer, “u” settlement period (MWh),

x: Number of realized bids submitted to the intraday market for “t” trade zone, “p” market participant, “u” settlement period,

y: Number of realized offers submitted to the intraday market for “t” trade zone, “p” market participant, “u” settlement period.

In the same regulation, in Article No.110, the monetary amount of energy imbalance is defined as formula (3).

$$EDT_f = \sum_{t=1}^{m}\sum_{u=1}^{n}\begin{bmatrix}\left(EDM_{f,t,u}(-)x\max(PTF_{t,u}, SMF_{t,u})x(1+k)\right)+ \\ \left(EDM_{f,t,u}(+)x\min(PTF_{t,u}, SMF_{t,u})\,\mathrm{x}(1-l)\right)\end{bmatrix} \tag{3}$$

In this formula,

EDT_f : Monetary amount of energy imbalance for “f” balancing responsible party in a billing period (TL),

$EDM_{f,t,\mathrm{u}}(-)$: Amount of energy taken from the system in order to eliminate energy imbalance for ”f” balancing responsible party, “t” trade zone, “u” settlement period (MWh),

$EDM_{f,t,\mathrm{u}}(+)$: Amount of energy injected to the system in order to eliminate energy imbalance for ”f” balancing responsible party, “t” trade zone, “u” settlement period (MWh),

$PTF_{t,u}$: System day-ahead price for “t” trade zone, “u” settlement period (TL/MWh),

$SMF_{t,u}$: System marginal price for “t” trade zone, “u” settlement period (TL/MWh),

m : Number of trade zones for the corresponding billing period,

n : Number of settlement periods in a billing period,

k : Coefficient between 0 and 1, which will be applied in the case of negative energy imbalance,

l : Coefficient between 0 and 1, which will be applied in the case of positive energy imbalance.

According to (3), the existence of dual price mechanism for the settlement of imbalances can be observed. This methodology has been in force since December 1, 2011.

Prior to December 2011, a generator had to sell the energy that it had produced more than its generation program and buy the energy that it had produced less than its generation program at the system marginal price for the corresponding hour in the balancing market. The same logic applied for a supplier, i.e., he had to settle his imbalances at the system marginal price. This mechanism enabled market participants to manipulate arbitrage opportunities in the market when they were able to predict that the system marginal price would be more or less than the day-ahead price.

Following December 2011, the new mechanism has created an environment that makes arbitraging impossible. If a market participant purchases energy from the balancing market, he has to pay at whichever price is greater among the day-ahead price and the system marginal price for the corresponding hour. In a similar way, if he sells energy to the balancing market, he receives at whichever price is smaller.

In formula (3), there are k and l coefficients that will further punish both positive and negative imbalances. Up to January 2014, these coefficients have been set to 0. However, with the new Electricity Market Balancing and Settlement Regulations, which is under preparation, the aforementioned coefficients will be set to 0.1. Such an action will definitely enhance the importance of energy imbalances and the mechanisms, which enable market participants to reduce their imbalance, such as intraday markets; considering that there are significant uncertainties in the power system primarily based on wind generators, power plant outages and load forecast errors.

5.2 Analysis of Net Energy Imbalances

In this part, energy imbalances in the electricity market, which occur due to the uncertainties mentioned in Chapter 4, will be analyzed for the year 2012.

Imbalances cannot be examined on the basis of market participants due to lack of data. This prevents the investigation of positive and negative imbalances for any hour of the year. However, the data for net imbalances for an hour can be retrieved based on the daily statistics published by Market Financial Settlement Center and National Load Dispatch Center. The methodology for the calculation of net imbalances is as formula (4).

$$NI_i = -\left[\left(\left(\sum_{x=0}^{2} YAL_{x,i}\right) - TEYAL_i\right) - \left(\left(\sum_{y=0}^{2} YAT_{y,i}\right) - TEYAT_i\right)\right] - \left[LF_i - L_i\right] \qquad (4)$$

In formula (4),

NI_i : Net imbalance at hour "i",

$YAL_{x,i}$: Total generation increase order by NLDC with code "x" at hour "i",

$TEYAL_i$: Total generation increase order that cannot be performed at hour "i",

$YAT_{y,i}$: Total generation decrease order by NLDC with code "y" at hour "i",

$TEYAL_i$: Total generation decrease order that cannot be performed at hour "i",

LF_i : Load forecast for hour "i",

L_i : System load at hour "i".

In this formula, the first part with square brackets represents net order in the balancing market and the latter part represents load forecast error. It should be noted that, one of the most critical parameter in the above formula is LF_i that is published by NLDC for 24 hours of the next day. It is not the sum of load forecasts of incumbent suppliers; however these companies benefit from the load forecast data of NLDC. Therefore, in this study, it is assumed that the sum of the aforementioned forecasts equals to the one performed by NLDC.

The application of formula (4) is exemplified in Table 5.

Table 5: Exemplification for the Calculation of Net Imbalances

Item (MWh)	01.01.2012 at hour 0	01.01.2012 at hour 13
YAL0 Order	0	1022
YAL1 Order	168	98
YAL2 Order	652	560
TEYAL Order	0	249
YAT0 Order	2365	0
YAT1 Order	0	0
YAT2 Order	355	461
TEYAT Order	30	0
Net Order	-1870	970
Load Forecast[9]	23100	24500
Load[10]	23312	24965
Load Forecast Error[11]	-212	-465
Net Imbalance	2082 (Positive)	-505 (Negative)

[9] Load forecast is represented as average consumption forecast for the relevant hour. Therefore, the unit can be MWh instead of MW.
[10] Load is represented as average consumption for the relevant hour. Therefore, the unit can be MWh instead of MW.
[11] Since load forecast and load data are represent as average consumption, also error is represented as average error. Therefore, its unit is MWh.

With the utilization of this methodology, total positive and total negative imbalances of market participants for any hour cannot be obtained. Only the net value related to imbalances can be retrieved.

When net positive and negative imbalances are examined on hourly basis, it can be seen that the values range from -4,500 MWh for net negative imbalances to 3,500 MWh for net positive imbalances, as shown in Figure 31. The small squares in this figure represent net imbalances encountered at different hours of the year 2012 and the circles represent average net imbalances for that hour throughout the year. It should be stressed that there is a tendency for net positive imbalances in the mornings and for negative imbalances in the afternoons. Hour-6 with 609 MW net positive hourly imbalance and hour-14 with 282 MW net negative hourly imbalances stand out.

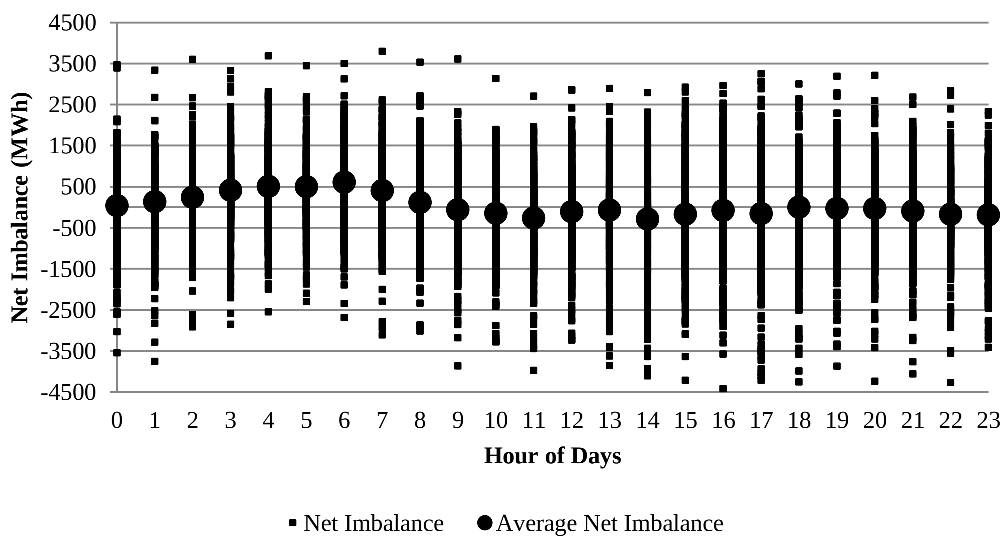


Figure 31: Distribution of Net Imbalances on Hourly Basis in 2012

One of the indicators for net imbalances is its relationship with system load. For the year 2012, it is shown in Figure 32. Each black square in this figure represents an hour and contains the information of the system load and net imbalance for the corresponding hour. In 2012, net imbalances in the electricity market are over 5% of the system load in 1477 hours of total 8784 hours, which correspond to 16.8% of the year.

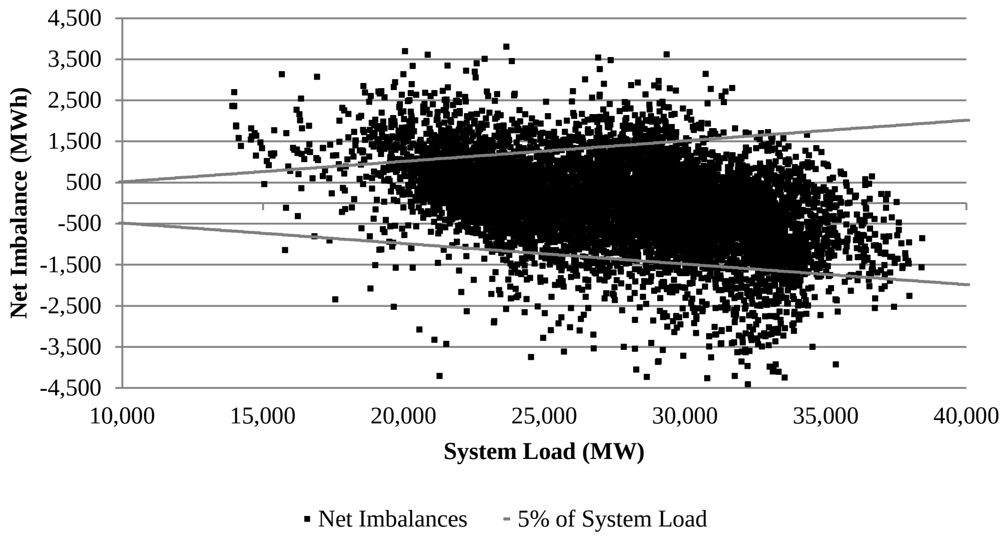


Figure 32: Net Imbalances vs. System Load

For the relevant year, the amount of net positive imbalances is 3.41 TWh and that of net negative imbalances is 3.52 TWh. By using the formula (3), which implies dual price mechanism for energy imbalances, the worth of net positive imbalances is 273,302,121 TL and that of net negative imbalances is 760,015,059 TL. In other words, theoretically, market participants might get approximately 273 million TL and might pay nearly 760 million TL for their imbalances in 2012. It should be emphasized that these numbers are definitely much higher in total for market participants, taking into account that they are not the exact imbalances but only net ones. The pivot table summarizing these points along with the unit production and consumption costs in the balancing market is shown in Table 6.

Table 6: Pivot Table for Net Imbalances and Relevant Points in 2012

Entry	Net Positive	Net Negative
Volume (MWh)	3,409,377	-3,524,236
Cost (TL)	273,302,121	-760,015,059
Unit Cost (TL/MWh)	80.16	215.65

Table 6 shows that generators get only 80 TL per MWh for their nonscheduled extra generation and pay 216 TL per MWh for their nonscheduled deficit generation. Considering that the average PTF and SMF are 149 and 139 TL/MWh respectively in 2012, the generation companies have lost considerable amount of money. Also, the same logic applies to the supplier companies. They get 80 TL per MWh for their nonscheduled deficit consumption and pay 216 TL/MWh for their nonscheduled extra consumption.

Intraday markets will emerge as one of the most prominent ways to reduce imbalances and provide financial gains for market participants by enabling them to make transactions in intraday time horizon, from the closure of the day-ahead market until two hours prior to the delivery. In order to show the benefits of intraday markets based on continuous bilateral trading, five synthetic weighted average intraday prices are derived based on the fact that intraday prices are established between day-ahead price and system marginal price most of the time [104]. The derivation of these prices for 8784 hours in 2012 is shown in Table 7.

In this table, WAID Price 1 is equal to the day-ahead price PTF, which symbolizes that all imbalances are settled as if the transactions are performed in the day-ahead market. Similarly, WAID Price 5 is equal to the system marginal price SMF, however this does not imply that these imbalances are settled as if in the balancing market inasmuch as the assumption in this situation is that transactions are realized at only at WAID Price, i.e. SMF, and the dual price mechanism that punishes electricity trading in the balancing market does not exist in the intraday market.

Table 7: Derivation of Weighted Average Intraday Market Prices

Price	Methodology
WAID Price 1	PTF
WAID Price 2	PTF-(PTF-SMF)*0.25
WAID Price 3	PTF-(PTF-SMF)*0.50
WAID Price 4	PTF-(PTF-SMF)*0.75
WAID Price 5	SMF

The unit costs for net positive and net negative imbalances become as Table 8, based on the synthetic prices derived for intraday markets as in Table 7. It can interpreted that by looking at the intraday prices the unit costs prove that making transactions in the intraday market could be much beneficial than using the balancing market.

Table 8: Unit Costs for Net Positive and Net Negative Imbalances in 2012

Price (TL/MWh)	Unit Cost (TL/MWh)	
	Net Positive	Net Negative
WAID Price 1	127.71	184.19
WAID Price 2	116.07	191.49
WAID Price 3	104.42	198.79
WAID Price 4	92.77	206.09
WAID Price 5	81.13	213.39

In Table 8, making transactions at WAID Price 1 implies that those are performed as if in the day-ahead market since the prices are equal to PTF. The unit prices in the direction of energy sales are 128 TL/MWh, which is 48 TL/MWh higher than those in the balancing market. Also, the unit prices in the direction of energy purchases are 184 TL/MWh, which is 32 TL/MWh lower than those in the balancing market. In both directions, energy transactions are beneficial for market participants which make imbalances. For other WAID prices, the unit prices are still better compared to the ones in the balancing market.

Besides five different intraday price levels, four scenarios are established based on what percent of imbalances would be settled in the intraday market as shown in Table 9. Imbalances are in the nature of power systems due to uncertainties, but mechanisms like intraday markets favor the reduction of these uncertainties. Since it is not completely possible to handle all of the imbalances in the intraday market, there are defined different scenarios in this study in order to improve the sensitivity and show the different possibilities.

Table 9: Scenarios for Imbalances

Scenarios	% of Imbalance That Would Be Settled in Intraday Market
Scenario 1	25
Scenario 2	50
Scenario 3	75
Scenario 4	100

According to these four scenarios, the change in the revenue of market participants which make imbalances and prefer to settle these imbalances in the intraday market based on five synthetic weighted average intraday market prices is presented in Figure 33. The financial benefits range from 3 million TL to 273 million TL depending on the prices and the volumes in the intraday market. If the WAID Price 3, which is the average of PTF and SMF; and Scenario 2, which indicates 50% of imbalances would be settled in the intraday market, are evaluated as the most sensible cases, the financial benefit is 71 million TL. The aforementioned benefit could be much higher if the trading volume of intraday market increases.

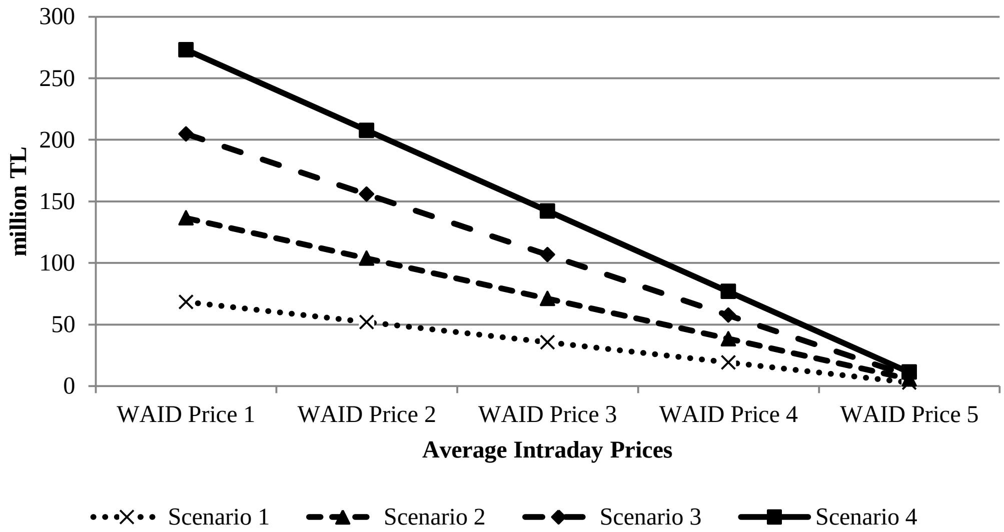


Figure 33: Change in the Revenue in case of Preference of Intraday Market for Net Imbalances

It should be stressed again that those financial benefits are only calculated for net hourly imbalances. It is assumed that only a positive or a negative imbalance occurs within an hour, which is not theoretically correct, taking into account that both positive and negative imbalances can occur in the same hour. Therefore, the given financial benefits can be much higher in real conditions providing that the intraday market is utilized by market participants at the expected intraday market prices.

In the following parts of this chapter, the similar analyses will be performed for the breakdown of imbalances, i.e. three main previously mentioned uncertainties; wind generators, power plant failures and load forecast errors.

5.3 Imbalance Analysis of Wind Generators and the Possible Effects of Intraday Markets

In this part, the aim is to show the potential benefits of intraday markets in the reduction financial losses due to wind forecast errors. The data to be utilized in this part belongs to the wind generators which in total provide over 50% of the total wind generation for Turkey in 2012. These wind generators are grouped and treated as if they belong to a single company and they are not under a balancing responsible party. This assumption is somewhat logical due to the fact that the imbalances of renewable plants with feed-in-tariff are under the responsibility of NLDC which compensates these financial viability from SBDT, distributed to all market participants.

The relationship between wind error and total net imbalance is pictured in Figure 34 with a scatter plot. An important point to be stressed is that the correlation between these two quantities is -0.0009 and the trendline is y=0, which imply that total net imbalances are not directly decided by the forecast errors of the selected wind turbines as should be expected because there are also other possible sources of net imbalances such as power plant failures and load forecast errors.

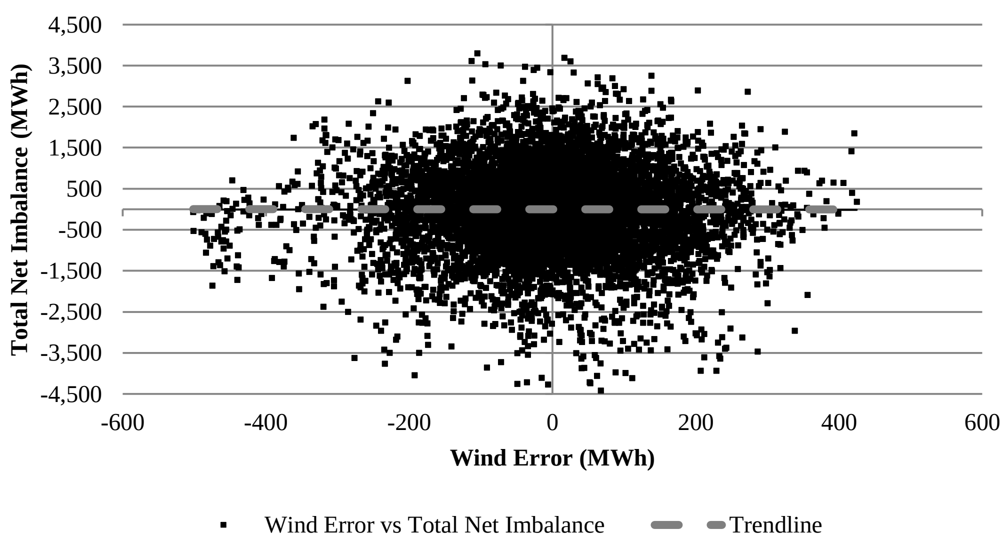


Figure 34: Relationship between Wind Error and Total Net Imbalance

In 2012, the amount of net positive imbalances of the selected wind generators is 0.38 TWh and that of net negative imbalances is 0.42 TWh, which are approximately one-tenth of total net imbalances. However, low correlation is an indication of the fact that total imbalances of market participants in both positive and negative direction are higher than those mentioned under total net imbalances. By using the formula (3), which implies dual price mechanism for energy imbalances, the worth of net positive imbalances is 55,212,830 TL and that of net negative imbalances is 66,151,699 TL. In other words, theoretically, selected wind generators might get approximately 55 million TL and might pay nearly 66 million TL for their imbalances in 2012. The pivot table summarizing these points along with the unit production and consumption costs in the balancing market is shown in Table 10.

Table 10: Pivot Table for Imbalances of Selected Wind Generators and Relevant Points in 2012

Entry	Net Positive	Net Negative
Volume (MWh)	379,835	-416,473
Cost (TL)	55,212,830	-66,151,699
Unit Cost (TL/MWh)	137.46	158.86

Table 10 shows that generators earn 137 TL per MWh for their nonscheduled extra generation and pay 159 TL per MWh for their nonscheduled deficit generation. Considering that the average PTF and SMF are 149 and 139 TL/MWh respectively in 2012, the generation companies have lost some amount of money inasmuch as they are not able to utilize day-ahead market for their imbalances.

Based on the synthetic weighted average intraday market prices derived by the methodology defined in Table 7, the unit costs for positive and negative imbalances for wind generators are represented in Table 11. Performing transactions at WAID Price 1 implies that those are performed as if in the day-ahead market since the prices are equal to PTF. The unit prices in the direction of energy sales are 158 TL/MWh, which is 21 TL/MWh higher than those in the balancing market. Also, the unit prices in the direction of energy purchases are 148 TL/MWh, which is 11 TL/MWh lower than those in the balancing market. In both directions, energy transactions are beneficial for market participants which make imbalances. For other WAID prices, it should be noted that the unit costs for net positive imbalances decreases as the prices converge to SMF, similar to the total net imbalances in Table 8. However, the unit costs for net negative imbalances decrease as the prices converge to SMF, which exhibits a different behavior in contrast with Table 8. This is primarily due to the fact that at the hours at which the wind generators make negative imbalances, they have the opportunity to find cheaper energy compared to the day-ahead market.

Table 11: Unit Costs for Positive and Negative Imbalances of Wind Generators in 2012

Price (TL/MWh)	Unit Cost (TL/MWh)	
	Net Positive	Net Negative
WAID Price 1	158.05	148.04
WAID Price 2	155.43	145.58
WAID Price 3	152.81	143.11
WAID Price 4	150.19	140.65
WAID Price 5	147.58	138.18

Based on the four scenarios defined in Table 9, the change in the revenue of market participants which make imbalances due to the characteristics of wind generators and prefer to settle these imbalances in the intraday market based on five synthetic weighted average intraday market prices is presented in Figure 35. The financial benefits range from 3 million TL to 12 million TL depending on the prices and the volumes in the intraday market. They present stable behavior, i.e. the revenue does not change depending on the WAID prices. It can be explained with the view that as the prices converge SMF, decreasing benefit for positive imbalances and increasing benefit for negative imbalances neutralize each other. If the WAID Price 3, which is the average of PTF and SMF; and Scenario 2, which indicates 50% of imbalances would be settled in the intraday market, are evaluated as the most sensible cases, the financial benefit is 6 million TL. Scenario 4, indicating 100% of imbalances would be settled in the intraday market, offers approximately 12 million TL profit but it is an unrealistic one. However, it is still an approach to demonstrate what the benefits would be for wind generators if their output could be perfectly predicted in the intraday time horizon.

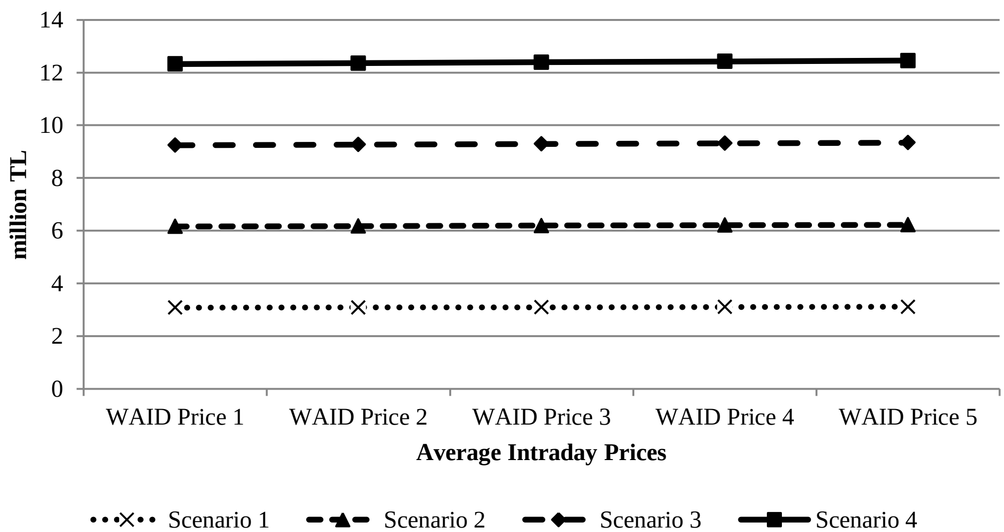


Figure 35: Change in the Revenue in case of Preference of Intraday Market for Selected Wind Generators

5.4 Imbalance Analysis of Power Plant Failures and the Possible Effects of Intraday Markets

In this part, the object is to represent the potential benefits of intraday markets in the reduction of financial losses due to power plant outages.

The data that will be utilized in this study belong to failure data of power plants which primarily belong to EÜAŞ, the affiliates of EÜAŞ, and other generation companies owning generation facilities in the concept of BO, BOT and TOOR. They contain the information of failure data and hour, failed unit and its capacity. For intraday analysis, it is assumed that the market participants can make transactions in the intraday time horizon after two hours their power plant has failed, due to the impossibility of purchasing energy for that exact hour. The possibility of self-balancing within the portfolio in the intraday time horizon is ignored for this study.

Another assumption is that if the outage occurs before 11 am, before the submission of bids to the day-ahead is closed, the company can purchase energy in the day-ahead market and will be able to eliminate its imbalances starting from 0 am in the following day. Otherwise, for the outages emerging after 11 am, the company will have the opportunity to utilize the day-ahead market next day and will be able to eliminate its imbalances starting from 0 am in the day after tomorrow. This assumption brings itself another assumption which implies that each failure lasts at least 36 hours. Another implication is that generation companies commit all of their capacity with bilateral agreements and day-ahead transactions from day-ahead and they do not belong to any balancing responsible party, which means that they have to settle their imbalances in the balancing market unless an intraday market exists.

Taking into account that the financial viability for imbalances of the majority of the aforementioned power plants belongs to two public companies EÜAŞ and TETAŞ, it will not be logical to search a relation between these power plant failures and total net imbalances owing to the fact that EÜAŞ, with its installed capacity and generation capability, has such a important position in the electricity generation sector that it can settle its own imbalances that occur in intraday time horizon. However, providing the relationship between loss of energy due to power plant failures and total net imbalance is investigated as shown in Figure 36, it can be observed that the correlation between these two quantities is 0.21 and the trendline is y=0.296x, which imply that total net imbalances are not directly decided by those outages as expected taking into account the other sources of uncertainties.

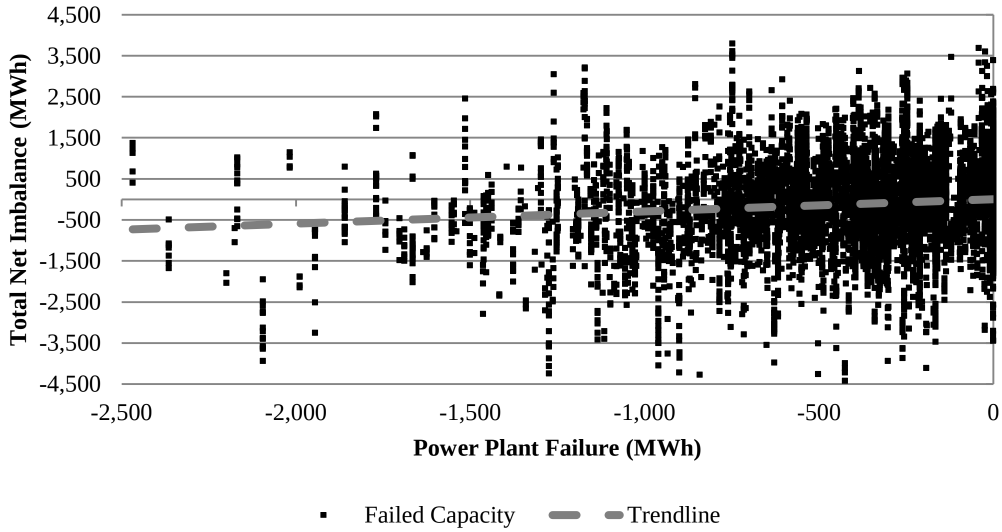


Figure 36: Relationship between Power Plant Failure and Total Net Imbalance

In the remaining of the study, it will be assumed that the previously mentioned imbalances are performed by different generation companies rather than EÜAŞ, in order to evaluate the potential benefits of the opportunity to make energy trading in the intraday market. In 2012, the amount of negative imbalances due to power plant failures is 3.49 TWh, which are approximately equal to total net negative imbalances. Again, low correlation is an indication of the fact that total imbalances of market participants in negative direction are higher than those mentioned under total net imbalances. By using the formula (3), which implies dual price mechanism for energy imbalances, the worth of net negative imbalances is 591,078,036 TL. In other words, the owner of the failed generators might pay nearly 591 million TL for their negative imbalances in 2012. The pivot table summarizing these points along with the unit production and consumption costs in the balancing market is shown in Table 12. It should be noted that the column concerning positive imbalances is empty inasmuch as it is impossible for a failed generator to make additional generation above its program.

Table 12: Pivot Table for Imbalances of Power Plant Failures and Relevant Points in 2012

Entry	Positive	Negative
Volume (MWh)	-	-3,494,260
Cost (TL)	-	-591,078,036
Unit Cost (TL/MWh)	-	169.16

Based on the synthetic weighted average intraday market prices derived by the methodology defined in Table 7, the unit costs for negative imbalances due to power plant failures are represented in Table 13. By performing transactions at WAID Price 1, i.e. at PTF, the unit prices become 156 TL/MWh, which is 13 TL/MWh lower than those in the balancing market. It is obvious that energy transactions in the intraday time horizon are beneficial for market participants which make imbalances for this situation. For other WAID prices, it should be noted the unit costs for net negative imbalances decrease as the prices converge to SMF, which exhibits a different behavior in contrast with Table 8 and a similar behavior compared to Table 11. This is primarily due to the fact that at the hours at which the power plant failures occur, the generation companies have the opportunity to find cheaper energy compared to the day-ahead market.

Based on the four scenarios defined in Table 9, the change in the revenue of market participants which make imbalances due to power plant outages and prefer to settle these imbalances in the intraday market based on five synthetic weighted average intraday market prices is presented in Figure 37.

The financial benefits range from 11 million TL to 66 million TL depending on the prices and the volumes in the intraday market. They present an increasing tendency as intraday prices converges to SMF. It can be explained with the view that as the prices converge to SMF, there exists a beneficial situation for negative imbalances as transaction are performed at cheaper prices and the expensive dual price mechanism is avoided. If the WAID Price 3 and Scenario 2 are evaluated as the most sensible cases, the financial benefit is 28 million TL.

Table 13: Unit Costs for Negative Imbalances of Power Plant Failures in 2012

Price (TL/MWh)	Unit Cost (TL/MWh)	
	Net Positive	Net Negative
WAID Price 1	-	156.13
WAID Price 2	-	154.65
WAID Price 3	-	153.17
WAID Price 4	-	151.70
WAID Price 5	-	150.22

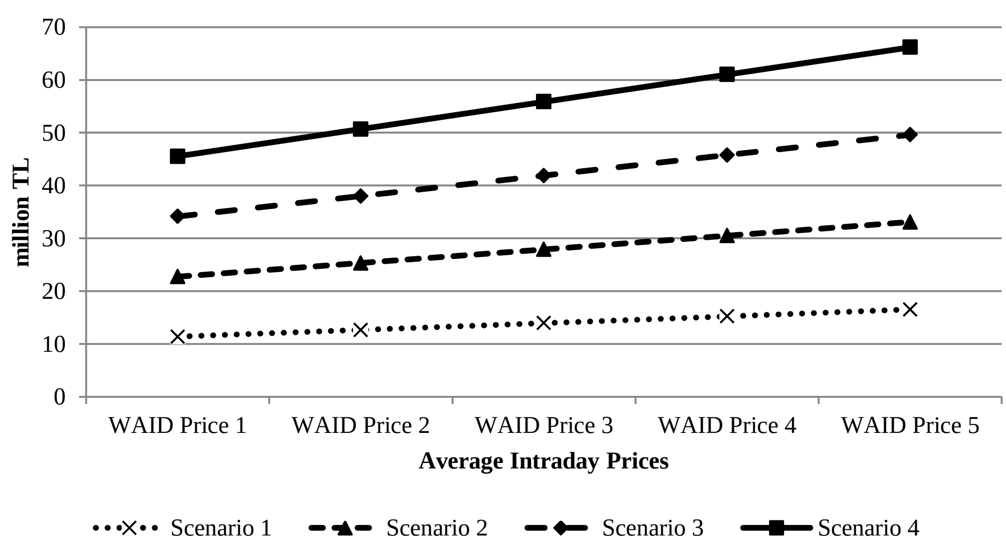


Figure 37: Change in the Revenue in case of Preference of Intraday Market for Power Plant Failures

5.5 Imbalance Analysis of Load Forecast Errors and the Possible Effects of Intraday Markets

In this part, the object is to investigate the potential benefits of intraday markets in the reduction of financial losses emerging due to load forecast errors.

The data to be utilized in this part of the study are load forecasts performed by NLDC and hourly realized loads in terms of average consumption per unit time for the relevant hour. An important point that should be stressed is that these load forecasts are intended for informative purposes only and they do not bring any viability to energy suppliers. However, incumbent suppliers in different distribution regions in Turkey are assumed to take benefit of these forecasts and they are expected to adjust their forecasts in accordance with the ones centrally performed by NLDC. In this study, it is assumed that the sum of consumption forecast of all suppliers is equal to the one generated by NLDC, which is fairly admissible.

The relationship between load forecast errors and total net imbalances is presented in Figure 38. A critical point to be mentioned is that the correlation between these two quantities is -0.31 and the trendline is y=-0.586, which imply that the relationship among these quantities is not strong as should be expected taking into account the contribution of other sources of uncertainties. However it is quite remarkable that the relationship is in the reverse direction, signifying that total net imbalance increases in the positive direction, i.e. excess generation; as load forecast errors in the negative direction, i.e. deficit forecast, increases. Again, just like in the analysis for wind generators and power plant failures, the encountered low correlation is an indication of the fact that total imbalances of market participants in both positive and negative direction are higher than those mentioned under total net imbalances in the electricity market.

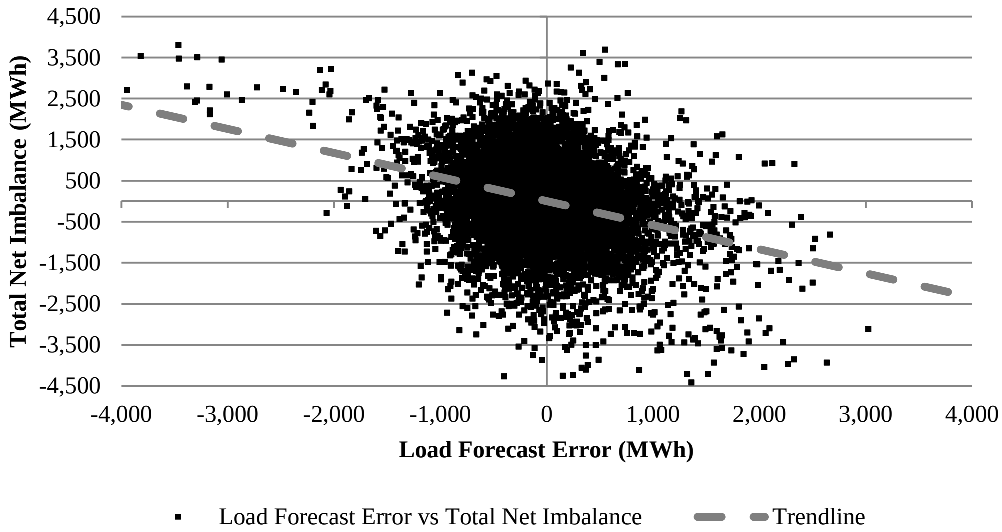


Figure 38: Relationship between Load Forecast Error and Total Net Imbalance

In 2012, the amount of net positive imbalances of load forecast errors is 1.63 TWh and that of net negative imbalances is 1.82 TWh, which are approximately half of the total net imbalances. By using the formula (3), which implies dual price mechanism for energy imbalances, the worth of net positive imbalances is 217,603,110 TL and that of net negative imbalances is 299,706,767 TL. In other words, theoretically, energy suppliers might get approximately 218 million TL and might pay nearly 300 million TL for their imbalances in 2012. The pivot table summarizing these points along with the unit production and consumption costs in the balancing market is shown in Table 14.

Table 14: Pivot Table for Imbalances due to Load Forecast Errors and Relevant Points in 2012

Entry	Net Positive	Net Negative
Volume (MWh)	1,634,364	-1,823,993
Cost (TL)	217,603,110	-299,151,699
Unit Cost (TL/MWh)	133.14	164.31

Based on the synthetic weighted average intraday market prices derived by the methodology defined in Table 7, the unit costs for positive and negative imbalances for load forecast errors are shown in Table 15. Performing transactions at WAID Price 1, i.e. at PTF, the unit prices in the direction of energy sales become 168 TL/MWh, which is 35 TL/MWh higher than those in the balancing market. Also, the unit prices in the direction of energy purchases are 150 TL/MWh, which is 14 TL/MWh lower than those in the balancing market. In both directions, it seems that energy transactions are beneficial for market participants which make imbalances. For other WAID prices, the unit prices are also better compared to the ones in the balancing market.

Table 15: Unit Costs for Positive and Negative Imbalances due to Load Forecast Errors in 2012

Price (TL/MWh)	Unit Cost (TL/MWh)	
	Net Positive	Net Negative
WAID Price 1	168.50	150.35
WAID Price 2	161.58	151.22
WAID Price 3	154.67	152.09
WAID Price 4	147.76	152.96
WAID Price 5	140.84	153.83

Based on the four scenarios defined in Table 9, the change in the revenue of market participants which make imbalances due to load forecast errors and prefer to settle these imbalances in the intraday market based on five synthetic weighted average intraday market prices is presented in Figure 39. The financial benefits range from 8 million TL to 84 million TL depending on the prices and the volumes in the intraday market. If the WAID Price 3 and Scenario 2 are evaluated as the most sensible cases, the financial benefit becomes 29 million TL.

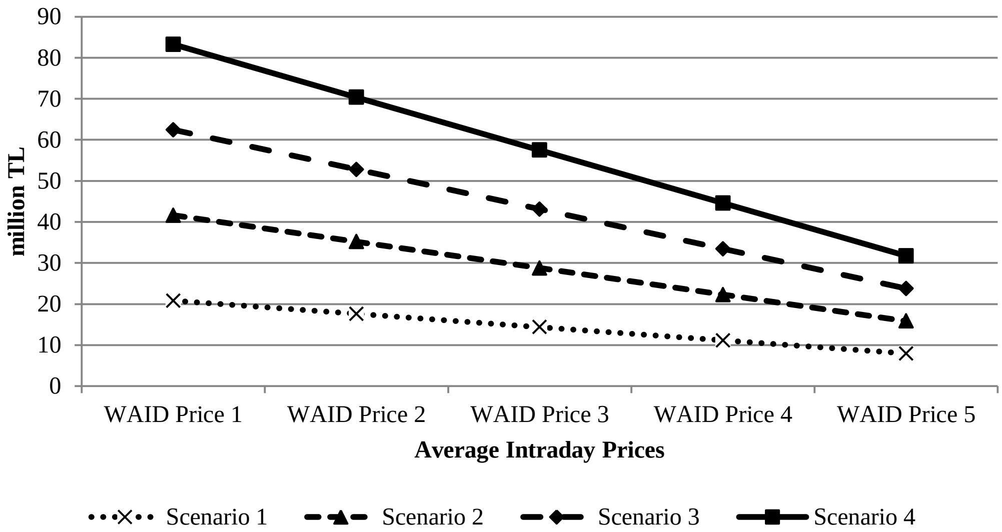


Figure 39: Change in the Revenue in case of Preference of Intraday Market for Load Forecast Errors

5.6 Summary of Imbalance Analysis of Uncertainties in Power Systems and the Effects of Intraday Markets

In Chapter 4, the main uncertainties in power systems such as wind forecast errors, power plant failures and load forecast errors have been defined. It is claimed that these uncertainties are expected to be the fundamental causes of imbalances of market participants.

In this chapter, the analyses of net positive and net negative imbalances have been covered. It is proved that for positive imbalances, market participants have to sell their over generation or deficit consumption at a significantly cheaper level and have to buy deficit generation or over consumption at a significantly expensive level compared to the day-ahead and system marginal prices in the day-ahead and balancing market. The possible favorable effects of intraday markets have been discussed with different synthetic weighted average intraday prices of which derivation based on PTF and SMF, assuming that the trading method is continuous bilateral trading. It is propounded that even in moderate cases intraday trading offer beneficial transactions to market participants, ranging from 3 million TL to 273 million TL based on the 2012-year data and scenarios. It is mentioned that these benefits can be much higher taking into account that these imbalance are the net ones, implying the subtraction of the positive and negative quantities for every hour.

In the remainder of the chapter, the components constituting the imbalances and their relationship with these imbalances have been studied in three different titles. When the imbalances caused by each uncertainty are evaluated among itself, the theoretical financial benefits of intraday markets are unraveled even in moderate scenarios. As for correlations, there are not strong relations among net imbalances and different sources of uncertainties. However, if the mentioned three uncertainties are combined, the correlation emerges as -0.13 as Figure 40 represents; i.e. there are not significantly meaningful statistical relationships among these quantities combined and net imbalances, of which data belong to the year 2012.

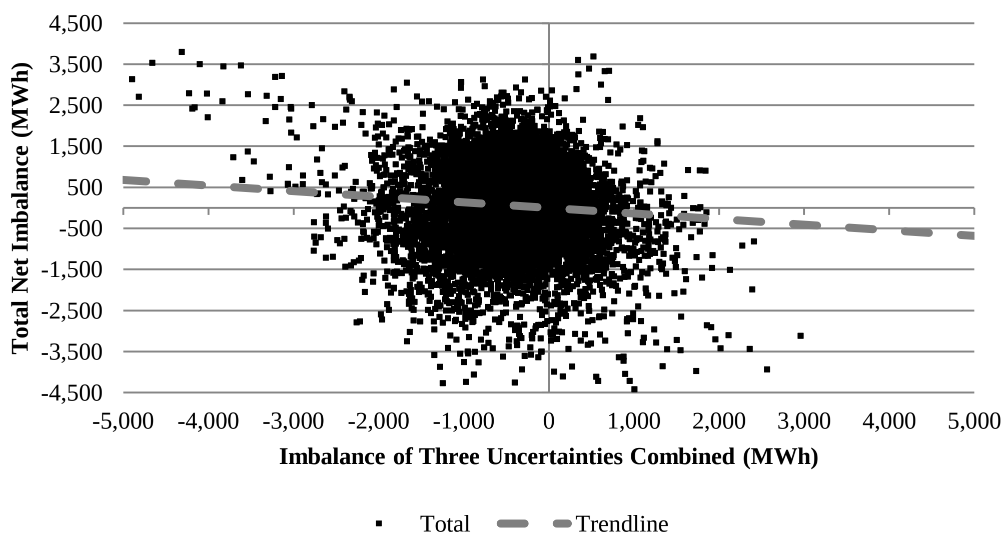


Figure 40: Relationship between Imbalances of Three Uncertainties Combined and Total Net Imbalances

There can be different reasons that can be put forward for the low correlation of three main uncertainties and net imbalances. One of them is the requirement of more detailed data for extended studies. The exact numbers of positive and negative imbalances for each hour are not available. The lack of imbalance data may hamper reaching statistically meaningful relationships. Also, for the analysis related to wind errors, the data belong to the wind generators which comprises of approximately half of the total wind generation in Turkey. The data covering all the wind turbines could present better results. Furthermore, for the analysis related to power plant outages, the data does not cover the failures of free generators which compose over half of the installed capacity in Turkey. The data that would include all the failures along with the exact outage periods would represent better results. Besides, for the analysis related to load forecast errors, the forecasts are centrally performed and they do not include the data from suppliers. The data of combined hourly consumption forecasts submitted by suppliers would exhibit better results.

Nevertheless, the available data for wind errors, power plant outages and load forecast errors contain significant information and also cover the majority of the cases related to these uncertainties. A claim saying that the net imbalances occur regardless of the three main uncertainties in the power systems will not be completely wrong according to theoretical perspective. This brings forward the possibility that market participants make imbalances for other reasons that have not been covered or they make transactions regardless of performing imbalances.

The dual price mechanism shown in formula (3) punishes imbalances of market participants by giving them the price which is lower among PTF and SMF for their over generation or deficit consumption and the price which is higher among PTF and SMF for their deficit generation or over consumption. Therefore, it seems that it would be illogical for a company to make imbalances intentionally. However, the current mechanisms; enabling incumbent supplier companies to reflect all the cost of the energy they purchase from day-ahead market via distribution tariffs; and daily day-ahead and monthly balancing market settlement in the electricity market and the structure of electricity sector; enabling a conglomerate to own generation companies and incumbent supplier companies in the distribution regions; may favor some of the companies to perform these imbalances in order to maximize their profits. This subject will not be approached deeply because it is beyond the scope of the thesis; nonetheless it has to be mentioned due to its importance, signifying the fact that intraday markets can only solve imbalance problems of market participants which virtually suffer from fundamental uncertainties in the electricity market; but it cannot help the ones which have imbalance problems of which origin depends on the problematic mechanisms and structures in the market.

The analyses performed in this chapter are somewhat primitive. In the remaining parts of this thesis, two different variables in the intraday market such as the intraday price and the intraday trading volume will be determined with more scientific approaches. These approaches include “Electricity Price Model” and “Short Term Load Forecasting Model”, utilized in the separate chapters. The main idea is to perform more complex analyses primarily based on investigating the potential benefits of the intraday market specifically for some particular cases such as wind generators in peak consumption hours, and with the same motive the benefits emerging for suppliers in the intraday time horizon.

CHAPTER 6

POTENTIAL BENEFITS OF INTRADAY MARKETS FOR WIND GENERATORS WITH ELECTRICITY PRICE MODEL

In intraday markets, there are mainly two parameters such as intraday price and intraday trading volume. The theoretical study performed in Chapter 5 is based on synthetic intraday prices and intraday transactions depending on materialized imbalances in the balancing market. In order to make some realistic analyses, these studies should include dynamic intraday price and intraday volume movements with realistic models. However, incorporating the aforementioned two dynamic parameters to the analyses at the same time is troublesome. Therefore, starting from Chapter 6 and Chapter 7, two different models will be established, which will provide the dynamic data for intraday market prices and intraday market volumes separately. For the model that will be utilized in this chapter, wind energy forecast errors at peak hours are chosen as the subject; while for the model in the next chapter, load forecast errors are selected as the topic. In the first model for wind generators, the intraday trading volume will depend on some basic assumptions; but the intraday prices will be determined by the “Electricity Price Model” which reflects the conditions in the Turkish electricity spot market. In the second model for load forecast errors, the intraday prices will depend on some basic assumptions; but at this time the intraday trading volume will be determined by “Short Term Load Forecasting Model” which will shed light on to the decisions of suppliers in the intraday time horizon. The studies in Chapter 6 and Chapter 7 should be evaluated taking into account these approaches.

6.1 Introduction

The characteristics of wind energy those are difficult to deal with, such as variability and uncertainty, have been presented in Chapter 4. These characteristics have been painstakingly analyzed for Turkey with the data belonging to previous years. The results have shown that the velocity of the wind can vary significantly within several hours and also the actual generation of wind turbines can diverge substantially from hourly generation forecasts performed in the day-ahead. Studies from the literature have proposed that making wind predictions in the intraday time horizon with the updated weather data along with the opportunity for market participants to be able to make transactions after the day-ahead market is closed can provide great benefits.

In this chapter, the aim is to represent the risks for wind generators, the importance of wind forecasts from the day-ahead and the benefits of the intraday markets, especially for yearly peak days in which the maximum yearly electrical energy consumption occurs. The importance of this study will flourish as the penetration of wind turbines flourishes in the system, i.e. the installed capacity of wind generators increases. In the period of 2012-2013, the installed capacity of wind energy has reached slightly over 2,000 MW and according to the capacity projections, in the period of 2018-2019, it may reach up to 9,000 MW considering the ongoing and potential investments in the electricity market [105].

One of the greatest risks for wind generators in peak hours is that the generation forecast from the day-ahead fairly diverges from the actual generation, especially in the case of deficit generation which causes imbalances that have to be punished in the balancing market with the dual price mechanism. They may have to bear serious additional costs if the prices in the balancing market rise.

The owners of the wind generators can reduce the risks by participating in the balancing responsible parties and handle the financial viabilities of the imbalances among the members in these groups, but not each owner participates or is able to participate in these parties. Another issue is the incentives for renewable energy which are still in force and continue providing guarantee of purchase for wind energy. The owners are free to choose whether bidding into the market or selling the energy with fixed prices. In the latter case, the responsibility of establishing a balance between forecasts and actual generation belongs to NLDC. In this case, the risks shift to NLDC and it covers the additional costs from market participants. In every case, unsuccessful forecasting and making imbalances cause financial losses which have to be taken from the system users.

Intraday markets, a continuous trading mechanism with extending trading period until two hours prior to the delivery, offer market participants to rearrange their positions in the market. With the help of these markets, the wind generators do not have to buy energy in the balancing market at the system marginal price. They will have the chance to buy energy in the intraday time horizon with more reasonable prices.

In order to fulfil the targets designated in this chapter, “Electricity Price Model” that will be introduced in the next part will be utilized. This study is inspired from the previous study of Sanli [106]. The model calculates the day-ahead price with the given peak system load for the next day. Then, taking into account the uncertainties that would make imbalances in the system; the model calculates the system marginal price for the relevant hour. Following this procedure, the options for wind generators to compensate their deficit generation in intraday time horizon with better prices will be investigated and the resulting benefits will be presented.

6.2 Model, Scenarios and Assumptions

The object of the model is to determine the day-ahead and system marginal prices on summer and winter peak hours in Turkish electricity market and then to establish possible intraday transactions for wind generators to provide them with the opportunity of compensating their expected deficit generation. In order to do so, estimation of the marginal price curve in Turkish electricity market is needed. The model is constructed with the data of the year 2012. Also, the model is extended with the data of the year 2018 for additional analysis.

In the construction of the model, the first step was obtaining the total installed capacity of power plants on the basis of primary energy resources from 1990 to 2012. There are 10 groups in total, which includes natural gas over 73 MW, natural gas under 73 MW, import coal, lignite, hydraulic dam, hydraulic run-of-river, fuel oil, wind, geothermal and biogas. Natural gas turbines and hydraulic power plants are separated into two parts in itself because the characteristics and performances vary appreciably. The change in the total installed capacity from year to year gives the installed capacity that has been taken into operation in that year. In order to increase the sensitivity of the model, the installed capacity in the year 1990, which is approximately 14,000 MW, split into five equal parts and spread into 1985-1989 period.

Secondly, the generators in Turkey are divided into two parts according to their ownerships. The first part of the generators belongs to the Electricity Generation Company, EÜAŞ; and free producers and autoproducers, the latter of which were attached to the group of free producers with the new electricity market law. The second part of them are the ones of which production come via purchase guarantee contracts such as BO, BOT and TOOR. It is assumed that the generators installed in 2012 have the best efficiency ratios among their peers. The efficiency numbers of each kind of power plant installed in 2012 are assumed to be as in Appendix-A Table 28. Efficiency values are not applicable to renewable power plants including hydraulic, wind, geothermal and biomass ones. Anyway, this does not cause any problem in the model due to the fact that the fuel costs of renewable power plants are assumed to be zero, as will be mentioned in the next paragraph.

The next step is to determine the fuel costs and operation and maintenance costs of the aforementioned power plants. Owing to the fact that the exact fuel costs are not open to public, some assumptions can be made only. These assumptions are presented in Appendix-A Table 29. The average calorific value of natural gas is assumed as 10.64 kWh/m^3, the average heating value of import coal as 6,000 kcal/kg and lignite as 1,800 kcal/kg. It must be noted that the fuel cost of renewable energy systems is taken zero. Also, it must be kept in mind that these costs include taxes.

As for operational and maintenance costs, the ones that the International Energy Agency has published are taken as basis. These costs and the corresponding capacity factors are given in Appendix-A Table 30. The acquisition of fuel costs and operational and maintenance cost of power plants enables the calculation of total costs for the generation of 1 kWh energy from each type of power plant and this will help to obtain the marginal costs which are required to run the model.

The last step is to define what the availability factors of each type of generators might be. These factors reveal the total available capacity in the system. The definition of these factors depends on the time for which the simulations will be performed, i.e. summer peak and winter peak times. In order to find the availability factors of these generators in summer peak on the basis of resources, the ability and production of each kind of generator are examined in terms of contribution to the daily peak load from 1 July 2012 to 31 August 2012. It is assumed that the plants, rather than natural gas and fuel-oil, have worked with full of their capacity in peak hours. However, natural gas and fuel-oil turbines were not able to work with full of their capacity in these hours inasmuch as their marginal cost might be higher than the day-ahead price. Therefore, for these generators, additional factors are added in order to provide to get a more realistic model.

The same procedure is repeated to find the availability factors of these generators in winter peak. The examined period is from 1 January 2013 to 28 February 2013. The reason for why the data in 2013 are chosen for the assessments of winter peak is that the year-end installed capacity of Turkey for 2012 is calculated by the numbers belonging to the first day of 2013. Therefore, it will be more realistic to make the analysis for the winter peak in 2013 not in 2012.

The availability factors are not taken as the same among each group of power plants. The age is an important element on the availability factor. The best availability factors belong to the power plants installed recently, i.e. in 2012. The degradation factor is selected as 0.3% per year except wind turbines. Due to the fact that the available capacity of them is extremely volatile, the corresponding factor is chosen as 0.1% per year.

The example of the resulting marginal price curve is pictured in Figure 41. The black line shows the marginal prices of the corresponding generation and the vertical grey line represents the system load which is forecasted to be 40,000 MW for this case. The intersection of the marginal price curve and the system load gives the day-ahead price, called as PTF. Approximately until 9,000 MW, the value of the marginal prices is zero, implying that the relevant generation is from purchase guarantee contacts such as BO, BOT and TOOR ones. The availability of generators is arranged as from cheaper generation to expensive generation. All price units are US dollar and the maximum price can be as much as 1 $/kWh, i.e. 1,000 $/MWh. The cross exchange rate for US dollar is taken 2 TL throughout all the analyses.

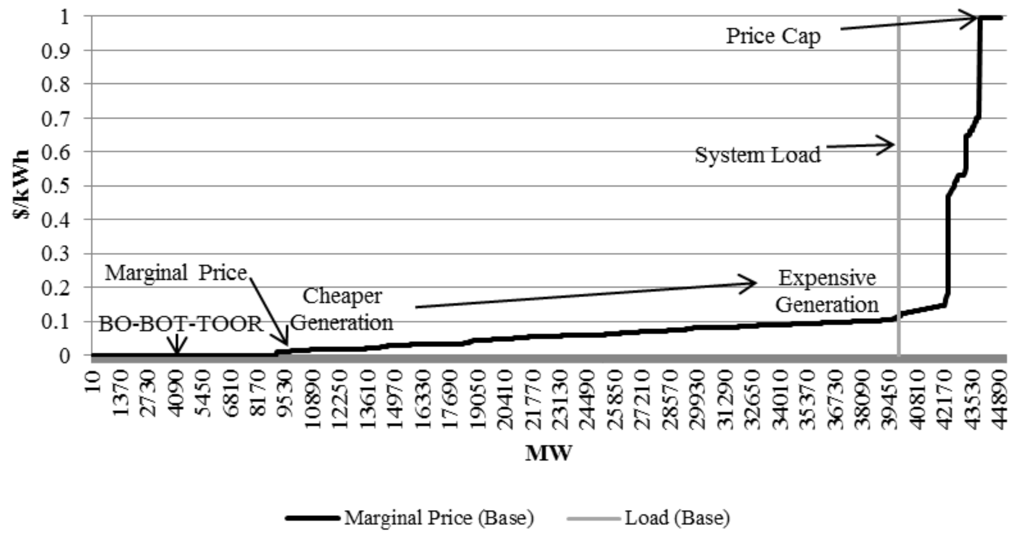


Figure 41: Example of the Marginal Price Curve

There are three scenarios for wind energy. The first one is the base case, which assumes the availability of wind generators 72.1% in summer season and 81.4% in winter season as the highest measured numbers in summer 2012 and winter 2013. The second and third scenarios are the cases in which the availability factors reduce to 50% and 25% respectively, which are quite logical considering that hourly wind forecast error can be up to 45% of the total installed capacity as mentioned in Chapter 4.

The determination of system marginal price in the balancing market is based on the imbalances in the system, which occur after the day-ahead market is closed. So far, three kinds of uncertainty that affects the imbalances have been mentioned such as wind errors, power plant outages and load forecast errors. The first kind of uncertainty, wind errors, has been included in this model, as given in the previous paragraph. The second kind of uncertainty, power plant failures, will be included in the model as 460 MW base load power loss for the hour at which the simulations will be performed. 460 MW corresponds to the average daily power loss of the generators mentioned in Chapter 4. The third kind of uncertainty, load forecast errors, will also be included in the model as deficit forecast which amounts 1.43% of the forecasted load. 1.43% corresponds to the value of the average load forecast error realized in 2012. Taking into account all the imbalances coming from three distinct components, the marginal price curves and system load curves are rearranged as shown in Figure 42.

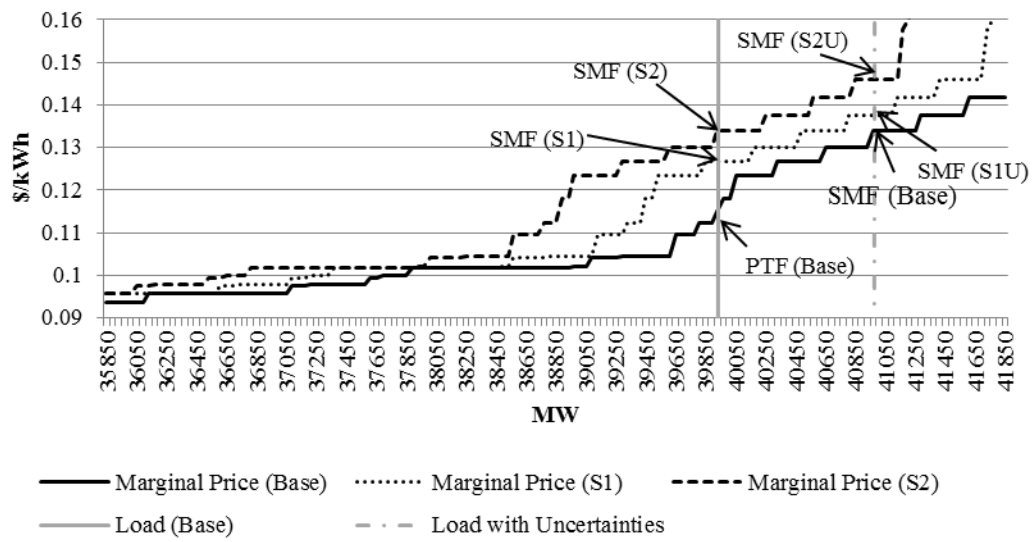


Figure 42: Example of the Marginal Price Curve Considering Uncertainties

There are three different marginal price curves in this case, called as marginal price (base), marginal price (S1) and marginal price (S2). The base marginal price curve is the same as shown in Figure 41. The marginal price curves S1 and S2 correspond to the shifted versions of the first curve due to the reductions in the availability factors of wind generators, reducing to 50% and 25%, respectively. Furthermore, there are two different system load curves. The grey straight line shows the forecasted load from the day-ahead. The dashed grey line shows the system load in real time considering the negative imbalances caused by 460 MW power plant outages and 1.43% error in load forecast. In fact, any power plant outage does not increase the system load; however for this case it is added to the system load in order to see its effect on the system marginal price and to differentiate the effect of wind variability and uncertainty from the other components.

The intersection of base marginal price curve and base load curve is the day-ahead price, as shown as PTF (base) in the figure. The intersection of the same line and with the other load curve including uncertainties gives the system marginal price for the base case, as shown as SMF (base). The intersections of other marginal price curves and system load curves present four different system marginal prices, shown as SMF (S1), SMF (S2), SMF (S1U) and SMF (S2U). All of these abbreviations contain the information of the scenario of wind availability and system load. These marginal prices are based on the assumptions that the electricity market is competitive; there is no congestion in the electric grid, assuring that no bids in the market gets over the system marginal price due to congestion. Indeed, the mechanisms in the balancing market is quite complex, but the logic suggested previously is fairly reasonable in terms of providing simplicity in the model.

As mentioned in the beginning of the chapter, the main idea of the construction of this model is to measure and show the benefits of intraday trading via intraday markets for wind generators in the reduction of risks. Risks emerge from the soaring system marginal price with the diminishing available capacity as it reduces due to wind scenarios and power plant outages along with load forecast error. For intraday trading, the study assumes that the available capacities of which marginal prices are higher than the day-ahead price are offered in the intraday market at the true marginal costs. Therefore, the wind generators will be able to compensate their expected deficit generation with the best available priced energy at that time at those true marginal costs, not at the system marginal price in the balancing market. The possible transactions in the intraday market will be via 40 MW products. This means that if there are 10 possible transactions in the intraday market, the total intraday trading volume will be 400 MW. The unit resolution is selected high in order to run the model more simply.

The expressions indicated up to this paragraph summarize the model, scenarios and assumptions that will investigate the benefits of intraday trading for wind generators. In the simulations, the model is also run for the year 2018. The model extended for that year is based on all the previous assumptions. The critical point for this model is the increase in the installed capacity year by year until 2019. Utilizing the Capacity Projection Report, the approximate increase in the power capacity is fixed for the model. Also, efficiency factors are expected to increase in five year time as presented in Appendix-A Table 31. The possible transactions in the intraday market are based on the same structure that is mentioned in the previous page. Also, the cross exchange rate for US dollar is again taken 2 TL for 2018 as in the model for 2012.

6.3 Simulations for 2012-2013 Peaks

The first part of the simulations will be performed for the period of 2012-2013. The model, scenarios and assumptions related to this period have been previously mentioned in the previous part in detail. Besides, several issues can be added to this information.

The flourishing electricity trading activities with the neighbors is taken into account in the simulations. For the relevant period, the trading volume with is taken as 500 MW in the net import direction at peak hours and supplemented to the base of the marginal price curve along with the purchase guarantee energy.

As for the system peak load, for 2012-2013 periods, the real data will be utilized, which is 38,500 MW for summer peak and 36,000 MW for winter peak load. The sensitivity analysis for system loads includes two steps composed of 1,000 MW increments.

6.3.1 Simulations for Summer 2012

Firstly, the situation in summer peak in the year 2012 will be examined. The forecasted system load is 38,500 MW; but the cases including 39,500 MW and 40,500 MW will also be evaluated for sensitivity analysis. Taking into account the effects of uncertainties, the real system loads are 39,511 MW, 40,525 MW and 41,539 MW respectively.

The simulation performed from the day-ahead is shown in Figure 43. The vertical grey line is at 38,500 MW, which is the forecasted base load. The intersection of the base marginal price curve and base system load curve is at 10.19 c$/kWh, corresponding to 203.78 TL/MWh. The maximum demand that can be meet is at 43,970 MW, represented by 1 $/kWh marginal price in the same figure.

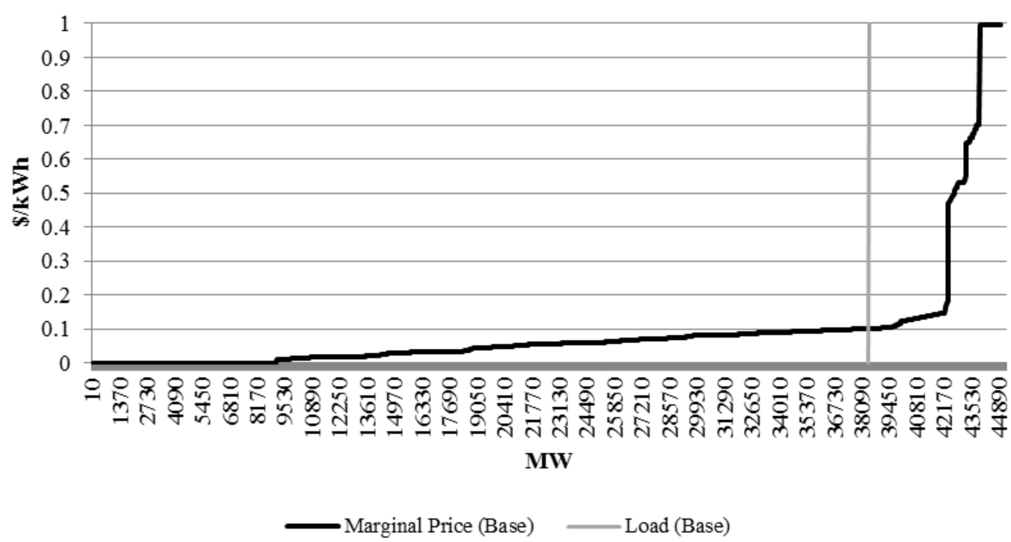


Figure 43: The Marginal Price Curve in Summer 2012

The wind capacity factor is 72.1% as mentioned in the assumptions and the corresponding generation for this capacity factor is 1,613 MWh. The first scenario assuming that the wind capacity factor decreases from 72.1% to 50% implies the deficit generation of 496 MWh from wind turbines. The second scenario, decreasing of wind capacity factor from 72.1% to 25%, implies the deficit generation of 1,057 MWh. The marginal price curves S1 and S2 are the shifted versions of based marginal price curve as much as 496 MW and 1,057 MW in the negative direction of the x-axis as shown in Figure 44. The SMF of S1 is 204.29 TL/MWh and that of S2 is 209.03 TL/MWh, which can be the system marginal prices in the balancing market, the prices at which wind generators would have to purchase their deficit generation considering no other uncertainty exists besides wind errors. The dashed vertical grey line regards all the uncertainties, at which the theoretical load is at 39,511 MW. The new SMF of S1 is denoted by SMF S1U is 236.21 TL/MWh and that of S2 denoted by SMF S2U is 253.32 TL/MWh.

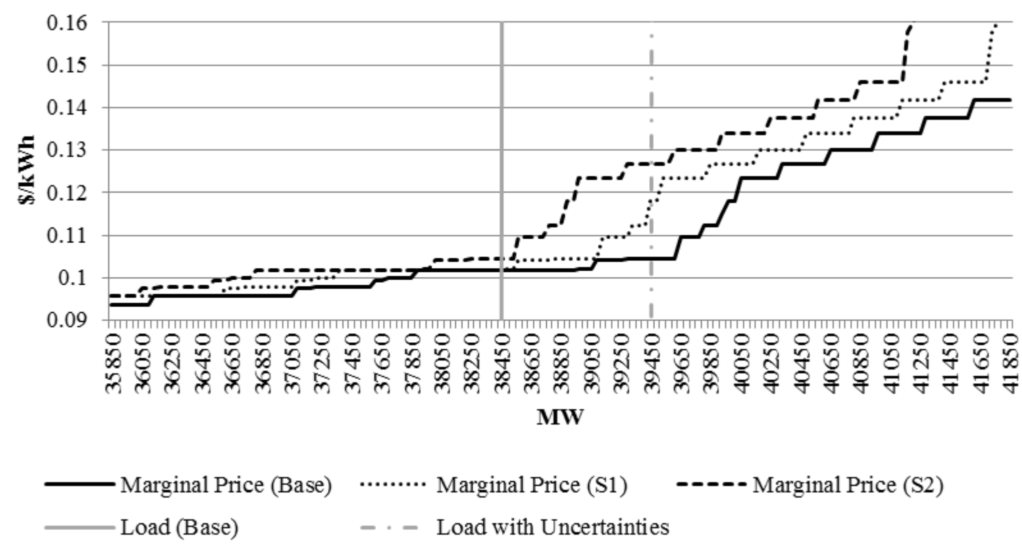


Figure 44: The Marginal Price Curve in Summer 2012 with Scenarios

Based on these assumptions, the trading opportunities in the intraday market will be as shown in Table 16. This table contains the information for system marginal prices mentioned above, number of possible transactions, total profit that can be obtained by wind generators compared to the case of imbalances and punishment by the dual price mechanism in the balancing market and the corresponding average profit per transaction.

Table 16: Results of Simulations for Summer 2012 at Base Load

Uncertainty	Scenario	SMF (TL/MWh)	Number of Transaction	Total Profit (x1000 TL)	Profit per Trade (TL)
Only Wind	S1	204.29	13	0.2	19
	S2	209.03	27	3.0	111
All	S1U	236.21	13	16.8	1,295
	S2U	253.32	27	50.8	1,882

The table shows that when only wind error is considered, the marginal price for both scenarios is at around 10-10.5 c$/kWh at base load which is forecasted to be 38,500 MW. However, when the other sources of uncertainties are included, the marginal price rises to the level of 12-13 c$/kWh. The resulting benefit for wind generators in the intraday market also increases depending on the level of marginal price and volume of transactions.

For higher electricity demand, such as 39,500 MW and 40,500 MW forecasted load, the sensitivity analysis can be performed and the total profits that can be utilized by wind generators in the intraday market with the corresponding marginal prices are presented in Figure 45.

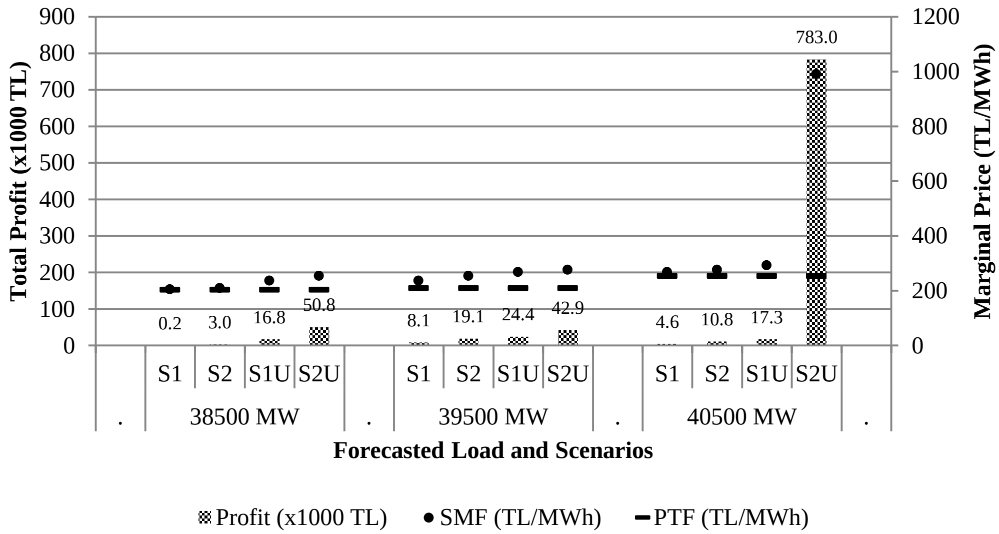


Figure 45: Results of Simulations for Summer 2012 at Different Loads

On the left side of the figure, the results for the base load that is summarized in Table 16 are also represented. The fact that the profits of wind generators in the intraday market depend mainly on the difference between SMF and PTF becomes obvious by looking at the levels of these prices which are shown with black circles and small lines in the same figure. At 39,500 MW forecasted load, the profits show similar trend compared to the base load. However, at 40,500 MW forecasted load, the intraday market can yield great benefits for wind generators especially for the cases when the other sources of uncertainty, power plant outages and load forecast errors, are included as shown with the scenarios S1U and S2U. The profit can reach up to 783,000 TL for only one hour, which is assumed to be the summer peak hour.

The average profit of the four scenarios as for 38,500 MW forecasted load is 17,800 TL, as for 39,500 MW 23,600 TL and as for 40,500 MW 204,000 TL. These results are an indication of the fact that as far as imbalances exist in the power system, wind power producers are highly exposed to the risks in the balancing market, especially at times in which the available capacity is the system reduces and electricity security of supply is under threat.

6.3.2 Simulations for Winter 2013

In the second part of the simulations for 2012-2013 period, the situation in winter peak in the year 2013 will be examined. The forecasted system load is 36,000 MW; but the cases including 37,000 MW and 38,000 MW will also be evaluated for sensitivity analysis. Taking into account the effects of uncertainties, the real system loads are 36,975 MW, 37,989 MW and 39,003 MW respectively.

The simulation of the model performed from the day-ahead is shown in Figure 46. The vertical grey line is at 36,000 MW, which is the forecasted load. The intersection of the base marginal price curve and base system load curve is at 9.56 c$/kWh, corresponding to 191.19 TL/MWh. The maximum demand that can be meet is at 43,050 MW, represented by 1 $/kWh marginal price in this figure.

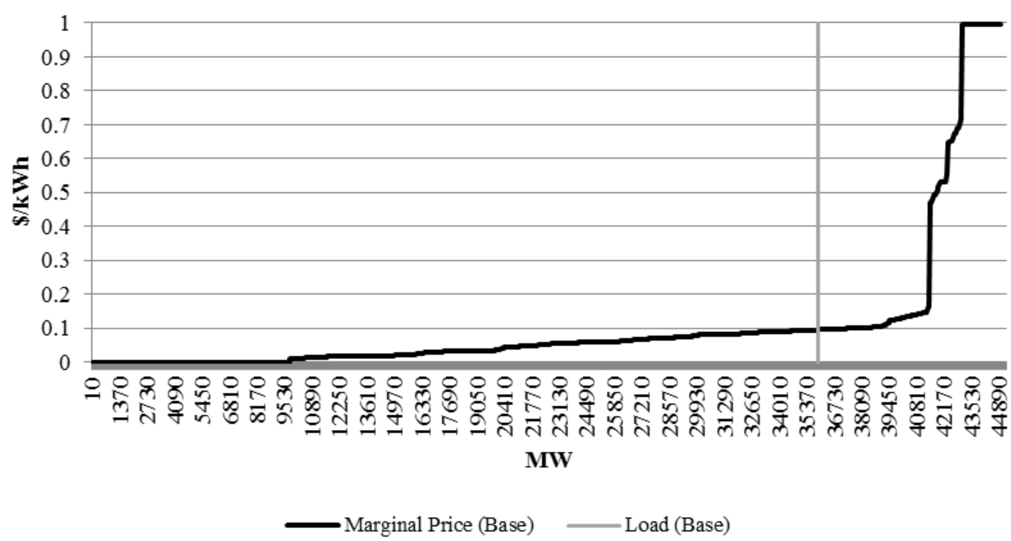


Figure 46: The Marginal Price Curve in Winter 2013

The wind capacity factor is 81.4% as mentioned in the assumptions and the corresponding generation for 81.4% capacity factor is 1,822 MWh. The first scenario assuming that the wind capacity factor decreases from 81.4% to 50% implies the deficit generation of 705 MWh for wind generators. The second scenario, decreasing of wind capacity factor from 81.4% to 25%, implies the deficit generation of 1,265 MWh. The marginal price curves S1 and S2 are the shifted versions of base marginal price curve as much as 705 MW and 1,265 MW in the negative direction of the x-axis as shown in Figure 47. The SMF of S1 is 191.42 TL/MWh and that of S2 is 195.66 TL/MWh, which can be the system marginal prices in the balancing market, the prices at which wind generators would have to purchase their deficit generation considering no other uncertainty exists besides wind. The dashed vertical grey line regards all the uncertainties, at which the load is at 36,975 MW. The new SMF of S1 is denoted by SMF S1U is 203.78 TL/MWh and that of S2 denoted by SMF S2U is 203.78 TL/MWh as well.

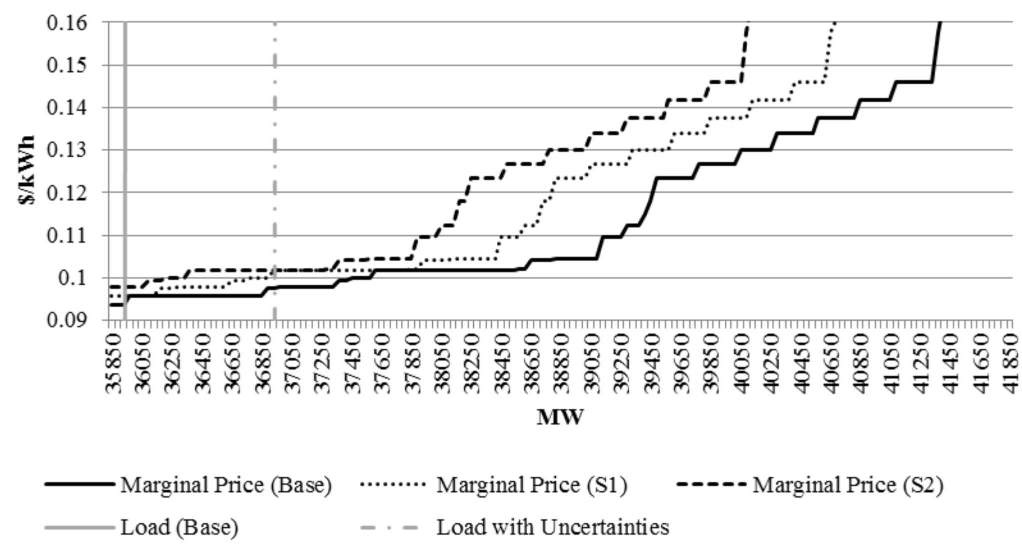


Figure 47: The Marginal Price Curve in Winter 2013 with Scenarios

Based on these assumptions, the trading opportunities for wind generators in the intraday market for winter 2013 are shown in Table 17. This table is quite similar to Table 16 and contains the same information. The table shows that when only wind error is considered, the marginal price for both scenarios is at around 9.5-10 c$/kWh at base load forecasted to be 36,000 MW. When the other sources of uncertainties are included, the marginal price rises just a little and reaches just over 10 c$/kWh.

Table 17: Results of Simulations for Winter 2013 at Base Load

Uncertainty	Scenario	SMF (TL/MWh)	Number of Transaction	Total Profit (x1000 TL)	Profit per Trade (TL)
Only Wind	S1	191.42	17	0.1	6
	S2	195.66	31	3.7	119
All	S1U	203.78	17	8.5	500
	S2U	203.78	31	13.8	444

For higher electricity demand, such as 37,000 MW and 38,000 MW forecasted load, the sensitivity analysis can be performed as it does for the summer peak in 2012 and the total profits that can be utilized by wind generators in the intraday market with the corresponding marginal prices are presented in Figure 48. Again, the fact that the profits of wind generators in the intraday market depends mainly on the difference between SMF and PTF must be underlined. At 37,000 MW and 38,000 MW forecasted loads, the intraday market can yield a good amount of benefit, but slightly lower than the case in summer 2012. The difference of the simulations for summer 2012 and winter 2013 is that although the available capacity is lower in winter, the system load is assumed to be fairly higher in summer, based on realized values in Turkish electricity market. In the analysis for winter 2013, the electricity security of supply is not threatened as much as it is in summer 2012. For wind generators especially for the cases when the other sources of uncertainty, power plant outages and load forecast errors, are included as shown with the scenarios S1U and S2U. The profit can reach up to 65,600 TL for only one hour, which is assumed to be the winter peak hour.

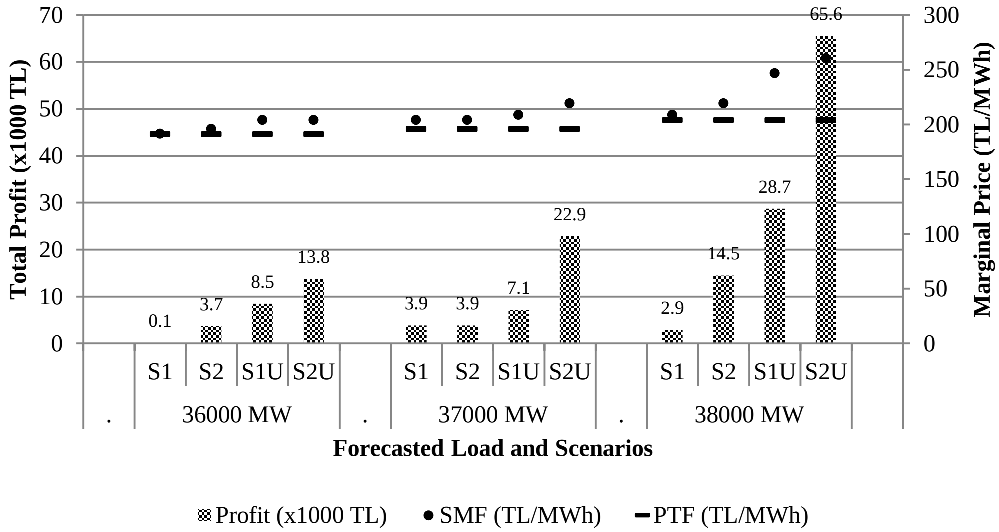


Figure 48: Results of Simulations for Winter 2013 at Different Loads

The average profit of the four scenarios as for 36,000 MW forecasted load is 6,500 TL, as for 37,000 MW 9,400 TL and as for 38,000 MW 27,900 TL. The corresponding benefits are obviously lower compared to the ones obtained from the simulation performed for summer 2012 due to the reasons mentioned in the above paragraph. Nevertheless, it is still a good example for the fact that as far as imbalances exist in the power system, wind power producers are exposed to the risks in the balancing market, especially as the available capacity in the system reduces and as it reaches to the critical levels for electricity security of supply.

6.4 Simulations for 2018-2019 Peaks

The second section of the simulations will be performed for the period of 2018-2019, in which the penetration of wind generators will be expected to increase in the system and reach up to 9,000 MW. The model, scenarios and assumptions related to this period have been already stressed in the previous parts in detail. Besides, several issues can be added to this information.

The flourishing electricity trading activities with the neighbors is also taken into account in the simulations, considering that a number of interconnection lines are under construction as of the beginning of 2014. Furthermore, considering the integration of Turkish electricity network and European transmission network, the electricity trading capacity with Europe is increasing gradually. Therefore, for the relevant period, the trading capacity is taken as 1,500 MW in the import direction at peak hours.

As for the system peak loads, for 2018-2019 periods, they are assumed to be 53,000 MW for summer and 52,000 MW for winter peak load. The sensitivity analysis includes two steps composed of 2,000 MW increments.

The simulations that will be performed in this section will be quite similar to the ones performed for 2012-2013 period. The object of these further simulations is to investigate the potential benefits of intraday markets for wind generators with the increasing wind power capacity.

6.4.1 Simulations for Summer 2018

In the first part, the situation in summer peak in the year 2018 will be examined. The forecasted system load is 53,000 MW; but the cases including 55,000 MW and 57,000 MW will also be evaluated for sensitivity analysis. Taking into account the effects of uncertainties, the real system loads are 54,218 MW, 56,247 MW and 58,275 MW respectively.

The simulation performed from the day-ahead is shown in Figure 49. The vertical grey line is at 53,000 MW, which is the forecasted load. The intersection of the base marginal price curve and base system load curve is at 9.13 c$/kWh, corresponding to 182.58 TL/MWh. The maximum demand that can be meet is at 64,850 MW, represented by 1 $/kWh marginal price in this figure.

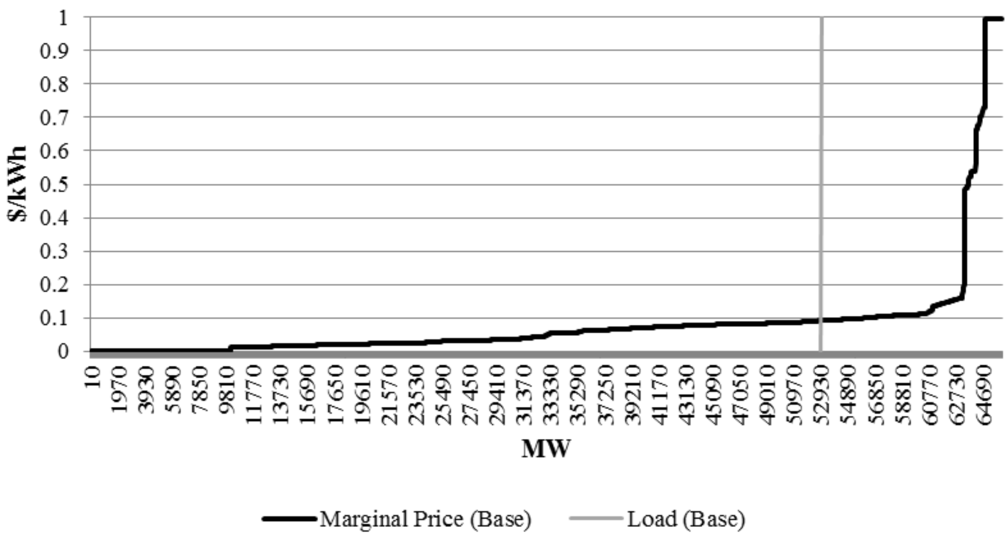


Figure 49: The Marginal Price Curve in Summer 2018

The wind capacity factor is 72.1% as designated for the summer case, and the corresponding generation for 72.1% capacity factor is 6,459 MWh. The first scenario assuming that the wind capacity factor decreases from 72.1% to 50% implies the deficit generation of 1,991 MWh for wind turbines. The second scenario, decreasing of wind capacity factor from 72.1% to 25%, implies the deficit generation of 4,243 MWh. The marginal price curves S1 and S2 are the shifted versions of the base marginal price curve as much as 1,991 MW and 4,243 MW in the negative direction of the x-axis as shown in Figure 50. The SMF of S1 is 195.14 TL/MWh and that of S2 is 205.41 TL/MWh, which can be the system marginal prices in the balancing market, the prices at which wind generators would have to purchase the deficit generation considering no other uncertainty exists besides wind. The dashed vertical grey line regards all the uncertainties, at which the load is at 54,218 MW. The new

SMF of S1 is denoted by SMF S1U is 198.10 TL/MWh and that of S2 denoted by SMF S2U is 216.42 TL/MWh.

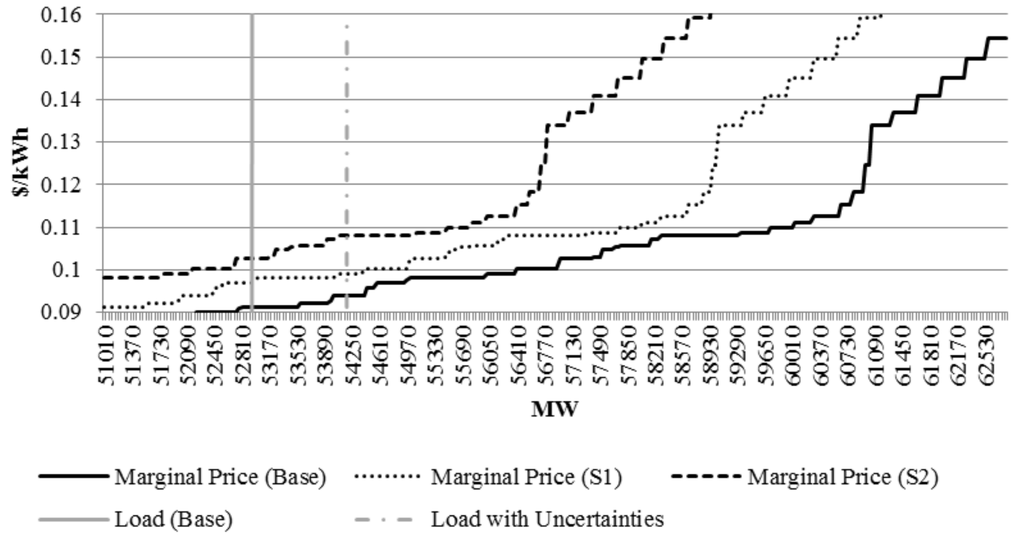


Figure 50: The Marginal Price Curve in Summer 2018 with Scenarios

Based on these assumptions, the trading opportunities in the intraday market will be as shown in Table 18. This table is quite similar to Table 16 and Table 17, and contains the same information.

Table 18: Results of Simulations for Summer 2018 at Base Load

Uncertainty	Scenario	SMF (TL/MWh)	Number of Transaction	Total Profit (x1000 TL)	Profit per Trade (TL)
Only Wind	S1	195.14	50	16.0	321
	S2	205.41	106	51.2	483
All	S1U	198.10	50	22.0	440
	S2U	216.42	106	98.0	924

The table shows that when only wind error is considered, the marginal price for both scenarios is at around 9.5-10.5 c$/kWh at base load forecasted to be 53,000 MW. However, when the other sources of uncertainties are included, the marginal price rises to the level of 10-11 c$/kWh. The resulting benefit for wind generators in the intraday market also increases depending on the level of marginal price and volume of transactions as it does in the previous simulations.

For higher electricity demand, such as 55,000 MW and 57,000 MW forecasted load, the sensitivity analysis are performed and the total profits that can be utilized by wind generators in the intraday market with the corresponding marginal prices are presented in Figure 51. On the left side of the figure, the results for the base load that is summarized in Table 18 are also represented. At 57,000 MW forecasted load, the intraday market can yield financial benefits over 300,000 TL for wind generators especially for the cases when the availability factor of these generators reduces significantly and the other sources of uncertainty, power plant outages and load forecast errors, are included as shown with the scenarios S2U. The profit can reach up to 352,000 TL for only one hour, which is assumed to be the summer peak hour in 2018.

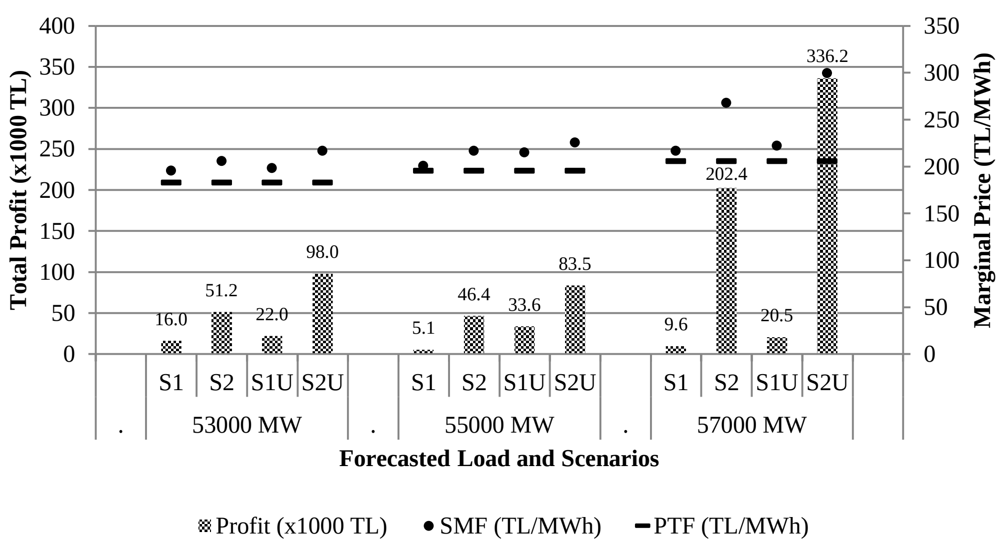


Figure 51: Results of Simulations for Summer 2018 at Different Loads

The average profit of the four scenarios as for 53,000 MW forecasted load is 46,800 TL, as for 55,000 MW 42,100 TL and as for 57,000 MW 142,200 TL. The corresponding benefits are fairly higher compared to the ones obtained from the simulations performed for summer 2012, except the highest loads. The SMF for highest load of S2U is approximately 1,000 TL/MWh in summer 2012, but in this case it is at around 300 TL/MWh. This causes the lower financial gain compared to summer 2012; nonetheless, for the lower values of system load, simulations have proven that due to increasing amount of possible transaction in the intraday market, the financial benefits also increase correspondingly. Similar to the previous cases, as the remaining availability capacity in the system decreases, the importance of the utilization from the intraday market flourishes.

6.4.2 Simulations for Winter 2019

In the second part of the simulations regarding 2018-2019 period, the situation in winter peak in the year 2019 will be examined. The forecasted system load is 52,000 MW; but the cases including 54,000 MW and 56,000 MW will also be evaluated for sensitivity analysis. Taking into account the effects of uncertainties, the real system loads are 53,204 MW, 55,232 MW and 57,261 MW respectively.

The simulation performed from the day-ahead is shown in Figure 52. The intersection of the base marginal price curve and base system load curve is at 8.63 c$/kWh, corresponding to 172.66 TL/MWh. This value is approximately 20 TL/MWh lower than the day-ahead price in the winter peak of 2013. The reason for the reduction is the expected installed capacity increase, which would be faster than the increase in peak demand. The maximum demand that can be meet is at 65,450 MW, represented by 1 $/kWh marginal price in that figure.

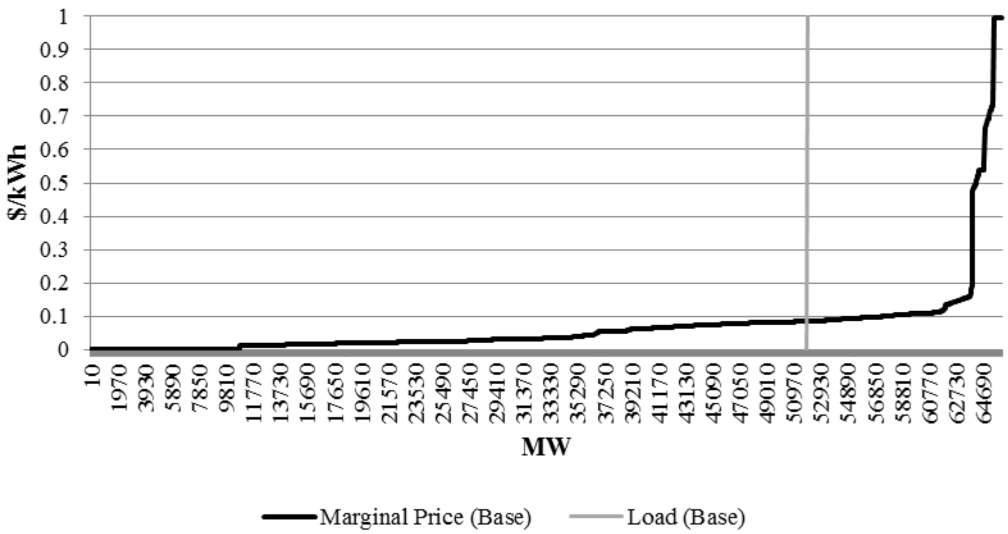


Figure 52: The Marginal Price Curve in Winter 2019

The wind capacity factor is 81.4% as defined for the winter cases and the corresponding generation 7,297 MWh. The first scenario assuming that the wind capacity factor decreases from 81.4.5 to 50% implies the deficit generation of 2,829 MWh for wind energy. The second scenario, decreasing of wind capacity factor from 81.4% to 25%, implies the deficit generation of 5,081 MWh. The marginal price curves S1 and S2 are the shifted versions of base marginal price curve as much as 2,829 MW and 5,081 MW in the negative direction of the x-axis as shown in Figure 53. The SMF of S1 is 182.58 TL/MWh and that of S2 is 196.22 TL/MWh, which can be the system marginal prices in the balancing market, the prices at which wind generators would have to purchase the deficit generation considering no other uncertainty exist besides wind. The dashed vertical grey line regards all the uncertainties, at which the load is at 53,204 MW. The new SMF of S1 is denoted by SMF S1U is 193.76 TL/MWh and that of S2 denoted by SMF S2U is 205.41 TL/MWh.

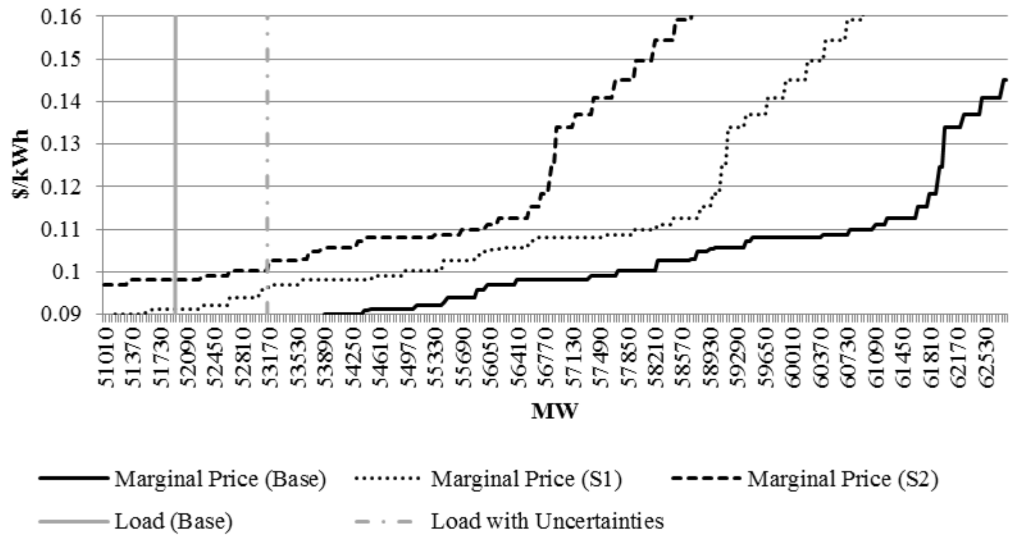


Figure 53: The Marginal Price Curve in Winter 2019 with Scenarios

Based on these assumptions, the trading opportunities in the intraday market for winter 2019 will be as shown in Table 19. This table contains the same type of information as in Table 16, Table 17 and Table 18.

Table 19: Results of Simulations for Winter 2019 at Base Load

Uncertainty	Scenario	SMF (TL/MWh)	Number of Transaction	Total Profit (x1000 TL)	Profit per Trade (TL)
Only Wind	S1	182.58	70	16.8	240
	S2	196.22	127	68.7	541
All	S1U	193.76	70	48.1	687
	S2U	205.41	127	115.3	908

The table shows that when only wind error is considered, the marginal price for both scenarios is at around 9-10 c$/kWh at base load forecasted to be 52,000 MW. When the other sources of uncertainties are included, the marginal price can rise just a little and reaches approximately 10 c$/kWh.

For higher electricity demand, such as 54,000 MW and 56,000 MW forecasted load, the sensitivity analysis are performed and the total profits that can be utilized by wind generators in the intraday market with the corresponding marginal prices are presented in Figure 54. At all levels for the forecasted load, the intraday market can yield significant benefits. Even for low peak demand projection, which is 52,000 MW, the profit can reach up to 115,300 TL. For higher levels of load, it can be as much as 342,500 TL for only one hour, which is assumed to be the winter peak hour.

The average profit of the four scenarios as for 52,000 MW forecasted load is 62,200 TL, as for 54,000 MW 66,800 TL and as for 56,000 MW 122,600 TL. The corresponding benefits are obviously higher compared to the ones obtained from the simulations performed for winter 2013 owing to the effect of increasing trading volume in the intraday market.

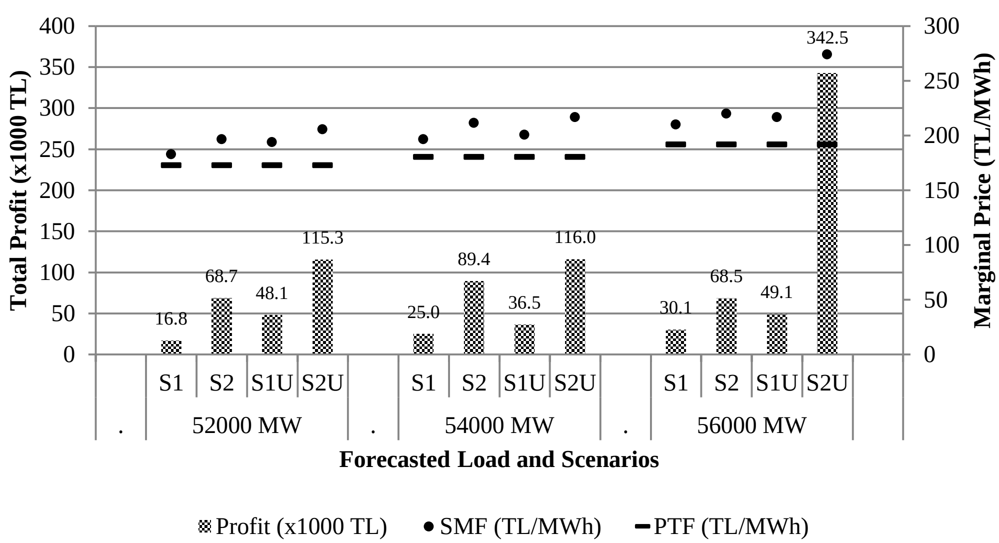


Figure 54: Results of Simulations for Winter 2019 at Different Loads

6.5 Further Analysis from Crisis Perspective

In the previous parts, simulations are performed with the Electricity Price Model for the periods of 2012-2013 and 2018-2019 summer and winter peak hours, in order to manifest the benefits and opportunities for wind generators with the opportunity of electricity trading in the intraday time horizon via intraday markets.

The results of the simulations until now have proven that intraday markets can yield great financial benefits for wind generators, especially at times in which the remaining available capacity in the power market reduces and more expensive generators have to be dispatched. The decreasing margin between available capacity and system load may cause a considerable difference between the day-ahead price and the system marginal price. This situation poses great risks for wind generators in case they make wrong wind forecasts and make imbalances which have to be settled in return via the balancing market with the high system marginal price.

In the last couple of years, Turkish electricity market has experienced rising electricity prices at times in which there are problems in the procurement of the electricity security of supply. Considering these incidents, further analyses from energy crisis perspective will be performed, which are mainly related to the benefits for wind generators in the intraday market.

In order to realize the analyses, the same model is used with the same assumptions. There are two situations defined for summer and winter seasons. For summer season, the problematic condition will be drought, which would cause the availability of all hydraulic power plants to reduce by 10% compared to the best availability factors obtained in summer 2012. For winter season, the corresponding condition will be related to the problems in the procurement of natural gas supply for power plants, which is assumed to cause the availability of all natural gas power plants to reduce by 20% compared to the best availability factors obtained in winter 2013. The reduction of the availability factors are chosen higher for the winter case due to the fragile structure of natural gas supply in Turkey.

The first part of these simulations is performed for 2012-2013 period summer and winter peak hours. The results are presented in Figure 55. Owing to the fact that the marginal price curve and the system load curve do not intersect, the forecasted loads of 40,500 MW for summer and 38,000 MW for winter are eliminated. As the forecasted system load increases along with the availability factor of wind generators reduces to 50% in the scenario S1U, and 25% in the scenario S2U, the potential benefits in the intraday market also increases correspondingly. The financial gains of the wind generators in the intraday market can reach up to 820,000 TL for summer peak and over 1.2 million TL for winter peak. Again, it should be underlined that these financial benefits are only for one hour, implying that they can surge substantially if examined in yearly time frame.

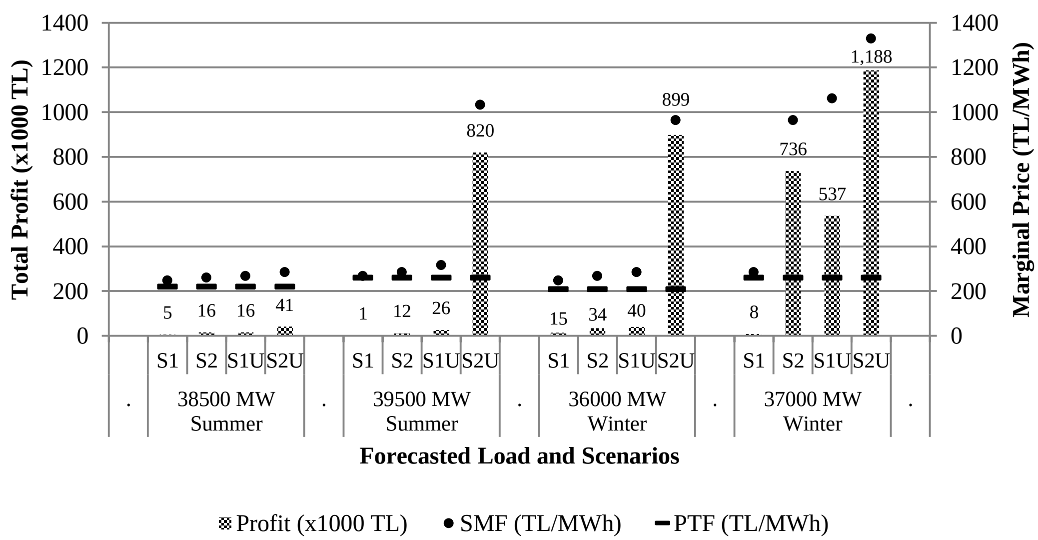


Figure 55: Results of Simulations with Crisis for 2012-2013 Peaks

The second part of these simulations is performed for 2018-2019 period summer and winter peak hours. The results are summarized in Figure 56.

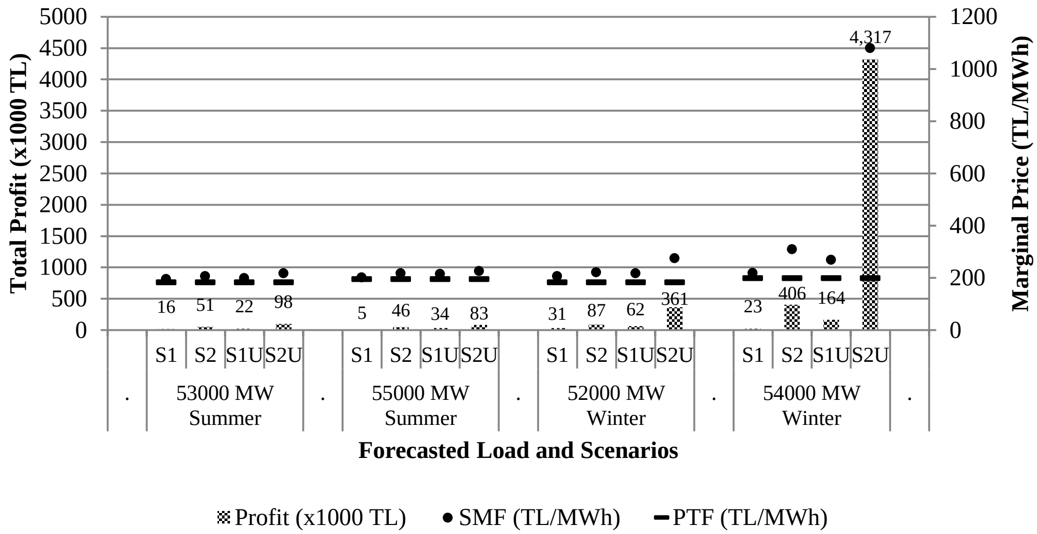


Figure 56: Results of Simulations with Crisis for 2018-2019 Peaks

Owing to the fact that the marginal price curve and the system load curve do not intersect, the forecasted loads of 57,000 MW for summer and 56,000 MW for winter are removed. The greatest benefits are obtained as much as 4.3 million TL for an hour in the case of scenario S2U with 54,000 MW peak demand in winter. The main reason behind such an enormous benefit is the potentially increasing trading volume intraday market along with the rising system marginal price reaching up to 1,100 TL/MWh. In other cases, financial gains up to 400,000 TL are possible. The most moderate cases are within 53,000 MW and 55,000 MW summer peak scenarios. It shows that even in case of a drought affecting hydraulic power plants, there is still enough remaining moderate priced capacity preventing the system marginal price from surging. However, the decreasing capacity factor of natural gas power plants as well as that of wind turbines might cause troubling conditions that may lead system marginal price to upper levels, which in return poses the aforementioned benefits for wind generators.

6.6 Results of the Simulations Performed in This Chapter

In this chapter, the object is to represent the potential benefits of intraday markets for wind generators at peak hours, considering the characteristics of wind energy such as variability and uncertainty makes generation forecasting troubling for these facilities. The instantaneous variation in wind velocity that has not been expected from day-ahead but becomes apparent in the intraday time horizon can cause significant financial viabilities for the owner or the operator of these turbines with the current market mechanism in Turkey inasmuch as wind generators have to purchase their over forecasted generation from the balancing power market with the price according to the dual price mechanism mentioned in Chapter 5, which could be quite costly in some cases.

The model constructed specifically for this chapter is based on the marginal prices of the generators that would determine the marginal price curve and the day-ahead price according to a definite value of system load. Then, taking into account the uncertainties in the power system such as wind errors, power plant failures and load forecast errors but separating the errors of wind generators to propound the benefits for wind generators; different marginal price curves are obtained for different scenarios that would assume to give the system marginal price in the balancing market.

For intraday trading, the model assumes that the intraday prices will be the marginal prices of the generators which are not dispatched from the day-ahead but expected to make generation in real time by getting orders in the balancing market. Some criticism might be expressed for the determination of the intraday price and system marginal price in this model. However, these prices are truly dependent on the true costs of generators with a reasonable profit margin and considering that in the literature there are some studies determining the theoretical intraday prices with the interpolation of the day-ahead price and the system marginal price, the intraday market prices used in this model is quite rational and acceptable taking into account that the intraday market mechanism in Turkey will be based on continuous bilateral trading. Another criticism might be directed for the fact that in the simulations only wind generators are able to make intraday transaction in the market; the errors due to power plant outages and load forecasting could not be compensated in the intraday market. This is deliberately performed in order to show the potential benefits specifically for wind generators due to their increasing importance in the generation portfolio of the Turkish electricity market.

The simulations have shown that there is always risk for wind generators for their deficit generation compared to the day-ahead forecasting; but the risk substantially increases in case the amount of remaining available capacity in the market decreases and the possibility of dispatch of high-priced generators in the balancing market increases. This period also coincides to the time in which the procurement of electricity security of supply could be problematic. Considering the uncertainties emerging in the relatively long time span between day-ahead and real time, the establishment of the intraday markets is essential. The risk for wind generators exponentially surges with the increasing installed capacity of wind generators in the power system. If the incentives for the renewable power plants become a feasible and lucrative option for wind generators, it is highly possible for them to sell their energy in this concept with fixed price and shifting the viability of making imbalances to NLDC. In this case, better wind forecasting mechanisms in the intraday time horizon and well-functioning intraday markets will be mostly beneficial for NLDC and hence for the market participants and indirectly for end electricity users to whom the additional costs of NLDC are reflected.

CHAPTER 7

POTENTIAL BENEFITS OF INTRADAY MARKETS FOR SUPPLIERS WITH LOAD FORECASTING MODEL

7.1 Introduction

In Chapter 5, the imbalances in the Turkish electricity market, occurring due to wind generators, power plant failures and load forecast error, were covered and a number of analyses related to these issues were performed. In these analyses, potential benefits of intraday markets in the reduction of imbalances were investigated with a theoretical approach. Intraday analyses were mainly based on the synthetic intraday market prices which were obtained with the interpolation of the day-ahead price and the system marginal price for different levels. Following the determination of the intraday prices, four different scenarios were defined according to the different volumes of imbalances that would possibly be settled in the intraday market. Both of these approaches were essential to reveal the current condition of three kinds of sources of imbalances in Turkey.

Although the aforementioned analyses give a general idea about the necessity and the potential benefits of intraday markets in Turkey, these analyses are not grounded on dynamic conditions but static theoretical conditions in terms of price and volume of the intraday market. Since the intraday market has not been opened yet in Turkey, it is difficult to certainly decide on the intraday prices but there are some examples in the literature claiming that these prices are most likely to occur at the levels between the day-ahead price and the system marginal price, according to the experiences. Therefore, defining different levels for intraday prices between these two prices are the most sensible assumption for this issue considering that no intraday market is under operation at the current period. The second variable in the intraday market, the trading volume, depends on the necessity of market participants with the incoming updated information regarding the uncertainties they are to deal with. As mentioned in Chapter 4, meteorological conditions specifically in the plant area are the decisive factor for wind generation forecasts. Hence, the analyses performed in the previous chapter depend on static trading volumes in the intraday time horizon but dynamic prices with the utilization on the Electricity Price Model. Regarding power plant outages, any failure can occur in any generation facility at any time. The decision for the owner of the power plant having experienced an outage is based on the failed capacity and the arbitrage opportunities in the market according to its vision. The possible arbitrage opportunities in the intraday market cannot be covered in this thesis due to the utilization of static and synthetic intraday prices.

In order to make simulations with a dynamic model in which the variability will rest on the volume of the intraday market, the subject of load forecasting errors and short term load forecasting is an excellent option over which a realistic model can be established. Taking into account that the energy requirement of an electricity supplier is subject to some changes in the intraday time horizon; whether making active trading in the intraday market based on the changes in the load forecasts or making passive trading in the intraday market and waiting until the closure of this market or performing no trading in the intraday market and making all the transactions in the balancing market will be evaluated throughout this chapter with the utilization of a short term load forecasting module based on Artificial Neural Networks (ANN) structure in MATLAB, which would make some estimations for the intraday time horizon.

7.2 Model and Assumptions

In this part of the chapter, the construction of the load forecasting model, simulations regarding the load forecasting model and the results of these simulations will be summarized. The details for the short term load forecasting model utilized via ANN structure in MATLAB are explained in an elaborative manner in Appendix-B.

The model will try to forecast the hourly electricity consumption of Turkey in 2012 with the utilization of the data belonging to the years 2010, 2011 and 2012. Since the model will make forecasts covering whole Turkey, there will be assumed only one supplier in Turkey, which would provide electricity to all customers.

By its very nature, electricity demand cannot be estimated precisely. However, the meteorological conditions and the trend of electricity consumption in the intraday time horizon can send significant signals to the electricity suppliers which are responsible for making demand forecasts of their customers. With the utilization of ANN structure, the target is to obtain a load series based on the estimations in the period between the day-ahead and real time; i.e. the intraday period. At the same time, it is crucial that the load series that will be obtained as the output of the model give better forecasting results compared to the ones centrally performed by the NLDC. Following the determination of to what extent load forecast errors can be minimized within the intraday time horizon, some strategies for the intraday market will be evaluated and will be able to come to some conclusion on whether intraday trading opportunities provide market participants with some benefits.

There are several options for the construction of short term load forecasting model but ANN has been chosen for this study thanks to its clear implementation and good performance.

In short term load forecasting, historical load and weather temperature are claimed to be the most crucial factors. For historical load, the hourly system load data can be given as input. For temperature and other data like humidity and wind velocity, in order to obtain a single weather data set reflecting the conditions of Turkey, the weather data of five big cities in different regions of Turkey such as İstanbul, Ankara, İzmir, Antalya and Diyarbakir are used. The cities are selected according the level of electricity consumption in 2012. The levels of consumption ratio of cities are selected as coefficients for weather data, which would in return form a single weather data set needed as input for the model.

Besides load and weather data, there are also other data sets including the day of the week from Monday to Sunday enumerated from 1 to 7; the type of the day defining whether it is a work day or public holiday enumerated by 0 and 1; and the hour of the day enumerated from 0 to 23. These data are also the inputs of the model along with system load and weather data.

Following the completion of the required data, the next step is to form the scenarios and obtain the best load forecast series in terms of load forecast percentage error, which will be used in the intraday analysis in this chapter. There are four scenarios designated according to the number of data sets used such as TEMP, HUM, VEL and ALL; of which details are in Appendix-B as mentioned previously. In all of these scenarios the day of the week, the type of the day, the hour of the day, previous load and temperature data exist. TEMP is the base scenario; HUM includes humidity data set and VEL includes wind velocity data set in addition to the ones in TEMP. The last scenario, ALL, includes both humidity and wind velocity data in addition to those in TEMP scenario.

After the scenarios are formed, four simulations are performed based on the model constructed as mentioned in the previous paragraphs. The object is to obtain a load forecast series for 168, 24, 18, 12, 8, 4 and 2 hour before real time. Although 168-hour load forecasting is not required for this study, it is solely implemented for test purposes. The results of the simulations are represented in Appendix-B from Figure 63 to Figure 72. The benchmark criteria for the results are the mean absolute percentage error, MAPE. The first simulation is based on the scenarios with previous n-hour load data which are utilized by separately. The second simulation depends on the scenarios with cumulative previous n-hour load data which are utilized cumulatively. According to these two simulations, the best results are obtained from ALL scenario in the second simulation. Therefore, in the next two simulations, only ALL scenario and the cumulative previous n-hour load data selection are exercised. In the third and fourth simulation, data partitioning methods are employed; i.e. they are performed for different seasons such as winter, summer, spring and autumn. The results show improvement compared to the previous cases.

In overall, this model gives the required load forecast series in order to conduct the study. The interpretation of results is presented in Table 22. The performance indicator, MAPE, of the acquired load forecast series two hours prior to the delivery for winter season is 0.95%, for summer season 0.84%, for spring season 0.87% and for autumn season 1.14%. The improvement of the results for two hours prior to the delivery varies between 32% and 39% compared to the forecastes performed from the day-ahead. The fact that the MAPE of actual load forecasts performed by NLDC varies between 1.22% and 1.49% is another factor showing the improvement of the load forecasts performed in the intraday time horizon according to the obtained series. The results can further be improved by taking into account weather condition updates in the intraday time horizon.

7.3 Scenarios

In this part, the model of which formation has been summarized in the previous part and has been explained with all details in Appendix-B will be utilized. In order to run the model, three scenarios for intraday trading strategy are considered. The scenarios can be counted as follows:

- Scenario 1: Active trading in the intraday market
- Scenario 2: Moderate trading in the intraday market

- Scenario 3: No trading in the intraday market

The starting conditions such as energy positions and load forecasts of these three scenarios are the same from the day-ahead. The differences for these scenarios lie on the choices of the market participants following the closure of the day-ahead market, in terms of energy transactions depending on the changing load forecasts with updated information.

Scenario 1 symbolizes active trading in the intraday market, implying that the market participant actively makes intraday trading with the updated load forecasts in all time intervals of the intraday market. Scenario 2 is characterized by moderate trading in the intraday market, referring that the market participant do not actively participate in the intraday trading and only make transactions depending on the updated information two hours prior to the delivery at the closure of the intraday market. In Scenario 1 and Scenario 2, it is assumed that the market participant is able to make transactions based on continuous bilateral trading when wants to do so. Scenario 3 is denoted by no trading in the intraday market, meaning that the market participant disregards or prefers not to participate in this market and settle its imbalances in the balancing market, being aware of the fact that the imbalances are punished by the dual price mechanism.

There are five trading levels in the model which enables intraday transactions in the intraday time horizon 18, 12, 8, 4 and 2 hours prior to the delivery hour. The determination of the intraday prices depends on the derivation of synthetic intraday prices similar to ones in Chapter 5. The prices in Chapter 5 were the weighted average ones projected as PTF, SMF and the values on three equal intervals between PTF and SMF. The synthetic intraday prices in this chapter rest on the hours left to real time operation and in their formation the linear interpolation technique is applied between PTF and SMF as shown in Figure 57.

The figure symbolizes the movement of intraday prices depending on the values of PTF and SMF. The object of the figure is to show the intraday price trends and as shown in the figure, there are three possible directions of the prices: down trend, upward trend and stable trend. The starting points of the figure are day-ahead prices at 24 hours prior to the delivery on the right side and the end points are the system marginal prices at 0 hours prior to the delivery, implying real time on the left side. The synthetic intraday prices are derived at five segments based on this procedure for all 8784 hours in 2012.

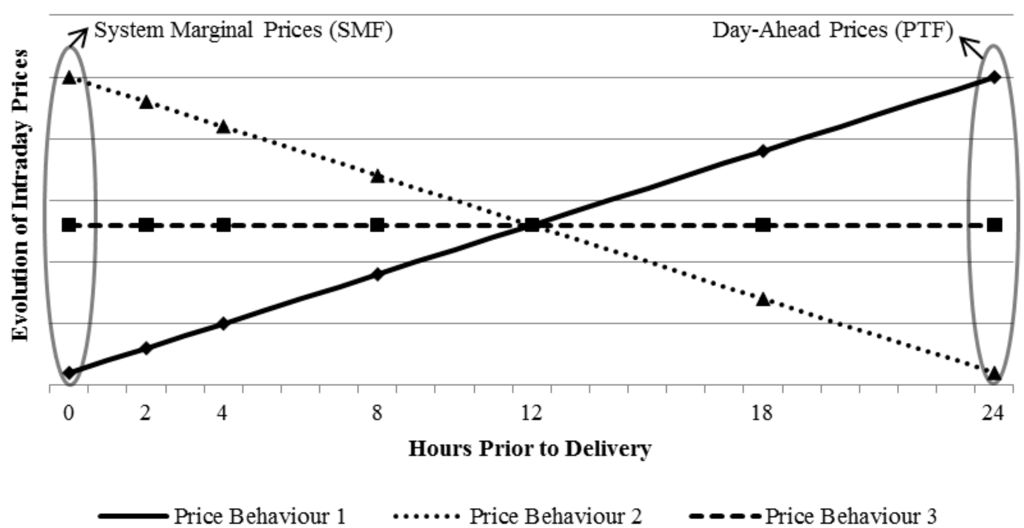


Figure 57: Evolution of Intraday Prices for This Model

7.4 Simulations

Based on the scenarios defined in the previous part, the cash flow of these scenarios is presented in Table 20. The table is composed of the items of energy sales, energy purchases, balance and profit or loss as the results of each scenario. Energy sales represent the money that the market participant obtains from the energy that it sells in the intraday and balancing markets combined for the first two scenarios and in the balancing market only for the third scenario. Moreover, energy purchases represent the money that the market participant pays for to the energy that it obtains in the intraday and balancing market combined for the first two scenarios and in the balancing market only for the third scenario. The third item, balance, represents the net positions of the market participant depending on the transactions following the closure of the day-ahead market.

For the last item in the table, Scenario 3 is chosen as the base case, in which no intraday trading is performed. Therefore, it shows the profit or loss of Scenario 1 and Scenario 2 compared to the net position of Scenario 3.

Table 20: Cash Flow of Scenarios for 2012

Item	Scenario 1	Scenario 2	Scenario 3
Energy Sales (TL)	173,887,826	164,695,373	161,703,417
Energy Purchases (TL)	-352,248,756	-348,116,027	-360,566,214
Balance (TL)	-178,360,930	-183,420,654	-198,862,797
Profit/Loss (TL)	20,501,867	15,442,143	0

Before commenting on the first three items in the table, the profits and losses should be evaluated. According to the overall results, Scenario 1, performing active trading in the intraday market emerges as the most beneficial scenario. Scenario 2, performing moderate trading in the intraday market comes just after Scenario 1. There is not a huge difference between the profits obtained in Scenario 1 and Scenario 2. Besides, Scenario 3 turns up to be the least beneficial case. Anyway, the expectation is that due to the dual price mechanism applied in the balancing market, market participants are claimed to suffer financial losses for their imbalances. Intraday markets, which provide market participants with the opportunity of electricity trading after the day-ahead market is closed, are alleged to procure financial benefits for market participants by somewhat extending day-ahead trading and alleviating the losses in the balancing market.

For the first three items in the table, the numbers are directly based on the volumes and unit prices of transactions performed in overall. In each scenario, the volumes of energy trading are surely different owing to the distinct trading strategies of the market participant. Therefore, the evaluation of these three items; energy sales, energy purchases and balance; must be realized by taking into account the comparison prepared in Table 21.

Table 21: Benchmark of Volumes and Unit Prices for 2012

Scenarios	Energy Sales (MWh)	Unit Price Sales (TL/MWh)	Energy Purchases (MWh)	Unit Price Purchases (TL/MWh)
Intraday Trading in Scenario 1	6,049,325	141.21	-6,701,478	143.95
Intraday Trading in Scenario 2	1,289,641	131.50	-1,941,794	146.82
Imbalance Trading in Scenario 1 & 2	1,085,742	119.10	-1,179,077	167.27
Imbalance Trading in Scenario 3	1,416,933	114.12	-2,162,421	166.74
Actual Condition for Load Forecasting	1,634,364	133.14	-1,823,993	164.31

The first item is related to the energy sales and unit prices of intraday transactions in Scenario 1. The volume of energy sales and energy purchases in Scenario 1 is significantly higher compared to the other scenarios due to the active trading strategy in the intraday market. For Scenario 1, energy sales are approximately 6 TWh and energy purchases are 6.7 TWh. Combining this information with the one for Scenario 2, telling that energy purchases are higher than energy sales; it can be deduced that that the outputs of the load forecasting model as for 24 hours prior to the delivery have tendency to make deficit forecasts, which are later settled in the intraday market. This determination can also be proved by the energy sales and purchasing number of the imbalance trading in Scenario 3. As regards the unit prices of intraday trading in Scenario 1, the numbers reflect that sold energy in the intraday market is more valuable and the purchased energy in the intraday market is more economical compared to both the imbalance trading in Scenario 1 & 2 and the imbalance trading in Scenario 3. That is exactly compatible with what the construction of intraday markets aim; both the buyer and the seller do not suffer from the unfavorable prices in the balancing market.

Regarding the second item in the table, the subject of disequilibrium between the volumes of purchases and sales has been previously mentioned. When the unit purchase and sales prices are examined, the conditions are still better than the imbalance trading scenarios. However, the unit prices are located between the intraday trading Scenario 1 and the imbalance trading scenarios shown by the third and fourth item in the same table.

As for the third item in the table, it should be stressed that the imbalance trading scenarios for Scenario 1 and Scenario 2 are the same due to the fact that in both scenarios the market participant enters to the balancing market with the same energy positions. The volume of energy sales and energy purchases must be compared with that of in the fourth item. Approximately 1.1 TWh energy sales and 1.2 TWh energy purchases in the balancing market show the improvement in the self-balancing of the market participant with the help of the intraday market utilized in Scenario 1 and 2, compared to 1.4 TWh energy sales and 2.2 TWh energy purchases in the balancing market in which no trading in utilized. When the same comparison is performed for the unit sales and purchases prices, the numbers are fairly close to each other. The unit purchase price can be slightly higher than the price in the next scenario; however the energy purchase volume is remarkably lower, which provides financial gains to the market participant.

The fifth item in the table represents the results obtained in Chapter 5. It takes part in this table for comparison purposes although it will not be completely sensible to compare two quantities of which data source is different; i.e. in one case the data belong to the load forecast model established for making simulations and in the other case the data belong to the actual load forecast values. The actual condition for the imbalances due to load forecast errors shows that volumes in the balancing market are quite different due to the reasons explained in the previous sentence. As for unit prices for purchases are close to each other but there is significant difference in the unit prices for sales. This is directly related to the volume and the timing of the transactions in the balancing market. Besides the volume, also the timing of the transactions for each condition change correspondingly owing to the different sources of data.

In conclusion of this part, it is shown that intraday markets provide financial gain for the market participants in case of updated data and forecasts in the intraday time horizon. The benefits of active and moderate participation in the intraday market are quite close to each other according the profits indicated in Table 20, but the first is seemingly one step ahead. However, this subject must be investigated one step further in order to find the answers of the following questions: Is the intraday market always beneficial for the market participants? Should the market participants prefer active trading in the intraday market over moderate trading at all times? Can the balancing market be beneficial for market participants although they are penalized by the dual price mechanism?

7.5 Further Analysis for Extreme Cases

In order to clarify the points mentioned at the end of the previous section, further analysis will be performed based on the extreme cases experienced in the simulations of the model. Therefore, daily analysis will be carried out depending on hourly simulation data. The scenarios mentioned in the previous section are also applicable for the analyses of this section.

7.5.1 Case 1: Trading on January 21, 2012

The first case belongs to January 21, 2012. The data related to this case such as hour, load, PTF, SMF, load forecasts, errors in load forecasts, intraday prices, and financial situation are given in Appendix-C.

This is a kind of day in which the remaining available capacity decreased to such a point that relatively expensive generators have to be dispatched. This remark can be made depending on the high prices in the balancing market reaching 641 TL/MWh at some of the hours. Across the day, the average PTF becomes 208.72 TL/MWh and the average SMF becomes 317.83 TL/MWh, together signifying that there are probably a couple of problems while ensuring the electricity security of supply.

According the result of the model for this day, the day-ahead load forecast error is 2.30%. The load forecast errors in the intraday time horizon become 1.61%, 0.94%, 0.95%, 0.82% and 0.96% for the forecasts carried out 18, 12, 8, 4 and 2 hours prior to the delivery respectively. There is a tendency for load forecast errors to reduce throughout the day.

The cash flow of three scenarios specific to January 21, 2012 is presented in Table 22. Moreover, the benchmark of these scenarios concerning trading volumes and unit prices for the same day is shown in Table 23.

Table 22: Cash Flow of Scenarios for January 21, 2012

Item	Scenario 1	Scenario 2	Scenario 3
Energy Sales (TL)	352,502	344,226	341,221
Energy Purchases (TL)	-5,467,204	-6,506,586	-6,672,666
Balance (TL)	-5,114,702	-6,162,360	-6,331,445
Profit/Loss (TL)	1,216,744	169,085	0

Table 23: Benchmark of Volumes and Unit Prices for January 21, 2012

Scenarios	Energy Sales (MWh)	Unit Price Sales (TL/MWh)	Energy Purchases (MWh)	Unit Price Purchases (TL/MWh)
Intraday Trading in Scenario 1	14,246	264.12	-21,448	300.99
Intraday Trading in Scenario 2	1,701	145.26	-8,903	447.91
Imbalance Trading in Scenario 1 & 2	1,243	182.32	-5,431	487.60
Imbalance Trading in Scenario 3	2,281	149.59	13,671	488.10

According to the results, Scenario 1 is by far the most beneficial case compared to the other scenarios. The profit compared to the base case, which is previously assumed to be Scenario 3, is approximately 1.2 million TL. When the volumes of energy sales and purchases are examined, due to the energy requirement in the system, the volume of the latter one significantly prevails that of energy sales. The degree of benefits can also be tracked from the table. The average unit price for sales in 264 TL/MWh, which is remarkably higher that the sales price in any other scenario and implying the value of sold energy more than the other scenarios. In the similar sense, the average unit price for purchases is 301 TL/MWh, which is significantly lower and meaning that purchased energy is more economical compared to the other scenarios.

Although the market participant participates in the intraday market in Scenario 2, there are almost no differences between the financial positions in Scenario 2 and Scenario 3. Waiting until the closure of the intraday market and not moderate participation in this market has resulted in missed opportunities. Anyway, considering the unit prices for Scenario 2, the considerable difference in the both direction of energy transactions draws attention. Especially, the fact that the average value of the sold energy in Scenario 2 is lower than that of in Scenario 3 although dual price mechanism is applied in the balancing market is quite meaningful. However, the main reason for the low profit in Scenario 2 is high amount of energy purchases at high prices.

When the imbalance trading for Scenario 1 & 2 and Scenario 3 is compared, the effect of improved load forecasting can be realized by looking at the decreasing volume of energy sales and purchases thanks to intraday trading. As for unit prices, the average price for sales is fairly advantageous and there is almost no difference between the purchase prices. Nevertheless, the decreasing volume of the transactions in the balancing market makes the real difference for this case.

In order to summarize the points narrated in this section, the comparative analysis of hourly net positions of three scenarios is presented in Figure 58.

The straight black line in the figure represents the difference of net positions between active trading and moderate trading scenarios, and the dotted black line represents the mentioned difference between active trading and no trading scenarios. The beneficial effect of the active intraday trading takes place generally during day time especially at hours 13 and 17. For these hours, with the help of the active intraday trading, the market participant is able to utilize the reasonable opportunities at better prices in the intraday market. The last sentence is the main distinction constituting 1 million TL difference in profits between Scenario 1 and Scenario 2. The adjacency of the net positions of Scenario 2 and Scenario 3 lies on the fact that especially at these hours of the day the system marginal price abruptly skyrocketed and waiting until the closure of the intraday market converges the intraday prices to system marginal prices accordingly. However, at the start and middle of the intraday session, the market participant is able to balance itself with correct updated information at reasonable intraday prices.

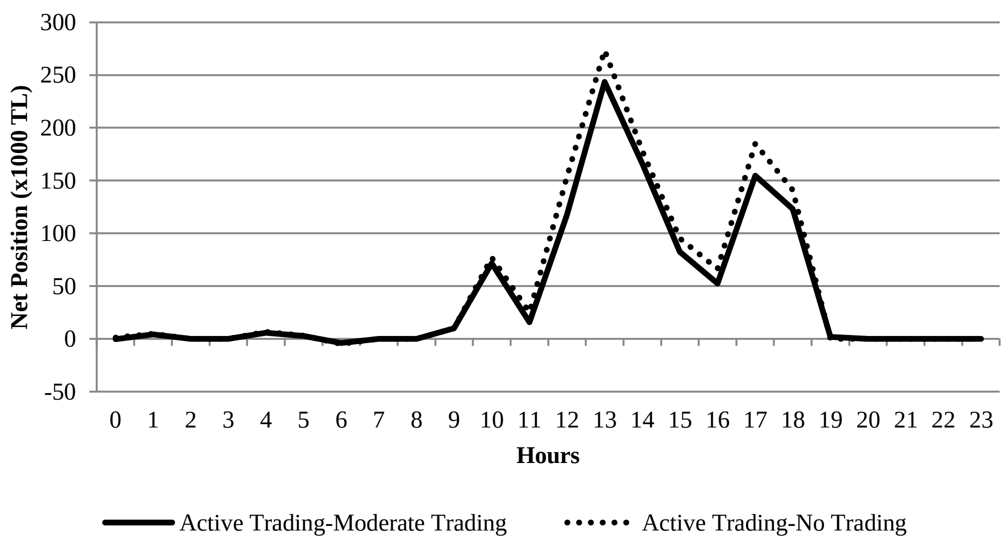


Figure 58: Comparison of Active Trading with Scenario 2 and 3

At the end of this section, it can be interpreted that depending on the advantages in the intraday time horizon, active participation in the intraday market can offer great benefits for market participants depending on the improving accuracy of forecasts.

7.5.2 Case 2: Trading on October 24, 2012

The second case belongs to October 24, 2012. The data related to this case such as hour, load, PTF, SMF, load forecasts, errors in load forecasts, intraday prices, and financial situation are given in Appendix-C as in the first case.

This day coincides with the eve of the Sacrifice Holiday in 2012. Hence, the electricity consumption is expected to be low compared to the similar days of the year. This can be exemplified by the day-ahead prices decreasing to 64 TL/MWh and system marginal prices decreasing to 11 TL/MWh at some of the hours. Across the day, the average PTF becomes 124.58 TL/MWh and the average SMF becomes 46.58 TL/MWh, together pointing that there are no problems in the procurement of electricity also taking into account that no considerable price spikes are encountered during that day.

According to the result of the model for this day, the day-ahead load forecast error is 3.55%. It is over the averages of both in the output of the model and in the actual conditions, in which the average error is between 1.4% and 1.5%. The load forecast errors in the intraday time horizon become 2.93%, 3.48%, 4.73%, 3.13% and 2.31% for the forecasts carried out 18, 12, 8, 4 and 2 hours prior to the delivery respectively. There is a tendency for load forecast errors to oscillate throughout the day. At some point of the intraday horizon, it can reach nearly 5% which is a proof of the fact that the model can give load forecasts with large errors.

The cash flow of three scenarios specific to October 24, 2012 is presented in Table 24. Moreover, the benchmark of these scenarios concerning trading volumes and unit prices for the same day is shown in Table 25.

To start with Scenario 1, according to the results, the oscillating predictions in the intraday time horizon and active intraday trading result in high volumes of energy sales and energy purchases at the same time, by approximately doubling those in both directions on January 21. Despite this condition, Scenario 1 still makes profit compared to the base case, Scenario 3. The unit prices for energy sales and purchases are reasonable compared to the prices in the balancing market. However, oscillating predictions and trading prevent this scenario from being the most profitable one.

Table 24: Cash Flow of Scenarios for October 24, 2012

Item	Scenario 1	Scenario 2	Scenario 3
Energy Sales (TL)	128,266	36,404	28,635
Energy Purchases (TL)	-1,878,408	-1,340,435	-2,019,123
Balance (TL)	-1,750,143	-1,304,031	-1,990,488
Profit/Loss (TL)	240,346	686,458	0

Table 25: Benchmark of Volumes and Unit Prices for October 24, 2012

Scenarios	Energy Sales (MWh)	Unit Price Sales (TL/MWh)	Energy Purchases (MWh)	Unit Price Purchases (TL/MWh)
Intraday Trading in Scenario 1	31,239	70.54	-49,586	76.15
Intraday Trading in Scenario 2	1,544	24.65	-19,891	58.53
Imbalance Trading in Scenario 1 & 2	7,515	31.58	-2,856	145.37
Imbalance Trading in Scenario 3	1,822	15.72	-15,510	130.18

Unlike the previous case, Scenario 2, implying moderate intraday trading, is the most beneficial scenario. By looking at the volumes of trading, the load forecasts performed from the day-ahead is consistently lower than those performed in two hours prior to the delivery. Therefore, the volume of energy sales is significantly low and conversely that of energy purchases is significantly high for this scenario. The average unit prices of purchases are the lowest among all scenarios, which favors Scenario 2 in terms of profits.

When the imbalance trading for Scenario 1 & 2 and Scenario 3 is compared, the behavior of the volume of energy sales and purchases are completely different. While the imbalance trading in Scenario 1 & 2 signifies that the market participant is in the position of excess energy with the transactions performed in the intraday market, the imbalance trading for Scenario 3 shows that the position is on the side of deficit energy by looking at the volumes of energy sales and purchases. As for unit prices, the average price for sales is slightly advantageous while that for purchases is lightly disadvantageous. Nevertheless, the fact that high volumes of energy purchases in Scenario 3 are realized at relatively higher purchase prices compared to the intraday prices makes this scenario the least profitable one.

The comparative analysis of hourly net positions of three scenarios is presented in Figure 59. The straight black line in the figure represents the difference of net positions between moderate trading and active trading scenarios, and the dotted black line represents the mentioned difference between moderate trading and no trading scenarios.

The behavior of the comparative net positions is predominantly fluctuating across the day. The difference of the net positions between moderate trading and active trading scenarios has negative sign at some points implying that at these points active trading in the intraday market is more beneficial. It completely depends on the success of load forecasts regarding intraday time horizon. The sign of the other curve is almost positive except two hours due to high energy purchases in the balancing market in Scenario 3, which is unfavorable.

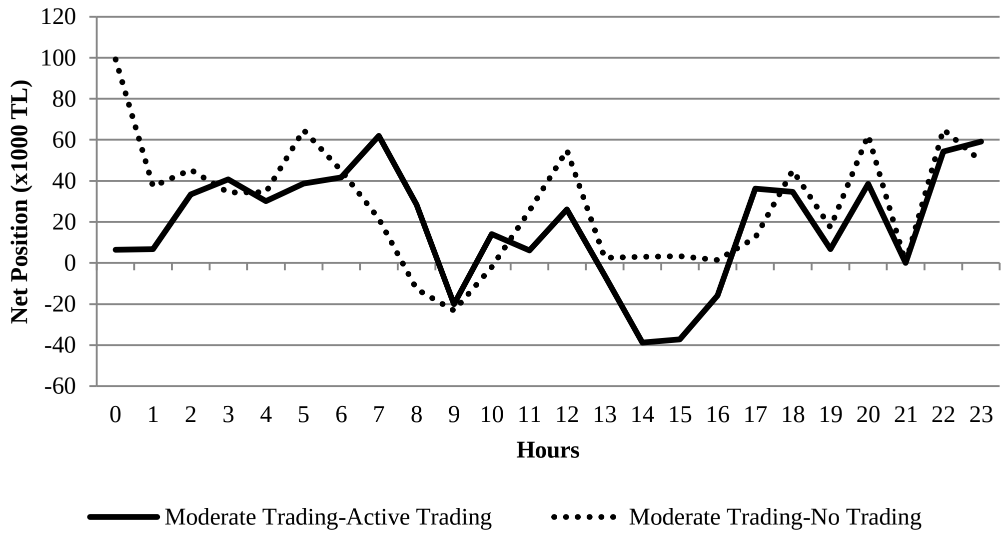


Figure 59: Comparison of Moderate Trading with Scenario 1 and 3

The most important deduction that can be made from the case in this section is that active participation does not always offer the best solution for the market participants. When they are unsure about the forecasts for the intraday market, sometimes it can be better not to make any active trading in this market and better to wait until the closure in order to clarify their energy positions depending on the most updated data.

7.5.3 Case 3: Trading on November 1, 2012

The third case belongs to November 1, 2012. The data related to this case such as hour, load, PTF, SMF, load forecasts, errors in load forecasts, intraday prices, and financial situation are given in Appendix-C as in the first and second case.

This is a kind of weekday in which the normal operational conditions prevail. The most distinctive characteristic of this day is that there is excess energy in the market causing the system marginal prices to fall. Across the day, the average PTF is 167.57 TL/MWh and the average SMF becomes 98.34 TL/MWh, together indicating that there are no problems in the procurement of electricity also taking into account that no considerable price spikes are encountered during that day.

According the result of the model for this day, the day-ahead load forecast error is 1.00%. It is under the averages of both in the output of the model and in the actual conditions. The load forecast errors in the intraday time horizon become 1.00%, 1.31%, 1.41%, 0.81% and 0.76% for the forecasts carried out 18, 12, 8, 4 and 2 hours prior to the delivery respectively. There is a tendency for load forecast errors to increase until midday and to decrease until two hours before delivery.

The cash flow of three scenarios specific to November 1, 2012 is presented in Table 26. Moreover, the benchmark of these scenarios concerning trading volumes and unit prices for the same day is shown in Table 27.

According to the results, the volume of energy sales in intraday trading in Scenario 1 and Scenario 2 draws attention. It is significantly higher than the one of energy purchases, which means that the load forecasts in the intraday time horizon give signal to sell energy in order to maintain energy balance of the portfolio. The relatively high unit price of energy sales in Scenario 1 can be viewed as providing extra financial benefit. The same comment can be made for Scenario 2 considering that there are hardly any purchases for the market participant in the intraday market. However, the behavior of the market participant must be evaluated along with the results of the balancing market in order to assess the decisions made in the intraday horizon.

The fact that the volume of imbalance trading in Scenario 1 & 2 is in the direction of energy purchases along with the relative high unit purchase price demonstrates that the energy position of the market participant at the closure of the intraday market is not near perfect. The average unit price of the electricity for purchase is high owing to the energy purchases of the market participant at peak hours in the balancing market as a result of wrong decisions in the intraday market. The imbalance trading in Scenario 3 shows that there is almost no need to purchase energy in the balancing market if the energy position should be kept stable following the closure of the day-ahead market. For all these reasons, Scenario 3 is financially the most beneficial scenario among others.

Table 26: Cash Flow of Scenarios for November 1, 2012

Item	Scenario 1	Scenario 2	Scenario 3
Energy Sales (TL)	586,150	471,390	466,237
Energy Purchases (TL)	-301,356	-369,594	-131,317
Balance (TL)	284,793	101,797	334,921
Profit/Loss (TL)	-50,127	-233,124	0

Table 27: Benchmark of Volumes and Unit Prices for November 1, 2012

Scenarios	Energy Sales (MWh)	Unit Price Sales (TL/MWh)	Energy Purchases (MWh)	Unit Price Purchases (TL/MWh)
Intraday Trading in Scenario 1	19,622	127.68	-13,274	123.73
Intraday Trading in Scenario 2	6,755	104.67	-406	66.58
Imbalance Trading in Scenario 1 & 2	2,406	75.21	-4,257	178.34
Imbalance Trading in Scenario 3	5,345	87.24	-847	155.12

The comparative analysis of hourly net positions of three scenarios is presented in Figure 60. The straight black line in the figure represents the difference of net positions between no trading and active trading scenarios, and the dotted black line represents the mentioned difference between no trading and moderate trading scenarios.

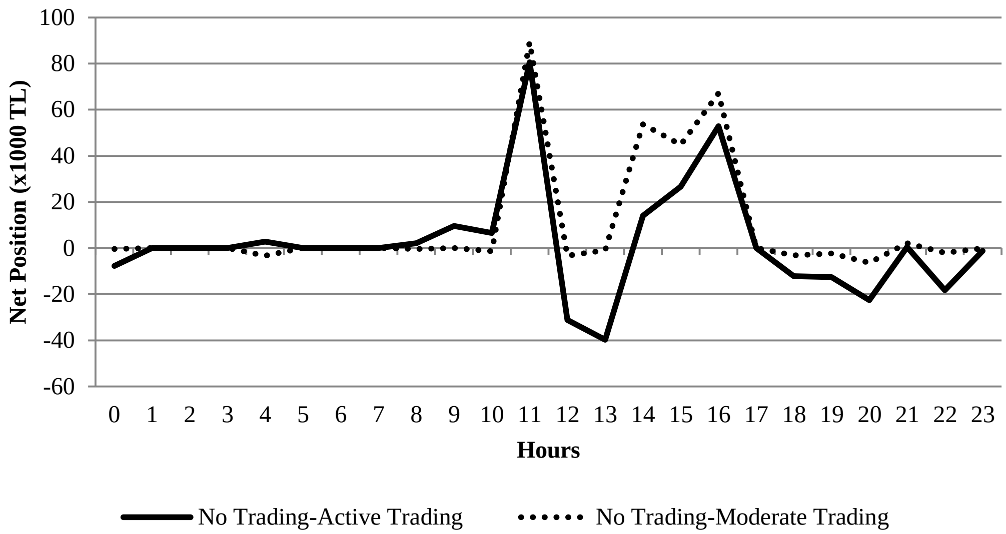


Figure 60: Comparison of No Trading with Scenario 1 and 2

The behavior of each curve represents a stable pattern except several hours including the ones between 11 and 16. This verifies the determination made in the previous paragraph indicating that the financial benefits for Scenario 3 emerge in peak hours of the day. The points at which the value of the curve has positive sign show that the day-ahead load forecasts are more accurate than the ones performed in the intraday time horizon for the relevant hours. This statement is applicable for the hours 11, 14, 15 and 16. The different behavior for the hours 12 and 13 is originated from the fact that the forecasts in the intraday time make progress compared to the previous ones. The difference in the positions of the first and second line lies behind the advantageous trading opportunities arose in the intraday market for Scenario 1.

The most important deduction that can be made from the case in this section is that active and moderate participation in the intraday market does not necessarily provide the best solution for the market participants. There can be some time at which trading only in the balancing market can be beneficial although market participants are penalized by the dual price mechanism in this market. Also, the accuracy of intraday forecasts are extremely important inasmuch as it is sometimes possible that the forecasts performed in the day-ahead give better results compared to the ones performed in the intraday time horizon.

7.6 Results of the Simulations in This Chapter

In this chapter, the difference of the analyses from other chapters is that the trading volume in the intraday market model changes as the updated information is obtained by the market participant. In order to realize this, of the three kinds of uncertainties in the power system, the concept of load forecast errors are used.

Firstly, a load forecast series have to be obtained that would provide somewhat dynamic data to the intraday market model. Therefore, ANN structure in MATLAB is utilized and a load forecasting model is established, which includes load forecasts in the intraday time horizon in 24, 18, 12, 8, 4 and 2 hours prior to the delivery. The object of the model is not to directly diminish the load forecast error, i.e. MAPE, as much as possible but to get a forecast series that shows similar performance to the actual forecasts from day-ahead and makes progress as the closure of the intraday market approaches. This plan requires making a number of simulations in MATLAB as explained in Appendix-B.

The next step is to establish the intraday market model. The trading volumes in this market would depend on the results of forecasts performed for all hours of the year 2012. The other variable in the market, the prices are determined by using linear interpolation between PTF and SMF, based on the forecast horizon proximity or distance to the hours at which the day-ahead price and the system marginal price are formed.

Following this procedure, the scenarios are defined. The first one implies performing active trading in the intraday market, i.e. the market participant regards all the information and rearranges its energy position in all intraday price intervals as previously mentioned. The second scenario contains performing moderate trading in the intraday market, i.e. the market participant waits until the closure of this market and rearranges its energy position only depending on the most updated data. The third scenario represents performing no trading in the intraday market, i.e. the market participant disregards the information that it takes in the intraday time horizon.

Depending on these three scenarios, firstly the yearly analysis of the market model is carried out. The results have shown that concerning the financial positions of the market participant at the end of the scenarios, Scenario 1 is financially the most beneficial one. There comes Scenario 2 following Scenario 1 and Scenario 3 is the least beneficial scenario among others. If Scenario 3 is accepted as the base case considering that it reflects the condition of Turkish electricity market prior to the opening of the intraday market, the yearly profit of Scenario 1 is approximately 20 million TL and that of Scenario 2 is nearly 15 million TL, which is somewhat closer to Scenario 1.

The result of the previous yearly analysis has pointed out that preferring active trading over passive trading in the intraday market is slightly advantageous and preferring these two types of trading over no trading in the intraday market is fairly beneficial. The subjects of whether active trading is always the most profitable or moderate trading is always less profitable than the other scenarios or not preferring intraday trading always results in financial losses are covered through further analysis.

The first analysis covers the date January 21, 2012. In this case, the daily financial profit of Scenario 1 reaches 1.2 million TL while that of Scenario 2 is only 0.2

million TL. This shows that the financial benefits are not stable throughout the year and changes depending on the accuracy of forecasts performed for the intraday time horizon.

The second analysis is for October 24, 2012. In this case, the daily financial profit of Scenario 2 can reach 0.7 million TL while that of Scenario 1 is lower than the previous one by 0.5 million TL. This signifies that waiting the most updated information in the intraday market can sometimes provide better results especially for cases in which the forecast accuracy significantly deteriorates in the forecasting horizon although it is expected to perform better.

The third analysis concerns the date November 1, 2012. In this case, for both Scenario 1 and Scenario 2, financial losses are recorded and Scenario 3 emerges as the best option. This is arisen from the fact that the day-ahead forecasts can sometimes give the closest prediction for the following day and making load forecast errors especially at peak hours of the day can be costly.

To sum up, combining all the results obtained in this chapter, it can be commented that intraday market offers financial benefits for market participants. According to the load forecasting model and the market model, it has been proved that making active trading in the intraday market is more advantageous among other scenarios. However, this is not always true. The definitive factor determining the benefits of intraday trading is the forecast accuracy. The market participants should think twice before trading in the intraday market if they realize any inaccuracies in their forecasts. Sometimes, waiting the most updated information can give the best results and sometimes it can give the worst results. Especially the forecasts performed for the peak hours of the day can be the important factor. The wrong decisions for these hours can be costly, depending on the fact that the prices in the relevant hours are significantly higher than the others.

CHAPTER 8

CONCLUSIONS AND FUTURE WORK

This study investigates the intraday electricity markets in terms of their principles, applications, logic and benefits specifically for the market participants in Turkey.

Intraday markets have emerged as a new concept in the electricity markets in the last couple of years. This is a mechanism related to wholesale electricity market concept. It is in countries which adopt wholesale or retail competition model for the electricity sector. These countries also represent some characteristics to apply mixed market model, combining bilateral agreements model and power exchange model for wholesale structural mechanism. In wholesale markets, trading is performed based on different timings. In this respect, wholesale markets can be separated into two groups: One of them is the up-to-day-ahead stage markets in which long term electricity trading in order to hedge the price risks, and the other one is the spot markets in which electricity trading is performed immediately or at short notice. Intraday markets belong to the classification of spot markets along with the day-ahead markets and balancing markets.

Intraday market enables market participants to make transactions from the closure of day-ahead markets to the delivery time of electrical energy. It is somewhat the extension of day-ahead markets. Therefore, intraday markets and day-ahead markets show similar characteristics. However, they also present some characteristics that differ from each other in terms of participation, bidding philosophy, trading method, price range, timeline, trading products, bid and offer format and cross-border congestion management.

The applications of intraday markets are most widely observed in European countries. The structures among these countries can vary due to the previously applied mechanisms and choices of power exchanges. In general terms, there are two different types of applications of intraday markets. The first one is observed in the countries such as Belgium, the Netherlands, Germany, France, Denmark and Nordic countries. In this structure, the physical characteristics of units are not taken into consideration; the bidding philosophy is portfolio based; the trading method is continuous bilateral trading. The second one is observed in countries such as Spain, Portugal and Italy. In this structure, differently from the first type of application, the physical characteristics of units are considered, the bidding philosophy is unit based, the trading method is auction trading. The first application is compatible to the target model in Europe, aiming to constitute a single electricity market to maintain efficiency and competitiveness, sustainability and electricity security of supply.

The targets for forming a single electricity market in Europe require the coupling of intraday markets among Europe with efficient usage of cross-border transmission lines. Implicit continuous trading mechanism should be applied at the borders, but due to lack of harmonization in intraday markets among national levels, the line capacities are generally inefficiently utilized for now. However, there have been significant improvements in the last couple of years with the intraday coupling mechanism for neighboring countries.

The intraday electricity market in Turkey is expected to open within the year 2014. The mechanism that will be applied in Turkey is similar to countries in the western and northern part of Europe. Considering the given importance to enable market participants to perform trading in the intraday time horizon with intraday markets in Europe and the extended studies in the literature, the logic and benefits of these markets are worth investigation especially for Turkey. The object is to reveal the opportunities and benefits that could exist for market participants in intraday markets. In order to find out the logic and benefits of intraday markets, some detailed and comprehensive analyses are performed for Turkey. The studies include the examination of uncertainties in power systems that create need for intraday markets, and handling imbalances with the utilization of different models and approaches.

The logic of the intraday markets lies behind the uncertainties in power systems, which results in as imbalances in the balancing market. There are three main sources of uncertainty for power systems; such as wind forecast errors, power plant outages and load forecast errors. According to the results of the studies performed for Turkey, it is discovered that the variability of all wind generation can reach up to 16% in 1 hour, 22% in 2 hours and 40% in 6 hours with respect to total the installed capacity. Also, regarding uncertainty concept, the hourly wind forecast errors can reach up to 45%. Considering the capacity requirement and the generation licenses given for wind energy in Turkey, there is a huge risk for wind generators and NLDC which is responsible for the financial viability of imbalances of power plants opting in feed-in-tariff. Furthermore, for the other sources of uncertainty, as for power plant failures, a power plant of 460 MW fails every day taking into account the statistics of generators except free producers. As for load forecast errors, the hourly MAPE is 1.43% in 2012 and it is over 2.5% approximately for the 18% of the hours in 2012. All of these factors pose remarkable risks for market participants and intraday markets stand out as an important tool to deal with these uncertainties.

The risk for the aforementioned uncertainties is making imbalances in the balancing market and being punished by the dual price mechanism applied this market. It means that a market participant purchasing energy from the balancing market has to pay whichever price is greater among PTF and SMF; and the one selling energy to the balancing market has to receive whichever price is smaller among PTF and SMF for the corresponding hour. This may cause market participants to lose an important amount of money. From theoretical perspective, net positive and net negative imbalances in the balancing market show that net positive imbalances are settled at 80

TL/MWh and net negative imbalances are settled at 216 TL/MWh on average in 2012. Considering the average PTF and SMF are 149 and 139 TL/MWh respectively, taking wrong energy position after the closure of the day-ahead market can be costly for market participants.

The intraday market mechanism in Turkey will offer market participants to make energy trading at their own prices until two hours prior to delivery and it emerges as a good opportunity to rearrange the energy positions before the start of the balancing market. In order to analyze the potential benefits of the intraday market from theoretical perspective, synthetic intraday prices are formed based on PTF and SMF, and different scenarios are formed for the intraday market volume. Potential benefits for the settlement of imbalances in the intraday market emerge and they range from 3 million TL to 273 million TL in a year depending on the intraday price and volume. When the study is repeated for the imbalances due to wind errors, power plant failures and load forecast errors separately, intraday markets still offer good benefits for each group of uncertainty. An important point regarding this study is that there is not a correlation between the imbalances due to three sources of uncertainty combined and net imbalances in the balancing market. This indicates that there can be another source of uncertainty other than the aforementioned ones or the companies make transactions regardless of performing imbalances. It is concluded that intraday markets can solely solve imbalance problems of market participants that virtually suffer from the fundamental uncertainties in the balancing market; however it could not help the imbalance problems of which origin depends on the problematic mechanisms and structures in the market.

In order to make a more comprehensive and scientific study, the variables of intraday markets such as the price and the volume should depend on more dynamic structures in the analyses. Therefore, "Electricity Price Model" and "Short Term Load Forecasting Model" are utilized. "Electricity Price Model" is used to represent the risks and the potential benefits for wind generators at peak hours in the period of 2012-2013 and 2018-2019. Different scenarios regarding the unexpected change in the availability of wind generators proved that there is fundamental risk for wind generators at peak hours and intraday trading opportunities with continuous bilateral trading in the spot market would definitely help to alleviate these risks. An important note from the analysis is that the risk for wind generators multiplies with the possible problems in electricity security of supply. In those cases, the intraday market becomes even a more important tool for wind generators. Considering the increase in the installed capacity of wind turbines until the period of 2018-2019, the relevant studies prove that due to the variability and uncertainty problems of wind energy, the possibility of making more imbalances increases and this is another important factor for generators to utilize intraday market more efficiently in order hedge their price risks in the balancing market. Taking into account the incentive mechanism for the renewable power plants in Turkey, NLDC is responsible for the financial viability of imbalances of those plants which prefer to opt in feed-in-tariff mechanism. In this respect, NLDC should be obliged to rearrange the energy positions of these power plants in the intraday time horizon considering that the financial losses resulting from these imbalances are reflected to all market participants.

Another model utilized in this thesis is "Short Term Load Forecasting Model" based on ANN structure for energy suppliers. It is used to represent the change in the energy positions of the suppliers as the updated information regarding the load is obtained. Depending on this model, trading strategies for supplier companies are composed such as active trading, moderate trading and no trading in the intraday market. For 2012 year data, it has been shown that actively participating in the intraday market is the most beneficial case for suppliers; then there comes moderate trading strategy and not participating in the intraday market is the least beneficial case. However, the aforementioned result does not imply that actively participating in the intraday market is always the most profitable case. Daily analyses have proved that moderate trading in the intraday market and even not participating in the intraday market can be the most profitable scenarios. This is an important indication of the fact that intraday markets are required and useful tools for market participants who perform imbalances; but besides that they must be able to rearrange their energy positions in the market, based on successful forecasting tools. Wrong forecasts especially at the peak hours of the day, when PTF and SMF are high, may result in unexpected financial losses for the market participants.

In the future studies, the benefits for the market participants will be evaluated more practically based on the realized intraday market prices and intraday trading volumes with the establishment of the intraday market mechanism in Turkey. In this thesis work, the potential benefits for wind generators can only be applied for the peak hours in the period of 2012-2013 and 2018-2019. This analysis will again be performed with “Electricity Price Model” but for the results comprising of a full year thanks to further developments in this model. Also, “Short Term Load Forecasting Model” used in this thesis disregards the meteorological information updated in the intraday time horizon. It will be included in the model for the next studies in order to get a better forecasting model to assess the potential benefits and the trading strategies in intraday market. Furthermore, for any market participant, i.e. a generator or a supplier, a more extensive study can be performed on the intraday trading strategies based on the realized market data in Turkey for future.

REFERENCES

[1] E. Camadan, "Balancing and Settlement Mechanism In Turkish Electricity Market: A Comparative Analysis," EMRA, Ankara, 2009.

[2] "Market Models Based On Contractual Arrangements," NPTEL, [Online]. Available: http://nptel.iitm.ac.in/courses/108101005/philosophy%20of%20market%20models/market%20models.html. [Accessed 27 November 2013].

[3] A. Ockenfels, V. Grimm and G. Zoettl, "The Pricing Mechanism of the Day Ahead Electricity Spot Market Auction on the EEX," 2008.

[4] K. Rademaekers, A. Slingenberg and S. Morsy, "Review and Analysis of EU Wholesale Energy Markets," 09 December 2008. [Online]. Available: http://ec.europa.eu/energy/gas_electricity/studies/doc/2008_eu_wholesale_energy_market_historical.pdf. [Accessed 27 September 2012].

[5] A. Pototschnig, "Electricity Markets: the Wholesale Market," Florence, 2011.

[6] D. Kirschen and G. Strbac, Fundamentals of Power System Economics, England: John Wiley & Sons Ltd., 2004.

[7] M. Dupuy, "Electricity Markets: Balancing Mechanisms and Congestion Management," EDF (Electricite de France), 2007.

[8] "Benefits and Practical Steps Towards the Integration of Intraday Electricity Markets and Balancing Mechanisms," Frontier Economics, 2005. [Online]. Available: http://ec.europa.eu/energy/gas_electricity/studies/doc/electricity/2005_12_intraday_electricity_markets.pdf. [Accessed 26 September 2013].

[9] F. Azevedo, Z. A. Vale and A. A. Vale, "Hedging Using Futures and Options Contracts in the Electricity Market," [Online]. Available: http://www.icrepq.com/pdfs/AZEVE.407.pdf. [Accessed 29 October 2013].

[10] Z. Korkulu, "Utilization of Derivative Tools, Futures and Options Market in Liberalized Electricity Markets," EMRA, 2006.

[11] S. Kevin, Commodity and Financial Derivatives, Eastern Economy Edition, 2010.

[12] O. E. Baccino, "Options and Futures Contracts in Electricity for Argentina," [Online]. Available: http://www.aaep.org.ar/anales/works/works2000/BACCINO.PDF. [Accessed 28 October 2013].

[13] "International Swaps and Derivatives Association," [Online]. Available: http://www.isda.org/educat/faqs.html#1. [Accessed 29 October 2013].

[14] P. Bajpai and S. N. Singh, "Electricity Trading In Competitive Power Market: An Overview and KEy Issues," *International Conference On Power Systems, ICPS2004, Kathmandu, Nepal,* 571-576.

[15] S. Stoft, Power System Economics: Designing Markets for Electricity, John Wiley & Sons Inc., 2002.

[16] "Spot Market," [Online]. Available:

http://www.investopedia.com/terms/s/spotmarket.asp. [Accessed 7 December 2013].

[17] "Nord Pool Spot Day Ahead Market," [Online]. Available: http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/. [Accessed 28 October 2013].

[18] "Nord Pool Spot Day Ahead Market Price Calculation," [Online]. Available: http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/Price-calculation/. [Accessed 28 October 2013].

[19] S. Zhou, T. Grasso and G. Niu, "Comparison of Market Designs: Market Oversight Division Report," Public Utility Commission of Texas, 2003.

[20] R. Madlener and M. Kaufmann, "Power Exchange Spot Market Trading in Europe: Theoretical Considerations and Empirical Evidence," OSCOGEN, 2002.

[21] M. Reguant, "Complementary Bidding Mechanism and Startup Costs in Electricity Markets," Stanford GSB and NBER, 2013.

[22] J. Barquin, R. Luis and R. Enrique, "Current Designs and Expected Evolutions of Day-ahead, Intra-day and Balancing Market/Mechanisms in Europe," Optimate and Seventh Framework Programme, 2011.

[23] "Options Trading Beginner," [Online]. Available: http://optionstradingbeginner.blogspot.com/. [Accessed 18 December 2013].

[24] I. Androcec and I. Wangensteen, "Different Methods for Congestion Management and Risk Management," *9th International Conference on Probabilistic MEthods Applied to Power Systems,* 2006.

[25] T. Lajovic, *Regional Integration and Cross-Border Trading Presentation*, Energy Trading Programme for South East Europe, 2013.

[26] V. Glamocanin and J. Vasiljevska, *Flow-Based Methods for Capacity Allocation Presentation*, Ss.Cyril and Methodius University, 2013.

[27] H. Bahar and J. Sauvage, "Cross-Border Trade in Electricity and The Development of Renewables-Based Electric Power: Lessons From Europe," OECD Trade and Environment Paper No.2013/02, 2013.

[28] "Consultation of XBID Rules: Synthesis of Questions and Answers," 2013. [Online]. Available: http://clients.rte-france.com/htm/fr/offre/telecharge/Consultation_XIBD_Rules_QA_Synthesis.pdf. [Accessed 12 January 2014].

[29] "Guidelines forthe Intraday Capacity Allocation for the Interconnections between Germany and the Netherlands," Amprion and Tennet, 2011.

[30] "Charging Methodology Statement for the Anglo-French Interconector," National Grid, 2011.

[31] "Daily Capacity: Belgium-France," ELIA, [Online]. Available: http://www.elia.be/en/grid-data/interconnections/daily-capacity-bel-fra. [Accessed 12 January 2014].

[32] A. P. Houmoller, "The KONTEK Bidding Area," Nord Pool Spot, 2006.

[33] J. Matthys-Donnadieu, "Introduction aux marchés électriques du point de vue d’une bourse d’énergie," 28 October 2013. [Online]. Available: http://www.montefiore.ulg.ac.be/~ernst/uploads/energy-markets/IntrodMarch%C3%A9Electricit%C3%A9%20Li%C3%A8ge%2028102013.pdf. [Accessed 14 January 2014].

[34] "Development and Implementation of a Coordinated Model for Regional and Inter-Regional Congestion Management," Europex and Etso, 2008.

[35] A. Pototschnig, "The Integration of Electricity Markets across the EU: Objectives, Tools, Progress," ACER, 2013.

[36] P. Taylor, "Capacity Allocation Congestion Management Framework Guideline Intraday," European Regulators' Group for Electricity and Gas, 2010.

[37] S. Dourlens, "France-UK-Ireland Regional Electricity Market," ERGEG, 2007.

[38] "Target Model and European Market Integration in the Electricity Sector," REKK, 2011.

[39] M. Sandulescu, "Model of the European Internal Electricity Market," FOREN 2012 - WEC Central & Eastern Europe Energy Forum, Romania, 2012.

[40] "Target Model for Interregional Congestion Management," The Project Coordination Group , 2009.

[41] "Cross-Regional Roadmap for Intraday," Agency for the Cooperation of Energy Regulators, 2011.

[42] "Framework Guidelines on Capacity Allocation and Congestion Management for Electricity," Agency for the Cooperation of Energy Regulators , 2011.

[43] R. Loos, "How a Power Exchange Can Help Integrate RES into the Wholesale Power Market," 2012. [Online]. Available: http://www.elia.be/en/about-elia/Users%20group/renewable-energy-

sources/~/media/files/Elia/About-Elia/Users%20Group/Renewable%20Energy%20Sources/19-04-2012/19042012Renewable%20energy%20sources2Presentation%20Belpex.pdf. [Accessed 20 December 2013].

[44] "Belpex Continuous Intraday Market," [Online]. Available: http://www.belpex.be/wp-content/uploads/13092013-Belpex-Continuous-Intraday-Product-sheet.pdf. [Accessed 20 December 2013].

[45] J. Matthys-Donnadieu, "The Role of the Spot Market in Successful Demand Side Management," 2013. [Online]. Available: http://www.febeliec.be/data/1370860746Belpex_handouts.pdf. [Accessed 20 December 2013].

[46] R. Loos, *Power Markets and Power Spot Exchanges*, 2010.

[47] "BELPEX Product Specifications," 2014. [Online]. Available: http://www.belpex.be/trading/product-specification/. [Accessed 12 January 2014].

[48] "Intraday Allocations at the Dutch-Belgian Border: An Implicit Mechanism Based on the Continuous Trading and the Coupling of Both Markets," Elia, 2013.

[49] J.-B. Spitzley and C. Najdawi, "Integration of Electricity from Renewables to the Electricity Grid and to the Electricity Market National Report: Belgium," Eclareon, 2011.

[50] "Intraday Allocations at the French-Belgian Border: A Way for Balance Responsible Parties to Deal with Unforeseen Circumstances," Elia, 2013.

[51] "Cross-Border Mechanisms," Elia, [Online]. Available:

http://www.elia.be/en/products-and-services/cross-border-mechanisms/cross-border-mechanisms#anchor41. [Accessed 13 January 2014].

[52] "APX Power NL," [Online]. Available: http://www.apxgroup.com/trading-clearing/continuous-markets-intraday/. [Accessed 13 January 2014].

[53] "Competition in 2012: Where is the Position of the German Energy Market?," BDEW, 2013.

[54] "Cross-Border Intraday Market Extended to Nordic Region over NorNed Cable," APX NL, 2012.

[55] E. C. Stavseth, *The Nordic/Baltic Power Market*, Oslo: Nord Pool Spot, 2013.

[56] "Guidelines for the Intraday Capacity Allocation for the Interconnections between Germany and the Netherlands," Amprion-Tennet, 2011.

[57] "Intraday Market with Delivery on the German TSO Zone," EPEX Spot, [Online]. Available: http://www.epexspot.com/en/product-info/Intraday/germany. [Accessed 12 January 2014].

[58] S. Tarnai, *Launch of the Swiss Intraday Market*, Zurich: EPEX Spot, 2013.

[59] A. Mahuet, "Case Example of Power Exchanges: Market Coupling and Cross-Border Trading," EPEX Spot, 2012.

[60] "EPEX Spot Operational Rules".

[61] "Intraday Congestion Management Rules at the Border Denmark (W)-Germany," Energinet-Tennet.

[62] "Intraday Trading on ELBAS," 2013. [Online]. Available: http://www.npspot.com/Global/Download%20Center/Elbas/Elbas-product-sheet_2013.pdf. [Accessed 13 January 2014].

[63] "CEE Intraday Capacity Allocation and Nomination Procedure," 2010.

[64] "Energy Exchange Austria Annual Report 2013," [Online]. Available: http://www.exaa.at/exaa/docs/exaa_folder_power_2013_e_web.pdf. [Accessed 13 January 2013].

[65] "Swiss Grid Intraday Market," 2013. [Online]. Available: http://www.swissgrid.ch/dam/swissgrid/current/News/2013/Joint-Communication_Swiss-Intraday_en.pdf. [Accessed 13 January 2014].

[66] "French-German Interconnection Intraday Capacity Allocation Rules," Amprion-RTE-Transnet, 2013.

[67] "Intraday Market with Delivery on the French TSO," EPEX Spot, [Online]. Available: http://www.epexspot.com/en/product-info/Intraday. [Accessed 13 January 2014].

[68] "French-Swiss Interconnection Intraday Capacity Allocation Rules," RTE and Swissgrid, 2013.

[69] "Charging Methodology Statement for the Anglo-French Interconnector," National Grid, 2013.

[70] "NordPool Spot Website," 2014. [Online]. Available: http://www.nordpoolspot.com/.

[71] "Nord Pool Spot Product Specifications of Physical Markets," 2011.

[72] "ELBAS 3.1 User Guide," Nord Pool Spot, 2012.

[73] C. V. Penados, "Role of the Physical Power Exchanges in the Electricity Wholesale Market, Master Thesis," Universidad Pontificia Comillas, 2008.

[74] "Iberia/Spain-France-Germany Cross-Border Intraday: Techncal Feasibility Study," EPEX-OMIE, 2012.

[75] D. Furio, "A Survey on the Spanish Electricity Intraday Market," *Estudios De Economia Aplicada*, vol. 29, no. 2, pp. 1-20, 2011.

[76] "Main Results of the Electricity Market in 2012," Iberian Electricity Market.

[77] "Capacity Allocation for the France-Spain Interconnection for Daily and Intraday Timeframes," RTE-Red Electrica de Espana, 2013.

[78] "Vademecum of the Italian Power Exchange".

[79] "Gestore Mercati Energetici Glossary Section," GME, [Online]. Available: http://www.mercatoelettrico.org/en/tools/glossario.aspx. [Accessed 12 January 2014].

[80] "GME Annual Report," 2012.

[81] F. D. Pizzo, *Build-up of Italian Power Market and Interconnections to Neighboring Systems*, Dubai: Terna, 2013.

[82] "Rules for Intraday Capacity Allocation by Explicit Auctions," Terna, 2012.

[83] "Cross Border Intraday on the Italian Borders - Interim Solution," 2012.

[84] "PMUM Intraday Market Notes," 2014. [Online]. Available: https://gunce.pmum.gov.tr/.

[85] D. Furio, "A Survey on the Spanish Electricity Intraday Market," *Estudios*

De Economia Aplicada, vol. 29, no. 2, pp. 1-20, 2011.

[86] T. Haring, D. Mountouri and G. Andersson, "Ensuring Energy-Market Liquidity through Adequate Imbalance Settlement," *IEEE Transactions on Power Systems*, 2012.

[87] "Balancing and Intraday Market Design: Options for Wind Integration Report," Climate Policy Initiative, 2011. [Online]. Available: http://climatepolicyinitiative.org/wp-content/uploads/2011/12/Intraday-and-Wind-Integration-Paper.pdf. [Accessed 12 March 2013].

[88] C. Weber, "Adequate Market Design to Enable the Integration of Wind Energy into European Power Systems," *Elsevier, Energy Policy 38*, pp. 3155-3163, 2009.

[89] "The Future of the Electric Grid Report," Massachusetts Institute of Technology, 2011. [Online]. Available: http://mitei.mit.edu/publications/reports-studies/future-electric-grid. [Accessed 13 March 2013].

[90] "Accomodating High Levels of Variable Generation Report," North American Electric Reliability Corporation, 2009. [Online]. Available: http://www.nerc.com/files/IVGTF_Report_041609.pdf. [Accessed 13 March 2013].

[91] "Turkish Electricity Transmission Company," [Online]. Available: http://www.teias.gov.tr/.

[92] "Renewable Energy Directive," [Online]. Available: http://en.wikipedia.org/wiki/Renewables_Directive. [Accessed 27 July 2013].

[93] "National Renewable Energy Action Plans," [Online]. Available: http://www.ecn.nl/units/ps/themes/renewable-energy/projects/nreap/data. [Accessed 28 July 2013].

[94] "Turkish Electricity Transmission Company Data," [Online]. Available: http://www.teias.gov.tr. [Accessed 17 August 2013].

[95] "Electricity Demand Projection Report of Turkey," Turkish Ministry of Energy and Natural Resources, General Directorate for Energy Affairs, [Online]. Available: http://www.enerji.gov.tr. [Accessed 17 August 2013].

[96] "Energy Balance Sheet 2011," Turkish Ministry of Energy and Natural Resources, General Directorate for Energy Affairs, [Online]. Available: http://www.enerji.gov.tr. [Accessed 17 August 2013].

[97] "2010-2014 Strategic Paper," Turkish Ministry of Energy and Natural Resources, 2010.

[98] "Electricity Energy Market and Supply Security Strategic Paper," Higher Board of Planning, 2009.

[99] *Energy and Environment Department, General Directorate for Energy Affairs.* [Interview]. 19 August 2013.

[100] "One-Year Delay of the First Nuclear Power Plant in Turkey," [Online]. Available: http://enerjienstitusu.com/2013/10/09/turkiyenin-ilk-nukleer-santrali-bir-yil-gecikebilir/. [Accessed 11 October 2013].

[101] "Wind Energy," [Online]. Available: http://www.enerji.gov.tr/index.php?dil=tr&sf=webpages&b=ruzgar&bn=231&hn=&nm=384&id=40696. [Accessed 13 March 2013].

[102] "Energy Market Regulatory Authority Data," 2012. [Online]. Available: http://www.epdk.gov.tr. [Accessed 13 March 2013].

[103] "Market Financial Settlement Center," [Online]. Available: https://dgpys.pmum.gov.tr/dgpys/.

[104] K. De Vos, S. De Rijcke, J. Driesen and A. Kyriazis, "Value of Market Mechanisms Enabling Improved Wind Power Predictions: A Case Study of the Estinnes Wind Power Plant," *EWEA Annual Conference*, 2011.

[105] "TEİAŞ Capacity Projection Report".

[106] B. Sanlı, "An Electricity Supply and Demand Model for Turkey," *ICCI*, 2012.

[107] H. Chen, C. A. Canizares and A. Singh, "ANN-based Short-Term Load Forecasting in Electricity Markets," *Power Engineering Society Winter Meeting, IEEE*, vol. Volume 2, pp. 411-415, 2001.

[108] O. B. Tör, "Short Term Planning Issues in Power Markets," in *EE578 Power System Planning Lecture Notes*, Middle East Technical University, 2011.

[109] P. Manzi and P. Barbini, "From Creativity to Artificial Neural Networks: Problem-Solving Methodologies," [Online]. Available: http://www.intechopen.com/books/current-topics-in-public-health/from-creativity-to-artificial-neural-networks-problem-solving-methodologies-in-hospitals. [Accessed 07 October 2013].

[110] M. Shahidehpour, H. Yamin and Z. Li, "Short Term Load Forecasting," in *Market Operations in Electric Power Systems: Forecasting, Scheduling and Risk Management*, John Wiley & Sons, 2002, pp. 21-57.

[111] "Weather Underground," [Online]. Available: http://www.wunderground.com/. [Accessed 28 September 2013].

APPENDIX-A

THE DATA USED FOR THE ELECTRICITY PRICE MODEL IN CHAPTER 6

Table 28: Efficiency Factors of Power Plants

Primary Source	Efficiency in 2012 (%)	
Natural Gas >73 MW	50	50
Natural Gas <73 MW	58	58
Import Coal	45	45
Lignite	34	34
Fuel Oil	40	40

Table 29: Fuel Costs of Power Plants

Primary Source	Fuel Cost	Fuel Cost ($/kWh)
Natural Gas	450 $/1000 m³	0.042
Import Coal	80 $/ton	0.011
Lignite	35 $/ton	0.017
Fuel Oil	300 $/barrel	0.184

Table 30: Operational and Maintenance Costs of Power Plants

Primary Source	Capacity Factors (%)	O & M Costs ($/kWh)
Natural Gas > 73 MW	45.7	0.006
Natural Gas < 73 MW	45.7	0.00513
Import Coal	74.2	0.00469
Lignite	74.2	0.00815
Hydraulic Dam	32.0	0.016
Hydraulic Run-of-River	35.0	0.018
Fuel Oil	-	0.002345
Wind	25.0	0.0107
Geothermal	69.0	0.0181
Biogas	70.0	0.01133

Table 31: Efficiency Factors of Power Plants for 2018

Primary Source	Efficiency in 2018 (%)	
Natural Gas >73 MW	54	54
Natural Gas <73 MW	62	62
Import Coal	48	48
Lignite	36	36
Fuel Oil	42	42

APPENDIX-B

SHORT TERM LOAD FORECASTING IN THE INTRADAY TIME HORIZON FOR THE MODEL IN CHAPTER 7

1. Introduction

Short term load forecasting means predicting electricity demand with a leading time of one hour to seven days in order to provide the system operator with the data required for adequate scheduling and operation. As Chen et al. mentions, load forecasting has gained importance with the coming of the deregulation in electricity sector and the balancing mechanisms that would punish imbalances with dual price mechanism [107]. In this part, the object is to construct a model which would make load forecasting with a leading time covering from day-ahead to two hour prior to the delivery.

There are various techniques to make short term load forecasting, which can be categorized as traditional and modern. Traditional methods are such as regression, time series, pattern recognition, Kalman filters, etc.; which have been utilized for a long time, but they are not able to properly show the complex nonlinear relationships between the electricity demand and the factors affecting it. Modern methods can be exemplified by expert systems, Artificial Neural Networks (ANN), fuzzy logic, wavelets, etc. ANN techniques, which are good at learning by example, are able to represent the nonlinear relationships between the electricity demand and the factors influencing it directly from historical data [107]. Furthermore, they are easy to use by utilizing MATLAB, which would procure an environment for clear implementation and good performance [108].

1.1 The Structure of ANN Models

ANN models can be classified as architecture, processing and training as shown in Figure 61.

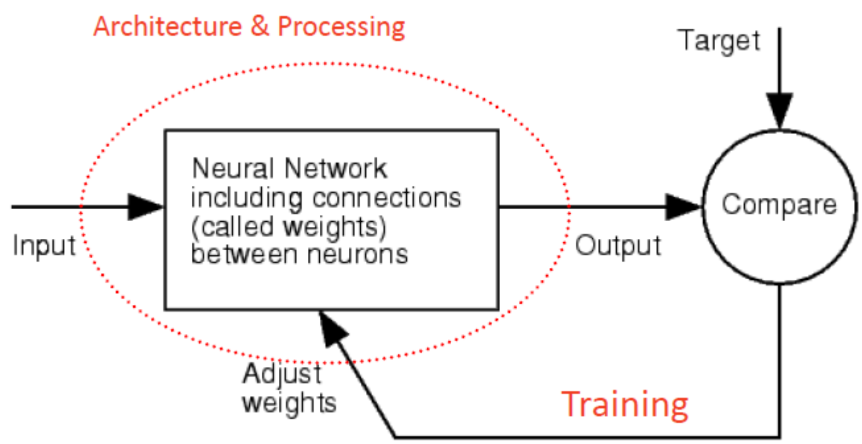


Figure 61: The Classification of ANN Models [108]

The ANN architecture consists of three parts such as input layer, hidden layer and output layer. The input layer is responsible for interacting with outside environment and receiving information. The hidden layer functions as a bridge between input layer and output layer without having any connection to outside world. The output layer presents outputs to outside environment following the incoming data are processed by the network. The layers of the aforementioned ANN architecture are as illustrated in Figure 62.

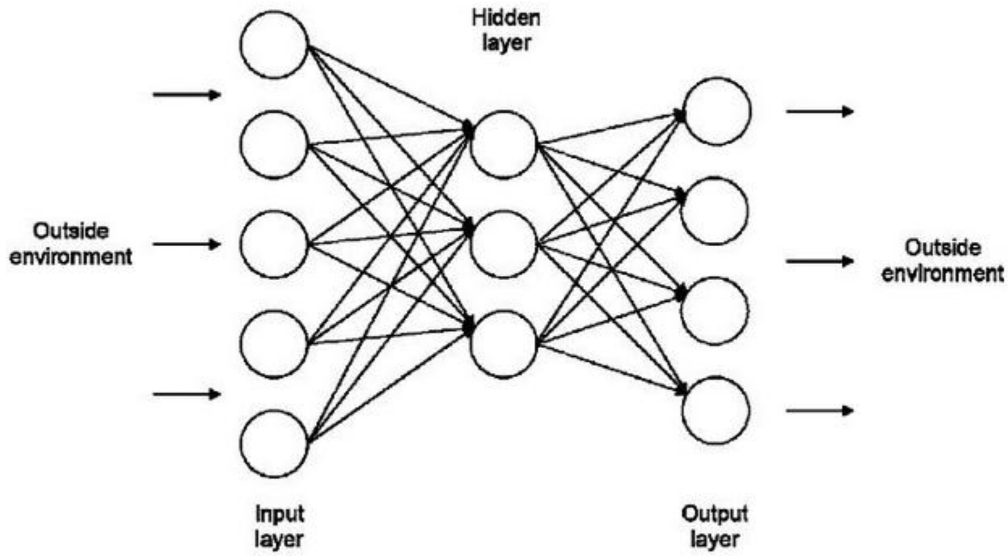


Figure 62: Layers of ANN Architecture [109]

1.2 Factors Affecting Load Patterns

Shahidehpour et al. suggests that there are six factors having an impact on load patterns. These are economical factors, time factors, weather factors, random disturbances, price factors and other factors such as geographical conditions and the type of the customers [110].

As a matter of principle, historical system load and temperature are the most dominant inputs for ANN models. However, short term load forecasts are dominated by historical system load. For a normal climate area, these are sufficient to make short term load forecasting. For extreme weather conditions, additional weather factors such as humidity and the wind velocity can be included. In order to increase the sensitivity in forecasts; seasonal, weekly and holiday effects can be added as inputs [108].

2. Construction of the ANN Model

In this study, the main idea is not to minimize the errors before the day as much as possible. Instead, it is to assess the potential progress of the load forecasts within the day by using ANN, in order to obtain a load series for the analyses in Chapter 7.

2.1 Weather Data Set

In order to fulfill this objective, aside from the electricity demand data taken from NLDC; temperature, humidity and wind velocity data are required for Turkey. The relevant data are obtained from the website [111], by writing visual basic code in Microsoft Excel. The codes for five big cities in Turkey can be accessed in Appendix-D.

Since the load forecast will be performed for whole Turkey, the weather data for only one city will not be appropriate. Therefore, the data of the biggest three cities in Turkey, İstanbul, Ankara and İzmir are utilized. Besides, the data of Antalya, the city of which population is increasing sharply in summer season due to tourism activities; and the data of Diyarbakir, the city in which agricultural irrigation occurs from July to September are added alongside İstanbul, Ankara, İzmir and Antalya in order to procure a better data set reflecting Turkey in general.

In order to get better results from the model; single weather data series should be given as input. This requires obtaining single temperature, humidity and wind velocity data for Turkey and defining the correct or realistic coefficients for these cities. The methodology is to use electricity consumption data of three cities in different regions in addition to the selected above five big cities for different seasons as shown in Table 32. It is assumed that January, April, July and October represents the conditions of winter, spring, summer and autumn respectively. Also, the weather data belonging to selected five big cities are similar to the ones for the additional cities placed in their regions. Furthermore, it should be noted that the data cover only the year 2012.

Table 32: Electricity Consumption Data for Four Cities in a Region

City	Additional Cities	Electricity Consumption of Four Cities in a Region by Seasons (MWh)			
		January	April	July	October
İstanbul	Kocaeli, Bursa, Tekirdağ	5,968,603	5,087,173	5,747,250	5,014,574
Ankara	Konya, Eskişehir, Kayseri	1,929,733	1,771,635	2,192,505	1,681,229
İzmir	Manisa, Muğla, Denizli	2,423,584	2,108,039	2,811,015	2,138,652
Antalya	Hatay, Adana, Kahramanmaraş	2,167,978	1,750,110	2,599,106	1,874,526
Diyarbakır	Gaziantep, Diyarbakır, Mardin	1,861,395	1,727,215	2,155,456	1,295,245
Total		14,351,293	12,444,173	15,505,333	12,004,225
Total (Whole Turkey)		20,295,628	17,602,218	21,725,465	17,339,818
Percent (%)		70.7	70.7	71.4	69.2

The above table shows that the weather data of five cities reflect the weather conditions in regions where approximately 70% of electricity consumption of Turkey is materialized. In the determination of the single weather data series, the next step is to establish coefficients with the utilization of the electricity consumption data in Table 32. The methodology depends on the ratio of electricity consumption of each region to the total consumption of five regions combined. Table 33 shows the aforementioned coefficients for each of the five big cities for different seasons.

Table 33: Weather Data Coefficients for Five Big Cities

City	Corrected Coefficients of Five Cities (%)			
	January	April	July	October
İstanbul	41.6	40.9	37.1	41.8
Ankara	13.4	14.2	14.1	14.0
İzmir	16.9	16.9	18.1	17.8
Antalya	15.1	14.1	16.8	15.6
Diyarbakır	13.0	13.9	13.9	10.8
Total	100.0	100.0	100.0	100.0

Now, single weather data can be accomplished with the coefficients in Table 33. In order to do so, the weather data for İstanbul will be multiplied by 41.6% for December, January and February; by 40.9% for March, April and May; 37.1% for June, July and August; 41.8% for September, October and December. The same procedure is applied to the other cities, Ankara, İzmir, Antalya and Diyarbakır. Four examples of the derivation of single weather data are as in Table 34, Table 35, Table 36 and Table 37.

Table 34: Example of Obtaining Single Data for January 29, 2010 at 10 a.m.

City	Temperature (ºC)	Humidity (%)	Wind Velocity (km/h)	Coefficient (%)
İstanbul	7	93	18.5	41.6
Ankara	-1	93	5.6	13.4
İzmir	11	94	7.4	16.9
Antalya	12	94	24.1	15.1
Diyarbakır	1	93	7.4	13.0
Turkey	6.6	93.3	14.3	100.0

Table 35: Example of Obtaining Single Data for April 20, 2011 at 2 p.m.

City	Temperature (ºC)	Humidity (%)	Wind Velocity (km/h)	Coefficient (%)
İstanbul	11	76	31.5	40.9
Ankara	10	66	18.5	14.2
İzmir	14	63	31.5	16.9
Antalya	13	82	14.8	14.1
Diyarbakır	21	35	29.6	13.9
Turkey	13.0	67.5	27.0	100.0

Table 36: Example of Obtaining Single Data for July 27, 2012 at 8 p.m.

City	Temperature (ºC)	Humidity (%)	Wind Velocity (km/h)	Coefficient (%)
İstanbul	28	66	22.2	37.1
Ankara	34	17	25.9	14.1
İzmir	32	46	16.7	18.1
Antalya	29	84	5.6	16.8
Diyarbakır	35	13	11.1	13.9
Turkey	30.7	51.1	17.4	100.0

Table 37: Example of Obtaining Single Data for October 20, 2012 at 4 a.m.

City	Temperature (ºC)	Humidity (%)	Wind Velocity (km/h)	Coefficient (%)
İstanbul	14	77	7.4	41.8
Ankara	5	70	1.9	14.0
İzmir	17	68	18.5	17.8
Antalya	23	33	20.4	15.6
Diyarbakır	13	36	14.8	10.8
Turkey	14.6	63.1	11.4	100.0

The resulting weather data set are composed of 8760 day data from both 2010 and 2011, and 8784 day data from 2012, 26304 day data in total. Taking into account that a single day data consists of temperature, humidity and wind velocity; the number data related with weather conditions rises up to 78912.

2.2 Other Data Set

Aside from weather data set, some other data are utilized as inputs to ANN structure. These are the day of the week, the type of the day, the hour of the day, previous week load, previous day load and previous n-hour load.

In order to define the day of the week, days from Monday to Sunday are enumerated from 1 to 7. The type of the day shows whether the corresponding day is a work day, weekend day or public holiday. If it is a work day, 0 is given; and if it is a weekend day or public holiday, 1 is given to specify the type of the day. Hours are from 0 to 23, representing 24 hours in a day.

Previous week load and previous day load can be procured from hourly electricity demand data. Besides, previous 18-hour, 12-hour, 8-hour, 4-hour and 2-hour load data are utilized in order to see the potential progress of load forecasts within intraday time horizon. Similar to previous week load and previous day load data, these can also be procured from hourly electricity demand data.

2.3 Scenarios for Short Term Load Forecasting

The first step prior to simulations is to determine the best data combination to be utilized. For this purpose, four combinations are determined with the abbreviations TEMP, HUM, VEL and ALL. Their contents are as shown in Table 38. TEMP is the abbreviation of temperature, which is the base case scenario with the most definite characteristic of temperature. HUM is the abbreviation of humidity, which has humidity data in addition to TEMP scenario. VEL is the abbreviation of velocity, which has wind velocity data in addition to TEMP scenario. Lastly, ALL is the scenario which consists of both humidity and wind velocity in addition to temperature.

The criterion for the performance of different the models is the mean absolute percentage error (MAPE). In order to see the progress of load forecast errors, system loads concerning different time horizons are utilized from 2 hours to 168 hours.

Table 38: Contents of Different Combinations

Scenario	Content
TEMP	Day of the week, Type of the day, Hour of the day, Previous load, Temperature
HUM	Day of the week, Type of the day, Hour of the day, Previous load, Temperature, Humidity
VEL	Day of the week, Type of the day, Hour of the day, Previous load, Temperature, Wind Velocity
ALL	Day of the week, Type of the day, Hour of the day, Previous load, Temperature, Humidity, Wind Velocity

3. Simulations

The aim of the simulations in this part is to obtain a load forecast series specifically for 24, 18, 12, 8, 4 and 2 hours prior to the delivery. Also, obtaining a load forecast series giving better results for the intraday time horizon compared to the one performed by NLDC is the other target.

3.1 Simulation 1: Simulation with Previous n-hour Load Data

The first simulation is performed for each of the four scenarios and cover the time period between the years 2010 and 2012. For 168-hour time horizon, only the system load of 168 hours before is utilized. Similarly, for different time horizons, only the corresponding system load data are employed; i.e. for 2-hour time horizon, only the system load of 2 hours before real time is used. As shown in Figure 63, the average MAPE before 168 hours is 3.26%, before 24 hours is 1.59% and before 2 hours is 1.31%. The most successful scenario is ALL in which MAPE can diminish up to 1.27% for the forecasts performed with the previous 2-hour system load data. Taking into account that the ALL scenario MAPE before 24 hours is 1.68% and before 2 hours is 1.27%, the progress in load forecast accuracy is 0.41 points corresponding 24.7% improvement.

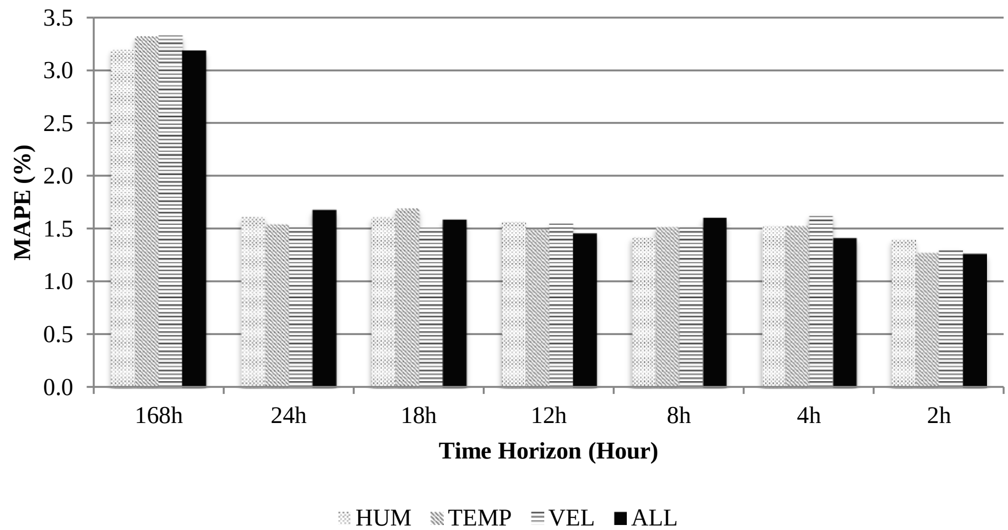


Figure 63: Results of Previous n-hour Load Data Simulation

On yearly basis, the most successful results are obtained from ALL scenario again. The smallest MAPE before 2 hours is 1.22% for 2011 and the largest MAPE before 2 hours is 1.32% for 2010. The corresponding MAPE in 2012 is 1.25%. The average MAPE of all of the scenarios, TEMP, HUM, VEL and ALL, is presented in Figure 64 on yearly breakdown.

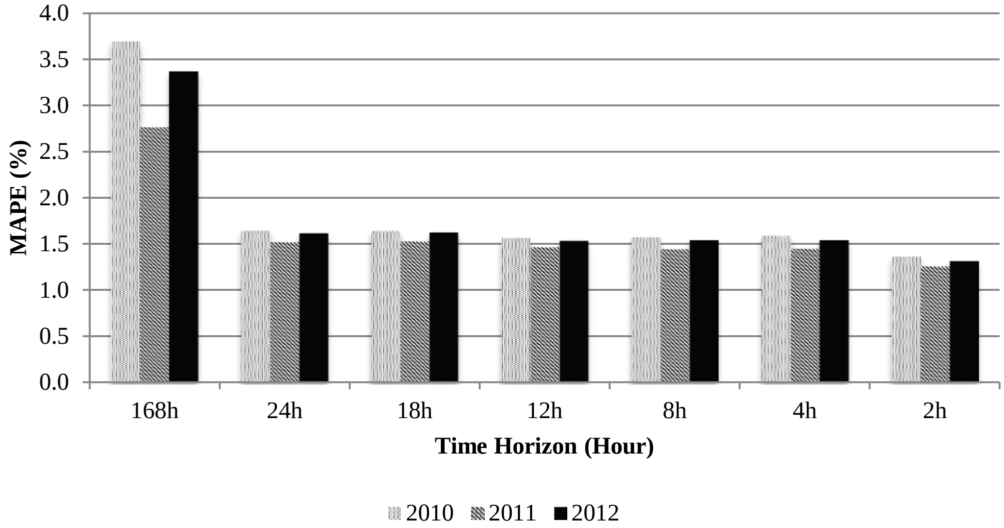


Figure 64: Yearly Results of Previous n-hour Load Data Simulation

3.2 Simulation 2: Simulation with Cumulative Previous n-hour Load Data

The second simulation is performed for each of the four data sets between 2010 and 2012 similar to the first one. For 168-hour time horizon, only the system load of 168 hours before is utilized. However, for different time horizons, the corresponding system load data and the load data regarding other time horizons are employed; i.e. for 24-hour time horizon, both the system load of 168 hours before and that of 24 hour before are used. Similarly, for 2-hour time horizon, all of the system load data concerning 168, 24, 18, 12, 8, 4 and 2 hours before are given as inputs to ANN. The results obtained from Simulation 2 are fairly better than the previous one as shown in Figure 65. The average MAPE before 168 hours is 3.23%, before 24 hours is 1.58% and before 2 hours is 1.12%. The most successful scenario is ALL in which MAPE can diminish up to 1.06% for the forecasts performed with the previous 2-hour system load data. Taking into account that the ALL scenario MAPE before 24 hours is 1.53% and before 2 hours is 1.06%, the progress in load forecast accuracy is 0.47 points corresponding 30.6% improvement.

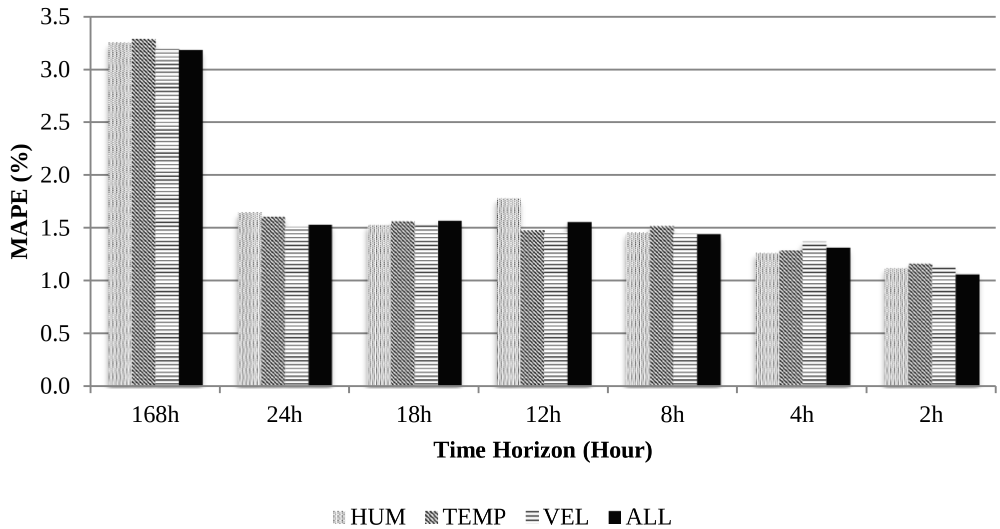


Figure 65: Results of Cumulative Previous n-hour Load Data Simulation

On yearly basis, the most successful results are obtained from ALL scenario again. The smallest MAPE before 2 hours is 1.02% for 2011 and the largest MAPE before 2 hours is 1.11% for 2010. The corresponding MAPE in 2012 is 1.06%. The average MAPE of all of the scenarios, TEMP, HUM, VEL and ALL, is presented in Figure 66 on yearly breakdown.

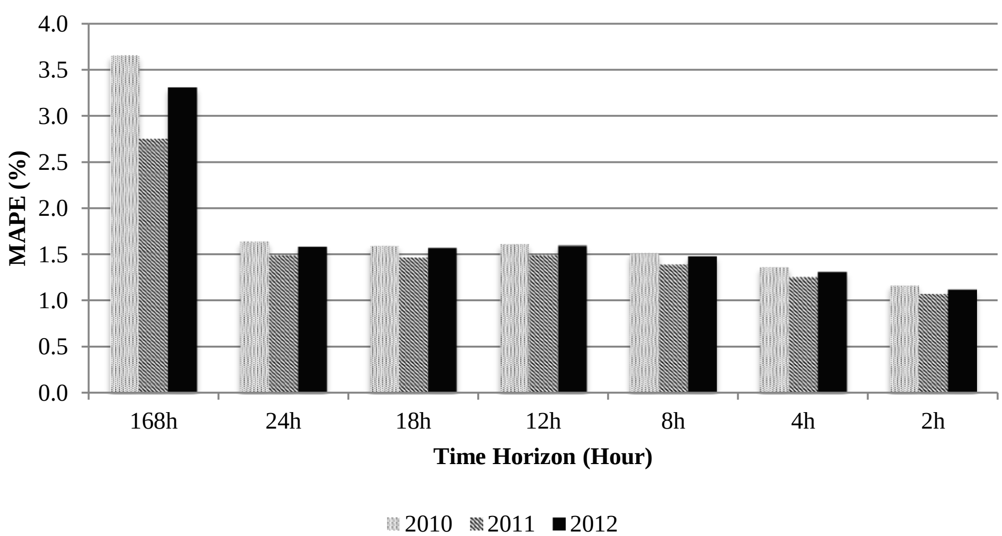


Figure 66: Yearly Results of Cumulative Previous n-hour Load Data Simulation

On the ground that Simulation 2 gives significantly better results than Simulation 1, cumulative load data for different time horizons are utilized for the next two simulations which will aim to increase the forecast accuracy. Furthermore, on account of the fact that ALL scenario remarkably prevail the other scenarios TEMP, HUM and VEL, these are eliminated for the next simulations.

3.3 Simulation 3: Seasonal Simulation with Cumulative Previous n-hour Load Data

The third simulation is performed only with ALL scenario data from 2010 to 2012 on seasonal basis. In other words, winter data, summer data and spring-autumn data are grouped among themselves in order to enhance the sensitivity of the analysis for better results. The results of Simulation 3 represent improved results compared to the first two simulations, as shown in Figure 67.

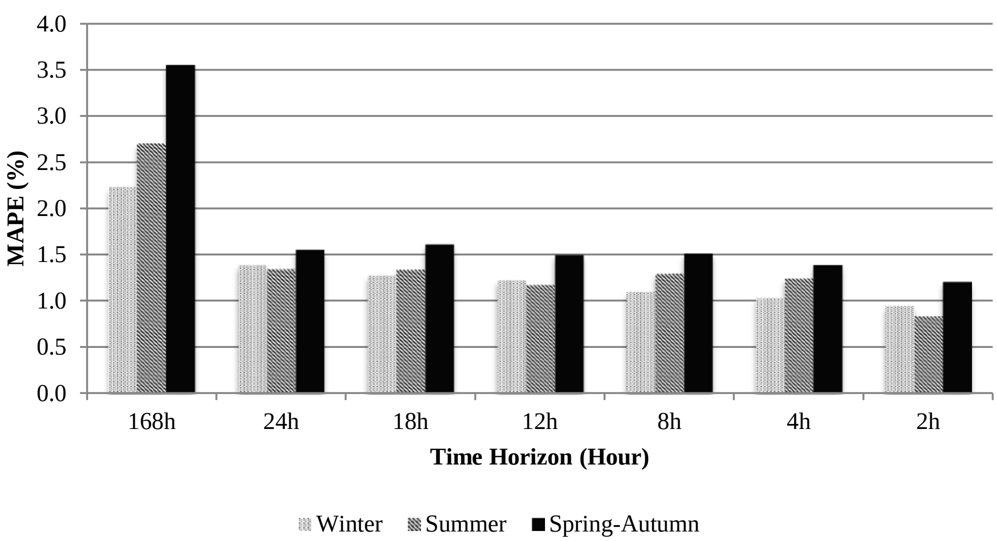


Figure 67: Results of Seasonal Simulation with Cumulative Previous n-hour Load Data

The average MAPE before 168 hours for winter is 2.23%, before 24 hours is 1.39% and before 2 hours is 0.95%. As for MAPE for summer, the numbers are 2.70%, 1.34% and 0.84% respectively. The third category, spring-autumn, shows somewhat unsatisfactory results with MAPE before 168 hours 3.55%, before 24 hours is 1.55% and before 2 hours is 1.21%. Taking into account that the progresses in load forecast accuracy is 0.44 points for winter, 0.51 points for summer and 0.34 points for spring-autumn period, the corresponding improvements are 31.9%, 37.7% and 22.1% respectively.

On yearly seasonal basis for winter, the most successful results belong to the year 2011 with MAPE before 24 hours 1.28% and before 2 hours 0.85%, as shown in Figure 68. The corresponding numbers for 2012 is 1.43% and 0.95%. As for summer season, the smallest MAPE is for 2011 again with 1.26% and 0.81% before 24 hours and 2 hours, respectively, as presented in Figure 69. The corresponding numbers for 2012 is 1.44% and 0.87%.

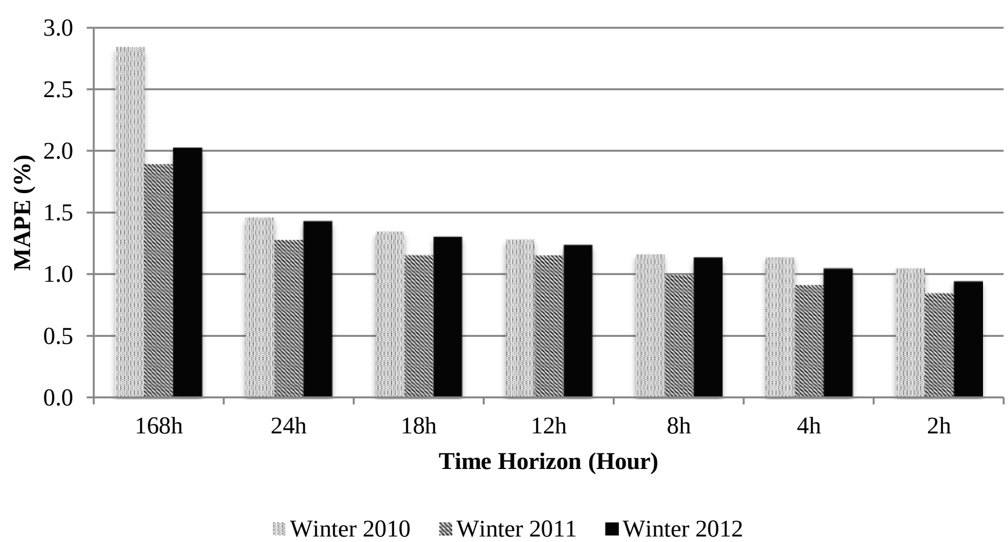


Figure 68: Yearly Results of Seasonal Simulation with Cumulative Previous n-hour Load Data for Winter

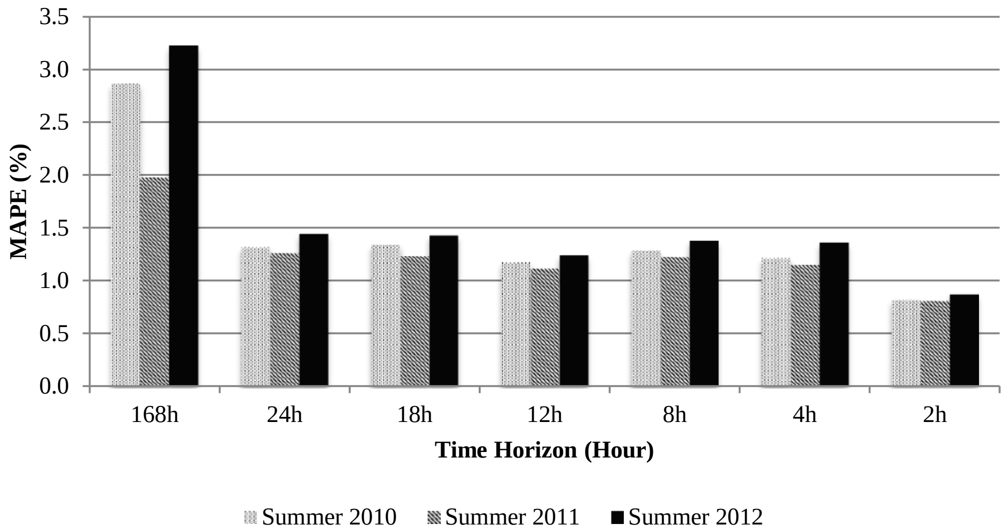


Figure 69: Yearly Results of Seasonal Simulation with Cumulative Previous n-hour Load Data for Summer

3.4 Simulation 4: Seasonal Simulation with Previous n-hour Load Data for Spring and Autumn

The fourth simulation intends to diminish MAPE for spring and autumn seasons, which have been found relatively high in the previous simulation. It is performed only with ALL scenario data again from 2010 to 2012 along with the partitioning of spring and autumn seasons. The results of Simulation 4 reveal improved results compared to the third simulation, as shown in Figure 70.

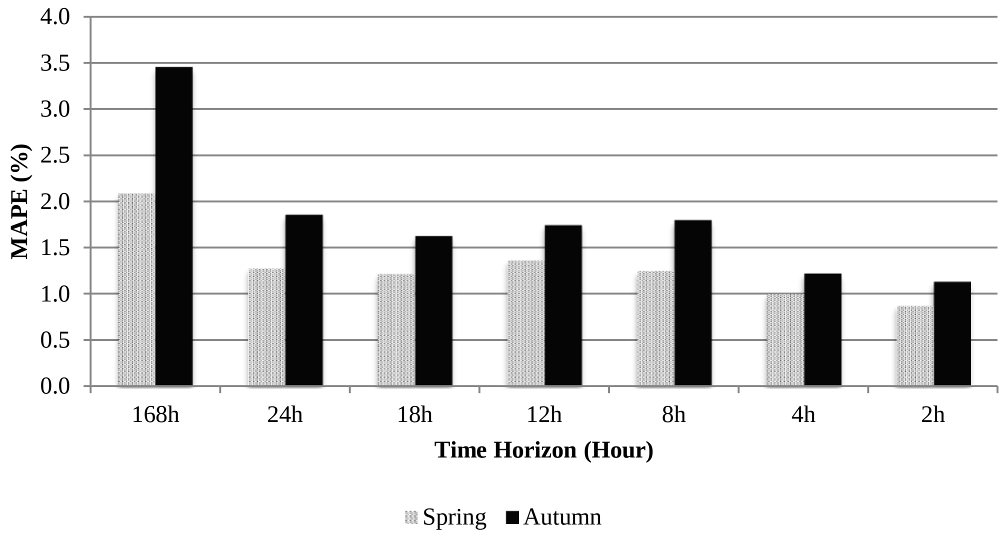


Figure 70: Results of Seasonal Simulation with Cumulative Previous n-hour Load Data for Spring and Autumn

The average MAPE before 168 hours for spring is 2.09%, before 24 hours is 1.27% and before 2 hours is 0.87%. As for MAPE for autumn the numbers are 3.45%, 1.86% and 1.13% respectively. Taking into account that the progresses in load forecast accuracy is 0.40 points for spring and 0.72 points for autumn, the corresponding improvements are 31.3% and 38.8% respectively.

On yearly seasonal basis for spring, the most successful results belong to the year 2011 with MAPE before 24 hours 1.17% and before 2 hours 0.86%, as shown in Figure 71. The corresponding numbers for 2012 is 1.36% and 0.87%. As for autumn season, the smallest MAPE is for 2012 with 1.65% and 1.02% before 24 hours and 2 hours, respectively, as presented in Figure 72.

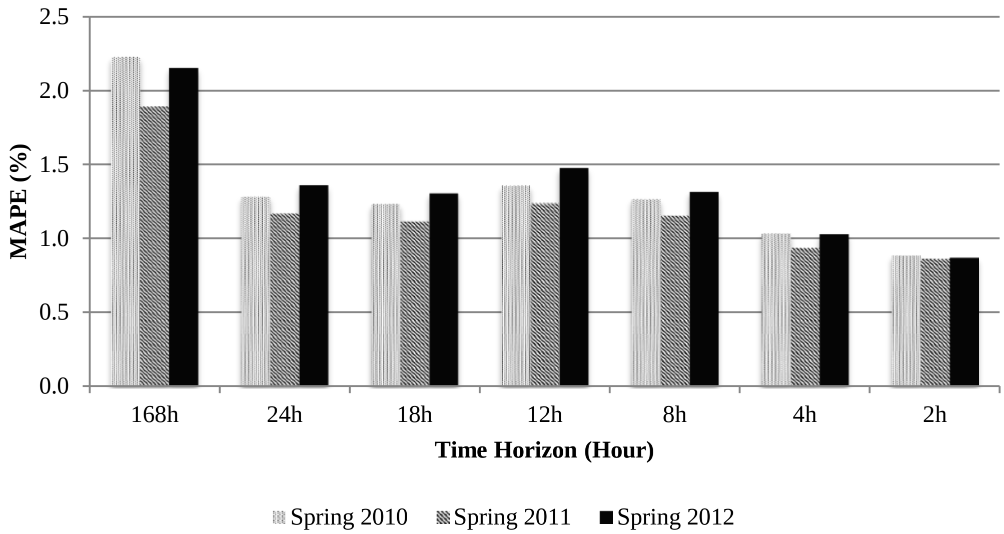


Figure 71: Yearly Results of Seasonal Simulation with Cumulative Previous n-hour Load Data for Spring

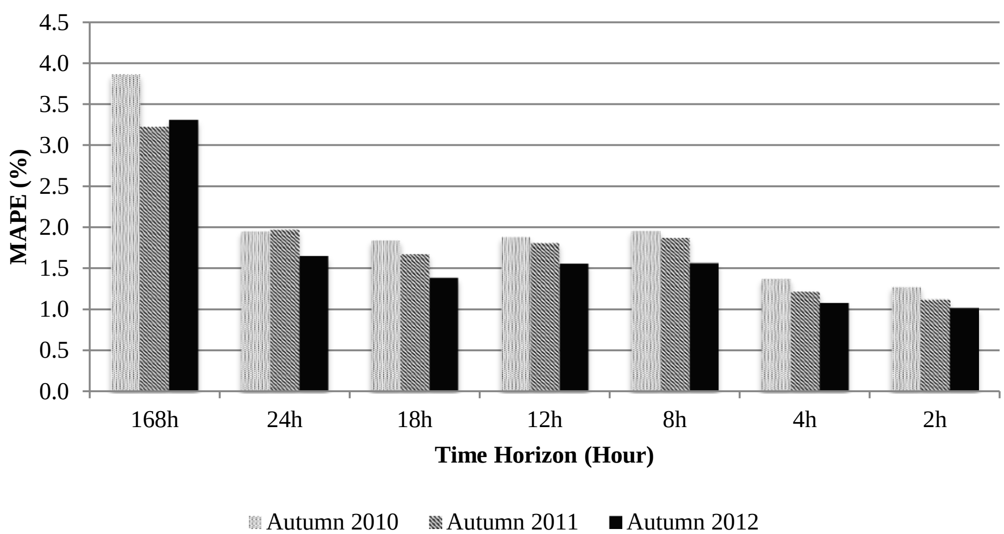


Figure 72: Yearly Results of Seasonal Simulation with Cumulative Previous n-hour Load Data for Autumn

4. Interpretation of Results

The results of the simulations are summarized and they are compared with actual MAPEs in Table 39.

Table 39: Comparison of MAPE from Simulation Results and Actual MAPE

Season	MAPEs from Simulation Results (%)			Actual MAPEs from 2010 to 2012 (%)
	Before 24 hours	Before 2 hours	Progress	
Winter	1.39	0.95	31.9	1.22
Summer	1.3	0.84	37.7	1.31
Spring	1.27	0.87	31.3	1.31
Autumn	1.86	1.14	38.8	1.49

MAPEs obtained from simulations before 24 hours are similar to the actual day-ahead loaf forecasting MAPEs from 2010 to 2012 except autumn season. Considering that the actual MAPEs are slightly better than those from simulation results, it is obvious that current ANN models can be improved further. Furthermore, taking into account the updated meteorological data will contribute to the study. However, it is not an issue to be handled within this thesis inasmuch as observing the potential progress of MAPEs is the main topic. In this part, the aim was to obtain a load forecast series which would be used in Chapter 7 in the research of the potential benefits of intraday markets.

APPENDIX-C

THE SYSTEM DATA RELATED TO THE ANALYSES PERFORMED FOR JANUARY 21, OCTOBER 24 AND NOVEMBER 1, 2012 IN CHAPTER 7

This part is composed of Table 40, Table 41 and Table 42. In those tables,

Load: Hourly consumption per unit time,

PTF and SMF: Hourly day-ahead and system marginal prices,

“n”h Forecast: Forecasted load for “n” hours prior to delivery time according to the model,

“n”h ID Price: Synthetic intraday prices for “n” hours prior to delivery time,

ID Trading “n”h: The amount of electrical energy that should be purchased or sold “n” hours prior to delivery time according to the model,

Gap 2h-0h Load: Difference of the energy positions between 2 hours prior to delivery and real time,

Gap 24h-2h Load: Difference of the energy positions between day-ahead and 2 hours prior to delivery.

Gap 24h-0h Load: Difference of the energy positions between 24 hours prior to delivery and real time, S1, S2 and S3: Scenario 1, Scenario 2 and Scenario 3,

Financial Position of S “n”: Financial position of scenario number “n” for the corresponding hour compared to the financial position in day-ahead,

Gap S “n1”- S “n2”: Difference of the financial positions for the corresponding hour between scenario number “n1” and scenario number “n2”.

Table 40: The Data of January 21, 2012

Date	Hour	Load (MW)	PTF (TL/MWh)	SMF (TL/MWh)	24h Forecast (MW)	18h Forecast (MW)	12h Forecast (MW)	8h Forecast (MW)	4h Forecast (MW)	2h Forecast (MW)
21.01.2012	0	27221.4	170.00	191.01	27,371	27,461	27,755	26,843	27,177	27,282
21.01.2012	1	25627.6	160.00	190.00	25,220	25,599	25,709	24,968	25,321	25,474
21.01.2012	2	24166.7	155.00	155.00	24,584	24,722	24,235	24,199	24,156	24,211
21.01.2012	3	23502.4	155.00	155.00	24,031	24,152	23,547	23,697	23,694	23,753
21.01.2012	4	23316.4	154.99	121.00	23,700	23,488	23,311	23,560	23,318	23,375
21.01.2012	5	23452.2	155.00	112.00	23,769	23,633	23,565	23,867	23,618	23,432
21.01.2012	6	23954.4	155.00	120.00	23,773	23,972	23,854	24,096	23,724	23,749
21.01.2012	7	24471.4	159.99	159.99	24,379	24,927	24,549	24,835	24,474	24,158
21.01.2012	8	27652.1	170.00	170.00	27,211	27,863	27,671	27,798	27,550	27,712
21.01.2012	9	30796.5	200.00	289.90	30,406	30,499	30,697	30,787	30,124	30,422
21.01.2012	10	32097.7	280.09	641.00	31,495	31,458	31,953	32,023	32,016	31,675
21.01.2012	11	33191.8	302.63	641.00	32,086	31,827	32,339	32,390	32,306	32,416
21.01.2012	12	32574.2	280.02	641.00	30,955	31,283	31,147	31,785	31,827	32,158
21.01.2012	13	32434.2	250.01	630.00	30,692	31,837	31,427	31,733	31,395	31,647
21.01.2012	14	32046.2	235.00	350.00	30,344	32,998	32,141	32,424	31,937	31,615
21.01.2012	15	31644.0	200.00	350.00	30,437	31,404	31,362	30,971	31,224	31,445
21.01.2012	16	31855.6	201.47	350.00	30,386	31,087	31,005	30,723	30,622	31,512
21.01.2012	17	32375.3	275.00	641.00	30,982	31,694	31,506	31,671	31,490	31,975
21.01.2012	18	31892.5	275.00	630.00	30,878	31,409	31,161	31,653	31,325	31,483
21.01.2012	19	30815.8	275.01	289.90	30,746	31,178	30,614	30,845	31,116	30,965
21.01.2012	20	30154.6	220.07	220.07	30,068	30,356	30,433	30,351	30,345	30,016
21.01.2012	21	29553.0	199.99	199.99	29,453	29,627	29,803	29,867	29,858	29,592
21.01.2012	22	29481.7	199.99	199.99	29,437	29,359	29,305	29,446	29,737	29,443
21.01.2012	23	28068.7	180.00	180.00	28,552	28,306	28,317	28,545	28,945	28,650

Table 40: The Data of January 21, 2012 (Continued)

Date	Hour	18h ID Price (TL/ MWh)	12h ID Price (TL/ MWh)	8h ID Price (TL/ MWh)	4h ID Price (TL/ MWh)	2h ID Price (TL/ MWh)	ID Trading 18h (MWh)	ID Trading 12h (MWh)	ID Trading 8h (MWh)	ID Trading 4h (MWh)	ID Trading 2h (MWh)
21.01.2012	0	175.25	180.51	184.01	187.51	189.26	-90	-294	912	-334	-105
21.01.2012	1	167.50	175.00	180.00	185.00	187.50	-379	-110	741	-353	-153
21.01.2012	2	155.00	155.00	155.00	155.00	155.00	-137	487	35	44	-56
21.01.2012	3	155.00	155.00	155.00	155.00	155.00	-121	605	-150	3	-59
21.01.2012	4	146.49	138.00	132.33	126.67	123.83	212	178	-250	243	-57
21.01.2012	5	144.25	133.50	126.33	119.17	115.58	136	68	-301	248	186
21.01.2012	6	146.25	137.50	131.67	125.83	122.92	-199	118	-243	373	-25
21.01.2012	7	159.99	159.99	159.99	159.99	159.99	-548	378	-285	360	317
21.01.2012	8	170.00	170.00	170.00	170.00	170.00	-652	192	-128	249	-163
21.01.2012	9	222.48	244.95	259.93	274.92	282.41	-93	-198	-90	664	-298
21.01.2012	10	370.32	460.55	520.70	580.85	610.92	37	-495	-70	7	341
21.01.2012	11	387.22	471.82	528.21	584.61	612.80	259	-512	-51	84	-110
21.01.2012	12	370.27	460.51	520.67	580.84	610.92	-328	135	-638	-42	-331
21.01.2012	13	345.01	440.01	503.34	566.67	598.33	-1,144	410	-306	338	-252
21.01.2012	14	263.75	292.50	311.67	330.83	340.42	-2,655	858	-283	487	322
21.01.2012	15	237.50	275.00	300.00	325.00	337.50	-967	42	391	-253	-221
21.01.2012	16	238.60	275.74	300.49	325.25	337.62	-701	82	282	101	-890
21.01.2012	17	366.50	458.00	519.00	580.00	610.50	-712	188	-165	182	-486
21.01.2012	18	363.75	452.50	511.67	570.83	600.42	-531	248	-492	328	-158
21.01.2012	19	278.73	282.46	284.94	287.42	288.66	-432	564	-231	-271	152
21.01.2012	20	220.07	220.07	220.07	220.07	220.07	-288	-77	82	7	329
21.01.2012	21	199.99	199.99	199.99	199.99	199.99	-174	-176	-64	9	265
21.01.2012	22	199.99	199.99	199.99	199.99	199.99	78	54	-142	-291	294
21.01.2012	23	180.00	180.00	180.00	180.00	180.00	247	-11	-228	-400	295

Table 40: The Data of January 21, 2012 (Continued)

Date	Hour	Gap 2h-0h Load	Gap 24h-2h Load	Gap 24h-0h Load	Financial Position of S1 (TL)	Financial Position of S2 (TL)	Financial Position of S3 (TL)	Gap S1-S2 (TL)	Gap S1-S3 (TL)
21.01.2012	0	60	90	150	26,830	27,202	25,474	-372	1,355
21.01.2012	1	-154	-254	-408	-72,542	-76,823	-77,457	4,281	4,915
21.01.2012	2	45	373	418	64,747	64,747	64,747	0	0
21.01.2012	3	251	278	529	81,966	81,966	81,966	0	0
21.01.2012	4	58	326	384	53,273	47,387	46,465	5,886	6,808
21.01.2012	5	-20	337	317	38,622	35,859	35,504	2,763	3,118
21.01.2012	6	-205	24	-182	-32,851	-28,897	-28,133	-3,954	-4,718
21.01.2012	7	-314	222	-92	-14,730	-14,730	-14,730	0	0
21.01.2012	8	60	-501	-441	-74,993	-74,993	-74,993	0	0
21.01.2012	9	-374	-16	-390	-102,978	-113,026	-113,145	10,049	10,167
21.01.2012	10	-423	-180	-603	-309,369	-380,975	-386,381	71,606	77,012
21.01.2012	11	-776	-330	-1,106	-683,997	-699,795	-709,106	15,798	25,109
21.01.2012	12	-417	-1,203	-1,619	-884,382	-1,001,721	-1,037,897	117,339	153,515
21.01.2012	13	-787	-955	-1,742	-823,756	-1,067,190	-1,097,419	243,434	273,663
21.01.2012	14	-431	-1,272	-1,703	-417,822	-583,725	-595,910	165,903	178,089
21.01.2012	15	-199	-1,008	-1,207	-327,251	-409,848	-422,444	82,596	95,192
21.01.2012	16	-343	-1,126	-1,469	-447,741	-500,368	-514,305	52,627	66,564
21.01.2012	17	-400	-993	-1,394	-708,281	-862,985	-893,285	154,704	185,004
21.01.2012	18	-410	-605	-1,015	-498,440	-621,453	-639,347	123,013	140,908
21.01.2012	19	149	-219	-70	-20,177	-22,164	-20,220	1,987	43
21.01.2012	20	-139	53	-86	-18,984	-18,984	-18,984	0	0
21.01.2012	21	39	-139	-100	-19,930	-19,930	-19,930	0	0
21.01.2012	22	-38	-7	-45	-8,979	-8,979	-8,979	0	0
21.01.2012	23	581	-98	484	87,064	87,064	87,064	0	0
Total					-5,114,702	-6,162,360	-6,331,445	1,047,659	1,216,744

Table 41: The Data of October 24, 2012

Date	Hour	Load (MW)	PTF (TL/MWh)	SMF (TL/MWh)	24h Forecast (MW)	18h Forecast (MW)	12h Forecast (MW)	8h Forecast (MW)	4h Forecast (MW)	2h Forecast (MW)
24.10.2012	0	21829.1	165.99	65.00	20,708	20,780	22,359	18,959	21,448	22,376
24.10.2012	1	20208.6	134.93	65.00	19,572	19,494	21,216	18,329	20,155	20,815
24.10.2012	2	19246.3	109.99	30.00	18,619	18,989	20,480	18,335	19,366	19,336
24.10.2012	3	18602.7	91.00	11.00	17,975	18,778	19,674	17,723	18,785	18,444
24.10.2012	4	18296.8	64.00	11.00	17,540	18,494	18,914	17,747	18,326	18,249
24.10.2012	5	18243.1	75.00	11.00	17,127	18,205	18,178	17,709	17,877	18,388
24.10.2012	6	18044.9	64.00	11.00	17,048	17,902	18,161	18,941	17,921	18,788
24.10.2012	7	17722.5	90.00	10.00	17,290	18,482	17,925	19,103	18,112	19,238
24.10.2012	8	19161.7	140.01	10.99	19,173	19,542	19,115	20,086	19,000	20,361
24.10.2012	9	20825.8	159.87	20.00	20,648	20,353	20,394	20,482	20,651	20,466
24.10.2012	10	21693.0	167.80	58.00	21,160	21,193	21,660	21,236	21,448	21,140
24.10.2012	11	21808.0	166.00	65.00	21,362	21,124	22,195	21,144	21,582	21,637
24.10.2012	12	21338.9	150.00	65.00	20,178	20,237	20,991	20,322	21,760	20,883
24.10.2012	13	20935.5	101.42	40.00	20,514	19,997	20,582	20,388	20,994	20,558
24.10.2012	14	20423.0	100.00	25.00	21,037	19,963	20,545	20,533	20,054	20,547
24.10.2012	15	19999.4	100.03	11.00	20,631	19,735	20,319	20,091	20,014	19,983
24.10.2012	16	19872.7	97.99	10.99	20,437	19,444	20,376	20,685	20,846	20,233
24.10.2012	17	20290.1	100.07	20.00	20,045	19,804	20,802	21,653	21,466	21,142
24.10.2012	18	21974.5	151.88	65.00	21,351	21,030	21,790	22,998	22,920	22,615
24.10.2012	19	22528.2	165.00	150.00	21,250	21,330	21,538	22,627	23,075	22,699
24.10.2012	20	22228.2	159.93	90.00	20,945	21,168	21,983	22,222	22,268	21,915
24.10.2012	21	21469.1	150.01	150.00	20,066	21,150	21,563	21,280	21,648	21,100
24.10.2012	22	21043.3	155.01	65.00	20,220	21,094	20,833	21,323	21,408	21,008
24.10.2012	23	19853.6	129.99	58.00	19,055	20,646	19,529	20,502	20,305	20,375

Table 41: The Data of October 24, 2012 (Continued)

Date	Hour	18h ID Price (TL/ MWh)	12h ID Price (TL/ MWh)	8h ID Price (TL/ MWh)	4h ID Price (TL/ MWh)	2h ID Price (TL/ MWh)	ID Trading 18h (MWh)	ID Trading 12h (MWh)	ID Trading 8h (MWh)	ID Trading 4h (MWh)	ID Trading 2h (MWh)
24.10.2012	0	140.74	115.50	98.66	81.83	73.42	-73	-1,578	3,400	-2,489	-928
24.10.2012	1	117.45	99.97	88.31	76.66	70.83	79	-1,722	2,886	-1,826	-660
24.10.2012	2	89.99	70.00	56.66	43.33	36.67	-370	-1,491	2,145	-1,031	30
24.10.2012	3	71.00	51.00	37.67	24.33	17.67	-803	-896	1,952	-1,063	342
24.10.2012	4	50.75	37.50	28.67	19.83	15.42	-954	-420	1,168	-579	77
24.10.2012	5	59.00	43.00	32.33	21.67	16.33	-1,078	26	470	-169	-510
24.10.2012	6	50.75	37.50	28.67	19.83	15.42	-854	-258	-781	1,020	-867
24.10.2012	7	70.00	50.00	36.67	23.33	16.67	-1,192	557	-1,178	991	-1,127
24.10.2012	8	107.76	75.50	54.00	32.49	21.74	-369	427	-971	1,085	-1,361
24.10.2012	9	124.90	89.94	66.62	43.31	31.66	295	-41	-88	-169	184
24.10.2012	10	140.35	112.90	94.60	76.30	67.15	-33	-467	424	-212	307
24.10.2012	11	140.75	115.50	98.67	81.83	73.42	238	-1,070	1,051	-438	-55
24.10.2012	12	128.75	107.50	93.33	79.17	72.08	-59	-754	669	-1,438	876
24.10.2012	13	86.07	70.71	60.47	50.24	45.12	517	-584	194	-606	436
24.10.2012	14	81.25	62.50	50.00	37.50	31.25	1,074	-582	12	479	-494
24.10.2012	15	77.77	55.52	40.68	25.84	18.42	896	-584	228	77	31
24.10.2012	16	76.24	54.49	39.99	25.49	18.24	993	-932	-309	-161	613
24.10.2012	17	80.05	60.04	46.69	33.35	26.67	240	-998	-851	187	325
24.10.2012	18	130.16	108.44	93.96	79.48	72.24	321	-760	-1,208	78	305
24.10.2012	19	161.25	157.50	155.00	152.50	151.25	-80	-208	-1,089	-448	376
24.10.2012	20	142.45	124.97	113.31	101.66	95.83	-223	-815	-239	-46	353
24.10.2012	21	150.01	150.01	150.00	150.00	150.00	-1,084	-413	283	-368	548
24.10.2012	22	132.51	110.01	95.00	80.00	72.50	-874	260	-490	-85	400
24.10.2012	23	111.99	94.00	82.00	70.00	64.00	-1,591	1,117	-973	197	-70

Table 41: The Data of October 24, 2012 (Continued)

Date	Hour	Gap 2h-0h Load	Gap 24h-2h Load	Gap 24h-0h Load	Financial Position of S1 (TL)	Financial Position of S2 (TL)	Financial Position of S3 (TL)	Gap S2-S1 (TL)	Gap S2-S3 (TL)
24.10.2012	0	547	-1,668	-1,121	-93,311	-86,908	-186,094	6,403	99,186
24.10.2012	1	607	-1,243	-636	-55,284	-48,597	-85,845	6,687	37,247
24.10.2012	2	90	-718	-628	-57,018	-23,610	-69,024	33,408	45,414
24.10.2012	3	-159	-469	-627	-63,471	-22,725	-57,094	40,746	34,369
24.10.2012	4	-48	-709	-756	-44,045	-13,975	-48,415	30,070	34,440
24.10.2012	5	145	-1,261	-1,116	-57,689	-19,007	-83,734	38,682	64,727
24.10.2012	6	743	-1,740	-997	-60,382	-18,653	-63,805	41,728	45,152
24.10.2012	7	1,516	-1,948	-433	-79,272	-17,313	-38,927	61,959	21,613
24.10.2012	8	1,199	-1,188	11	-41,073	-12,652	123	28,420	-12,776
24.10.2012	9	-360	181	-178	-31,664	-51,732	-28,465	-20,069	-23,267
24.10.2012	10	-553	20	-533	-105,442	-91,377	-89,372	14,065	-2,005
24.10.2012	11	-171	-275	-446	-54,730	-48,538	-74,033	6,192	25,495
24.10.2012	12	-455	-706	-1,161	-145,201	-119,177	-174,157	26,025	54,980
24.10.2012	13	-378	-44	-422	-34,227	-40,299	-42,759	-6,072	2,460
24.10.2012	14	124	490	614	57,182	18,422	15,359	-38,761	3,063
24.10.2012	15	-16	648	632	47,475	10,302	6,951	-37,173	3,351
24.10.2012	16	360	204	564	23,609	7,680	6,201	-15,929	1,479
24.10.2012	17	852	-1,097	-245	-48,470	-12,225	-24,548	36,245	12,322
24.10.2012	18	641	-1,264	-624	-84,331	-49,706	-94,755	34,625	45,048
24.10.2012	19	171	-1,449	-1,278	-200,260	-193,519	-210,879	6,741	17,360
24.10.2012	20	-313	-970	-1,283	-181,615	-143,030	-205,211	38,585	62,181
24.10.2012	21	-369	-1,035	-1,403	-210,517	-210,508	-210,518	9	9
24.10.2012	22	-35	-788	-824	-116,985	-62,644	-127,676	54,340	65,032
24.10.2012	23	521	-1,320	-799	-113,423	-54,239	-103,814	59,185	49,575
Total					-1,750,143	-1,304,031	-1,990,488	446,112	686,458

Table 42: The Data of November 1, 2012

Date	Hour	Load (MW)	PTF (TL/MWh)	SMF (TL/MWh)	24h Forecast (MW)	18h Forecast (MW)	12h Forecast (MW)	8h Forecast (MW)	4h Forecast (MW)	2h Forecast (MW)
01.11.2012	0	23424.8	174.00	150.00	23,658	23,060	23,873	22,844	22,962	23,476
01.11.2012	1	22347.1	165.00	165.00	22,538	22,240	22,825	22,332	22,488	22,537
01.11.2012	2	21602.1	137.99	137.99	21,704	21,777	22,416	21,401	21,736	21,504
01.11.2012	3	21197.9	100.03	100.03	21,139	21,371	21,858	20,939	21,279	21,162
01.11.2012	4	21243.0	100.03	65.00	21,051	21,331	21,599	20,996	21,345	21,155
01.11.2012	5	21644.6	100.06	100.06	21,529	21,607	21,929	21,522	21,657	21,602
01.11.2012	6	21711.1	137.99	137.99	21,805	21,776	21,575	21,712	21,815	21,778
01.11.2012	7	23084.7	167.99	167.98	23,263	23,360	23,170	23,170	22,994	22,890
01.11.2012	8	26260.3	179.99	150.00	26,432	26,894	26,378	26,407	26,180	26,293
01.11.2012	9	28062.3	180.00	93.00	28,098	28,704	27,937	28,034	28,064	28,096
01.11.2012	10	28711.9	184.68	78.00	28,977	29,517	28,900	28,765	28,833	28,817
01.11.2012	11	29025.1	187.63	65.00	29,229	29,389	29,190	28,902	28,627	28,213
01.11.2012	12	27292.3	199.38	64.00	27,839	27,575	28,133	27,147	26,960	27,547
01.11.2012	13	27880.4	187.99	64.00	28,436	28,025	28,224	27,614	27,990	28,342
01.11.2012	14	28353.3	200.00	64.00	28,151	27,664	27,902	27,585	27,735	27,720
01.11.2012	15	28328.4	200.00	58.00	28,164	27,942	28,033	27,902	28,083	27,820
01.11.2012	16	29222.2	187.64	78.00	29,109	28,895	28,989	28,951	28,748	28,441
01.11.2012	17	30068.5	159.00	159.00	30,238	30,142	29,840	30,019	29,640	29,006
01.11.2012	18	28984.3	184.29	64.00	29,344	29,210	29,330	29,291	28,980	29,027
01.11.2012	19	27871.4	185.01	58.00	28,330	28,061	28,378	28,271	28,185	28,112
01.11.2012	20	27097.9	179.99	58.00	27,736	27,539	27,677	27,384	27,564	27,106
01.11.2012	21	26145.6	164.99	40.00	26,691	26,624	26,883	26,409	26,909	26,897
01.11.2012	22	26606.5	185.00	78.00	26,888	26,748	26,697	26,542	26,567	26,656
01.11.2012	23	25462.1	173.00	165.00	25,775	25,524	25,725	25,432	25,577	25,580

Table 42: The Data of November 1, 2012 (Continued)

Date	Hour	18h ID Price (TL/ MWh)	12h ID Price (TL/ MWh)	8h ID Price (TL/ MWh)	4h ID Price (TL/ MWh)	2h ID Price (TL/ MWh)	ID Trading 18h (MWh)	ID Trading 12h (MWh)	ID Trading 8h (MWh)	ID Trading 4h (MWh)	ID Trading 2h (MWh)
01.11.2012	0	168.00	162.00	158.00	154.00	152.00	598	-813	1,029	-118	-515
01.11.2012	1	165.00	165.00	165.00	165.00	165.00	298	-585	492	-156	-49
01.11.2012	2	137.99	137.99	137.99	137.99	137.99	-73	-639	1,015	-335	232
01.11.2012	3	100.03	100.03	100.03	100.03	100.03	-232	-487	919	-340	118
01.11.2012	4	91.27	82.52	76.68	70.84	67.92	-280	-268	603	-349	190
01.11.2012	5	100.06	100.06	100.06	100.06	100.06	-78	-322	406	-135	54
01.11.2012	6	137.99	137.99	137.99	137.99	137.99	29	201	-137	-103	37
01.11.2012	7	167.99	167.99	167.98	167.98	167.98	-97	190	-1	176	104
01.11.2012	8	172.49	165.00	160.00	155.00	152.50	-462	517	-29	227	-113
01.11.2012	9	158.25	136.50	122.00	107.50	100.25	-605	766	-96	-30	-32
01.11.2012	10	158.01	131.34	113.56	95.78	86.89	-540	617	135	-68	16
01.11.2012	11	156.97	126.32	105.88	85.44	75.22	-160	199	289	274	414
01.11.2012	12	165.54	131.69	109.13	86.56	75.28	264	-558	986	187	-587
01.11.2012	13	156.99	126.00	105.33	84.67	74.33	411	-198	610	-376	-352
01.11.2012	14	166.00	132.00	109.33	86.67	75.33	486	-238	317	-149	15
01.11.2012	15	164.50	129.00	105.33	81.67	69.83	221	-91	131	-181	263
01.11.2012	16	160.23	132.82	114.55	96.27	87.14	214	-94	38	203	307
01.11.2012	17	159.00	159.00	159.00	159.00	159.00	97	302	-179	378	634
01.11.2012	18	154.22	124.15	104.10	84.05	74.02	134	-120	39	311	-46
01.11.2012	19	153.26	121.51	100.34	79.17	68.58	269	-316	107	86	73
01.11.2012	20	149.49	119.00	98.66	78.33	68.17	198	-138	293	-179	458
01.11.2012	21	133.74	102.50	81.66	60.83	50.42	67	-259	474	-500	12
01.11.2012	22	158.25	131.50	113.67	95.83	86.92	141	50	156	-25	-89
01.11.2012	23	171.00	169.00	167.67	166.33	165.67	251	-201	293	-145	-4

Table 42: The Data of November 1, 2012 (Continued)

Date	Hour	Gap 2h-0h Load	Gap 24h-2h Load	Gap 24h-0h Load	Financial Position of S1 (TL)	Financial Position of S2 (TL)	Financial Position of S3 (TL)	Gap S3-S1 (TL)	Gap S3-S2 (TL)
01.11.2012	0	52	182	233	42,726	35,352	34,989	-7,737	-363
01.11.2012	1	190	1	191	31,536	31,536	31,536	0	0
01.11.2012	2	-98	199	102	14,057	14,057	14,057	0	0
01.11.2012	3	-36	-22	-58	-5,849	-5,849	-5,849	0	0
01.11.2012	4	-88	-104	-192	-22,059	-15,870	-19,212	2,848	-3,342
01.11.2012	5	-42	-73	-116	-11,565	-11,565	-11,565	0	0
01.11.2012	6	67	27	94	12,950	12,950	12,950	0	0
01.11.2012	7	-195	374	179	30,033	30,032	30,034	1	2
01.11.2012	8	33	139	172	23,711	26,147	25,799	2,088	-347
01.11.2012	9	34	2	36	-6,296	3,356	3,340	9,636	-16
01.11.2012	10	105	160	265	14,170	22,116	20,691	6,520	-1,426
01.11.2012	11	-812	1,016	203	-67,304	-75,994	13,224	80,528	89,218
01.11.2012	12	255	292	547	66,138	38,291	34,999	-31,139	-3,292
01.11.2012	13	461	95	556	75,292	36,550	35,573	-39,719	-977
01.11.2012	14	-634	431	-203	-54,579	-94,268	-40,545	14,034	53,723
01.11.2012	15	-509	344	-165	-59,647	-77,719	-32,972	26,676	44,748
01.11.2012	16	-781	668	-113	-74,057	-88,330	-21,175	52,882	67,155
01.11.2012	17	-1,062	1,232	170	27,010	27,010	27,010	0	0
01.11.2012	18	42	317	360	35,235	26,207	23,024	-12,211	-3,183
01.11.2012	19	241	218	459	39,219	28,906	26,600	-12,620	-2,307
01.11.2012	20	8	631	639	59,606	43,451	37,036	-22,570	-6,414
01.11.2012	21	751	-207	545	21,300	19,647	21,798	498	2,151
01.11.2012	22	49	233	282	40,292	24,066	21,991	-18,301	-2,075
01.11.2012	23	118	194	313	52,875	51,717	51,587	-1,288	-130
Total					284,793	101,797	334,921	50,127	233,124

APPENDIX-D

VISUAL BASIC CODES FOR THE WEATHER DATA OF THE MODEL IN APPENDIX-B

Visual Basic Code for the Weather Data of İstanbul:

```
Sub FetchData()

    x = 1
    For x = 1 To 1096
        With ActiveSheet.QueryTables.Add(Connection:= _
            "URL;http://www.wunderground.com/history/airport/LTBA/2010/1/" & x &
"/DailyHistory.html?req_city=NA&req_state=NA&req_statename=NA&MR=1&&th
eprefset=SHOWMETAR&theprefvalue=0&format=1" _
            , Destination:=Range("$A$1"))

            .Name =
"DailyHistory.html?req_city=NA&req_state=NA&req_statename=NA&MR=1&&th
eprefset=SHOWMETAR&theprefvalue=0&format=1"
            .FieldNames = True
            .RowNumbers = False
            .FillAdjacentFormulas = False
            .PreserveFormatting = True
            .RefreshOnFileOpen = False
```

```
            .BackgroundQuery = True
            .RefreshStyle = xlInsertDeleteCells
            .SavePassword = False
            .SaveData = True
            .AdjustColumnWidth = True
            .RefreshPeriod = 0
            .WebSelectionType = xlEntirePage
            .WebFormatting = xlWebFormattingNone
            .WebPreFormattedTextToColumns = True
            .WebConsecutiveDelimitersAsOne = True
            .WebSingleBlockTextImport = False
            .WebDisableDateRecognition = False
            .WebDisableRedirections = False
            .Refresh BackgroundQuery:=False
        End With
    Next x
End Sub
```

Visual Basic Code for the Weather Data of Ankara:

```
Sub FetchData()
    x = 1
    For x = 1 To 1096
        With ActiveSheet.QueryTables.Add(Connection:= _
            "URL;http://www.wunderground.com/history/airport/LTAC/2010/1/"  &  x  &
"/DailyHistory.html?req_city=NA&req_state=NA&req_statename=NA&format=1" _
            , Destination:=Range("$A$1"))
```

```
        .Name                                                                    =
"DailyHistory.html?req_city=NA&req_state=NA&req_statename=NA&format=1"
        .FieldNames = True
        .RowNumbers = False
        .FillAdjacentFormulas = False
        .PreserveFormatting = True
        .RefreshOnFileOpen = False
        .BackgroundQuery = True
        .RefreshStyle = xlInsertDeleteCells
        .SavePassword = False
        .SaveData = True
        .AdjustColumnWidth = True
        .RefreshPeriod = 0
        .WebSelectionType = xlEntirePage
        .WebFormatting = xlWebFormattingNone
        .WebPreFormattedTextToColumns = True
        .WebConsecutiveDelimitersAsOne = True
        .WebSingleBlockTextImport = False
        .WebDisableDateRecognition = False
        .WebDisableRedirections = False
        .Refresh BackgroundQuery:=False
      End With
   Next x
End Sub
```

Visual Basic Code for the Weather Data of İzmir:

```
Sub FetchData()
   x = 1
```

```
    For x = 1 To 1096
        With ActiveSheet.QueryTables.Add(Connection:= _
            "URL;http://www.wunderground.com/history/airport/LTBJ/2010/1/" & x &
"/DailyHistory.html?req_city=NA&req_state=NA&req_statename=NA&format=1" _
            , Destination:=Range("$A$1"))

            .Name =
"DailyHistory.html?req_city=NA&req_state=NA&req_statename=NA&format=1"
            .FieldNames = True
            .RowNumbers = False
            .FillAdjacentFormulas = False
            .PreserveFormatting = True
            .RefreshOnFileOpen = False
            .BackgroundQuery = True
            .RefreshStyle = xlInsertDeleteCells
            .SavePassword = False
            .SaveData = True
            .AdjustColumnWidth = True
            .RefreshPeriod = 0
            .WebSelectionType = xlEntirePage
            .WebFormatting = xlWebFormattingNone
            .WebPreFormattedTextToColumns = True
            .WebConsecutiveDelimitersAsOne = True
            .WebSingleBlockTextImport = False
            .WebDisableDateRecognition = False
            .WebDisableRedirections = False
            .Refresh BackgroundQuery:=False
        End With
    Next x
End Sub
```

Visual Basic Code for the Weather Data of Antalya:

```
Sub FetchData()
    x = 1
    For x = 1 To 1096
        With ActiveSheet.QueryTables.Add(Connection:= _
            "URL;http://www.wunderground.com/history/airport/LTAI/2010/1/" & x & "/DailyHistory.html?format=1" _
            , Destination:=Range("$A$1"))

            .Name = "DailyHistory.html?format=1"
            .FieldNames = True
            .RowNumbers = False
            .FillAdjacentFormulas = False
            .PreserveFormatting = True
            .RefreshOnFileOpen = False
            .BackgroundQuery = True
            .RefreshStyle = xlInsertDeleteCells
            .SavePassword = False
            .SaveData = True
            .AdjustColumnWidth = True
            .RefreshPeriod = 0
            .WebSelectionType = xlEntirePage
            .WebFormatting = xlWebFormattingNone
            .WebPreFormattedTextToColumns = True
            .WebConsecutiveDelimitersAsOne = True
            .WebSingleBlockTextImport = False
            .WebDisableDateRecognition = False
            .WebDisableRedirections = False
            .Refresh BackgroundQuery:=False
```

```
        End With
    Next x
End Sub
```

Visual Basic Code for the Weather Data of Diyarbakır:

```
Sub FetchData()
    x = 1
    For x = 1 To 1096
        With ActiveSheet.QueryTables.Add(Connection:= _
            "URL;http://www.wunderground.com/history/airport/LTCC/2010/1/" & x &
"/DailyHistory.html?req_city=NA&req_state=NA&req_statename=NA&format=1" _
            , Destination:=Range("$A$1"))

            .Name =
"DailyHistory.html?req_city=NA&req_state=NA&req_statename=NA&format=1"
            .FieldNames = True
            .RowNumbers = False
            .FillAdjacentFormulas = False
            .PreserveFormatting = True
            .RefreshOnFileOpen = False
            .BackgroundQuery = True
            .RefreshStyle = xlInsertDeleteCells
            .SavePassword = False
            .SaveData = True
            .AdjustColumnWidth = True
            .RefreshPeriod = 0
            .WebSelectionType = xlEntirePage
            .WebFormatting = xlWebFormattingNone
```

```
            .WebPreFormattedTextToColumns = True
            .WebConsecutiveDelimitersAsOne = True
            .WebSingleBlockTextImport = False
            .WebDisableDateRecognition = False
            .WebDisableRedirections = False
            .Refresh BackgroundQuery:=False
        End With
    Next x
End Sub
```