INTEGRATED SIMULATION AND OPTIMIZATION OF DECENTRALIZED TURKISH ELECTRICITY MARKET

by

Soner Özdinç

B.S., Computer Engineering, Bilkent University, 2008

Submitted to the Institute for Graduate Studies in
Science and Engineering in partial fulfillment of
the requirements for the degree of
Master of Science

Graduate Program in Industrial Engineering

Boğaziçi University

2012

ACKNOWLEDGEMENTS

I am heartily thankful to my supervisor, Prof. İlhan OR, whose encouragement, guidance and support from the initial phase to the final level enabled me to develop an understanding of Turkish Electricity Market. Moreover, I offer my regards and blessings to all of those who supported me in any respect during the completion of this thesis. Lastly, I would like to thank my mother for supporting me during the master study.

ABSTRACT

INTEGRATED SIMULATION AND OPTIMIZATION OF A DECENTRALIZED TURKISH ELECTRICITY MARKET

Unlike most other commodities, electricity cannot be stored. Therefore, its generation must closely match the demand on a continuous time scale. Primarily for this reason, an independent system operator is needed to manage, monitor and supervise the market behavior and control the physical operations to balance the demand and supply. The regulation called "Balancing and Settlement" based on Electricity Market Law No.4628 enacted in 2001, was put into practice in 2004 to form more liberalized market where uncontracted generation can be traded. In this new system, transmission was completely separated from the distribution and the ownership of the national grid, the responsibilities of planning new transmission investments and building new transmission facilities were transferred to the TEIAS. Generation, on the other hand, was to be accomplished by many individual power companies (some public and some private) who would be selling the electricity produced in an "auction" system. This "auction" system consists of the Day-Ahead Market and of the Real-Time Balancing Market. This study analyzes the Day-Ahead and the Real-Time Balancing markets and power generator agents in many aspects like system prices, demand levels, profits, market shares, capacity utilization and algorithms which enable power generator agents to take decision regarding the matters related to the Day-Ahead Market operations according to administration of the "Balancing and Settlement" regulation in an agent-based simulation model. Results provide key insights into the behavioral and the structural aspects of decentralized electricity market and investigate the electricity market restructuring and implication of competitive power market based on hourly bidding.

ÖZET

TÜRKİYE ELEKTRİK PİYASASININ MODELLENMESI VE BÜTÜNLEŞİK BENZETIM/ENİYİLEME UYGULAMASI

Çoğu diğer metaların aksine, elektrik saklanabilen metalardan değildir. Bu nedenle, elektrik üretimi sürekli bir zaman ölçeği üzerinde gerçekleşen taleple yakından eşleşmelidir. Öncelikle bu nedenden dolayı, sistemde gerçekleşen arz ve talebi dengelemek için gereken fiziksel işlemleri yönetmek ve kontrol etmek amacıyla, tek bir merkezi sistem operatörü gerekmektedir. Bu dengelemeyi gerçekleştirmek ve kontraksız üretimin alım/ satımını gerçekleştirilecek pazarı oluşturmak için 2004 yılında 'Dengeleme ve Uzlaştırma' olarak adlandırılan sistem yürürlüğe konulmuştur. Bu sistemde, iletim yani ulusal şebekeye dağıtım ve mülkiyet tamamen birbirlerinden ayrılmış, yeni iletim yatırımlarının planlanması ve yeni iletim tesislerinin inşa sorumlulukları Türkiye Elektrik İletim A.Ş.'e (TEIAS) devredilmiştir. Diğer bir taraftan üretim ise bu sistemde bir 'açık artırma' sistemi ile ürettiği elektriği satan bazıları kamu, bazıları ise özel bireysel enerji şirketleri tarafından yerine getirilmektedir. Bu "açık artırma" sistemi, Gün Öncesi Piyasası ve Gerçek Zamanlı Dengeleme Piyasası adı verilen iki çeşit bağımsız dengeleme ve uzlaştırma faaliyetlerinden oluşmaktadır. Bu çalışma "Dengeleme ve Uzlaştırma" yönetmeliğine bağlı kalarak, Gün Öncesi ve Gerçek Zamanlı Dengeleme piyasalarını ve piyasaya katılan elektrik üretim santrallerini; sistem fiyatları, karlılık, kapasite kullanımı, pazar payı indeksleri gibi birçok açıdan incelemekte ve bu piyasalarda karar almasını sağlayacak algoritma analizleri yapmaktadır. Sonuçlar, bağımsız elektrik üreticilerinin saatlik teklif vermesi prensibi altında çalışan dağınık elektrik piyasasının kilit özelliklerine ve rekabetçi piyasa ortamının incelenmesine ışık tutmaktadır.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF SYMBOLS

BOP_m	Price of Block Offer indexed by m
BOQ_m	Quantity of Block Offer indexed by m
BOQ_m	Maximum Quantity of Block Offer indexed by m
D_t	Daily Total Power Demand at time t
FOP_m	Price of Flexible Offer indexed by m
FOQ_m	Quantity of Flexible Offer indexed by m
FOQ_m	Maximum Quantity of Flexible Offer indexed by m
G_t	Daily Power Generation Schedule at time t
HOP_m	Price of Hourly Offer indexed by m
HOQ_m	Quantity of Hourly Offer indexed by m
HOQ_m	Maximum Quantity of Hourly Offer indexed by m
h(m)	Duration of Block Offer indexed by m
m	Offer index
SBO	Block Offer Set
SFO	Flexible Offer Set
SHO	Hourly Offer Set
t	Time index, t=0,1,2,…,23
t0(m)	Hour of Hourly Offer indexed by m
t1(m)	Starting Time of Block Offer indexed by m
t2(m)	Ending Time of Block Offer indexed by m
x_m^{offer}	Accept/Reject of Not Partially-Acceptable Hourly Offer indexed by m
y_m^{offer}	Accept/Reject of Not Partially-Acceptable Block Offer indexed by m
z_m^{offer}	Accept/Reject of Partially-Acceptable Flexible Offer indexed by m

LIST OF ACRONYMS/ABBREVIATIONS

BOO	Build Operate and Own
BOT	Build Operate and Transfer
BSS	Balancing and Settlement System
CU	Capacity Utilization
DAP	Day-Ahead Market System Price
DGS	Daily Generation Schedule
DSI	State of Hydraulics of Turkey
EML	Electric Market Law No. 4628
EMRA	Energy Market Regulatory Authority
GENCO	Generation Company
GDP	Gross Domestic Product
ISO	Independent System Operator
IMF	International Monetary Fund
MERN	Republic of Turkey Ministry of Energy and Natural Resources
MS	Market Share
MSA	Market Share Algorithm
MTA	General Directorate of Mineral Research and Exploration
NPP	Nuclear Power Plant
PPS	Profit per Sale
PPU	Profit per Unit
REL	Renewable Energy Law No.5346
TEAS	Turkish Electricity Generation Co
TEDAS	Turkish Electricity Distribution Co.
TEIAS	Turkish Electricity Transmission Co.

TEK	Turkish Electricity Administration
TETAS	Turkish Electricity Trade and Contracting Co.
TEUAS	Turkish Electricity Generation Co.
TOOR	Transfer of Operating Rights
SD	Standard Deviation
SMP	System Marginal Price
UEDT	Underlying Energy Demand Trend

1. INTRODUCTION AND STUDY OBJECTIVES

Since 1980s the electricity markets in many countries have been gradually evolving from monopoly markets into multi-actor, competitive and liberalized markets. This liberalized market structure brings to the generation companies the opportunity to increase their profits while taking more risks (of not being dispatched). Therefore, defining bidding strategies for the generation companies to maximize their profit and minimize the risks while participating in liberalized electricity market has become a core interest for researchers. The literature pertaining to this issue features many different modeling approaches, such as mathematical programming, game theory and agent-based simulation models. On the other hand, the increased penetration of renewable power sources into the electricity market has introduced additional complexities to the modeling efforts due to the inherent uncertainties and variability over time regarding the available generation capacities of such technologies. These issues necessitate further constraints in the optimal bidding strategy models and increase the complexity and solving-time of the models.

Since electricity cannot be stored easily, unlike most other commodities, electricity generation should closely match the demand on a continuous time scale. Therefore, in decentralized electricity markets, electricity generation companies face significant risks for not being dispatched (if they overproduce and/or bid at high prices, then they may lose the opportunity to sell more and/or higher priced electricity). Accordingly, they need suitable decision support system to help them improve their policies. In this environment, bidding, operating level, capacity expansion, available technology and competitors' unknown actions/reactions play a crucial role in determining individual generator's load assignments and profits on one hand, and market electricity price on the other. Primarily for this reason, an independent system operator is needed to manage, monitor and supervise the market behavior and control the physical operations to balance the demand and supply. As Al-Sunaidy and Green state that the degree of liberalization of an electricity market or independent market design does not change this reality (Al-Sunaidy and Green, 2006). Haas and Auer state that effective competition may be achieved in a decentralized market if the following six prerequisites are met (Haas and Auer, 2006);

(i) Separation of the grid from generation and supply;
(ii) Wholesale price deregulation;
(iii) Sufficient transmission capacity and non-discriminating grid access
(iv) Excess generation capacity provided by a large number of competing generators;
(v) An equilibrium relationship between short term and long term financial instruments that marketers use to manage spot-market price volatility;
(vi) A government policy that encompasses enhanced oversight (increasing monitoring and auditing capabilities as a regulator) and privatization (increasing private sector and foreign capital investment while decreasing the public investments).

Even if the above conditions are met, market participants still need to answer many questions and take the proper decisions in order to increase their profits while decreasing the risks of not being dispatched. For this purpose, integrated simulation and optimization models can provide best fitting tools to help market participants to better understand the market dynamics. Simulation models can represent the market behavior and related activities of decentralized electricity market by considering the competition among the market participants. Optimization models can mimic the minimum cost policy used by the regulatory authority while considering the transmission constraints, cost and technical limitations. By the help of integrated models giving consideration to both approaches, the decision makers can better understand the possible consequences of the different policies under different market conditions.

1.1. The Turkish Electricity Market History

In the first years of the republic, Turkey was heavily dependent on foreign investments in the electricity generation industry. Starting from 1930s, Turkey followed the nationalization trend which was widespread all over the word at that time. So, almost all the industry was replaced with public domain assets between the years 1938 and 1944 (Erdogdu, 2007). In 1963, The Ministry of Energy and Natural Resources (MENR) was established to develop and execute the development plans in all segments of the Turkish energy market which required a radical restructuring. This was followed by the foundation of the Turkish Electricity Administration (TEK). Except the distribution of electricity (which was left to local public bodies), the Turkish electricity market became a monopoly controlled by the TEK in all aspects (Bagdadioglu and Odyakmaz, 2009). The domination of the state-owned, vertically integrated company the TEK on the Turkish electricity market continued up to the early of 1980s (Ozkivrak, 2005). Starting from 1982, government sought to attract private participation into the electricity generation industry due to the investment burden of the industry on the general budget; so, private generation companies were allowed to be built and sell their electricity to the TEK. In order to increase the private sector participation in the electricity market, various models for reorganization and investment were put into practice and formed the legal basis for enlarged private participation through Build Operate and Transfer (BOT) contracts for new generation companies, Transfer of Operating Rights (TOOR) contracts for existing generation companies and auto producer system for companies to produce their own electricity (Cetin and Oguz, 2007). In 1993, the TEK split into two separate state-owned enterprises called the Turkish Electricity Generation Co. (TEAS) and the Turkish Electricity Distribution Co. (TEDAS). In 1997, an additional contract type namely Build, Operate and Own (BOO) contract (which featured guarantees provided by Treasury) was enacted to increase the private sector participation in the construction and operation of new power plants. However, current structure of the contracts acted as a major barrier to the development of the competition in the electricity sector because a typical BOT, BOO or TOOR electricity generation contract signed between a private power generation company and TEAS included fixed quantities and prices (or prices formula) over 15-30 years which destroys the framework for competition in the electricity market.

1.2. Market Reforms

The main problems that triggered the electricity market reform process in the Turkish electricity market can be listed as follows;

(i) Governments could not raise necessary public funds for new generation facilities urgently needed in order to meet the rapidly growing demand for electricity consumption (Erdogdu, 2007);

(ii) Poor performance of the state-owned generation companies due to political meddling, conflicts of interest among multiple regulatory institutions and a lack of efficiency in the state-dominated market which leads to a serious supply shortage in the electricity sector (Ozkivrak, 2005);

(iii) A foreign pressure by the World Bank, the International Monetary Fund and the European Union on the government to accelerate the reform process (Erdogdu, 2007).

In February 2001, Turkey enacted the Turkish Electricity Law No. 4628, which laid ground for a totally different legal framework for the Turkish electricity market; next, the Energy Market Regulatory Authority was established as an independent regulator (in many respects, including its income and its authority over the market activities) and the TEAS was separated into three companies which are responsible for different sub-sectors of the electricity market. These three companies are the TEUAS which is responsible for generation, the TEIAS which is the market operator and responsible for transmission and the TETAS which is the regulator for the whole electricity sales. The new law provided the private sector's direct participation in all sub-sectors of the electricity sector except transmission.

As Ozkivrak (2005) states the key features of the restructuring of the Turkish electricity market are;

(i) Unbundling the electricity sector from the previous vertically integrated form;

(ii) Increasing the competition in the non-monopoly segments mainly in generation and in retail sale sectors;

(iii) Establishing a licensing method for the market participants to prevent the inequalities and interruptions in the market;

(iv) Establishing an independent regulatory authority to ensure the competition and transparency among the market participants;

(v) Increasing the participation of private power generation companies in the generation and distribution sectors.

1.3. The New Turkish Electricity Market Structure

The main objective of the Turkish Electricity Market Law No. 4628, as stated before, is to establish a financially viable, transparent and competitive electricity market. It has created the necessary legal framework for the introduction of a competitive environment to ensure the adequate, efficient, high quality and low cost electricity to consumers. In this regard, the Turkish Electricity Market Law No. 4628 designs the Turkish electricity market based on bilateral contracts (between market participants) and a balancing and settlement mechanism. Bilateral contracts, which are one of the major components of this market model, are agreements whose terms and duration are freely determined by parties (entities in both supply and demand sides). Within the context of bilateral contracts, liberalization is realized not only on the supply side but also on consumption side because consumers whose electricity consumption is above one million KWh and those who are directly connected to the transmission grid have the right to choose their suppliers (generation companies, distribution companies with retail license, retailers and wholesalers) and sign bilateral contracts as eligible consumers. On the other hand, non-eligible consumers purchase electricity energy and/or capacity at the regulated retail tariffs. So, briefly the purpose of the bilateral contracts is to meet the eligible consumers' entire electricity needs by suppliers. However, there may be real-time imbalances in the predicted electricity need of the consumers due to changes in the consumers' consumption behavior, unexpected social events, climate changes and extraordinary circumstances on the generation side. Under the cases of imbalance, physical balance of the system is established by the transmission system operator (National Load Dispatch Center) which gives orders to generators to load or de-load (up-regulation or down-regulation), based on the bids and offers submitted by generation companies within the context of the balancing and settlement mechanism.

Balancing and settlement mechanism covers activities related to the Day-Ahead Market and the Real-Time Balancing Market. The Day-Ahead Market is performed one day before the real-time on the basis of forecasted demand which is announced by the system operator. For each day, generation companies participating in the Day-Ahead Market notifies the day-ahead generation schedules (DGS) which are the generation values anticipated to realize in the following day to meet the bilateral contracts; day-ahead hourly, block and flexible offers (buy and sale) to the system operator. The system operator determines the day-ahead market price (DAP), which is the final market clearing price and announces the accepted offers for each hour of the following day by taking into consideration transmission system capacities, technical constraints of generation companies, reliability and quality of supply criteria. The Real-Time Balancing Market consists of balancing activities that aim to balance the realized demand in the real-time. The sale and buy offers submitted to the Real-Time Balancing Market consist of reserved capacity that can be activated within maximum of 15 minutes. The system operator determines the system marginal price (SMP), which is set to the maximum accepted real-time offer price for each hour in the Real-Time Balancing Market. If electricity supply deficiency exists, the system operator issues up-regulation instructions which regulates how generation companies increase their generation level and sell energy to the system. On the other hand, if electricity supply abundance exists, the system operator issues down-regulation instruction which regulates how generation companies decrease their generation level and buy energy from the system. As the new market model features all the above factors, the electricity generation activities are performed by the state-owned Electricity Generation Company (EUAS), its affiliates, private generation companies, auto-producers and auto-producers groups. Auto-producers and auto-producers groups operate essentially to meet their own electricity needs. However, they can also sell in the competitive electricity market a certain amount of generated electricity which does not exceed fifteen percent of the total electricity they have generated. Additionally, the total market share of any private generation company and its affiliates cannot exceed twenty per cent of Turkey’s total installed capacity published. The transmission activities in the market are performed by the Turkish Electricity Transmission Company (TEIAS). The TEIAS holds the ownership of all transmission assets, serve as system operator to form an infrastructure suitable for a competitive market**.** The distribution activities in the market are performed by the Turkish Electricity Distribution Company (TEDAS), its affiliates and private sector distribution companies. Private sector distribution companies cannot purchase electricity from the generation companies they own or they are affiliated with.

1.4. Historical Development of Turkish Electricity Power Industry

The first electricity power plant was constructed in Mersin by a private organization in 1902 and ten years after that, the first thermal power plant was built in Istanbul. After the foundation of Etibank in 1935 which is a state organization, the state started to operate many hydroelectricity and thermal electricity plants by the support of the General Directorate of Mineral Research and Exploration (MTA), Iller Bank and State of Hydraulics of Turkey (DSI). At the end of 1970, the total annual electricity generation was 23,275 GWh and nearly 80% of the population was able to use electricity. However, in year 1973, Turkey was heavily affected by the oil price increase so the first oil crisis forced Turkey to make better use of national and renewable sources for electricity energy which in most cases was hydraulic resource. This trend continued up to year 1982 and after 1982, (with the recovery of the oil crisis' effects and available competitive natural gas prices) Turkey again started to use thermal power as the primary electricity generation source.

Figure 1.1 displays the annual development of Turkey's installed capacity between year 1990 and 2009 according to the three main types of electric power plants (Bilgili *et al.*, 2012).

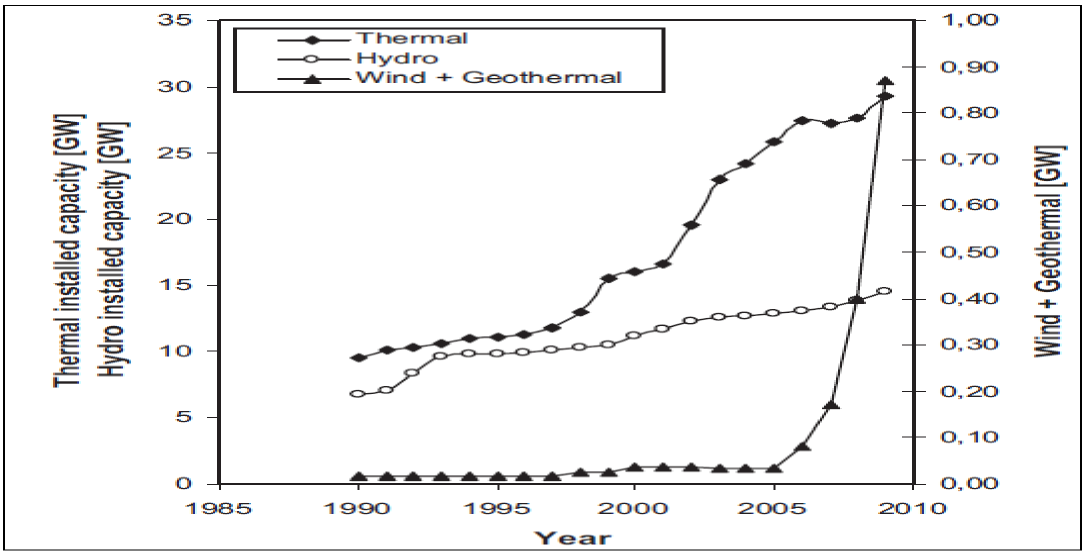


Figure 1.1. Annual development of Turkey's installed capacity between year 1990 and 2009.

Currently, Turkey has a wide range of energy resources including hard coal, lignite, oil, hydraulic, natural gas, geothermal and solar. Apart from these, Turkey is also planning to invest in nuclear energy between 2015 and 2020 to meet the increasing electricity demand. Figure 1.2 displays the annual development of Turkey's thermal power plants' installed capacity in the last ten years according to the primarily resources used in the generation of electricity.

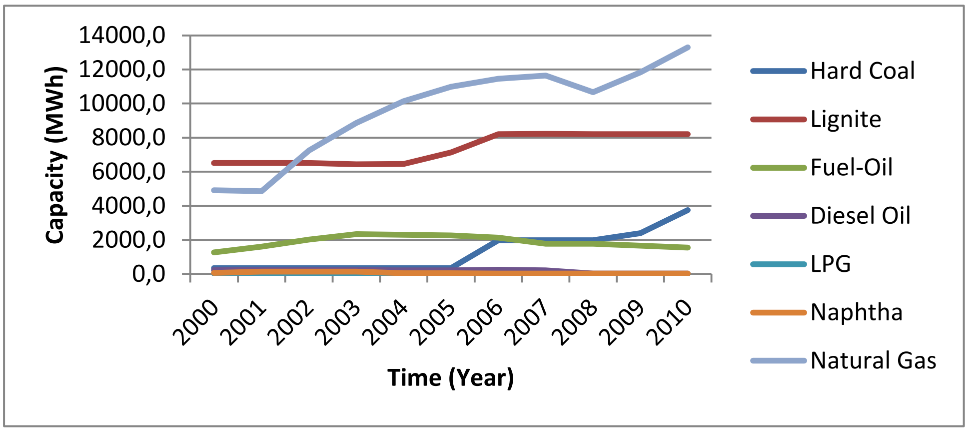


Figure 1.2. Annual development of Turkey's thermal power plants' installed capacity.

However, both inadequate utilization of these resources and improper government policies (insufficient support and promotion of natural and renewable resources) have forced Turkey to increase its dependence on foreign energy supplies. Figure 1.3 displays the shares of energy resources in terms of the Turkey's total electricity generation in year 2009 as:

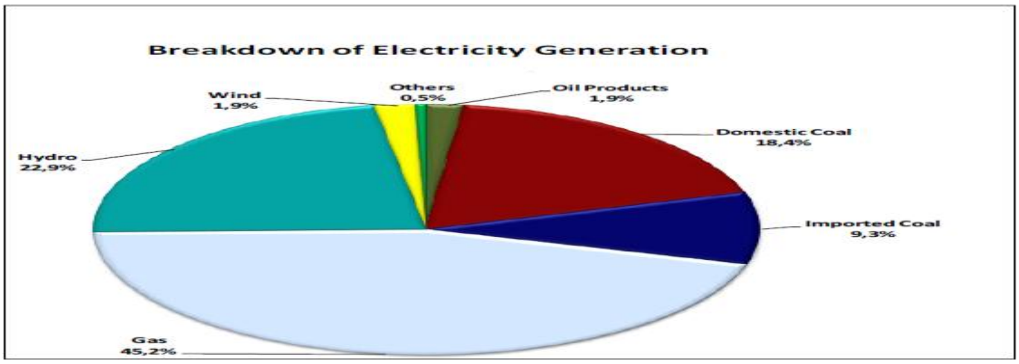


Figure 1.3. Shares of resources in terms of total electricity generation of Turkey in 2009.

With its rapidly growing population (growth rate per annum is nearly 1.4%) and a significant shift away from agriculture towards industrialization in the last 30 years, the electricity demand of Turkey has been growing more rapidly than the electricity production. Turkey's net electricity consumption has increased at an average rate of 8.89% per year since 1975. While net electricity consumption was 13.5 TWh in 1975, it increased to nearly 190 TWh in 2009. According to the Turkish government projections, an 8% annual growth rate is expected for the next 15 years. So, by the year 2020, the net electricity consumption is estimated to be the value of 434.57 TWh (Bilgili *et al*., 2012). However, during the same period, the average electricity consumption increased by only 2.9% annually in OECD countries. As a result, Turkey has inevitably become a net electricity importing country even though the total installed capacity increased from 2234 to 41744 MW between years 1970 and 2008.

Figure 1.4 displays the total electricity production of Turkey between year 2000 and 2011 (Bilgili *et al*., 2012).

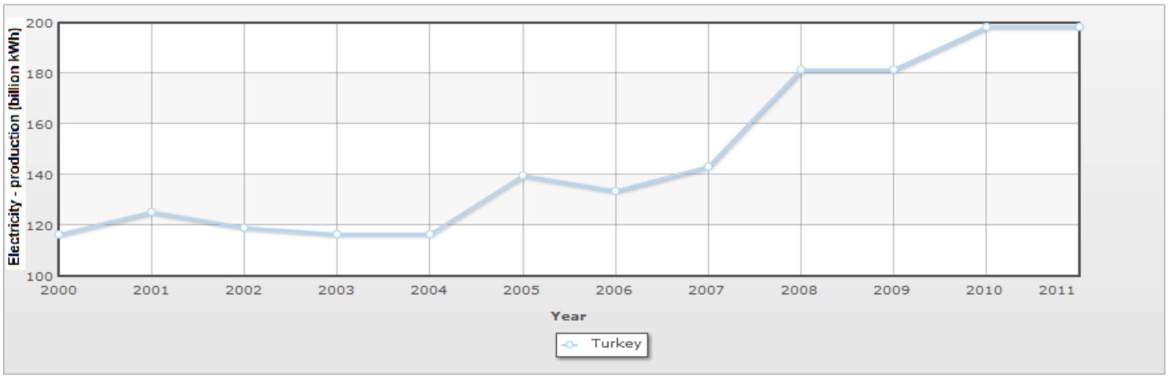


Figure 1.4. Trends in total electricity production of Turkey between year 2000 and 2011.

In 2001, the restructuring of the electricity market led private companies to make a move for taking part in the production of electricity in Turkey besides the government bodies. The share of the state-owned electricity generation plants in terms of total installed capacity decreased from 85% to 48.23% during the time between year 1984 and 2007. Figure 1.5 displays the share of the producers in Turkey installed capacity in year 2010 where the share of the state-owned electricity generation plants in terms of total installed capacity is 48.87%.

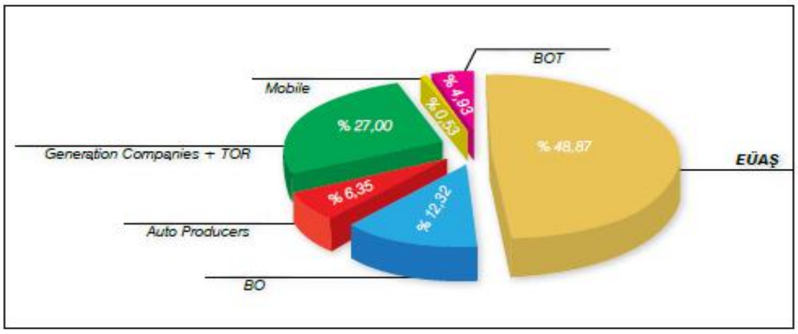


Figure 1.5. Shares of the producers in Turkish electricity generation in terms of total installed capacity in year 2010.

Additionally, the share of the state owned electricity generation reduced to 45.23% from 87.2% between year 1984 and 2010. In parallel with this new restructuring, the shares of private generation companies in terms of electricity generation and total installed capacity has increased and been expected to grow in the following years.

Figure 1.6 displays the shares of the producers in Turkish electricity generation in year 2010.

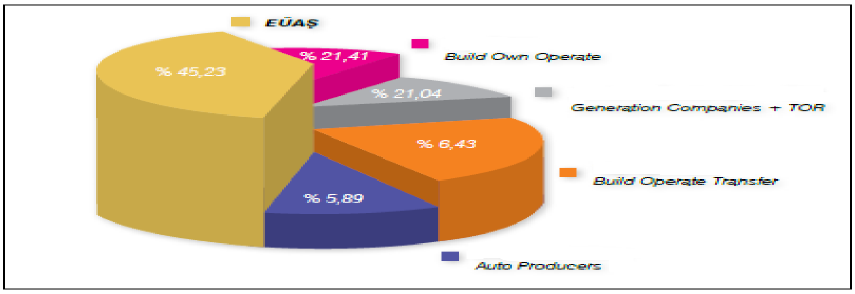


Figure 1.6. Shares of the producers in Turkish electricity generation in year 2010.

Gross domestic product (GDP) which is the value of all final goods and services made within the border of a nation in a year, is considered to be the most important determinant for electricity consumption in literature. Despite the economic crisis in 1994, 1998, 2001 and 2008; the average GDP growth rate has been 4.2% and the average electricity demand growth rate has been 8.4% between the years 1970 and 2010. As displayed in Figure 1.7, there is a significant and stable positive correlation between GDP and electricity consumption (at least in the 1971 and 2009 period).

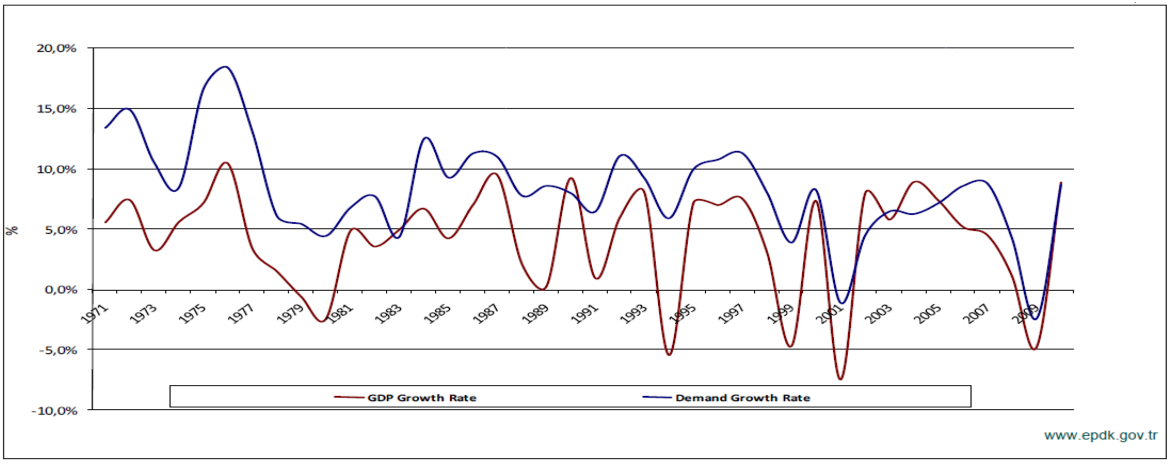


Figure 1.7. Correlation between GDP and electricity consumption between 1971 and 2009.

1.5. Study Objectives and Structure of the Thesis

This study analyzes the Day-Ahead and the Real-Time Balancing markets along with power generator agents in many aspects like system prices, demand levels, profits (overall profit, profit per unit and profit per capacity), capacity utilizations, market shares and policies which enable power generator agents to take decisions regarding market operations according to the administration of the “Balancing and Settlement” regulation in an agent-based simulation model. Agent-based simulation modeling refers to a class of computational models for simulating the actions and interactions of autonomous agents (generation companies) with a view of assessing their effects on the system as a whole.

The model developed in this study is to investigate and better understand the implications of a competitive and decentralized electricity market consisting of power generator agents (with the learning mechanism and related functional/technical properties), an independent system operator whose behavior is mimicked by an integrated simulation/optimization model regarding the balancing mechanism and an aggregate power user agent (whose demand characteristics resemble the demand profile in Turkey).

In the next section, various studies related to the electricity market modeling around the world and the Turkish electricity market and its recent reforms are summarized.

The third section explains the structure and design of the developed simulation/optimization model with the descriptions of each power generator agent including the learning mechanism and other related functional/technical properties, the system operator behavior including the optimization procedure and formulation used in the balancing mechanism, compilation of the hypothetical demand data and the flow of the simulation model.

In the fourth section, scenarios' analysis and results are obtained, classified and comparisons are made to see the effect of parameters on many aspects like system prices of the markets, profits, capacity utilizations and market shares of power generator agents.

Results provide key insights into the behavioral and structural aspects of decentralized electricity markets and investigate the electricity market restructuring (and implication of a competitive power market based on hourly bidding) and help to define bidding strategies for the generation companies to maximize their profit and minimize the risks while participating in liberalized electricity market under many different market conditions.

Last section concludes the outcomes of the study and further possible studies are introduced.

2. LITERATURE SURVEY

In this section, previous studies relevant to the scope of the study and related to liberalized electricity markets modeling are introduced.

2.1. Studies on Electricity Market Modeling around the World

Rich and flexible modeling techniques help to understand the complexity of the electricity markets and also provide insights for the design of appropriate regulatory frameworks. Given the complexity of an electricity market and its high importance in a competitive economy, researches are increasingly willing to create new models to better understand the various aspects of electricity markets. In this section, the literature and previous studies on agent-based modeling which is a recent research area for simulation of electricity markets are presented;

The study of Bower and Bunn (Bower and Bunn, 2000) presents an agent-based simulation model of the England and Wales electricity market, where transmission costs and constraints are neglected and demand side of the market is modeled as a linear demand curve. In the simulation model, they simply compare the daily versus hourly bidding mechanism and uniform versus discriminatory pricing (or pay-as-bid) methods. Under uniform pricing, power generator agents whose offers are accepted, are paid by market price times the accepted offered quantity. Under pay-as-bid pricing, power generator agents are paid by their bid price times the accepted offered quantity. According to their different scenarios, the lowest market clearing prices are achieved in the case of daily bidding with uniform pricing, while highest prices emerge in the case of hourly bidding with pay-as-bid pricing.

The study of Bunn, Bower and Wattendrup (Bower *et al.*, 2001) applies an agent-based model to the German electricity sector. The simulation is based on a pay-as-bid mechanism in a day-ahead market. They mainly analyze the effects of merging of the power generator agents in the model and claim that electricity prices rise considerably as an effect of merging. The rate of price increase becomes higher when the number of merged power generators increases in both on-peak time and off-peak time.

Visudhiphan and Ilic (Visudhiphan and Ilic, 2001) analyze the simulation results in a model where power generator agents are allowed to withhold their capacity in order to improve their overall profitability. In their study, each power generator agent has a memory which is represented as a matrix with rows corresponding to the different load ranges and columns corresponding to electricity auctions. By using this memory matrix, each agents can propose six different bid prices: (i) maximum, (ii) mean and (iii) minimum of the previous market prices, (iv) the sum of the weighted market prices, (v) the last offer price plus the absolute value of the difference between the last market price and last offer price and (vi) a target price plus the absolute value of the difference between last market price and target price. The authors conclude that the power generator agents are able to increase the system prices if they bid strategically.

The study of Weidlich and Veit (Weidlich and Veit, 2006) analyzes the simulation of a day-ahead market and a following balancing power market in sequence. In their model, power generator agents can bid in both markets and evaluate their individual success in one market while also considering the opportunity cost of profit in the other market. In their study, they explore four different scenarios which differ in the order of market execution and pricing mechanism which are; (i) day-ahead market then balancing market with uniform pricing, (ii) day-ahead market then balancing market with pay-as-bid pricing, (iii) balancing market then day-ahead market with uniform pricing, (iv) balancing market then day-ahead market with pay-as-bid pricing. They point out that the impact of the execution order of the markets on the system prices is crucial. If the day-ahead market is established and implemented first, lower system prices are generated due to the increased competition in the balancing power market where agents have more capacity to offer in the auction. Additionally, lower prices in the day-ahead market also cause lower prices in the balancing power market. The authors also observe that power generator agents tend to bid lower prices in the case of uniform pricing.

Another study of Weidlich and Veit (Weidlich and Veit, 2008) compares the different agent-based models in the electricity market and shows the differences and similarities of the compared models. They mainly show that transmission grid constraints are generally neglected in the studies and that the demand side is represented as a fixed and price-insensitive load in most cases. Moreover, they observe that capacity withholding strategies are not explicitly modeled in many cases. According to their study, they claim that power generator agents bid higher under the pay-as-bid system but overall prices are higher in the uniform pricing system.

The study of Gan, Wang and Bourcier (Gan *et al.*, 2005) analyzes the suppliers' strategic behavior in a pool-based electricity market with tight capacity constraints where a supplier aims to maximize its profit, but the independent system operator always selects least expensive generators to supply power. According to their study, they claim that when the capacity in the market is very tight, all suppliers are needed to satisfy the electricity demand, thus large capacity suppliers can easily raise the market price. On the other hand, in a market with weak capacity constraint (abundant supply), market clearing prices are likely to be low since large capacity suppliers hesitate to risk having their large capacities kept idle by offering high prices. Another important analysis in their paper is that the degree of cost asymmetry among suppliers is an important index in the electricity market.

The study of Mahvi and Ardehali (Mahvi and Ardehali, 2011) aims to provide optimum bidding strategies for power generator agents in the electricity market by using an agent-based approach and sensitivity analysis. In their model, sensitivity analysis provides information about the market to identify the critical decision point to be taken by power generator agents. Sensitivity analysis is mainly used to predict price changes under the dynamic fluctuation of factors which influences the electricity demand. In this study, the goal of the independent system operator is to minimize the total generation cost which is modeled as the sum of the costs of all generation units. The independent system operator achieves this by simply reordering the bids of generation companies according to the ascending order of the bidding prices. In this paper, power generator agents use knowledge from a sensitivity matrix which includes their bidding results and market clearing price in order to adjust their succeeding bidding strategies. Moreover, generation companies can also access market price, quantity of electricity in each bidding auctions and their rewards (increased profits and increased locational marginal electricity price (LMP) which is used by the generation companies in their pricing mechanism for each period). Then generation companies can accomplish their sensitivity analysis for their short term and long term economic goals with respect to their bids according to the proposed formulation. The authors implement a test scenario (in which 5 generation companies and 3 demand nodes are distributed across a 5 node transmission grid) to test their proposed bidding strategy. According to the results of the case studies, the proposed bidding strategy enables power generator agents to increase system prices and their profits.

The study of Trigo, Marques and Coelho (Trigo *et al.*, 2010) analyzes a multi-agent based simulation framework with learning agents. The results mainly focus on learnt bidding policies in the light of market specific dynamics. In their first experiment, they show that in the constant hourly demand environment, the agent with the active bidding policy has the highest long-term profit. In the second experiment, they raise the constant demand from 600 MW to 2000 MW and compare the small capacity agent with active bidding policy with the large capacity agent with fixed pricing strategy. The results of the second experiment show that small capacity power generator agent gets around 18% of market share from the large capacity power generator by lowering its prices. In the third experiment, active learning bidding policy is applied to the large capacity generator but the remaining features are the same with the second experiment. The results of the third experiment show that market shares of the both generators oscillate due to the reaction of the large generator to the small generator’s strategy to win the market.

2.2. Studies on the Turkish Electricity Sector

As mentioned in Section 1.3, in 2001, Turkey initiated the electricity market reforms with the activation of Electricity Market Law No.4628 to liberalize Turkish Electricity Market. However, the institutional and political structure was not ready for establishing a financially strong, stable, transparent and efficiently competitive electricity market. Moreover, the independent regulator did not have enough experience to direct the industry to a more competitive environment. For this reason, in 2004, Electricity Market Balancing and Settlement regulation was issued to clarify and ease the implementation of the Electricity Market Law No.4628.

The study of Cetin and Oguz (Cetin and Oguz, 2007) discusses the reasons for the slow initiation of the reform activities by focusing on the relationship between government, independent regulator and the judiciary. They highlight that the main reason of this slow performance is the conflicts of interests between de facto authority institutions like the Constitutional Court, Danistay, the Higher Planning Council, Ministry of Energy and Natural Resources (MERN) and Energy Market Regulatory Authority (EMRA) and they suggest that the efficient policies can only be achieved when these institutions work in cooperation. They also claim that, the uncertainty that existed in the legal environment negatively impacted the implementation of the reforms in the electricity market and damaged the regulatory commitments. Moreover, this uncertainty had also negative impacts on the long-term planning of market participants and discouraged them from taking risks and making investments.

The study of Bagdadioglu and Odyakmaz (Bagdadioglu and Odyakmaz, 2009) provides suggestions on the implementation of the Turkish Electricity Market Law No.4628 in the future. They claim that the most serious problem in the market is still the dominant position of the public sector in both generator and decision maker position. They also criticize that Turkish Electricity Market Law No.4628 is heavily imitative of UK's regulation and market reforms, and it does not consider Turkey's own special circumstances. So they suggest taking an incremental approach to reform the electricity market in order to allow all aspects of the inherited system to adapt to new circumstances for Turkey.

The study of Akkemik and Oguz (Akkemik and Oguz, 2011) analyzes a general equilibrium model of liberalization and competition in the Turkish Electricity Market. The paper investigates the impacts of deregulation on the economy by using a computational general equilibrium model and claims that full liberalization leads to the reduced electricity prices which have a positive impact on the improvement of utility level of consumers. However, the reduced electricity prices have a negative impact on the electricity generation and transmission sector. But at the end, empirical findings draw a positive picture of the electricity market and confirm that there is good potential to gain efficiency and welfare from full liberalization.

The paper of Erdogdu (Erdogdu, 2010) points at some inconsistencies between the objective of the Electricity Market Law No.4628 and the results of the “Electricity Balancing and Settlement” regulation and offers a consistent model to Turkish policy makers in order to replace the current inconsistent electricity market model based on “Electricity Balancing and Settlement” regulation. Additionally the author claims that the current regulation undermines the healthy development of supply in the Turkish electricity market due to uncertainties it created. According to the author, in Turkey supply shortages lead to electricity purchases in the balancing market by the system operator within the context of balancing and settlement framework. Since demand forecasts are not reliable in Turkey, necessary investments could not be done and even currently, present level of investment is not enough to cover present and expected future demand. For that reason, the system operator is frequently forced to purchase electricity from the balancing market. Since the prices emerged in the balancing market are mostly higher than those prices in the bilateral agreements (which is determined between buyers and sellers), private generation companies have preferred to cancel their bilateral agreements in order to sell electricity they produced in the balancing market. So, it can be said the actual implementation of the balancing and settlement system causes a significant decrease in the volume of bilateral contracts. The author proposes a pool model which provides a mechanism reducing the scheduling risk faced by generators and hence hopefully, the cost of electrical energy. When a generator sells energy on the basis of simple bids for each period separately, it runs the risk that for some periods; it may not sell enough energy to keep the plant on-line. At that point, it must decide whether to sell energy at a loss to keep the unit running or to shut it down and face the expense of another start-up at a later time. Either option increases the cost of producing energy and forces the generation companies to raise their average bid price. According to the author, pool market reduces these types of risks faced by generation companies and foster lower average electricity prices.

Another paper of Erdogdu (Erdogdu, 2007) provides an analysis of the Turkish electricity regulatory reform. The critical analysis in this paper is that deregulation which requires the development of effective competition in a fully liberalized market is a very unrealistic aim in the Turkish case because currently Turkey does not have a fully functioning electricity and natural gas market (there is no need for restructuring in petroleum and LPG markets because they already have appropriate competitive structures). Moreover, the author argues that in Turkey, there exists no consensus over the actual size of the problem of “rapid electricity demand growth” and official electricity projections have overestimated future electricity demand to justify the construction of new power plants (which leads to usage of excess amount of natural gas). Furthermore the author also criticizes the quality of persons in the position of regulators (not only the members of Energy Market Regulatory Board but also its staffs) which is important for the credibility of EMRA and needs a merit selection and a high level of expertise so he claims that Turkey is still at the very beginning of this deregulation process.

The study of Camadam (Camadam, 2011) underlines the importance of the year 2012 for the restructured Turkish electricity market and highlights some issues about the market that should be fixed in year 2012. Since the transition period ends by the end of year 2012, important steps must be taken in order to insure a viable, competitive and well-functioning electricity market in Turkey. According to Camadam, the first issue which should be solved in year 2012 is the determination of supplier of last resort (default supplier) which implies servicing the customers who can not choose their suppliers and determining the tariff to be implemented (so called non-eligible customers). The author claims that supply of last resort is an important mean to protect consumers in the market and that in Turkey who will be responsible for supplying energy as last resort is not clear in the regulation. Accordingly the author proposes to designate distribution companies which are separated from retail entities to be suppliers of last resort because when the retail companies are appointed as supplier of the last resort, correctly determining and analyzing the costs of different consumer groups are not easy. The author speculates that faster privatization of the state-owned generation companies will form a more liberal market and minimize the uncertainties. Moreover, he points out the importance of clarified division of responsibilities of distribution companies and suppliers in the market.

The study of Dilaver and Hunt (Dilaver and Hunt, 2011) tries to forecast the future Turkish aggregate electricity demand by using a structural time series technique on annual data over the period 1960 to 2008 and analyzes the relationship between the Turkish aggregate electricity consumption, GDP and electricity prices. They claim that GDP, electricity prices and UEDT (Underlying Energy Demand Trend) are all important drivers of the Turkish electricity demand. Moreover, the forecast scenarios suggest that Turkish electricity demand will be between 259 and 368 TWh in the year 2020.

The study published by Uzlu, Akpinar and Komurcu (Uzlu *et al.*, 2011) investigates the contribution of hydropower energy in the Turkish electricity market and analyzes the 25 hydrological basins in Turkey in the context of small hydropower potential and points out that Northeast region of Turkey has the greatest advantage regarding small hydropower potential. They also claim that hydropower potential in Turkey is an attractive solution for energy needs of the Turkish electricity market.

The study of Ozturk, Yilanci and Atalay (Ozturk *et al.*, 2007) analyzes the past, present and future status of the electricity market in Turkey and the share of the energy sources. They point out that share of hydroelectric (which is a renewable source) and the share of lignite (which is a national resource) in the electricity generation have been decreasing while the share of natural gas (which is imported) has been increasing. They argue that to meet the expected increase in electricity consumption, Turkey ought to increase electricity generation capacity and also take the necessary steps to decrease the transmission and distribution losses which consumed of 16% of the net electricity generation during 1985-2001.

The study of Kucukali and Baris (Kucukali and Baris, 2010) aims to forecast Turkey’s short-term gross annual electricity demand by applying a fuzzy logic methodology with only one parameter, which is gross domestic product. According to this study, the Turkish electricity consumption growth rates in the short-term are projected to be about 4% between years 2010-2014 and the total installed capacity increment to meet the forecasted consumption is estimated to be 30 TWh.

The study of Alboyaci and Dursun (Alboyaci and Dursun, 2008) analyzes the share of wind energy production in the Turkish electricity market and argues that due to very limited primary energy resources, Turkey is heavily dependent on imports of primary energy. For this reason, wind energy has become a valuable source of energy for Turkey but it has not been paid sufficient attention until the Renewable Energy Law No.5346. However, after this law which encourages wind energy, a high level of investment to wind energy in Turkey is expected in the coming years.

The study of Or and Kilanc (Or and Kilanc, 2008) develops a system dynamics model with up to 6 players (which are one regulator, three large power generators and three small power generators) in order to better understand and analyze the decentralized and competitive electricity market in a 20-year planning horizon. The developed simulation model has many modules, such as a demand module (which reflects the monthly and hourly variability in electricity demand), a capacity expansion module (which conducts investment decisions), a power generation module, an accounting and finance module (which traces the financial status and credibility of each investor and is a distinctive difference between the developed model and others in the literature) and a bidding mechanism to make the developed model usable by decision makers for realistic market analysis. On the other hand, transmission capacity constraints, consumers and distribution companies are not modeled but reflected within the detailed demand profile. 48 different scenarios based on the Turkish Electricity Market data have been configured, run and analyzed in order to understand the three factors; (i) effects of support for renewable energy, (ii) debt-equity ratio and (iii) presence of long term contracts on long-term and medium-term performance. According to this study, investments in power plants are not consistent with the demand growth and the capacity retirement because of imperfect foresight and delays in investment decisions and physical plant constructions. Additionally, natural gas and small hydro power generator are preferred over other plant types and investing in wind power does not become desirable. Another observation based on the scenarios is that capacity withholding raises the system prices so makes a valuable environment for the competitors to enter the market.

The study of Sarica (Sarica, 2010) develops an integrated agent based simulation model and network flow optimization models (linear and nonlinear) with an alternating current transmission network (including 30 bus, 41 transmission lines, 9 generators and 21 power user agents) in order to investigate the electricity market restructuring and understand the implications of a competitive power market based on hourly biddings. Within this framework, various hourly and daily bidding strategies of power generator agents are introduced under various setting of market parameters, such as demand heterogeneity, agents' size, number and allocation over the network to analyze the possible effects on market price formation and agents' behavior. According to this study, the effect of the transmission network on market price formation is minimal in the linear network case as long as excess capacity is present within the system. However, transmission fee has a vital role in the market price formation because an increase in the transmission fee directly increases the electricity production costs. In addition to this, implemented bidding strategies have different effects at different time intervals. The Market Share bidding strategy is found to be effective at low demand time intervals whereas, the Price Tracking bidding strategy is observed to be effective at all time intervals in linear case. In non-linear case, the Market Share bidding strategy is effective at all time periods because it is found that the power generator agents that are producing less than their capacity lower their bid prices in order to increase their market shares. For, the Price Tracking bidding strategy, significant price decreases are observed at low demand time intervals.

3. DESIGN AND STRUCTURE OF INTEGRATED SIMULATION AND OPTIMIZATION OF A DECENTRALIZED TURKISH ELECTRICITY MARKET

In this section, the components of the integrated simulation and optimization model developed for a hypothetical electricity market are presented. In the first section, power user agent's, power generator agents' and system operator's properties and objectives together with structural forms configured are explained in detail with various parameters and variables related to each agent. In the second section, the structure and content of electricity sale offers and their properties are explained in detail together with the various parameters and variables related to each offer. In the third section, the compilation of the hypothetical demand data is explained including the assumed load variations considered in the simulation runs. In the fourth section, the operational characteristics of the hypothetical Day-Ahead and Real-Time Balancing markets are described. In the fifth section, the minimum cost mixed integer model formulation associated with the bid selection problem (of the regulatory authority) is presented and explained. In the sixth section, the performance indicators used in the model are described and defined in a mathematical form to track the performance of each power generator agent and of the overall system in the simulation runs. In the last section, self-learning algorithm with the related information flow is presented. It should be noted that, even though all electricity demand, generation capacities, technologies, cost parameters and data deployed in the model are hypothetical, the general set-up (i.e. the profile of the generator technology set, of overall electricity demand data and of overall generation capacity ratios and assumed cost structures) is guided by actual data from the Turkish electricity sector.

3.1. Agents

3.1.1. The Power User Agent

The demand side of the electricity market is represented by various power user agents. Independent power consumers and distribution companies are the primary power user agents in the electricity market. In this model, since geographic characteristic of power user agents and transmission network related costs and limitations in the system are ignored, power user agents are treated as one aggregated consumption unit representing total electricity demand (for each hourly period of the planning horizon). The overall electricity market simulation is designed to achieve sufficient power to satisfy this aggregate power user agent's consumption at each hourly period of the planning horizon. Power user agent's demand is assumed to be deterministic and inelastic during the simulation runs. The demand profile of this aggregate power user agent is represented through a three-period daily load curve (according to fluctuation profile in a day) named as "Peak", "Ordinary" and "Off-peak" (low demand) time periods. In both the Day-Ahead Market and the Real-Time Balancing Market, the system operator aims to satisfy the hourly uncovered demand of the aggregate power user agent at a minimum cost in each hour (part of the power user agent's demand is assumed to be met/covered through bilateral agreements with power generator agents). Inability of the system operator to satisfy the uncovered demand of the aggregate power user agent, results in power cuts or black-outs.

3.1.2. The Power Generator Agents

The electricity in the market is produced by the power generator agents. They are primarily defined through a set of parameters according to the type of technology, related costs, trading behavior (as reflected by bidding characteristics) and the capacity available in each power generator agent. Table 3.1 displays the parameters' list related to power generator agents in the model;

Table 3.1. Power generator agent properties.

Power generator agent parameters
Type
Id
Investment cost
Capacity
Marginal cost
Operating cost
Offer characteristics

Each parameter mentioned in Table 3.1 varies significantly among power generator agents according to the technology selected and the primary resources used in the generation of electricity power. Type parameter defines the primary energy resources used by power generator agents while generating electricity. According to primary energy resources considered in the model, there are four different types of power generator agents which are hydraulic, natural gas, coal and wind. Id parameter defines the unique sequence given to power generator agent to identify it during the simulation runs. Investment costs describe the needed funds to construct, test and prepare the power generator agents for the final production stages (Kucukali and Baris, 2009). Capacity parameter represents maximum power that each power generator agent can generate at each hour when it is fully deployed. Power generator agents calculate their daily generation schedule (DGS) based on their full capacity. The DGS of each power generator agent at each hour is calculated as 70%-75% of its full capacity. In the base scenario considered, the shares of the capacity of the power generator agents according to primary resources (depicted in Figure 3) are quite reflective of the current situation in Turkey. The share of natural gas (natural gas plus fuel oil and other thermals except coal) in power generation is about 54%, the share of hydro is about 21%, while the share of wind (wind plus the other renewable sources except hydro) and coal are about 7% and 18% respectively (Ozturk, 2007). Marginal costs are the cost of electricity (TL/MWh) including fuel cost (high for fossil fuel plants, zero for renewables) and capital costs (such as waste disposal cost and insurance costs, which are low for fossil fuel station but high for wind and hydraulic turbine) and used by power generator agents to produce one unit of electricity. In this study, marginal costs of power generator agents are taken from the study of Erdogdu (Erdogdu, 2007). Operating costs are fixed costs charged to power generator agents at each hour according to function of technology and prices of primary resources (including labor and own use costs which is the portion of generated electricity cost used by the generator). For wind power generator agents, operating costs are assumed to be 10% of marginal costs but for natural gas and coal power generator agents, they are assumed as 20%. Operating costs for hydro power generator agents are assumed to 0.5 cent/KWh and is taken from the study of Kucukali and Baris (Kucukali and Baris, 2009). Offer characteristics are specific to each power generator agent according to primary resource and define the type of offers that a power generator agent can give to the system operator in the Day-Ahead Market (which is detailed in Section 3.2). Table 3.2 depicts the power generator agents and their key parameters as deployed in the study.

Table 3.2. Power generator agent parameters.

Name	**Type**	**Capacity (MW)**	**Marginal Cost/Oper. Cost (cent /KWh)**	**Investment Cost ($/Kw)**
Generator 1	Hydraulic	4000	0.16 / 0.5	1000
Generator 2	Hydraulic	2500	0.16 / 0.5	1000
Generator 3	Natural Gas	4500	5 / 1	650
Generator 4	Natural Gas	4500	5 / 1	650
Generator 5	Natural Gas	2500	5 / 1	650
Generator 6	Natural Gas	2500	5 / 1	650
Generator 7	Coal	2500	3 / 0.6	750
Generator 8	Coal	1500	3 / 0.6	750
Generator 9	Wind	1000	2 / 0.2	1000
Generator 10	Wind	500	2 / 0.2	1000

Figure 3.1 displays the seasonal capacity variation of hydraulic power generator agents assumed in the simulation model to reflect the seasonality of this resource in reality. Seasonality impacts on the wind power generator agents are described in Section 3.2. As anticipated, seasonality impacts on natural gas and coal power generator agents are not considered.

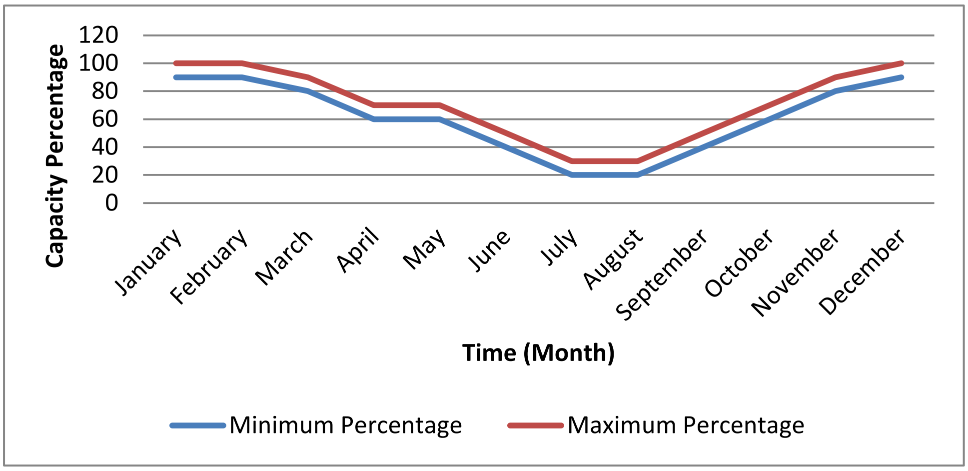


Figure 3.1. Hydraulic power generator agents' capacity variation.

3.1.3. The System Operator

The central planner of the Day-Ahead Market and the Real-Time Balancing Market is the system operator. At each hour, the system operator tries to satisfy the overall demand of the aggregated power user agent with the supply received from power generator agents at minimum cost. In detail, the system operator pursues to find an optimum balance of active electricity power generated by the power generator agents and the electricity demand of the aggregated power user agent, while considering the power generator agents' offers' quantities, prices, characteristics and offered time periods, power user agent's aggregated demand quantities and the amount of demand satisfied by bilateral agreements in each hour at minimum cost. Henceforward, the system operator also determines the day-ahead market system prices (DAP) and system marginal prices (SMP) and announces the accepted electricity sale offers to the power generator agents. Generally, the Day-Ahead Market prices (DAP) are obtained by solving a mixed integer optimization problem (which is detailed in Section 3.5) and the Real-Time Balancing Market prices (SMP) are found by covering the realized demand at minimum cost, while simply ordering the hourly load offers with respect to their prices and quantities.

3.2. The Structure and Content of Offers

In the Day-Ahead Market, each power generator agent can submit three types of day-ahead market electricity sale offers (which are called hourly, block and flexible offers), to the system operator in order to sell their products (electricity). All offers submitted by the power generator agents within the context of the Day-Ahead Market and the Real-Time Balancing Market contain following information;

(i) ID of the relevant offer (unique sequence);
(ii) Name and ID of the relevant power generator agent;
(iii) Time interval when the offer is valid (excluding flexible offers);
(iv) Offer type;
(v) Offer price expressed in Turkish Lira;
(vi) Offer volume expressed as MWh per offer time interval.

3.2.1. The Structure and Content of Hourly Offers

Hourly offers are the price and quantity pairs regarding to every hour of the next day and submitted separately to the system operator by power generator agents in the Day-Ahead Market. Agents participating in the Day-Ahead Market can submit three hourly offers with different volumes (quantities) at each hour except wind power generator agents. Number of hourly offers submitted to the Day-Ahead Market by wind power generator agents is randomized between 1-3 in every 6 hours in order to reflect the uncertainty in wind availability. All hourly offer prices are submitted such that the price of the next offer is higher than or equal to the price of the previous offer (to represent the generator behavior of getting bolder and more aggressive, as more of its generation gets accepted). Hourly offer prices for current bids may be at most 10% higher than the Day-Ahead Market (DAP) price corresponding to the same hours of the previous day. Additionally, there are two types of hourly offers named as partially-acceptable and partially-nonacceptable hourly offers. For partially-acceptable hourly offers, the system operator can accept part of the quantity of the offer submitted by the power generator agents. However, for partially-nonacceptable hourly offer, the system operator can only accept the offered quantity as a whole or totally reject it.

All hourly offer prices are assumed to possess a (marginal cost plus % profit) structure where the marginal cost component refers to the related generator's marginal production cost (as displayed in Table 3.2) and the profit component is a key "generator bid policy" parameter depending on individual generators competitive nature, aggressiveness and past experience. Profit mark-up ranges (as percentages of marginal costs) considered for hourly offers are displayed in Table 3.3.

Table 3.3. Hourly offer price mark-up parameters.

	First Offer	**Second Offer**	**Third Offer**
Min Ratio	15%	25%	35%
Max Ratio	25%	35%	50%

All hourly offer prices are submitted in a way that the price of the next offer level is higher than or equal to the price of the previous offer.

The actual number of hourly offers submitted by wind power generator agents is randomized in the model (to reflect the actual behavior in real-life). Table 3.4 displays the frequencies of the number of hourly offers that are submitted to the system operator in the context of the Day-Ahead Market by wind power generator agents to reflect the uncertainty in the wind availability with the seasonal impact in the simulation model.

Table 3.4. Frequencies of the number of hourly offers submitted by wind generators.

Number of Hourly Offers	Frequency	Season
1	20%	Winter
2	20%	Winter
3	60%	Winter
1	60%	Summer
2	20%	Summer
3	20%	Summer

Additionally, Table 3.5 displays the frequency of non-availability of wind power according to the hourly offers submitted to the system operator in the context of the Day-Ahead Market by wind power generator agents. In case of non-availability of wind power, a penalty cost is calculated and applied (amount of product undelivered and unit penalty cost equal to the Day-Ahead Market price announced for the related hour). Wind power generator agents who become subject to such penalties are unable to submit offers in the context of the Real-Time Balancing Market.

Table 3.5. Frequency of non-availability of the wind power.

Number of Hourly Offers	Possibility of occurrence	Possibility of non-occurrence
1	20%	80%
2	60%	40%
3	80%	20%

In the Day-Ahead Market, all hourly offers' volumes are submitted such that the volume of the next offer is lower than or equal to the volume of the previous offer. In the Day-Ahead Market, all hourly offers' volumes are calculated as percentage of the power generator agents' remaining capacity as depicted in Table 3.6, which displays the hourly offers' volume's upper and lower bound as percentages of power generator agents' capacities.

Table 3.6. Hourly offers' volume parameters.

	First Offer	**Second Offer**	**Third Offer**
Min Ratio	35%	25%	10%
Max Ratio	45%	35%	25%

3.2.2. The Structure and Content of Block Offers

The power generator agents participating in the Day-Ahead Market may also submit block offers to the system operator. Block offers are the active electricity sales offers that are valid for more than one consecutive hour of the next day. Block offers considered in the model cover a period of at least 4 hours and the maximum number of block offers submitted to the system operator by the power generator agents cannot exceed 2 in a day. Each block offer is either accepted for the entire period of time it covers or it is rejected (block offers cannot be accepted for a period of time shorter than they cover). Power generator agents participating in the Day-Ahead Market may submit more than one block offers that span same or different time intervals of the same day. In the Day-Ahead Market, each hydraulic and natural gas power generator agents may submit 2 block offers, and each coal power generator agent offers 1 block offer (which covers 24 hours due to the high cost of start-up of coal generators) to the system operator. Wind power generator agents do not submit any block offers due to the uncertainty of the wind power. All block offer prices are assumed to possess a (marginal cost plus % profit) structure where the marginal cost component refers to the related generator's marginal production cost (as displayed in Table 3.2) and the profit component is a key "generator bid policy" parameter depending on individual generators competitive nature, aggressiveness and past experience. Profit mark-up ranges (as percentages of marginal costs) considered for block offers are displayed in Table 3.7.

Table 3.7. Block offers' price mark-up parameters.

	First Offer	**Second Offer**
Min Ratio	5%	10%
Max Ratio	10%	15%

In the Day-Ahead Market, all block offers' volumes are calculated as percentage of the power generator agents' remaining capacity as depicted in Table 3.8, which displays the block offers' volume's upper and lower bound as percentages of power generator agents' capacities.

Table 3.8. Block offers' volume parameters.

Generator	**First Offer**	**Second Offer**
Hydraulic	40% - 60%	40% - 60%
Natural Gas	40% - 60%	40% - 60%
Coal	70% - 80%	-------------

3.2.3. The Structure and Content of Flexible Offers

Flexible offers are the price and quantity pairs for the Day-Ahead Market, which are not associated with a certain hour (unlike the hourly and the block offers). Flexible offers can be accepted by the system operator for any hour of the Day-Ahead Market based on the minimum cost principle. Each power generator agent except coal generator agents (whose offers cannot be flexible due to their operational characteristic) can submit one flexible offer, whose volume is defined as the smallest remaining capacity, to the system operator in the context of the Day-Ahead Market. Flexible offers can be partially accepted.

All flexible offer prices are assumed to possess a (marginal cost plus % profit) structure where the marginal cost component refers to the related generator's marginal production cost (as displayed in Table 3.2) and the profit component is a key "generator bid policy" parameter depending on individual generators competitive nature, aggressiveness and past experience. Profit mark-up ranges (as percentages of marginal costs) considered for flexible offers are displayed in Table 3.9.

Table 3.9. Flexible offers' price mark-up parameters.

Mark-up Ratio	**Single Offer**
Min Mark-up Ratio	75%
Max Mark-up Ratio	100%

3.2.4. The Structure and Content of Load Offers

Load offers are offers consisting of price and quantity pairs related to hourly periods of the current day and they are submitted to the system operator in the context of the Real-Time Balancing Market. These offers are called for and submitted after the Day-Ahead Market is finalized and if the system operator detects a shortfall in supply. Power generator agents participating in the Real-Time Balancing Market can submit only one load offer in the context of the Real-Time Balancing Market. All load offer prices are submitted in a way such that the price of the load offer related to a current hour is higher than or equal to the announced day-ahead market price (DAP) of the relevant hour. In the model, all load offer prices submitted by the power generator agents to the system operator in the context of the Real-Time Balancing Market are calculated through a moving average principle which is shown in Equation 3.1.

$$Load\ Offer\ Price_t = \max\left(DAP_t, \left\{\left(\frac{\sum_i^{t-2} DAP_i}{t-2} * 0{,}2 + \ (DAP_{t-1} * 0{,}8)\right) * \beta\right\}\right) \quad (3.1)$$

During the simulation runs, five power generator agents (Generator 1, Generator 3, Generator 5, Generator 7 and Generator 9) are assumed to follow an aggressive pricing strategy in the Real-Time Balancing Market, whereas the remaining power generator agents follow a conservative pricing strategy according to the mark-up component β. The following Table 3.10 displays the load offers' price mark-up component β parameters of power generator agents in the model.

Table 3.10. Load offers' price mark-up components.

Mark-up Component	Conservative Pricing	Aggressive Pricing
Max Mark-up Component	30%	50%
Min Mark-up Component	50%	70%

3.3. Compilation of the Hypothetical Demand Data

The assumed general demand pattern of the aggregate power user agent is actually quite reflective of the demand pattern of Turkey for the year 2009. The following Figure 3.2 displays the actual demand pattern of Turkey in year 2009, where the realized total demand is around 190 TWh. The hourly demand of the aggregate power user agent is calculated by dividing the realized demand of Turkey in 2009 (190 TWh) by the total hour in a year (365 days multiplied by 24 hours in a day).

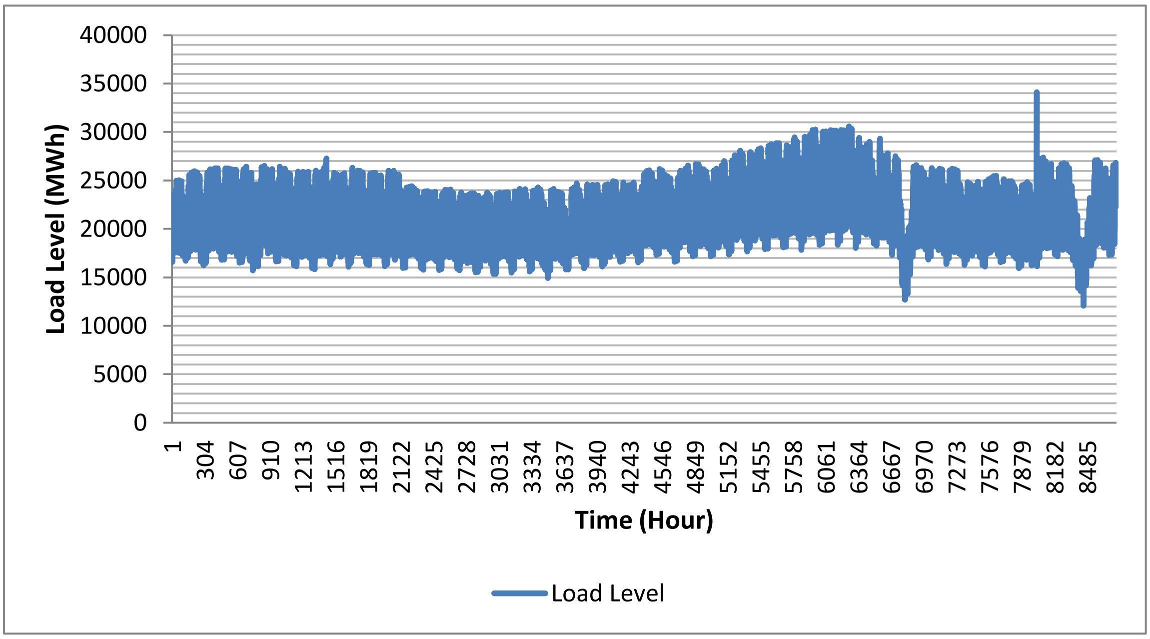


Figure 3.2. The demand pattern of Turkey in 2009.

The aggregate power user agent's hourly demand is assumed to be about 22000MWh which is about 10% less than the available supply (the demand/supply ratio being equal to the demand/supply ratio in the Turkish electricity market in 2009).

The fluctuation profile used in the model is calculated from the 2009 Turkey daily consumption data. For the investigation and comparison of scenarios, four time periods in a day are selected according to the electricity load profile. These time periods are; (i) the full 24 hour period, (ii) peak times, (iii) low demand times (off-peak times) and (iv) ordinary demand times, whose time intervals are displayed in Table 3.11.

Table 3.11. Analyzed time periods.

Time Period	**Hours**
Off-peak Time	02:00 – 02:59
Ordinary Time	12:00 – 12:59
Peak Time	20:00 – 2059
Daily Average	00:00 – 23:59

The demand of the aggregate the aggregate power user agent is assumed to fluctuate randomly through a day as depicted in Figure 3.3.

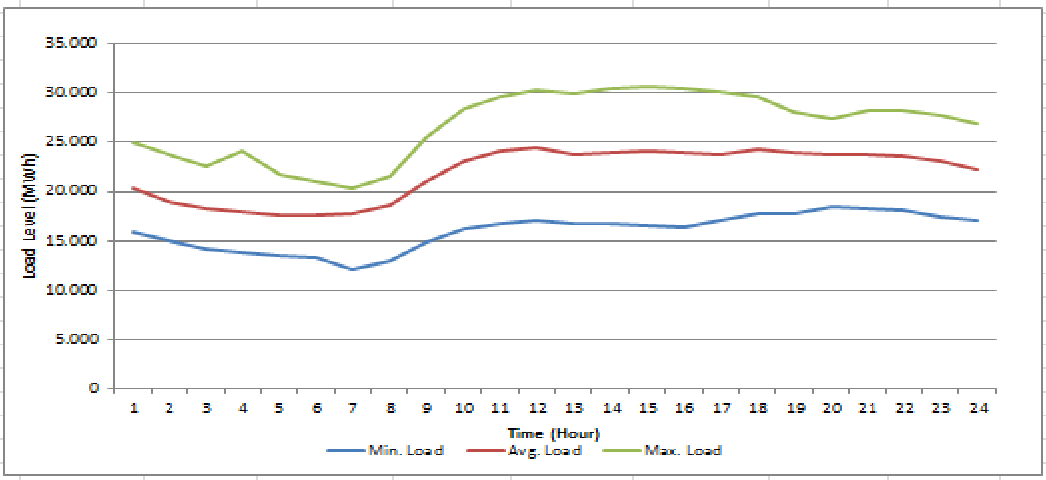


Figure 3.3. Daily electricity demand fluctuation in the Turkish electricity market in 2009

The assumed demand fluctuations in these periods are displayed in Table 3.12.

Table 3.12. Daily load fluctuation percentage used in the model.

Time Period	Fluctuation Percentage
Peak Time	80% - 100%
Ordinary Time	60% - 80%
Off-peak Time	50% - 60%

Figure 3.4 displays the pattern of monthly average of the Day-Ahead Market and of the Real-Time Market prices of the Turkish Electricity Market in year 2009. It should be noted that the Day-Ahead Market prices are lower than the Real-Time Balancing Market prices and both prices increase in the summer period.

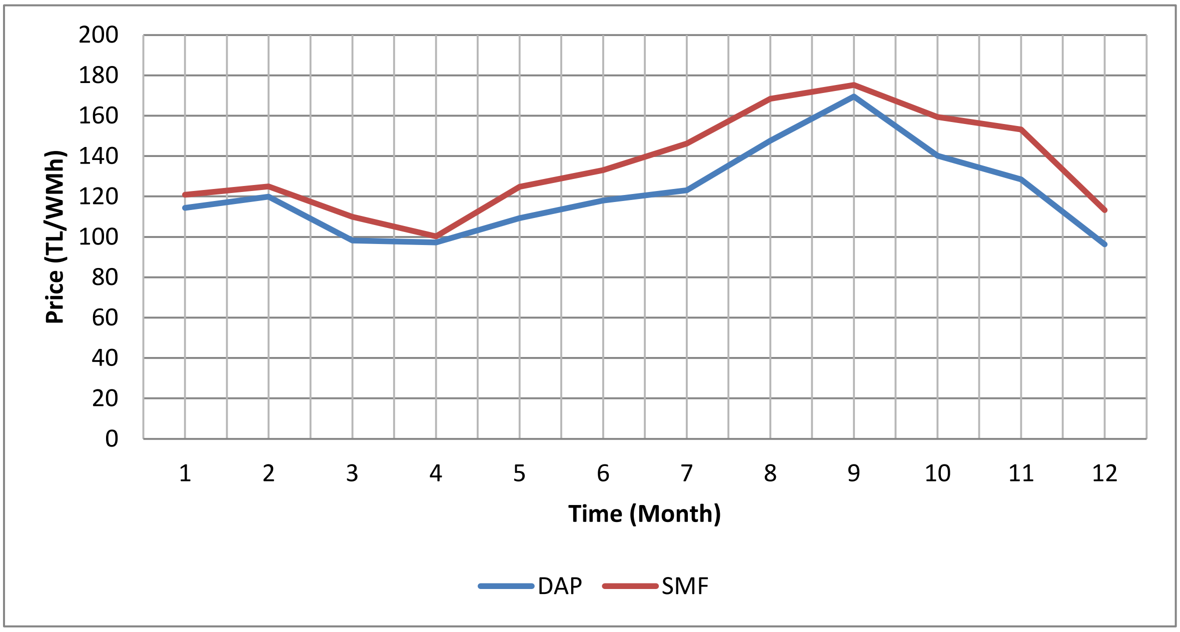


Figure 3.4. Day-ahead and real-time balancing markets' prices in the Turkish electricity market in 2009.

Table 3.13 displays the monthly average of the Day-Ahead Market and of the Real-Time Balancing Market prices of the Turkish Electricity Market in year 2009.

Table 3.13. Monthly electricity prices in the Turkish electricity market in 2009.

Month	**DAP(TL/MWh)**	**SMP(TL/MWh)**
01.12.2008	114.4	120.8
01.01.2009	119.8	124.9
01.02.2009	98.1	109.9
01.03.2009	97.3	100.2
01.04.2009	109.3	124.9
01.05.2009	117.9	133.1
01.06.2009	123.0	146.1
01.07.2009	147.7	168.4
01.08.2009	169.6	175.2
01.09.2009	140.2	159.3
01.10.2009	128.4	153.1
01.11.2009	96.3	113.2

3.4. The Simulation Flow

The flow of the simulation model is based on the Day-Ahead Market followed by the Real-Time Balancing Market. The flows of the operations of the hypothetical Day-Ahead Market and the Real-Time Balancing Market are depicted in Figure 3.5. The high level UML class diagram of the simulation model is provided in Appendix A.

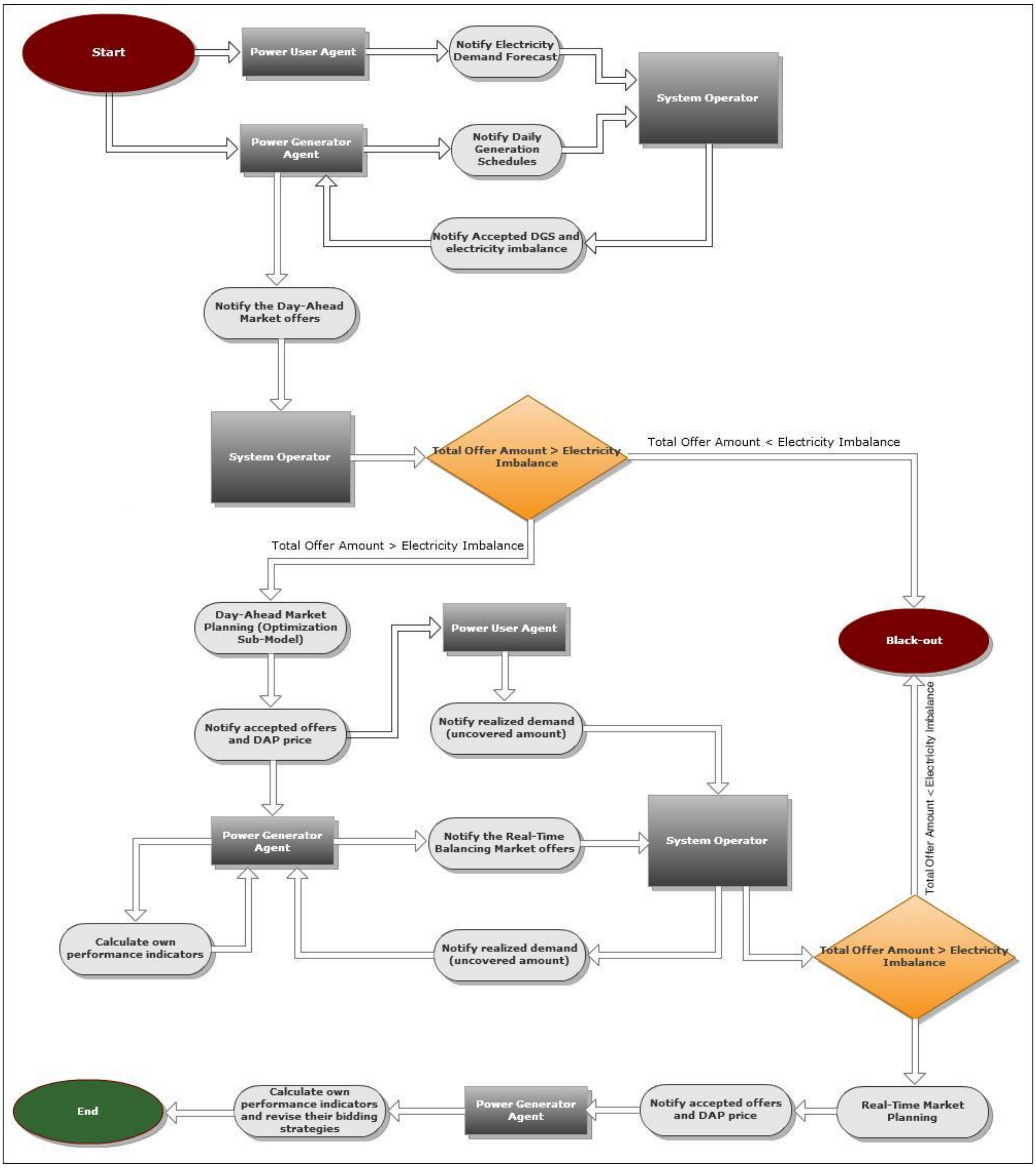


Figure 3.5. Flow of operations in the hypothetical day-ahead and real-time balancing markets.

The following steps describe the flow of operations of the hypothetical Day-Ahead Market and Real-Time Balancing Market;

(i) For each hour in a day, hourly electricity demand forecasts of the aggregate power user agent for the next day (as considered in the Day-Ahead Market) are estimated by the system operator. The demand forecast announced by the system operator contains information on total uncovered demand (total consumption forecasted beyond the amount covered by bilateral agreements) to be met by all power generator agents in the system for each hour between 00:00 and 23:59;

(ii) Daily electricity generation schedules (DGS) of the power generator agents (which are considered in the Day-Ahead Market) are submitted to the system operator in order to understand the quantity of electricity to be met via bilateral agreements;

(iii) For each hour in a day, the system operator announces accepted daily generation schedules (which are used to meet bilateral agreements) and system electricity imbalance (difference between total consumption forecasts and bilateral agreements) to each power generator and power user agent;

(iv) For each hour in a day, power generator agents submits the hourly, block and flexible sale offers (bids) to the system operator in the context of the Day-Ahead Market in order to meet the “electricity imbalance” defined above;

(v) The system operator generates a daily production schedule (by accepting, partially accepting or rejecting the submitted bids) based on the total cost minimization mixed-integer linear programming model (which is described in Section 3.5) and determines the Day-Ahead Market price (DAP) for each hour in the context of the Day-Ahead Market;

(vi) The accepted offers and Day-Ahead Market system prices (DAP) are announced to the power user agent and the power generator agents. Power generator agents calculate their capacity utilization, market share and remaining capacity after the Day-Ahead Market is finalized;

(vii) For the Real-Time Balancing Market, hourly actual electricity demands of the power user agent are submitted to the system operator;

(viii) For the Real-Time Balancing Market, the system operator announces the remaining electricity demand imbalance (if exists) to the power generator agents and takes their Real-Time Balancing Market load offers;

(ix) The system operator announces the accepted load offers in the Real-Time Balancing Market by a cost minimization procedure based on forming an ordered list of all electricity offers and start accepting from the smallest, then moving up and accepting higher offers until the demand of the period is satisfied;

(x) The accepted offers and the system marginal price (SMP) for the Real-Time Balancing Market are announced to the power generator and power user agents. Power generator agents calculate their Capacity Utilization, Profits, market share and reserved capacity for the Real-Time Balancing Market;

(xi) Based on the list of accepted offers, generators deploy their learning processes and revise their strategy for the Day-Ahead and Real-Time Balancing markets of the next day;

(xii) Daily generation and consumption activities are carried on and for the next day, Step i is initiated.

3.5. The Minimum Cost Mixed Integer Model Formulation

The developed model is a Minimum Cost Mixed Integer Linear Programming Model. Linearity is a desired structure since the handling of computationally simple linear programming problems is much easier as compared to nonlinear cases and fast solvers are available. Additionally, analysis of the results is more interpretable due to the simple structure. The objective function of the problem can be stated as follows;

Minimize;

$$\sum_{m \varepsilon SHO} HOP_m * HOQ_m + \sum_{m \varepsilon SBO} BOP_m * H(m) * BOQ_m + \sum_{m \varepsilon SFO} \sum_{t} FOP_m * FOQ_{m,t} \qquad (3.2)$$

Where t is the time index starting from 0 to 23 and m is the offer index. This cost function reflects all type of offers received from power generator agents and tries to achieve the overall minimum cost while satisfying the expected hourly demands and taking the offer characteristics into consideration. The constraints of the mixed integer linear programming model can be stated as follows;

Subject To;

$$\sum_{m\varepsilon SHO|t0(m)=t} HOQ_m + \sum_{m\varepsilon SBO|t1(m)\le t\le t2(m)} BOQ_m + \sum_{m\varepsilon SFO} FOQ_{m,t} = [D_t - G_t] \quad (3.3)$$

$$HOQ_m \le \overline{HOQ_m} \qquad for\ \ m\,\varepsilon\,SHO\ \ where\ Type(m) = 0 \quad (3.4)$$

$$HOQ_m \le \overline{HOQ_m} * x_m^{offer} \qquad for\ m\,\varepsilon\,SHO\ where\ \ Type(m) = 1 \quad (3.5)$$

$$BOQ_m \ = \overline{BOQ_m} * y_m^{offer} \qquad for\ \ m\,\varepsilon\,SBO \quad (3.6)$$

$$FOQ_{m,t} \le \overline{FOQ_m} * z_{m,t}^{offer} \qquad for\ \ m\,\varepsilon\,SFO\ \ where\ \ t = 0,1,2,3,\ldots,23 \quad (3.7)$$

$$\sum_t z_{m,t}^{offer} \le 1 \qquad for\ \ m\,\varepsilon\,SFO\ where\ \ t = 0,1,2,3,\ldots,23 \quad (3.8)$$

$$HOQ_m \ge 0 \qquad for\ \ m\,\varepsilon\,SHO \quad (3.9)$$

$$BOQ_m \ \ge 0 \qquad for\ \ m\,\varepsilon\,SBO \quad (3.10)$$

$$FOQ_{m,t} \ge 0, \qquad for\ m\,\varepsilon\,SFO\ \ where\ \ t = 0,1,2,3,\ldots,23 \quad (3.11)$$

$$x_m^{offer} \in (0,1) \qquad for\ m\,\varepsilon\,SHO\ where\ \ Type(m) = 1 \quad (3.12)$$

$$y_m^{offer} \in (0,1) \qquad for\ \ m\,\varepsilon\,SBO \quad (3.13)$$

$$z_{m,t}^{offer} \ \in (0,1) \qquad for\ \ m\,\varepsilon\,SFO\ \ where\ \ t = 0,1,2,3,\ldots,23 \quad (3.14)$$

The first constraint set (3.3) is the condition of net power balance at each hour, where the power generated by the power generator agents must be equal to the power consumed. The next constraint set (3.4) states that partially acceptable hourly offers can be accepted up to their offer quantity but a lesser amount can also be accepted. The constraint set (3.5) states that non-partially acceptable hourly offers can either be accepted at offered level or be rejected. The next constraint set (3.6) states that block offers are accepted as a whole or not. The next two constraint sets ((3.7), (3.8)) are related to flexible offers, the first constraint set (3.7) indicates that flexible offers can be partially acceptable (any amount up to the offer quantity) and the second constraint set indicates that (3.8) a flexible offer can be accepted for only one time interval in a day (any time interval from 0 to 23). Constraint sets (3.9), (3.10) and (3.11) are the non-negativity constraints which state that the related decision variables should be zero or positive. Constraint sets (3.12), (3.13) and (3.14) are integrality constraints which state that the related decision variables can take one of two values; 0 or 1. For the validation of the model, results of a hypothetical day are added in Appendix B.

The list of decision variables and their descriptions are provided in Table 3.14.

Table 3.14. Decision variables used in the model.

Decision Variable	**Description**
HOQ_m	Quantity of Hourly Offer indexed by m
BOQ_m	Quantity of Block Offer indexed by m
FOQ_m	Quantity of Flexible Offer indexed by m
x_m^{offer}	Accept/Reject of Not Partially-Acceptable Hourly Offer indexed by m
y_m^{offer}	Accept/Reject of Not Partially-Acceptable Block Offer indexed by m
z_m^{offer}	Accept/Reject of Partially-Acceptable Flexible Offer indexed by m

The list of parameters and their descriptions are provided in Table 3.15.

Table 3.15. Parameters used in the model.

Parameter	**Description**
T	Time index, t=0,1,2,…,23
m	Offer index
SHO	Hourly Offer Set
SBO	Block Offer Set
SFO	Flexible Offer Set
t0(m)	Hour of Hourly Offer indexed by m
type(m)	Type of Hourly Offer indexed by m
t1(m)	Starting Time of Block Offer indexed by m
t2(m)	Ending Time of Block Offer indexed by m
h(m)	Duration of Block Offer indexed by m
G_t	Daily Power Generation Schedule at time t
D_t	Daily Total Power Demand at time t
HOP_m	Price of Hourly Offer indexed by m
BOP_m	Price of Block Offer indexed by m
FOP_m	Price of Flexible Offer indexed by m
$\overline{HOQ_m}$	Maximum Quantity of Hourly Offer indexed by m
$\overline{BOQ_m}$	Maximum Quantity of Block Offer indexed by m
$\overline{FOQ_m}$	Maximum Quantity of Flexible Offer indexed by m

3.6. Performance Tracking

In this section, the performance indicators used in the model are described and defined in a mathematical structural form to track the performance of power generator agents and the performance of both balancing markets (Day-Ahead and Real-Time Balancing) during the simulation/optimization runs.

3.6.1. Tracking Electricity Prices

The system operator determines the maximum price among all accepted hourly, block and flexible offers' prices in the Day-Ahead Market as the Day-Ahead System Price (DAP) and the maximum price among all accepted load offers' prices in the Real-Time Balancing Market is set as the System Marginal Price (SMP). The Day-Ahead Market System Prices (DAP) are obtained by solving the mixed-integer linear optimization problem described in Section 3.5 and the System Marginal Prices (SMP) are found by covering the realized demand at minimum cost while simply ordering the hourly load offers with respect to their prices and quantities. For each hour *t*, where *m* is the accepted offer index, the mathematical formulations of electricity system prices are presented in Equation 3.15 and 3.16.

$$DAP_t = \max\left(HOP_{m\varepsilon SHO|t0(m)=t}, BOP_{m\varepsilon SBO|t1(m)\leq t\leq t2(m)}, FOP_{m\varepsilon SFO}\right) \quad (3.15)$$

$$SMP_t = \max\left(ROP_{m\varepsilon SRO,t}\right) \quad (3.16)$$

Within this context, the model maintains the capability of single system price functionality (uniform pricing) during the simulation runs.

3.6.2. Tracking Generators' Revenue and Profit

For each power generator agent, the *Revenue* of the relevant power generator agent *i* at each hour *t* (where *t* = 0,...,23), is calculated as follows (where *m* is the accepted offer index of generator *i)*;

$$Revenue_{i,t} = \left(\sum_{m\varepsilon SHO|t0(m)=t} HOQ_m + \sum_{m\varepsilon SBO|t1(m)\leq t\leq t2(m)} BOQ_m + \sum_{m\varepsilon SFO} FOQ_{m,t}\right) \times DAP_t + \left(\sum_{m\varepsilon SRO} ROQ_{m,t}\right) \times SMP_t \quad (3.17)$$

In Equation 3.17, SMP_t and DAP_t are the Real-Time Balancing Market and the Day-Ahead Market prices at time *t* respectively. HOQ_m is the accepted hourly offers' volume, BOQ_m is the accepted block offers' volume and $FOQ_{m,t}$ is the accepted flexible offers' volume in the Day-Ahead Market at time *t* respectively. $ROQ_{m,t}$ is the accepted real-time offer volume in the Real-Time Balancing Market. Accordingly, a revenue of the power generator agent *i* is the sum of the revenues in the Day-Ahead and Real-Time Balancing markets.

For each power generator agent, the *Profit* of the relevant power generator agent *i* at each hour *t* (where *t* = 0,.., 23), is calculated as follows;

$$Profit_{i,t} = Revenue_{i,t} - \left(\sum (Operating\ Cost_{i,t} + Marginal\ Cost_{i,t} + Annualized\ Investment\ Cost_{i,t} + Penalty\ Cost_{i,t})\right) \quad (3.18)$$

As Equation 3.18 indicates, *Profit* of a power generator is aggregately calculated for both the Day-Ahead and the Real-Time Balancing markets. In Equation 3.18, *Operating Cost* are assumed to be 10% of *Marginal Cost* for wind power generator agents, but for natural gas and coal power generator agents, they are assumed as 20% of *Marginal Cost*. For each generator, *Annualized Investment Cost* is calculated hourly based on 30 years. The details of each cost item can be seen in Table 3.2. For wind generators, *Penalty Cost* is the fine amount when the power generator agent fails to fulfill its obligation (committed in the Day-Ahead Market) in case of the nonexistence of the wind power. It is calculated as the not-generated amount multiplied by the Day-Ahead Market (DAP) price.

3.6.3. Tracking Generators' Capacity Utilization

For each power generator agent, the *Capacity Utilization* of the power generator agent *i* at each hour *t* (where *t* = 0,.., 23), is calculated as follows (where *m* is the accepted offer index of generator *i)*;

$$Capacity\ Utilization_{i,t} = \frac{(\sum_{m\varepsilon SHO|t0(m)=t} HOQ_m + \sum_{m\varepsilon SHO|t1(m)\leq t\leq t2(m)} BOQ_m + \sum_{m\varepsilon SHO} FOQ_{m,t} + \sum_{m\varepsilon SRO} ROQ_{m,t})}{Capacity_{i,t} - DGS_{i,t}} \quad (3.19)$$

As can be seen in Equation 3.19, the hourly *Capacity Utilization* factor of power generator agent takes into consideration of all the accepted offers' volume (submitted to both Day-Ahead and Real-Time Balancing Markets) divided by all remaining capacity left after the Daily Generation Schedule (DGS) (generation amount committed through bilateral agreements) is subtracted from full capacity.

3.6.4. Tracking Generators' Market Shares

For each power generator agent, the *Market Share* of the power generator agent *i* at each hour *t* (where *t* = 0,.., 23) in the Day-Ahead and the Real-Time Balancing markets, is calculated as follows (where *m* is the accepted offer index of generator *i)* in Equation 3.20;

$$Market\ Share_{i,t} = \frac{(\sum_{m\varepsilon SHO|t0(m)=t} HOQ_m + \sum_{m\varepsilon SBO|t1(m)\leq t\leq t2(m)} BOQ_m + \sum_{m\varepsilon SFO} FOQ_{m,t} + \sum_{m\varepsilon SRO} ROQ_{m,t})}{Realized\ Demand_{i,t}} \quad (3.20)$$

And for each power generator agent, the *Market Share* of the power generator agent *i* at each hour *t* (where *t* = 0,.., 23) in the Day-Ahead Market, is calculated as follows (where *m* is the accepted offer index of generator *i)* in Equation 3.21;

$$Market\ Share_{i,t} = \frac{(\sum_{m\varepsilon SHO|t0(m)=t} HOQ_m + \sum_{m\varepsilon SBO|t1(m)\leq t\leq t2(m)} BOQ_m + \sum_{m\varepsilon SFO} FOQ_{m,t})}{Forecasted\ Demand_{i,t}} \quad (3.21)$$

And for each power generator agent, the *Market Share* of the power generator agent *i* at each hour *t* (where *t* = 0,.., 23) in the Real-Time Balancing Market, is calculated as follows (where *m* is the accepted offer index of generator *i)* in Equation 3.22;

$$Market\ Share_{i,t} = \frac{(\sum_{m\varepsilon SRO} ROQ_{m,t})}{Realized\ Demand_{i,t} - Forecasted\ Demand_{i,t}} \tag{3.22}$$

3.6.5. Tracking Generators' Profits per Unit

For each power generator agent, the *Profit per Unit factor* of the relevant power generator agent *i* at each hour *t* (where *t* = 0,.., 23), is calculated as follows (where *m* is the accepted offer index of generator *i)*;

$$Profit\ Per\ Unit_{i,t} = \frac{Profit_{i,t}}{(\sum_{m\varepsilon SHO|t0(m)=t} HOQ_m + \sum_{m\varepsilon SBO|t1(m)\leq t\leq t2(m)} BOQ_m + \sum_{m\varepsilon SFO} FOQ_{m,t} + \sum_{m\varepsilon SRO} ROQ_{m,t})} \tag{3.23}$$

Since *Profit* is calculated at the end of Real-Time Balancing Market, according to Equation 3.23, *Profit per Unit* indicator of a power generator agent is also calculated at the end of Real-Time Balancing Market by dividing the *Profit* by the total of all the accepted offers' volume submitted to the Day-Ahead Market and the Real-Time Balancing Market.

3.6.6. Tracking Generators' Profits per Capacity

For each power generator agent, the *Profit per Capacity factor* of the relevant power generator agent *i* at each hour *t* (where *t* = 0,…, 23), is calculated as follows in Equation 3.24;

$$Profit\ Per\ Capacity_{i,t} = \frac{Profit_{i,t}}{(Capacity_{i,t} - DGS_{i,t})} \tag{3.24}$$

Profit per Capacity indicator of a power generator agent is also calculated at the end of Real-Time Balancing Market by dividing the *Profit* by all remaining capacity left after the Daily Generation Schedule is subtracted from full capacity.

3.7. Integration of The Simulation and The Optimization Models

The solution architecture in this framework is based on the agent-based simulation model and the minimum cost mixed integer linear programming model. The integration of these two models is depicted in Figure 3.6.

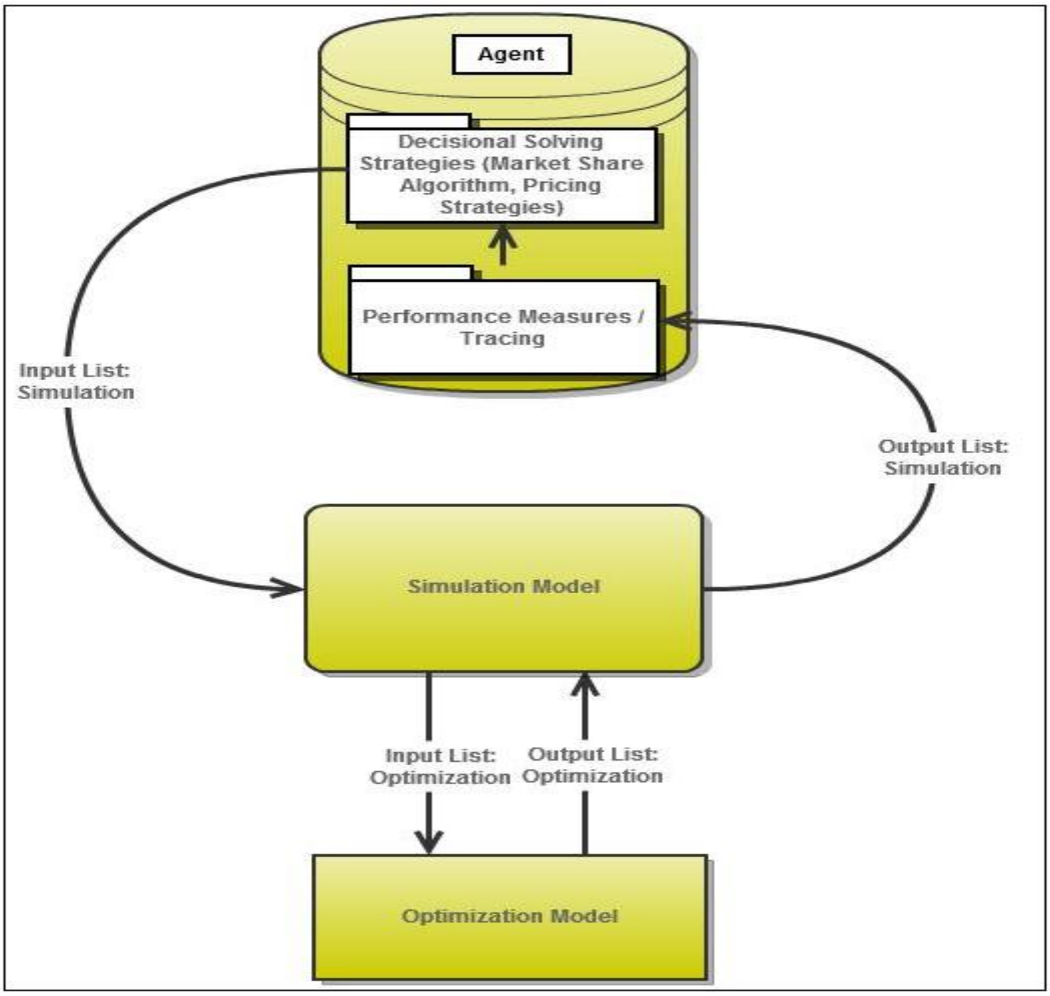


Figure 3.6. Integration of the simulation and the optimization models.

The input/output list used in this framework are listed in Table 3.16 (where *m* is the accepted offer index of generator *i* and *t* is the time index).

Table 3.16. Input/output list used in the framework.

Simulation Input Parameters	***Optimization Input Parameters***	***Optimization Output Parameters***	***Simulation Output Parameters***
$Capacity_{i,t}$	SHO, SBO, SFO	$\mathrm{HOQ_m}, \mathrm{BOQ_m}, \mathrm{FOQ_m}$	$Profit_{i,t}$
$Marginal\ Cost_{i,t}$	$\mathrm{G_t}, \mathrm{D_t}$	$DAP_t,\ SMP_t$	$Market\ Share_{i,t}$
$Operating\ Cost_{i,t}$	$\mathrm{HOP_m}, \mathrm{BOP_m}, \mathrm{FOP_m}$		$Profit\ Per\ Unit_{i,t}$
$Investment\ Cost_{i,t}$	$\overline{\mathrm{HOQ_m}}, \overline{\mathrm{BOQ_m}}, \overline{\mathrm{FOQ_m}}$		$Profit\ Per\ Capacity_{i,t}$
β, $alpha$	t0(m),type(m), t1(m), t2(m), h(m)		$Capacity\ Utilization_{i,t}$

In the simulation sub-model, the system operator collects all types of offers (hourly, block and flexible) from the power generator agents which are then fed to the optimization sub-model in order to meet all uncovered electricity demand of the aggregated power user agent by the minimum cost combination of the active electricity generated by the power generator agents.

3.8. The Market Share Learning Algorithm

All power generator agents in the model are assumed to independently apply a market share learning algorithm (which is explained below in detail) in order to maximize their daily profit obtained in the Day-Ahead and the Real-Time Balancing markets. This self-reinforcement learning algorithm is used by the power generator agents in determining the price of the offers submitted to the system operator. The learning process involves the analysis of the past information of previous balancing results and self-strong points. However, it should be stated that the primary shortcoming of this learning approach is that, there is no distinction among the demand levels like peak, standard or off-peak time periods during the day; so power generator agents apply a single strategy in all time intervals. An algorithm used in the study to determine the bidding prices is the Market Share Algorithm (Sarica, 2010). This algorithm analyzes the market shares of the power generator agents on the balancing market at each hour on the current day. The algorithm indicates that a generator with a high market share in the system can add a mark-up to its marginal production cost. This mark-up is labeled as Market Share Effect Factor, which is an important parameter used to determine the maximum price mark-up that a generator agent can add to its basic bid prices according to its market shares. If the market share of the power generator agent is greater (less) than the predefined level, a bid price mark-up is added (subtracted) to basic pricing strategy. It should be noted that a bid price mark-up is added (or subtracted) to (or from) only hourly offers and more important is that this mark-up is applied to all the hourly offers submitted to the system operator in the Day-Ahead Market for each hour. Table 3.16 displays the steps of the Market Share Algorithm.

Table 3.17. The steps of Market Share Algorithm.

```
 In every time interval(hour) = i
          When i= 1, ExpectedMarketShare(i) = MarketShare(i)
MarketShare(i) = Load(i) / Demand(i)
If (MarketShare(i) > ExpectedMarketShare(i-1)
          ExpectedMarket Share(i) = ExpectedMarketShare(i-1) +alpha *
          (MarketShare(i) – Expected Market Share(i-1))
Else
          ExpectedMarketShare(i) = ExpectedMarketShare(i-1) - alpha *
          (MarketShare(i) – Expected Market Share(i-1))
If ( ExpectedMarket Share(i) / ExpectedMarket Share(i-1) < 1)
          Market ShareEffectFactor(i+1)  = - ( 1- ExpectedMarketShare(i) /
          ExpectedMarket Share(i-1) )
Else
          MarketShareEffectFactor(i+1)  = + (ExpectedMarketShare(i) /
          ExpectedMarketShare(i-1) )  -1
```

4. SIMULATION SCENARIOS AND COMPUTATIONAL RESULTS

This section analyzes the results of the simulation runs conducted based on the model described in detail in section three. The scenario analyses are carried out separately and outcomes are investigated independently in this framework.

4.1. Demand Level Scenarios

These scenarios focus on demand level variations in the simulation model. Two different types of demand levels named as "*High Demand"* and "*Low Demand*" are deployed independently in the simulation model. These two demand levels are calculated by adding/subtracting 10% to/from the standard demand level. After the end of each simulation run; the average, the standard deviation and the standard deviation per average values are computed for, (i) electricity sale prices (as TL/MWh) of both Day Ahead and Real Time Balancing markets and (ii) *profit*s, (iii) *capacity utilization*, (iv) *market share*, (v) *profit per unit*, (vi) *profit per capacity* indicators of each power generator agent in the system. In all scenarios, simulation runs consist of 3600 days which cover 10-year periods. For the investigation and comparison of scenarios, four representative time periods are selected according to electricity load profiles and corresponding to the daily average, peak time, ordinary time and off-peak time periods, as displayed in Table 4.1. For each time period, the results are obtained and represented as the average of the considered 10-year periods.

Table 4.1. Analyzed time periods.

Time Period	Hours
Off-peak Time	02:00 – 02:59
Ordinary Time	12:00 – 12:59
Peak Time	20:00 – 20:59
Daily Average	00:00 – 23:59

Figure 4.1 and Table 4.2 display that in the high demand environment daily averages of the Day-Ahead Market (DAP) and of the Real-Time Balancing Market (SMP) prices are higher than the respective prices in the low demand environment ($\mu_{1,1} > \mu_{2,1}$ and $\mu_{1,2} > \mu_{2,2}$).

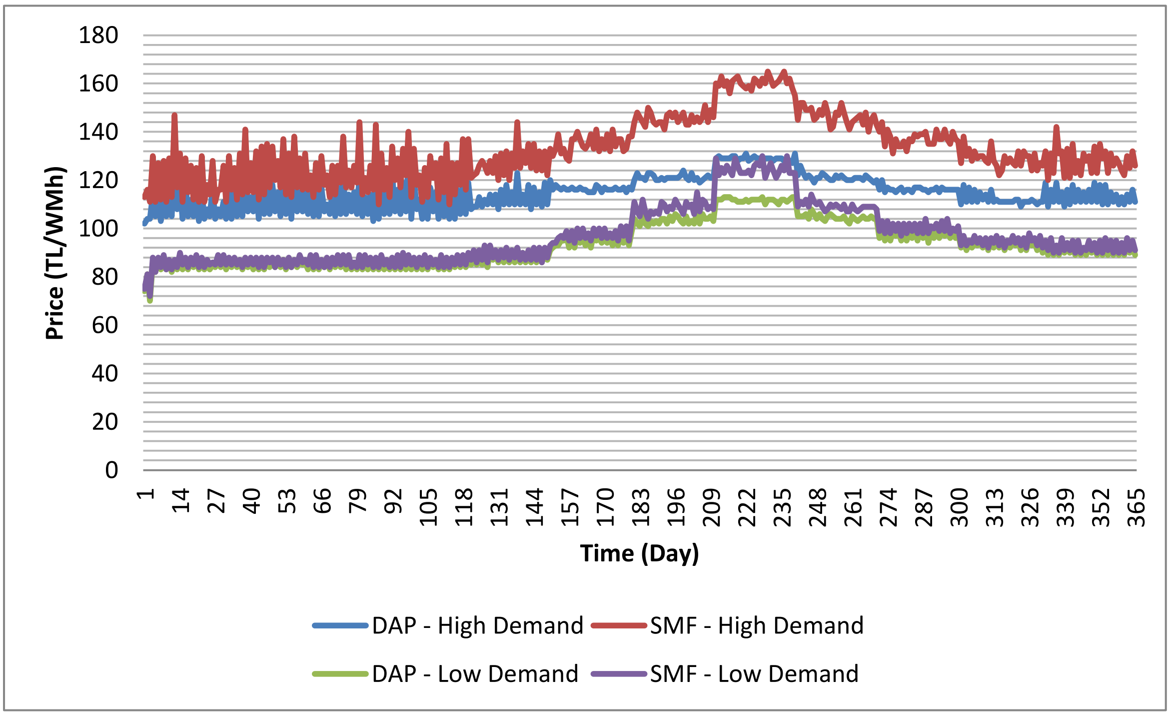


Figure 4.1. Daily average electricity system prices (high and low demand scenarios).

In the low demand environment, the daily averages of the DAP and of the SMP prices' movements are smoother. The daily averages of the DAP prices are closer to the daily averages of the SMP prices in the low demand environment than in the high demand environment. This is mainly due to the fact that the electricity demand in the Real-Time Balancing Market is mostly met by the power generator agents who follow the conservative pricing strategy. The daily averages of the SMP prices in the low demand environment show low variations compared to the high demand environment ($\sigma_{2,2} < \sigma_{1,2}$), as depicted in Table 4.2.

Table 4.2. Daily average electricity system prices (high and low demand scenarios).

Daily Average Electricity System Prices In The High Demand Environment			
System Price	$\mu_{1,a}$ (TL)	$\sigma_{1,a}$ (TL)	$\sigma_{1,a} / \mu_{1,a}$
DAP (a=1)	115.46	6.83	0.05
SMP (a=2)	133.06	13.13	0.09
$(\mu_{1,2} - \mu_{1,1}) / \mu_{1,1}$ (%)	+0.15		
Daily Average Electricity System Prices In The Low Demand Environment			
System Price	$\mu_{2,b}$ (TL)	$\sigma_{2,b}$ (TL)	$\sigma_{2,b} / \mu_{2,b}$
DAP (b=1)	93.67	8.89	0.09
SMP (b=2)	96.71	11.80	0.12
$(\mu_{2,2} - \mu_{2,1}) / \mu_{2,1}$ (%)	+0.03		

Another observation is that the difference between the daily averages of the DAP and of the SMP prices are higher in the high demand environment than the case in the low demand environment ($\mu_{1,2} - \mu_{1,1} > \mu_{2,2} - \mu_{2,1}$). This is mainly due to the fact that the system operator accepts the higher priced offers submitted by the power generator agents who follow the aggressive pricing strategy in the Real-Time Balancing Market to avoid the black-outs. As such, the daily average of the SMP price is 18 TL (and 15%) higher than the daily average of the DAP price in the high demand environment, while it is only 3 TL (and 3%) higher in the low demand environment. The unit variations (i.e. σ / μ values) in the SMP and DAP prices are higher in the low demand environment, that is;

$$\sigma_{1,1} / \mu_{1,1} < \sigma_{2,1} / \mu_{2,1} \text{ and } \sigma_{1,2} / \mu_{1,2} < \sigma_{2,2} / \mu_{2,2}$$

One explanation for this price behavior is the relatively higher impact/influence of hydraulic power generator agents (specifically during the dry season) in the low demand environment. In the low demand environment, hydraulic power generator agents who have lower marginal costs, cover more of the demand both in the Day-Ahead and Real-Time Balancing markets, leading to lower electricity prices and price differentials. However, high capacity variations of hydraulic power generator agents (capacity variations of hydraulic power generator agents depicted in Figure 3.1) lead to larger price variations between non-dry(wet) and dry seasons.

Table 4.3 displays the minimum and the maximum values of the daily averages of the Day-Ahead Market (DAP) and of the Real-Time Balancing Market (SMP) prices in high and low demand environments.

Table 4.3. Daily average electricity system prices' ranges (high and low demand scenarios).

Daily Average System Prices In The High Demand Environment			
System Price	$Min_{1,a}$(TL)	$Max_{1,a}$ (TL)	$Max_{1,a}$ - $Min_{1,a}$((TL)
DAP (a=1)	102	131	+29
SMP(a=2)	110	165	+55
Daily Average System Prices In The Low Demand Environment			
System Price	$Min_{2,b}$(TL)	$Max_{2,b}$ (TL)	$Max_{2,b}$ - $Min_{2,b}$((TL)
DAP (b=1)	70	113	+43
SMP (b=2)	72	130	+58

In the high demand environment, the minimum and the maximum values of the daily averages of the DAP and of the SMP prices are higher than the respective minimum and maximum values of the daily averages of the DAP and of the SMP prices in the low demand environment, that is;

$$\mathrm{Min}_{1,1} > \mathrm{Min}_{2,1} \text{ and } \mathrm{Min}_{1,2} > \mathrm{Min}_{2,2} \text{ and } \mathrm{Max}_{1,1} > \mathrm{Max}_{2,1} \text{ and } \mathrm{Max}_{1,2} > \mathrm{Max}_{2,2}$$

This is consistent with the analysis of the daily average price behavior ($\mu_{1,1} > \mu_{2,1}$ *and* $\mu_{1,2} > \mu_{2,2}$). However, the range between the minimum and the maximum values of the daily averages of the DAP prices are wider in the low demand environment (same case is also valid for SMP prices), that is;

$$\text{Max}_{1,1} - \text{Min}_{1,1} < \text{Max}_{2,1} - \text{Min}_{2,1} \text{ and } \text{Max}_{1,2} - \text{Min}_{1,2} < \text{Max}_{2,2} - \text{Min}_{2,2}$$

This is consistent with the higher price variation in the low demand environment ($\sigma_{1,1}/\mu_{1,1} < \sigma_{2,1}/\ \mu_{2,1}$ *and* $\sigma_{1,2}/\mu_{1,2} < \sigma_{2,2}/\mu_{2,2}$) mainly due to the higher impact of the decreased capacity of renewable power generator agents (hydraulic and wind) on the DAP and SMP prices during the dry season in the low demand environment.

As displayed in Figure 4.2 and Table 4.4, the peak time Day-Ahead Market (DAP) and Real-Time Balancing Market (SMP) prices are consistently higher in the high demand environment than in the low demand environment ($\mu_{3,1} > \mu_{4,1}$ and $\mu_{3,2} > \mu_{4,2}$) and this is consistent with the study of Gan, Wang and Bourcier where they claim that when the capacity in the market is very tight, all suppliers are needed to satisfy the electricity demand, thus large capacity suppliers can easily raise the market price. The peak time Day-Ahead Market (DAP) prices in the high demand environment are smoother and feature a very low variation (especially during the dry season) compared to the peak time Day-Ahead Market (DAP) prices in the low demand environment ($\sigma_{3,1} < \sigma_{4,1}$).

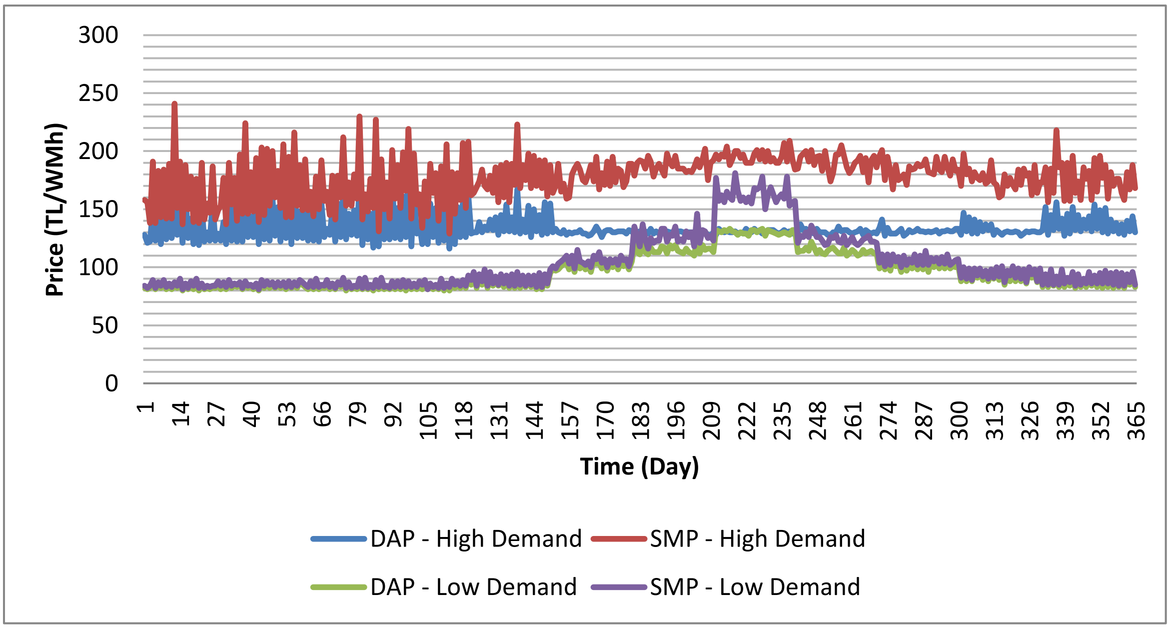


Figure 4.2. Peak time electricity system prices (high and low demand scenarios).

Table 4.4. Peak time system prices (high and low demand scenarios).

Peak Time System Prices In The High Demand Environment			
System Price	$\mu_{3,a}$ (TL)	$\sigma_{3,a}$ (TL)	$\sigma_{3,a}$ / $\mu_{3,a}$
DAP (a=1)	134.83	12.18	0.09
SMP (a=2)	178.19	19.02	0.10
$(\mu_{3,2} - \mu_{3,1}) / \mu_{3,1}$ (%)	+0.32		
Peak Time System Prices In The Low Demand Environment			
System Price	$\mu_{4,b}$ (TL)	$\sigma_{4,b}$ (TL)	$\sigma_{4,b}$ / $\mu_{4,b}$
DAP (b=1)	96.76	15.31	0.15
SMP (b=2)	103.24	16.71	0.16
$(\mu_{4,2} - \mu_{4,1}) / \mu_{4,1}$ (%)	+0.06		

In the low demand environment, the peak time DAP prices are closer to the peak time SMP prices than in the case of the high demand environment. In other words, the increase (which is around 44 TL) between the peak time prices of the DAP and of the SMP $(\mu_{3,2} - \mu_{3,1})$ are higher in the high demand environment than the increase (which is 7 TL) between the peak time prices of DAP and SMP $(\mu_{4,2} - \mu_{4,1})$ in the low demand environment. This is mainly due to the fact that higher demand existing in the Real-Time Balancing Market (which increases the SMP prices) is met by the power generator agents who follow the aggressive pricing strategy. Additionally, during the peak time period, the aggressive pricing strategy increases the SMP prices more than the case in the daily average $(\mu_{3,2} - \mu_{3,1} > \mu_{1,2} - \mu_{1,1})$ (in case of higher demand, the aggressive pricing strategy increases the SMP prices more). In the high demand environment, variation in the peak time SMP prices is around 19 TL, which is higher relative to variation in the peak time SMP prices in the low demand environment $(\sigma_{3,2} > \sigma_{4,2})$.

An interesting observation is that during the dry season, the peak time DAP prices in the low demand environment are closer to the peak time DAP prices in the high demand environment, which is mainly due to the impacts of the decreased capacity of hydraulic power generator agents. The explanation of this observation is that specifically during the dry season, (in both peak time periods of high and low demand environments), the system is fully dependent on higher cost power generator agents' electricity generation so this has an increasing impact on the DAP prices in the system. In addition to this, in the high demand environment, the capacity reductions of hydraulic power generator agents brings more stabilization (low level of variation) to the peak time DAP prices compared to the peak time DAP prices in the low demand environment. This observation can be explained by the argument that during the dry season, system meets its electricity demand mainly by the third offers (which has the highest price among the submitted offers) of high cost power generator agents so the impacts of price differences' between the offer levels is not seen during the dry season.

Table 4.5 displays the minimum and the maximum values of the peak time Day-Ahead (DAP) and Real-Time Balancing (SMP) prices in high and low demand environments.

Table 4.5. Peak time system prices' range (high and low demand scenarios).

Peak Time System Prices In The High Demand Environment			
System Price	$Min_{3,a}$(TL)	$Max_{3,a}$ (TL)	$Max_{3,a}$ - $Min_{3,a}$((TL)
DAP (a=1)	116	192	+76
SMP (b=2)	129	241	+112
Peak Time System Prices In The Low Demand Environment			
System Price	$Min_{4,b}$(TL)	$Max_{4,b}$ (TL)	$Max_{4,b}$ - $Min_{4,b}$((TL)
DAP (b=1)	80	133	+53
SMP (b=2)	81	181	+100

In the high demand environment, the minimum and the maximum values of the peak time DAP (and SMP) prices are higher than the minimum and maximum values of the respective prices in the low demand environment, that is;

$$Min_{3,1} > Min_{4,1} \text{ and } Min_{3,2} > Min_{4,2} \text{ and } Max_{3,1} > Max_{4,1} \text{ and } Max_{3,2} > Max_{3,2}$$

This is mainly due to the system meeting the higher demand by offers with higher prices (including offers submitted by higher cost power generator agents and also higher level offers). Moreover, the ranges between the minimum of the peak time DAP (and SMP) and the maximum values of the peak time DAP (and SMP) prices are narrower in the low demand environment, that is;

$$Max_{4,1} - Min_{4,1} < Max_{3,1} - Min_{3,1} \text{ and } Max_{4,2} - Min_{4,2} < Max_{3,2} - Min_{3,2}$$

This is in contradiction with the behavior of the daily average prices, that is;

$$\mathrm{Max}_{1,1} - \mathrm{Min}_{1,1} < \mathrm{Max}_{2,1} - \mathrm{Min}_{2,1} \text{ and } \mathrm{Max}_{1,2} - \mathrm{Min}_{1,2} < \mathrm{Max}_{2,2} - \mathrm{Min}_{2,2}$$

The likely reason is that during the peak time period (in both dry and non-dry season), electricity demand in the high demand environment is mostly satisfied with higher cost power generator agents (these generators also determine the system prices). So, impacts of the decreased capacity of hydraulic power generator agents on the electricity price variations are not seen.

Figure 4.3 and Table 4.6 display that in the high demand environment, the off-peak time Day-Ahead Market (DAP) and Real-Time Balancing (SMP) prices are higher than the respective prices in the low demand environment ($\mu_{5,1} > \mu_{6,1}$ and $\mu_{5,2} > \mu_{6,2}$), but lower than the respective prices of the peak time ($\mu_{5,1} < \mu_{3,1}$ and $\mu_{5,2} < \mu_{3,2}$) and of the daily average in the high demand environment ($\mu_{5,1} < \mu_{1,1}$ and $\mu_{5,2} < \mu_{1,2}$). Moreover, the off-peak time DAP and SMP prices' movements are smoother, when compared to the peak time and the daily average of the DAP and of the SMP prices in both high and low demand environments, that is;

$$\sigma_{5,1} < \sigma_{3,1} \text{ and } \sigma_{5,1} < \sigma_{1,1} \text{ and } \sigma_{5,2} < \sigma_{3,2} \text{ and } \sigma_{5,1} < \sigma_{1,1} \text{ and}$$
$$\sigma_{6,1} < \sigma_{4,1} \text{ and } \sigma_{6,1} < \sigma_{2,1} \text{ and } \sigma_{6,2} < \sigma_{4,2} \text{ and } \sigma_{6,2} < \sigma_{2,2}$$

The off-peak time DAP (and SMP) prices in the low demand environment are closer to the off-peak time DAP (and SMP) prices of the high demand environment, when compared to the case in the peak time periods and the daily average (price differences between environments are lowest during the off-peak time period).

Moreover, in the low demand environment, the off-peak time DAP prices are smoother and show a very low variation during the dry season compared to the daily average of the DAP prices. Indeed, impact of the decreased capacity of hydraulic power generator agents is also seen on the off-peak time DAP and SMP prices in both high demand and low demand environments (increased system prices during the dry season) as depicted in Figure 4.3.

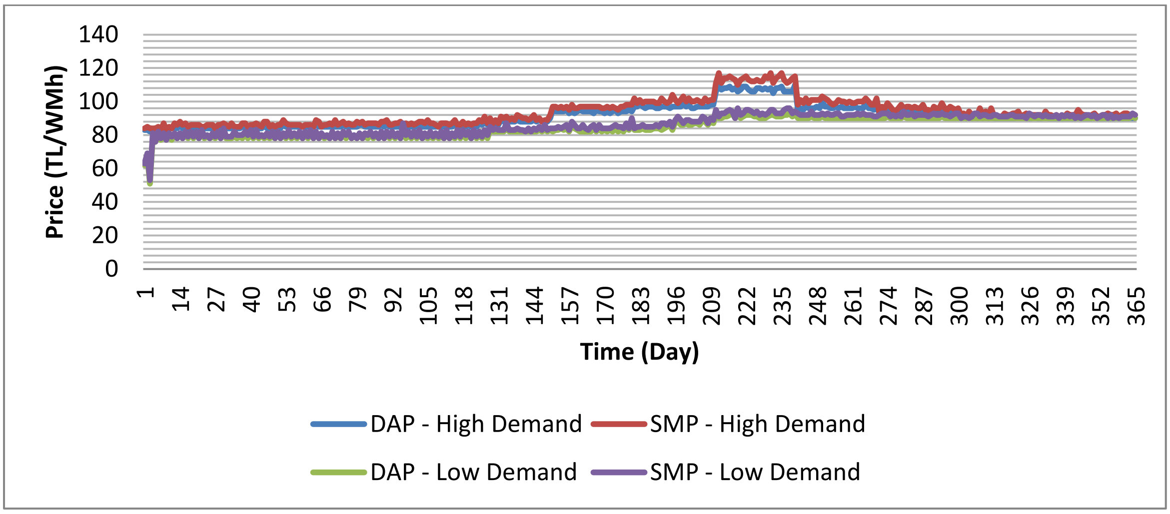


Figure 4.3. Off-peak time electricity system prices (high and low demand scenarios).

Table 4.6 displays the off-peak time DAP and SMP prices in high and low demand environments.

Table 4.6. Off-peak time system prices (high and low demand scenarios).

Off-peak Time System Prices In The High Demand Environment			
System Price	$\mu_{5,a}$ (TL)	$\sigma_{5,a}$ (TL)	$\sigma_{5,a}/\mu_{5,a}$
DAP (a=1)	91.27	6.64	0.07
SMP (a=2)	93.80	7.87	0.08
$(\mu_{5,2} - \mu_{5,1})/\mu_{5,1}$ (%)	+0.02		
Off-peak Time System Prices In The Low Demand Environment			
System Price	$\mu_{6,b}$ (TL)	$\sigma_{6,b}$ (TL)	$\sigma_{6,b}/\mu_{6,b}$
DAP (b=1)	84.70	5.62	0.06
SMP (b=2)	86.28	5.94	0.06
$(\mu_{6,2} - \mu_{6,1})/\mu_{6,1}$ (%)	+0.01		

As such, during the off-peak time period, the SMP price is 3 TL (about 2%) higher than the DAP price in the high demand environment, while it is 2 TL (and 1%) higher in the low demand environment. The increase between the DAP and the SMP prices is lowest during off-peak time period, compared to the peak time period and the daily average in both high and low demand environments, that is;

$$\mu_{5,2} - \mu_{5,1} < \mu_{3,2} - \mu_{3,1} \text{ and } \mu_{5,2} - \mu_{5,1} < \mu_{1,2} - \mu_{1,1} \text{ and}$$

$$\mu_{6,2} - \mu_{6,1} < \mu_{4,2} - \mu_{4,1} \text{ and } \mu_{6,2} - \mu_{6,1} < \mu_{2,2} - \mu_{2,1}$$

The difference between the DAP and the SMP prices are highest during the peak time period compared to the off-peak time and the daily average periods in both high and low demand environments, that is;

$$\mu_{3,2} - \mu_{3,1} > \mu_{1,2} - \mu_{1,1} \text{ and } \mu_{3,2} - \mu_{3,1} > \mu_{5,2} - \mu_{5,1} \text{ and}$$
$$\mu_{4,2} - \mu_{4,1} < \mu_{6,2} - \mu_{6,1} \text{ and } \mu_{4,2} - \mu_{4,1} < \mu_{2,2} - \mu_{2,1}$$

Table 4.7 displays that the minimum and the maximum values of the off-peak time DAP and SMP prices in high and low demand environments.

Table 4.7. Off-peak time system prices’ ranges (high and low demand scenarios).

Off-peak Time System Prices In The High Demand Environment			
System Price	$Min_{5,a}$(TL)	$Max_{5,a}$ (TL)	$Max_{5,a}$ - $Min_{5,a}$((TL)
DAP (a=1)	82	110	+28
SMP (a=2)	83	117	+34
Off-peak Time System Prices In The Low Demand Environment			
System Price	$Min_{6,b}$(TL)	$Max_{6,b}$ (TL)	$Max_{6,b}$ - $Min_{6,b}$((TL)
DAP (b=1)	51	93	+42
SMP (b=2)	53	96	+43

In the high demand environment, the minimum and the maximum values of the off-peak time DAP and SMP prices are higher than the minimum and the maximum values of the respective prices in the low demand environment, that is;

$$Min_{5,1} > Min_{6,1} \text{ and } Min_{5,2} > Min_{6,2} \text{ and } Max_{5,1} > Max_{6,1} \text{ and } Max_{5,2} > Max_{6,2}$$

So, a general observation according to the scenarios’ results is that the minimum and the maximum values of the DAP and of the SMP prices are directly proportional to demand level changes (higher demand leading to higher prices). However, the ranges between the minimum of the off-peak time DAP and SMP prices and the maximum values of the off-peak time DAP and SMP prices are wider in the low demand environment, that is;

$$Max_{6,1} - Min_{6,1} > Max_{5,1} - Min_{5,1} \text{ and } Max_{6,2} - Min_{6,2} > Max_{5,2} - Min_{5,2}$$

This is in contradiction with the case in the peak time DAP and SMP prices, that is;

$$\text{Max}_{4,1} - \text{Min}_{4,1} < \text{Max}_{3,1} - \text{Min}_{3,1} \text{ and } \text{Max}_{4,2} - \text{Min}_{4,2} < \text{Max}_{3,2} - \text{Min}_{3,2}$$

but it is consistent with case in the daily average of the DAP and of the SMP prices, that is;

$$\text{Max}_{1,1} - \text{Min}_{1,1} < \text{Max}_{2,1} - \text{Min}_{2,1} \text{ and } \text{Max}_{1,2} - \text{Min}_{1,2} < \text{Max}_{2,2} - \text{Min}_{2,2}$$

Therefore, during the off-peak time period, the impact of the capacity reductions of hydraulic power generator agents (which increases the system price variation as in the case of daily average) on the electricity system prices is higher in the low demand environment when compared to the high demand environment (this impact is not seen during the peak-time period as mentioned before).

Figure 4.4 and Table 4.8 display the daily average profits for each power generator agent in both high and low demand environments.

For each power generator agent, the daily average profits are higher in the high demand environment than the respective profits in the low demand environment ($\mu_{7,\text{id}} > \mu_{8,\text{id}}$ for $\text{id} = 1, \dots, 10$). Moreover, in both high and low demand environments, the high capacity generators have higher daily average profits compared to the respective same type of low capacity generators ($\text{i.e.}, \mu_{7,1} > \mu_{7,2}$ and $\mu_{7,3} > \mu_{7,5}$). This implies that the profit indicator is very much responsive to capacity (higher capacity leading to higher volume of electricity sales) and demand levels (higher demands leading to higher system prices as mentioned before).

In addition to this, power generator agents who follow the conservative pricing strategy have higher profits compared to the same type (with same marginal cost and capacity) power generator agents who follow the aggressive pricing strategy, that is;

$$\mu_{7,3} < \mu_{7,4} \text{ and } \mu_{7,5} < \mu_{7,6}$$

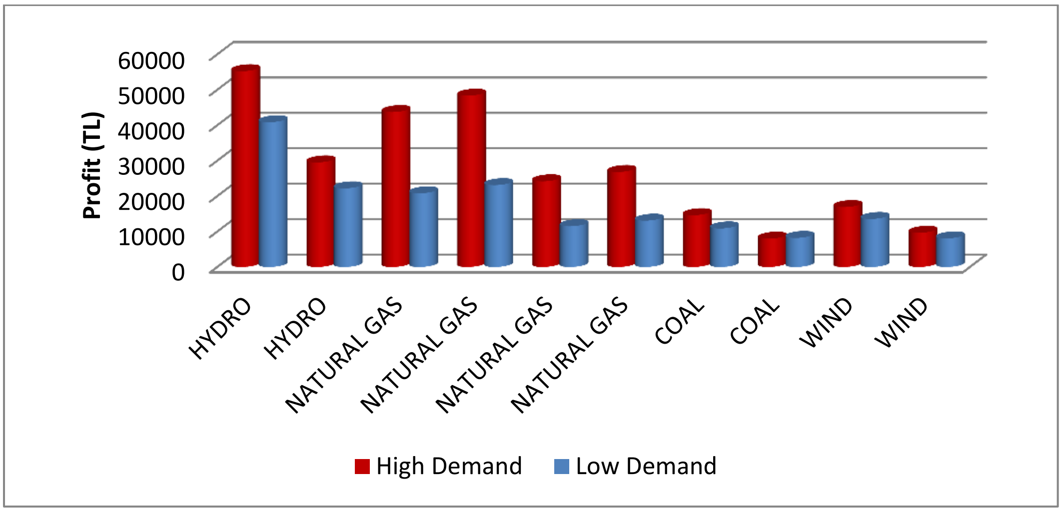


Figure 4.4. Daily average profits for each generator (high and low demand scenarios).

Table 4.8. Daily average profits for each power generator agent (high and low demand scenarios).

Daily Average Profits In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{7,id}$ (TL)	$\sigma_{7,id}$(TL)	$\sigma_{7,id}/\mu_{7,id}$
1	HYDRAULIC	4000	55247	18362	0.33
2	HYDRAULIC	2000	29524	9605	0.32
3	NATURAL GAS	4500	43730	12945	0.29
4	NATURAL GAS	4500	48341	14146	0.29
5	NATURAL GAS	2500	24194	7387	0.30
6	NATURAL GAS	2500	26821	7873	0.29
7	COAL	2500	14622	3130	0.21
8	COAL	1500	8002	2391	0.29
9	WIND	1000	16917	3389	0.20
10	WIND	500	9667	1967	0.20
Daily Average Profits In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{8,id}$ (TL)	$\sigma_{8,id}$(TL)	$\sigma_{8,id}/\mu_{8,id}$
1	HYDRAULIC	4000	40858	12632	0.30
2	HYDRAULIC	2000	22204	6981	0.31
3	NATURAL GAS	4500	20802	12686	0.60
4	NATURAL GAS	4500	23107	13722	0.59
5	NATURAL GAS	2500	11505	6926	0.60
6	NATURAL GAS	2500	13078	7444	0.56
7	COAL	2500	10894	4524	0.41
8	COAL	1500	8210	3191	0.38
9	WIND	1000	13571	3021	0.22
10	WIND	500	8080	2129	0.26

On the other hand, in the low demand environment, variations in profits are highest for natural gas generators mainly due to high priced offers (arising from high marginal costs) and low demand level (leading to the non-acceptance of bids and lower utilization levels) (i.e. $\sigma_{7,4} > \sigma_{7,\mathrm{id}}$ for id $\neq 4$).

In the low demand environment, natural gas generators can sell their generated electricity and increase their profits primarily during dry season when hydraulic power generator agents have low capacities.

For wind generators, variations in the profits are independent of the demand levels and show similar behaviors in both high and low demand environments mainly due to lower marginal costs (wind generators can sell their generated electricity in both environments) and same wind availability (frequency of non-availability of wind power is depicted in Table 3.5) in both demand environments ($\sigma_{7,\mathrm{id}} \cong \sigma_{8,\mathrm{id}}$ for id $= 9,10$).

Table 4.9 displays the impacts of seasonality on the daily average profits for the hydraulic and wind power generator agents in the high demand environment.

Table 4.9. Impact of seasonality on daily average profits for hydraulic and wind power generator agents (high and low demand scenarios).

Daily Average Profits In The High Demand Environment Winter					
ID	Type	Capacity (MW)	$\mu_{9,id}$ (TL)	$\sigma_{9,id}$ (TL)	$\sigma_{9,id}/\mu_{9,id}$
1	HYDRAULIC	4000	83482.11	2600.32	0.03
2	HYDRAULIC	2000	42224.66	1268.64	0.03
9	WIND	1000	15832.06	2028.98	0.12
10	WIND	500	7855.56	1127.87	0.14
Daily Average Profits In The High Demand Environment Summer					
ID	Type	Capacity (MW)	$\mu_{10,id}$ (TL)	$\sigma_{10,id}$ (TL)	$\sigma_{10,id}/\mu_{10,id}$
1	HYDRAULIC	4000	25167.95	1900.856	0.07
2	HYDRAULIC	2000	12941.05	950.37	0.07
9	WIND	1000	12356.68	2786.98	0.22
10	WIND	500	6017.65	1433.19	0.23

In the high demand environment, for hydraulic and wind power generator agents, as anticipated the daily average profits are higher in the winter (wet) season than the respective profits in the summer (dry) season, that is;

$$\mu_{9,id} > \mu_{10,id} \quad \text{for} \quad id = 1,2,9,10$$

For hydraulic power generator agents, daily average profits are higher in the winter season mainly due to the higher water capacity (the seasonal capacity variation of the hydraulic power generator agents is depicted in Figure 3.1) when compared to summer (dry) season as depicted in Figure 4.5 (higher capacity leading to higher profits as mentioned before).

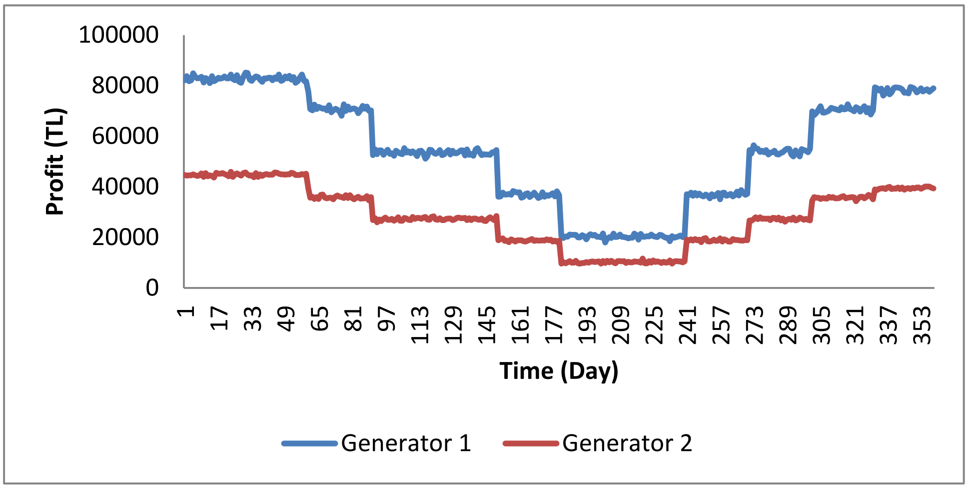


Figure 4.5. Daily average profits of hydraulic power generator agent (seasonality impact).

The daily average profits of the hydraulic power generator agents in the winter season are higher than the daily average profits of the whole year ($\mu_{9,id} > \mu_{7,id}$ for id = 1,2) mainly due to the negative impact of the lower capacity (capacity reduction leading to lower profits during the dry seasons) during dry season. A similar analysis can also be made for wind power generator agents. For wind power generator agents, the daily average profits are higher in winter season mainly due to higher wind power availability (frequency of non-availability of wind power depicted is in Table 3.4) when compared to the summer season. Moreover, the daily average profits of wind generators in the winter season are higher than the daily average profits of the whole year mainly due to the negative impact of wind power availability (lower wind availability leads to lower number of offers during the summer season) (frequency of the number of hourly offers submitted by wind power generators is depicted in Table 3.4). Another observation is that, in both winter and summer seasons, variations in the daily average profits are less than variations in the daily average profits of whole year, that is;

$$\sigma_{9,id} < \sigma_{7,id} \text{ and } \sigma_{10,id} < \sigma_{7,id} \text{ for id} = 1,2,9,10$$

As depicted in Figure 4.5, variations in the daily average profits during any season are lower than the respective variations between seasons.

Figure 4.6 and Table 4.10 display the peak time profits for each power generator agent in both high and low demand environments.

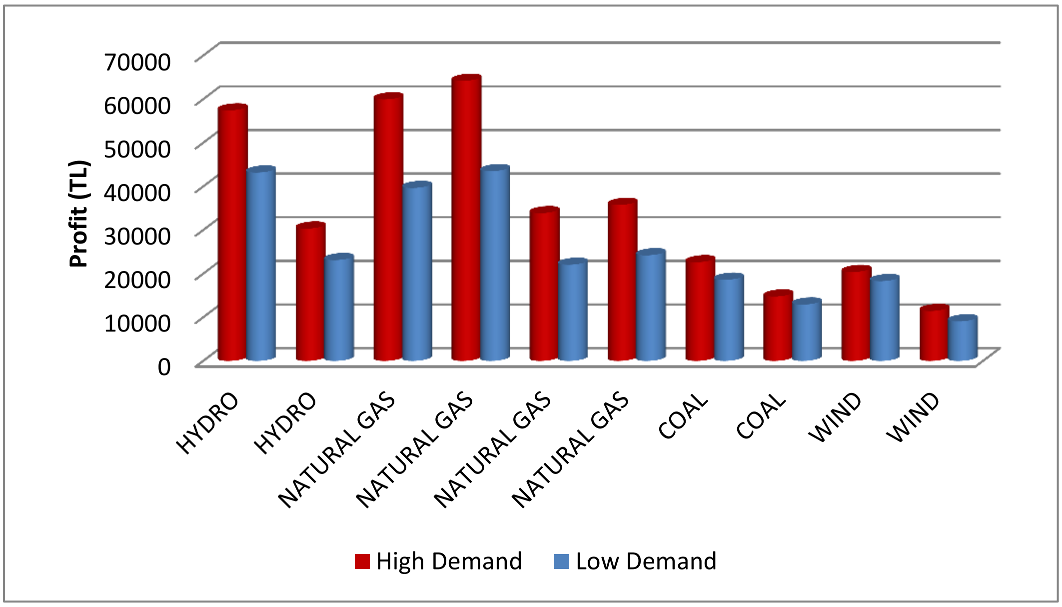


Figure 4.6. Peak time profits for each power generator agent (high and low demand scenarios).

For each power generator agent, the peak time profits in the high demand environment are higher than the respective peak time profits in the low demand environment, that is;

$$\mu_{11,id} > \mu_{12,id} \text{ for id} = 1,..,10$$

Additionally, in both demand environments, peak time profits for each power generator agent are higher than the respective daily average profits, that is;

$$\mu_{11,id} > \mu_{7,id} \text{ and } \mu_{12,id} > \mu_{8,id} \quad \text{for id} = 1,..,10$$

This is mainly due to higher demand during the peak time period leading to higher electricity system prices and higher volume of electricity sales. In the high demand environment, variations in profits are lower for natural gas and coal power generators because the system consistently needs their generated electricity (both in dry and non-dry seasons) during the peak time periods, that is;

$$\sigma_{11,id} < \sigma_{12,id} \text{ and } \sigma_{11,id} < \sigma_{7,id} \quad \text{for id} = 3,4,5,6$$

Table 4.10. Peak time profits for each power generator agent (high and low demand scenarios).

Peak Time Profits In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{11,id}$ (TL)	$\sigma_{11,id}$ (TL)	$\sigma_{11,id}/\mu_{11,id}$
1	HYDRAULIC	4000	57423	18648	0.32
2	HYDRAULIC	2000	30348	9902	0.32
3	NATURAL GAS	4500	59970	3915	0.06
4	NATURAL GAS	4500	64206	2843	0.04
5	NATURAL GAS	2500	33870	2443	0.07
6	NATURAL GAS	2500	35765	1638	0.04
7	COAL	2500	22629	2682	0.11
8	COAL	1500	14760	1064	0.07
9	WIND	1000	20375	4602	0.22
10	WIND	500	11449	2708	0.23
Peak Time Profits In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{12,id}$ (TL)	$\sigma_{12,id}$ (TL)	$\sigma_{12,id}/\mu_{12,id}$
1	HYDRAULIC	4000	43182	13781	0.31
2	HYDRAULIC	2000	23120	7307	0.31
3	NATURAL GAS	4500	39649	18934	0.47
4	NATURAL GAS	4500	43485	20483	0.47
5	NATURAL GAS	2500	22039	10780	0.48
6	NATURAL GAS	2500	24221	11417	0.47
7	COAL	2500	18600	7072	0.38
8	COAL	1500	12925	4691	0.36
9	WIND	1000	18296	4201	0.22
10	WIND	500	9069	2245	0.24

For hydraulic and wind generators, variations in profits are independent from demand levels and show similar behaviors during the peak time period in both high and low demand environments, that is;

$$\sigma_{11,id} / \mu_{11,id} \cong \sigma_{12,id} / \mu_{12,id} \quad \text{for id} = 1,2,9,10$$

Figure 4.7 and Table 4.11 display the off-peak time profits for each generator in both high and low demand environments.

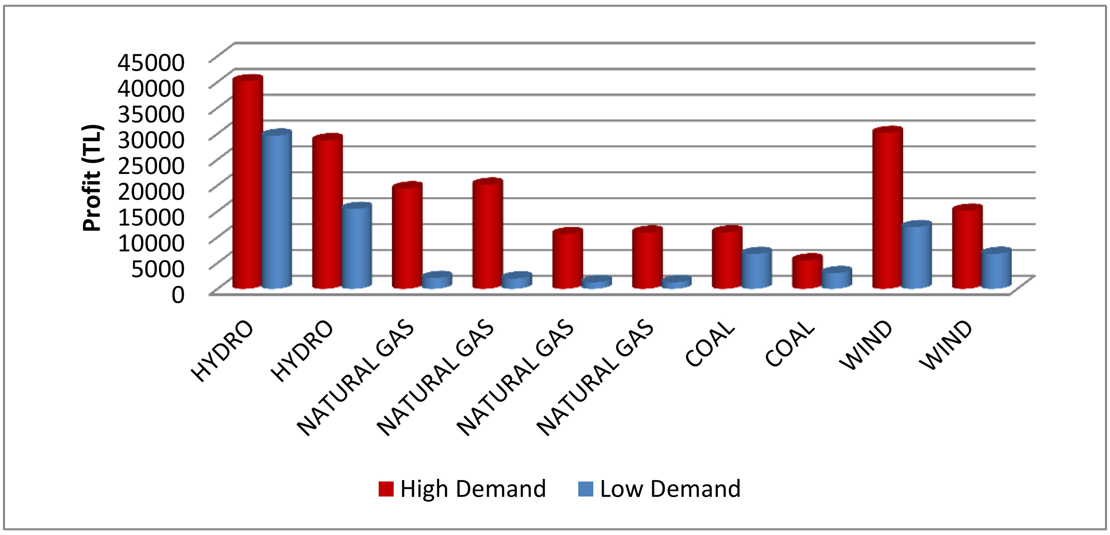


Figure 4.7. Off-peak time profits for each power generator agent (high and low demand scenarios).

In the high demand environment for each power generator agent, the off-peak time profits are higher than the respective profits in the low demand environment, that is;

$$\mu_{13,id} > \mu_{14,id} \quad \text{for} \quad \text{id} = 1, \dots, 10$$

The off-peak time profits for each power generator agent in the high demand environment are lower than the respective daily average ($\mu_{13,id} < \mu_{7,id}$ for id $= 1, \dots, 10$) and peak time profits ($\mu_{13,id} < \mu_{11,id}$ for id $= 1, \dots, 10$) mainly due to lower demand (lower demand leading to lower electricity prices and lower volume of electricity sales) existing during the off-peak time period. Similar analysis is also valid in the low demand environment, that is;

$$\mu_{14,id} < \mu_{12,id} \text{ and } \mu_{14,id} < \mu_{12,id} \text{ for id} = 1, \dots, 10$$

Table 4.11. Off-peak time profits for each power generator agent (high and low demand scenarios).

Off-peak Time Profits In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{13,id}$ (TL)	$\sigma_{13,id}$ (TL)	$\sigma_{13,id}/\mu_{13,id}$
1	HYDRAULIC	4000	40135	13925	0.34
2	HYDRAULIC	2000	28715	9101	0.31
3	NATURAL GAS	4500	19390	8123	0.41
4	NATURAL GAS	4500	20125	9012	0.44
5	NATURAL GAS	2500	10570	4023	0.38
6	NATURAL GAS	2500	10849	3845	0.35
7	COAL	2500	10892	3011	0.27
8	COAL	1500	5480	1821	0.33
9	WIND	1000	30137	7513	0.24
10	WIND	500	15087	3834	0.25
Off-peak Time Profits In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{14,id}$ (TL)	$\sigma_{14,id}$ (TL)	$\sigma_{14,id}/\mu_{14,id}$
1	HYDRAULIC	4000	29602	10743	0.36
2	HYDRAULIC	2000	15447	5877	0.38
3	NATURAL GAS	4500	2090	923	0.44
4	NATURAL GAS	4500	2001	985	0.49
5	NATURAL GAS	2500	1271	741	0.58
6	NATURAL GAS	2500	1253	554	0.44
7	COAL	2500	6737	2314	0.34
8	COAL	1500	3037	946	0.31
9	WIND	1000	11916	2849	0.23
10	WIND	500	6755	1745	0.25

Moreover, in both high and low demand environments, high capacity generators have higher off-peak time profits compared to the respective profits of low capacity generators (i.e., $\mu_{13,1} > \mu_{13,2}$ and $\mu_{13,3} > \mu_{13,5}$). A general observation is that the profit indicator is more responsive to capacity (higher capacity leading to higher volume of sales) and demand levels (higher demand leading to higher system prices), which is consistent with the other time periods.

Figure 4.8 and Table 4.12 display the daily average market shares for each power generator agent in both high and low demand environments.

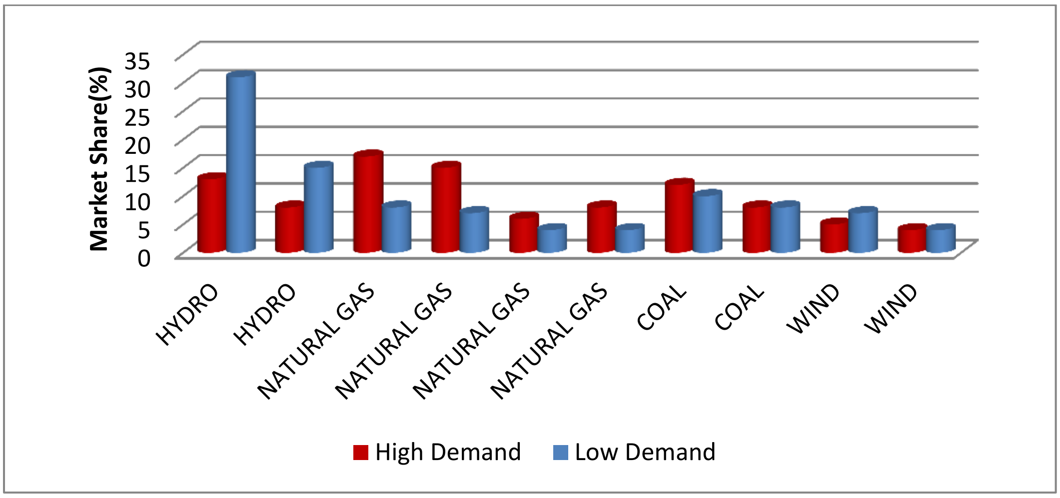


Figure 4.8. Daily average market shares for each power generator agent (high and low demand scenarios).

Table 4.12. Daily average market shares for each power generator agent (high and low demand scenarios).

Daily Average Market Shares In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{15,id}$ (%)	$\sigma_{15,id}$ (%)	$\sigma_{15,id}/\mu_{15,id}$
1	HYDRAULIC	4000	13	5	0.38
2	HYDRAULIC	2000	8	3	0.37
3	NATURAL GAS	4500	17	3	0.17
4	NATURAL GAS	4500	15	3	0.20
5	NATURAL GAS	2500	6	2	0.33
6	NATURAL GAS	2500	8	2	0.25
7	COAL	2500	12	1	0.08
8	COAL	1500	8	1	0.12
9	WIND	1000	5	2	0.40
10	WIND	500	4	2	0.50
Daily Average Market Shares In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{16,id}$ (%)	$\sigma_{16,id}$ (%)	$\sigma_{16,id}/\mu_{16,id}$
1	HYDRAULIC	4000	31	12	0.38
2	HYDRAULIC	2000	15	6	0.40
3	NATURAL GAS	4500	8	2	0.25
4	NATURAL GAS	4500	7	3	0.42
5	NATURAL GAS	2500	4	2	0.50
6	NATURAL GAS	2500	4	3	0.75
7	COAL	2500	10	6	0.60
8	COAL	1500	8	3	0.37
9	WIND	1000	7	3	0.42
10	WIND	500	4	2	0.50

In both high and low demand environments, high capacity generators have higher daily average market shares compared to the respective market shares of low capacity generators, that is;

$$\text{i.e., } \mu_{15,7} > \mu_{15,8} \text{ and } \mu_{16,1} > \mu_{16,2}$$

Hydraulic and wind power generator agents have higher daily average market shares in the low demand environment compared to their respective market shares in the high demand environment ($\mu_{16,\mathrm{id}} > \mu_{15,\mathrm{id}}$ for id = 1,2,9,10). This is mainly due to the fact that the system's electricity demand is supplied mostly by these two types of generators in the low demand environment. On the other hand, natural gas and coal generators have lower daily average market shares in the low demand environment compared to their respective market shares in the high demand environment ($\mu_{16,\mathrm{id}} < \mu_{15,\mathrm{id}}$ for id ≠ 1,2,9,10) mainly due to increased generator's idle time (higher priced offers not being accepted) in the low demand environment.

Variations in daily average market shares for high cost power generator agents (natural gas and coal) are higher in the low demand environment than their respective variations in the high demand environment, that is;

$$\sigma_{16,\mathrm{id}} / \mu_{16,\mathrm{id}} > \sigma_{15,\mathrm{id}} / \mu_{15,\mathrm{id}} \text{ for id} \neq 1,2,9,10$$

This is again mainly due to the higher competition in the low demand environment for high cost power generator agents (which does not have impact on low cost power generator agents), that is;

$$\sigma_{16,\mathrm{id}} / \mu_{16,\mathrm{id}} \cong \sigma_{15,\mathrm{id}} / \mu_{15,\mathrm{id}} \text{ for id} = 1,2,9,10$$

High cost power generator agents increase their market shares mainly during the dry season (when the system operator needs their generation to meet the electricity demand) as depicted in Figure 4.9.

A general point to sum up is that the increased electricity demand has a high negative impact on the daily average market shares for hydraulic power generator agents and has a high positive impact on the daily average market shares for natural gas power generator agents, that is;

$$\mu_{16,a} - \mu_{15,a} > \mu_{16,b} - \mu_{15,b} \; for\ a = 1,2\ and\ b \neq 1,2\ and$$
$$\mu_{15,a} - \mu_{16,a} > \mu_{15,b} - \mu_{16,b} \; for\ a = 3,4,5,6\ and\ b \neq 3,4,5,6$$

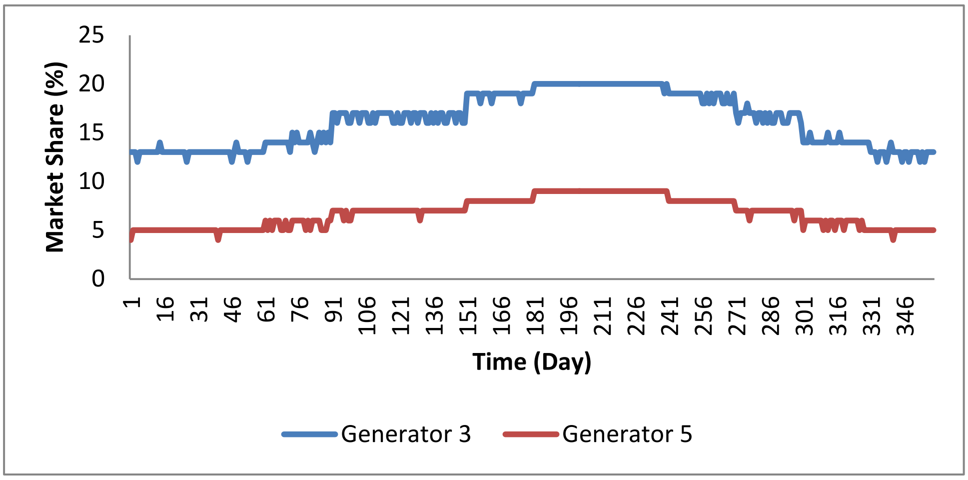


Figure 4.9. Daily average market shares for Generator 3 and Generator 5 (seasonality impact).

Figure 4.10 and Table 4.13 display the peak time market shares for each power generator agent in both high and low demand environments.

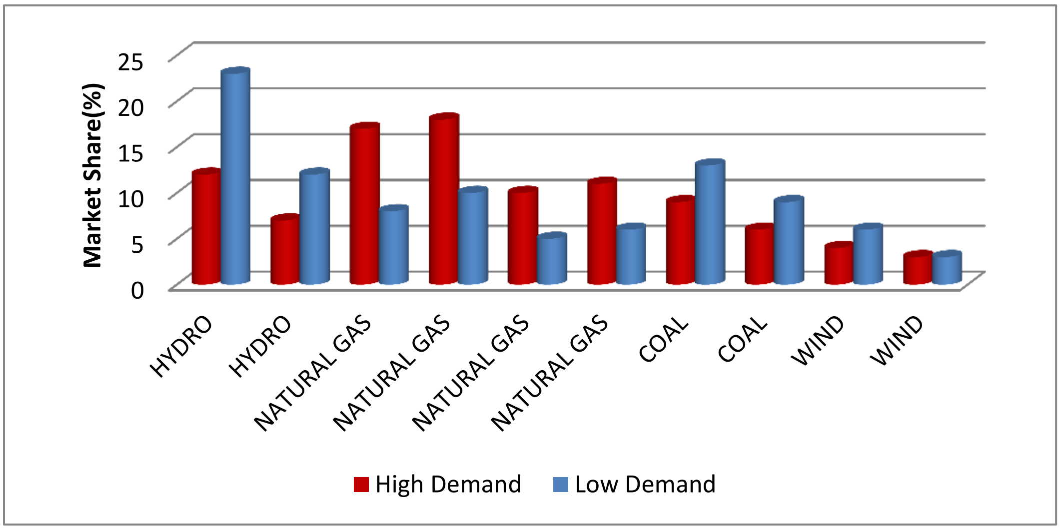


Figure 4.10. Peak time market shares for each power generator agent (high and low demand scenarios).

Table 4.13. Peak time market shares for each power generator agent (high and low demand scenarios).

Peak Time Market Shares In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{17,id}$ (%)	$\sigma_{17,id}$ (%)	$\sigma_{17,id}/\mu_{17,id}$
1	HYDRAULIC	4000	12	5	0.41
2	HYDRAULIC	2000	7	3	0.42
3	NATURAL GAS	4500	17	2	0.11
4	NATURAL GAS	4500	18	2	0.11
5	NATURAL GAS	2500	10	1	0.10
6	NATURAL GAS	2500	11	1	0.09
7	COAL	2500	9	1	0.11
8	COAL	1500	6	1	0.16
9	WIND	1000	4	1	0.25
10	WIND	500	3	1	0.33
Peak Time Market Shares In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{18,id}$ (%)	$\sigma_{18,id}$ (%)	$\sigma_{18,id}/\mu_{18,id}$
1	HYDRAULIC	4000	23	13	0.56
2	HYDRAULIC	2000	12	7	0.58
3	NATURAL GAS	4500	8	2	0.25
4	NATURAL GAS	4500	10	6	0.60
5	NATURAL GAS	2500	5	2	0.40
6	NATURAL GAS	2500	6	2	0.33
7	COAL	2500	13	2	0.15
8	COAL	1500	9	2	0.22
9	WIND	1000	6	2	0.33
10	WIND	500	3	1	0.33

In both high and low demand environments, high capacity generators have higher peak time market shares compared to the respective (same type) low capacity generators, that is;

$$i.e.,\ \mu_{17,7} > \mu_{17,8}\ and\ \mu_{18,1} > \mu_{18,2}$$

Hydraulic and wind power generator agents have higher peak time market shares in the low demand environment compared to their respective market shares in the high demand environment ($\mu_{17,id} > \mu_{18,id}$ for id = 1,2,9,10) (which is consistent with the case in the daily average).

However, in both high and low demand environments, for hydraulic and wind power generator agents, the peak time market shares are lower than their respective daily average market shares, that is;

$$\mu_{17,id} < \mu_{15,id} \text{ and } \mu_{18,id} < \mu_{16,id} \text{ for id} = 1,2,9,10$$

This is mainly due to the fact that more electricity demand is supplied by other types of generators during peak time periods. During the peak time period, variations in market shares for each power generator agent are higher in the low demand environment than their respective market shares in the high demand environment, mainly due to the higher competition in the low demand environment, that is;

$$\sigma_{18,id} / \mu_{18,id} > \sigma_{17,id} / \mu_{17,id} \text{ for id} = 1, \ldots ,10$$

In addition to this, power generator agents who follow the conservative pricing strategy have higher peak time market shares compared to the same type (with same marginal cost and capacity) power generator agents who follow the aggressive pricing strategy, that is;

$$\mu_{17,3} < \mu_{17,4} \text{ and } \mu_{17,5} < \mu_{17,6}$$

Figure 4.11 and Table 4.14 display the off-peak time market shares for each power generator agent in both high and low demand environments.

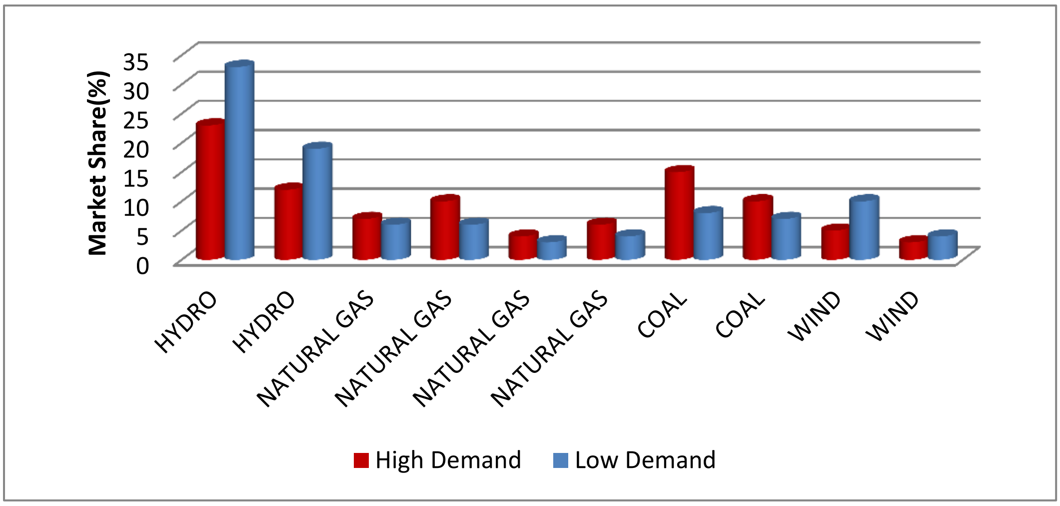


Figure 4.11. Off-peak time market shares for each power generator agent (high and low demand scenarios).

Table 4.14. Off-peak time market shares for each power generator agent (high and low demand scenarios).

Off-peak Time Market Shares In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{19,id}$ (TL)	$\sigma_{19,id}$ (TL)	$\sigma_{19,id}/\mu_{19,id}$
1	HYDRAULIC	4000	23	11	0.47
2	HYDRAULIC	2000	12	6	0.50
3	NATURAL GAS	4500	7	6	0.85
4	NATURAL GAS	4500	10	7	0.70
5	NATURAL GAS	2500	4	3	0.75
6	NATURAL GAS	2500	6	4	0.66
7	COAL	2500	15	2	0.13
8	COAL	1500	10	1	0.10
9	WIND	1000	5	2	0.40
10	WIND	500	3	1	0.33
Off-peak Time Market Shares In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{20,id}$ (TL)	$\sigma_{20,id}$ (TL)	$\sigma_{20,id}/\mu_{20,id}$
1	HYDRAULIC	4000	33	10	0.30
2	HYDRAULIC	2000	21	9	0.42
3	NATURAL GAS	4500	3	1	0.33
4	NATURAL GAS	4500	6	2	0.33
5	NATURAL GAS	2500	3	2	0.66
6	NATURAL GAS	2500	4	3	0.75
7	COAL	2500	8	10	1.25
8	COAL	1500	7	6	0.85
9	WIND	1000	10	3	0.30
10	WIND	500	6	2	0.33

In both high and low demand environments, high capacity generators have higher off-peak time market shares compared to the respective same type of low capacity generators, that is;

$$\text{i.e., } \mu_{20,7} > \mu_{20,8} \text{ and } \mu_{19,1} > \mu_{19,2}$$

Hydraulic and wind power generator agents have higher off-peak time market shares in the low demand environment compared to their respective market shares in the high demand environment, that is;

$$\mu_{20,\mathrm{id}} > \mu_{19,\mathrm{id}} \text{ for id} = 1,2,9,10$$

For hydraulic and wind power generator agents, the off-peak time market shares are higher than their respective market shares in the daily average and the peak time periods, that is;

$$\mu_{20,id} > \mu_{18,id} \text{ and } \mu_{20,id} > \mu_{16,id} \text{ for id} = 1,2,9,10$$

This is mainly due to the fact that reduced electricity demand in the system is mainly supplied by hydraulic and wind generators (low cost power generator agents) during the off-peak time period (minimum cost principle of the system operator increases the market shares of these power generator agents).

In addition to this, power generator agents who follow the conservative pricing strategy have higher off-peak time market shares compared to the same type (with same marginal cost and capacity) power generator agents who follow the aggressive pricing strategy, that is;

$$\mu_{19,3} < \mu_{19,4} \text{ and } \mu_{19,5} < \mu_{19,6}$$

Figure 4.12 and Table 4.15 display the daily average capacity utilizations for each power generator agent in both high and low demand environments.

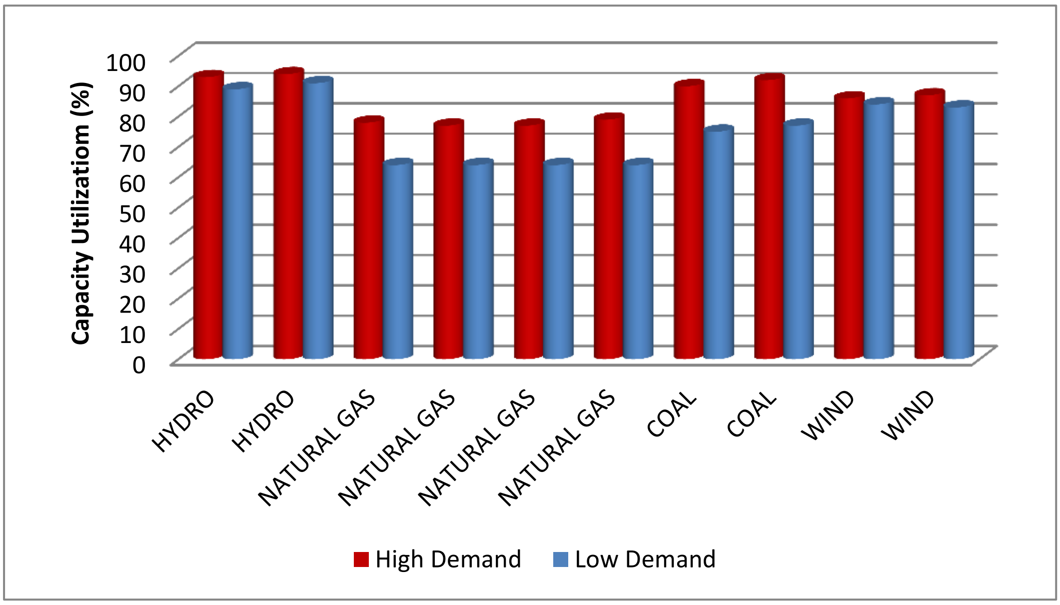


Figure 4.12. Daily average capacity utilizations for each power generator agent (high and low demand scenarios).

Table 4.15. Daily average of capacity utilizations for each power generator agent (high and low demand scenarios).

Daily Average Capacity Utilizations In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{21,id}$ (%)	$\sigma_{21,id}$ (%)	$\sigma_{21,id}/\mu_{21,id}$
1	HYDRAULIC	4000	93	1	0.01
2	HYDRAULIC	2000	94	1	0.01
3	NATURAL GAS	4500	78	7	0.08
4	NATURAL GAS	4500	77	7	0.09
5	NATURAL GAS	2500	77	7	0.09
6	NATURAL GAS	2500	79	7	0.08
7	COAL	2500	90	3	0.03
8	COAL	1500	92	2	0.02
9	WIND	1000	86	11	0.12
10	WIND	500	87	10	0.11
Daily Average Capacity Utilizations In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{22,id}$ (%)	$\sigma_{22,id}$ (%)	$\sigma_{22,id}/\mu_{22,id}$
1	HYDRAULIC	4000	89	4	0.04
2	HYDRAULIC	2000	91	4	0.04
3	NATURAL GAS	4500	64	6	0.09
4	NATURAL GAS	4500	64	6	0.09
5	NATURAL GAS	2500	64	6	0.09
6	NATURAL GAS	2500	64	6	0.09
7	COAL	2500	75	11	0.14
8	COAL	1500	77	11	0.14
9	WIND	1000	84	12	0.14
10	WIND	500	83	10	0.12

For each power generator agent, the daily average capacity utilizations are higher in the high demand environment than their respective capacity utilizations in the low demand environment ($\mu_{21,\mathrm{id}} > \mu_{22,\mathrm{id}}$ for $\mathrm{id} = 1, \ldots, 10$). This is mainly due to the fact that higher demand leads to higher capacity utilization (higher volume of electricity sales). Demand level changes have a higher impact on the daily average capacity utilizations of high cost power generator agents than low cost power generator agents, that is;

$$i.e.\ \mu_{21,a} - \mu_{22,a} > \mu_{21,b} - \mu_{22,b}\ for\ a = 3,4,5,6,7,8\ and\ b = 1,2,9,10$$

High cost power generator agents increase their capacity utilizations mainly during the dry season as depicted in Figure 4.13. Variations in the daily average capacity utilizations of wind power generator agents are higher than hydraulic power generator agents.

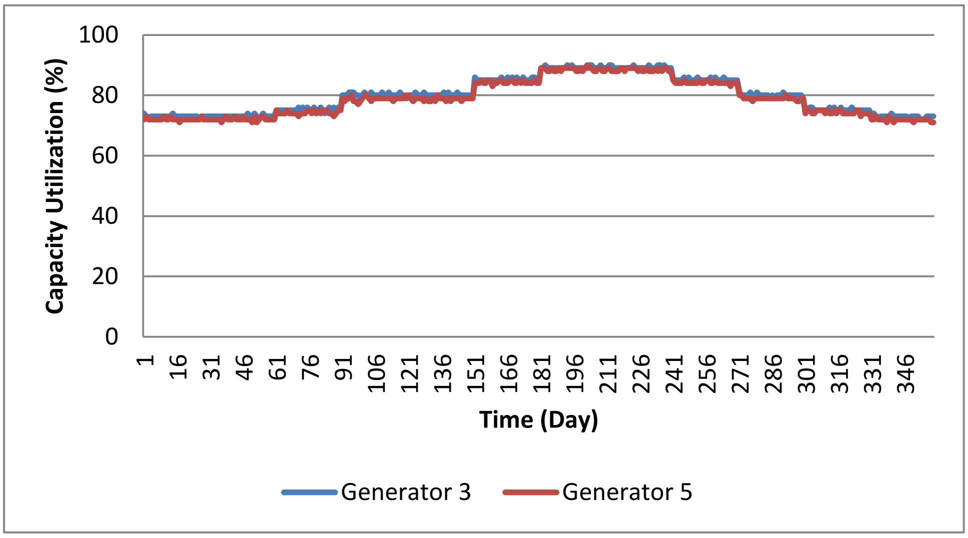


Figure 4.13. Daily average capacity utilizations for Generator 3 and Generator 5 (seasonality impact).

Figure 4.14 and Table 4.16 display the peak time capacity utilizations for each power generator agent in both high and low demand environments.

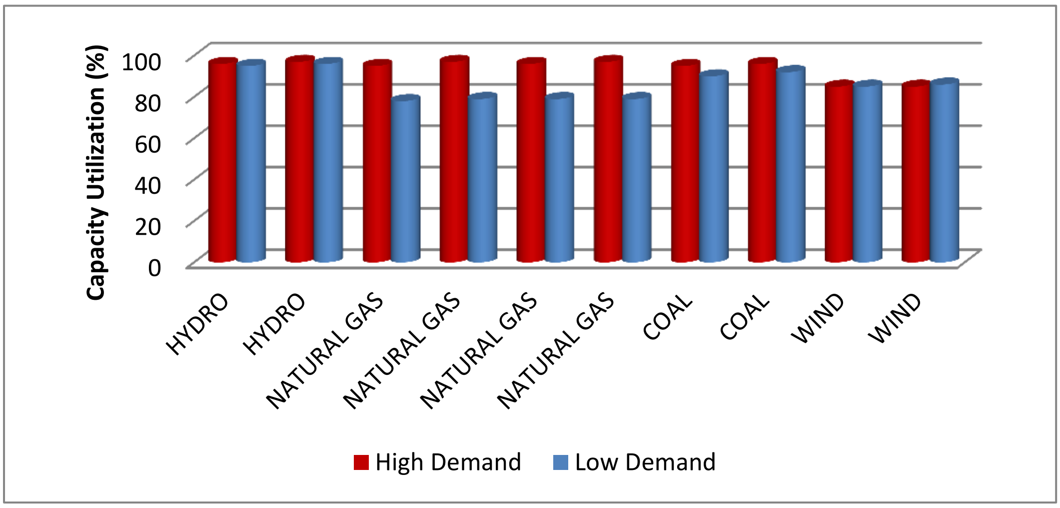


Figure 4.14. Peak time capacity utilizations for each power generator agent (high and low demand scenarios).

Table 4.16. Peak time capacity utilizations for each power generator agent (high and low demand scenarios).

Peak Time Capacity Utilizations In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{23,id}$ (%)	$\sigma_{23,id}$ (%)	$\sigma_{23,id}/\mu_{23,id}$
1	HYDRAULIC	4000	96	1	0.01
2	HYDRAULIC	2000	97	1	0.01
3	NATURAL GAS	4500	95	1	0.01
4	NATURAL GAS	4500	97	1	0.01
5	NATURAL GAS	2500	96	1	0.01
6	NATURAL GAS	2500	97	1	0.01
7	COAL	2500	95	1	0.01
8	COAL	1500	96	1	0.01
9	WIND	1000	85	8	0.09
10	WIND	500	85	10	0.12
Peak Time Capacity Utilizations In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{24,id}$ (%)	$\sigma_{24,id}$ (%)	$\sigma_{24,id}/\mu_{24,id}$
1	HYDRAULIC	4000	95	1	0.01
2	HYDRAULIC	2000	96	1	0.01
3	NATURAL GAS	4500	78	10	0.13
4	NATURAL GAS	4500	79	10	0.13
5	NATURAL GAS	2500	79	9	0.11
6	NATURAL GAS	2500	79	9	0.11
7	COAL	2500	90	5	0.06
8	COAL	1500	92	3	0.03
9	WIND	1000	85	11	0.13
10	WIND	500	86	9	0.10

For each power generator agent, the peak time capacity utilizations are higher in the high demand environment than their respective peak time capacity utilizations in the low demand environment ($\mu_{23,id} > \mu_{24,id}$ for id = 1,…,10) and also are higher than their respective daily average capacity utilizations in the high demand environment ($\mu_{23,id} > \mu_{21,id}$ for id = 1,…,10) mainly due to higher demand during the peak time periods (which leads to higher volume of electricity sales). Demand level changes have low impact on the peak time capacity utilizations of low cost power generator agents and have high impact on the peak time capacity utilizations of high cost power generator agents, that is;

$$\mu_{23,a} - \mu_{24,a} > \mu_{23,b} - \mu_{24,b} \text{ for a} = 3,4,5,6 \text{ and b} = 1,2,9,10$$

The peak time capacity utilizations show similar behaviors between the same types of power generator agents (i.e., $\mu_{23,1} \cong \mu_{23,2}$ and $\mu_{24,7} \cong \mu_{24,8}$).

In addition to this, power generator agents who follow the conservative pricing strategy have higher peak time capacity utilizations compared to the same type (with same marginal cost and capacity) power generator agents who follow the aggressive pricing strategy, that is;

$$\mu_{23,3} < \mu_{23,4} \, and \, \mu_{23,5} < \mu_{23,6}$$

Figure 4.15 and Table 4.17 display the off-peak time capacity utilizations for each power generator agent in both high and low demand environments.

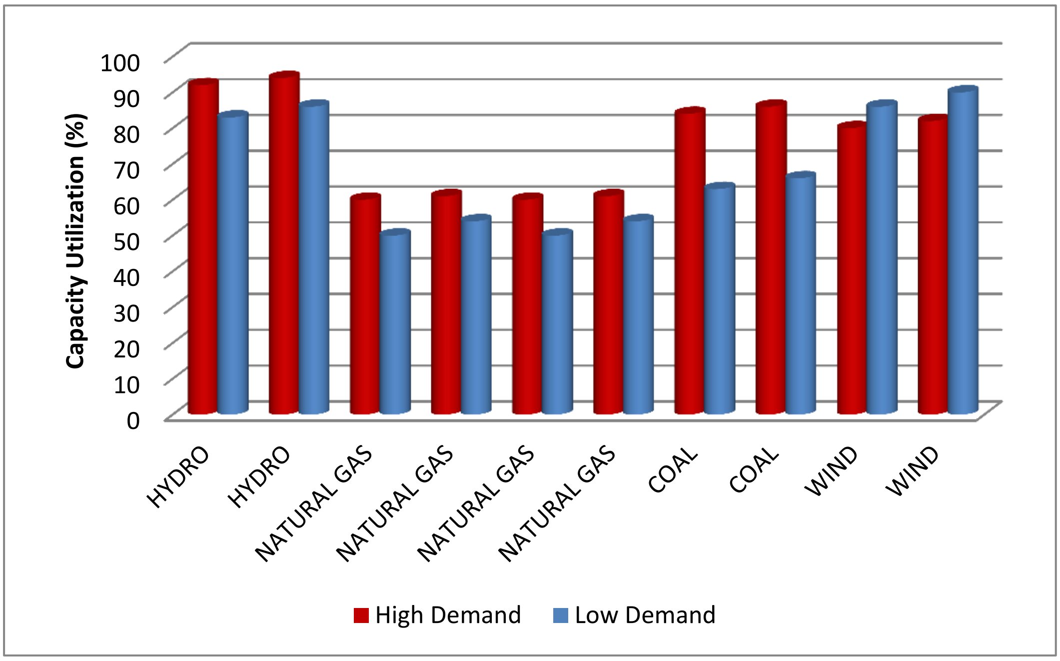


Figure 4.15. Off-peak time capacity utilizations for each power generator agent (high and low demand scenarios).

In both high and low demand environments, variations (and unit variation) in the off-peak time capacity utilizations show similar behaviors between the same type of generators, that is;

$$i.e. \, \sigma_{25,1} \cong \sigma_{25,2} \, and \, \sigma_{25,1}/\mu_{25,1} \cong \sigma_{25,2}/\mu_{25,2}$$

Table 4.17. Off-peak time capacity utilizations for each power generator agent (high and low demand scenarios).

Off-peak Time Capacity Utilizations In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{25,id}$ (%)	$\sigma_{25,id}$ (%)	$\sigma_{25,id}/\mu_{25,id}$
1	HYDRAULIC	4000	92	1	0.01
2	HYDRAULIC	2000	94	1	0.01
3	NATURAL GAS	4500	60	10	0.17
4	NATURAL GAS	4500	61	10	0.16
5	NATURAL GAS	2500	60	10	0.16
6	NATURAL GAS	2500	61	10	0.16
7	COAL	2500	84	5	0.06
8	COAL	1500	86	5	0.06
9	WIND	1000	90	10	0.11
10	WIND	500	92	10	0.11
Off-peak Time Capacity Utilizations In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{26,id}$ (%)	$\sigma_{26,id}$ (%)	$\sigma_{26,id}/\mu_{26,id}$
1	HYDRAULIC	4000	83	9	0.11
2	HYDRAULIC	2000	86	8	0.10
3	NATURAL GAS	4500	50	4	0.08
4	NATURAL GAS	4500	54	4	0.07
5	NATURAL GAS	2500	50	4	0.08
6	NATURAL GAS	2500	54	4	0.07
7	COAL	2500	63	16	0.25
8	COAL	1500	66	16	0.24
9	WIND	1000	86	9	0.10
10	WIND	500	90	9	0.10

For each power generator agent, the off-peak time capacity utilizations in the high demand environment are higher than their respective off-peak time capacity utilizations in the low demand environment ($\mu_{25,\mathrm{id}} > \mu_{26,\mathrm{id}}$ for id $= 1, \ldots, 10$) but are lower than their respective peak time and daily average capacity utilizations in the high demand environment, that is;

$$\mu_{25,id} < \mu_{23,id} \text{ } and \text{ } \mu_{25,id} < \mu_{21,id} \text{ } for \text{ } id = 1, \ldots, 10$$

In addition to this, power generator agents who follow the conservative pricing strategy have higher off-peak time capacity utilizations compared to the same type (with same marginal cost and capacity) power generator agents (impacts of the conservative pricing strategy on capacity utilization indicator are more seen during the off-peak time period as anticipated), that is;

$$\mu_{26,3} < \mu_{26,4} \, and \, \mu_{26,5} < \mu_{26,6}$$

So a general observation is that the capacity utilization indicator is more responsive to the marginal cost of the power generator agent and has no relation to the capacity indicator. In both high and low demand environments, the capacity utilizations of wind generators show similar behaviors during the off-peak time, peak time and the daily average periods. Hence this indicator for wind generators has no relation with demand levels but has strong relation with variability of wind power, that is;

$$\mu_{25,id} \cong \mu_{23,id} \cong \mu_{21,id} \, for \, id = 9{,}10$$

Figure 4.16 and Table 4.18 display the daily average profit per unit values for each power generator agent in both high and low demand environments.

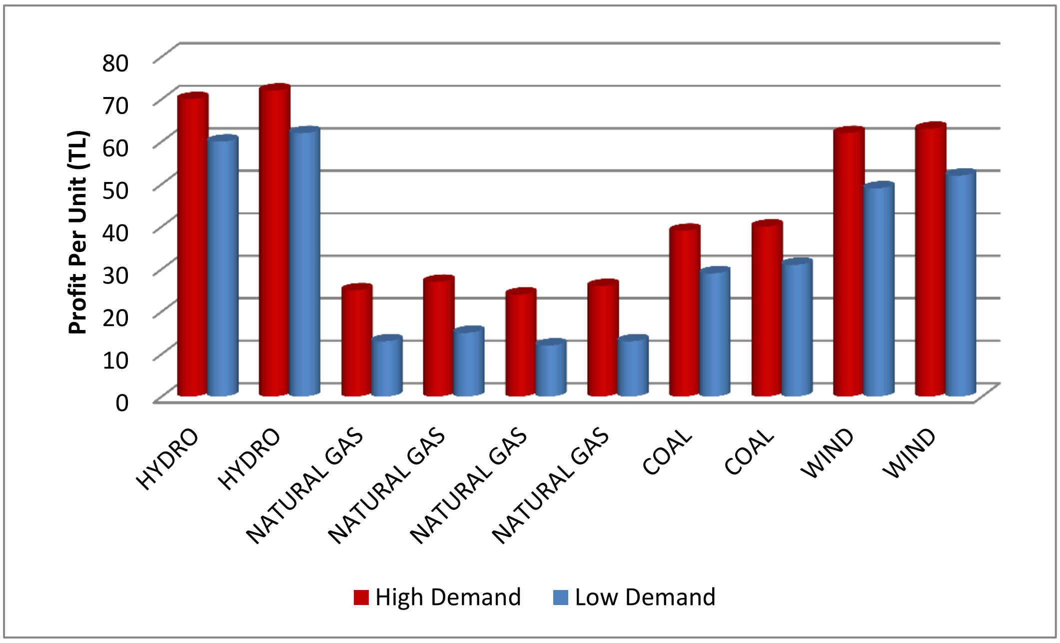


Figure 4.16. Daily average profit per unit values for each power generator agent (high and low demand scenarios).

Table 4.18. Daily average profit per unit values for each power generator agent (high and low demand scenarios).

Daily Average Profit per Unit Values In The High Demand Environment					
ID	Type	Capacity (MW)	$\mu_{27,id}$ (TL/MW)	$\sigma_{27,id}$ (TL/MW)	$\sigma_{27,id}/\mu_{27,id}$
1	HYDRAULIC	4000	70	3	0.04
2	HYDRAULIC	2000	72	4	0.06
3	NATURAL GAS	4500	25	4	0.16
4	NATURAL GAS	4500	27	4	0.15
5	NATURAL GAS	2500	24	5	0.21
6	NATURAL GAS	2500	26	5	0.19
7	COAL	2500	39	4	0.10
8	COAL	1500	40	4	0.10
9	WIND	1000	62	4	0.06
10	WIND	500	63	4	0.06
Daily Average Profit per Unit Values In The Low Demand Environment					
ID	Type	Capacity (MW)	$\mu_{28,id}$ (TL/MW)	$\sigma_{28,id}$ (TL/MW)	$\sigma_{28,id}/\mu_{28,id}$
1	HYDRAULIC	4000	60	5	0.08
2	HYDRAULIC	2000	62	5	0.08
3	NATURAL GAS	4500	13	8	0.62
4	NATURAL GAS	4500	15	8	0.53
5	NATURAL GAS	2500	12	8	0.67
6	NATURAL GAS	2500	13	8	0.62
7	COAL	2500	29	9	0.31
8	COAL	1500	31	8	0.26
9	WIND	1000	49	7	0.14
10	WIND	500	52	7	0.13

For each power generator agent, the daily average profit per unit values are higher in the high demand environment than the respective values in the low demand environment ($\mu_{27,\text{id}} > \mu_{28,\text{id}}$ for id $= 1, \ldots, 10$) mainly due to higher system prices (which leads to higher profit per unit). For the same type of power generator agents, the daily average profit per unit values are close to each other in both high and low demand environments (in other words, profit per unit values are not related to the capacity indicator), that is;

$$i.e., \mu_{27,1} \cong \mu_{27,2} \; and \; \mu_{28,7} \cong \mu_{28,8}$$

Another observation is that in both high and low demand environments, the daily average profit per unit values of low cost generators are higher than the respective values of high cost generators because of uniform pricing (single system price), that is;

$$\mu_{27,a} > \mu_{27,b} \; for \; a = 1,2,9,10 \; and \; b = 3,4,5,6,7,8$$

So, it is observed that the daily average profit per unit indicator is more responsive to the marginal costs of the power generator agents and is quite independent of the capacity indicator. All power generator agents (including hydraulic and wind generators) increase their profit per unit values mainly during the dry season (when electricity system prices increase) as depicted in Figure 4.17. In addition to this, for each power generator agent, variations in the daily average profit per unit values in the low demand environment are higher than the respective values in the high demand environment (which is consistent with the findings regarding the daily average electricity prices), that is;

$$\sigma_{2,a}/\mu_{2,a} > \sigma_{1,a}/\mu_{1,a} \; for \; a = 1,2$$

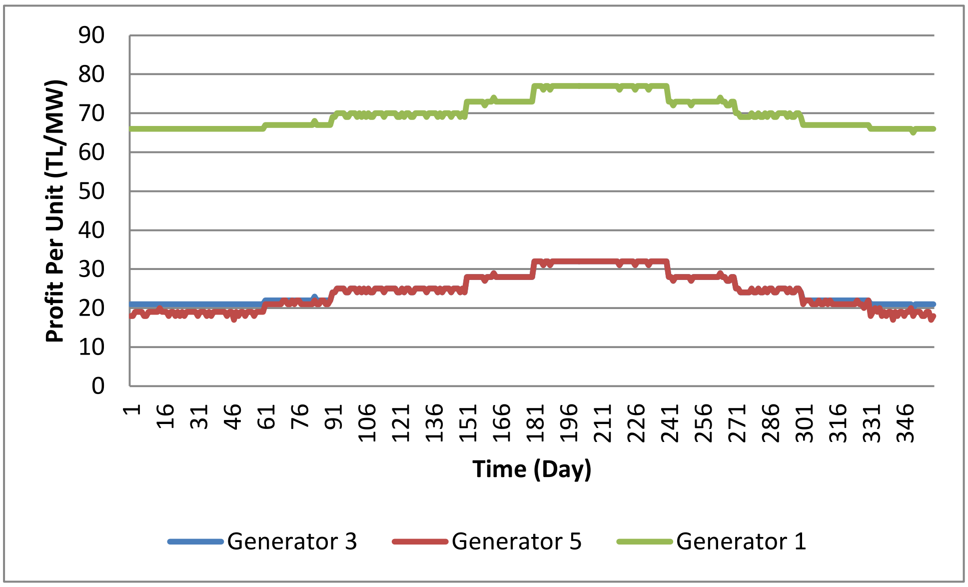


Figure 4.17. Daily average profit per unit values for generator 1, generator 3 and generator 5.

Figure 4.18 and Table 4.19 display the peak time profit per unit values for each power generator agent in both high and low demand environments.

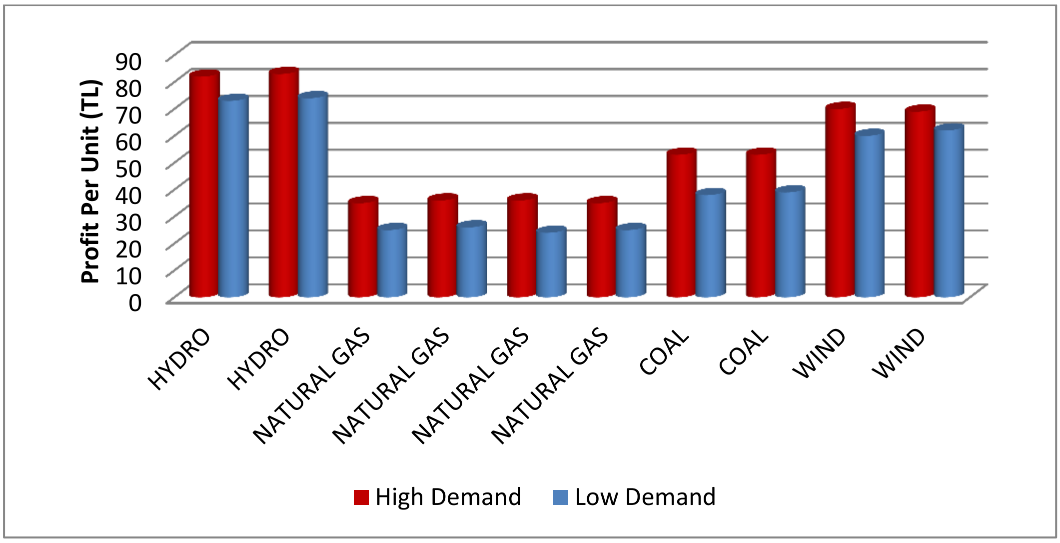


Figure 4.18. Peak time profit per unit values for each power generator agent (high and low demand scenarios).

Table 4.19. Peak time profit per unit values for each power generator agent (high and low demand scenarios).

Peak time Profit Per Unit Values In The High Demand Environment					
ID	Type	Capacity	$\mu_{29,id}$ (TL/MW)	$\sigma_{29,id}$ (TL/MW)	$\sigma_{29,id}/\mu_{29,id}$
1	HYDRAULIC	4000	82	1	0.01
2	HYDRAULIC	2000	83	2	0.02
3	NATURAL GAS	4500	35	3	0.09
4	NATURAL GAS	4500	36	2	0.06
5	NATURAL GAS	2500	36	3	0.08
6	NATURAL GAS	2500	35	2	0.06
7	COAL	2500	53	4	0.08
8	COAL	1500	53	2	0.04
9	WIND	1000	70	3	0.04
10	WIND	500	69	2	0.03
Peak time Profit Per Unit Values In The Low Demand Environment					
ID	Type	Capacity	$\mu_{30,id}$ (TL/MW)	$\sigma_{30,id}$ (TL/MW)	$\sigma_{30,id}/\mu_{30,id}$
1	HYDRAULIC	4000	73	9	0.12
2	HYDRAULIC	2000	74	8	0.11
3	NATURAL GAS	4500	25	9	0.36
4	NATURAL GAS	4500	26	8	0.31
5	NATURAL GAS	2500	24	9	0.38
6	NATURAL GAS	2500	25	7	0.28
7	COAL	2500	38	7	0.18
8	COAL	1500	39	9	0.23
9	WIND	1000	60	7	0.12
10	WIND	500	62	6	0.10

For each power generator agent, the peak time profit per unit values are higher in the high demand environment than the respective values in the low demand environment, that is;

$$\mu_{29,id} > \mu_{30,id} \; for \; id = 1,..,10$$

This is mainly due to higher peak time system prices in the high demand environment.

For the same type of power generator agents, peak time profit per unit values are close to each other in both high and low demand environments (which is consistent with the case in the daily average), that is;

$$i.e., \mu_{29,7} \cong \mu_{29,8} \; and \; \mu_{30,1} \cong \mu_{30,2}$$

Moreover, in both high and low demand environments, for each power generator agent, the peak time profit per unit values are higher than the respective daily profit per unit values, that is;

$$\mu_{29,id} > \mu_{30,id} \; for \; id = 1, \ldots ,10$$

This is consistent with higher peak time electricity system prices compared to daily average prices ($\mu_{3,1} > \mu_{1,1}$ and $\mu_{3,2} > \mu_{1,2}$). Additionally, variations in the peak time profit per unit values in the low demand environment are higher than the respective values in the high demand environment, that is;

$$\sigma_{29,id} / \mu_{29,id} < \sigma_{30,id} / \mu_{30,id} \; for \; id = 1, \ldots ,10$$

This is consistent with the analysis of the peak time electricity prices, that is;

$$\sigma_{3,a} / \mu_{3,a} < \sigma_{4,a} / \mu_{4,a} \; for \; a = 1,2$$

In addition to this, power generator agents who follow the conservative pricing strategy have higher peak time profit per unit values compared to the same type (with same marginal cost and capacity) power generator agents who follow the aggressive pricing strategy, that is;

$$\mu_{30,3} < \mu_{30,4} \, and \, \mu_{30,5} < \mu_{30,6}$$

Another observation is that in both high and low demand environments, the peak time profit per unit values of low cost generators are higher than the respective peak time profit per unit values of high cost generators ($\mu_{29,id} > \mu_{30,id}$ for id $= 1, \dots, 10$) which is also consistent with the analysis of the daily average.

Figure 4.19 and Table 4.20 display the off-peak time profit per unit values for each power generator agent in both high and low demand environments.

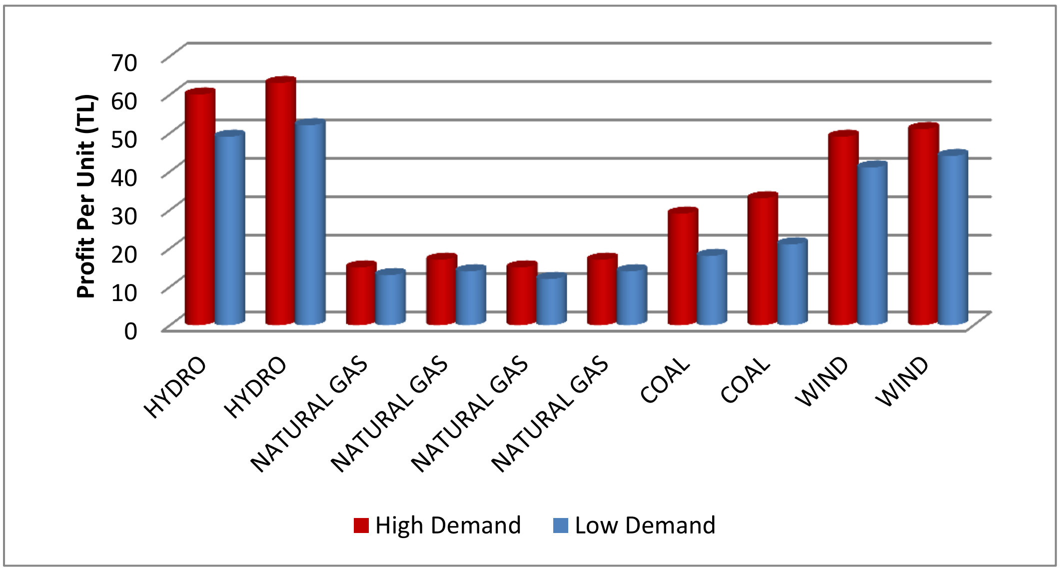


Figure 4.19. Off-peak time profit per unit values for each power generator agent (high and low demand scenarios).

For each power generator agent, the off-peak time profit per unit values are higher in the high demand environment than the respective values in the low demand environment ($\mu_{31,id} > \mu_{32,id}$ for id $= 1, \dots, 10$) mainly due to higher off-peak time electricity prices in the high demand environment.

Table 4.20. Off-peak time profit per unit values for each power generator agent (high and low demand scenarios).

Off-peak Time Profit per Unit Values In The High Demand Environment					
ID	Type	Capacity	$\mu_{31,id}$ (TL/MW)	$\sigma_{31,id}$ (TL/MW)	$\sigma_{31,id}/\mu_{31,id}$
1	HYDRAULIC	4000	60	3	0.05
2	HYDRAULIC	2000	63	4	0.06
3	NATURAL GAS	4500	15	4	0.27
4	NATURAL GAS	4500	17	5	0.29
5	NATURAL GAS	2500	15	5	0.33
6	NATURAL GAS	2500	17	5	0.29
7	COAL	2500	29	4	0.14
8	COAL	1500	33	4	0.12
9	WIND	1000	49	4	0.08
10	WIND	500	51	4	0.08
Off-peak Time Profit per Unit Values In The Low Demand Environment					
ID	Type	Capacity	$\mu_{32,id}$ (TL/MW)	$\sigma_{32,id}$ (TL/MW)	$\sigma_{32,id}/\mu_{32,id}$
1	HYDRAULIC	4000	49	13	0.27
2	HYDRAULIC	2000	52	12	0.23
3	NATURAL GAS	4500	13	8	0.62
4	NATURAL GAS	4500	14	8	0.57
5	NATURAL GAS	2500	12	9	0.75
6	NATURAL GAS	2500	14	8	0.57
7	COAL	2500	18	10	0.56
8	COAL	1500	21	9	0.43
9	WIND	1000	41	13	0.32
10	WIND	500	44	12	0.27

For the same type of power generator agents, the off-peak time profit per unit values are close to each other in both high and low demand environments, which is consistent with the case in the daily average and the peak time periods, that is,

$$i.e., \mu_{31,3} \cong \mu_{31,4} \; and \; \mu_{32,5} \cong \mu_{32,6}$$

Hence, a general observation is that the profit per unit indicator is not responsive to its capacity indicator, but highly responsive to system prices and its marginal cost. Moreover, in both high and low demand environments, for each power generator agent, the off-peak time profit per unit values are lower than the respective peak time and the daily average values, that is;

$$\mu_{31,\mathrm{id}} < \mu_{29,\mathrm{id}} \text{ for id} = 1, \ldots, 10$$

This is because of lower electricity prices during the off-peak time period. Moreover, variations in the off-peak time profit per unit values in the low demand environment are higher than the respective values in the high demand environment.

Another observation is that in both high and low demand environments, the off-peak time profit per unit values of low cost generators are higher than the respective off-peak time profit per unit values of high cost generators, which is consistent with the daily average and the peak time analyses, that is;

$$\text{i.e.}, \mu_{31,1} > \mu_{31,3} \text{ and } \mu_{32,9} > \mu_{32,7}$$

Figure 4.20 and Table 4.21 display the daily average profit per capacity values for each power generator agent in both high and low demand environments.

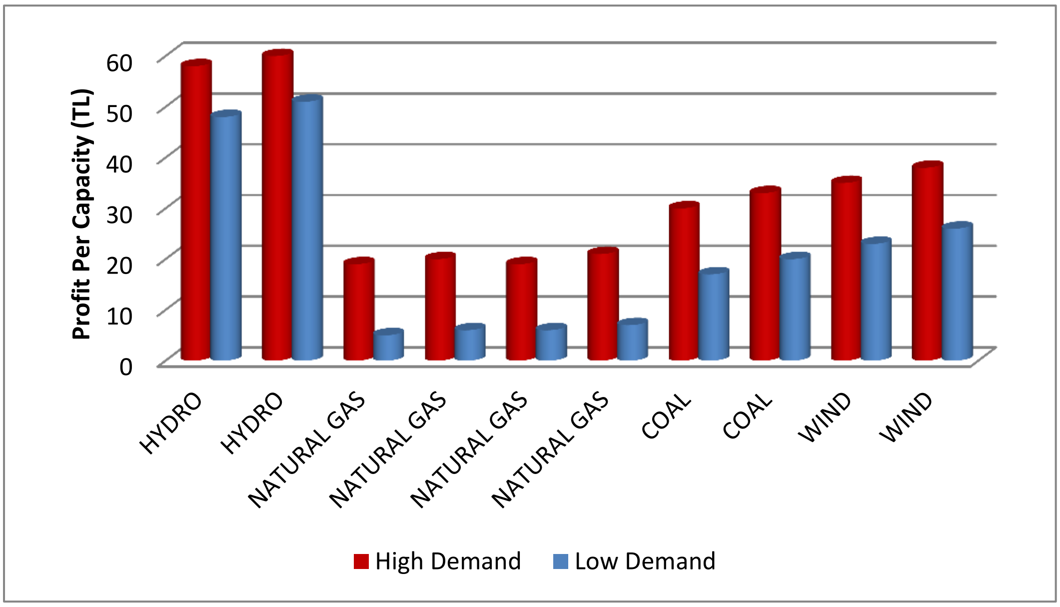


Figure 4.20. Daily average profit per capacity values for each power generator agent (high and low demand scenarios).

Table 4.21. Daily average profit per capacity values for each power generator agent (high and low demand scenarios).

Daily Average Profit per Capacity Values In The High Demand Environment					
ID	Type	Capacity	$\mu_{33,id}$ (TL/MW)	$\sigma_{33,id}$ (TL/MW)	$\sigma_{33,id}/\mu_{33,id}$
1	HYDRAULIC	4000	58	3	0.05
2	HYDRAULIC	2000	60	3	0.05
3	NATURAL GAS	4500	19	5	0.26
4	NATURAL GAS	4500	20	5	0.25
5	NATURAL GAS	2500	19	5	0.26
6	NATURAL GAS	2500	21	5	0.24
7	COAL	2500	30	6	0.20
8	COAL	1500	33	5	0.15
9	WIND	1000	35	10	0.29
10	WIND	500	38	12	0.32
Daily Average Profit per Capacity Values In The Low Demand Environment					
ID	Type	Capacity	$\mu_{34,id}$ (TL/MW)	$\sigma_{34,id}$ (TL/MW)	$\sigma_{34,id}/\mu_{34,id}$
1	HYDRAULIC	4000	48	4	0.08
2	HYDRAULIC	2000	51	5	0.10
3	NATURAL GAS	4500	5	2	0.40
4	NATURAL GAS	4500	6	4	0.67
5	NATURAL GAS	2500	6	3	0.50
6	NATURAL GAS	2500	7	3	0.43
7	COAL	2500	17	7	0.41
8	COAL	1500	20	6	0.30
9	WIND	1000	23	8	0.35
10	WIND	500	26	9	0.35

For each generator, the daily average profit per capacity values are higher in the high demand environment than the respective values in the low demand environment ($\mu_{33,id} > \mu_{34,id}$ for $id = 1, \dots, 10$) mainly due to higher capacity utilization and electricity system prices in the high demand environment.

As stated before, for the same type of power generator agents, the daily average profit per unit values are close to each other in both high and low demand environments. However, the daily average profit per capacity values of power generator agents who follow the conservative pricing strategy are higher than the respective values of same type power generator agents who follow the aggressive pricing strategy, that is;

$$i.e.\ \mu_{33,1} < \mu_{33,2}\ and\ \mu_{34,9} < \mu_{34,10}$$

Moreover, variations in the daily average profit per capacity values in the low demand environment are higher than the respective values in the high demand environment (which is consistent with the higher variations in the system prices in the low demand environment).

Another observation is that in both high and low demand environments, the daily average profit per capacity values of low cost generators are higher than the respective values of high cost generators except wind generators, that is;

$$i.e. \mu_{33,1} < \mu_{33,7} < \mu_{33,1}$$

Wind power generator agents have lower daily average profit per capacity values because of their restricted bidding strategies (full capacities can be not-dispatched because of the unavailability of wind power, as depicted in Table 3.4).

Furthermore, as a general observation; in both high and low demand environments, for each power generator agent, the daily average profit per capacity values are lower than the daily average profit per unit values because of the unused capacities left after the balancing markets, that is;

$$\mu_{33,id} < \mu_{27,id} \; for \; id = 1, \ldots, 10$$

Figure 4.21 and Table 4.22 display the peak time profit per capacity values for each power generator agent in both high and low demand environment.

For each generator, the peak time profit per capacity values are higher in the high demand environment than the respective values in the low demand environment ($\mu_{35,\mathrm{id}} > \mu_{36,\mathrm{id}}$ for $\mathrm{id} = 1, \ldots, 10$) mainly due to higher capacity utilization and electricity system prices in the high demand environment, that is;

$$\mu_{3,1} > \mu_{4,1} \text{ and } \mu_{3,2} > \mu_{4,2} \text{ and } \mu_{23,\mathrm{id}} > \mu_{24,\mathrm{id}} \text{ for id} = 1,\ldots,10$$

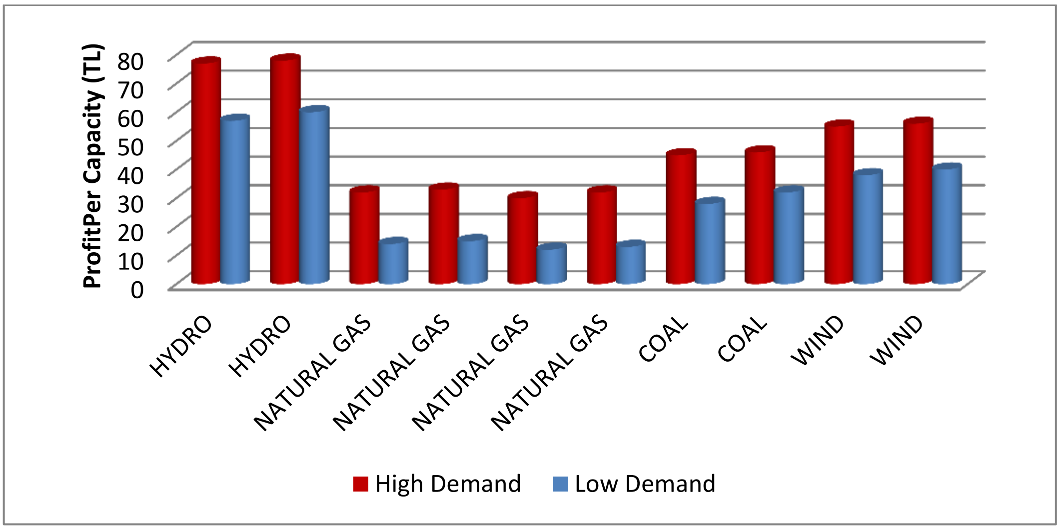


Figure 4.21. Peak time profit per capacity values for each power generator agent (high and low demand scenarios).

Table 4.22. Peak time profit per capacity values for each power generator agent (high and low demand scenarios).

Peak time Profit per Capacity Values In The High Demand Environment					
ID	Type	Capacity	$\mu_{35,id}$ (TL/MW)	$\sigma_{35,id}$ (TL/MW)	$\sigma_{35,id}/\mu_{35,id}$
1	HYDRAULIC	4000	77	2	0,03
2	HYDRAULIC	2000	78	2	0,03
3	NATURAL GAS	4500	32	2	0,06
4	NATURAL GAS	4500	33	2	0,06
5	NATURAL GAS	2500	30	2	0,07
6	NATURAL GAS	2500	32	2	0,06
7	COAL	2500	45	3	0,07
8	COAL	1500	46	2	0,04
9	WIND	1000	55	17	0,31
10	WIND	500	56	19	0,34
Peak time Profit per Capacity Values In The Low Demand Environment					
ID	Type	Capacity	$\mu_{36,id}$ (TL/MW)	$\sigma_{36,id}$ (TL/MW)	$\sigma_{36,id}/\mu_{36,id}$
1	HYDRAULIC	4000	57	8	0,14
2	HYDRAULIC	2000	60	10	0,17
3	NATURAL GAS	4500	14	5	0,36
4	NATURAL GAS	4500	15	6	0,40
5	NATURAL GAS	2500	12	5	0,42
6	NATURAL GAS	2500	13	6	0,46
7	COAL	2500	28	8	0,29
8	COAL	1500	32	9	0,28
9	WIND	1000	38	14	0,37
10	WIND	500	40	17	0,43

In both high and low demand environments, peak time profit per capacity values of power generator agents who follow the conservative pricing strategy in the Real-Time Balancing Market are higher than the respective values of same type of power generator agents who follow the aggressive pricing strategy in the Real-Time Balancing Market, that is;

$$\text{i.e.}\, \mu_{36,1} < \mu_{36,2} \text{ and } \mu_{35,5} < \mu_{35,6}$$

Moreover, in both high and low demand environments; for each power generator agent, the peak time profit per capacity values are higher than the respective daily average profit per capacity values, that is;

$$\mu_{35,id} > \mu_{33,id} \text{ and } \mu_{36,id} > \mu_{34,id} \text{ for id} = 1, \ldots, 10$$

This is mainly due to higher electricity prices and capacity utilizations during the peak time period. Moreover, variations in the peak time profit per capacity values in the low demand environment are higher than the respective variations in the high demand environment for each power generator agent.

Another observation is that in both high and low demand environments, the peak time profit per capacity values of low cost generators are higher than the respective values of high cost generators, that is;

$$\mu_{35,a} > \mu_{35,b} \text{ for a} = 1,2,9,10 \text{ and b} = 3,4,5,6,7,8$$

Furthermore, as a general observation; for each power generator agent, the peak time profit per capacity values are lower than the peak time profit per unit values because of the unused capacities left after the balancing market.

Figure 4.22 and Table 4.23 display the off-peak time profit per capacity values for each power generator agent in both high and low demand environments.

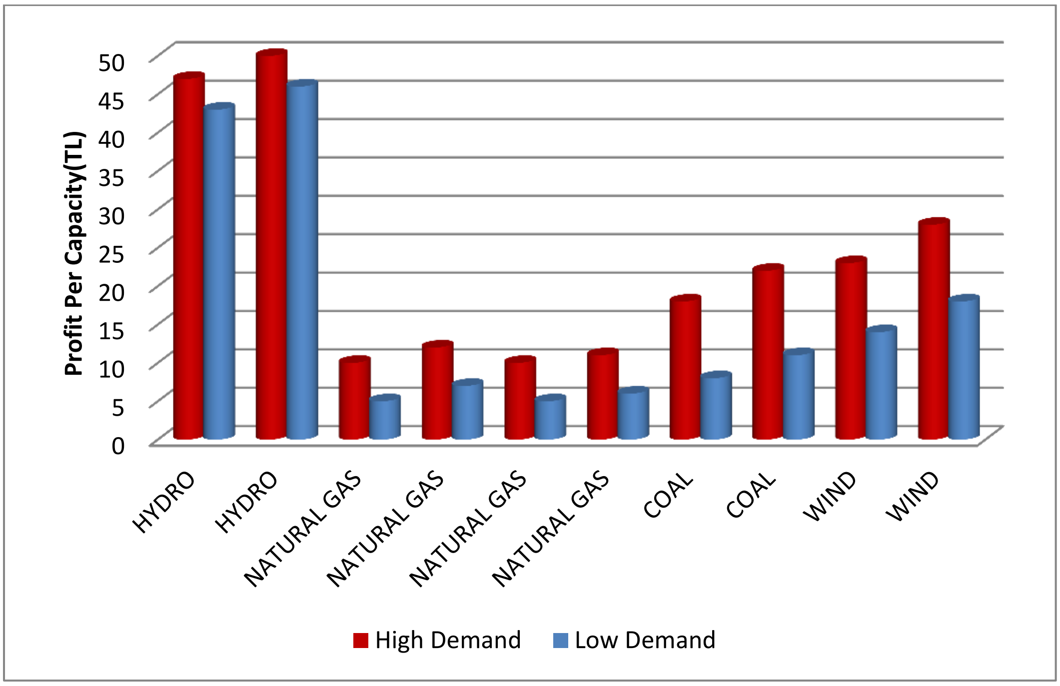


Figure 4.22. Off-peak time profit per capacity values for each power generator agent (high and low demand scenarios).

For each power generator agent, the off-peak time profit per capacity values are higher in the high demand environment than the respective values in the low demand environment ($\mu_{37,id} > \mu_{38,id}$ $for\ id = 1, \dots, 10$) mainly due to higher off-peak time system prices in the high demand environment.

Additionally, the off-peak time profit per capacity values of generators who follow the conservative pricing strategy in the Real-Time Balancing market are higher than the respective values of same type of generators who follow the aggressive pricing strategy (which is consistent with the cases in the daily average and the peak time periods), that is;

$$\text{i.e. } \mu_{33,1} < \mu_{33,2} \text{ and } \mu_{34,9} < \mu_{34,10} \text{ and } \mu_{36,1} < \mu_{36,2} \text{ and } \mu_{35,5} < \mu_{35,6}$$

Moreover, in both high demand and low demand environment, for each power generator agent, the off-peak time profit per capacity values are lower than the respective profit per capacity values of the peak time and of the daily average periods. This is mainly due to the fact that the off-peak time system prices and capacity utilizations are lower than the respective values in other time periods, that is;

$\mu_{5,1} < \mu_{1,1}$ and $\mu_{5,2} < \mu_{1,2}$ and $\mu_{25,id} < \mu_{21,id}$ for $id = 1, \ldots, 10$

Table 4.23. Off-peak time profit per capacity values for each power generator agent (high and low demand scenarios).

Off-peak Time Profit per Capacity Values In The High Demand Environment					
ID	Type	Capacity	$\mu_{37,id}$ (TL/MW)	$\sigma_{37,id}$ (TL/MW)	$\sigma_{37,id}/\mu_{37,id}$
1	HYDRAULIC	4000	47	2	0,04
2	HYDRAULIC	2000	50	3	0,06
3	NATURAL GAS	4500	10	3	0,30
4	NATURAL GAS	4500	12	4	0,33
5	NATURAL GAS	2500	10	3	0,30
6	NATURAL GAS	2500	11	4	0,36
7	COAL	2500	18	6	0,33
8	COAL	1500	22	5	0,23
9	WIND	1000	23	9	0,39
10	WIND	500	28	10	0,36
Off-peak Time Profit per Capacity Values In The Low Demand Environment					
ID	Type	Capacity	$\mu_{38,id}$ (TL/MW)	$\sigma_{38,id}$ (TL/MW)	$\sigma_{38,id}/\mu_{38,id}$
1	HYDRAULIC	4000	43	10	0,23
2	HYDRAULIC	2000	46	4	0,09
3	NATURAL GAS	4500	5	3	0,60
4	NATURAL GAS	4500	7	3	0,42
5	NATURAL GAS	2500	5	3	0,60
6	NATURAL GAS	2500	6	3	0,50
7	COAL	2500	8	4	0,50
8	COAL	1500	11	5	0,45
9	WIND	1000	14	5	0,36
10	WIND	500	18	6	0,33

In addition to this, for each generator, variations in the off-peak time profit per capacity values in the low demand environment are higher than the respective variations in the high demand environment.

4.2. Day-Ahead Market Pricing Strategy Related Scenarios

These scenarios feature different pricing strategies in the Day-Ahead Market. Two types of pricing strategies, named as “Aggressive” and “Conservative” are implemented. The average, standard deviation and standard deviation per average values are computed for, (i) electricity system prices (as TL/MWh) of both Day Ahead and Real-Time Balancing markets and for, (ii) *profits*, (iii) *capacity utilizations*, (iv) *market shares*, (v) *profit per unit* and (vi) *profit per capacity* indicators of the selected power generator agents in the system.

For the investigation and comparison of scenarios, two different types of power generator agents (according to load profiles in the system), are selected and named as '*Pricemaker'* and '*Non-pricemaker'*, which are respectively, 'Generator 3' (with high marginal cost and high capacity) and 'Generator 1' (with high capacity but low marginal cost). The simulation runs associated with these scenarios, consist of 3600 independent days, which cover 10-year periods.

Figure 4.23 indicates that in the high demand environment, when the aggressive pricing strategy is followed by the pricemaker generator, the daily average of the DAP and of the SMP prices are higher than the respective electricity prices in the reference high demand scenario.

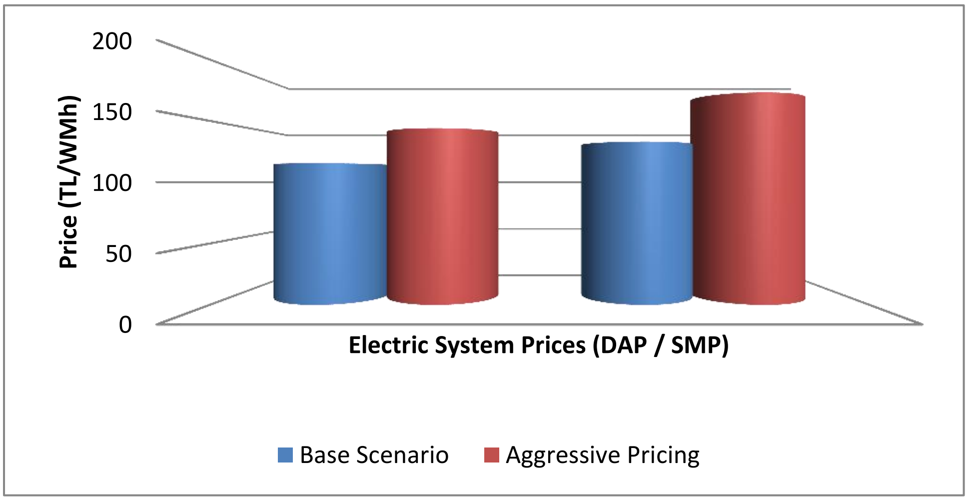


Figure 4.23. Daily average electricity system prices in the aggressive pricing strategy by the pricemaker generator under high demand environment.

Table 4.24 displays the daily average of the DAP and of the SMP prices when the aggressive pricing strategy is followed by the pricemaker generator in the high demand environment.

Table 4.24. Daily average electricity system prices in the aggressive pricing strategy by the pricemaker generator under high demand environment.

Daily Average System Prices In The High Demand Environment (Reference Scenario)			
System Price	$\mu_{1,a}$ (TL/MWh)	$\sigma_{1,a}$ (TL/MWh)	$\sigma_{1,a}/\mu_{1,a}$
DAP (a=1)	115.46	6.83	0.05
SMP(a=2)	133.06	13.14	0.09
$(\mu_{1,2} - \mu_{1,1})/\mu_{1,1}$ (%)	+0.15		
Daily Average System Prices In The High Demand Environment (Aggressive Pricing Strategy)			
System Price	$\mu_{38,b}$ (TL/MWh)	$\sigma_{38,b}$ (TL/MWh)	$\sigma_{38,b}/\mu_{38,b}$
DAP (b=1)	144.03	14.26	0.09
SMP (b=2)	173.17	23.65	0.13
$(\mu_{38,2} - \mu_{38,1})/\mu_{38,1}$ (%)	+0.20		

According to Table 4.24, the daily average of the DAP price is 30 TL (around 26 %) higher than the DAP price in the reference high demand scenario, which is closely related with the increased bid prices of the pricemaker generator in the aggressive pricing strategy. Furthermore, the difference between the daily average of the Day-Ahead (DAP) and of the Real-Time Balancing (SMP) markets' prices are higher when the aggressive pricing strategy is followed by the pricemaker generator compared to the difference in the reference high demand scenario, that is;

$$\mu_{38,2} - \mu_{38,1} > \mu_{1,2} - \mu_{1,1}$$

Moreover, variations in the daily average of the DAP and SMP prices are higher with the aggressive pricing strategy being followed by the pricemaker generator compared to the respective variations in the reference high demand scenario, that is;

$$\sigma_{38,1} > \sigma_{1,1} \text{ and } \sigma_{38,2} > \sigma_{1,2}$$

This is due to the fact that the pricemaker generator retains an incentive to raise its offer prices because system consistently needs its generated electricity especially during the dry season (impacts of the decreased capacity of renewable generators on electricity price variation are explained in Section 4.1).

Table 4.25 displays the minimum and the maximum values of the daily average of the DAP and SMP prices in the high demand environment when the aggressive pricing strategy is followed by the pricemaker generator.

Table 4.25. Daily average electricity system prices' range in the aggressive pricing strategy by the pricemaker generator under high demand environment.

Daily Average Electricity System Prices In High Demand Environment (Reference Scenario)			
System Price	$\mathrm{Min}_{1,a}$(TL)	$\mathrm{Max}_{1,a}$ (TL)	$\mathrm{Max}_{1,a}$ - $\mathrm{Min}_{1,a}$((TL)
DAP **(a=1)**	102	131	+29
SMP **(a=2)**	110	165	+55
Daily Average Electricity Prices In High Demand Environment (Aggressive Pricing Strategy)			
System Price	$\mathrm{Min}_{8,b}$(TL)	$\mathrm{Max}_{8,b}$ (TL)	$\mathrm{Max}_{8,b}$ - $\mathrm{Min}_{8,b}$((TL)
DAP **(b=1)**	129	172	+42
SMP**(b=2)**	145	218	+73

Table 4.25 shows that the difference between the minimum and the maximum values of the daily average of the DAP and SMP prices increases when the pricemaker generator follows the aggressive pricing strategy, that is;

$$\mathrm{Max}_{8,a} - \mathrm{Min}_{8,a} > \mathrm{Max}_{1,a} - \mathrm{Min}_{1,a} \text{ for a} = 1,2$$

This is consistent with the analysis of the increased variations in these two electricity system prices that is;

$$\sigma_{38,1} > \sigma_{1,1} \text{ and } \sigma_{38,2} > \sigma_{1,2}$$

Figure 4.24 and Table 4.26 display that in the high demand environment, when the aggressive pricing strategy is followed by the non-pricemaker generator, the daily average of the DAP and SMP prices are higher than the respective prices in the reference scenario ($\mu_{39,1} > \mu_{1,1}$ and $\mu_{39,2} > \mu_{1,2}$) but are lower than the respective prices when the aggressive pricing strategy is followed by the pricemaker generator in the high demand environment ($\mu_{38,1} > \mu_{39,1}$ and $\mu_{38,2} > \mu_{39,2}$).

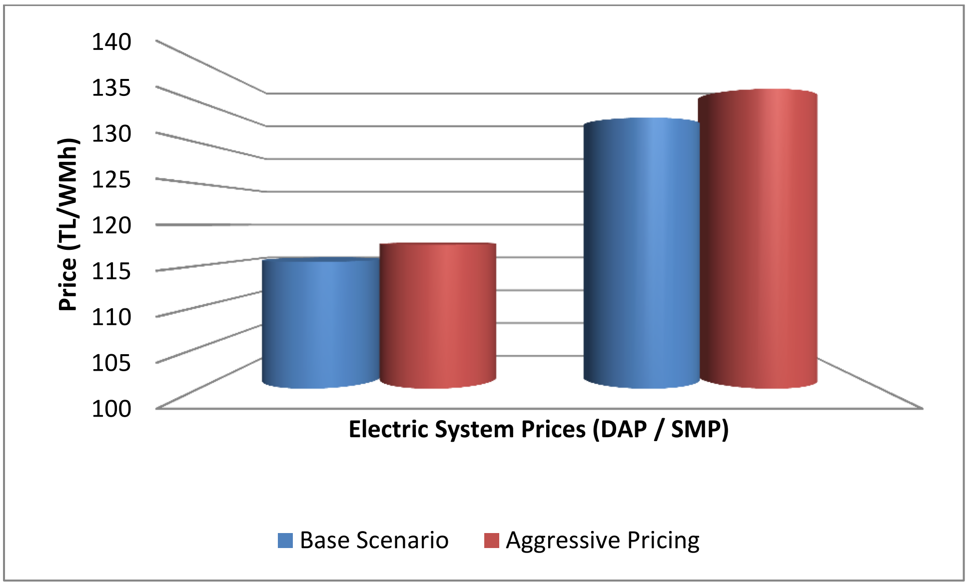


Figure 4.24. Daily average electricity system prices in the aggressive pricing strategy by the non-pricemaker generator under high demand environment.

Table 4.26. Daily average electricity system prices in the aggressive pricing strategy by the non-pricemaker generator under high demand environment.

Daily Average Electricity Prices In High Demand Environment (Reference Scenario)			
System Price	$\mu_{1,a}$ (TL/MW)	$\sigma_{1,a}$ (TL/MW)	$\sigma_{1,a}/\mu_{1,a}$
DAP **(a=1)**	115.46	6.83	0.05
SMP **(a=2)**	133.06	13.13	0.09
$(\mu_{1,2} - \mu_{1,1})/\mu_{1,1}$ (%)	+0.15		
Daily Average Electricity Prices In High Demand Environment (Aggressive Pricing Strategy Scenario)			
System Price	$\mu_{39,b}$ (TL/MW)	$\sigma_{39,b}$(TL/MW)	$\sigma_{39,b}/\mu_{39,b}$
DAP **(b=1)**	117.53	6.97	0.06
SMP **(b=2)**	136.57	14.49	0.11
$(\mu_{39,2} - \mu_{39,1})/\mu_{39,1}$ (%)	+0.16		

In the high demand environment, the daily average of the DAP price is 30 TL (around 26 %) higher than the DAP price in the reference high demand scenario when the aggressive pricing strategy is followed by the pricemaker generator, whereas the daily average of the DAP price is 2 TL (around 2 %) higher than the respective price in the reference high demand scenario when the same strategy is followed by the non-pricemaker generator. The close electricity prices in the two scenarios (the reference scenario and the non-pricemaker case) is due to the fact that, the non-pricemaker (which is “Generator 1” and is a hydraulic generator) loses its capacity (and its power to rule the market price) during the dry season. So, in the high demand environment; the aggressive pricing strategy followed by the pricemaker generator has a higher impact on the electricity system prices than the same strategy followed by the non-pricemaker generator.

Another observation is that in the high demand environment, the aggressive pricing strategy followed by both the pricemaker and the non-pricemaker generators, increases variations in the daily averages of the DAP and SMP prices compared to the respective variations in the reference high demand scenario, that is;

$$\sigma_{39,a} > \sigma_{31,a} \; and \; \sigma_{38,a} > \sigma_{31,a} \; for \; a = 1,2$$

But variations in the daily average of the DAP and SMP prices when the aggressive pricing strategy being followed by the non-pricemaker generator are lower than variations in the respective prices when the aggressive pricing strategy being followed by the pricemaker generator, that is;

$$\sigma_{39,b} < \sigma_{38,b} \text{ and } \sigma_{39,b}/\mu_{39,b} < \sigma_{38,b}/\mu_{38,b} \text{ for b} = 1,2$$

Figure 4.25 and Table 4.27 display the daily average profits for each power generator agent in high demand environment when the aggressive pricing strategy is followed by the pricemaker generator.

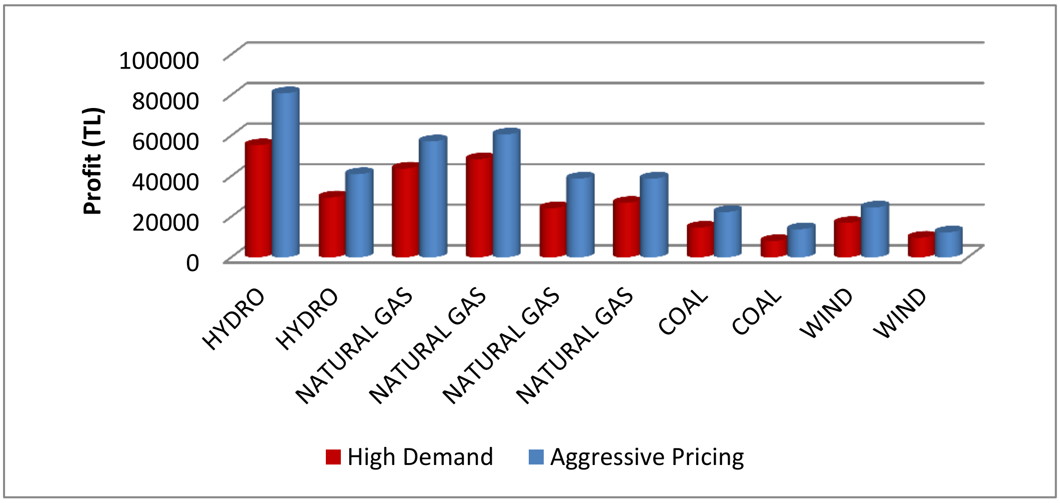


Figure 4.25. Daily average profits for each power generator agent in the aggressive pricing strategy by the pricemaker generator under high demand environment.

As can be seen in Table 4.27, the daily average profits for each power generator agent in the high demand environment when the aggressive pricing strategy being followed by the pricemaker generator are higher than the respective profits in the reference high demand scenario, that is;

$$\mu_{40,\mathrm{id}} > \mu_{1,\mathrm{id}} \text{ for id} = 1, \ldots, 10$$

Table 4.27. Daily average profits for each power generator agent in the aggressive pricing strategy by the pricemaker generator under high demand environment.

Daily Average Profits In High Demand Environment (Reference Scenario)					
ID	Type	Capacity	$\mu_{7,id}$ (TL)	$\sigma_{7,id}$ (TL)	$\sigma_{7,id}/\mu_{7,id}$
1	HYDRAULIC	4000	55247	18362	0.33
2	HYDRAULIC	2000	29524	9605	0.32
3	NATURAL GAS	4500	43730	12945	0.29
4	NATURAL GAS	4500	48341	14146	0.29
5	NATURAL GAS	2500	24194	7387	0.30
6	NATURAL GAS	2500	26821	7873	0.29
7	COAL	2500	14622	3130	0.21
8	COAL	1500	8002	2391	0.29
9	WIND	1000	16917	3389	0.20
10	WIND	500	9667	1967	0.20
Daily Average Profits In High Demand Environment (Aggressive Pricing Strategy Scenario)					
ID	Type	Capacity	$\mu_{40,id}$ (TL)	$\sigma_{40,id}$ (TL)	$\sigma_{40,id}/\mu_{40,id}$
1	HYDRAULIC	4000	80827	22964	0.28
2	HYDRAULIC	2000	41005	11714	0.28
3	NATURAL GAS	4500	57144	22804	0.39
4	NATURAL GAS	4500	60552	24637	0.40
5	NATURAL GAS	2500	38797	14753	0.38
6	NATURAL GAS	2500	38822	14764	0.38
7	COAL	2500	22328	5768	0.25
8	COAL	1500	13862	4023	0.29
9	WIND	1000	24556	5438	0.22
10	WIND	500	12305	2773	0.22

Moreover, increased ratio of the profits of each generator is consistent with increased ratio in the DAP and SMP prices. Therefore, the aggressive pricing strategy followed by a single pricemaker generator (with high capacity in the tight capacity-demand system) has a positive impact on the whole system (increases system prices and all generators' profits).

Furthermore, as can be seen in the electricity prices, the aggressive pricing strategy followed by the pricemaker generator increases variations in the profits of each generator, that is;

$$\mu_{40,id} > \mu_{1,id} \text{ for id} = 1, \ldots, 10$$

This is mainly due to the positive and strong correlation between electricity prices and profits.

Figure 4.26 and Table 4.28 display the daily average profits for each power generator agent in the high demand environment when the aggressive pricing strategy is followed by the non-pricemaker generator.

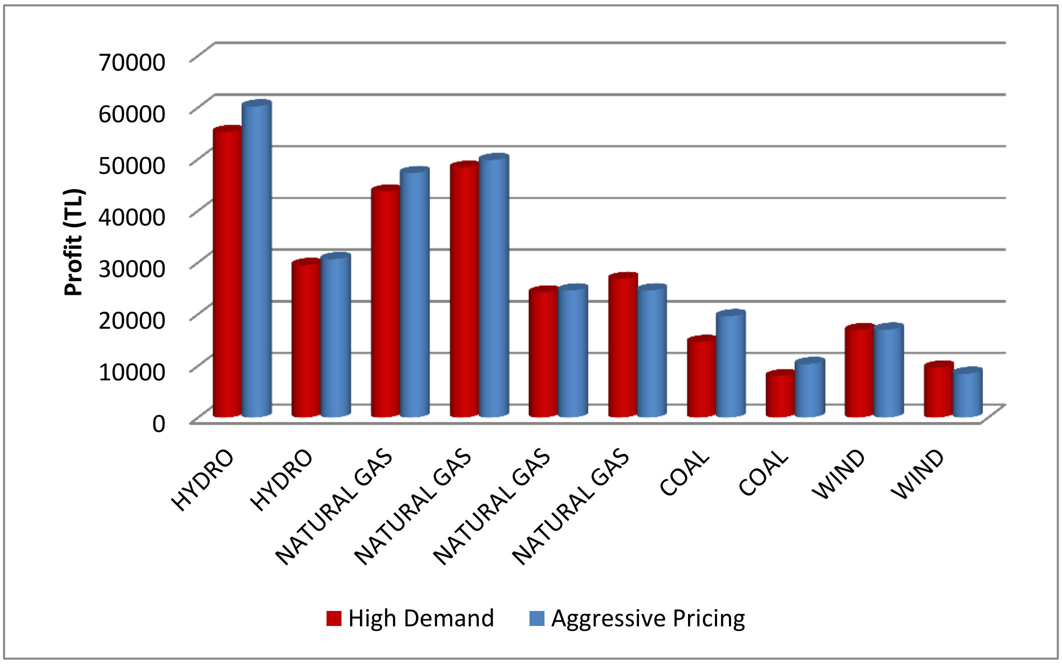


Figure 4.26. Daily average profits for each power generator agent in the aggressive pricing strategy by the non-pricemaker generator under high demand environment.

As can be seen in Table 4.28, the daily average profits for each power generator agent in the high demand environment when the aggressive pricing strategy being followed by the non-pricemaker generator are higher than the daily average profits of each power generator agent in the reference high demand scenario, that is;

$$\mu_{41,id} > \mu_{7,id} \text{ for id} = 1, \ldots, 10$$

But they are lower than the respective profits when the aggressive pricing strategy is followed by the pricemaker generator, that is;

$$\mu_{40,\mathrm{id}} > \mu_{41,\mathrm{id}} \text{ for id} = 1, \dots, 10$$

Table 4.28. Daily average profits for each power generator agent in the aggressive pricing strategy by the non-pricemaker generator under high demand environment.

Daily Average Profits In High Demand Environment (Reference Scenario)					
ID	Type	Capacity	$\mu_{7,id}$ (TL)	$\sigma_{7,id}$ (TL)	$\sigma_{7,id}$ / $\mu_{7,id}$
1	HYDRAULIC	4000	55247	18362	0.33
2	HYDRAULIC	2000	29524	9605	0.32
3	NATURAL GAS	4500	43730	12945	0.29
4	NATURAL GAS	4500	48341	14146	0.29
5	NATURAL GAS	2500	24194	7387	0.30
6	NATURAL GAS	2500	26821	7873	0.29
7	COAL	2500	14622	3130	0.21
8	COAL	1500	8002	2391	0.29
9	WIND	1000	16917	3389	0.20
10	WIND	500	9667	1967	0.20
Daily Average Profits In High Demand Environment (Aggressive Pricing Strategy Scenario)					
ID	Type	Capacity	$\mu_{41,id}$ (TL)	$\sigma_{41,id}$ (TL	$\sigma_{41,id}$ / $\mu_{41,id}$
1	HYDRAULIC	4000	60205	20617	0.34
2	HYDRAULIC	2000	30656	10540	0.34
3	NATURAL GAS	4500	47297	9521	0.20
4	NATURAL GAS	4500	49815	9470	0.20
5	NATURAL GAS	2500	24587	5233	0.21
6	NATURAL GAS	2500	24596	5229	0.21
7	COAL	2500	19612	5014	0.25
8	COAL	1500	10356	2656	0.25
9	WIND	1000	17008	2650	0.15
10	WIND	500	8473	1332	0.15

Moreover, increased ratio of the profits of each generator is consistent with increased ratio in the electric system prices (but not consistent with the increased ratio of the non-pricemaker's bid prices) when the aggressive pricing strategy is followed by the non-pricemaker generator.

Variations in the profits of each power generator agent when the aggressive pricing strategy is followed by the non-pricemaker generator are lower than the respective variations when the aggressive pricing strategy followed by the pricemaker generator, that is;

$$\sigma_{41,id} < \sigma_{40,id} \text{ for id} = 1, \ldots, 10$$

Figure 4.27 and Table 4.29 display that in the low demand environment, when the aggressive pricing strategy is followed by the pricemaker generator, the daily averages of the DAP and SMP prices are higher than the respective prices in the low demand environment.

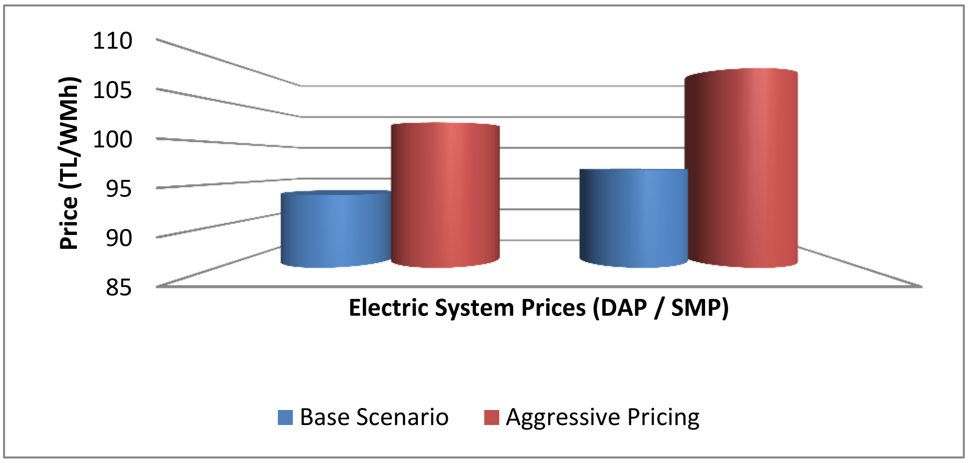


Figure 4.27. Daily average electricity system prices in the aggressive strategy by the pricemaker generator under low demand environment.

According to Table 4.29, the daily average of the DAP price is 9 TL (about 10 %) higher than the DAP price in the reference low demand scenario ($\mu_{42,1} > \mu_{2,1}$). So, the pricemaker generator, while following the aggressive pricing strategy cannot increase electricity system prices in the low demand environment as expected, because the system without tight capacity-demand relation (as is the case in the low demand environment) accepts only the lower priced offers. Therefore, the difference between daily average of the DAP price is higher when the aggressive pricing strategy being followed by pricemaker power generator agent in the high demand environment than in the low demand environment, that is;

$$\mu_{38,1} - \mu_{2,1} > \mu_{42,1} - \mu_{2,1}$$

Table 4.29. Daily average electricity system prices in the aggressive strategy by the pricemaker generator under low demand environment.

Daily Average Electricity Prices In Low Demand Environment (Reference Scenario)			
System Price	$\mu_{2,a}$ (TL/MW)	$\sigma_{2,a}$ (TL/MW)	$\sigma_{2,a}$ / $\mu_{2,a}$
DAP **(a=1)**	93.67	8.89	0.09
SMP **(a=2)**	96.71	11.80	0.12
$(\mu_{2,2} - \mu_{2,1}) / \mu_{2,1}$ (%)	+0.03		
Daily Average Electricity Prices In Low Demand Environment (Aggressive Pricing Strategy Scenario)			
System Price	$\mu_{42,b}$ (TL/MW)	$\sigma_{42,b}$ (TL/MW)	$\sigma_{42,b}$ / $\mu_{42,b}$
DAP **(b=1)**	102.37	4.89	0.04
SMP **(b=2)**	108.85	10.15	0.10
$(\mu_{42,2} - \mu_{42,1}) / \mu_{42,1}$ (%)	+0.06		

Furthermore, the level of variations of the daily average of the DAP and SMP prices are lower when the aggressive pricing strategy is followed by the pricemaker generator than the level of variations of the respective prices in the reference low demand scenario, that is;

$$\sigma_{2,a} > \sigma_{42,a} \text{ and } \sigma_{2,a} / \mu_{2,a} > \sigma_{42,a} / \mu_{42,a} \text{ for a} = 1,2$$

Table 4.30 displays the minimum and the maximum values of the daily average of the DAP and SMP prices in the low demand environment when the aggressive pricing strategy is followed by the pricemaker generator.

Table 4.30 displays that the difference between the minimum and the maximum values of the daily average of the DAP and SMP prices when the pricemaker generator follows the aggressive pricing strategy in the low demand environment is lower than the case in the reference low demand scenario, that is;

$$\text{Max}_{2,a} \text{ - Min}_{2,a} > \text{Max}_{9,a} \text{ - Min}_{9,a} \text{ for a} = 1,2$$

As can be seen in Table 4.30, in the low demand environment, the aggressive pricing strategy being followed by the pricemaker generator increases the minimum of the electricity prices but maximums are not affected

Table 4.30. Daily average system prices' range in the aggressive strategy by the pricemaker generator under low demand environment.

Daily Average System Prices In Low Demand Environment (Reference Scenario)			
System Price	$Min_{2,a}$(TL)	$Max_{2,a}$ (TL)	$Max_{2,a}$ - $Min_{2,a}$((TL)
DAP	70	113	+43
SMP	72	130	+58
Daily Average System Prices In Low Demand Environment (Aggressive Pricing Strategy)			
System Price	$Min_{9,b}$(TL)	$Max_{9,b}$ (TL)	$Max_{9,b}$ - $Min_{9,b}$((TL)
DAP	96	111	+15
SMP	98	128	+30

. Hence, the aggressive pricing strategy followed by the pricemaker (with high marginal cost) leads to increased number of unacceptable second or third level offers (which determines the maximums of electricity prices).

Figure 4.28 and Table 4.31 display that in the low demand environment, when the aggressive pricing strategy is followed by the non-pricemaker generator, the daily average of the DAP and SMP prices are higher than the respective prices in the reference low demand scenario.

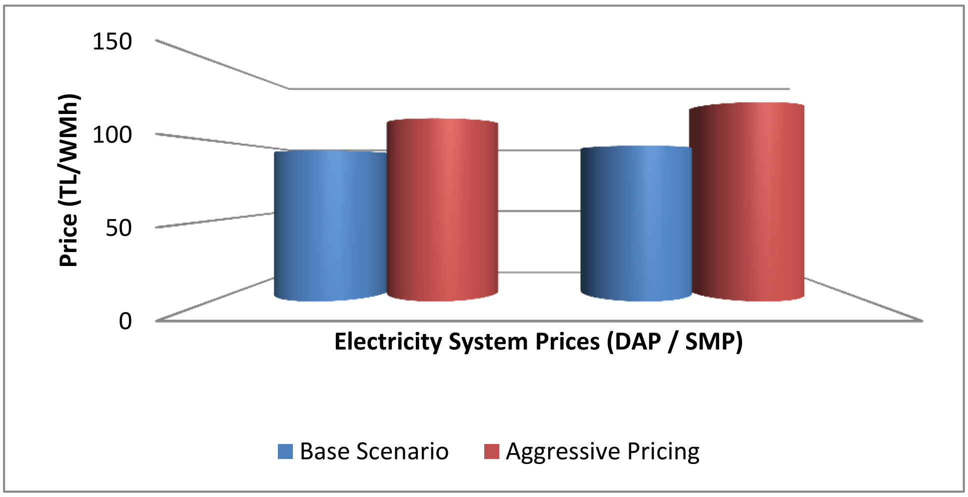


Figure 4.28. Daily average electricity system prices in the aggressive strategy by the non-pricemaker generator under low demand environment.

In the low demand environment, as analyzed before, the daily average of the DAP price is 9 TL (and close to 10 %) higher than the DAP price in the reference low demand scenario when the aggressive pricing strategy is followed by the pricemaker power generator agent, whereas the daily average of the DAP price is 20 TL (and close to 22%) higher than the DAP price in the reference low demand scenario when the same strategy is followed by the non-pricemaker power generator agent. Hence, in the low demand environment, the aggressive pricing strategy being followed by the non-pricemaker generator has more impact on the electricity system prices than the same strategy followed by the pricemaker generator. The main reason behind this analysis is that, the non-pricemaker generator (Generator 1), is a low cost power generator agent. In other words, in the low demand environment, low cost power generator agents' pricing strategy has more impact on electricity system prices than high cost power generator agents' strategy. As pointed out in the above paragraph, the pricemaker generator (with high marginal cost) cannot determine electricity prices in the system without tight capacity constraints.

Table 4.31. Daily average electricity system prices in the aggressive strategy by the non-pricemaker generator under low demand environment.

Daily Average Electricity Prices In Low Demand Environment (Reference Scenario)			
System Price	$\mu_{2,a}$ (TL/MW)	$\sigma_{2,a}$ (TL/MW)	$\sigma_{2,a}$ / $\mu_{2,a}$
DAP	93.67	8.89	0.09
SMP	96.71	11.80	0.12
$(\mu_{2,2} - \mu_{2,1})/\mu_{2,1}$	+0.03		
Daily Average Electricity Prices In Low Demand Environment (Aggressive Pricing Strategy)			
System Price	$\mu_{43,b}$ (TL/MW)	$\sigma_{43,b}$ (TL/MW)	$\sigma_{43,b}$ / $\mu_{43,b}$
DAP	113.73	16.35	0.14
SMP	123.80	25.04	0.20
$(\mu_{43,2} - \mu_{43,1})/\mu_{43,1}$	+0.08		

Another observation is that in the low demand environment, the aggressive pricing strategy being followed by the non-pricemaker generator increases variations in the daily average of the DAP and SMP prices compared to the respective variations in the reference low demand scenario, that is;

$$\sigma_{43,a} > \sigma_{2,a} \text{ and } \sigma_{43,a}/\mu_{43,a} > \sigma_{2,a}/\mu_{2,a} \text{ for } a = 1,2$$

Furthermore, variations in the daily average of the DAP and SMP prices are higher when the aggressive pricing strategy is followed the by the non-pricemaker generator than the respective variations when the aggressive pricing strategy is followed by the pricemaker generator in the low demand environment, that is;

$$\sigma_{43,b} > \sigma_{42,b} \text{ and } \sigma_{43,b} / \mu_{43,b} > \sigma_{42,b} / \mu_{42,b} \text{ for } b = 1,2$$

Table 4.32 displays the minimum and the maximum values of the daily averages of the DAP and SMP prices in the low demand environment when the aggressive pricing strategy is followed by the non-pricemaker generator.

Table 4.32. Daily average system prices' range in the aggressive strategy by the non-pricemaker generator under low demand environment.

Daily Average System Prices In Low Demand Environment (Reference Scenario)			
System Price	$Min_{2,a}$(TL)	$Max_{2,a}$ (TL)	$Max_{2,a}$ - $Min_{2,a}$ (TL)
DAP	70	113	29
SMP	72	130	55
Daily Average System Prices In Low Demand Environment (Aggressive Pricing Strategy)			
System Price	$Min_{10,b}$(TL)	$Max_{10,b}$ (TL)	$Max_{10,b}$ - $Min_{10,b}$ (TL)
DAP	96	139	43
SMP	98	167	69

Table 4.32 displays that the difference between the minimum and the maximum values of the daily averages of DAP and SMP prices when the non-pricemaker generator follows the aggressive pricing strategy in the low demand environment is higher than the case in the reference low demand scenario, that is;

$$Max_{2,a} - Min_{2,a} < Max_{10,a} - Min_{10,a} \text{ for } a = 1,2$$

This is consistent with the analysis of the increased variations in the electricity system prices ($\sigma_{43,b} > \sigma_{42,b}\ for\ b = 1,2$).

Table 4.33 displays the daily average profits for each power generator agent in the low demand environment when the aggressive pricing strategy is followed by the pricemaker generator.

As can be seen in Table 4.33, in the low demand environment; the daily average profits for each power generator agent (except the pricemaker generator) when the aggressive pricing strategy is followed by the pricemaker generator are higher than their respective profits in the reference low demand scenario, that is;

$$\mu_{45,id} > \mu_{3,id} \; for \; id \neq 3$$

Table 4.33. Daily average profits for each power generator agent in the aggressive strategy by the pricemaker generator under low demand environment.

Daily Average Profits In Low Demand Environment (Reference Scenario)					
ID	Type	Capacity	$\mu_{8,id}$ (TL)	$\sigma_{8,id}$ (TL)	$\sigma_{8,id} / \mu_{8,id}$
1	HYDRAULIC	4000	40858	12632	0.30
2	HYDRAULIC	2000	22204	6981	0.31
3	NATURAL GAS	4500	20802	12686	0.60
4	NATURAL GAS	4500	23107	13722	0.59
5	NATURAL GAS	2500	11505	6926	0.60
6	NATURAL GAS	2500	13078	7444	0.56
7	COAL	2500	10894	4524	0.41
8	COAL	1500	8210	3191	0.38
9	WIND	1000	13571	3021	0.22
10	WIND	500	8080	2129	0.26
Daily Average Profits In Low Demand Environment (Aggressive Pricing Strategy Scenario)					
ID	Type	Capacity	$\mu_{45,id}$ (TL)	$\sigma_{45,id}$ (TL)	$\sigma_{45,id} / \mu_{45,id}$
1	HYDRAULIC	4000	46078	14153	0.30
2	HYDRAULIC	2000	26063	8846	0.33
3	NATURAL GAS	4500	15167	5962	0.39
4	NATURAL GAS	4500	26551	7883	0.29
5	NATURAL GAS	2500	13990	3811	0.27
6	NATURAL GAS	2500	14048	4406	0.31
7	COAL	2500	23431	9274	0.39
8	COAL	1500	16586	5902	0.35
9	WIND	1000	14624	2496	0.17
10	WIND	500	9586	1397	0.14

This is mainly due to the increased unsold capacities of the pricemaker generator who follows the aggressive pricing strategy in the low demand environment (as mentioned before, second or third level offers of the pricemaker generator are not accepted by the system operator in the low demand environment).

Furthermore, as can be seen in the electricity system prices, the aggressive pricing strategy followed by the pricemaker generator decreases variations in the profits of each power generator agent ($\sigma_{45,\mathrm{id}} > \sigma_{8,\mathrm{id}}$ for id $= 1, \ldots, 10$). This is mainly due to the positive and strong correlation between electricity prices and profits.

Table 4.34 displays the daily average profits for each power generator agent in the low demand environment when the aggressive pricing strategy is followed by the non-pricemaker generator.

Table 4.34. Daily average profits for each power generator agent in the aggressive strategy by the non-pricemaker generator under low demand environment.

Daily Average Profits In The Low Demand Environment (Reference Scenario)					
ID	Type	Capacity	$\mu_{8,id}$ (TL)	$\sigma_{8,id}$ (TL)	$\sigma_{8,id}$ / $\mu_{8,id}$
1	HYDRAULIC	4000	40858	12632	0.30
2	HYDRAULIC	2000	22204	6981	0.31
3	NATURAL GAS	4500	20802	12686	0.60
4	NATURAL GAS	4500	23107	13722	0.59
5	NATURAL GAS	2500	11505	6926	0.60
6	NATURAL GAS	2500	13078	7444	0.56
7	COAL	2500	10894	4524	0.41
8	COAL	1500	8210	3191	0.38
9	WIND	1000	13571	3021	0.22
10	WIND	500	8080	2129	0.26
Daily Average Profits In The Low Demand Environment (Aggressive Pricing Strategy)					
ID	Type	Capacity	$\mu_{46,id}$ (TL)	$\sigma_{46,id}$ (TL)	$\sigma_{46,id}$ / $\mu_{46,id}$
1	HYDRAULIC	4000	53979	13577	0.25
2	HYDRAULIC	2000	28798	7017	0.24
3	NATURAL GAS	4500	23134	16960	0.73
4	NATURAL GAS	4500	28339	20902	0.73
5	NATURAL GAS	2500	12091	9050	0.74
6	NATURAL GAS	2500	14809	11256	0.76
7	COAL	2500	15531	8239	0.53
8	COAL	1500	11601	4508	0.38
9	WIND	1000	15745	5891	0.37
10	WIND	500	10038	3395	0.33

As can be seen in Table 4.34, the daily average profits for each power generator agent in the low demand environment when the aggressive pricing strategy is followed by the non-pricemaker generator are higher than the daily average profits of each generator in the reference low demand scenario ($\mu_{46,\mathrm{id}} > \mu_{8,\mathrm{id}}$ for id = 1, … ,10) and are higher than the daily average profits of each generator when the aggressive pricing strategy followed by the pricemaker generator ($\mu_{46,id} > \mu_{45,id}$ *for id* = 1, … ,10).

Furthermore, in the low demand environment, variations in the profits of each generator when the aggressive pricing strategy followed by the non-pricemaker generator are higher than variations in the profits of each power generator agent when the aggressive pricing strategy followed by the pricemaker generator because the difference between the minimum and the maximum values of the daily averages of DAP and SMP prices when the non-pricemaker generator follows the aggressive pricing strategy in the low demand environment is higher than the pricemaker case, that is;

$$\sigma_{46,\mathrm{id}} > \sigma_{45,\mathrm{id}} \text{ for id} = 1, \dots, 10$$

This is consistent with the analysis of the electricity system prices, that is;

$$\sigma_{43,\mathrm{b}} / \mu_{43,\mathrm{b}} > \sigma_{42,\mathrm{b}} / \mu_{42,\mathrm{b}} \text{ for b} = 1,2$$

Figure 4.29 and Table 4.35 display the daily average profits for each power generator agent in the high demand environment when the conservative pricing strategy is followed by the pricemaker generator.

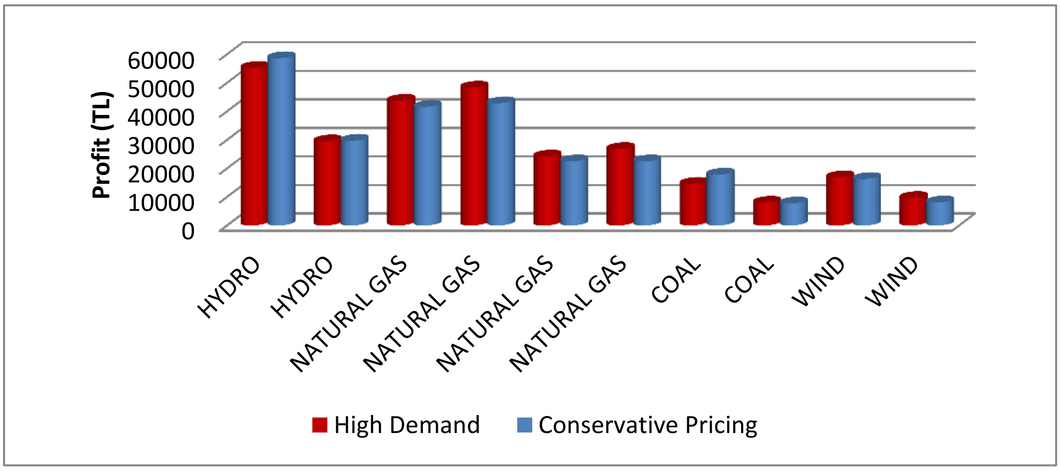


Figure 4.29. Daily average profits for each power generator agent in the aggressive pricing strategy by the pricemaker generator under high demand environment

Table 4.35. Daily average profits for each power generator agent in the aggressive pricing strategy by the pricemaker under high demand environment

Daily Average Profits In The High Demand Environment (Reference Scenario)					
ID	Type	Capacity	$\mu_{7,id}$ (TL)	$\sigma_{7,id}$ (TL)	$\sigma_{7,id}/\mu_{7,id}$
1	HYDRAULIC	4000	55247	18362	0.33
2	HYDRAULIC	2000	29524	9605	0.32
3	NATURAL GAS	4500	43730	12945	0.29
4	NATURAL GAS	4500	48341	14146	0.29
5	NATURAL GAS	2500	24194	7387	0.30
6	NATURAL GAS	2500	26821	7873	0.29
7	COAL	2500	14622	3130	0.21
8	COAL	1500	8002	2391	0.29
9	WIND	1000	16917	3389	0.20
10	WIND	500	9667	1967	0.20
Daily Average Profits In The High Demand Environment (Conservative Pricing Strategy)					
ID	Type	Capacity	$\mu_{47,id}$ (TL)	$\sigma_{47,id}$ (TL)	$\sigma_{47,id}/\mu_{47,id}$
1	HYDRAULIC	4000	58657	20273	0.34
2	HYDRAULIC	2000	29735	10271	0.34
3	NATURAL GAS	4500	41563	8158	0.19
4	NATURAL GAS	4500	42857	9099	0.21
5	NATURAL GAS	2500	22493	4986	0.22
6	NATURAL GAS	2500	22495	4987	0.22
7	COAL	2500	17852	6312	0.35
8	COAL	1500	7770	2945	0.37
9	WIND	1000	16308	2543	0.15
10	WIND	500	8099	1321	0.16

As can be seen in Table 4.35, in the high demand environment, the conservative pricing strategy being followed by a single pricemaker generator has low impacts on the profits of the power generator agents, because in the high demand environment, the system operator still needs to accept the offers with higher prices from other high cost power generator agents in order to meet electricity demand. So, the conservative pricing strategy being followed by a single pricemaker generator does not have high impact on electricity system prices. This analysis is in contradiction with the aggressive pricing strategy case in the high demand environment where a single power generator agent alone can increase electricity system prices.

Furthermore, generally all power generator agents' profits remain same. However, an interesting point is that the conservative pricing strategy decreases variations in the profits especially on the natural gas power generator agents, that is;

$$\sigma_{47,id} < \sigma_{7,id} \text{ and } \sigma_{47,id} / \mu_{47,id} < \sigma_{7,id} / \mu_{7,id} \text{ for id} = 3,4,5,6$$

Figure 4.30 displays that in the high demand environment, the daily averages of the DAP and of the SMP prices are lower than the respective prices when the conservative pricing strategy is followed by two pricemaker power generators instead of one pricemaker generator;

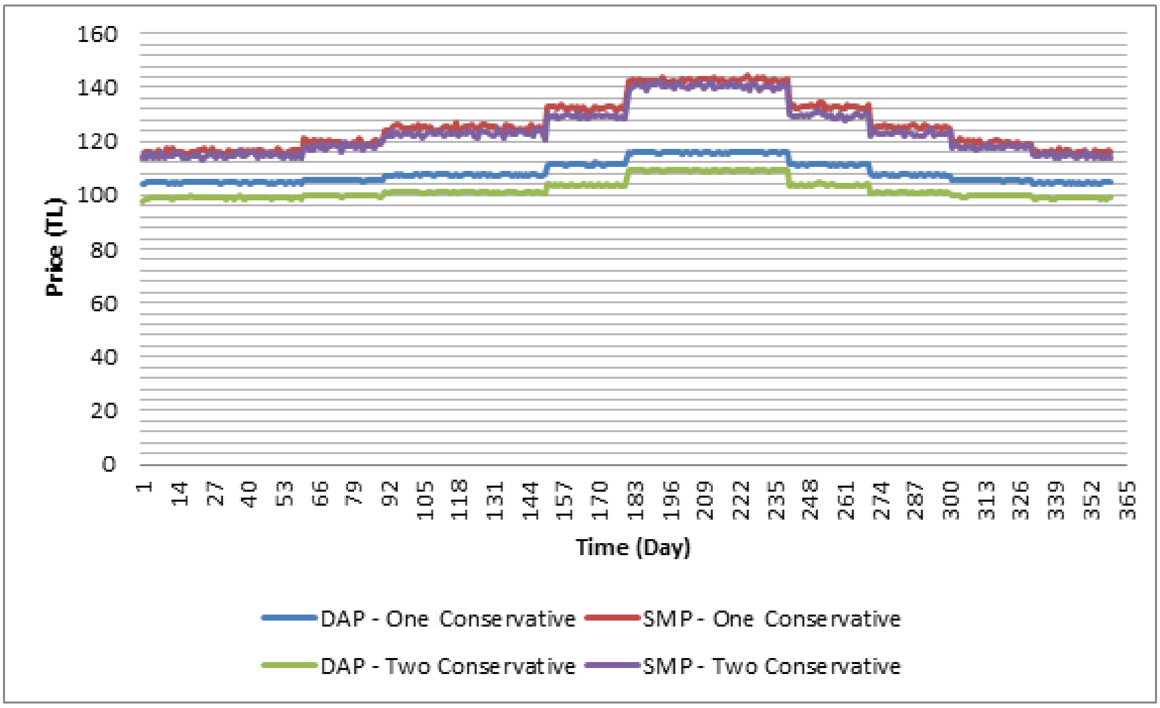


Figure 4.30. Daily average system prices in the conservative pricing strategy by two pricemaker generators under high demand environment.

As can be easily seen in the Table 4.36, in the high demand environment, impacts of the conservative pricing strategy followed by two pricemaker generators are higher compared to the single pricemaker case. This analysis is consistent with the study of Bunn, Bower and Wattendrup (2001), where they analyze the effects of merging of power generator agents and state that the impacts on the electricity prices becomes higher when the number of merged power generators increases.

Table 4.37 displays the daily averages of electricity system prices when the conservative pricing strategy is followed by the two pricemaker generators in the high demand environment;

Table 4.36. Daily averages of electricity system prices (two-pricemaker conservative pricing strategy scenario).

Daily Average Electricity Prices In High Demand Environment (Single Pricemaker Case)			
System Price	$\mu_{49,a}$ (TL)	$\sigma_{49,a}$(TL)	$\sigma_{49,a} / \mu_{49,a}$
DAP **(a=1)**	108.5	3.94	0.03
SMP **(a=2)**	126.16	9.28	0.07
$(\mu_{49,2} - \mu_{49,1}) / \mu_{49,1}$ (%)	+0,16		
Daily Average Electricity Prices In High Demand Environment (Two-Pricemaker Case)			
System Price	$\mu_{50,b}$ (TL)	$\sigma_{50,b}$(TL)	$\sigma_{50,b} / \mu_{50,b}$
DAP (b=1)	102.12	3.29	0.03
SMP (b=2)	124.12	8.89	0.07
$(\mu_{50,2} - \mu_{50,1}) / \mu_{50,1}$ (%)	+0.21		

According to Table 4.37, the daily averages of the DAP and of the SMP prices are lower when the conservative pricing strategy is followed by two pricemaker generators ($\mu_{50,a} < \mu_{49,a}$ for $a = 1,2$). Moreover, since the conservative pricing strategy is followed in the Day-Ahead Market, the decrease in DAP prices are higher than the decrease in SMP prices, that is;

$$\mu_{1,1} - \mu_{50,1} > \mu_{1,1} - \mu_{49,1} \text{ and } \mu_{1,1} - \mu_{50,1} > \mu_{1,2} - \mu_{50,2}$$

Furthermore, an interesting observation is that the level of variation in both electricity system prices is lower when the conservative pricing strategy is followed by two pricemaker generator instead of one pricemaker generator, that is;

$$\sigma_{50,a} < \sigma_{49,a} < \sigma_{1,a} \text{ for } a = 1,2$$

4.3. Market Share Algorithm Related Scenarios

These scenarios feature the implementation of the Market Share Algorithm (which is explained in detail at Section 3.7) in the Day-Ahead Market. After the end of each simulation run, the average, standard deviation and standard deviation per average values are computed for, (i) electricity system price (as TL/MWh) of the Day Ahead Market (DAP) and (ii) *profit*s, (iii) *capacity utilization*, (iv) *market share*, (v) *profit per sale* and (vi) *profit per capacity* indicators of the each power generator agents in the system. For the investigation and comparison of scenarios, two different types of power generator agents in are selected (according to load profiles) and named as the "*Pricemaker"* and the "*Non-pricemaker"*, which are respectively, Generator 3 (with high capacity and high marginal cost) and Generator 1(with high capacity but low marginal cost).

Single demand level named as '*Standard Demand'* is deployed in these scenarios. This demand level is calculated by dividing the realized demand of Turkey in 2009 (190000 GWh) by the total hours in a year (365 day multiply by 24 hour in a day). The simulation runs associated with these scenarios consist of 1800 independent days, which cover 5-year period. "*Alpha"* is selected as '0.1'.

Figure 4.32 and Table 4.38 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, the daily average of the DAP prices are higher than the respective prices in the reference standard demand environment.

Table 4.37. Daily average of electricity system prices in the Market Share Algorithm by the pricemaker generator under standard demand environment.

	DAP (a=1)	**DAP-MSA** (a=2)
$Min_{11,a}$	96	98
$Max_{11,a}$	116	125
$\mu_{51,a}$	106.55	107.75
$\sigma_{51,a}$	4.59	5.55

According to Table 4.37, the Market Share Algorithm followed by the pricemaker generator does not have a high impact on the daily average of the DAP prices ($\mu_{51,2} \cong \mu_{51,2}$).

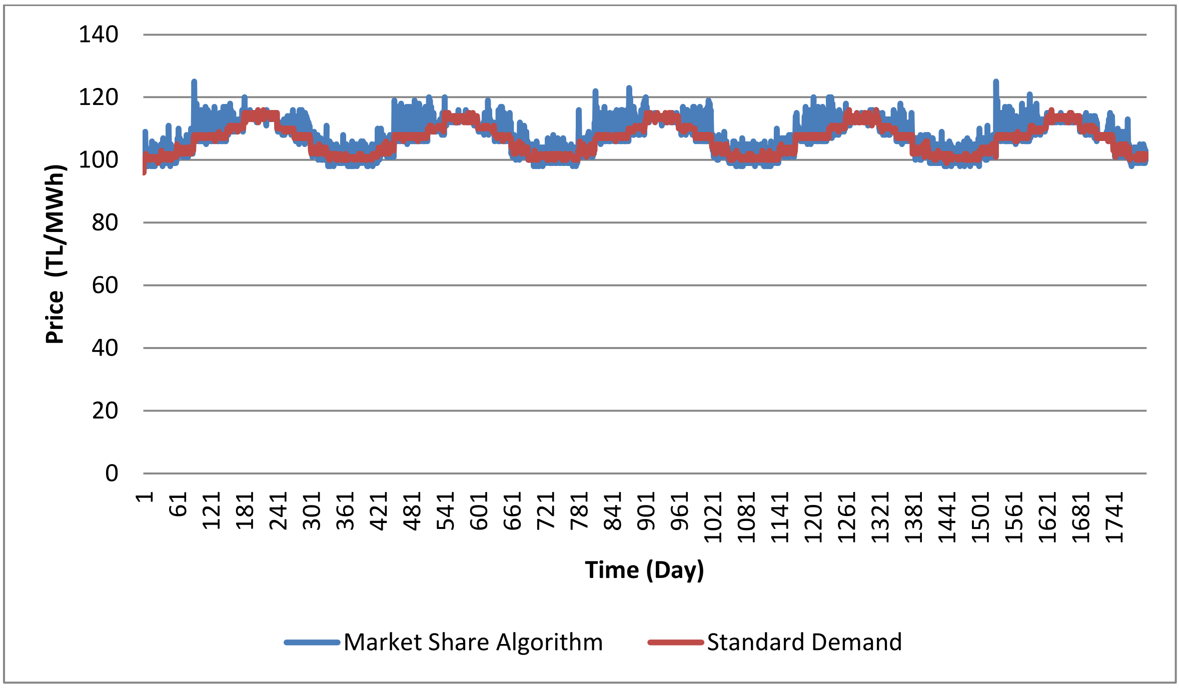


Figure 4.31. Daily average of electricity system prices in the Market Share Algorithm by the pricemaker generator under standard demand environment.

However, as can be seen in both Figure 4.31 and Table 4.38, the Market Share Algorithm followed by the pricemaker generator increases variations in the DAP prices ($\sigma_{51,2} > \sigma_{51,1}$) and increases the maximum value of the DAP prices ($\text{Max}_{11,2} > \text{Max}_{11,1}$).

Figure 4.32 and Table 4.38 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, the peak time DAP prices are higher than the respective prices in the reference standard demand environment.

Table 4.38. Peak time electricity system prices in the Market Share Algorithm by the pricemaker generator under standard demand environment.

	DAP (a=1)	DAP-MSA (a=2)
$Min_{12,a}$	99	96
$Max_{12,a}$	118	166
$\mu_{52,a}$	111.69	115.60
$\sigma_{52,a}$	5.87	10.11

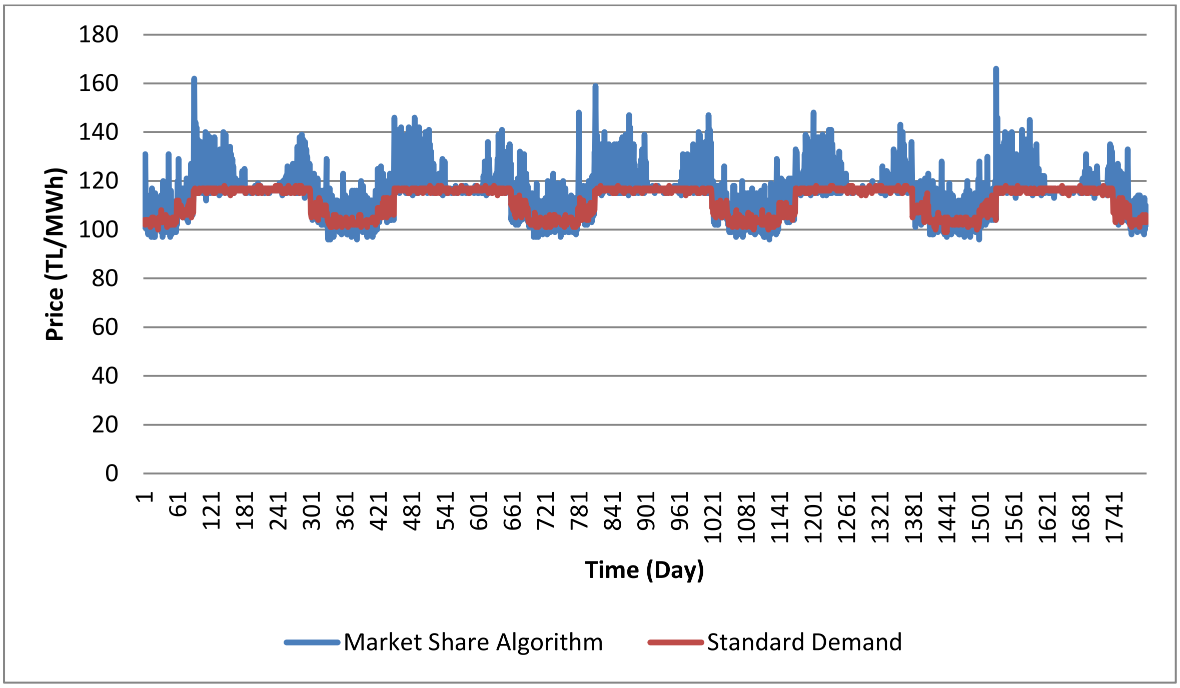


Figure 4.32. Peak time electricity system prices in the Market Share Algorithm by the pricemaker generator under standard demand environment.

According to Table 4.38, the Market Share Algorithm followed by the pricemaker generator has a high impact on the peak time DAP prices ($\mu_{52,2} > \mu_{52,1}$) mainly during the dry season. As can be seen from Figure 4.32, during the dry season when hydraulic power generator agents lose their capacity, the pricemaker generator (which is 'Generator 3') starts to increase its market shares (as stated in Section 4.1) and also increases its offer prices (the system operator is forced to accept its offers to avoid black-outs) so, electricity system prices increase. But as depicted in Figure 4.33, when the pricemaker generator saturated in the market (as displayed with black arrows) and cannot increase its market shares, the Market Share Algorithm does not increase the offer prices of the generator so electricity system prices become stable.

Moreover, as can be seen in both Figure 4.33 and Table 4.38, the Market Share Algorithm being followed by the pricemaker generator significantly increases variations in the peak time DAP prices ($\sigma_{52,2} > \sigma_{52,1}$). Another interesting analysis is that the Market Share Algorithm does not have a significant impact on the minimum value of the electricity prices ($Min_{12,1} \approx Min_{12,2}$), but a high impact on the maximum value of the electricity prices ($Max_{12,2} > Max_{12,1}$).

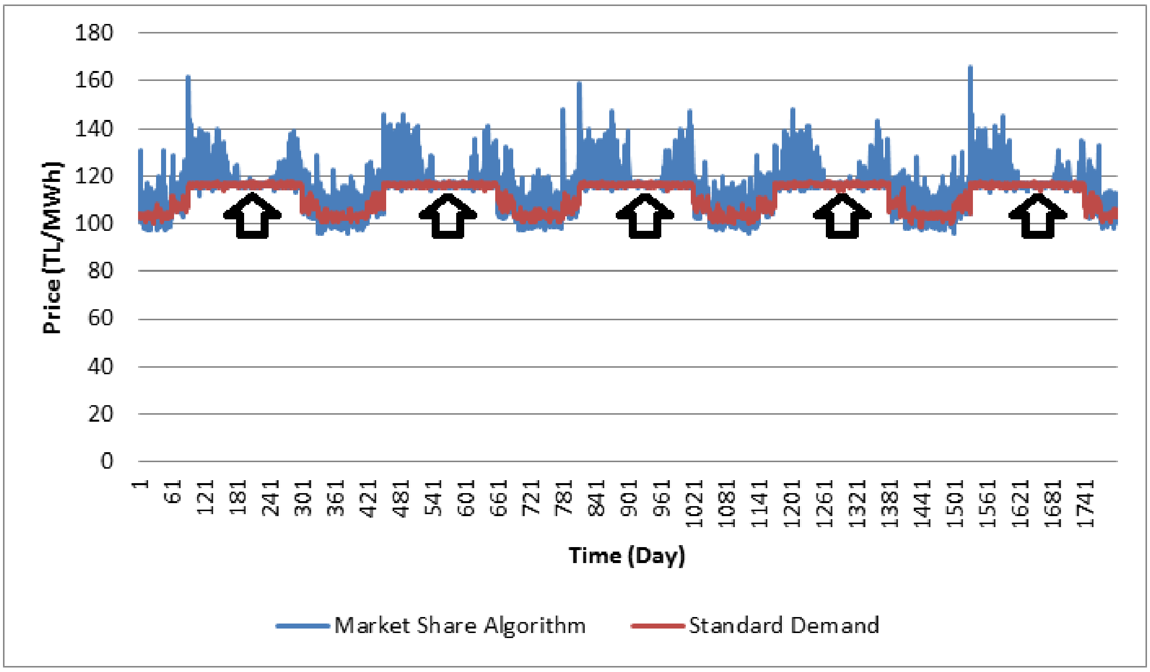


Figure 4.33. Peak time electricity system prices in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Figure 4.34 and Table 4.39 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, the off-peak DAP prices are almost equal to the respective prices in the reference standard demand environment.

Table 4.39. Off-peak time electricity system prices in the Market Share Algorithm by the pricemaker generator under standard demand environment.

	DAP (a=1)	**DAP-MSA** (a=1)
$Min_{13,a}$	90	88
$Max_{13,a}$	101	101
$\mu_{53,a}$	93.44	93.23
$\sigma_{53,a}$	2.65	2.80

According to Table 4.39, the Market Share Algorithm being followed by the pricemaker generator does not have a significant impact on the off-peak time DAP prices and on variations in the DAP prices.

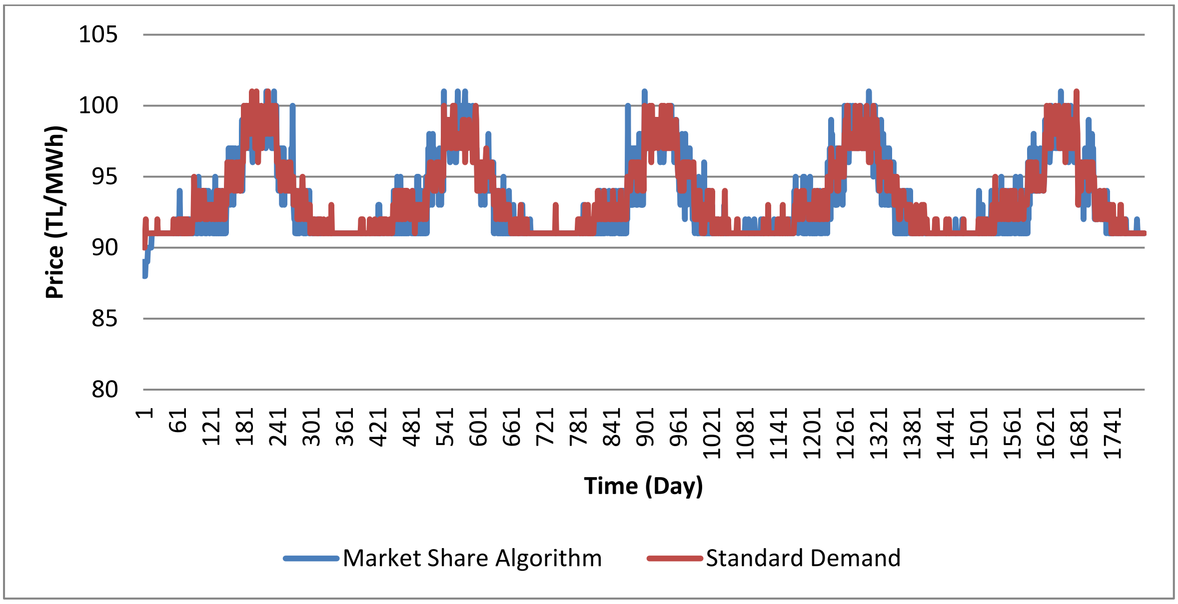


Figure 4.34. Off-peak time system prices in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Figure 4.35 and Table 4.40 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, for each generator, the daily average profits are higher than the respective profits in the reference standard demand environment.

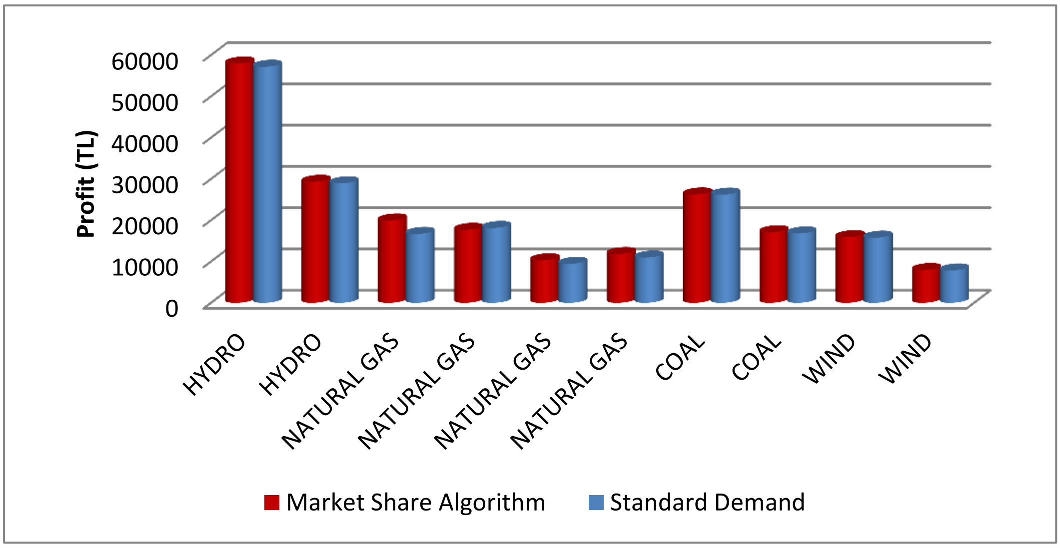


Figure 4.35. Daily average profits for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Table 4.40. Daily average profits for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Daily Average Profits In Standard Demand (Market Share Algorithm Scenario)					
ID	Type	Capacity	$\mu_{54,id}$ (TL)	$\sigma_{54,id}$ (TL)	$\sigma_{54,id}/\mu_{54,id}$
1	HYDRAULIC	4000	57959	19712	0.34
2	HYDRAULIC	2000	29314	10039	0.34
3	NATURAL GAS	4500	19948	6908	0.34
4	NATURAL GAS	4500	17683	6068	0.34
5	NATURAL GAS	2500	10310	3631	0.35
6	NATURAL GAS	2500	11830	4619	0.39
7	COAL	2500	26259	7971	0.30
8	COAL	1500	17102	3578	0.20
9	WIND	1000	15907	2713	0.17
10	WIND	500	7953	1353	0.17
Daily Average Profits In Standard Demand (Reference Scenario)					
ID	Type	Capacity	$\mu_{55,id}$ (TL)	$\sigma_{55,id}$ (TL)	$\sigma_{55,id}/\mu_{55,id}$
1	HYDRAULIC	4000	57176	19424	0.33
2	HYDRAULIC	2000	28942	9885	0.34
3	NATURAL GAS	4500	16692	5604	0.33
4	NATURAL GAS	4500	18142	5907	0.32
5	NATURAL GAS	2500	9435	3136	0.33
6	NATURAL GAS	2500	10965	3140	0.28
7	COAL	2500	26218	6849	0.26
8	COAL	1500	16809	3133	0.18
9	WIND	1000	15778	2594	0.16
10	WIND	500	7846	1279	0.16

According to Table 4.41, the Market Share Algorithm being followed by the pricemaker generator does not have a high impact on the daily average profits of power generator agents which is consistent with the analysis of daily average of electricity system prices ($\mu_{54,id} \cong \mu_{55,id}\ for\ id\ \neq 3$). So a general observation is that in the standard demand environment, the Market Share Algorithm being followed by a single pricemaker generator does not increase the daily average electricity system prices and for that reason it does not have a high impact on the whole system's profitability.

However, Generator 3 who follows the Market Share Algorithm has higher profits when compared to same type and equal capacity Generator 4 even when Generator 4 follows the conservative pricing strategy in the Real-Time Balancing Market (hence

Generator 4 has more profits in the reference scenario as mentioned in Section 4.1). For that reason, the following observation can be made: the Market Share Algorithm being followed by a pricemaker generator does not have a high impact on the overall system but, has a high impact on a single generator (especially, high impact on the volume of electricity sales of the selected generator).

Moreover, variations in the daily average profits for each generator, has a slightly increase when the Market Share Algorithm is followed by a single pricemaker generator, which is consistent with the analysis of the daily average of electricity system prices($\sigma_{51,2} > \sigma_{51,1}$).

Figure 4.36 and Table 4.41 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, the peak time profits are much higher than the respective profits in the reference standard demand environment.

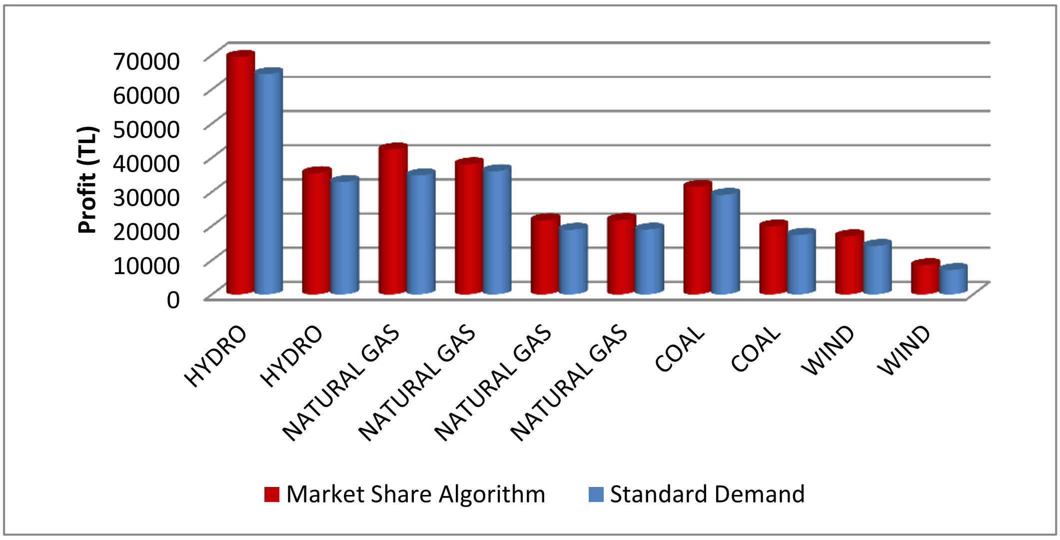


Figure 4.36. Peak time profit for each generator in the Market Share Algorithm by the pricemaker generator under standard demand environment.

According to Table 4.41, the Market Share Algorithm being followed by a single pricemaker generator has a high impact on the peak time profits of power generator agents, ($\mu_{56,id} > \mu_{57,id}$ for id = 1, ... ,10).

Table 4.41. Peak time profits for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Peak Time Profits In Standard Demand (Market Share Algorithm Scenario)					
ID	Type	Capacity	$\mu_{56,id}$ (TL)	$\sigma_{56,id}$ (TL)	$\sigma_{56,id}/\mu_{56,id}$
1	HYDRAULIC	4000	69445	23953	0.34
2	HYDRAULIC	2000	35462	12784	0.36
3	NATURAL GAS	4500	42363	16815	0.39
4	NATURAL GAS	4500	38072	15067	0.39
5	NATURAL GAS	2500	21690	8342	0.38
6	NATURAL GAS	2500	21735	8322	0.38
7	COAL	2500	31431	6367	0.20
8	COAL	1500	19860	3800	0.19
9	WIND	1000	16987	4205	0.24
10	WIND	500	8525	2099	0.24
Peak Time Profits In Standard Demand (Reference Scenario)					
ID	Type	Capacity	$\mu_{57,id}$ (TL)	$\sigma_{57,id}$ (TL)	$\sigma_{57,id}/\mu_{57,id}$
1	HYDRAULIC	4000	64445	20953	0.32
2	HYDRAULIC	2000	32852	10784	0.32
3	NATURAL GAS	4500	34800	11000	0.31
4	NATURAL GAS	4500	36043	10938	0.30
5	NATURAL GAS	2500	18911	6021	0.31
6	NATURAL GAS	2500	18937	6012	0.31
7	COAL	2500	29099	3791	0.13
8	COAL	1500	17434	2266	0.12
9	WIND	1000	14156	3644	0.25
10	WIND	500	7118	1789	0.25

This is consistent with the analysis of the peak time electricity prices ($\mu_{52,2} > \mu_{52,1}$). So a general analysis can be made that in the standard demand environment, the Market Share Algorithm being followed by a single pricemaker generator increases the peak time electricity system prices and for that reason it has a high impact on the whole system.

Additionally, Generator 3 who follows the Market Share Algorithm has higher profits compared to same type and equal capacity Generator 4, even when Generator 4 follows the conservative pricing in the Real-Time Balancing Market (hence Generator 4 has more peak time profits in the reference scenario as mentioned in Section 4.1).

Therefore, the Market Share Algorithm also increases the volume of electricity sales of the selected generator.

Furthermore, variations in the peak time profits for each power generator agent increase when the Market Share Algorithm is followed by a single pricemaker generator, that is;

$$\sigma_{56,id} > \sigma_{57,id} \text{ for id} = 1,..,10$$

However, there is another interesting point such that, while variations in the profits are smallest during the peak time period for natural gas generators (since the system consistently needs their generated electricity) however, with the Market Share Algorithm variations in the peak time profits of natural gas generators increase considerably.

Figure 4.37 and Table 4.42 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, the off-peak time profits are slightly higher than the respective profits in the reference standard demand environment.

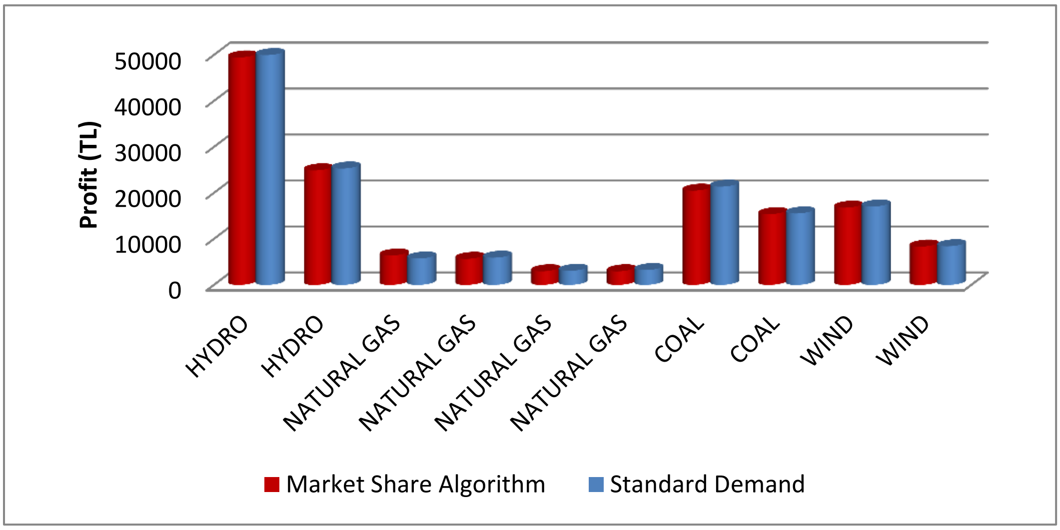


Figure 4.37. Off-peak time profits for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Table 4.42. Off-peak time profits for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Off-peak Time Profits In Standard Demand (Market Share Algorithm Scenario)					
ID	Type	Capacity	$\mu_{58,id}$ (TL)	$\sigma_{58,id}$ (TL)	$\sigma_{58,id}/\mu_{58,id}$
1	HYDRAULIC	4000	49471	16752	0.33
2	HYDRAULIC	2000	24918	8862	0.35
3	NATURAL GAS	4500	6395	3268	0.51
4	NATURAL GAS	4500	5678	2895	0.50
5	NATURAL GAS	2500	2973	1162	0.39
6	NATURAL GAS	2500	2969	1104	0.37
7	COAL	2500	20502	5932	0.28
8	COAL	1500	15386	4432	0.28
9	WIND	1000	16799	2561	0.15
10	WIND	500	8338	1173	0.14
Off-peak Time Profits In Standard Demand (Reference Scenario)					
ID	Type	Capacity	$\mu_{59,id}$ (TL)	$\sigma_{59,id}$ (TL)	$\sigma_{59,id}/\mu_{59,id}$
1	HYDRAULIC	4000	49971	16659	0.33
2	HYDRAULIC	2000	25318	8462	0.33
3	NATURAL GAS	4500	5743	2660	0.46
4	NATURAL GAS	4500	5928	2630	0.44
5	NATURAL GAS	2500	3068	1201	0.39
6	NATURAL GAS	2500	3233	1228	0.37
7	COAL	2500	21364	6096	0.28
8	COAL	1500	15548	4422	0.28
9	WIND	1000	17057	2566	0.15
10	WIND	500	8414	1148	0.13

According to Table 4.42, the Market Share Algorithm being followed by the pricemaker generator does not have a high impact on the off-peak time profits of the power generator agents, that is;

$$\sigma_{58,\mathrm{id}} > \sigma_{59,\mathrm{id}} \text{ for id} = 1,..,10$$

This is consistent with the analysis of the off-peak time electricity system prices. So, a general observation is that in the standard demand environment, the Market Share Algorithm being followed by a single pricemaker generator does not increase the off-peak time electricity prices and for that reason the algorithm does not have a high impact on the whole system's profitability. However, Generator 3 who follows the Market Share Algorithm has higher profits compared to same type and equal capacity Generator 4 even when Generator 4 follows the conservative pricing strategy in the Real-Time Balancing Market. In other words, the Market Share Algorithm does not have a high impact on the overall system, but has a high impact on the individual generator.

In addition, the Market Share Algorithm being followed by a single pricemaker generator (Generator 3) has low impact on variations in the profits values except the Generator 3 and Generator 4, mainly due to the high competition between these two power generator agents during the off-peak time period.

Figure 4.38 and Table 4.43 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, the daily average market shares of the pricemaker generator are closer to their respective market shares in the reference standard demand environment.

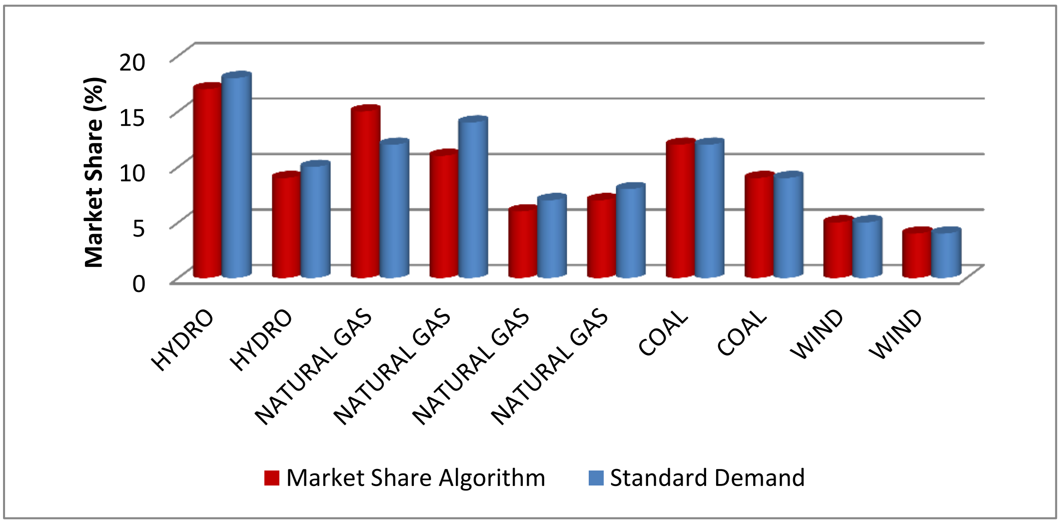


Figure 4.38. Daily average market shares for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

According to Table 4.44, the Market Share Algorithm being followed by a single pricemaker generator does not have a high impact on the daily average market shares of power generator agents. However, Generator 3 who follows the Market Share Algorithm has higher market shares compared to same type and equal capacity Generator 4 who follows the conservative pricing strategy in the Real-Time Balancing Market. Furthermore, the Market Share Algorithm increases variations in the daily average market shares of these two power generator agents (Generator 3 and Generator 4). This impact is not seen for other generators as anticipated.

Table 4.43. Daily average market shares for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Daily Average Market Shares (Market Share Algorithm Scenario)					
ID	Type	Capacity	$\mu_{60,id}$ (%)	$\sigma_{60,id}$ (%)	$\sigma_{60,id}/\mu_{60,id}$
1	HYDRAULIC	4000	17	9	0.52
2	HYDRAULIC	2000	9	5	0.55
3	NATURAL GAS	4500	15	6	0,40
4	NATURAL GAS	4500	11	4	0,36
5	NATURAL GAS	2500	6	2	0,33
6	NATURAL GAS	2500	7	2	0,28
7	COAL	2500	12	2	0,16
8	COAL	1500	9	1	0,11
9	WIND	1000	5	1	0,20
10	WIND	500	4	1	0,25
Daily Average Market Shares (Reference Scenario)					
ID	Type	Capacity	$\mu_{61,id}$ (%)	$\sigma_{61,id}$ (%)	$\sigma_{61,id}/\mu_{61,id}$
1	HYDRAULIC	4000	18	9	0,50
2	HYDRAULIC	2000	10	5	0,50
3	NATURAL GAS	4500	12	4	0,33
4	NATURAL GAS	4500	14	4	0,28
5	NATURAL GAS	2500	7	2	0,28
6	NATURAL GAS	2500	8	2	0,25
7	COAL	2500	12	1	0,08
8	COAL	1500	9	1	0,11
9	WIND	1000	5	1	0,20
10	WIND	500	4	1	0,25

Figure 4.39 and Table 4.44 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, the peak time market shares of the pricemaker are much higher than its respective market shares in the reference standard demand environment.

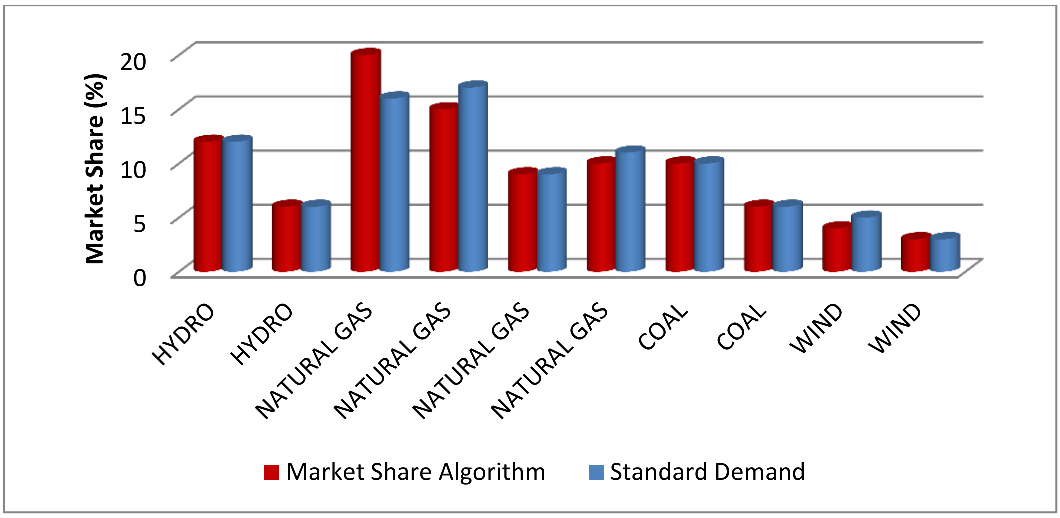


Figure 4.39. Peak time market shares for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

According to the Table 4.45, the Market Share Algorithm being followed by a single pricemaker generator increases the peak time market shares of Generator 3 ($\mu_{62,3} > \mu_{63,3}$). The impacts of the Market Share Algorithm on market shares are higher during the peak time period in the standard demand environment. Moreover, Generator 3 who follows the Market Share Algorithm gets the market shares of the generator 4 because the other generator market shares do not change much. Additionally, during the peak time period, the Market Share Algorithm has high impact on all high cost power generators' market shares' variations.

Figure 4.40 and Table 4.45 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, the off-peak time market shares of the pricemaker generator are slightly higher than respective market shares in the reference standard demand environment.

Table 4.44. Peak time market shares for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Peak Time Market Shares (Market Share Algorithm Scenario)					
ID	Type	Capacity	$\mu_{62,id}$ (%)	$\sigma_{62,id}$ (%)	$\sigma_{62,id}/\mu_{62,id}$
1	HYDRAULIC	4000	12	6	0.50
2	HYDRAULIC	2000	6	3	0.50
3	NATURAL GAS	4500	20	5	0.25
4	NATURAL GAS	4500	15	3	0.20
5	NATURAL GAS	2500	9	2	0.22
6	NATURAL GAS	2500	10	2	0.20
7	COAL	2500	10	2	0.20
8	COAL	1500	6	1	0.16
9	WIND	1000	4	1	0.25
10	WIND	500	3	1	0.33
Peak Time Market Shares (Reference Scenario)					
ID	Type	Capacity	$\mu_{63,id}$ (%)	$\sigma_{63,id}$ (%)	$\sigma_{63,id}/\mu_{63,id}$
1	HYDRAULIC	4000	12	6	0.50
2	HYDRAULIC	2000	6	3	0.50
3	NATURAL GAS	4500	16	2	0.12
4	NATURAL GAS	4500	17	2	0.11
5	NATURAL GAS	2500	9	1	0.11
6	NATURAL GAS	2500	11	1	0.09
7	COAL	2500	10	2	0.20
8	COAL	1500	6	1	0.16
9	WIND	1000	5	1	0.20
10	WIND	500	3	1	0.33

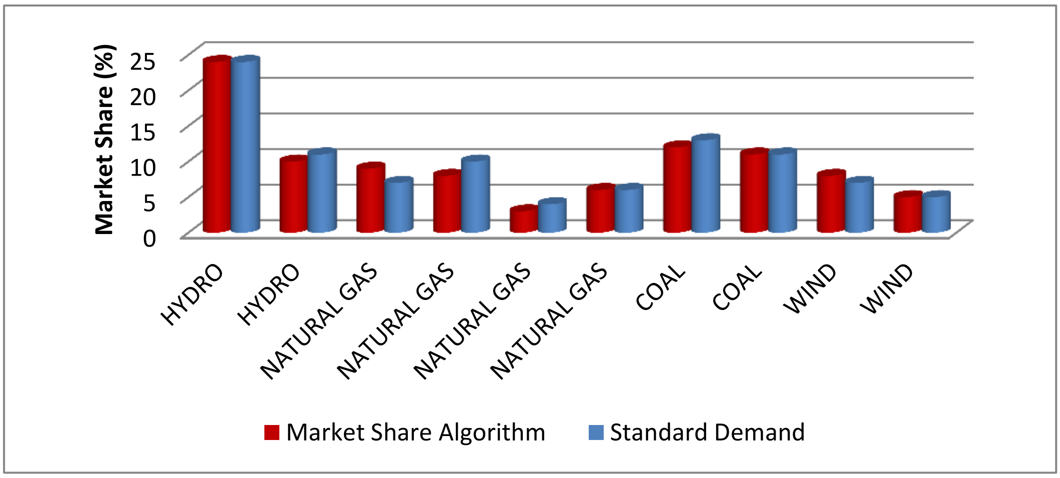


Figure 4.40. Off-peak time market shares for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Table 4.45. Off-peak time market shares for each power generator agent in the Market Share Algorithm by the pricemaker generator under standard demand environment.

Off-peak Time Market Shares in Standard Demand (Market Share Algorithm Scenario)					
ID	Type	Capacity	$\mu_{64,id}$ (%)	$\sigma_{64,id}$ (%)	$\sigma_{64,id}/\mu_{64,id}$
1	HYDRAULIC	4000	24	10	0,41
2	HYDRAULIC	2000	10	5	0,50
3	NATURAL GAS	4500	9	4	0,44
4	NATURAL GAS	4500	8	4	0,50
5	NATURAL GAS	2500	3	2	0,66
6	NATURAL GAS	2500	6	4	0,66
7	COAL	2500	12	5	0,41
8	COAL	1500	11	2	0,18
9	WIND	1000	8	2	0,25
10	WIND	500	5	1	0,20
Off-peak Time Market Shares In Standard Demand (Reference Scenario)					
ID	Type	Capacity	$\mu_{65,id}$ (%)	$\sigma_{65,id}$ (%)	$\sigma_{65,id}/\mu_{65,id}$
1	HYDRAULIC	4000	24	9	0,37
2	HYDRAULIC	2000	11	4	0,36
3	NATURAL GAS	4500	7	3	0,42
4	NATURAL GAS	4500	10	4	0,40
5	NATURAL GAS	2500	4	2	0,50
6	NATURAL GAS	2500	6	4	0,66
7	COAL	2500	13	5	0,38
8	COAL	1500	11	2	0,18
9	WIND	1000	7	2	0,28
10	WIND	500	5	1	0,20

According to Table 4.46, the Market Share Algorithm followed by a single pricemaker generator does not have a high impact on the off-peak time market shares of power generator agents, that is;

$$\mu_{64,id} \cong \mu_{65,id} \text{ for all id } \neq 3,4$$

However, Generator 3 who follows the Market Share Algorithm has higher market shares compared to same type and equal capacity Generator 4 even Generator 4 who follows the conservative pricing strategy in the Real-Time Balancing Market (hence Generator 4 has a larger off-peak market share in the reference standard demand scenario).

Moreover, hydraulic and wind power generator agents (low cost generators) have higher market shares during the off-peak time periods compared to the peak time and the daily average periods in the standard demand environment (which is consistent with the market share analyses in both high and low demand environments presented in Section 4.1) .

Figure 4.41 and Table 4.46 display that in the standard demand environment, when the Market Share Algorithm is followed by the non-pricemaker generator, the daily average of the DAP prices are closer to the respective prices in the reference standard demand environment.

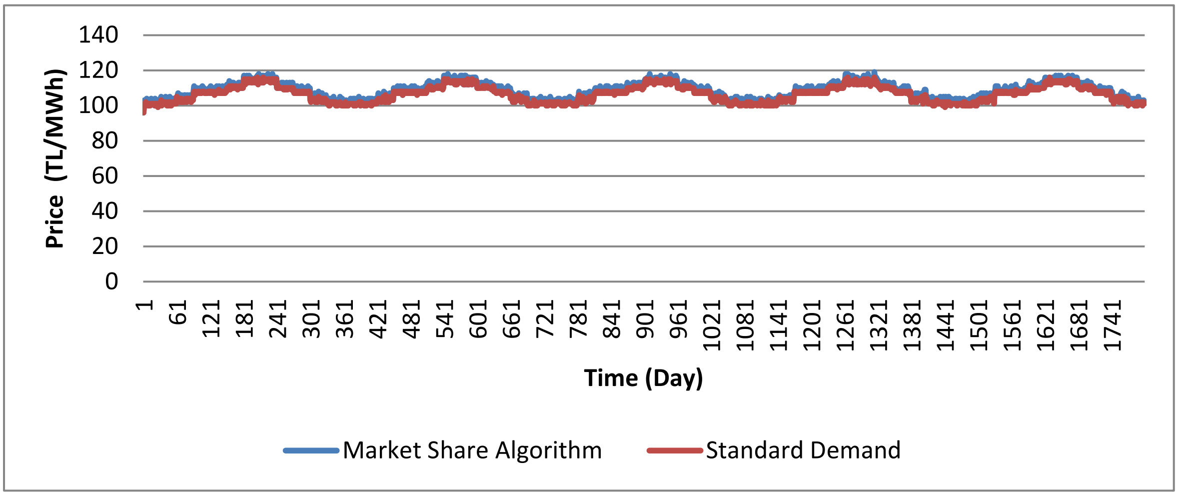


Figure 4.41. Daily average electricity system prices in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

Table 4.46. Daily average of electricity system prices in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

	DAP (a=1)	DAP-MSA (a=2)
$Min_{14,a}$	96	98
$Max_{14,a}$	116	119
$\mu_{66,a}$	106.55	106.85
$\sigma_{66,a}$	4.59	4.68

According to Table 4.46, the Market Share Algorithm being followed by the non-pricemaker generator does not have a significant impact on the daily average of the DAP prices ($\mu_{66,2} \cong \mu_{66,1}$). Moreover, the daily average of the DAP prices when the Market

Share Algorithm is followed by the non-pricemaker generator are lower than the respective prices when the Market Share Algorithm is followed by the pricemaker generator ($\mu_{66,2} < \mu_{51,2}$).

Figure 4.42 and Table 4.47 displays that in the standard demand environment, when the Market Share Algorithm is followed by the non-pricemaker generator, the peak time DAP prices are closer to the respective prices in the reference standard demand environment.

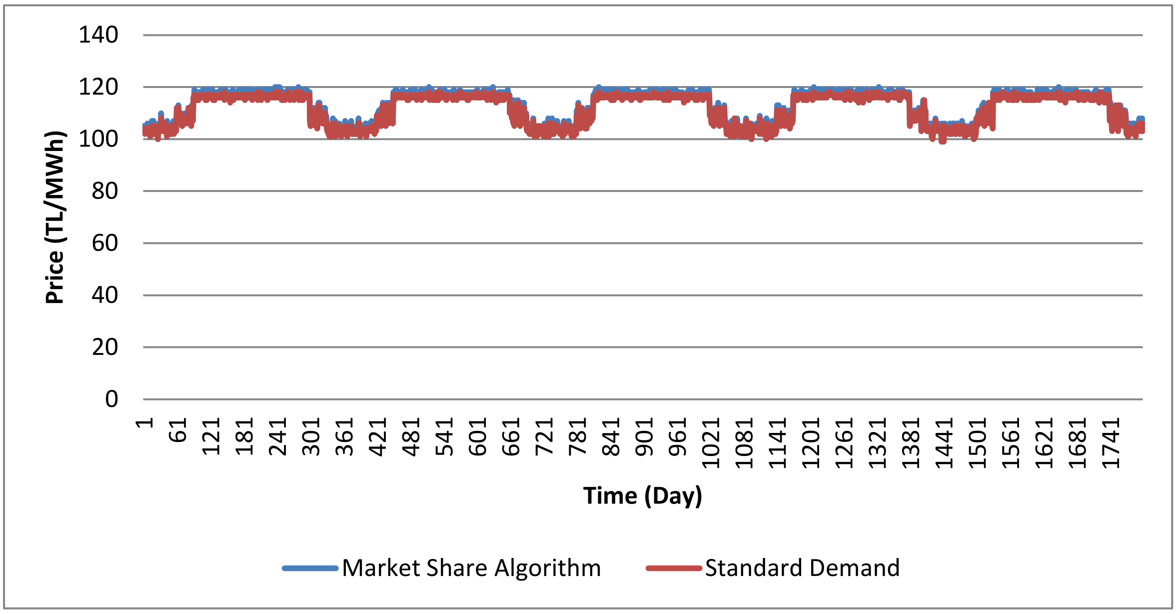


Figure 4.42. Peak time electricity system prices in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

Table 4.47. Peak time electricity system prices in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

	DAP (a=1)	DAP-MSA (a=2)
$\boldsymbol{Min_{15,a}}$	99	100
$\boldsymbol{Max_{15,a}}$	118	120
$\boldsymbol{\mu_{67,a}}$	111.69	112.85
$\boldsymbol{\sigma_{67,a}}$	5.87	6.01

According to Table 4.47, the Market Share Algorithm being followed by the non-pricemaker generator does not have a significant impact on the peak time DAP prices ($\mu_{67,2} \cong \mu_{67,1}$). Furthermore, the peak time DAP prices when the Market Share Algorithm is followed by the non-pricemaker generator are lower than the respective prices when the Market Share Algorithm is followed by the pricemaker generator ($\mu_{67,2} < \mu_{52,2}$).

As can be seen in the both Table 4.38 and Table 4.47, variations in the peak time prices when the Market Share Algorithm is followed by the non-pricemaker generator are lower than the respective variations when the Market Share Algorithm is followed by the pricemaker generator, that is;

$$\sigma_{67,2} < \sigma_{52,2}$$

In addition to this, the difference between the minimum and the maximum values of the peak time DAP prices when the Market Share Algorithm is followed by the pricemaker generator are wider than the respective difference when the Market Share Algorithm being followed by the non-pricemaker generator.

$$\text{Max}_{15,2} - \text{Min}_{15,2} < \text{Max}_{12,2} - \text{Min}_{12,1}$$

Figure 4.43 and Table 4.48 displays that in the standard demand environment, when the Market Share Algorithm is followed by the non-pricemaker generator, the off-peak time DAP prices are closer to the respective prices in the reference standard demand environment.

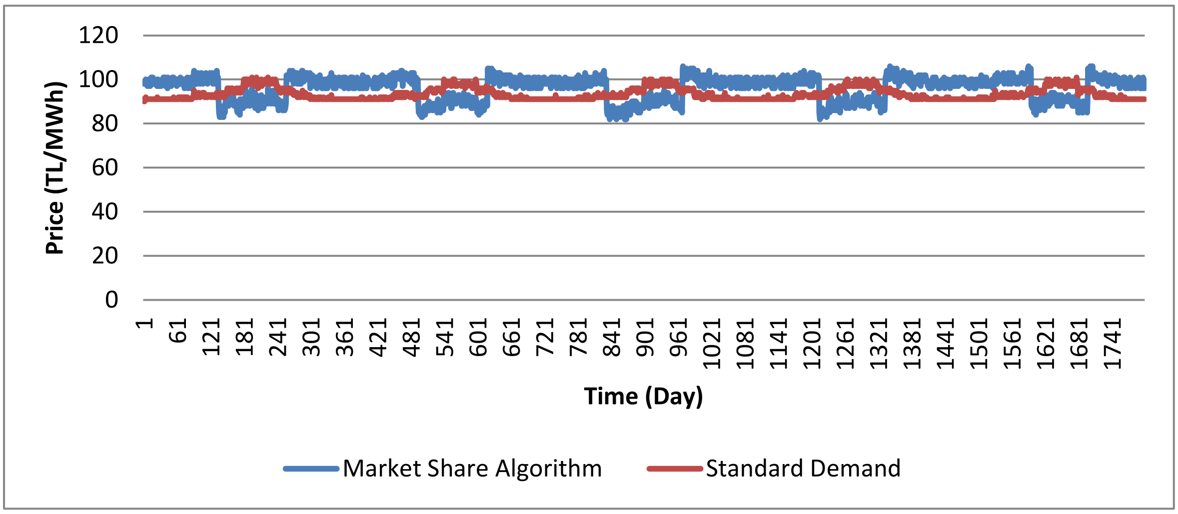


Figure 4.43. Off-peak time electricity system prices in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

Table 4.48. Off-peak time electricity system prices in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

	DAP (a=1)	DAP-MSA (a=1)
$Min_{16,a}$	90	83
$Max_{16,a}$	101	107
$\mu_{68,a}$	93.44	98.23
$\sigma_{68,a}$	2.65	4.80

According to Table 4.48, the Market Share Algorithm being followed by the non-pricemaker generator has a high impact on the off-peak time DAP prices ($\mu_{68,2} > \mu_{68,1}$) mainly on the dry season. As can be seen from Figure 4.43, during the dry season, when hydraulic power generator agents loses their capacity, the non-pricemaker generator (Generator 1) starts to lose its market shares and also decreases its offer prices hence electricity system prices decrease because Generator 1 dominates the market during the off-peak time period. According to the $Min_{16,2} < Min_{16,1}$, Generator 1 determines electricity prices. But as depicted in Figure 4.43, after the dry season, when the capacity of the non-pricemaker generator starts to increase (higher capacity leading to higher market shares), the Market Share Algorithm being followed by the non-pricemaker generator increases its offer prices so electricity system prices increase (as stated in 4.1, during the off-peak time periods, system electricity demand is mainly supplied by low cost generators).

Figure 4.44 and Table 4.49 display that in the standard demand environment, when the Market Share Algorithm is followed by the pricemaker generator, the off-peak time profits are slightly higher than the respective profits in the reference standard demand environment.

According to Table 4.49, the Market Share Algorithm followed by the non-pricemaker generator has a high impact on the off-peak time profits of power generator agents ($\mu_{69,id} > \mu_{70,id}\ for\ id = 1, \ldots, 10$) which is consistent with the analysis of the off-peak time electricity prices ($\mu_{68,2} > \mu_{68,1}$).

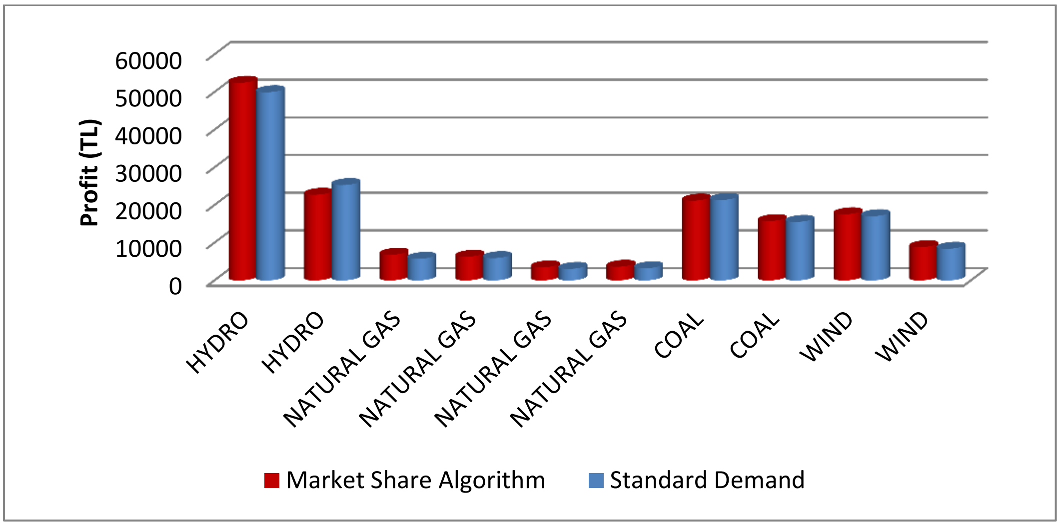


Figure 4.44. Off-peak time profits for each power generator agent in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

So, a general observation can be made that in the standard demand environment during the off-peak time, the Market Share Algorithm followed by the non-pricemaker generator increases the off-peak time electricity system prices and for that reason it has a high impact on the whole system.

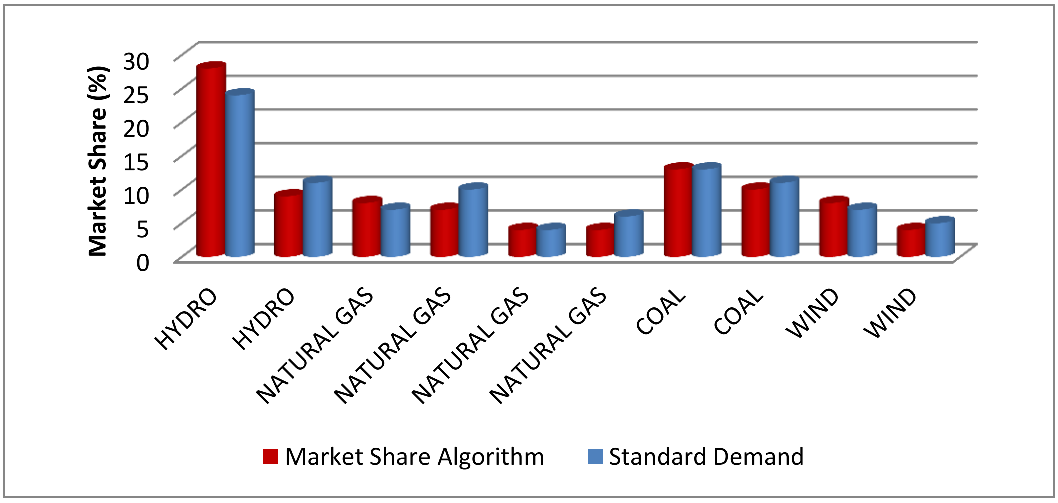


Figure 4.45. Off-peak time market shares for each power generator agent in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

Table 4.49. Off-peak time profits for each power generator agent in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

Off-peak Time Profits In Standard Demand (Market Share Algorithm Scenario)					
ID	Type	Capacity	$\mu_{69,id}$ (TL)	$\sigma_{69,id}$ (TL)	$\sigma_{69,id}/\mu_{69,id}$
1	HYDRO	4000	52471	16752	0.31
2	HYDRO	2000	22754	8862	0.38
3	NATURAL GAS	4500	6841	3434	0.50
4	NATURAL GAS	4500	6294	3074	0.48
5	NATURAL GAS	2500	3471	1472	0.42
6	NATURAL GAS	2500	3636	1350	0.37
7	COAL	2500	21194	6131	0.28
8	COAL	1500	15766	4727	0.29
9	WIND	1000	17574	2883	0.16
10	WIND	500	8842	1399	0.15
Off-peak Time Profits In Standard Demand (Reference Scenario)					
ID	Type	Capacity	$\mu_{70,id}$ (TL)	$\sigma_{70,id}$ (TL)	$\sigma_{70,id}$ / $\mu_{70,id}$
1	HYDRO	4000	49971	16659	0.33
2	HYDRO	2000	25318	8462	0.33
3	NATURAL GAS	4500	5743	2660	0.46
4	NATURAL GAS	4500	5928	2630	0.44
5	NATURAL GAS	2500	3068	1201	0.39
6	NATURAL GAS	2500	3233	1228	0.37
7	COAL	2500	21364	6096	0.28
8	COAL	1500	15548	4422	0.28
9	WIND	1000	17057	2566	0.15
10	WIND	500	8414	1148	0.13

Figure 4.45 and Table 4.50 display the off-peak time market shares for each power generator agent, when the Market Share Algorithm is followed by the non-pricemaker generator in the standard demand environment.

According to the Table 4.45, the Market Share Algorithm being followed by the non-pricemaker generator increases the off-peak time market shares of Generator 1 ($\mu_{70,1} > \mu_{71,1}$). So a general observation is that the impact of the Market Share Algorithm is high on the market shares of the selected agent during the off-peak time period in the standard demand environment. Moreover, Generator 1 who follows the Market Share Algorithm gets the market shares of the Generator 2 due to the competition of low cost generators during the off-peak time period.

Table 4.50. Off-peak time market shares for each power generator agent in the Market Share Algorithm by the non-pricemaker generator under standard demand environment.

Off-peak Time Market Shares in Standard Demand (Market Share Algorithm Scenario)					
ID	Type	Capacity	$\mu_{71,id}$ (%)	$\sigma_{71,id}$ (%)	$\sigma_{71,id}$ / $\mu_{71,id}$
1	HYDRO	4000	28	11	0.39
2	HYDRO	2000	9	5	0.55
3	NATURAL GAS	4500	8	4	0.50
4	NATURAL GAS	4500	7	3	0.42
5	NATURAL GAS	2500	4	2	0,5
6	NATURAL GAS	2500	4	2	0,5
7	COAL	2500	13	5	0.38
8	COAL	1500	10	2	0.20
9	WIND	1000	8	2	0.25
10	WIND	500	4	1	0.25
Off-peak Time Market Shares In Standard Demand (Reference Scenario)					
ID	Type	Capacity	$\mu_{72,id}$ (%)	$\sigma_{72,id}$ (%)	$\sigma_{72,id}$ / $\mu_{72,id}$
1	HYDRO	4000	24	9	0,37
2	HYDRO	2000	11	4	0,36
3	NATURAL GAS	4500	7	3	0,42
4	NATURAL GAS	4500	10	4	0,40
5	NATURAL GAS	2500	4	2	0,50
6	NATURAL GAS	2500	6	4	0,66
7	COAL	2500	13	5	0,38
8	COAL	1500	11	2	0,18
9	WIND	1000	7	2	0,28
10	WIND	500	5	1	0,20

5. CONCLUSION AND FURTHER STUDIES

In the last decade, the trend for improving economic efficiency in the electricity industry made significant changes in the sector based on deregulation and competition. In this new context, centralized regulatory agency is required only to monitor/control and supervise the market operations and the generation of electricity no longer depends on state or centralized producers but rather on decentralized decision of each generator in the system. This decentralized decision and support procedure for each generator brings competition in the market which leads to higher risk of being not-dispatched for electricity firms. For that reason, their need for suitable decision-support models has greatly increased. Hence research community has given high priority to develop these decision and analysis support models and a new area of highly interesting research for electricity industry has open up (Ventosa *et al.*, 2005).

For that reason, in this thesis, an integrated simulation and optimization model is developed to mimic and analyze the decentralized Turkish electricity market. For this purpose, an integrated simulation/optimization model is developed to represent the Day-Ahead and the Real-Time Balancing markets, while enforcing technological and other constraints. In the simulation sub-model, the system operator collects all types of offers (hourly, block and flexible) from the power generator agents which are then fed to the optimization sub-model to find an optimum (minimum cost) combination of the active electricity power generated by power generator agents. In the optimization sub-model, it is aimed to meet all uncovered electricity demand of the aggregate power user agent, while considering the power generator agents' offers' quantities, prices, characteristics and offered time periods in each hour at minimum cost. The system operator generates a generation schedule for each power generator agent in the market according to the total cost minimization procedure based on the developed mixed-integer linear model and determines the electricity system prices.

Within this framework, various scenarios are developed and analyzed for many performance indicators, such as average, standard deviation and standard deviation per average values computed for electricity system prices (as TL/MWh) for both Day Ahead and Real Time Balancing markets and for *profit*s, *capacity utilizations, market shares, profits per unit* and *profits per capacity* indicators of each power generator agent in the system. Further policy analysis is carried out under various setting of market conditions such as demand levels, pricing strategies of power generator agents and self-learning algorithms.

According to the first scenario analyses, first of all, electricity system prices are highly related to electricity power demand; increase (decrease) of electricity demand directly leads to increase (decrease) in electricity system prices in both daily time periods (such as peak/off-peak time) and whole seasons (dry/non-dry seasons).

Secondly, the decreased capacity of low cost power generator agents during the dry season (such as hydraulic power generator agents) has a higher positive impact on electricity system prices (such as μ, σ and σ/μ values) in the low demand environment (since in the low demand environment system electricity is mainly satisfied by low cost power generator agents until the dry season). This impact is smaller in the high demand environment where the system electricity demand is mostly met by high cost power generator agents (like natural gas and coal generators). Moreover, the decreased capacity of low cost generators (during dry season) leads to a larger variation in electricity system prices in the low demand environment compared to the high demand environment.

Thirdly, the Day-Ahead Market (DAP) prices are closer to the Real-Time Balancing Market (SMP) prices during the off-peak time period in both high and low demand environments. This is mainly due to the fact that the electricity demand in the Real-Time Balancing Market is mostly met by the power generator agents who follow the conservative pricing strategy during the off-peak time period. Furthermore, electricity system prices in the low demand environment are closer to electricity system prices in the high demand environment during the off-peak time period.

Fourthly, in both high and low demand environments, high capacity power generator agents have higher profits compared to the same type of low capacity generators. Moreover, for each power generator agent, profits are higher in the high demand environment than their respective profits in the low demand environment; in other words, the profit indicator is more responsive to capacity (higher capacity leading to higher volume of electricity sales) and demand levels (higher demand leading to higher electricity system prices).

Another observation is that in the high demand environment, variations in profits are highest for hydraulic generators mainly due to low capacity and low profits during the dry season; whereas in the low demand environment, variations in profits are highest for natural gas generators mainly due to high marginal costs and low demand level (resulting in low dispatch rates). In the low demand environment, natural gas generators can sell their electricity and increase their profits primarily during the dry season when hydraulic power generator agents have low capacities. For wind generators, variations in profits are independent from demand levels and show a similar behavior in both high and low demand environments (mainly due to low marginal cost and same wind availability in both demand environments). For hydraulic generators, profits are higher in the winter (non-dry) season mainly due to higher water capacity in the winter season.

Fifthly, hydraulic and wind generators have higher market shares in the low demand environment compared to their respective market shares in the high demand environment (mainly due to the system electricity demand being supplied by these two types of generators in the low demand environment). In the high demand environment, more electricity demand is supplied by other types of generators and low cost power generator agents lose their market shares. On the other hand, natural gas and coal generators have lower market shares in the low demand environment compared to their respective market shares in the high demand environment, mainly due to increased generators' idle time (high priced offers not being accepted) in the low demand environment. In addition to this, high capacity generators have higher market shares compared to the respective same type of low capacity generators. Additionally, power generator agents who follow the conservative pricing strategy have higher market shares compared to the same type (with same marginal cost and capacity) power generator agents who follow the aggressive pricing strategy.

Sixthly, demand level changes generally have a higher impact on capacity utilization indicator of high cost power generator agents than low cost power generator agents. Variations in capacity utilizations show a similar behavior between the same type of power generator agent implying that the capacity utilization indicator is more responsive to the marginal cost of the generators and is not responsive to their capacity. In both high and low demand environments, capacity utilization levels of wind generators show a similar behavior during the off-peak time, the peak time and the daily average periods implying that this indicator for wind generators has low relation with demand level but has strong relation with values of wind power availability. Additionally , power generator agents who follow the conservative pricing strategy have higher capacity utilizations compared to the same type power generator agents who follow the aggressive pricing strategy. Positive impact of the conservative pricing strategy on capacity utilization indicator is higher during the off-peak time.

Seventhly, for each power generator agent, profit per unit values are higher in the high demand environment than the respective values in the low demand environment (mainly due to higher electricity system prices in the high demand environment). In addition, all power generator agents (including hydraulic and wind generators) increase their profit per unit values mainly during the dry season (when electricity system prices increase).

Another observation is that in both high and low demand environments, profit per unit values of low cost generators are higher than the respective values of high cost generators, implying that that profit per unit indicator is more responsive to the marginal cost of the power generator agent and has no relation with its capacity.

Eighthly, for each power generator agent, profit per capacity values are higher in the high demand environment than their respective values in the low demand environment (mainly due to higher electricity system prices in the high demand environment). In addition, profit per capacity values of generators who follow the conservative pricing strategy are higher than the respective values of same type generators who follow the aggressive pricing strategy in the Real-Time Balancing Market.

According to second scenario analyses, in the high demand environment, the difference between the daily averages of the Day-Ahead (DAP) and of the Real-Time Balancing (SMP) markets' prices is higher under the aggressive pricing strategy compared to the respective difference in the reference high demand scenario. Furthermore, in the high demand environment, the aggressive pricing strategy followed by the pricemaker generator increases electricity system prices more than the same strategy followed by the non-pricemaker generator. This is due to the fact that the pricemaker generator retains an incentive to raise its offer prices because system consistently needs its generated electricity especially during the dry season (impacts of the decreased capacity of renewable generators on electricity prices are explained in Section 4.1).

The close electricity prices in the two scenarios (the reference scenario and the non-pricemaker case) is due to the fact that the non-pricemaker (which is "Generator 1" and is a hydraulic generator) loses its capacity (and its power to rule the market price) during the dry season. So, in the high demand environment; the aggressive pricing strategy followed by the pricemaker generator has a higher impact on the electricity system prices than the same strategy followed by the non-pricemaker generator.

Another observation is that in the high demand environment, the aggressive pricing strategy followed by both the pricemaker and the non-pricemaker generators increases level of variation in the daily averages of the Day-Ahead (DAP) and of the Real-Time Balancing (SMP) markets' prices compared to the respective level of variation in the reference high demand scenario. But variations in the daily average of the Day-Ahead Market (DAP) and of the Real-Time Balancing (SMP) markets' prices (when the aggressive pricing strategy is followed by the non-pricemaker generator) are lower than the respective variations (when the aggressive pricing strategy is followed by the pricemaker generator).

Secondly, for each power generator agent, in the high demand environment (with the aggressive pricing strategy being followed by the pricemaker generator), the daily average profits are higher than their respective values in the reference high demand scenario. The daily average profits for each generator in the high demand environment (when the aggressive pricing strategy is followed by the non-pricemaker generator) are higher than their respective values in the reference high demand scenario but are lower than their respective values when the aggressive pricing strategy followed by the pricemaker generator. Furthermore, in the high demand environment, for each power generator agent, variations in profits (when the aggressive pricing strategy is followed by the non-pricemaker generator) are lower than the respective variations when the aggressive pricing strategy is followed by the pricemaker generator (which is consistent with the analysis of electricity system prices). To sum up, in the high demand environment, the aggressive pricing strategy followed by a single pricemaker generator (with high capacity) has a positive impact on the whole system (increases system prices and all generators' profits)

Fourthly, in the low demand environment, the aggressive pricing strategy being followed by the non-pricemaker generator increases electricity system prices more than the same strategy followed by the pricemaker generator. The main reason behind this observation is that the non-pricemaker generator (which is 'Generator 1'), is low cost power generator agent with high capacity so a general observation is that, in the low demand environment, low cost power generator agents' (with high capacity) pricing strategy has more impacts on electricity system prices than high cost power generator agents' strategy.

Another observation is that in the low demand environment, the aggressive pricing strategy being followed by the non-pricemaker generators also increases variations in electricity system prices, compared to the respective variations in the reference low demand scenario.

Fifthly, in the low demand environment, for each generator (except the pricemaker generator), the daily average profits when the aggressive pricing strategy is followed by the pricemaker generator are higher than their respective levels in the reference low demand scenario. However, the aggressive pricing strategy increases unsold capacities of the pricemaker generator (due to the low dispatch rates).

Sixthly, in the high demand environment, the conservative pricing strategy being followed by a single pricemaker generator has low impacts on the profits of the power generator agents because in the high demand environment, the system operator still needs to accept the offers with higher prices from other high cost power generator agents in order to meet electricity demand. So, the conservative pricing strategy being followed by a single pricemaker generator does not have high impact on electricity system prices. This analysis is in contradiction with the aggressive pricing strategy case in the high demand environment where a single power generator agent can increase electricity system prices.

Seventhly, impacts of the conservative pricing strategy being followed by two pricemaker generators are higher on the profits of the power generator agents than a single pricemaker case. This analysis is consistent with the study of Bunn, Bower and Wattendrup (2001) where they analyze the increased impact of merging of power generator agents on electricity system prices.

According to third scenario analyses, the pricemaker generator who follows the Market Share Algorithm has a high impact on the peak time DAP prices mainly during the dry season because during the dry season (when renewable generators lose their capacity), the pricemaker agent start to increase its market share (and also increase its offer prices) so system electricity prices increase (which also leads to a higher level of variation). However, the impacts of the Market Share Algorithm being followed by the pricemaker generator are not high during the off-peak time period. The main reason is that in the Market Share Algorithm, minimum bid prices of a power generator agent are its marginal cost even if the algorithm tries to lower the bid prices. For that reason, high cost generators who follow the Market Share Algorithm can still be dispatched during the off-peak time period (as also stated in Section 4.1).

Secondly, variations in the profits are smallest during the peak time period for natural gas generators because the system operator consistently needs their generated electricity. However, with the Market Share Algorithm variations in the peak time profits for natural gas generators increase considerably which shows that the generator who follows the Market Share strategy seizes the competitor's market shares during the balancing operations.

Thirdly, in the daily market share analysis, the Market Share Algorithm increases variations only for two power generator (Generator 3 and Generator 4), but in the peak time market share analysis, the Market Share Algorithm has high impacts on all natural gas generators' market shares where system needs all high cost generators' electricity and increases the level of variation during the peak-time period.

To sum up, the Market Share Algorithm being followed by the pricemaker generator is found to be especially effective during the peak-time (high demand) period, whereas the same algorithm being followed by the non-pricemaker generator is observed to be effective at low demand (off-peak time) period.

5.1. Further Studies

The current integrated optimization and simulation framework mainly focuses on the supply side of the market structure. Introducing demand elasticity into this framework is an important aspect to complete the end-to-end model. Moreover, exporting and importing of electricity can be considered as additional demand side studies. Finally, the electricity consumption rate in the previous studies shows that consumption will continue to increase over the next 15 years mainly due to increase of population, of urbanization and social and economic development. For that reason, accurate electricity consumption studies will be very important for the near future.

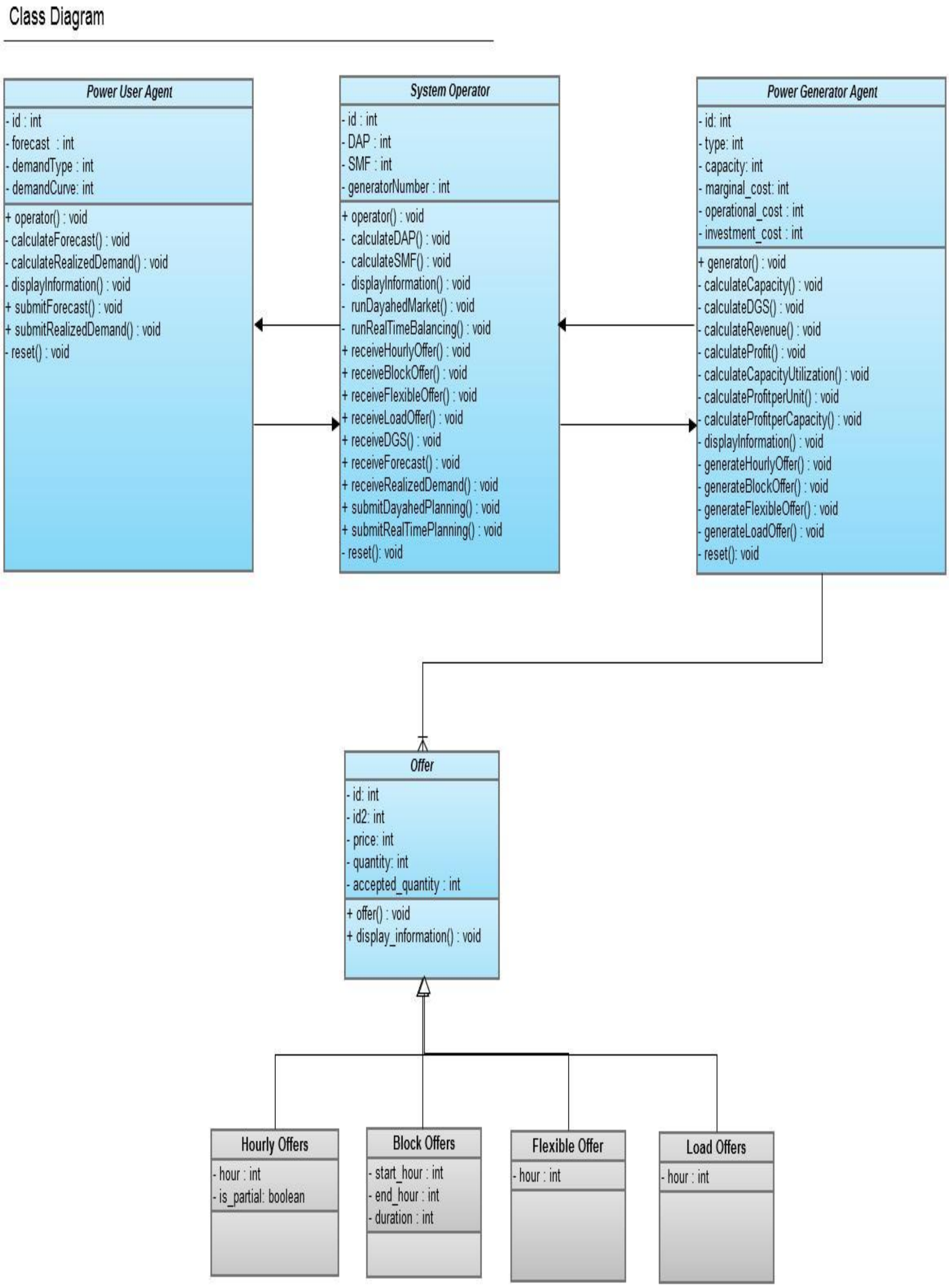
Another aspect that may be studied with the developed framework is to introduce new type of generators like solar, geothermal and nuclear power generator agents which are used by many developed countries for meeting rapid electricity demand growth. Especially nuclear power generators are important carbon-free power sources that can potentially make a significant contribution to Turkey's future energy needs if their complex safety, legal and insurance requirements can be properly met. Moreover, in this developed framework cost of power generator agents is fixed during the simulation runs. To reflect the reality, cost variability can be added into the simulation model.

On the other hand, the transmission network and its extension can be added into this developed framework because the effect of line capacity extension and / or new line construction is an important research area for the deregulated electricity market. Furthermore, with the addition of the transmission network structure, the system operator will be extended with congestion management capability and also introducing the transmission network into the framework will bring the transmission cost accounting into power generator and power user agents.

Currently, the developed framework focuses on the daily-optimization of the electricity market. However, scheduling period can be extended to weekly-optimization or monthly optimization. But, deviation from daily schedule will increase the complexity of the simulation / optimization framework significantly.

All in all, in the last 10 years Turkish electricity market has experienced significant changes towards deregulation process. For that reason, there are major areas which have rooms for research in the near future.

APPENDIX A: HIGH LEVEL UML DESIGN



APPENDIX B: MODEL VALIDATION RESULT

####################################
####################################
Day 1

HOUR	DGS	FORECAST	DIFFERENCE	OFFER AMOUNT
1:00	12751	17000	4249	10967
2:00	12824	17000	4176	10979
3:00	13001	17000	3999	10566
4:00	12925	17750	4825	10770
5:00	12718	17500	4782	10906
6:00	12808	17000	4192	10828
7:00	12848	17000	4152	10830
8:00	12979	17500	4521	10602
9:00	14763	20000	5237	9267
10:00	14653	19750	5097	9345
11:00	14708	19750	5042	8854
12:00	14726	20000	5274	8798
13:00	14859	19750	4891	9110
14:00	14456	20250	5794	9536
15:00	14842	20250	5408	8999
16:00	14649	20000	5351	8921
17:00	17923	24500	6577	6798
18:00	18000	24750	6750	6656
19:00	18061	24250	6189	6364
20:00	17705	24500	6795	6614
21:00	18151	24500	6349	6385
22:00	18285	24500	6215	5952
23:00	17816	24000	6184	6414
24:00	18081	24500	6419	6153

HOURLY OFFER

ID	ID2	AMOUNT	PRICE	HOUR	PARTIAL
1	1	744	85$	1:00	Yes
2	1	563	110$	1:00	No
3	1	321	149$	1:00	Yes
4	2	426	81$	1:00	No
5	2	307	102$	1:00	No
6	2	118	143$	1:00	No
7	3	999	172$	1:00	Yes
8	3	697	198$	1:00	No

9	3	278	214$	1:00	No
10	4	842	170$	1:00	No
11	4	728	197$	1:00	No
12	4	341	235$	1:00	No
13	5	418	173$	1:00	Yes
14	5	347	193$	1:00	No
15	5	155	239$	1:00	Yes
16	6	509	172$	1:00	No
17	6	407	201$	1:00	Yes
18	6	229	242$	1:00	Yes
19	7	494	153$	1:00	No
20	7	313	145$	1:00	Yes
21	7	192	176$	1:00	No
22	8	259	127$	1:00	Yes
23	8	244	143$	1:00	Yes
24	8	72	163$	1:00	Yes
25	9	206	90$	1:00	Yes
26	10	92	86$	1:00	Yes
27	10	84	101$	1:00	No
28	10	29	122$	1:00	Yes
29	1	797	87$	2:00	No
30	1	602	103$	2:00	No
31	1	194	123$	2:00	No
32	2	377	78$	2:00	No
33	2	278	109$	2:00	No
34	2	178	124$	2:00	No
35	3	966	161$	2:00	No
36	3	667	196$	2:00	Yes
37	3	230	243$	2:00	Yes
38	4	797	162$	2:00	Yes
39	4	686	189$	2:00	Yes
40	4	398	221$	2:00	Yes
41	5	475	162$	2:00	No
42	5	390	194$	2:00	Yes
43	5	183	225$	2:00	No
44	6	436	172$	2:00	No
45	6	348	196$	2:00	Yes
46	6	236	217$	2:00	No
47	7	557	139$	2:00	No
48	7	418	148$	2:00	Yes
49	7	228	175$	2:00	No
50	8	275	123$	2:00	No
51	8	193	148$	2:00	No
52	8	89	175$	2:00	Yes
53	9	194	91$	2:00	No
54	10	99	91$	2:00	No
55	10	87	108$	2:00	No
56	10	48	126$	2:00	Yes

57	1	756	79$	3:00	No
58	1	531	110$	3:00	No
59	1	388	127$	3:00	No
60	2	370	89$	3:00	No
61	2	292	108$	3:00	No
62	2	175	128$	3:00	No
63	3	754	172$	3:00	No
64	3	582	194$	3:00	No
65	3	258	229$	3:00	No
66	4	922	170$	3:00	No
67	4	557	198$	3:00	Yes
68	4	343	240$	3:00	No
69	5	487	165$	3:00	Yes
70	5	344	189$	3:00	Yes
71	5	178	215$	3:00	No
72	6	448	163$	3:00	Yes
73	6	385	189$	3:00	No
74	6	236	225$	3:00	Yes
75	7	495	153$	3:00	Yes
76	7	309	144$	3:00	No
77	7	210	182$	3:00	Yes
78	8	276	129$	3:00	No
79	8	239	151$	3:00	No
80	8	97	181$	3:00	Yes
81	9	178	89$	3:00	Yes
82	10	97	93$	3:00	No
83	10	72	102$	3:00	Yes
84	10	34	127$	3:00	No
85	1	856	88$	4:00	No
86	1	550	111$	4:00	Yes
87	1	326	136$	4:00	No
88	2	413	79$	4:00	No
89	2	272	102$	4:00	No
90	2	131	127$	4:00	Yes
91	3	970	166$	4:00	No
92	3	639	200$	4:00	No
93	3	242	233$	4:00	Yes
94	4	878	169$	4:00	No
95	4	720	190$	4:00	Yes
96	4	270	231$	4:00	Yes
97	5	423	170$	4:00	Yes
98	5	352	197$	4:00	Yes
99	5	129	222$	4:00	Yes
100	6	440	168$	4:00	Yes
101	6	428	198$	4:00	Yes
102	6	239	211$	4:00	Yes
103	7	409	151$	4:00	Yes
104	7	397	143$	4:00	No

105	7	140	169$	4:00	Yes
106	8	296	120$	4:00	Yes
107	8	244	151$	4:00	No
108	8	74	173$	4:00	Yes
109	9	181	92$	4:00	Yes
110	10	91	90$	4:00	No
111	10	76	102$	4:00	Yes
112	10	31	117$	4:00	No
113	1	844	89$	5:00	No
114	1	535	109$	5:00	Yes
115	1	350	133$	5:00	No
116	2	380	80$	5:00	No
117	2	328	113$	5:00	No
118	2	123	147$	5:00	No
119	3	938	170$	5:00	No
120	3	618	197$	5:00	Yes
121	3	251	238$	5:00	No
122	4	995	166$	5:00	Yes
123	4	633	193$	5:00	Yes
124	4	429	228$	5:00	Yes
125	5	544	168$	5:00	No
126	5	396	190$	5:00	No
127	5	123	217$	5:00	Yes
128	6	417	161$	5:00	Yes
129	6	298	198$	5:00	No
130	6	131	226$	5:00	Yes
131	7	434	151$	5:00	Yes
132	7	421	141$	5:00	Yes
133	7	210	179$	5:00	No
134	8	279	126$	5:00	No
135	8	198	142$	5:00	Yes
136	8	73	181$	5:00	Yes
137	9	200	87$	5:00	Yes
138	10	95	88$	5:00	No
139	10	66	105$	5:00	Yes
140	10	44	122$	5:00	No
141	1	715	88$	6:00	No
142	1	580	106$	6:00	No
143	1	212	120$	6:00	No
144	2	386	82$	6:00	Yes
145	2	267	109$	6:00	No
146	2	109	129$	6:00	Yes
147	3	885	161$	6:00	Yes
148	3	721	196$	6:00	Yes
149	3	349	226$	6:00	No
150	4	841	161$	6:00	No
151	4	686	190$	6:00	Yes
152	4	265	233$	6:00	Yes

153	5	556	165$	6:00	Yes
154	5	401	194$	6:00	Yes
155	5	246	225$	6:00	Yes
156	6	491	166$	6:00	No
157	6	368	194$	6:00	Yes
158	6	196	221$	6:00	Yes
159	7	535	147$	6:00	Yes
160	7	423	151$	6:00	No
161	7	211	166$	6:00	Yes
162	8	271	121$	6:00	No
163	8	235	144$	6:00	No
164	8	78	171$	6:00	Yes
165	9	204	90$	6:00	Yes
166	10	98	86$	6:00	No
167	10	75	105$	6:00	Yes
168	10	42	129$	6:00	Yes
169	1	820	86$	7:00	Yes
170	1	553	108$	7:00	Yes
171	1	190	147$	7:00	No
172	2	401	84$	7:00	Yes
173	2	306	102$	7:00	No
174	2	153	142$	7:00	No
175	3	866	162$	7:00	No
176	3	577	200$	7:00	Yes
177	3	377	214$	7:00	Yes
178	4	976	170$	7:00	Yes
179	4	710	190$	7:00	Yes
180	4	244	236$	7:00	Yes
181	5	538	169$	7:00	No
182	5	338	193$	7:00	No
183	5	137	240$	7:00	Yes
184	6	552	170$	7:00	No
185	6	385	191$	7:00	No
186	6	167	217$	7:00	No
187	7	524	149$	7:00	No
188	7	393	141$	7:00	Yes
189	7	248	176$	7:00	No
190	8	307	126$	7:00	Yes
191	8	210	143$	7:00	No
192	8	90	166$	7:00	No
193	9	176	87$	7:00	No
194	10	104	88$	7:00	No
195	10	63	101$	7:00	Yes
196	10	43	122$	7:00	No
197	1	863	86$	8:00	Yes
198	1	608	109$	8:00	Yes
199	1	215	124$	8:00	Yes
200	2	345	87$	8:00	Yes

201	2	285	102$	8:00	No
202	2	187	136$	8:00	No
203	3	796	168$	8:00	Yes
204	3	729	189$	8:00	Yes
205	3	265	211$	8:00	Yes
206	4	972	163$	8:00	Yes
207	4	641	189$	8:00	Yes
208	4	420	218$	8:00	No
209	5	492	173$	8:00	No
210	5	319	198$	8:00	No
211	5	221	214$	8:00	No
212	6	424	163$	8:00	Yes
213	6	351	193$	8:00	Yes
214	6	133	217$	8:00	No
215	7	431	151$	8:00	Yes
216	7	332	148$	8:00	No
217	7	221	180$	8:00	No
218	8	289	129$	8:00	Yes
219	8	185	144$	8:00	Yes
220	8	81	171$	8:00	No
221	9	214	90$	8:00	Yes
222	10	95	92$	8:00	No
223	10	75	105$	8:00	No
224	10	31	118$	8:00	Yes
225	1	690	79$	9:00	Yes
226	1	466	108$	9:00	Yes
227	1	224	143$	9:00	No
228	2	304	81$	9:00	No
229	2	270	102$	9:00	Yes
230	2	156	145$	9:00	Yes
231	3	671	170$	9:00	No
232	3	578	194$	9:00	Yes
233	3	279	210$	9:00	No
234	4	715	168$	9:00	No
235	4	508	201$	9:00	Yes
236	4	339	224$	9:00	Yes
237	5	379	170$	9:00	No
238	5	347	191$	9:00	Yes
239	5	179	243$	9:00	No
240	6	410	169$	9:00	Yes
241	6	315	194$	9:00	Yes
242	6	105	228$	9:00	Yes
243	7	440	139$	9:00	No
244	7	303	144$	9:00	Yes
245	7	146	175$	9:00	No
246	8	257	128$	9:00	No
247	8	153	150$	9:00	No
248	8	104	171$	9:00	No

249	9	162	86$	9:00	No
250	9	141	102$	9:00	No
251	9	66	114$	9:00	No
252	10	79	90$	9:00	Yes
253	10	64	103$	9:00	No
254	10	35	114$	9:00	Yes
255	1	674	78$	10:00	Yes
256	1	539	113$	10:00	Yes
257	1	303	124$	10:00	No
258	2	339	85$	10:00	Yes
259	2	271	112$	10:00	Yes
260	2	144	123$	10:00	No
261	3	812	166$	10:00	Yes
262	3	528	200$	10:00	No
263	3	283	215$	10:00	No
264	4	732	173$	10:00	No
265	4	544	193$	10:00	Yes
266	4	338	239$	10:00	Yes
267	5	387	170$	10:00	No
268	5	272	190$	10:00	No
269	5	177	226$	10:00	Yes
270	6	401	161$	10:00	No
271	6	323	189$	10:00	Yes
272	6	145	243$	10:00	Yes
273	7	451	155$	10:00	Yes
274	7	354	144$	10:00	Yes
275	7	193	177$	10:00	No
276	8	273	121$	10:00	No
277	8	182	144$	10:00	No
278	8	65	157$	10:00	Yes
279	9	193	90$	10:00	No
280	9	118	108$	10:00	No
281	9	48	117$	10:00	No
282	10	96	86$	10:00	No
283	10	61	104$	10:00	No
284	10	41	114$	10:00	No
285	1	662	85$	11:00	Yes
286	1	526	103$	11:00	Yes
287	1	288	123$	11:00	No
288	2	314	87$	11:00	Yes
289	2	220	109$	11:00	Yes
290	2	84	121$	11:00	Yes
291	3	802	168$	11:00	Yes
292	3	546	194$	11:00	No
293	3	218	238$	11:00	Yes
294	4	725	172$	11:00	Yes
295	4	607	194$	11:00	Yes
296	4	235	240$	11:00	No

297	5	389	169$	11:00	No
298	5	284	189$	11:00	No
299	5	126	232$	11:00	Yes
300	6	443	163$	11:00	No
301	6	309	193$	11:00	No
302	6	123	211$	11:00	Yes
303	7	469	151$	11:00	No
304	7	313	151$	11:00	Yes
305	7	111	166$	11:00	No
306	8	236	120$	11:00	No
307	8	204	141$	11:00	Yes
308	8	63	172$	11:00	No
309	9	155	87$	11:00	No
310	9	118	105$	11:00	No
311	9	41	122$	11:00	No
312	10	79	91$	11:00	Yes
313	10	71	102$	11:00	Yes
314	10	35	120$	11:00	Yes
315	1	600	82$	12:00	No
316	1	437	111$	12:00	Yes
317	1	291	131$	12:00	No
318	2	331	87$	12:00	Yes
319	2	218	104$	12:00	Yes
320	2	87	123$	12:00	Yes
321	3	692	163$	12:00	No
322	3	593	190$	12:00	Yes
323	3	336	235$	12:00	Yes
324	4	699	169$	12:00	No
325	4	679	196$	12:00	No
326	4	199	226$	12:00	No
327	5	403	162$	12:00	No
328	5	272	194$	12:00	No
329	5	161	226$	12:00	No
330	6	380	162$	12:00	Yes
331	6	285	196$	12:00	Yes
332	6	169	212$	12:00	Yes
333	7	431	153$	12:00	No
334	7	251	151$	12:00	Yes
335	7	110	159$	12:00	Yes
336	8	254	129$	12:00	Yes
337	8	189	149$	12:00	No
338	8	100	157$	12:00	Yes
339	9	188	86$	12:00	Yes
340	9	145	102$	12:00	No
341	9	72	123$	12:00	Yes
342	10	82	87$	12:00	No
343	10	59	104$	12:00	Yes
344	10	27	123$	12:00	Yes

345	1	593	87$	13:00	No
346	1	527	109$	13:00	Yes
347	1	296	140$	13:00	Yes
348	2	318	87$	13:00	Yes
349	2	212	112$	13:00	No
350	2	81	133$	13:00	Yes
351	3	766	172$	13:00	No
352	3	602	196$	13:00	No
353	3	310	222$	13:00	No
354	4	782	170$	13:00	No
355	4	564	201$	13:00	No
356	4	309	236$	13:00	No
357	5	408	168$	13:00	No
358	5	301	191$	13:00	Yes
359	5	118	219$	13:00	No
360	6	401	165$	13:00	Yes
361	6	327	196$	13:00	Yes
362	6	116	224$	13:00	Yes
363	7	418	147$	13:00	Yes
364	7	316	142$	13:00	Yes
365	7	192	168$	13:00	Yes
366	8	256	126$	13:00	No
367	8	200	148$	13:00	No
368	8	75	174$	13:00	Yes
369	9	157	92$	13:00	Yes
370	9	136	101$	13:00	No
371	9	68	118$	13:00	No
372	10	96	92$	13:00	Yes
373	10	74	102$	13:00	Yes
374	10	33	119$	13:00	No
375	1	685	85$	14:00	Yes
376	1	489	106$	14:00	No
377	1	244	128$	14:00	No
378	2	366	79$	14:00	Yes
379	2	282	112$	14:00	No
380	2	141	128$	14:00	No
381	3	810	161$	14:00	No
382	3	652	194$	14:00	Yes
383	3	296	225$	14:00	Yes
384	4	874	165$	14:00	No
385	4	516	201$	14:00	No
386	4	258	211$	14:00	No
387	5	480	169$	14:00	Yes
388	5	301	193$	14:00	Yes
389	5	156	222$	14:00	No
390	6	378	163$	14:00	No
391	6	294	200$	14:00	Yes
392	6	199	219$	14:00	Yes

393	7	442	147$	14:00	Yes
394	7	385	150$	14:00	Yes
395	7	124	177$	14:00	Yes
396	8	266	129$	14:00	Yes
397	8	186	149$	14:00	No
398	8	93	174$	14:00	No
399	9	179	90$	14:00	No
400	9	148	107$	14:00	No
401	9	61	124$	14:00	No
402	10	79	87$	14:00	Yes
403	10	63	107$	14:00	No
404	10	31	130$	14:00	Yes
405	1	739	79$	15:00	No
406	1	487	102$	15:00	No
407	1	235	140$	15:00	Yes
408	2	346	79$	15:00	No
409	2	211	108$	15:00	No
410	2	84	125$	15:00	Yes
411	3	715	173$	15:00	No
412	3	584	191$	15:00	Yes
413	3	320	243$	15:00	Yes
414	4	661	170$	15:00	No
415	4	459	191$	15:00	No
416	4	312	219$	15:00	No
417	5	431	172$	15:00	No
418	5	308	194$	15:00	No
419	5	185	240$	15:00	Yes
420	6	398	166$	15:00	No
421	6	293	194$	15:00	Yes
422	6	146	221$	15:00	No
423	7	400	139$	15:00	Yes
424	7	358	147$	15:00	Yes
425	7	189	175$	15:00	No
426	8	261	130$	15:00	No
427	8	167	150$	15:00	Yes
428	8	105	157$	15:00	No
429	9	172	90$	15:00	Yes
430	9	137	102$	15:00	No
431	9	48	112$	15:00	No
432	10	79	87$	15:00	Yes
433	10	73	106$	15:00	No
434	10	38	114$	15:00	Yes
435	1	609	78$	16:00	Yes
436	1	510	112$	16:00	No
437	1	214	130$	16:00	No
438	2	340	82$	16:00	Yes
439	2	279	103$	16:00	No
440	2	113	122$	16:00	Yes

441	3	706	166$	16:00	Yes
442	3	477	200$	16:00	No
443	3	248	226$	16:00	No
444	4	735	166$	16:00	No
445	4	638	189$	16:00	Yes
446	4	212	226$	16:00	No
447	5	415	172$	16:00	Yes
448	5	339	198$	16:00	Yes
449	5	207	240$	16:00	Yes
450	6	423	163$	16:00	No
451	6	360	190$	16:00	No
452	6	169	210$	16:00	No
453	7	374	141$	16:00	No
454	7	288	151$	16:00	No
455	7	128	160$	16:00	No
456	8	237	126$	16:00	No
457	8	168	151$	16:00	No
458	8	87	162$	16:00	Yes
459	9	170	87$	16:00	Yes
460	9	119	107$	16:00	No
461	9	59	120$	16:00	No
462	10	88	87$	16:00	No
463	1	487	79$	17:00	No
464	1	321	103$	17:00	No
465	1	155	136$	17:00	No
466	2	260	84$	17:00	Yes
467	2	157	109$	17:00	Yes
468	2	109	147$	17:00	Yes
469	3	579	173$	17:00	Yes
470	3	329	200$	17:00	No
471	3	236	232$	17:00	No
472	4	631	168$	17:00	No
473	4	444	193$	17:00	No
474	4	215	229$	17:00	Yes
475	5	307	165$	17:00	No
476	5	258	193$	17:00	Yes
477	5	153	233$	17:00	Yes
478	6	275	172$	17:00	Yes
479	6	228	189$	17:00	Yes
480	6	114	222$	17:00	Yes
481	7	307	149$	17:00	Yes
482	7	230	145$	17:00	No
483	7	138	177$	17:00	No
484	8	154	129$	17:00	No
485	8	113	144$	17:00	No
486	8	69	172$	17:00	Yes
487	9	114	90$	17:00	No
488	9	85	102$	17:00	No

489	9	60	129$	17:00	Yes
490	10	61	90$	17:00	Yes
491	1	526	84$	18:00	No
492	1	358	112$	18:00	No
493	1	143	139$	18:00	No
494	2	274	87$	18:00	Yes
495	2	217	105$	18:00	Yes
496	2	121	135$	18:00	Yes
497	3	539	165$	18:00	Yes
498	3	388	190$	18:00	Yes
499	3	225	217$	18:00	Yes
500	4	514	165$	18:00	No
501	4	367	191$	18:00	No
502	4	208	211$	18:00	No
503	5	329	161$	18:00	Yes
504	5	196	194$	18:00	No
505	5	125	212$	18:00	No
506	6	287	166$	18:00	No
507	6	204	201$	18:00	Yes
508	6	120	212$	18:00	Yes
509	7	334	143$	18:00	No
510	7	197	142$	18:00	No
511	7	136	180$	18:00	No
512	8	155	127$	18:00	No
513	8	115	145$	18:00	Yes
514	8	48	176$	18:00	Yes
515	9	105	89$	18:00	No
516	9	84	105$	18:00	Yes
517	9	29	112$	18:00	Yes
518	10	54	90$	18:00	No
519	1	472	87$	19:00	No
520	1	382	102$	19:00	Yes
521	1	180	147$	19:00	No
522	2	191	81$	19:00	Yes
523	2	170	108$	19:00	Yes
524	2	58	131$	19:00	No
525	3	524	170$	19:00	Yes
526	3	393	194$	19:00	Yes
527	3	248	214$	19:00	Yes
528	4	546	162$	19:00	No
529	4	434	200$	19:00	No
530	4	182	243$	19:00	Yes
531	5	254	170$	19:00	No
532	5	197	191$	19:00	No
533	5	98	215$	19:00	No
534	6	309	163$	19:00	Yes
535	6	186	200$	19:00	Yes
536	6	79	229$	19:00	No

537	7	264	147$	19:00	Yes
538	7	218	149$	19:00	Yes
539	7	75	172$	19:00	No
540	8	175	126$	19:00	Yes
541	8	132	147$	19:00	Yes
542	8	42	176$	19:00	No
543	9	126	87$	19:00	No
544	9	79	103$	19:00	No
545	9	34	130$	19:00	Yes
546	10	58	88$	19:00	Yes
547	1	519	79$	20:00	Yes
548	1	309	105$	20:00	Yes
549	1	136	121$	20:00	No
550	2	213	85$	20:00	Yes
551	2	194	109$	20:00	No
552	2	103	133$	20:00	No
553	3	522	169$	20:00	No
554	3	493	190$	20:00	Yes
555	3	203	226$	20:00	No
556	4	493	162$	20:00	Yes
557	4	386	190$	20:00	Yes
558	4	186	233$	20:00	Yes
559	5	351	172$	20:00	Yes
560	5	231	200$	20:00	Yes
561	5	79	210$	20:00	Yes
562	6	273	166$	20:00	Yes
563	6	242	200$	20:00	No
564	6	106	215$	20:00	Yes
565	7	283	147$	20:00	Yes
566	7	226	145$	20:00	No
567	7	77	178$	20:00	No
568	8	187	124$	20:00	Yes
569	8	126	144$	20:00	No
570	8	78	171$	20:00	Yes
571	9	130	90$	20:00	Yes
572	9	87	101$	20:00	No
573	9	59	115$	20:00	Yes
574	10	64	91$	20:00	Yes
575	1	504	78$	21:00	Yes
576	1	332	113$	21:00	No
577	1	126	136$	21:00	Yes
578	2	220	86$	21:00	Yes
579	2	170	110$	21:00	Yes
580	2	71	130$	21:00	Yes
581	3	471	161$	21:00	Yes
582	3	403	200$	21:00	No
583	3	215	233$	21:00	No
584	4	456	161$	21:00	No

585	4	384	201$	21:00	Yes
586	4	228	229$	21:00	Yes
587	5	293	172$	21:00	No
588	5	234	200$	21:00	No
589	5	131	217$	21:00	Yes
590	6	274	161$	21:00	Yes
591	6	175	196$	21:00	No
592	6	126	219$	21:00	Yes
593	7	323	151$	21:00	No
594	7	246	150$	21:00	Yes
595	7	92	176$	21:00	No
596	8	181	124$	21:00	Yes
597	8	122	144$	21:00	Yes
598	8	58	172$	21:00	No
599	9	113	86$	21:00	Yes
600	9	81	102$	21:00	No
601	9	43	119$	21:00	No
602	10	55	89$	21:00	Yes
603	1	412	83$	22:00	No
604	1	289	110$	22:00	Yes
605	1	167	120$	22:00	No
606	2	194	78$	22:00	No
607	2	172	104$	22:00	No
608	2	100	126$	22:00	Yes
609	3	499	163$	22:00	No
610	3	418	191$	22:00	Yes
611	3	229	214$	22:00	No
612	4	429	161$	22:00	No
613	4	298	201$	22:00	Yes
614	4	155	226$	22:00	No
615	5	267	172$	22:00	Yes
616	5	212	191$	22:00	Yes
617	5	75	228$	22:00	No
618	6	248	162$	22:00	Yes
619	6	163	196$	22:00	Yes
620	6	111	225$	22:00	No
621	7	264	147$	22:00	No
622	7	183	149$	22:00	Yes
623	7	110	180$	22:00	Yes
624	8	176	123$	22:00	Yes
625	8	132	149$	22:00	Yes
626	8	83	172$	22:00	No
627	9	121	91$	22:00	Yes
628	9	95	105$	22:00	Yes
629	9	37	117$	22:00	No
630	10	55	88$	22:00	No
631	1	423	78$	23:00	Yes
632	1	326	104$	23:00	No

633	1	169	127$	23:00	No
634	2	256	87$	23:00	Yes
635	2	157	112$	23:00	Yes
636	2	69	133$	23:00	No
637	3	553	169$	23:00	Yes
638	3	442	190$	23:00	Yes
639	3	138	222$	23:00	No
640	4	589	162$	23:00	Yes
641	4	393	198$	23:00	Yes
642	4	196	224$	23:00	Yes
643	5	262	168$	23:00	Yes
644	5	195	191$	23:00	Yes
645	5	135	221$	23:00	Yes
646	6	274	173$	23:00	No
647	6	227	201$	23:00	No
648	6	148	236$	23:00	No
649	7	316	141$	23:00	Yes
650	7	237	150$	23:00	Yes
651	7	86	177$	23:00	Yes
652	8	156	130$	23:00	No
653	8	128	145$	23:00	Yes
654	8	45	175$	23:00	No
655	9	113	87$	23:00	Yes
656	9	77	101$	23:00	Yes
657	9	41	126$	23:00	Yes
658	10	54	87$	23:00	No
659	1	420	87$	24:00	No
660	1	363	108$	24:00	Yes
661	1	170	122$	24:00	Yes
662	2	217	78$	24:00	Yes
663	2	199	112$	24:00	Yes
664	2	108	129$	24:00	Yes
665	3	481	161$	24:00	No
666	3	414	198$	24:00	Yes
667	3	147	226$	24:00	No
668	4	486	163$	24:00	Yes
669	4	394	198$	24:00	Yes
670	4	131	214$	24:00	Yes
671	5	253	163$	24:00	Yes
672	5	198	189$	24:00	No
673	5	82	232$	24:00	Yes
674	6	300	172$	24:00	No
675	6	234	189$	24:00	No
676	6	73	243$	24:00	Yes
677	7	336	143$	24:00	Yes
678	7	213	144$	24:00	Yes
679	7	84	166$	24:00	Yes
680	8	150	121$	24:00	No

681	8	138	148$	24:00	Yes
682	8	52	160$	24:00	No
683	9	110	87$	24:00	No
684	9	81	104$	24:00	Yes
685	9	55	114$	24:00	No
686	10	55	87$	24:00	Yes

BLOCK OFFER

TOPLAM BLOK SATIS TEKLIF SAYISI 14

ID	ID2	START	END	DURATION	AMOUNT	PRICE
1	1	1:00	5:00	4	171	64$
2	1	18:00	22:00	4	49	64$
3	2	1:00	9:00	8	48	63$
4	2	16:00	24:00	8	12	65$
5	3	1:00	24:00	23	58	148$
6	3	16:00	24:00	8	20	147$
7	4	1:00	9:00	8	80	151$
8	4	16:00	24:00	8	61	156$
9	5	1:00	9:00	8	52	159$
10	5	16:00	24:00	8	33	151$
11	6	1:00	9:00	8	69	159$
12	6	16:00	24:00	8	25	158$
13	7	1:00	9:00	8	34	110$
14	8	1:00	9:00	8	41	117$

FLEXIBLE OFFER

ID	ID2	AMOUNT	PRICE
24	1	43	135$
24	2	15	126$
24	3	24	333$
22	4	73	295$
22	5	40	282$
24	6	29	319$
24	7	30	222$
24	8	46	229$
24	9	23	186$
24	10	17	186$

ACCEPTED HOURLY OFFERS

ID	ID2	AMOUNT	PRICE	HOUR	PARTIAL	ACCEPTED AMOUNT
1	1	744	85$	1:00	Yes	744
20	7	313	145$	1:00	Yes	251
22	8	259	127$	1:00	Yes	259
23	8	244	143$	1:00	Yes	244
25	9	206	90$	1:00	Yes	206
26	10	92	86$	1:00	Yes	92
28	10	29	122$	1:00	Yes	29
2	1	563	110$	1:00	No	563
4	2	426	81$	1:00	No	426
5	2	307	102$	1:00	No	307
6	2	118	143$	1:00	No	118
19	7	494	153$	1:00	No	494
27	10	84	101$	1:00	No	84
48	7	418	148$	2:00	Yes	43
56	10	48	126$	2:00	Yes	48
29	1	797	87$	2:00	No	797
30	1	602	103$	2:00	No	602
31	1	194	123$	2:00	No	194
32	2	377	78$	2:00	No	377
33	2	278	109$	2:00	No	278
47	7	557	139$	2:00	No	557
50	8	275	123$	2:00	No	275
51	8	193	148$	2:00	No	193
53	9	194	91$	2:00	No	194
54	10	99	91$	2:00	No	99
55	10	87	108$	2:00	No	87
81	9	178	89$	3:00	Yes	134
57	1	756	79$	3:00	No	756
58	1	531	110$	3:00	No	531
59	1	388	127$	3:00	No	388
60	2	370	89$	3:00	No	370
61	2	292	108$	3:00	No	292
62	2	175	128$	3:00	No	175
76	7	309	144$	3:00	No	309
78	8	276	129$	3:00	No	276
79	8	239	151$	3:00	No	239
82	10	97	93$	3:00	No	97
86	1	550	111$	4:00	Yes	550
106	8	296	120$	4:00	Yes	230
109	9	181	92$	4:00	Yes	181
111	10	76	102$	4:00	Yes	76
85	1	856	88$	4:00	No	856
87	1	326	136$	4:00	No	326
88	2	413	79$	4:00	No	413

89	2	272	102$	4:00	No		272
91	3	970	166$	4:00	No		970
104	7	397	143$	4:00	No		397
110	10	91	90$	4:00	No		91
112	10	31	117$	4:00	No		31
114	1	535	109$	5:00	Yes		535
128	6	417	161$	5:00	Yes		224
131	7	434	151$	5:00	Yes		434
132	7	421	141$	5:00	Yes		421
135	8	198	142$	5:00	Yes		198
137	9	200	87$	5:00	Yes		200
139	10	66	105$	5:00	Yes		66
113	1	844	89$	5:00	No		844
115	1	350	133$	5:00	No		350
116	2	380	80$	5:00	No		380
117	2	328	113$	5:00	No		328
118	2	123	147$	5:00	No		123
134	8	279	126$	5:00	No		279
138	10	95	88$	5:00	No		95
140	10	44	122$	5:00	No		44
144	2	386	82$	6:00	Yes		386
146	2	109	129$	6:00	Yes		109
159	7	535	147$	6:00	Yes		314
165	9	204	90$	6:00	Yes		204
167	10	75	105$	6:00	Yes		75
168	10	42	129$	6:00	Yes		42
141	1	715	88$	6:00	No		715
142	1	580	106$	6:00	No		580
143	1	212	120$	6:00	No		212
145	2	267	109$	6:00	No		267
160	7	423	151$	6:00	No		423
162	8	271	121$	6:00	No		271
163	8	235	144$	6:00	No		235
166	10	98	86$	6:00	No		98
169	1	820	86$	7:00	Yes		820
170	1	553	108$	7:00	Yes		553
172	2	401	84$	7:00	Yes		401
188	7	393	141$	7:00	Yes		384
190	8	307	126$	7:00	Yes		307
195	10	63	101$	7:00	Yes		63
173	2	306	102$	7:00	No		306
187	7	524	149$	7:00	No		524
191	8	210	143$	7:00	No		210
193	9	176	87$	7:00	No		176
194	10	104	88$	7:00	No		104
196	10	43	122$	7:00	No		43
197	1	863	86$	8:00	Yes		863
198	1	608	109$	8:00	Yes		608

199	1	215	124$	8:00	Yes	215
200	2	345	87$	8:00	Yes	345
212	6	424	163$	8:00	Yes	105
215	7	431	151$	8:00	Yes	431
218	8	289	129$	8:00	Yes	289
219	8	185	144$	8:00	Yes	185
221	9	214	90$	8:00	Yes	214
224	10	31	118$	8:00	Yes	31
201	2	285	102$	8:00	No	285
202	2	187	136$	8:00	No	187
216	7	332	148$	8:00	No	332
222	10	95	92$	8:00	No	95
223	10	75	105$	8:00	No	75
225	1	690	79$	9:00	Yes	690
226	1	466	108$	9:00	Yes	466
229	2	270	102$	9:00	Yes	270
230	2	156	145$	9:00	Yes	139
244	7	303	144$	9:00	Yes	303
252	10	79	90$	9:00	Yes	79
254	10	35	114$	9:00	Yes	35
227	1	224	143$	9:00	No	224
228	2	304	81$	9:00	No	304
231	3	671	170$	9:00	No	671
234	4	715	168$	9:00	No	715
243	7	440	139$	9:00	No	440
246	8	257	128$	9:00	No	257
247	8	153	150$	9:00	No	153
249	9	162	86$	9:00	No	162
250	9	141	102$	9:00	No	141
251	9	66	114$	9:00	No	66
253	10	64	103$	9:00	No	64
255	1	674	78$	10:00	Yes	674
256	1	539	113$	10:00	Yes	539
258	2	339	85$	10:00	Yes	339
259	2	271	112$	10:00	Yes	271
261	3	812	166$	10:00	Yes	486
273	7	451	155$	10:00	Yes	451
274	7	354	144$	10:00	Yes	354
278	8	65	157$	10:00	Yes	65
257	1	303	124$	10:00	No	303
260	2	144	123$	10:00	No	144
270	6	401	161$	10:00	No	401
276	8	273	121$	10:00	No	273
277	8	182	144$	10:00	No	182
279	9	193	90$	10:00	No	193
280	9	118	108$	10:00	No	118
281	9	48	117$	10:00	No	48
282	10	96	86$	10:00	No	96

283	10	61	104$	10:00	No	61
284	10	41	114$	10:00	No	41
285	1	662	85$	11:00	Yes	662
286	1	526	103$	11:00	Yes	526
288	2	314	87$	11:00	Yes	314
289	2	220	109$	11:00	Yes	220
290	2	84	121$	11:00	Yes	84
291	3	802	168$	11:00	Yes	615
304	7	313	151$	11:00	Yes	313
307	8	204	141$	11:00	Yes	204
312	10	79	91$	11:00	Yes	79
313	10	71	102$	11:00	Yes	71
314	10	35	120$	11:00	Yes	35
287	1	288	123$	11:00	No	288
300	6	443	163$	11:00	No	443
303	7	469	151$	11:00	No	469
305	7	111	166$	11:00	No	111
306	8	236	120$	11:00	No	236
309	9	155	87$	11:00	No	155
310	9	118	105$	11:00	No	118
311	9	41	122$	11:00	No	41
316	1	437	111$	12:00	Yes	437
318	2	331	87$	12:00	Yes	331
319	2	218	104$	12:00	Yes	218
320	2	87	123$	12:00	Yes	87
330	6	380	162$	12:00	Yes	249
334	7	251	151$	12:00	Yes	251
335	7	110	159$	12:00	Yes	110
336	8	254	129$	12:00	Yes	254
338	8	100	157$	12:00	Yes	100
339	9	188	86$	12:00	Yes	188
341	9	72	123$	12:00	Yes	72
343	10	59	104$	12:00	Yes	59
344	10	27	123$	12:00	Yes	27
315	1	600	82$	12:00	No	600
317	1	291	131$	12:00	No	291
321	3	692	163$	12:00	No	692
327	5	403	162$	12:00	No	403
333	7	431	153$	12:00	No	431
337	8	189	149$	12:00	No	189
340	9	145	102$	12:00	No	145
342	10	82	87$	12:00	No	82
346	1	527	109$	13:00	Yes	527
347	1	296	140$	13:00	Yes	296
348	2	318	87$	13:00	Yes	318
350	2	81	133$	13:00	Yes	81
363	7	418	147$	13:00	Yes	280
364	7	316	142$	13:00	Yes	316

369	9	157	92$	13:00	Yes	157
372	10	96	92$	13:00	Yes	96
373	10	74	102$	13:00	Yes	74
345	1	593	87$	13:00	No	593
349	2	212	112$	13:00	No	212
354	4	782	170$	13:00	No	782
357	5	408	168$	13:00	No	408
366	8	256	126$	13:00	No	256
367	8	200	148$	13:00	No	200
370	9	136	101$	13:00	No	136
371	9	68	118$	13:00	No	68
374	10	33	119$	13:00	No	33
375	1	685	85$	14:00	Yes	685
378	2	366	79$	14:00	Yes	366
393	7	442	147$	14:00	Yes	442
394	7	385	150$	14:00	Yes	12
396	8	266	129$	14:00	Yes	266
402	10	79	87$	14:00	Yes	79
404	10	31	130$	14:00	Yes	31
376	1	489	106$	14:00	No	489
377	1	244	128$	14:00	No	244
379	2	282	112$	14:00	No	282
380	2	141	128$	14:00	No	141
381	3	810	161$	14:00	No	810
384	4	874	165$	14:00	No	874
390	6	378	163$	14:00	No	378
397	8	186	149$	14:00	No	186
399	9	179	90$	14:00	No	179
400	9	148	107$	14:00	No	148
401	9	61	124$	14:00	No	61
403	10	63	107$	14:00	No	63
407	1	235	140$	15:00	Yes	235
410	2	84	125$	15:00	Yes	84
423	7	400	139$	15:00	Yes	400
424	7	358	147$	15:00	Yes	358
427	8	167	150$	15:00	Yes	87
429	9	172	90$	15:00	Yes	172
432	10	79	87$	15:00	Yes	79
434	10	38	114$	15:00	Yes	38
405	1	739	79$	15:00	No	739
406	1	487	102$	15:00	No	487
408	2	346	79$	15:00	No	346
409	2	211	108$	15:00	No	211
414	4	661	170$	15:00	No	661
417	5	431	172$	15:00	No	431
420	6	398	166$	15:00	No	398
426	8	261	130$	15:00	No	261
428	8	105	157$	15:00	No	105

430	9	137	102$	15:00	No	137
431	9	48	112$	15:00	No	48
433	10	73	106$	15:00	No	73
435	1	609	78$	16:00	Yes	609
438	2	340	82$	16:00	Yes	340
440	2	113	122$	16:00	Yes	113
441	3	706	166$	16:00	Yes	201
458	8	87	162$	16:00	Yes	87
459	9	170	87$	16:00	Yes	170
436	1	510	112$	16:00	No	510
437	1	214	130$	16:00	No	214
439	2	279	103$	16:00	No	279
444	4	735	166$	16:00	No	735
450	6	423	163$	16:00	No	423
453	7	374	141$	16:00	No	374
454	7	288	151$	16:00	No	288
455	7	128	160$	16:00	No	128
456	8	237	126$	16:00	No	237
457	8	168	151$	16:00	No	168
460	9	119	107$	16:00	No	119
461	9	59	120$	16:00	No	59
462	10	88	87$	16:00	No	88
466	2	260	84$	17:00	Yes	260
467	2	157	109$	17:00	Yes	157
468	2	109	147$	17:00	Yes	109
469	3	579	173$	17:00	Yes	579
474	4	215	229$	17:00	Yes	147
476	5	258	193$	17:00	Yes	258
478	6	275	172$	17:00	Yes	275
479	6	228	189$	17:00	Yes	228
480	6	114	222$	17:00	Yes	114
481	7	307	149$	17:00	Yes	307
486	8	69	172$	17:00	Yes	69
489	9	60	129$	17:00	Yes	60
490	10	61	90$	17:00	Yes	61
463	1	487	79$	17:00	No	487
464	1	321	103$	17:00	No	321
465	1	155	136$	17:00	No	155
470	3	329	200$	17:00	No	329
471	3	236	232$	17:00	No	236
472	4	631	168$	17:00	No	631
473	4	444	193$	17:00	No	444
475	5	307	165$	17:00	No	307
482	7	230	145$	17:00	No	230
483	7	138	177$	17:00	No	138
484	8	154	129$	17:00	No	154
485	8	113	144$	17:00	No	113
487	9	114	90$	17:00	No	114

488	9	85	102$	17:00	No	85
494	2	274	87$	18:00	Yes	274
495	2	217	105$	18:00	Yes	217
496	2	121	135$	18:00	Yes	121
497	3	539	165$	18:00	Yes	539
498	3	388	190$	18:00	Yes	388
499	3	225	217$	18:00	Yes	225
503	5	329	161$	18:00	Yes	329
507	6	204	201$	18:00	Yes	204
508	6	120	212$	18:00	Yes	120
513	8	115	145$	18:00	Yes	115
514	8	48	176$	18:00	Yes	48
516	9	84	105$	18:00	Yes	84
517	9	29	112$	18:00	Yes	29
491	1	526	84$	18:00	No	526
492	1	358	112$	18:00	No	358
493	1	143	139$	18:00	No	143
500	4	514	165$	18:00	No	514
501	4	367	191$	18:00	No	367
502	4	208	211$	18:00	No	208
504	5	196	194$	18:00	No	196
505	5	125	212$	18:00	No	125
506	6	287	166$	18:00	No	287
509	7	334	143$	18:00	No	334
510	7	197	142$	18:00	No	197
511	7	136	180$	18:00	No	136
512	8	155	127$	18:00	No	155
515	9	105	89$	18:00	No	105
518	10	54	90$	18:00	No	54
520	1	382	102$	19:00	Yes	382
522	2	191	81$	19:00	Yes	191
523	2	170	108$	19:00	Yes	170
525	3	524	170$	19:00	Yes	524
526	3	393	194$	19:00	Yes	393
527	3	248	214$	19:00	Yes	248
530	4	182	243$	19:00	Yes	7
534	6	309	163$	19:00	Yes	309
535	6	186	200$	19:00	Yes	186
537	7	264	147$	19:00	Yes	264
538	7	218	149$	19:00	Yes	218
540	8	175	126$	19:00	Yes	175
541	8	132	147$	19:00	Yes	132
545	9	34	130$	19:00	Yes	34
546	10	58	88$	19:00	Yes	58
519	1	472	87$	19:00	No	472
521	1	180	147$	19:00	No	180
524	2	58	131$	19:00	No	58
528	4	546	162$	19:00	No	546

529	4	434	200$	19:00	No	434
531	5	254	170$	19:00	No	254
532	5	197	191$	19:00	No	197
533	5	98	215$	19:00	No	98
536	6	79	229$	19:00	No	79
539	7	75	172$	19:00	No	75
542	8	42	176$	19:00	No	42
543	9	126	87$	19:00	No	126
544	9	79	103$	19:00	No	79
547	1	519	79$	20:00	Yes	519
548	1	309	105$	20:00	Yes	309
550	2	213	85$	20:00	Yes	213
554	3	493	190$	20:00	Yes	493
556	4	493	162$	20:00	Yes	493
557	4	386	190$	20:00	Yes	386
558	4	186	233$	20:00	Yes	186
559	5	351	172$	20:00	Yes	351
560	5	231	200$	20:00	Yes	231
561	5	79	210$	20:00	Yes	79
562	6	273	166$	20:00	Yes	273
564	6	106	215$	20:00	Yes	106
565	7	283	147$	20:00	Yes	283
568	8	187	124$	20:00	Yes	187
570	8	78	171$	20:00	Yes	78
571	9	130	90$	20:00	Yes	130
573	9	59	115$	20:00	Yes	59
574	10	64	91$	20:00	Yes	64
549	1	136	121$	20:00	No	136
551	2	194	109$	20:00	No	194
552	2	103	133$	20:00	No	103
553	3	522	169$	20:00	No	522
555	3	203	226$	20:00	No	203
563	6	242	200$	20:00	No	242
566	7	226	145$	20:00	No	226
567	7	77	178$	20:00	No	77
569	8	126	144$	20:00	No	126
572	9	87	101$	20:00	No	87
575	1	504	78$	21:00	Yes	504
577	1	126	136$	21:00	Yes	126
578	2	220	86$	21:00	Yes	220
579	2	170	110$	21:00	Yes	170
580	2	71	130$	21:00	Yes	71
581	3	471	161$	21:00	Yes	471
585	4	384	201$	21:00	Yes	384
586	4	228	229$	21:00	Yes	192
589	5	131	217$	21:00	Yes	131
590	6	274	161$	21:00	Yes	274
592	6	126	219$	21:00	Yes	126

594	7	246	150$	21:00	Yes	246
596	8	181	124$	21:00	Yes	181
597	8	122	144$	21:00	Yes	122
599	9	113	86$	21:00	Yes	113
602	10	55	89$	21:00	Yes	55
576	1	332	113$	21:00	No	332
582	3	403	200$	21:00	No	403
583	3	215	233$	21:00	No	215
584	4	456	161$	21:00	No	456
587	5	293	172$	21:00	No	293
588	5	234	200$	21:00	No	234
591	6	175	196$	21:00	No	175
593	7	323	151$	21:00	No	323
595	7	92	176$	21:00	No	92
598	8	58	172$	21:00	No	58
600	9	81	102$	21:00	No	81
601	9	43	119$	21:00	No	43
604	1	289	110$	22:00	Yes	289
608	2	100	126$	22:00	Yes	100
610	3	418	191$	22:00	Yes	418
613	4	298	201$	22:00	Yes	298
615	5	267	172$	22:00	Yes	267
616	5	212	191$	22:00	Yes	212
618	6	248	162$	22:00	Yes	248
619	6	163	196$	22:00	Yes	163
622	7	183	149$	22:00	Yes	183
623	7	110	180$	22:00	Yes	110
624	8	176	123$	22:00	Yes	176
625	8	132	149$	22:00	Yes	132
627	9	121	91$	22:00	Yes	121
628	9	95	105$	22:00	Yes	95
603	1	412	83$	22:00	No	412
605	1	167	120$	22:00	No	167
606	2	194	78$	22:00	No	194
607	2	172	104$	22:00	No	172
609	3	499	163$	22:00	No	499
611	3	229	214$	22:00	No	229
612	4	429	161$	22:00	No	429
614	4	155	226$	22:00	No	155
617	5	75	228$	22:00	No	75
620	6	111	225$	22:00	No	111
621	7	264	147$	22:00	No	264
626	8	83	172$	22:00	No	83
629	9	37	117$	22:00	No	37
630	10	55	88$	22:00	No	55
631	1	423	78$	23:00	Yes	423
634	2	256	87$	23:00	Yes	256
635	2	157	112$	23:00	Yes	157

637	3	553	169$	23:00	Yes	553
638	3	442	190$	23:00	Yes	442
640	4	589	162$	23:00	Yes	589
641	4	393	198$	23:00	Yes	393
642	4	196	224$	23:00	Yes	114
643	5	262	168$	23:00	Yes	262
644	5	195	191$	23:00	Yes	195
645	5	135	221$	23:00	Yes	135
649	7	316	141$	23:00	Yes	316
650	7	237	150$	23:00	Yes	237
651	7	86	177$	23:00	Yes	86
653	8	128	145$	23:00	Yes	128
655	9	113	87$	23:00	Yes	113
656	9	77	101$	23:00	Yes	77
657	9	41	126$	23:00	Yes	41
632	1	326	104$	23:00	No	326
633	1	169	127$	23:00	No	169
636	2	69	133$	23:00	No	69
639	3	138	222$	23:00	No	138
646	6	274	173$	23:00	No	274
647	6	227	201$	23:00	No	227
652	8	156	130$	23:00	No	156
654	8	45	175$	23:00	No	45
658	10	54	87$	23:00	No	54
660	1	363	108$	24:00	Yes	363
661	1	170	122$	24:00	Yes	170
662	2	217	78$	24:00	Yes	217
663	2	199	112$	24:00	Yes	199
664	2	108	129$	24:00	Yes	108
666	3	414	198$	24:00	Yes	414
668	4	486	163$	24:00	Yes	486
669	4	394	198$	24:00	Yes	394
670	4	131	214$	24:00	Yes	131
671	5	253	163$	24:00	Yes	253
673	5	82	232$	24:00	Yes	82
676	6	73	243$	24:00	Yes	73
677	7	336	143$	24:00	Yes	336
678	7	213	144$	24:00	Yes	213
679	7	84	166$	24:00	Yes	84
681	8	138	148$	24:00	Yes	138
684	9	81	104$	24:00	Yes	81
686	10	55	87$	24:00	Yes	55
659	1	420	87$	24:00	No	420
665	3	481	161$	24:00	No	481
667	3	147	226$	24:00	No	147
672	5	198	189$	24:00	No	198
674	6	300	172$	24:00	No	300
675	6	234	189$	24:00	No	234

680	8	150	121$	24:00	No	150
682	8	52	160$	24:00	No	52
683	9	110	87$	24:00	No	110
685	9	55	114$	24:00	No	55

ID	ID2	START	END	DURATION	AMOUNT	PRICE
1	1	1:00	5:00	4	171	64$
2	1	18:00	22:00	4	49	64$
3	2	1:00	9:00	8	48	63$
4	2	16:00	24:00	8	12	65$
5	3	1:00	24:00	23	58	148$
6	3	16:00	24:00	8	20	147$
7	4	1:00	9:00	8	80	151$
8	4	16:00	24:00	8	61	156$
10	5	16:00	24:00	8	33	151$
12	6	16:00	24:00	8	25	158$
13	7	1:00	9:00	8	34	110$
14	8	1:00	9:00	8	41	117$

ID	ID2	AMOUNT	PRICE	HOUR	ACCEPTED AMOUNT
24	1	43	135$	24:00	43
24	2	15	126$	24:00	15
24	3	24	333$	24:00	24
22	4	73	295$	22:00	73
22	5	40	282$	22:00	40
24	6	29	319$	24:00	29
24	7	30	222$	24:00	30
24	8	46	229$	24:00	46
24	9	23	186$	24:00	23
24	10	17	186$	24:00	17

REFERENCES

Akkemik, A. K. and F. Oguz, 2011, "Regulation, Efficiency And Equilibrum: A General Equilibrum Analysis Of Liberalization In The Turkish Electricity Market", *Energy*, Vol. 36, pp. 3282-3292.

Al-Sunaidy, A. and R. Green, 2006, "Electricity Deregulation In OECD (Organization For Economic Cooperation and Development) Countries", *Energy*, Vol. 31, pp. 769-787.

Bagdadioglu, N. and N. Odyakmaz, 2009, "Turkish Electricity Reform", *Utilities Policy*, Vol. 17, pp. 144-152.

Bilgili, M., B. Sahin, A. Yasar, E. Simsek, 2012, "Electric Energy Demands Of Turkey In Residential And Industrial Sectors", *Renewable and Sustainable Energy Reviews*, Vol. 16, pp. 404-414.

Bower, J. and D. W. Bunn, 2000, "Model-Based Comparisons of Pool And Bilateral Markets For Electricity", *The Energy Journal*, Vol. 21, No. 3, pp. 1-30.

Camadam, E., 2011, "Why 2012 Will Be So Important For The Restructured Turkish Electricity Market", *The Electricity Journal*, Vol. 22, pp. 70-78

Cetin, T. and F., Oguz, 2007, "The Politics Of Regulation In The Turkish Electricity Market", *Energy Policy*, Vol. 35, pp. 1761-1770.

Dilaver, Z. and L., C., Hunt, 2011, "Turkish Aggregate Electricity Demand: An Outlook To 2020", *Energy,* Vol. 36, pp. 6686-6696.

Erdogdu, E., 2007, “Regulatory Reform In Turkish Energy Industry: An Analysis”, *Energy Policy*, Vol. 35, pp.984-993.

Erdogdu, E., 2007, “Nuclear Power In Open Energy Markets: A Case Study Of Turkey”, *Energy Policy*, Vol. 35, pp. 3061-3073.

Erdogu, E., 2009, “Some Thoughts On The Turkish Electricity Distribution Industry”, *Renewable and Sustainable Energy Reviews*, Vol. 13, pp. 1485-1494.

Erdogdu, E., 2010, “A Paper On The Settled Question Of Turkish Electricity Market: Balancing and Settlement System (Part I)”, *Applied Energy*, Vol. 87, pp. 251-258.

Gan, D., J., Wang, D., V., Bourcier, 2005, “An Auction Game Model For Pool-based Electricity Markets”, *Electrical Power and Energy Systems*, Vol. 27, pp. 480-487.

Guerci, E., S. Ivaldi, S. Pastore and S. Cincotti, 2005, “Modeling And Implementation Of An Artificial Electricity Market Using Agent-based Technology”, *Physica A*, Vol. 355, pp. 69-76.

Haas, R. and H. Auer, 2006, “The Prerequisites For Effective Competition In Restructured Wholesale Electricity Markets”, *Energy*, Vol. 31, pp. 857-864.

Kucukali, S. and K., Baris, 2009, “Assessment Of Small Hydropower (SHP) Development In Turkey: Law, Regulations And EU Policy Perspective”, *Energy Policy*, Vol. 37, pp. 3872-3879.

Kucukali, S. and K., Baris, 2010, “Turkey’s Short-term Gross Annual Electricity Demand Forecast By Fuzzy Logic Approach”, *Energy Policy*, Vol. 38, pp. 2438-2445.

Mahvi, M. and M., M., Ardehali, 2011, "Optimal Bidding Strategy In A Competitive Electricity Market Based On Agent-based Approach And Numerical Sensitivity Analysis", *Energy*, Vol. 36, pp. 6367-6374.

Or, I. and Guzay, K., 2008, "A Decision Support Tool For The Analysis Of Pricing, Investment And Regulatory Processes In A Decentralized Electricity Market", *Energy Policy*, Vol. 36, pp. 3036-3044.

Ozkivrak, O., 2005, "Electricity Restructuring In Turkey", *Energy Policy*, Vol. 33, pp. 1339-1350.

Ozturk, H., K., A., Yilanci, O., Atalay, 2007, "Past, Present And Future Status Of Electricity In Turkey And The Share Of Energy Resources", *Renewable and Sustainable Energy Reviews*, Vol. 11, pp. 183-209.

Sarica, K., 2010, '*Modeling and Analysis of a Decentralized Electricity Market: An Integrated Simulation/Optimization Approach', Ph.D. Thesis*., Bogazici University

Uzlu, E., A., Akpinar, M., I., Komurcu, 2011, "Restructuring of Turkey's Electricity Market And The Share Of Hydropower Energy: The Case Of The Eastern Black Sea Basin", *Renewable Energy*, Vol. 36, pp. 676-688.

Ventosa M., A. Baillo, A. Ramos and M. Rivier, 2005, "Electricity Market Modeling Trends", *Energy Policy*, Vol. 33, pp. 897-913.

Weidlich, A., D., Veit, 2008, "A Critical Survey Of Agent-based Wholesale Electricity Market Models", *Energy Economic*, Vol.30, pp. 1728-1759.

Trigo, P., P., Marques, H. Coelho, 2010, "(Virtual) Agents For Running Electricity Markets", *Simulation Modelling Practice and Theory*, Vol. 18, pp. 1442-1452.