CAPACITY TRADING IN ELECTRICITY MARKETS

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ABSTRACT

CAPACITY TRADING IN ELECTRICITY MARKETS

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In electricity markets, capacity cost must be determined in order to make capacity trading. In this thesis, capacity cost and the factors deriving the capacity cost are studied. First, fixed capacity cost of power plants is examined. Direct and indirect costs of fixed capacity cost are detailed with respect to different types of power plants and the impact of these factors to the capacity cost is given. Second, interconnection and system utilization costs of transmission and distribution system are considered in order to simulate energy flow from the producer to the customer. Finally, a capacity cost calculation program is practiced. By the help of this program, capacity cost of power plants is figured out, different cases are compared and the main factors affecting the capacity cost are discussed in detail.
Keywords: Capacity, Capacity Trading, Fixed Capacity Cost, Transmission System Interconnection Cost, Transmission System Utilization Cost, Distribution System Interconnection Cost, Distribution System Utilization Cost

ÖZ

ELEKTRİK PİYASASINDA KAPASİTE TİCARETİ

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Elektrik piyasalarında kapasite ticaretinin yapılabilmesi için öncelikle söz konusu kapasitenin fiyatlandırılması gerekmektedir. Bu tezde, kapasitenin fiyatlandırılması ve fiyatlandırmayı etkileyen unsurlar sunulmaktadır. İlk bölümde, tüketiciye kapasiteyi sunacak olan elektrik santrallerinin sabit kapasite bedelleri incelenmektedir. Sabit kapasite bedellerini etkileyen direkt ve dolaylı maliyetler santral türlerine göre ayrı ayrı belirlenmiş ve kapasite fiyatlandırmasına etkileri detaylandırılmıştır. İkinci bölümde, kapasitenin tüketiciye ulaştırılması için gerekli olan iletim ve dağıtım sistemi bağlantılarının sistem kullanım ve bağlantı bedelleri incelenmektedir. Tezin son bölümünde ise, hazırlanan program ile elektrik santrallerinin kapasite bedelleri hesaplanmakta ve çeşitli durumlarda elde edilen veriler karşılaştırılarak kapasite fiyatına etki eden ana faktörler ayrıntılı olarak tartışılmaktadır.
Anahtar Kelimeler: Kapasite, Kapasite Ticareti, Sabit Kapasite Bedeli, İletim Sistemi Sistem Bağlantı ve Kullanım Bedeli, Dağıtım Sistemi Sistem Bağlantı ve Kullanım Bedeli

To My Family, with love, gratitude and hope

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TABLE OF CONTENTS

LIST OF FIGURES

FIGURES

LIST OF TABLES

TABLES

CHAPTER 1

GENERAL OVERVIEW OF THE TURKISH ELECTRICITY MARKET

In this chapter, first, the general overview of Turkish Electricity Market and Turkish Electricity Market Regulations are handled in order to have general knowledge about the market structure. Then, the concept of capacity used in the thesis shall be explained briefly. Finally, the outline of the thesis shall be presented.

1.1 Introduction

Energy has always been important for the countries' economic and social life. It is important since it has been one of the major and driving inputs for the industrial development. Also, it is a necessity for sustainable development. Increasing concern related to the adverse socio-economic and environmental effects of energy use patterns, in many cases coupled with excessive levels of fossil resource import dependence, call for substantial changes in the energy technology and energy supply system. Valuable insights for a better understanding of the actual and required transitions in the energy converting capital stock, the related resource consumption patterns and the underlying investment decisions can be provided by the technology adoption and diffusion models both at the micro-economic and macro-economic level.

Energy is also very important for social development that it fairly assists life through heating, lighting and transportation while it also contributes to scientific studies as well as education. The aptitude of managing the energy resources and sustaining the energy flow seem vital given that the long-term goals are mostly achieved via the possession and the intelligence-based management of the energy reserves. Consequently, leading countries are taken the leading role and even carried out wars for utilizing the energy resources, particularly primary or fossil resources that are natural gas, coal and oil.

In the 20th and 21st centuries, the humanity has witnessed many wars, which were undoubtedly involved in the energy areas. Therefore, the strategic position of energy finds room in the countries' plans. Indeed, unexpected hikes in the energy prices or any bottleneck in the production of primary energy resources instantly reverberate within the national economies. In this manner, energy and power turn out to be a crucial driving factor for the management of these resources.

The unequal distribution of the energy sources in the world geography and the struggle to utilize these sources in maximum terms make one contemplate about the degrees of power, given that the energy concept has been playing a crucial role in economy and policy and also has been determining the distribution of wealth. Since there are clear differences between the national economies, the degrees of power on the management of the energy resources formulate the levels of dependence and somewhat improve the conditions in favor of the developed countries. In addition, because of the fact that energy becomes an article of trade, the power business has also been deepened and new participants such as society and regional firms have come onto the stage.

Turkey stands at the intersection of Europe and Asia, where is a very strategic location for energy trading. Turkey has been one of the fastest growing electricity markets in the world for the last two decades, with a 9 % average annual growth rate. In spite of the decrease by 1.1 % in 2001 and 2 % in 2009 due to the economic crisis, this growth trend is predicted to continue till 2020 at an average increase of 6.5-7.5 % per year [1]. Official projections and estimations indicate that rapid growth in electricity consumption will persist over the next ten years. Still, the Ministry of Energy and Natural Resources (MENR) anticipates the need for upgrading transmission and distribution systems as well as the necessity of significant increases in power generation capacity, requiring an average $5.5 to $6.5 billion investment in a year for the energy sector [2]. This makes Turkey to be the third largest area of investment after China and India in the global market. Although only a few decades ago the Turkish Government was playing an active role in the Turkish economy and still the energy policy is largely centrally-driven and governed by MENR, it is presently being transformed into a liberalized market so as to attract foreign investment and to regulate market structure in parallel with the energy policy of the European Union (EU). In this context, Turkey has begun to pursue new policies and laws to liberalize its energy market to meet increasing demand through diminishing the government intervention. Turkey has approved the Energy Charter Treaty, international arbitration tribunals and introduced laws that will eliminates the Government's monopoly in the energy sector and set up a regulatory body to supervise the market activities.

Legislations that allow the liberalization of these entities, two of which, TEAŞ and TEDAŞ, were natural monopolies, were passed in the Turkish Parliament throughout the 1980s and this process accelerated in the 1990s. This caused a major improvement in Turkish economic policies and in time had an effect on the energy sector. The model for deregulation in the energy sector was mainly inspired from the Electricity Directives of EU and this was promoted by the international finance institutions such as the World Bank and the International Monetary Fund (IMF). Thus, the idea of "financial development" in other words "to become rich" prevailed. It can be claimed that the neo-liberal economic thought began to affect Turkey's energy policies via the channels of liberalization since the 1980s. The early 2000s also witnessed the establishment of an independent regulatory body Energy Market Regulatory Authority (EMRA) in Turkey. EMRA is responsible for the establishment of the competition based energy market. [2] Besides, the energy policies started to go into a transformation stage, as the state was to abandon its superior managing duty on the energy issues.

Firms and consumers in Turkey face with very high electricity and natural gas prices, which affect the competitiveness of the economy because nowadays several state economic enterprises and private sector companies in the energy sector continue to dominate the electricity and energy activities in Turkey. With the general objective of improving the functioning of the sector and reducing costly Government transfers, the Turkish energy sector has become the primary target of the liberalization program. Under the recently enacted laws, the electricity and natural gas markets are being progressively liberalized to be more efficient.

1.2 Overview of Turkish Electrical Energy Sector and Energy Policies

There have been mainly two contentious approaches in Turkish energy market structure since the early 1980s: “The liberalization through a competition based structure” and “The approach that aims to conserve and continuous role of the state in energy management and investments.” The discussions between the two approaches have been continuing for the last two decades, yet, neo-liberal economic policies seemed to offset and even prevailed over the counter approach.

The main basis behind the liberalization in Turkish energy market structure has been the desire to realize the long-run economical profits to be gained from competition based market structures for the electricity, natural gas and oil sectors. When looked at this stance, the defenders claim that the stability in realizing the necessary investment for energy infrastructure can only be maintained by a feasible competitive market environment, while at the same time, the prices must be kept at a reasonable level and hence, expected long-run economical profit shall be provided. Moreover, this model is capable to ease the clumsiness of the state and ends discussions on whether the state should continue to make investments in the energy sector and eventually direct the state to allocate the scarce resources to more demanding social fields, such as health, education, justice and defense in a more effective manner. This discussion supports the idea that state should “take its hands off” from economy; so that the economical stability can be enhanced with Foreign Direct Investment (FDI) and liberalizations.

On the other hand, defenders of the "Continuous role of the state" try to position the priority of the state investments and a balanced public enterprise in the energy sector. Therefore, a fully liberalized program for energy sector is refused by the defenders. They rather stand solid with the absolute role of the state with reference to the penetration of the private capital. The defenders also oppose to the claim that liberalization in the energy sector will bring higher public benefit and satisfaction, since this sort of transformation will rather serve more profit margins to the private companies and invalidate the common rules and duties of the state. Therefore, they keep a strict suspicious stand against the neo-liberal economic wave since this will extremely credit the individual interest and drive the public interest to diminish progressively. However because of the liberalization progress taken place in Turkey, this state control based ideology was implicitly terminated. Finally, Turkey has eventually understood the reality of opening the doors to the private sector.

Turkey has been taking steps to support its role as the energy bridge between the major oil producing areas of the Caspian Sea and the Middle East and their European markets. However, Turkey's limited energy maneuver capability can hardly meet the increasing domestic demand, and country is highly dependent on imported oil and natural gas. Even though the geographical nearness of Turkey to "rich areas" holds significance, it hardly advances a stable basis for sustainable of energy flow and political stability in Turkey's close neighborhood. Another well-known aspect is that there has hardly been a comprehensive energy strategy in Turkey's economic and political agenda.

1.2.1 Turkey's Supply and Demand Balances

1.2.1.1 Installed Capacity

In terms of primary energy demand, Turkey ranks among one of the fastest growing energy markets in the world, the total primary energy supply (TPES) growth rate is nearly 5 % per year and total final consumption (TFC) growth has been around 6%

per year over the last three decades. MENR predicts acceleration in demand growth in the coming years.

In terms of electricity, The Turkish electricity market is one of the fastest growing power markets in the world. The reasons behind this growth can be explained with long-term ignorance in electrification in the past, i.e. low per capita electricity consumption, young and rapidly growing population, rapid urbanization and strong economic growth. By 2010, the electricity consumption in Turkey per capita is 2.400 kWh.[1] The total installed capacity of Turkey has risen to 49.524 MW in 2010. 65.1 % of the installed capacity (32.278 MW) is thermal and the rest (17.246 MW) is hydroelectricity, biogas/waste and renewable resources as seen in Table 1 [3]. In power generation the share of natural gas has been increased remarkably to a level of 48,6 % in 2010 [3]. Also, 28,3 % of this production is met by coal-fired power plants, 18,6 % by hydroelectric, 3,4 % by oil fired and 1,1 % by renewable energy [4]. EÜAŞ and Affiliated Partnerships are responsible for the generation activities on behalf of the state-owned thermal and hydroelectric plants. The overall portfolio of EÜAŞ and Affiliated Partnerships accounts 48.8 % of the total electric generation capacity. The rest is provided by the Build Operate Transfer (BOT), Build Operate (BO), generation companies and auto producers. The installed capacities of the generation companies in 2010 are detailed in Table 1.

Table 1. Installed Capacities of Generation Companies (derived from [3])

Companies	**Thermal (MW)**	**Hydroelectric (MW)**	**Wind + Geother. (MW)**	**Total (MW)**
EÜAŞ Plants	8.690,9	11.677,9	-	20.368,8
EÜAŞ Affiliated Partners	3.834,0	-	-	3.834,0
TOOR Plants	620,0	30,1	-	650,1
MOBILE Plants	262,7	-	-	262,7

[1] 24.868 kWh in Norway, 8.523 kWh in Belgium and 5.723 kWh in Greece.

Table 1. Installed Capacities of Generation Companies (continued)

Companies	Thermal (MW)	Hydroelectric (MW)	Wind + Geother. (MW)	Total (MW)
BO Plants	6.101,8	-	-	6.101,8
BOT Plants	1.449,6	972,4	17,4	2.439,4
Auto-producers	2.597,7	544,2	1,2	3.143,1
Generation Companies Plants	8.721,7	2.606,7	1395,8	12.724,2
Total	**32.278,5**	**15.831,2**	**1.414,4**	**49.524,1**

The evolution of the technological composition represented by the shares of installed capacity for different energy sources used is illustrated in Figure 1.

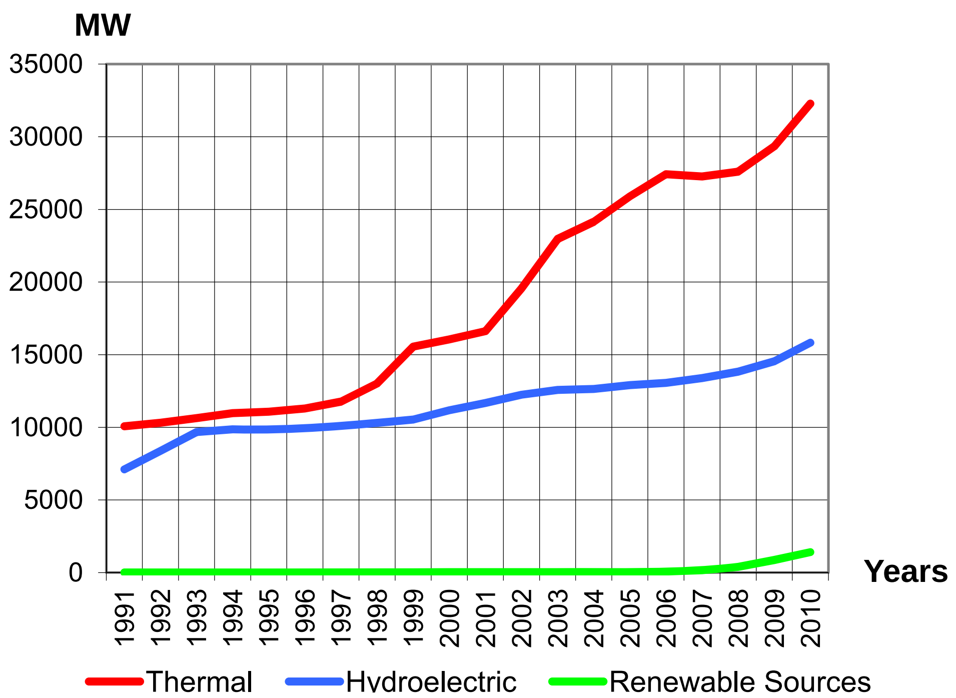

Figure 1. Development of the Installed Capacity w.r.t. Energy Source(1991-2010) [4]

1.2.1.2 Generation and Demand

MENR announced that the Turkey's total electricity demand is 210.4 GWh (total generation + export - import) in 2010. It is estimated that the demand for electricity in 2020 is predicted to be over 433.900 GWh according to high scenario and 398.160 GWh according to low scenario [3]. The electricity sector needs vital investments by looking at the high and the low demand scenarios presented in the Table 2, Table 3, Table 4 and Figure 3, Figure 4 respectively.

Table 2. Peak Power and Energy Demand in Turkey between 2001 and 2010 [3]

Years	**Peak Power Demand**		**Energy Demand**	
	MW	**Incr (%)**	**GWh**	**Incr (%)**
2001	19.612	1,1	126.871	-1,1
2002	21.006	7,1	132.553	4,5
2003	21.729	3,4	141.151	6,5
2004	23.485	8,1	150.018	6,3
2005	25.174	7,2	160.794	7,2
2006	27.594	9,6	174.637	8,6
2007	29.249	6,0	190.000	8,8
2008	30.517	4,3	198.085	4,2
2009	29.870	-2,1	194.079	-2,0
2010	33.392	11,8	210.434	8,4

Table 3. High Demand Scenario (Prediction[2]) [3]

Years	Peak Power Demand		Energy Demand	
	MW	Incr (%)	GWh	Incr (%)
2011	36.000	7,8	227.000	7,9
2012	38.400	6,7	243.430	7,2
2013	41.000	6,8	262.010	7,6
2014	43.800	6,8	281.850	7,6
2015	46.800	6,8	303.140	7,6
2016	50.210	7,3	325.920	7,5
2017	53.965	7,5	350.300	7,5
2018	57.980	7,4	376.350	7,4
2019	62.265	7,4	404.160	7,4
2020	66.845	7,4	433.900	7,4

Table 4. Low Demand Scenario (Prediction[3]) [3]

Years	Peak Power Demand		Energy Demand	
	MW	Incr (%)	GWh	Incr (%)
2011	36000	7,8	227000	7,9
2012	38000	5,6	241130	6,2
2013	40130	5,6	257060	6,6

[2] The power and energy demand values for high demand scenario are forecasted by the TEİAŞ according to various factors and the predictions are updated each year. Since the exact power and energy demand for 2011 is not declared yet by the Authority, the projection for 2011 is stated.

[3] The power and energy demand values for low demand scenario are forecasted by the TEİAŞ according to various factors and the predictions are updated each year. Since the exact power and energy demand for 2011 is not declared yet by the Authority, the projection for 2011 is stated.

Table 4. Low Demand Scenario (Prediction) (continued)

Years	Peak Power Demand		Energy Demand	
	MW	Incr (%)	GWh	Incr (%)
2014	42360	5,6	273900	6,6
2015	44955	6,1	291790	6,5
2016	47870	6,5	310730	6,5
2017	50965	6,5	330800	6,5
2018	54230	6,4	352010	6,4
2019	57685	6,4	374430	6,4
2020	61340	6,3	398160	6,3

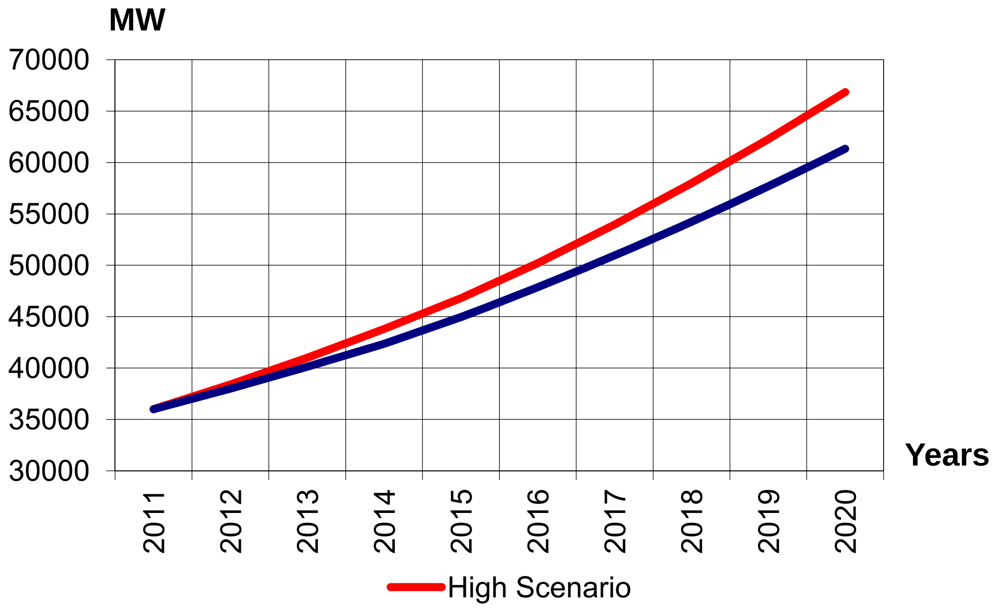

Figure 2. Turkey's Peak Power Demand Projection w.r.t High and Low Scenarios [3]

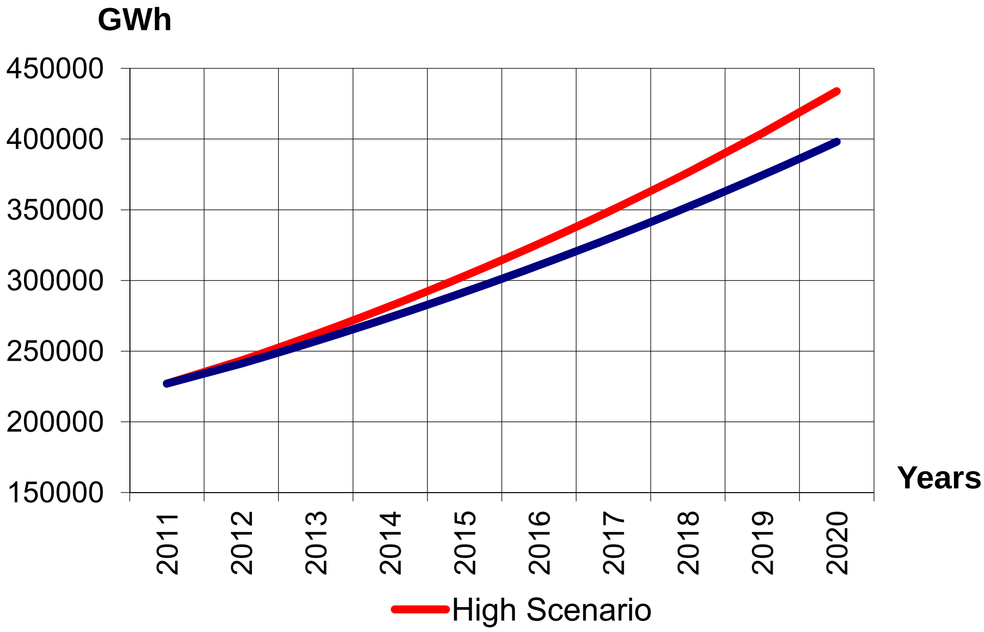

Figure 3. Turkey's Energy Demand Projection w.r.t High and Low Scenarios [3]

Under the light of the figures and tables above by looking at both the high and the low scenarios, it can be expressed that Turkey will face with a significant energy need that cannot be easily satisfied in the near future. As a result, new investments will be needed to deal with the growth in demand. Indeed, the uncertainty in the electricity market should be removed in order to attract large electricity investments to the sector.

The lack of sufficient investment introduces a significant risk that may lead to the power shortages in the system in the short and long term. Increasing the Turkey's electricity generation capacity continues to be a top priority for MENR, which seems to turn out to be the private sector's responsibility for new investment and restructuring of the sub-sector in the near future.

In addition to the legal changes since the early 1980s, it will be convenient to emphasize the ways of how electricity is generated in Turkey. Indeed, electricity consumption already makes up 13,4 % of overall consumption and is growing at an annual 8,5-10% [5], and this somewhat makes electricity the most important and contentious aspect of Turkish energy. However, since Turkey imports a high percentage of its energy, she seems to face with difficulties both in an economical point of view and the energy demand point of view in the near future.

Another important aspect of the Turkish electricity market is that both the domestic and the industrial prices seem to increase in a proportional manner. As seen in Figure 4, the domestic and the industrial prices are nearly the same which is deemed as undesirable by foreign consultants [6].

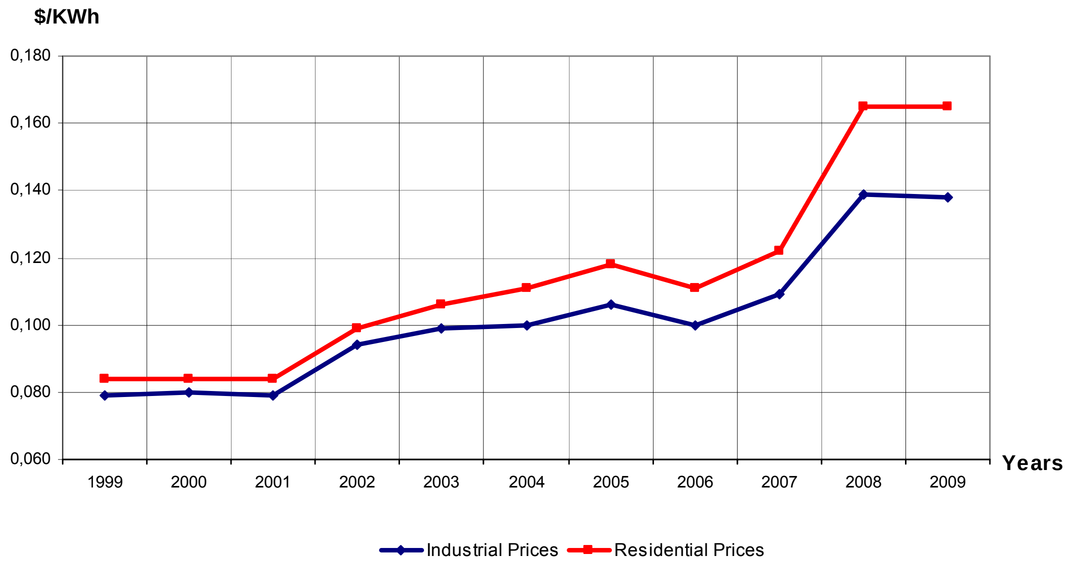

Figure 4. Residential-Industrial Electricity Prices Comparison (derived from [9])

The response to the question of "how to satisfy these needs in what preconditions" has remained within the studies of major energy sub-sectors. A set of policies undertaken by the policy-makers, legal amendments in Turkish energy sector, and the role of the transnational actors in shaping Turkey's energy policies will be the crucial answers to these questions in the future.

1.3 Turkish Electricity Market Regulations

In principle the main objective of energy policies is to supply uninterrupted, reliable, affordable, -not cheap- and environmental-friendly energy. However, verbal explanations have not been enough to accomplish these objectives. The resistance and negotiation capability against the other external powers and influences also have to be taken into consideration since the political will is the leading determination force in realizing these goals. Global financial institutions and the regional organizations such as IMF, EU, the Organization of Economic Cooperation and Development (OECD) can be considered as these external powers and influences. Thus, MENR enacted several laws along with the legal basis of the liberalization efforts through this crucial interaction since 1984 [7]. The principal types of legal instrument in order of superiority are described in APPENDIX A.

The regulations of Turkish Electricity Market could be divided into three sub-groups namely; preliminary development period, liberalization efforts period and reform period. The significant improvements cover the years up to 1993 whereas the liberalization efforts are called until the enactment of Electricity Market Law No: 4628. And the reform period starts with the Law No: 4628 [8].

1.3.1 Preliminary Developments in Turkish Electricity Market

The Turkish Parliament passed legal amendments, which were "seeking for significant improvements in trade and investment" in 1984. MENR enacted Law No: 3096, which opened the electricity sector to private companies including private investors in this year. Until the enactment of Law No: 3096, the services in the electricity sector were only carried out by the Turkish Electricity Agency (TEK). This law authorized enterprises other than the Turkish Electricity Authority for the Generation, Transmission, Distribution and Trading of Electricity, which allows private firms build, generate, distribute and trade electricity. Thus, the investors would be granted the right to build and operate the power plants. In this sense, the implementation of this legislation for financing major energy projects brought about four basic models: “Build-Operate-Transfer” (BOT), “Transfer of Operating Rights” (TOOR) and “Auto-Production Model”. These models would ensure the liberalization of major electricity power plants and the state would eventually be withdrawn from the “costly way of energy supply with huge financial support”. This would further mean that the natural monopolistic character of the electricity sector would be converted to a new model by unbundling TEK. As a conclusion, it can be said that the monopolistic structure of Turkish Electricity Authority (TEK) was changed with the enactment of Law No: 3096 [8].

One of the major regulations of law 3096 is that a new investment model known as the ‘Build Operate Transfer’ (BOT) model which is based on the principle of granting private investors to build and operate electricity generation, transmission and distribution systems for a certain period of operation time, for instance 20 years, and then transfer the ownership of the plants to the State at the end of this period.

1.3.2 Liberalization Efforts of Turkish Electricity Market

Another important effort that has been realized in 1993, based on the principles of outlined in Law No: 3096 and after the Law No: 3996 (BOT Law) in which the generation investments in BOT model gain pace. Furthermore, the Turkish Electricity Authority is vertically unbundled into two functional companies, namely, Turkish Electricity Generation and Transmission Company (TEAŞ) and the Turkish Electricity Distribution Company (TEDAŞ), the former is being responsible for the operation of the generation and the transmission infrastructure, while the latter being responsible for the operation and planning of the distribution system. Although inadequate, the main aim of all of those efforts was to establish a competitive electricity market structure.

MENR’s overall macroeconomic stabilization program involves special emphasis on strengthening the private sector participation in the Turkish economy. The liberalization program was further accelerated with the Law No: 4646, introduced on 23 November 1994. Within the directions outlined in these legislations, electricity would no more be perceived as a public service and would become a commodity to be traded for profit.

A further step in enhancing private participation to energy sector has taken place in 1997, with the BO (Build Operate) Law, which grants the ownership right to the investors. Typically, under a BOT or TOOR (A Concession Agreement made on an existing plant or infrastructure with private investors to renovate and operate for a certain period of time) contracts, the state guarantees to purchase a certain amount of the production at a tariff determined in the Agreement, so that investors can recover their fixed costs. Moreover, Transfer of Operating Rights (TOOR) model has also been used by MENR to transfer the operation rights of the generation plants and distribution assets. Under BO, private law PPA contracts are enacted with TEAŞ and the companies. BOT along with BO have achieved partial success in attracting private investment in generation and have left significant contingent legal responsibility for the Treasury through the guarantees given to the private investors. Despite of all these liberalization efforts, in 2000, 75% of the overall installed generation capacity in the electricity sector was still owned by State owned generation and transmission company TEAŞ.

The “Letter of Development Policy” for economic reform in 2000 was clearly emphasizing the intension of MENR in establishing a competitive and liberal electricity market. The letter, which was sent to the World Bank before the new Electricity Law is put in action in 2001, put several objectives for liberalization. These can be listed as “the financial deterioration of Turkish Electricity Generation and Transmission Company (TEAŞ)”, high purchasing price of electricity from “the newly established BOT Projects” and the poor level of bill collection for the electricity sold to the Turkish Electricity Distribution Company (TEDAŞ) [9]. The letter also pointed that MENR would decide to address these problems through a comprehensive framework based on establishing a competitive market for electricity, which transfers the task of supplying and trading electricity with the associated market risks, to the private sector.

The types of contracts which are Build-Operate-Transfer (BOT), Transfers-Of-Operating-Rights (TOOR), and Build-Operate (BO) are for 20 years and are subject to power purchase agreements on predetermined quantities with the Treasury's guarantee. The system has led to the accumulation of significant contingent liabilities, and implicit subsidization of an inefficient sector. Moreover, in order to eliminate the lack of coordination within the sector, the benefits from low cost generation from the hydroelectric power plants and its affiliated partners were used to offset the cost burden. Because of the purchasing guarantees and high prices, the efforts have been an unfavorable impact on the market for many years, and in the absence of further measures, it hampers the liberalization procedure and delays the consequent reduction of energy prices.

Moreover, the volume of supplementary investments for the energy infrastructure by the public sector have been significantly reduced; the choices for the primary sources for electricity generation have been shifted and also the percentage share of the natural gas for electricity generation has relatively been increased to a high level with respect to the other resource alternatives; and finally, the legal framework of the market has been significantly altered by the new legislations leading to the liberalization of the public enterprises and establishing a competitive electricity market. Basically, the liberalization in Turkey has been considered as a prerequisite for the liberalization of the electricity sector via a competitive market structure.

1.3.3 Turkish Electricity Market Reform

The fast economic growth in Turkey has been augmented by a similar growth in demand for energy. Huge investments have to be realized to meet this rapidly growing demand. Therefore, MENR felt the need for encouraging private investors through paving the way for them with a new law based on liberalization principles. Therefore, as a candidate country of the EU, MENR has prepared Law No: 4628, which is also known as Electricity Market Law (Law No: 4628), in line with the EU Electricity Directives. In this context, MENR is committed to realize an ambitious liberalization program through the Electricity Market Law No: 4628, in the electricity generation and distribution sectors, which is a crucial step for the liberalization of the market. The Law was enacted on 3 March 2001 by the recommendations of IMF and World Bank [10], which envisages the opening of the electricity market to private participations. The main aim of this law was to restructure and deregulate the generation and wholesale trading activities in electricity sector within the EU Directives to attract domestic and foreign resources to the sector. With similar objectives, Natural Gas Market Law No: 4646 was enacted in parallel with the Electricity Market Law in the same year. These laws aim to prevent public enterprises from involving in market activities except the transmission of electricity until the realization of liberalization.

The main objectives of Law No: 4628 [8] are to enhance the development of a financially sound, stable and transparent electricity market, with a competitive character in line with private law provisions, and to provide for an autonomous regulation and supervision.

Law No: 4628 regulates the transmission, distribution and state owned wholesale activities, while deregulates the generation, wholesale and retailing services. The Law envisages keeping a high percentage of the wholesale trading under the state control until the generation and distribution sectors are fully liberalized. The transmission assets and activities on the other hand, are planned to be owned and carried out by a state-owned company, named: TEİAŞ.

The Law outlines the principles of liberalization to be followed for the generation and distribution sectors, and tariffs. The Law aims to establish a competitive environment, where the market participants trade freely the electrical commodities in that market through bilateral agreements without any need for Treasury guarantees. A preparatory period of 18 months starting as of 3 March 2001 was specified to complete the necessary secondary legislations to be supplemented to the Law. The major objective of the liberalization efforts is to create a competition based market based on bilateral agreements among the market participants matched by a balancing and settlement mechanism.

Electricity Market Law No: 4628 sets up a path toward a competition based market structure in the electricity generation and distribution facilities. One of the basic implementations of the law is that the state-owned Turkish Electricity Generation and Transmission Company (TEAŞ) were vertically unbundled into three companies; namely, Electricity Generation Company (EÜAŞ), Turkish Electricity Transmission Company (TEİAŞ), and Turkish Wholesale Electricity Trading and Contracting Company (TETAŞ). The generation plants of the state-owned Turkish Electricity Generation and Transmission Company (TEAŞ) were transferred to the newly established state-owned company; Electricity Generation Company (EÜAŞ). Moreover, the assets and operation duty of the transmission system were given to Turkish Electricity Transmission Company (TEİAŞ) while the duty and responsibility for carrying out wholesale trading activities were assigned to newly established state-owned company; Turkish Wholesale Electricity Trading and Contracting Company (TETAŞ). Subsequently, the Law No: 4628 intended that the electricity generation plants of EÜAŞ and the distribution regions of TEDAŞ would be liberalized. Finally, TEİAŞ and TETAŞ would carry out the transmission and wholesale facilities, respectively. This legal basis led to an important change that escorted the replacement of “Sale of Property” with the “Transfer of Operating Rights” (TOOR) [4].

The vertical unbundled model of the Turkish Electricity sector [11] is given in Figure 5.

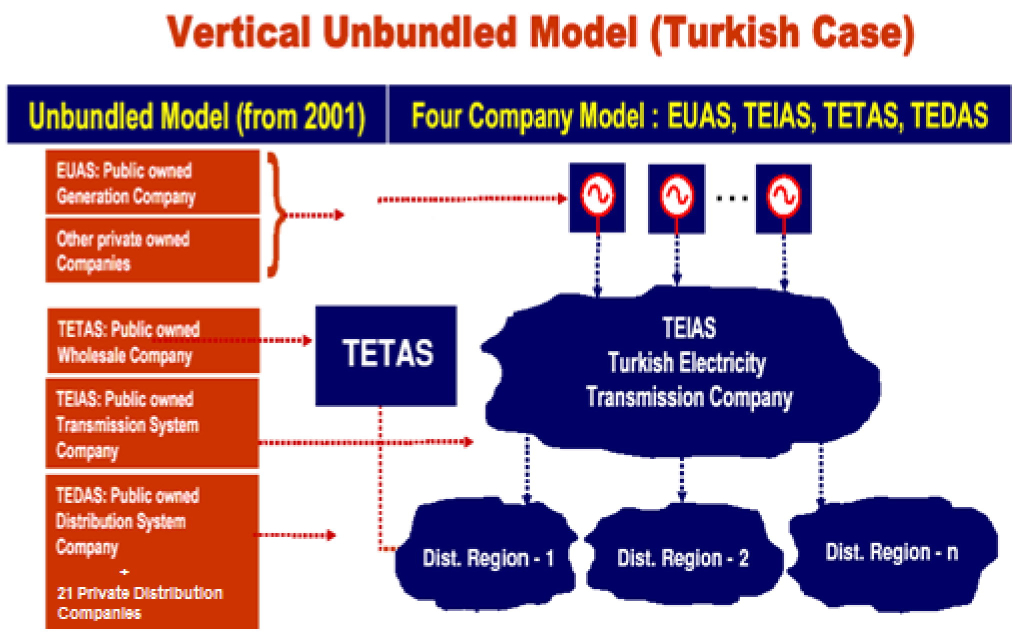

Figure 5. The Vertical Unbundled Model of the Electricity Sector [11]

The law includes the following key issues for liberalization;

- An independent regulatory body, called; Energy Market Regulatory Authority (EMRA), governed by the Board,
- Granting licenses to market participants,
- An energy market to be based on bilateral contracts among market participants,
- Eligible customer concept, which grants the right of choosing their suppliers to those customers whose annual consumptions exceed a certain level,
- Divestiture of the existing generation and distribution systems,
- Granting non-discriminatory access right to all market participants for the transmission and distribution facilities,
- Eliminating of all types of cross-subsidies in the electricity tariffs,

- Unbundling of the Turkish Generation and Transmission Company (TEAŞ) into three independent companies; the Turkish Electricity Transmission Company (TEİAŞ), the Electricity Generation Company (EÜAŞ) and the Turkish Wholesale Electricity Trading and Contracting Company (TETAŞ), a state-owned wholesale trading company.

Law No: 4628 set the stage for an independent institution, the Energy Market Regulatory Authority (EMRA), which supervises the electricity, oil and natural gas markets, including setting tariffs, granting licenses, and assuring competition for market participation.

Law No: 4628 has also introduced the concept of "eligible customer" and ensure the freedom for eligible customers to choose their suppliers. Policy issues related to energy markets are the responsibilities of the Energy Market Regulatory Authority (EMRA), whereas issues related to energy policy and planning are under the Ministry of Energy and Natural Resources (MENR). The Privatization Administration (PA) is responsible for transferring the operation rights of the State Economic Enterprises involving energy activities, and their preparation for liberalization.

Private sector companies may participate in all sectors of the market, except transmission, by obtaining licenses from EMRA. Liberalization of the generation sector is also on the agenda of the Law No: 4628 and according to the Strategy Paper dated March 17, 2004 issued by the High Planning Council (HPC) which explains the time table for the liberalization procedure for the generating and distribution companies. Turkish Electricity Transmission Company (TEİAŞ) is the only operator for the transmission system. TEİAŞ owns and operates the transmission system assets and also acts as a system and market operator. TEİAŞ will remain as the only transmission system operator (TSO) and the state will be the asset owner in the long-run.

Turkish Wholesale Electricity Trading and Contracting Company (TETAŞ) is in charge of wholesale trading of almost 43% of total generation with respect to 2009 data. TETAŞ prepares and submits tariff proposals to EMRA for approval. TETAŞ took over all the public sector purchasing contracts of the previous regime, in other words TETAŞ has taken over all purchasing obligations arising from the contracts. TETAŞ may sell electricity to new consumers or sign any new Power Purchase Agreements (PPAs) as the obligations stated in the Law No: 4628 and its role is intended to diminish over time, once the cost burden is mitigated and all the state-owned generation plants is liberalized.

Law No: 4628 foresees competition based electricity trading through bilateral contracts among the market participants supported by a complementing balancing and settlement mechanism. The Law also predicts cost-based tariffs calculated with respect to methodologies derived according to the Electricity Market Tariffs Regulation and the related statements, and are submitted to EMRA for approval.

After the enactment of Law No: 4628, High Planning Council has announced a second Strategy Paper dated March 17 of 2004, setting out the basic principles and a detailed action plan for the liberalization in the electricity sector. As for the liberalization strategy, priority shall be given to the distribution regions and generation portfolio of EÜAŞ which are the power plants under the control of EÜAŞ. The Paper has drawn a road map, pointing out important milestones for the liberalization. Liberalization of electricity should have begun with the offer for liberalization of distribution systems in 2005 and it should be finished in 2011 by all means according to the Paper. Presently, this objective has not been achieved yet in terms of the distribution systems and the generation plants. The Liberalization Strategy explained in the Strategy Paper also envisages liberalization of state-owned generation plants after successful completion of liberalization of distribution network.

With respect to Board Decision No: 3054, dated January 26, 2011, consumers with annual consumption above 30.000 kWh are considered as "eligible customers". [8] According to the Law No: 4628, those customers are granted to choose their suppliers through an Electricity Sales Agreement (ESA) with conditions completely determined by their wills with respect to principles of competition. According to Electricity Market Tariffs Regulation and the related statements, tariffs must be calculated on the basis of real costs which are directly related to the characteristics of the regular market operations such as resource and operation costs, network losses, illicit utilization.

According to Electricity Market Tariffs Regulation and the related statements, tariffs proposed by the companies, are forwarded to EMRA for review and approval. Approved tariffs are then published in the Official Gazette and on the EMRA's website for transparency.

Therefore, the fundamental principles of neo-liberal economic approach such as "the separation of economics from politics" and the realization of economic problems through a "technical perspective" had already been adopted in the electricity sector. Hence, the electricity sector has a special importance among the structural reforms, which should aim the recognition of a comprehensive transformation in Turkish Electricity Sector. The transformations described above, have led the political perspectives to review the possibility of divesting the relations between the State Economic Enterprises (SEEs) and State towards liberalization [12].

At a glance, policy of MENR for the energy resources is quite clear.[4] All laws up to date are directed to establish a liberal market structure. Turkey's energy sector improved as fast as it relates to the distribution of gas; safety and security equipment and services; and building materials. On 17 December 2004, the EU and Turkey agreed for Turkey to begin accession MENR initiations in fall 2005 and market liberalization procedure is still continuing. Turkey has begun to accept a number of European Union directives, regulations and laws to bring it more in line with the EU, which may impact foreign companies as Turkey establishes closer relations with Europe. Major opportunities may come out as a result of planned liberalization of electricity distribution grids and existing power plants owned by the State. The Privatization Administration should have finished these liberalizations especially for

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4 However, in 2005, a law is enacted to combine the production and distribution phases by the persecution of powerful electricity generating companies which suffers monopoly structure in electricity market. So the liberalization efforts are obviously undercut.

the distribution regions and generation portfolio of the EÜAŞ. However, the liberalization of the distribution regions and generation portfolio of the EÜAŞ has not been finished yet by PA.

About renewable energy sources, an important law is enacted in 29 December 2010 including a series of effective incentives in the field of renewable energy sources. It is argued that Turkey has a significant potential of wind, geothermal and solar energy sources. The efforts for exploring the potential reserves are continuing. About nuclear energy, MENR has declared its intention for building up nuclear power plants about 4500-6000 MW installed capacity and now it has revived the prospect of developing a nuclear power plant under state control. [12]

The other important legal instruments already promulgated are detailed in APPENDIX B.

The primary benefits expected from electricity sector reform and liberalization may be listed as follows:

- Decreasing of costs of operation through carrying out effective and efficient operation services for the generation and distribution services,
- Increasing the supply quality and security,
- Reducing the technical losses and illegal utilization in distribution regions to the level in OECD countries and by carrying out an effective and efficient rehabilitation and expansion program for the distribution system infrastructure,
- Ensuring that this program is financed by the private sector without creating any liability on the public resources,
- Reflecting the benefits obtained from competition to customers,
- Development of a financially sound and transparent electricity market operating in a competitive environment under provisions of civil law,
- Delivery of sufficient, good quality, low cost and environment-friendly electricity to consumers.

As part of this progress, efforts are spent to minimize the cost of transition to liberal market model on the public institutions. The main principle is the implementation of cost–based tariff in the electricity sector, whereas the national tariff practice is operational during the first implementation period through establishment of a tariff balancing mechanism that stabilizes the price differences in non-eligible customer tariffs.

In order to stabilize the prices in the retail market, during the first five-year transitional period, a “Tariff-Balancing Mechanism” has been developed and implemented for regions in the Country, where the income / customer rate is low and the ratio of loss and illicit utilization is high.

The market structure, as implemented, separates the basic functions of generation, transmission and distribution, although retail is bundled with distribution, at least at the outset. Regarding the technical/financial characteristics, existing contracts, the current legal structure, and the operational problems arising from the geographical characteristics, the size of the regions are so adjusted that the total number of regions is 21 as stated in [9]. The principal features of each type of player in the market are identified in APPENDIX C under the appropriate functional headings.

1.4 Illustration of the Market Functions

The following diagrams illustrate EMRA's role as regulator (Figure 6), power flows on the physical system and connections to the system (Figure 7), bilateral energy sales in the new market structure (Figure 8), balancing and settlement arrangements (Figure 9).

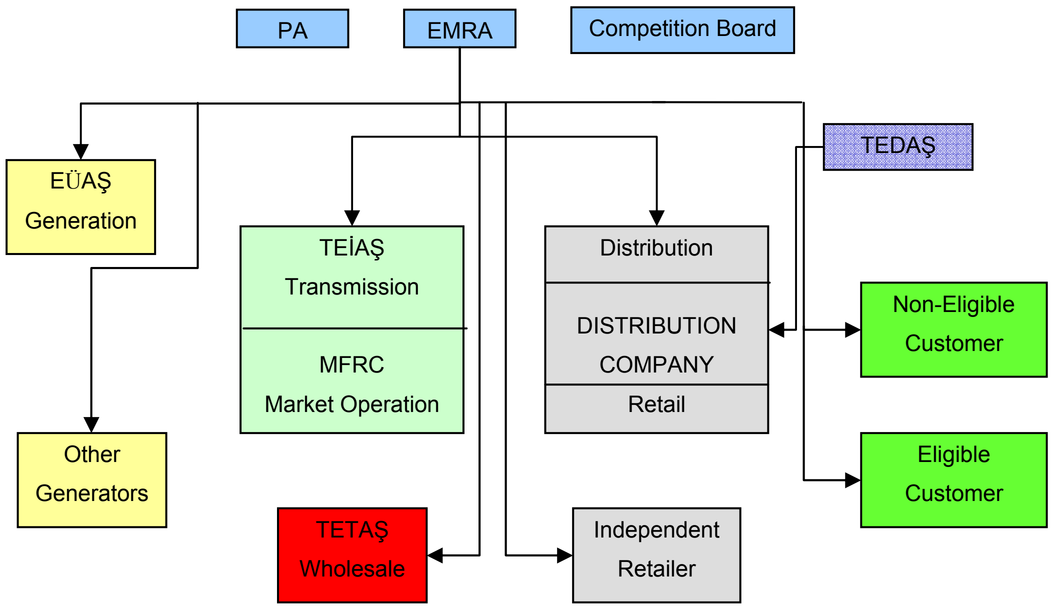

Figure 6. Regulation Duties of EMRA

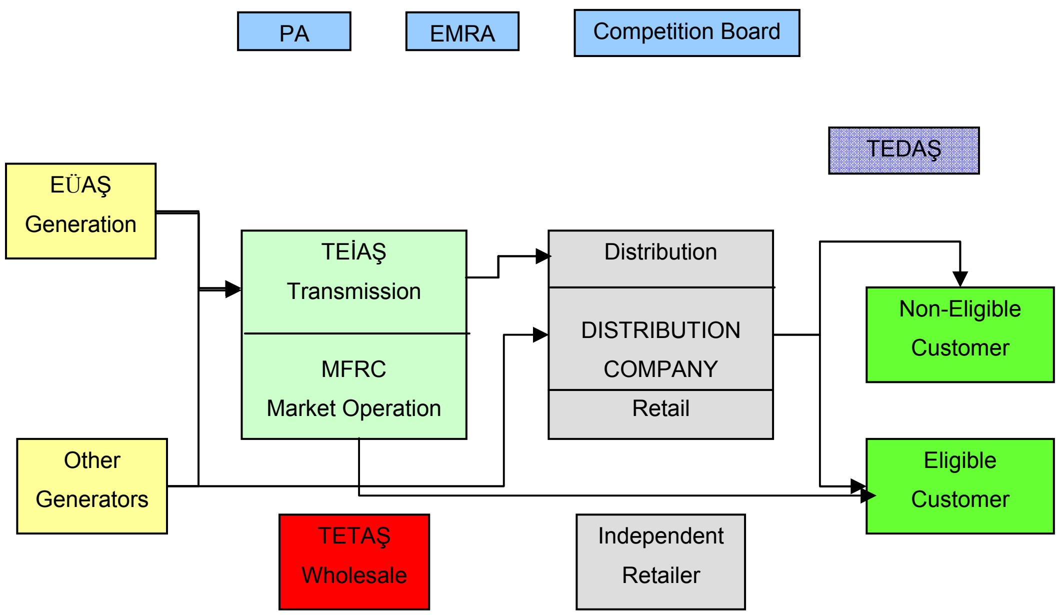

Figure 7. Industry Power Flows and Connections

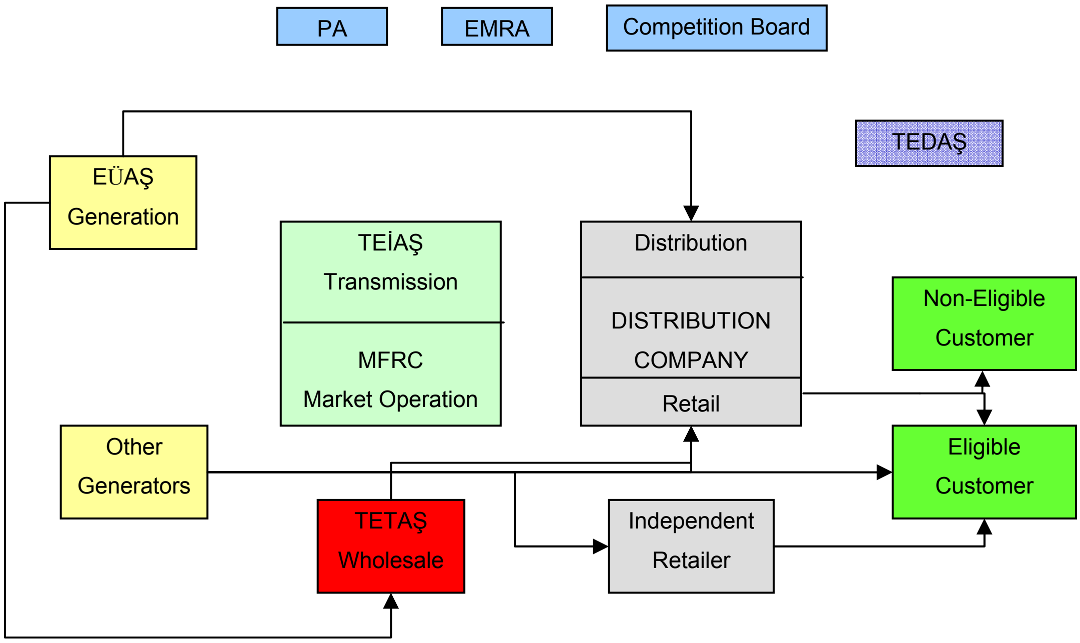

Figure 8. Energy Trading Diagram

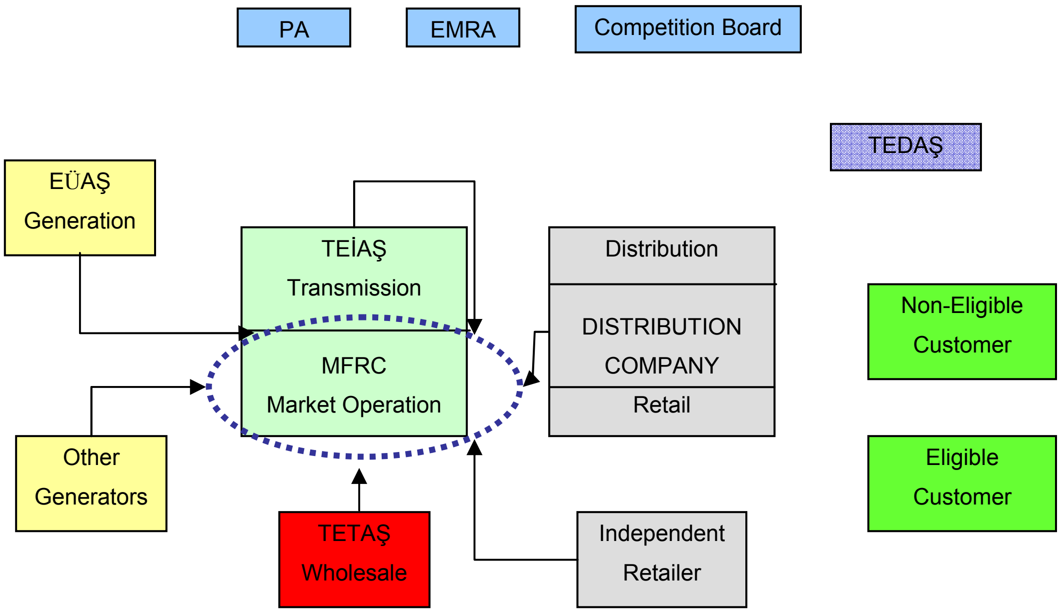

Figure 9. Balancing and Settlement Procedure

1.5 Difficulties in Turkish Electricity Market

The 2000's have been a period in which Turkey's public financial resources have generally showed a poor availability, with increasing deficits and public debt, and deterioration of the fiscal structure. There are still serious deficiencies in good governance, which lead to the loss of trust in private investors.

Another significant challenge in the market is the long-term agreements made with power generation plants realized on the principle of BOT and BO, with Treasury guarantees backing the payments of purchased energy. The prices of the energy purchased from the BOT power plants are comparatively higher than those purchased from EÜAŞ and its affiliated companies, due to the reason that terms related to capacity component in the tariffs are set to relatively high figures. These projects pose obstacle in front of market opening. Current market opening is estimated at around 30 % of the total Turkish Electricity Market, with a significant number of consumers either producing electricity for their own consumption, or buying from a supplier other than the current distribution company operating in the same region. Turkey aims to achieve the ambitious target of complete market opening by the end of 2011.

Another problem in the Turkish energy market is the strong influence of oil and gas prices on electricity prices due to the fact that a high percentage (48,6 % in 2010) of the electricity produced is obtained from the gas fired power plants. The share of natural gas in electricity consumption tends to increase within the next five years. The dependency on the Russian natural gas for electricity generation render an obligation of firm energy planning in order to assure Turkey's energy security. Although Turkey has sufficient domestic hydroelectric, coal and lignite potentials, these potentials are not widely utilized and security of supply is threatened by relying on imported resources, mostly natural gas, which is highly sensitive to the world prices. Although the aim is to establish a liberal electricity market by assigning roles to the private sector market participants, during the planning and restructuring procedure, their contributions and opinions are usually neglected. Admittedly, if a country does not search for alternative resources such as coal or at least does not diversify primary resources, it might ultimately encounter bottlenecks and difficulties in terms of both economic and strategic points.

There are also significant technical problems in the market. High loss and illicit utilization rates in the electricity distribution are the other crucial problems that have to be addressed by the authorities. It is estimated that an amount more than 15 % of electricity supplied to the grid is lost as resistive dissipation or illegal consumption. To use efficient energy and reduce the tariffs, necessary precautions for decreasing the loss and theft rates need to be taken.

Another important problem which led the liberalization procedure into uncertainty is the ambiguity of the border-line separating the relevant state-owned institutions in terms of their authorities and responsibilities. It is seen that there was a clash of authorities and interests among these institutions. The authorities like Ministry of Energy and Natural Resources, State Planning Organization and TEAŞ, TEDAŞ were playing the primary roles in the policy-making, planning, investment, operating and setting tariffs until the enactment of Law No: 4628. The uncertainty in the restructuring procedure has created serious problems in reaching consensus among these authorities. However, with the introduction of the Law No: 4628, there emerged new institutions like EMRA, an independent regulatory authority. Besides, new state enterprises such as EÜAŞ, TETAŞ, and TEİAŞ are established as the new market participants and playing the primary roles in planning, investing, operating the infrastructure and setting tariffs [4]. In the long-term, these state enterprises are expected to have limited functions in the market, except TEİAŞ in order to have a fully liberalized competition based market structure. That’s why EÜAŞ and its affiliated partners and the distribution regions related to the TEDAŞ and its affiliated partners have to be liberalized in the mean-term hence the mission of TETAŞ in the market will be reduced.

Moreover it can be assumed that the liberalization procedure for the electricity sector is carried out in favor of the social interests. The repercussions of the procedure that comes out in the long-term may sometimes be worse than anticipated, if the necessary precautions are not taken during the transition period.

Nonetheless, the recent experiences in the EU countries have shown that a competitive electricity market might not always lead to higher efficiency and low prices. The liberalization effort in the EU has transformed a fragmented electrical sector dominated by a small number of regional state utilities into a European market ruled by an oligopoly of powerful liberalized energy corporations. These led to several distortions in the EU electricity market that, small number of powerful electricity suppliers protected by their high price policies preventing competition.

Consequently, despite the reduction in the wholesale prices, non-eligible consumers could not effectively benefit from this reduction. Moreover, transmission and distribution systems generally had high sink costs, for the reasons of creating a competitive market, can sometimes hardly been met in a liberal electricity market. Considering these facts, Turkey has to take every kind of precautions in order not face with these difficulties during the liberalization procedure. [13]

The rulers should also take the Country's institutional structure and legal status into consideration that an unregulated electricity market may lead to consumer discrimination and market failure. For Turkish Electricity Sector, on the other hand, the regulatory authority (EMRA) is supposed to fulfill effective regulation and more involvement of MENR seems vital to protect the rights of all consumers. Turkish policy-makers also have to be aware of the financial differences between the countries.

Given that the liberalization in the electricity sector among the EU countries initially stepped at 30-35 % in market opening, even this rate was only 8 % in France, due to the dominancy of the nuclear plants as the main energy source, [14] it would not be too wise to envisage a full liberalization procedure in Turkish Electricity Sector, if the transition period activities are not examined carefully and practiced well. So, before fast transition into competition-based market, some transition period precautions are needed and the decisions must be applied in a deterministic manner. Transformations realized during the transition periods however, should not have the nature that they implement some permanent changes on the structure hindering or prohibiting to pass to a fully liberalized competitive market structure.

To conclude, in order to realize a successful liberalization procedure, experiences in various EU countries in establishing a fully competitive electricity market, such as the United Kingdom and the Scandinavian countries should be carefully examined.

CHAPTER 2

THE CONCEPT OF CAPACITY

2.1 Definition

Capacity is a term for allocating a certain section of infrastructure in the energy system. This section may be a generation plant, or some part of transmission and/or distribution system. [15] To attract generation plants to the system and assure new generation plant investments, the authorities such as Spain, Italy, South Korea, Chile, Columbia and Peru apply capacity payment methods. [36]

Although the Electricity Market Law No: 4628 outlines the concept of capacity and its trade, these concepts are not well-defined and understood in Turkey. The capacity trading mechanisms and their application, the principals and procedures of capacity, as well as kinds of capacity trading mechanisms are not well-known by the market participants. In addition, it is not easy to find adequate information about the application of the capacity trading mechanisms in the market in which both the public and private sector participants are acting as players.

2.2 Capacity of Generation Plants

Capacity of a generating plant is defined as the total electrical energy that can be supplied within the overall lifetime of a plant, by considering all the physical and other real constraints. In electricity markets, capacity payments secure additional revenue for the electricity producers in order to cover their fixed costs.

Capacity payments enhance reliability for the producers since the fixed costs of the generators can be recovered. [16] By this way, the investors find an environment in which they can act more bravely for investment and this reduces the uncertainties in the future prices in the market. Besides, in some markets, price signals can be estimated and calculated by the view of the capacity payments, which leads investment anticipation in the market. However, in case that the investor does not feel himself in a condition that the total cost of the investment cannot recovered by the annual revenue generated, then he will be reluctant to realize the investment.

Capacity of a plant is determined by;

$$C = P_{rated} \text{ x ADA x T } = \text{s x T} \qquad \text{(Eq. 1)}$$

according to [15] where,

P_{rated} is the power rating (MW) of the plant,

T is the overall lifetime (service duration[5]) of the plant, in which electrical energy is produced (years),

ADA is the Annual Duration of Availability (ADA)[6] or Annual Percentage of Availability (APA)[7] of the plant.

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5 Please note that the term “service duration” implies “being available for service”, instead of “being in service”. In other words, a plant may be “available for service”, in a certain period, but may not actually be “in service”, i.e. may not be “operated or committed” within this period due to commercial conditions in the contract.

6 Annual Duration of Availability (ADA) is the duration in which the plant will be available for service within one year period.

7 Annual Percentage of Availability (APA) is the percentage of the duration in which the plant is available within a year (i.e. percentage of duration obtained by excluding the period in which the plant is not available for one year period)

$$ADA = 8760\, h \; x \left(\frac{APA}{100}\right)$$

s is the annual capacity of the plant which can be written as;

$$s = P_{rated} \text{ x ADA } (\text{kWh / year}) \qquad \text{(Eq. 2)}$$

In addition to the capacity term, annual capacity is also used in electricity markets to describe the usage of capacity in an annual period. Annual capacity is the total energy that can be supplied within the period of "Annual Duration of Availability" by considering all the physical and other real constraints.

Capacity is a flow and measured in terms of MWh; it is priced in \$/MWh. Cost of capacity is mainly derived from the fixed costs of the investment. To find the total cost; cost of capacity, which is the fixed costs, is added to the variable costs, generally stated as the operational costs.

$$\text{Total Cost} = \text{Fixed Cost} + \alpha \text{ x Variable Cost} \qquad \text{(Eq. 3)}$$

where α is the capacity factor [8].

When generation cost data are presented, capacity cost is usually stated in \$/kWh. This is the cost of capacity flow produced by a generator over its lifetime, so the true units are \$/(kW x Lifetime). This cost provides useful information; but only for the purpose of finding fixed costs that can be expressed in terms of \$/MWh. No other

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8 The generator's capacity factor is its percentage utilization which is determined by the load's duration. Commercial capacity factor (not technical capacity factor), as it is used in capacity calculations, is determined by dividing actual energy output to the potential energy output of the generator. Standard technology generators have capacity factors determined by the market and not just by their technology. In this case, the duration of the load they serve, which determines their capacity factor, needs to be determined from their fixed and variable costs along with those of other technologies. This is done with screening curve analysis, or with algebra based on screening curves.

useful economic computation can be performed with the overnight cost of capacity given in $/kW because they cannot be compared with other costs until levelized.

2.2.1 Pricing of Generation Capacity

Pricing of the generation capacity is expressed in terms of the fixed costs, i.e. investments involved in the power plant. The main reason for imposing fixed capacity cost is due to the obvious fact that the customers with zero consumption would otherwise pay nothing, although they have allocated the plant, if only variable cost were imposed. [15] If only variable cost were imposed, it would be perfectly possible for these customers without making any consumption, to make agreement with plants for receiving only operating reserve services with no obligation of buying electricity and paying no charge for this service. [17] Therefore, the fixed capacity cost term is handled in order to prevent confusion.

Fixed capacity cost of a plant is the cost dependent only on the capacity, not on the system operating conditions, and percentage of availability, i.e. capacity factor.

Fixed capacity cost includes;

- Investment expenditures concerning the infrastructure and real properties,
- Regular repair and maintenance expenditures,
- Salaries of the permanently employed personnel,
- Financial costs of credits, loans, etc.

Fixed capacity cost components are given in Figure 10.

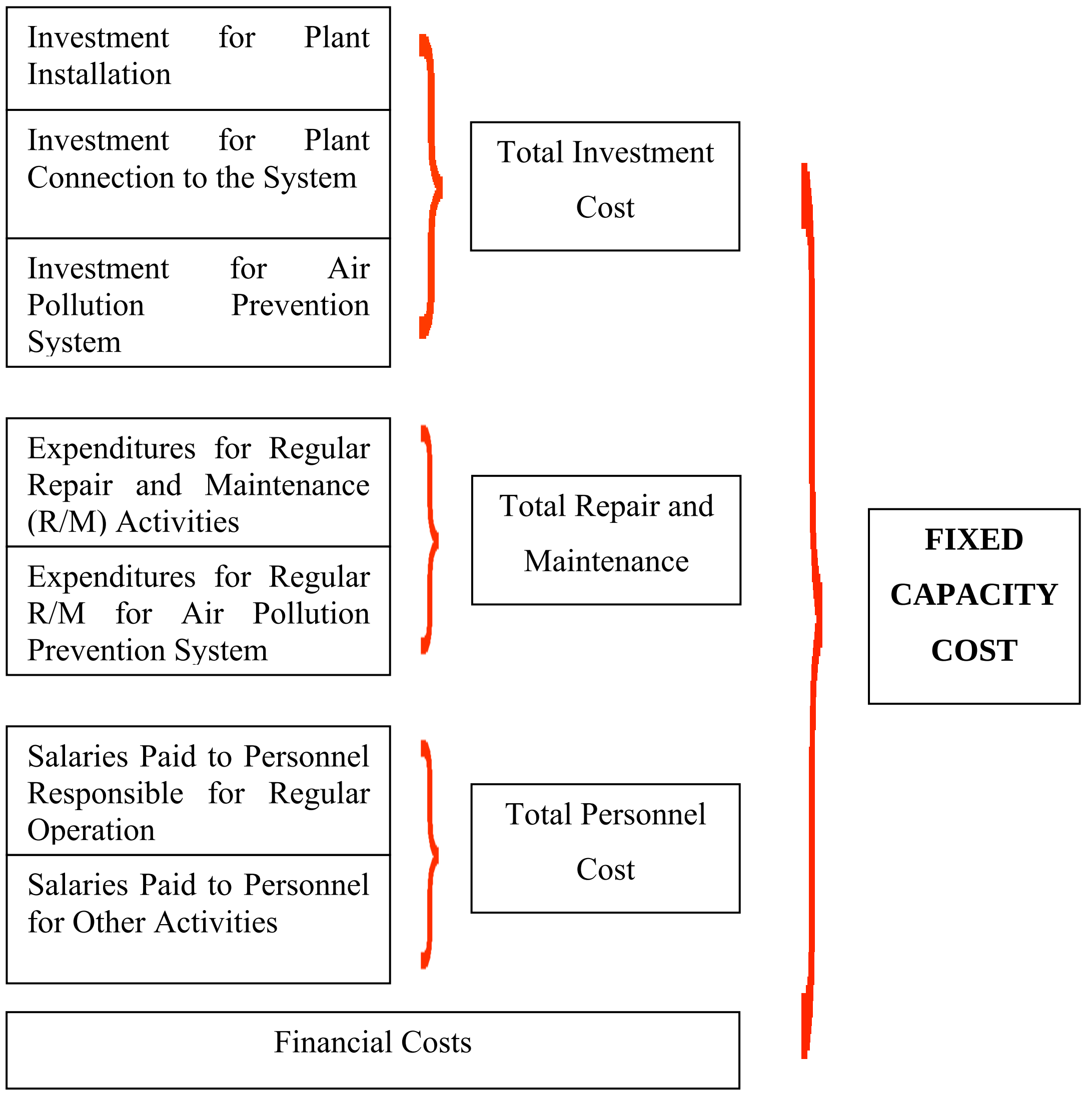

Figure 10. Fixed Capacity Cost Components (derived from [15])

2.2.1.1 Overnight Costs

Overnight cost of a plant is the present-value of the overall investment made for the plant. Overnight cost of a plant is the amount that would have to be invested as lump sum up front to pay completely for its completion until it is turned-on into service.

Since the rated power is parameter that may change widely with the capacity, overnight cost of a plant is usually expressed as a normalized figure stated as the ratio of the overall investment to the rated power in MW, i.e. as $/MW. For instance, the overnight cost of a coal fired plant might be $1.950.000/MW, so a 1000 MW coal fired plant would cost $1.950 million. The overnight cost is the cost that would be incurred if the building of power plant could be realized immediately following the payment. The overnight cost therefore should be accompanied with the escalations of the prices and payments made for the equipment, labor, and commodities that will occur during the time as the plant being constructed.

Overnight cost also excludes the financing charges, often referred to as interest during construction (IDC), incurred while the plant is being built. In short, Overnight Cost includes installation cost, tax and insurance premiums and all other expenditures spent during the construction period, except the financial costs. [18]

Overnight costs shall be classified as Direct Investments (EPC Costs[9]) and Indirect Investments. [19] EPC Cost includes direct investments in order to construct the power plant such as installation costs; whereas indirect investments are made for other auxiliary units for the sustainability of the power plant. Direct and indirect investments can be summarized as;

<u>Direct Investments (EPC Costs):</u>

- Engineering Costs;
    - Land cost for the site area,
    - Surveying costs for the site area,
    - Cost for project development,
    - Cost for project control
- Equipment purchasing costs,
- Construction costs,
- Equipment installation costs,

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9 EPC: Engineering, Procurement, Construction

- Test and commissioning costs

Indirect Investments:

- Licensing expenses for the justification of the preservation of the environmental conditions around site area,
- Licensing expenses of the plant,
- Construction costs for the Service Roads / Harbor,
- Cost of establishment of the cooling and service water infrastructure,
- Costs of fuel storage facilities,
- Cost of establishment of the facilities for SO2, CO2, NOx disposals, solid waste disposals and sewage water management facilities,
- Costs of transformer and switching substations,
- Costs of cables and transmission facilities connecting plant to grid,
- Site for Personnel Residence and Social Activities Expenses.

Overnight costs of power plants are studied and detailed cost breakdown structure of sample power plants are given in APPENDIX D as referenced to [20-31].

2.2.1.1.1 Direct Investment Costs

Direct investment cost is the cost of the primary contract[10] for building the plant. It includes the cost of designing the facility, buying the equipment and materials, and construction.

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10 Typical practice for the project developer to enter into a single EPC contract is with a large construction and engineering firm. The firm is responsible for most plant construction activities and absorbs significant cost, delay, and technical risk, which is reflected in the contract price. A developer can act as its own EPC manager and avoid paying the risk premium to a third party contractor, but in this case the developer absorbs the price and performance risks.

Engineering costs are the payments made for the feasibility analysis of the power plant before its construction. The area where the power plant is to be installed is inspected in the project phase in terms of various features, such as environment, closeness to the sea, roads, harbor, and other social aspects, whether the area is suitable for a power plant or not. Following the approval, the investor decides on the type and rated power of the power plant. All these studies, called engineering costs, increase the cost of the project. Engineering costs are very important since the construction of the power plant is fully dependent on these studies.

Depending on the engineering analysis and projects, the final decision is determined by the investor in terms of the construction and installation costs. These costs reflects the payment to be made for the raw material, desired equipment for installation and the hydro-mechanical and electromechanical equipment of the power plant. The main investment of a power plant is the composition of all these expenses.

Duration of the construction and installation of the power plant is an important parameter that influences the fixed costs, since a high percentage of the investment is to be realized in terms of loans to be obtained from credit resources.

2.2.1.1.2 Indirect Investment Costs

Indirect investment costs are the auxiliary costs required for the power plant in order to operate seamlessly in conformable with the environmental and social conditions.

Indirect investment costs are the construction costs that the investor handles outside the EPC contract. These costs are the combination of licensing, construction of transmission and fuel delivery facilities (such as a natural gas pipeline) to a power plant and personal expenses.

2.2.1.2 Financial Costs

Another important cost for the power plants utilization is the financial costs. Financing the capital cost of the investment involves borrowing funds from financial institutions that charge a rate of interest called debt capital. However, a certain portion of the financial capital is provided by the investors or shareholders of the firm or from profits earned by the firm which is called equity capital. The rate that the investors of the firm earn on their equity is described as the rate of return. If the firm is a regulated electric distribution company, the regulator decides on the appropriate rate of return to be charged on the customers to remunerate the providers of equity capital.

Profit-maximization theory states that firms will optimally demand a level of capital such that the increase in revenues that the capital produces is just equal to its price, which is the marginal revenue. Hence, if the cost of capital rises (when the total productivity is constant); the optimal level of capital used by the firms falls. In addition, the investors try to maximize their profits and therefore, prefer certain projects to uncertain projects. Hence many financial capital markets instead of one market should be considered in order to compete for the investments funds.

A plant investor incurs financial charges while the power plant is being built. This includes interest on debt and equity capital. Until the date of commissioning of the plant, these costs are capitalized; that is, they become part of the investment cost of the project for the taxing, regulatory, and financial analysis purposes. The Net Present Value (NPV) and Internal Rate of Return (IRR) are the most effective and valid analysis methods for the investment. [32]

2.2.1.2.1 Net Present Value (NPV) Method

The critical concept in NPV is the "time value of money," i.e., that today's money has a different value than the same amount one year ago or one year from now.

If an annual uniform amount (A) is invested in each year for T years with an annual discount or depreciation rate of the investment r %, then the present value of this invested shall be calculated and found as in given (Eq. 4):

$$PV_0 = (1+r)^{-1} \times A + (1+r)^{-2} \times A + (1+r)^{-3} + \ldots + (1+r)^{-T} \times A$$

$$= \frac{A \times \left[(1+r)^{T} - 1 \right]}{\left[r\,x\,(1+r)^{T} \right]} \qquad \text{(Eq. 4)}$$

where PV_0 represents the present values of the investment today.

The inverse of the last part of (Eq. 4), $\frac{\left[r\,x\,(1+r)^{T} \right]}{\left[(1+r)^{T} - 1 \right]}$, is the capital recovery factor, CRF. CRF represents the amount that shall be collected each year (after the investment) in order to recover the investment made in the present.

$$A = PV \times \frac{\left[r\,x\,(1+r)^{T} \right]}{\left[(1+r)^{T} - 1 \right]} \qquad \text{(Eq. 5)}$$

(Eq. 5) is also known as the levelized capital cost, since it is a level or a uniform cost in each year period.

NPV calculations mainly depend on the levelized capital costs and the profit of the firms, i.e. present value of future revenues, TR, minus (net of) future costs, TC as seen in (Eq. 6) (or alternatively $PR_t = (TR_t - TC_t)$ where PR represents the profit.)

$$NPV_0\left(PR_1,\ldots,PR_T\right) = \left(TR_1 - TC_1\right) \times \left(1 + r\right)^{-1} + \ldots + \left(TR_T - TC_T\right) \times \left(1 + r\right)^{-T}$$

(Eq. 6)

This approach assumes that costs are incurred in each future period, but some costs, such as capital costs, must be spent in the current period so revenues can be received in the future. If the fixed cost is incurred in the first period and variable costs are spent in the future periods, then (Eq. 6) becomes;

$$NPV = -FC_0 + \left(TR_1 - VC_1\right) \times \left(1 + r \right)^{-1} + \ldots + \left(TR_T - VC_T \right) \times \left(1 + r \right)^{-T}$$

(Eq. 7)

where TR_t and VC_t represent relevant positive and negative cash flows in each future period, discounted at the relevant cost of capital, r, to the present.

If TR and VC do not change over time, then (Eq. 7) simplifies to;

$$NPV = -FC_0 + \left(TR - VC \right) \times \left(\frac{1}{CRF} \right) \quad \text{(Eq. 8)}$$

The behavioral assumption of profit maximization can extend to a multi-period framework by assuming firms act to maximize their NPV. In particular, investors invest in power plants' projects with positive NPV, because all projects with positive NPV imply above normal discounted profits. This is the Net Present Value Rule. However, given constraints on the ability to manage multiple projects, it is assumed that firms rank possible projects by NPV and begin by investing in the project with the highest NPV. [33]

Overnight Cost per MW, per year gives the Annual Capacity Cost of a plant. Annual capacity cost is the cost, corresponding to the annual return of the overnight costs of a plant for each MW. Annual fixed capacity cost represents the fraction of capital paid annually in order to return it with interests, at the end of the project. Annual Fixed Capacity Cost (FCC) of a power plant shall be written in terms of the overnight costs (OC) and financial costs.

$$\mathrm{FCC} = \mathrm{OC}\ \mathrm{x} \left(\frac{r}{\left(1 - \frac{1}{(1+r)^{T}}\right)} \right) \qquad \text{(Eq. 9)}$$

$$= \mathrm{OC}\ \mathrm{x} \left(\frac{r\ \mathrm{x}\ (1+r)^{T}}{(1+r)^{T} - 1} \right)$$

Another approach to calculate the capacity cost is to take the Rental Rate into account. Rental rate or rental cost of a plant is the cost of renting the overall plant for a certain period of time, for instance, one year with all the variable costs are excluded. The ratio of rental rate to the rated power of the plant yields capacity cost.

$$\text{Capacity Cost } (\$/\mathrm{MWy}) = \frac{\text{Rental Rate } (\$/\text{year})}{\text{Rated Power } (\mathrm{MW})} \qquad \text{(Eq. 10)}$$

2.2.1.2.1.1 Depreciation

Depreciation is used in tax and regulatory accounts. For tax purposes depreciation reduces the value of an asset and can be counted against income, reducing tax liabilities. For regulatory purposes it provides the regulated firm with income from customers to pay for capital investments that must be replaced at the end of their useful life. Depreciation can also include economic or technical obsolescence.

However, when incorporating depreciation or other tax effects, discounting after-tax cash flows requires the use of after-tax discount rates.

For tax purposes there are several methods of calculating depreciation. The straight-line depreciation rate is equal to the inverse of the life of the asset. However, the tax authority can allow firms to accelerate their depreciation to encourage investment. One method of accelerated depreciation is double-declining balance. This method doubles the simple depreciation amount applied to the remaining book value of the asset. Double-declining balance and other accelerated depreciation methods increase depreciation in the early life of the asset and decrease depreciation in the later years. Therefore, after-tax income is higher in the early years than with straight-line depreciation and is lower in the later years. NPV maximizers prefer accelerated depreciation because the present value of income is greater the closer it is to the present.

In addition to these concepts, salvage value is also important in calculations. The salvage value is the value of an asset at the end of its lifecycle.

2.2.1.2.1.2 Internal Rate of Return (IRR) Method

The other critical approach is the Internal Rate of Return (IRR) method. Under IRR method, the decision maker calculates the rate of return that yields NPV = 0 and compares this rate with the firm's (internal) rate of return. If this Internal Rate of Return (IRR) is greater than the cost of capital, then the firm selects the project.

From (Eq. 6), the IRR shall be derived by solving the (Eq.11).

$$0 = \left(TR_1 - TC_1\right) \times \left(1 + IRR\right)^{-1} + \ldots + \left(TR_T - TC_T\right) \times \left(1 + IRR\right)^{-T} \qquad \text{(Eq.11)}$$

From (Eq. 7), the IRR shall be derived by solving the (Eq.12).

$$0 = -FC_0 + (TR_1 - VC_1) \times (1 + IRR)^{-1} + \ldots + (TR_T - VC_T) \times (1 + IRR)^{-T} \quad \text{(Eq.12)}$$

Although IRR and NPV approaches generally give equivalent results, in some cases they show different results. The differences take roots from the following reasons:

- Solution of IRR could involve multiple roots
- Different cash flow profiles could involve unreliable results for comparing IRRs.
- IRR method assumes only one cost of capital, if the cost of capital changes with the length of the borrowing period (e.g., the cost of capital might be low for a one-year loan, but higher on a five-year loan), there is indeterminacy.

Problems faced on IRR method can be avoided by using NPV analysis. But NPV Maximization assumes knowing the appropriate opportunity cost of capital.

Alternative method of these calculations is given in APPENDIX E.

2.3 Interconnection System Capacity Costs

The power plants must be connected to the interconnection system in order to transfer the electricity to customers. Connecting a power plant to the interconnection system is a complicated task. The interconnection system is generally composed of the transmission and distribution systems, and occasionally consisting either of those.

Transmission and distribution authorities are responsible for planning, development and operation of the interconnection and/or distribution systems with respect to certain standards; hence, require investments for achieving these goals. Investments of transmission authority are mainly depended on the expenditures made for expanding and refurbishing the transmission system and also for other auxiliary services so as to acquire safe and reliable electricity transmission service. In addition, the transmission authority is also responsible for providing the necessary transmission capacity to the market participants.

The distribution authorities on the other hand, carry out the same services as those provided by the transmission authority, with the exception that these services are carried out on the distribution level.

The transmission and distribution authorities make agreements, called connection agreements, with the generation companies for connecting the generation assets to the system, in order to be able to cover the connection investments. For this purpose, two different agreements are made between the parties; the Interconnection and the System Utilization Agreements. In terms of pricing objectives, transmission authority charges Transmission System Interconnection Cost and Transmission System Utilization Cost; while the distribution authorities charge Distribution System Interconnection Cost and Distribution System Utilization Costs. Interconnection Costs, are covered through the payments made by the parties, who need interconnection to the system. Besides, System Utilization Costs are covered from all parties, who need system services.

Parties responsible for the interconnection costs and the connection and utilization agreements are given in Table 5 as stated in [34].

As it is seen from the table, Transmission System Interconnection Cost incur only for the generation companies directly connected to the transmission system. These companies are exempted from the Distribution System Interconnection Costs, since these expenditures (connection costs between transmission system and distribution system) are charged to/paid by the distribution authorities.

Parties responsible for the system utilization costs and the connection and utilization agreements are given in Table 6.

Table 5. Types of Interconnection Costs [8]

	Parties	Type of Interconnection Cost
Interconnection Agreements	TEİAŞ ↔ Generation company directly connected to the transmission system	Transmission System Interconnection Cost
	TEİAŞ ↔ Generation company directly connected to the distribution feeders (36kV) of the transmission system	Transmission System Interconnection Cost
	TEİAŞ ↔ Consumer directly connected to the transmission system	Transmission System Interconnection Cost
	TEİAŞ ↔ Distribution company	Transmission System Interconnection Cost
	TEİAŞ ↔ Industial zones directly connected to the transmission system	Transmission System Interconnection Cost
	Distribution company ↔ Generation company directly connected to the distribution system	Distribution System Interconnection Cost
	Distribution company ↔ Consumer	Distribution System Interconnection Cost
	Distribution company ↔ Industial zones directly connected to the distribution system	Distribution System Interconnection Cost

Table 6. Types of System Utilization Costs [8]

	Parties	Types of System Utilization Costs
System Utilization Agreements	TEİAŞ ↔ Distribution company	Transmission System Utilization Cost
	TEİAŞ ↔ Generation company directly connected to the transmission system	Transmission System Utilization Cost
	TEİAŞ ↔ Generation company directly connected to the distribution feeders (36kV) of the transmission system	Transmission System Utilization Cost
	TEİAŞ ↔ Consumer directly connected to the transmission system	Transmission System Utilization Cost
	TEİAŞ ↔ Industial zones directly connected to the transmission system	Transmission System Utilization Cost
	TEİAŞ ↔ Energy export/import company by using transmission system	Transmission System Utilization Cost
	Distribution company ↔ Generation company directly connected to the distribution system	Distribution System Utilization Cost
	Distribution company ↔ Retail Company	Distribution System Utilization Cost (Transmission System Utilization Cost)

Table 6. Types of System Utilization Costs (continued)

	Parties	Types of System Utilization Costs
System Utilization Agreements	Distribution company ↔ Generation company directly sells energy to the consumer that is connected to the distribution system	Distribution System Utilization Cost (Transmission System Utilization Cost)
	Distribution company ↔ Autoproducer group that sells energy to the group partner	Distribution System Utilization Cost (Transmission System Utilization Cost)
	Distribution company ↔ Wholesale company directly sells energy to the consumer that is connected to the distribution system	Distribution System Utilization Cost (Transmission System Utilization Cost)

2.3.1 Interconnection Costs

Interconnection costs are determined with respect to the expenditures made for the investment and operation of specific equipment devoted to the single or group of companies in order to connect their generating unit(s)[11]. The transmission and/or distribution authorities may either realize the connection investment by its own financial resources or may utilize the financial/EPC resources of the company/companies for realizing the connections. These financial resources are then returned to the companies by exempting the system connection costs for a certain

[11] TEİAŞ allows sharing of equipment between the generators to increase efficiency of the system. Hence the interconnection costs are shared between these parties.

period of operation, until the investment has been recovered. [12] These costs are then reflected to the bills of prepared to customers in terms of the capacity cost of the power plant.

Interconnection costs are determined as the total asset value of the interconnection infrastructure and the related test and commissioning services. Interconnection infrastructure mainly consist of equipment, such as, lines, cables, transformers, circuit breakers, and other equipment, used for system operation and control, so as to connect the generators and customers to the transmission and/or distribution system[13]. The asset value owned by the generation companies does not effect the interconnection cost (gathered by the transmission and/or distribution authorities), but added to the generation capacity costs. Total asset value of the connection is determined with respect to the cost of additional investment to be made on the existing system in order to establish the connection.

The total investment/operation costs of the interconnection assets are influenced by the following factors [8]:

- Equipment Costs and Direct Engineering Costs,
- Operational Expenditures,
- Construction and Commissioning Expenditures,
- Interest and Exchange Rates.

[12] In some cases, the generators make also investment in order to connect its facility to the transmission system. At that time, TEİAŞ does not require additional investment and hence money injection to the system. The generator, in order to compensate its investment, makes agreement with TEİAŞ and it does not pay for interconnection cost to the TEİAŞ.

[13] Generators and customers are connected to the transmission and/or distribution systems at particular points, called interconnection point. Energy transfer from/to these points is continuously measured by a set of highly accurate energy/power meters.

Transmission and/or distribution authorities generally force the generation companies for making the connection payments in lump-sum form, in order to be able to realize the necessary investments, namely, displacement of some transmission infrastructure, installation of some extra protective equipment, or amounting/refurbishing the existing infrastructure for connection.

Other lump-sum payments are listed as:

- Testing and commissioning of the interconnection assets owned by the generation companies,
- Transportation costs incurred by the displacement and/or refurbishment of the transmission assets,
- Costs incurred by the transfer of rights,
- Land costs,
- Additional expenditures due to payments for overnight services made for realizing the task in accordance with the time schedule,
- Cost of delays (penalties).

In general, interconnection assets are realized by transmission and/or distribution authorities. However, due to insufficient funds, the transmission authority may sometimes force the generation companies to realize the investment for the connection assets, according to the Electricity Market License Regulations[14]. The ownership of these assets is then transferred to the transmission authority. In this case, the investment made for these assets are subtracted from the Transmission System Utilization Cost of the company. The methodology of this procedure is presented in detail in APPENDIX G.

So as to connect to the distribution system, the generation company may again realize the investment for the connection assets by itself. However, in this case, the ownership of the distribution assets remains in the investor, i.e. the generation

[14] Article no: 38

company. If the generation company makes investments for the connection assets, this investment is then exempted from the Distribution System Interconnection Costs. In this case, the company has to pay a small portion of money to the distribution authority related to the commissioning and test of his equipment. These costs are shown in Table 7.

Table 7. Test and Commissioning Costs of Self-Financed Distribution Assets [8]

Installed Power	Cost (TL)
Low Voltage Level	
0-15 kW	51,4
15-100 kW	117,6
Above 100 kW	149,4
Medium Voltage Level	
0-400 kVA	486,9
Above 400 kVA	605,1

2.3.2 System Utilization Costs

System utilization costs are the costs incurred by the utilization of system resources by the companies, who utilize the transmission or distribution system and other related system operation and maintenance services. The system utilization costs are determined from the system utilization tariffs of the interconnect system, which are defined according to maximum power supply capacity of generators and licensed power capacity. System utilization tariffs are determined according to transmission and distribution system authorities’ (TEİAŞ or distribution companies) expenditures with respect to marginal costs of transmission or distribution system utilization capacity.

System utilization capacity depends on the maximum system utilization quantity in specific divisions of the system. Maximum system utilization differs from the generation to the consumption; seasons (winter to summer) and other factors. Peak demand is taken as a reference for the system utilization and the increasing costs are calculated according to that point. System Utilization Tariff also varies according to the location of the connection point.

System utilization tariffs are influenced by two factors. The first one is the physical location of the generators, from which the cost, depending on this location, is determined by using the well known; "Nodal Pricing Method"[15]. The second factor influencing the system utilization tariff is the revenue cap of the generation companies. System utilization costs affecting the capacity cost of the generators are calculated by the addition of the network investment costs and required maintenance costs. The basis of ICBP model is governed by the services and economical signals that are being derived with respect to cost increments[16]. The detailed description of ICBP model and the calculation methodology of system utilization tariffs are given in APPENDIX F.

For the distribution and transmission systems, system utilization tariffs are given in Table 8 and Table 9.

[15] Nodal Pricing is a method of determining prices in which market clearing prices are calculated for a number of locations on the transmission grid, nodes. Each node represents the physical location on the transmission system where energy is injected by generators or withdrawn by loads. Price at each node represents the locational value of energy, which includes the cost of the energy and the cost of delivering it, i.e., losses and congestion. [35]

[16] Whenever the network has the sufficient capacity at peak demand points, desire of increasing the capacity at the "interconnection node point" leads increment in cost.

Table 8. Distribution System Utilization Costs (National Tariffs) [9]

Transmission System Consumer That Gets Energy From The Distribution Company	**Distribution Cost (kr/kWh)**	**Electricity Meter Measurement Cost (kr/kWh)**	**Losses (kr/kWh)**	**Transmission Cost (kr/kWh)**
Industry	0,000	0,000	0,000	0,000
Distribution System Consumer Connected To The Distribution System With Its Own Assets That Gets Energy From The Distribution Company	**Distribution Cost (kr/kWh)**	**Electricity Meter Measurement Cost (kr/kWh)**	**Losses (kr/kWh)**	**Transmission Cost (kr/kWh)**
Industry (Double Premises Tariff)	0,000	0,104	1,839	0,724
Industry (Single Premises Tariff)	0,000	0,104	1,839	0,724
Trading Establishment	0,000	0,104	3,042	0,724
Other 1 (Foundations, Museums, Public Enterprises etc.)	0,000	0,104	3,042	0,724
Other 2 (Water and Agricultural Based Establishment)	0,000	0,104	3,042	0,724
Agricultural Irrigation	0,000	0,104	4,146	0,724

Table 8. Distribution System Utilization Costs (National Tariffs) (continued)

Distribution System Consumer Connected To The Distribution System With The Assets of The Distribution Company That Gets Energy From The Distribution Company	Distribution Cost (kr/kWh)	Electricity Meter Measurement Cost (kr/kWh)	Losses (kr/kWh)	Transmission Cost (kr/kWh)
Industry (Double Premises Tariff)	1,211	0,104	1,839	0,724
Industry (Single Premises Tariff)	1,638	0,104	1,839	0,724
Trading Establishment	3,186	0,104	3,134	0,724
Other 1 (Foundations, Museums, Public Enterprises etc.)	3,186	0,104	3,134	0,724
Other 2 (Water and Agricultural Based Establishment)	3,186	0,104	3,134	0,724
Agricultural Irrigation	3,271	0,104	3,463	0,724

Table 8. Distribution System Utilization Costs (National Tariffs) (continued)

All Other Distribution System Consumers	**Distribution Cost (kr/kWh)**	**Electricity Meter Measurement Cost (kr/kWh)**	**Losses (kr/kWh)**	**Transmission Cost (kr/kWh)**
Industry (Double Premises Tariff)	1,211	0,104	1,839	0,724
Industry (Single Premises Tariff)	0,000	0,000	0,000	0,000
Medium Voltage (Single Premises Tariff)	1,638	0,104	1,839	0,724
Low Voltage (Single Premises Tariff)	2,558	0,104	2,680	0,724
Trading Establishment	3,186	0,104	3,134	0,724
Other 1 (Foundations, Museums, Public Enterprises etc.)	3,186	0,104	3,134	0,724
Other 2 (Water and Agricultural Based Establishment)	3,186	0,104	3,134	0,724
Resident/House	3,276	0,104	2,924	0,724
Ghazi and Martyr Families	3,276	0,104	1,768	0,724
Agricultural Irrigation	3,271	0,104	3,463	0,724
Lightening	3,471	0,104	4,747	0,724

Note 1: In normal operation, the generation companies do not generate reactive power and hence are exempted from the System Utilization Tariffs for reactive

power. In some cases, generation companies make subsidiary agreements with the customer in order the customer satisfy reactive power requirements. At this time, generation companies supply reactive power to the customer over the distribution companies. Therefore, generation companies are charged with System Utilization Tariffs for reactive power. However, this process and the related computations are not reflected to the capacity cost calculations.

Note 2: The values given in table reflect the sum of electricity loss cost, transmission system utilization cost, distribution system utilization cost and retail services cost.

Note 3: Distribution System Utilization Costs are based on the 2011 October tariffs.

Table 9. Transmission System Utilization Costs [34]

Area(*)	**Transmission System Utilization Costs (TL/MW-Year)**
101	14.178,94
102	7.682,67
103	94,55
104	94,59
105	6.137,88
106	11.025,03
107	8.030,81
108	1.972,26
109	22.915,85
110	2.267,42
111	6.343,73
112	12.722,04
113	93,78
114	8.288,92
115	14.258,94

(*) Areas are given in APPENDIX H.

Note 1: Transmission System Utilization Costs are based on the 2011 tariffs.

CHAPTER 3

RESULTS AND DISCUSSIONS

After the discussions about the calculation method of capacity cost, a “Capacity Cost Calculator” algorithm is developed in C++ in order to determine the capacity cost regarding that the cost of power plant and cost of interconnection system connection as well as tax issues are handled. This program helps the investors by its flexible architecture in the way that the following data are used as the inputs in the program. The inputs shall also be observed in Figure 11.

- Installed Power
- Type of the Power Plant
    - Advanced Coal Fired Power Plant
    - Simple Cycle Gas Turbine
    - Combined Cycle Gas Turbine
    - Oil-fired Steam Plant
    - Nuclear Power Plant
    - Biomass Power Plant
    - Hydroelectric Power Plant
    - Wind Power Plant (Land Based)
    - Wind Power Plant (Offshore)
    - Photovoltaic Power Plant

- Geothermal Power Plant
- Diesel Generator

- Depreciation Rate
- Commercial Lifetime of Power Plant
- Physical Lifetime of Power Plant
- Annual Percentage of Physical Availability
- Annual Percentage of Commercial Availability
- Connection to the Transmission System
    - Transmission System Transformer Area
    - Transmission System Transformer Center
- Connection to the Distribution System
    - Type of the Distribution System Consumer
    - End-User

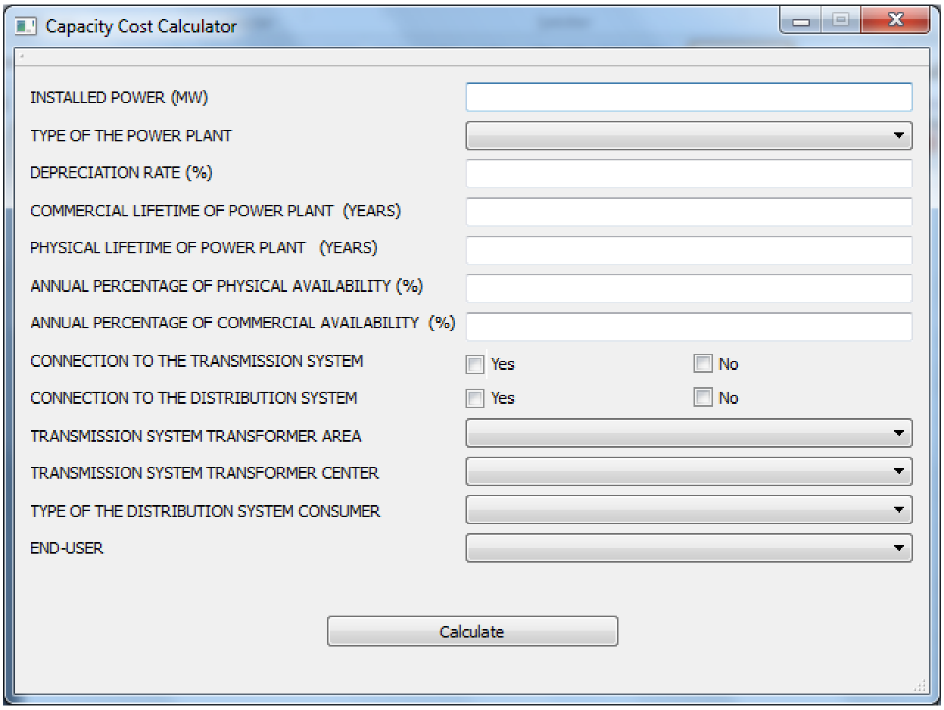


Figure 11. Main Screen of the Capacity Cost Calculator Program

At the beginning, the program calculates the total overnight cost of the power plant that is going to be invested by the investor. A sample screen of the overnight costs of Nuclear Power Plant and Hydroelectric Power Plant with 300 MW installed power are shown in Figure 12 and Figure 13; whereas the values are automatically calculated by the ratios given in APPENDIX D. Note that, the investor is able to change the data given in Overnight Cost screen in order to get more accurate results.

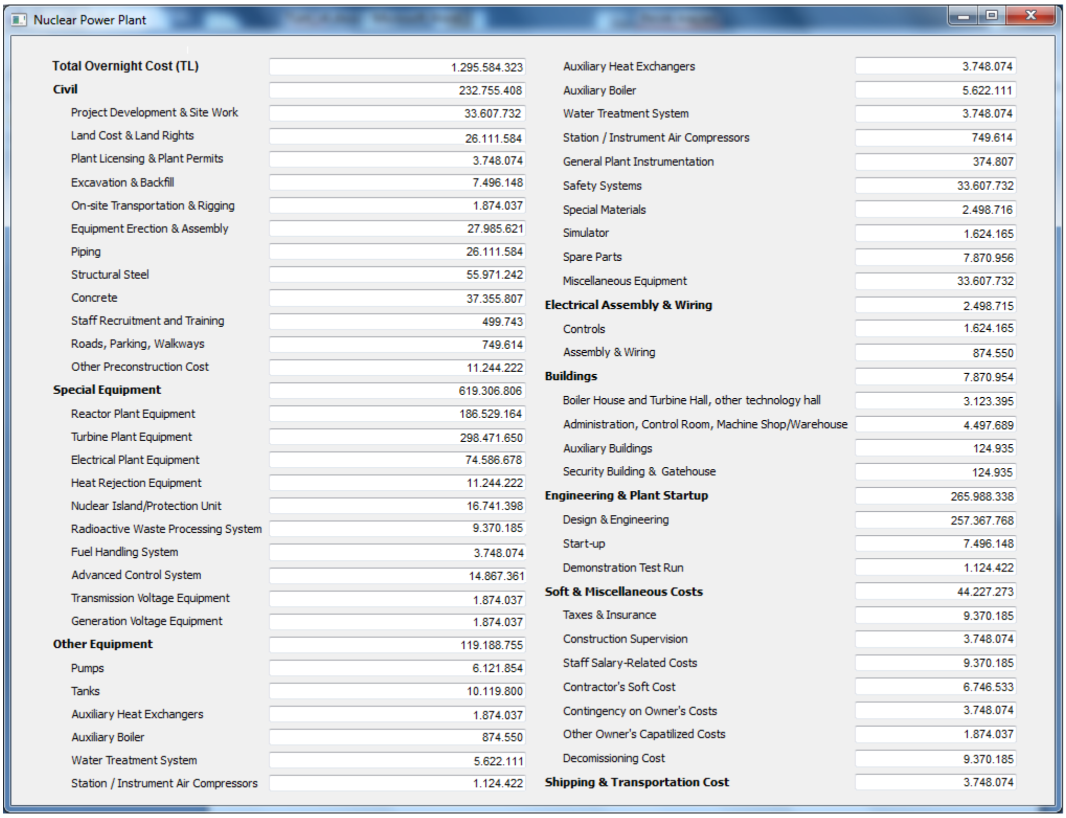
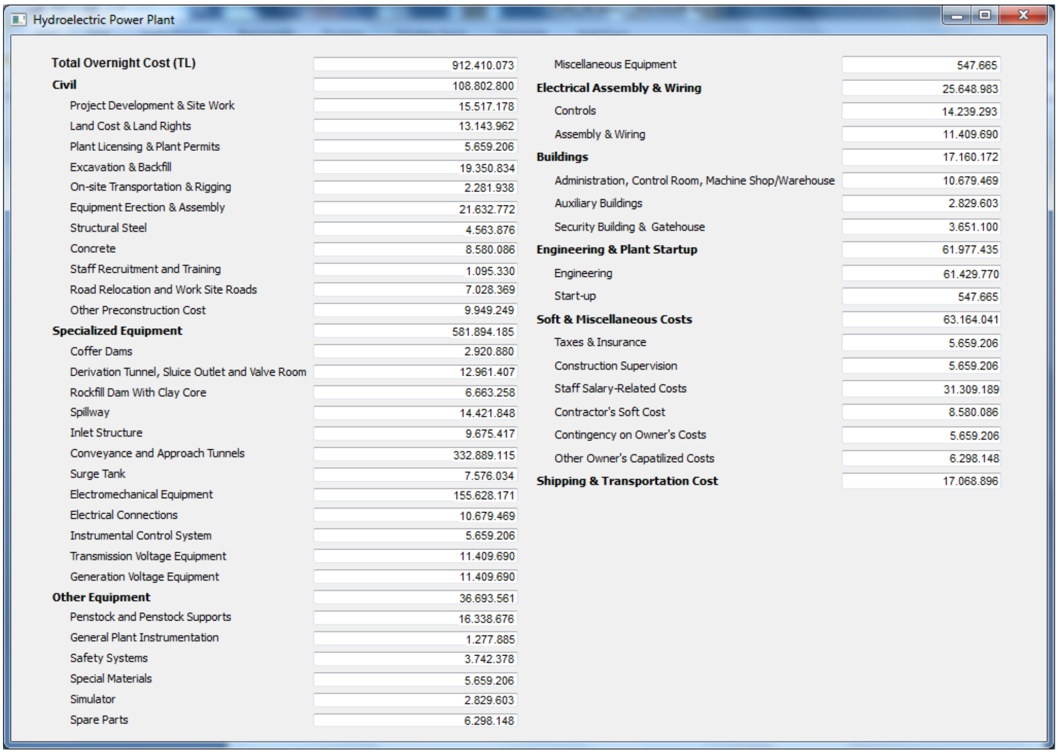


Figure 12. Overnight Cost of Nuclear Power Plant



Hydroelectric Power Plant

Total Overnight Cost (TL)	912.410.073
Civil	108.802.800
Project Development & Site Work	15.517.178
Land Cost & Land Rights	13.143.962
Plant Licensing & Plant Permits	5.659.206
Excavation & Backfill	19.350.834
On-site Transportation & Rigging	2.281.938
Equipment Erection & Assembly	21.632.772
Structural Steel	4.563.876
Concrete	8.580.086
Staff Recruitment and Training	1.095.330
Road Relocation and Work Site Roads	7.028.369
Other Preconstruction Cost	9.949.249
Specialized Equipment	581.894.185
Coffer Dams	2.920.880
Derivation Tunnel, Sluice Outlet and Valve Room	12.961.407
Rockfill Dam With Clay Core	6.663.258
Spillway	14.421.848
Inlet Structure	9.675.417
Conveyance and Approach Tunnels	332.889.115
Surge Tank	7.576.034
Electromechanical Equipment	155.628.171
Electrical Connections	10.679.469
Instrumental Control System	5.659.206
Transmission Voltage Equipment	11.409.690
Generation Voltage Equipment	11.409.690
Other Equipment	36.693.561
Penstock and Penstock Supports	16.338.676
General Plant Instrumentation	1.277.885
Safety Systems	3.742.378
Special Materials	5.659.206
Simulator	2.829.603
Spare Parts	6.298.148
Miscellaneous Equipment	547.665
Electrical Assembly & Wiring	25.648.983
Controls	14.239.293
Assembly & Wiring	11.409.690
Buildings	17.160.172
Administration, Control Room, Machine Shop/Warehouse	10.679.469
Auxiliary Buildings	2.829.603
Security Building & Gatehouse	3.651.100
Engineering & Plant Startup	61.977.435
Engineering	61.429.770
Start-up	547.665
Soft & Miscellaneous Costs	63.164.041
Taxes & Insurance	5.659.206
Construction Supervision	5.659.206
Staff Salary-Related Costs	31.309.189
Contractor's Soft Cost	8.580.086
Contingency on Owner's Costs	5.659.206
Other Owner's Capatilized Costs	6.298.148
Shipping & Transportation Cost	17.068.896

Figure 13. Overnight Cost of Hydroelectric Power Plant

In order to see the variation of the results with respect to the inputs, a sample investment i.e. 200MW Advanced Coal Fired Power Plant is chosen as seen in Figure 14. It is seen that in the program some default values are defined so as to help the user. The overnight cost of the sample investment is almost 845,8 Million TL. With the given data as seen in Figure 14, the capacity cost is calculated (with tax included) as seen in Figure 15. It is clear that until the commercial lifetime of the plant, the investor needs to overcome his expenditures for the investment as well as the interconnection costs. At the time that the commercial lifetime of the plant is over, total overnight cost of the plant is gathered by the investor. After that time, until the end of physical lifetime of the plant, the consumer needs to pay money for only interconnection costs[17].

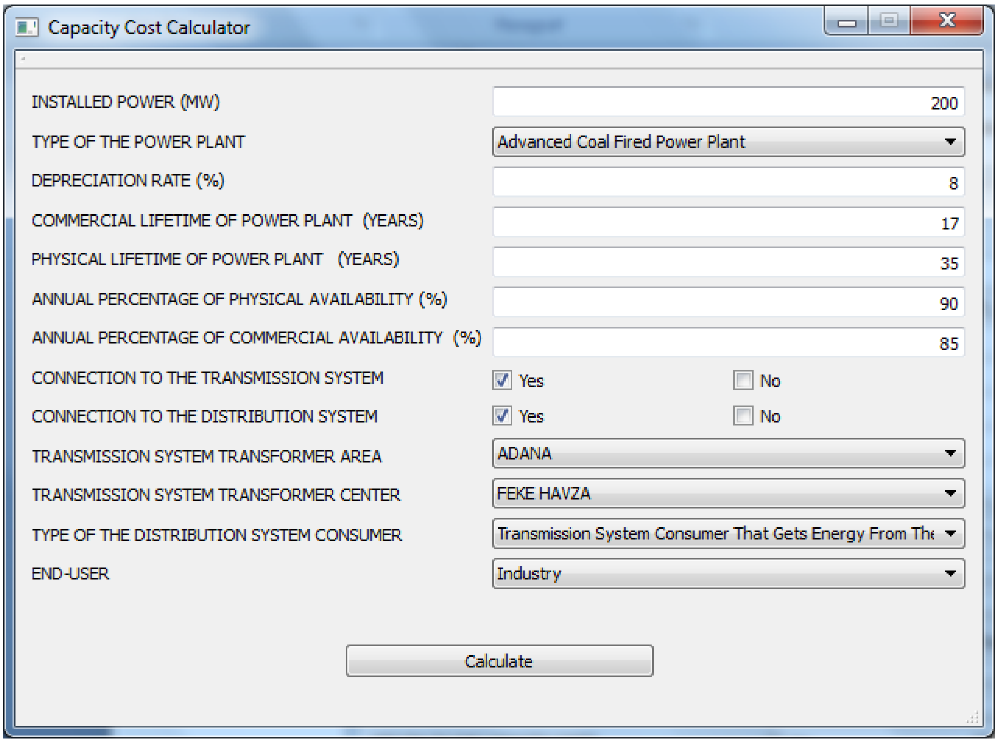


Figure 14. 200MW Advanced Coal Fired Power Plant

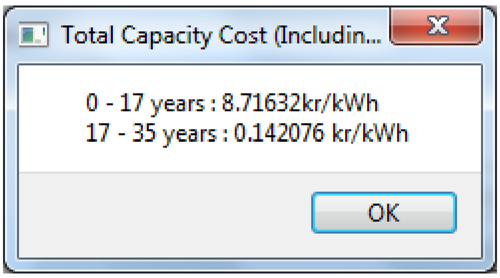


Figure 15. Capacity Cost of a 200MW Advanced Coal Fired Power Plant

[17] Please note that the consumer will also pay money for the variable costs which are not detailed in this thesis. Therefore, for full analysis these costs should be clarified.

If the depreciation rate is taken as 6% rather than 8%, it can be seen that this value only affects the capacity cost that shall be gathered until the end of commercial lifetime of the power plant because of the fact that depreciation has influence only on the overnight costs. In addition, if the depreciation rate is declined, the capacity cost is obviously decreased.

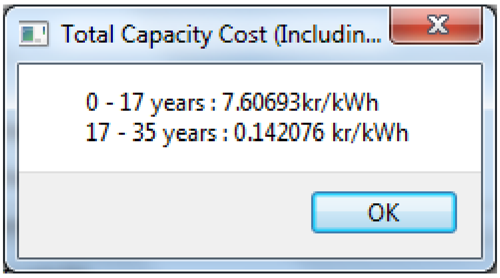


Figure 16. Capacity Cost when Depreciation Rate is 6%

Another factor affecting the capacity cost is commercial lifetime of the power plant. The relationship between the commercial lifetime and capacity cost is detailed in Chapter 2. In our sample, if the commercial lifetime of the power plant decreases, the capacity cost is increased as seen in Figure 17.

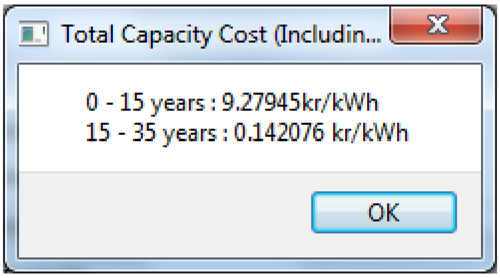


Figure 17. Capacity Cost when Commercial Lifetime is 15 Years

Actually, the physical lifetime of the power plant does not have an impact on the capacity cost. It only gives idea about the total lifetime of the power plant in order to help feasibility analysis for the investor reckon with variable costs. As it is seen in

Figure 18, if the physical lifetime of the power plant decreases, the capacity cost is not changed.

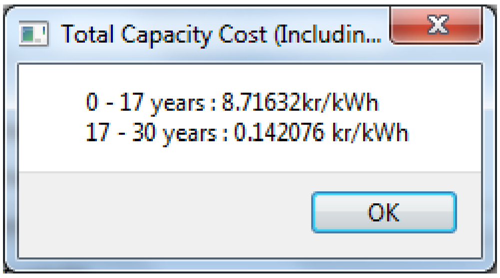


Figure 18. Capacity Cost when Physical Lifetime is 30 Years

The other important factors driving the capacity cost are annual percentage of commercial availability and annual percentage of physical availability. It is better for the consumers whenever these factors become large because it means that the power plant works effectively that leads charging less capacity cost from the consumers. To mention, these values have greater effect to overnight costs rather than the interconnection costs. If these values are set to 70% then the capacity costs are found as:

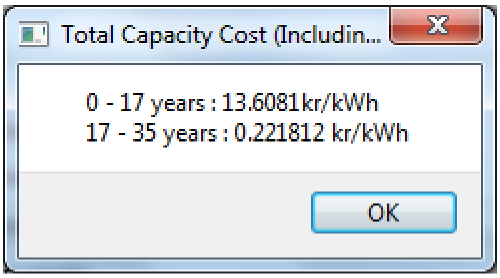


Figure 19. Capacity Cost when Percentage Availabilities are 70%

Besides the overnight costs and the relevant factors, the interconnection costs are very crucial to distinguish capacity costs. Especially, the distribution system connection costs are very important because these costs have greater values in comparison to both overnight costs and transmission system costs. Distribution costs affecting to the capacity cost are related to distribution cost, transmission cost, electricity meter measurement cost and cost of losses as stated in Chapter 2. These costs vary according to the type of distribution system consumer and connection type of the consumer to the interconnection system.

The below figures give idea to the user about the alteration of capacity cost with respect to the interconnection points.

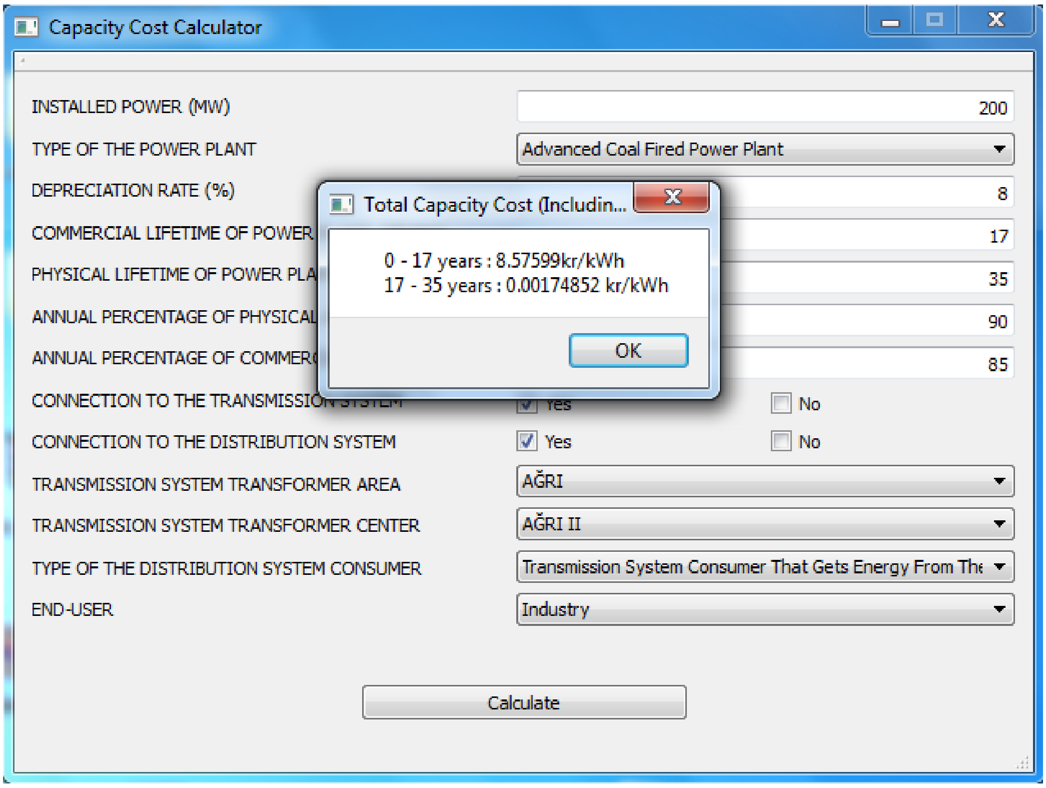
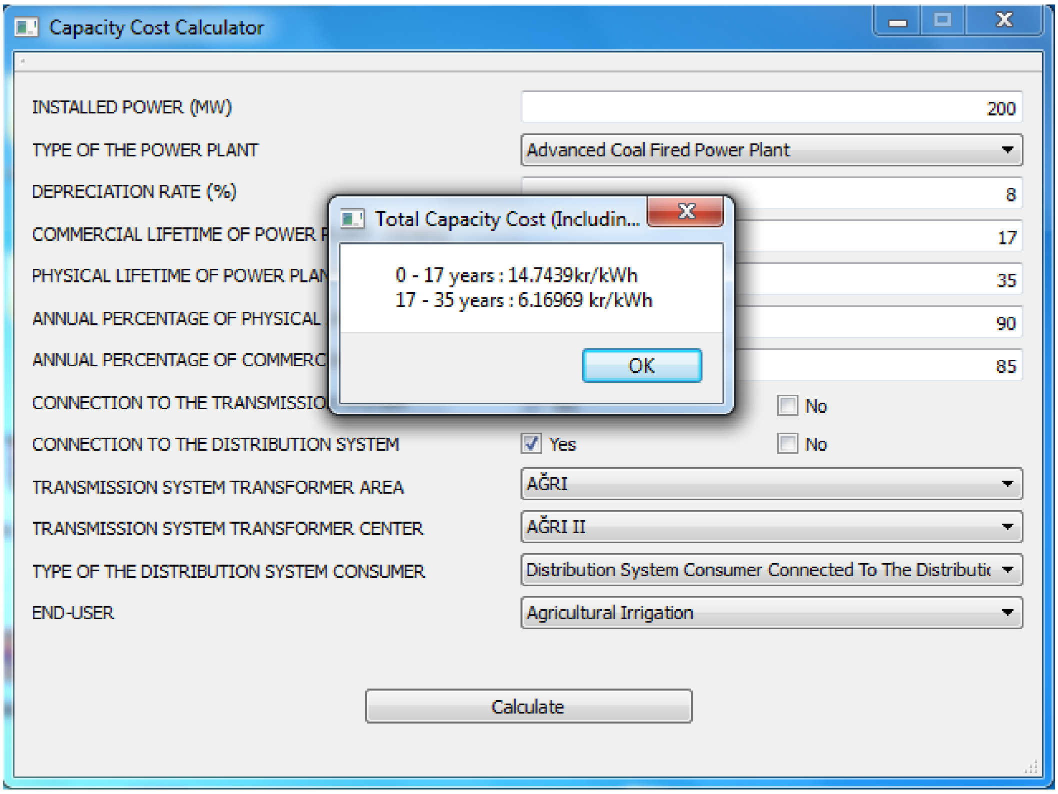


Figure 20. Capacity Cost with Different Transformer Area



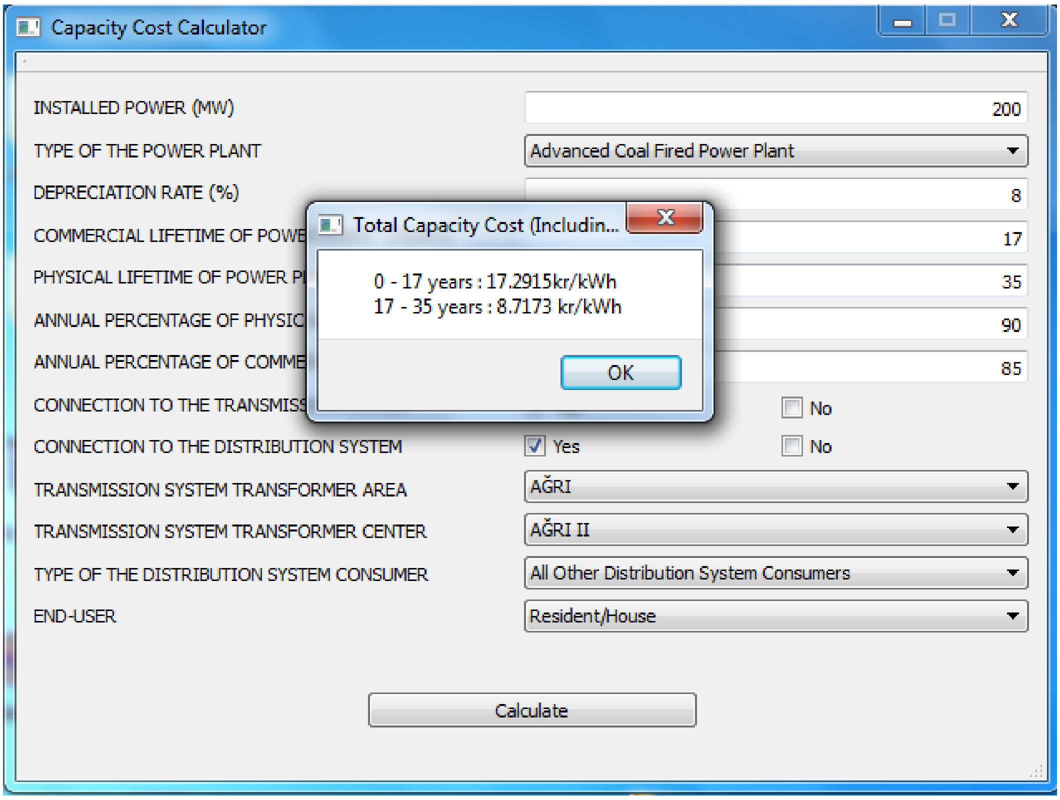


Figure 21. Capacity Cost for Various Distribution System Consumers

To mention, the capacity cost stated in the algorithm covers the tax issues. The state requires for different type of taxes under the name of tax liabilities such as TRT share (2%), Energy Fund (1%), VAT (18%) that burden cost load to the consumer.

For the feasibility analysis, the investor needs to be aware of the total price of the electricity in which variable costs are covered. These costs are stated in [8]. As a result, the user shall add the variable cost of the generator to the capacity cost that is calculated for a variety of cases via the algorithm and then compare the final price with the sale price of the electricity that is determined by the authority.

CHAPTER 4

CONCLUSIONS

In this thesis, capacity cost in electricity markets is examined and calculation methodology of the capacity cost is studied in this context. The factors deriving the capacity cost is presented and calculation approach of capacity cost is examined using the data gathered from the generation capacity cost and interconnection capacity cost. Capacity cost for different cases are compared by the help of "Capacity Cost Calculator" program and feasibility of the investments are discussed.

In the first part, the general overview of Turkish Electricity Market and Turkish Electricity Market Regulations are handled in order to have general knowledge about the market structure and the capacity trading. Turkish Electrical Energy Sector is discussed in detail. Within this context, Supply and Demand Balance of the system is reviewed and the necessity of generation investments for the power plants as well as the capacity reserves is revealed. Then, the market structure and the regulations implemented in the Turkish Electricity Market are discussed in detail. The development of Turkish Electricity Market is comprised of three parts, namely, preliminary development period, liberalization efforts period and reform period, and progresses in each period are defined clearly.

Although Turkish Electricity Market structure and regulations are examined in detail, the concept of capacity, capacity cost and capacity trading is not clearly defined and understood in Electricity Market Laws. Furthermore, the capacity trading mechanisms and their implementation, the principals and procedures of capacity, as well as kinds of capacity trading mechanisms are not clearly understood by the market participants. Also, it is not easy to find satisfying information about the implementation of the capacity trading mechanisms in the market in which both the public and private sector participants are acting as players.

The main object of the present thesis is to introduce the main concept of capacity, capacity cost and capacity trading in terms of the principals outlined by EMRA.

In the second part of the thesis, generation capacity and generation capacity cost of power plants are defined. Since the pricing of generation capacity is expressed in terms of the fixed costs, i.e. investments involved in the power plant, overnight cost term is concerned at the beginning. Overnight cost of a plant is the present-value of the overall investment made for the plant and these costs are the constitution of direct investment and indirect investment costs of power plants. In this scope, different kinds of power plants, namely, Advanced Coal Fired Power Plant, Simple Cycle Gas Turbine, Combined Cycle Gas Turbine, Oil Fired Steam Plant, Nuclear Power Plant, Biomass Power Plant, Hydroelectric Power Plant, Wind Power Plant (Land Based), Wind Power Plant (Off-shore), Photovoltaic Power Plant, Geothermal Power Plant, Diesel Generator are analyzed according to their overnight costs and then cost breakdown structure as well as the cost estimations for each type of power plant is detailed.

In the next part of the thesis, the concept of the overnight cost and the aforementioned factors directly affecting the generation capacity cost are presented. First, brief information about the annual percentage of availability expressed in terms of physical and commercial availability of a power plant is given. The specified term is studied and divided into two parts, i.e. annual percentage of physical availability which corresponds to the physical operational limitations of the power plants such as wind rate for Wind Power Plants and annual percentage of commercial availability which corresponds to business-related limitations of the power plants. Second, overall lifetime of power plants with respect to commercial and physical conditions is introduced. At that time, depreciation rate is presented. Thereafter, the relation between the commercial lifetime and the depreciation rate is concerned. Finally, details of Net Present Value Method is given in order to calculate the generation capacity cost of the plant with respect to overnight cost, annual percentage of physical and commercial availability, commercial lifetime and depreciation rate.

Next, the concept of interconnection system capacity and interconnection system capacity cost is defined, since the power plants are connected to the interconnection system in order to have transmission services. Interconnection system capacity is studied in two parts, that is to say, the transmission system and the distribution system capacity, since the transmission and the distribution authorities are responsible for planning, development and operation of the transmission and distribution systems. This responsibility includes making a significant amount of investment for the development of interconnection system, eventually burdening the cost terms reflected to the customers. These cost burdens are studied in detail in the present thesis and within this scope the capacity cost related to interconnection system services is divided into two parts, namely, the costs related to interconnection services and the costs related to transmission and distribution system utilization.

In the last part, a computer algorithm is developed for calculating the overall capacity cost reflected to the customers. In order to be flexible, for a variety of situations, a user-friendly interface is developed between the user and the database in order to be able to study a variety of situations.

One of the main conclusions derived from the studies carried out in this thesis is that the main factor influencing the capacity cost is the type of the power plant. Actually, it is an expected result because the generation cost characteristics of power plants differs a lot and also the overnight cost of the power plants directly gives input to the final capacity cost in calculations.

Commercial life time of the plant term is also highly effective on the capacity cost since all the investments must be retrieved by the end of their commercial life time. Hence, it is clear that the customers make less amount of payment unless the commercial life time of the power plant is short. In addition, percentages of physical and commercial availabilities of the power plants have also direct impact on the capacity cost.

The distribution capacity cost has a significant effect on the final capacity cost on the other hand the transmission capacity cost has less effect compared to other deriving costs. In fact, the customers are required to pay interconnection costs until the end of physical lifetime of the power plants. That is why, distribution capacity cost is very critical for the customer. It is clear that, choosing the night-time tariff is much better for the customers in order to get cheap energy from the system. Additionally, it is observed that type of the distribution system customer or the power plant connection point to the transmission system resulted in a remarkable capacity cost alternation.

After all, the final capacity cost that is gathered from the program is analyzed with respect to the tariffs stated by the distribution authority whether the investment is feasible or not.

As a future work, the algorithm can be modified so as to analyze more sophisticated cases. For that purpose, one can make a more detailed analysis on the power plant overnight costs since the calculation of overnight cost depends on various factors. Furthermore, the depreciation rate is taken as constant along the commercial life time of the plant in the calculations. Since the depreciation rate is a variable term changing instantaneously, a sophisticated mathematical model needs to be used in order to get more precise results. Besides, since the transmission and distribution service costs are determined by the authorities, the user has no right to interfere any part of those costs.

In this thesis, in addition to the feasibility analysis, the problems of the market structure are also discussed. The Electricity Market Law needs to be revised since the terms related to the capacity are not defined properly. Hence, the market participants have confusions about the concept of capacity mechanisms and the way how they work. Again, as a future work, after the revision of the law, the user needs to modify some parameters and maybe the applied method in the program.

Finally, the present thesis attempts to give an opinion about the amount of investments to be made by the investors in the generation and distribution sectors. Therefore, before making these investments, the investors should analyze the factors such as future electricity demand, alternative power plant investments, and the regulations concerning the governmental issues.

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APPENDIX A

LEGAL INSTRUMENTS IN TURKEY

Table 10. Types of legal instrument in order of superiority (derived from [4])

Types of Legal Investment	Legally Binding Operators	Authorized Institution	Method of Change	Ease of Change	Enacted
Primary Legislation Law, e.g. Electricity Market Law	Yes	Turkish Parliament	Only Turkish Parliament is entitled to change	Difficult	Yes
Regulations	Yes	EMRA	EMRA issues Regulations Following publication in the Official Gazette, the Regulations come into force.	Relatively easy	Yes
Letter	Yes	EMRA	EMRA may amend	Relatively easy	Yes
Board Decisions	Yes	Board of EMRA	Board of EMRA issues a new decision	Easy	Yes

APPENDIX B

IMPORTANT LEGISLATIONS IN REFORM PERIOD IN TURKEY

Table 11. Important legal instruments in Reform Period (derived from [1-7])

Date	Document	Contents
20 March 2001	Electricity Market Law	Establishes market structure and regulatory framework
4 August 2002	Electricity Market Licensing Regulation	Prescribes the process for obtaining licenses and contains the standard terms of each type of license
11 August 2002	Electricity Market Tariffs Regulation	Establishes basic framework for regulation of industry tariffs and their modification
11 August 2002	Communiqué regarding determination of transmission and distribution connection charges	Establishes principles for determination of connection tariffs
11 August 2002	Communiqué regarding regulation of transmission system revenue	Tariff formula for transmission use-of-system revenue cap

Table 11. Important legal instruments in Reform Period (continued)

Date	Document	Contents
4 September 2002	Electricity Market Eligible Consumer Regulation	Establishes the process and principles for determining the definition of eligible customers and its revision over time
4 September 2002	Electricity Market Import and Export Regulation	Defines regulation of import and export of power to/from Turkey
25 September 2002	Electricity Market Customer Services Regulation	Customer service quality rules
28 November 2002	Regulation Regarding the Amendments of the Agreements of the Legal Entities which are carrying more than one activity in the Electricity Market and the Transfer of the Transmission Activities and Abandoned Activates	Regulates the principles of amending the current activities of the legal entities carrying more than one activity and transfer of transmission activities (which is compulsory) and other activities which were abandoned.
27 March 2003	Communiqué Regarding Connection to and Use of Transmission and Distribution Systems in the Electricity Market	Prescribes process for obtaining transmission and distribution connections and connection and use-of-system agreements

Table 11. Important legal instruments in Reform Period (continued)

Date	Document	Contents
22 January 2003	Electricity Market Grid Regulation	Short form of grid code – technical regulation of transmission system
24 January 2003	Communiqué Regarding Regulatory Accounting Guidelines	Accounting rules to support operation of licensees' tariff formula
28 January 2003	Regulation Regarding the Procedures and Principles on Preliminary Research and Investigations of the Electricity Market	Principles and procedures to be complied by EMRA during the supervisions and investigations to be conducted by EMRA in relation to legal entities in the market.
19 February 2003	Electricity Market Distribution Regulation	Short form of grid code – technical regulation of transmission system
22 March 2003	Communiqué Regarding the Meters to be used in the Electricity Market	Prescribes industry metering points and standards
14 April 2003	Communiqué regarding to the fines which will be exercised within the scope of Article 11 of Electricity Market Law	Establishes the fines to be imposed by EMRA on the licensee in case the licensee does not comply with the Electricity Market Law and the relevant regulations and communiqués

Table 11. Important legal instruments in Reform Period (continued)

Date	Document	Contents
3 November 2004	Electricity Market Balancing and Settlement Regulation	Establishes trading arrangements
3 November 2004	Electricity Transmission System Supply Reliability and Quality Regulation	Technical regulation of connections to transmission system and transmission quality standards
7 September 2005	Communiqué Regarding Regulation of Market Management Revenue	Formula for determining cap on TEİAŞ' revenue for operating trading system
4 October 2005	Regulation on Principles and Procedures for Granting Guarantee of Origin	Process for obtaining and principles applied re the grant by EMRA of a certificate of guarantee of origin of power for renewable
4 April 2006	Regulation Concerning Electricity Demand Forecast	Principles and processes to be followed by industry parties in forecasting demand
12 September 2006	Regulation on the supply continuity, commercial and technical quality of electricity in the distribution system	Establishes principles with regards to the rules to be followed by distribution companies (about supply continuity, commercial and technical quality of electricity)

Table 11. Important legal instruments in Reform Period (continued)

Date	Document	Contents
7 January 2007	Regulation on arranging distribution system investments and auditing realization of plans.	Establishes principles with regards to distribution system investments and auditing realization of plans
27 December 2008	Electricity market regulation on ancillary services	Establishes principles with regards to supply of services provided within the framework of ancillary services
10 July 2009	Electricity market regulation on lightning	Establishes principles about the scope of lightning obligations, rules on the measurement of lightning consumption, payment and auditing
14 April 2009	Electricity Market Balancing and Settlement Regulation	Establishes trading arrangements
11 June 2009	Procedures and principles with regards to profile application to be used in settlement calculations	Self explanatory
01 December 2009	Electricity market regulation	Day Ahead Planning

APPENDIX C

PRINCIPAL FEATURES OF ELECTRICITY MARKET PLAYERS

C.1 Generation

EÜAŞ sells-on most of its power to TETAŞ which currently acts as the dominant wholesaler for the market. At the outset, all power will be purchased by TETAŞ as wholesaler. TETAŞ will sell power wholesale to the retail businesses of the Distribution Companies under initial 5-year 'vesting contracts'. MENR initiated the privatization of EÜAŞ's electricity generating facilities.

Each generator requires a license, granted by EMRA.

The generation licenses may engage in the activities of construction and commissioning of generation facilities, electricity generation, and sale of the generated electricity and/or capacity to customers. The generation companies may be affiliated to distribution companies, but may not have control over them.

A generation license holding company has different obligations, such as providing side services to TEİAŞ and distribution license holders and to pay transmission and distribution fees to TEİAŞ and distribution license holder that operates in the license holding company's region. In return, for fulfilling these obligations, the generation license holding company has the privilege to generate and sell electricity (and also the right to request from the administration to expropriate the immovable that it needs).

Permissions under the Environment Law are significant particularly for generation license holding companies. Pursuant to the Environment Law, in principle, all the facilities that plan activities which may cause environmental problems are required to prepare an Environmental Impact Assessment Report or a project presentation file depending on the particulars of the project. Regulatory authorities cannot issue approvals, permits or incentives to projects that do not obtain either an "Environmental Impact Assessment Affirmative Decision" or an " Environmental Impact Assessment is not Required Decision". In accordance with the above, generation facilities must fulfill the above requirements arising from the Environmental Law.

The total market share of any private sector generation company, together with its affiliates, may not exceed 20 % of the total installed capacity of Turkey.

EÜAŞ, its subsidiaries and private sector generation companies must obtain separate licenses and keep separate regulatory accounts for each generation facility.

The generation licenses can be issued for a maximum of forty-nine years and a minimum of ten years.

C.2 Transmission and Market Operation

TEİAŞ has been established as the state-owned transmission system operator. It owns the transmission system and is responsible for its operation and maintenance, connection of generation, distribution and certain larger customers to the grid. TEİAŞ requires a license, granted by EMRA.

TEİAŞ also has a role as operator of the balancing and settlement arrangements which are at the heart of the new market. These have been implemented by the Balancing and Settlement Regulation (the BSR). Broadly, the wholesale market functions on the basis of bilateral contracts between sellers of power (EÜAŞ, other generators, TETAŞ and other wholesalers) and buyers of power (TETAŞ, other wholesalers, the retail arms of the Distribution Companies and independent retailers and, potentially, eligible customers directly).

The purpose of the balancing and settlement arrangement is:

- To provide a mechanism by which TEİAŞ as system operator can balance the system in real time, by accepting bids and offers from generators to vary their intended levels of generation.
- To allow each party's net aggregated contracted positions to be compared with its aggregate physical positions (i.e. metered quantities generated and consumed). The difference between a party's contracted and physical position (for a defined settlement period) is an imbalance. An imbalance can arise where a seller of power into the market delivers more or less than he has contracted to, or where a purchaser of power offtakes more or less than he contracted to.

The arrangements provide for the settlement of accepted bids and offers, and the calculation and cash-out (settlement) of imbalances – in effect the system buys or sells the imbalance from or to the party. The cash-out price is a single price for each settlement period derived from the prices and volumes of accepted bids and offers.

TEİAŞ is responsible for balancing the transmission system and so is the natural operator of the balancing and settlement arrangements. It does this through the Market Financial Settlement Centre (MFSC).

There are no currently announced plans to privatize TEİAŞ.

TEİAŞ's principal duties are:

- Provision of access to its system and transmission services on a mandatory and non-discriminatory basis;
- Operation and maintenance of the transmission system in an environmentally friendly manner within the framework of the applicable legislation;
- Operation of the financial reconciliation system within the framework of the Balancing and Settlement Regulation and through the MFSC;

- Submission of proposals for transmission use-of-system and connection tariffs for approval by EMRA within the framework of the provisions of the Electricity Market Tariffs Regulation;

- Preparation of generating capacity projections based on demand forecasts prepared by distribution companies, within the framework of the Regulations that define the principles and procedures regarding the preparation of demand forecasts;

- Preparation of transmission system investment programs for approval by EMRA; and

- Keeping the records of suppliers providing electricity and/or capacity to eligible consumers directly connection to the transmission system, peak demands and follow meter records, within the framework of the applicable legislation.

C.3 Distribution

TEDAŞ was formerly responsible for distribution and retail of power within Turkey. In the new market structure, TEDAŞ's distribution systems have been divided into 21 zones, each of which will be the responsibility of a separate Distribution Company. The Distribution Company will not own its assets –the Electricity Market Law provides that TEDAŞ will continue to own the assets and grant rights of use of them (under a 'transfer of operating rights') to each Distribution Company.

Each Distribution Company will be responsible for operation and maintenance of its distribution system and will have a monopoly on distribution of electricity within its designed geographic zone. Within the zone, the distribution company will be responsible for new connections (of customers and enabled generators), system extensions etc. At the outset, it will also have a retail business within the defined zone.

Each Distribution Company is required to hold a distribution license granted by EMRA. A distribution license will have a term of between 10 and 49 years.

Each Distribution Company will have transmission connections with TEİAŞ (and potentially connections with other Distribution Companies), and will provide connections to embedded generation and to customers. It will sell use of its system to its retail business and, in future, to competing retailers.

The Distribution Company's principal duties are:

- operation and maintenance of the distribution system (which belongs to TEDAŞ) in an environmentally friendly manner within the framework of the applicable legislation;
- provision of connection, use-of-system and other distribution services on a mandatory, non-discriminatory basis;
- demand forecasting;
- proposing distribution connection and use-of-system tariffs for approval by EMRA within the framework of the provisions of the Electricity Market Tariffs Regulation; and supplier-of-last-resort duty-consumers who cannot obtain electricity and/or capacity from another supplier can oblige the Distribution Company to obtain a retail license and provide an electricity supply (starting from 1 January 2013, Distribution Companies will carry out their retail activities through separate legal entities).

Private sector distribution companies (seen in Table 12), in addition to their distribution and retail activities, may establish generation facilities.

Table 12. Companies with Distribution Licenses Granted [9]

Distribution Company	Region	Total No. of Customers	Date of Privatization
Kayseri ve Civarı Elektrik A.Ş.	Kayseri	443.746	14.07.1999
Aydem A.Ş.	Aydın, Denizli, Muğla	1.475.700	07.2007
Başkent Elektrik Dağıtım A.Ş.	Ankara, Zonguldak, Karabük, Bartın, Kırıkkale	3.075.800	28.01.2009
Sakarya Elektrik Dağıtım A.Ş.	Sakarya, Kocaeli, Düzce, Bolu	1.307.300	11.02.2009
Meram Elektrik Dağıtım A.Ş.	Konya, Aksaray, Nevşehir, Kırşehir, Niğde, Karaman	1.530.500	30.04.2009
Aras Elektrik Dağıtım A.Ş.	Ardahan, Kars, Ağrı, Iğdır, Erzurum, Bayburt, Erzincan	725.200	25.09.2008
Çoruh Elektrik Dağıtım A.Ş.	Artvin, Giresun, Gümüşhane, Rize, Trabzon	989.600	06.11.2008
Osmangazi Elektrik Dağıtım A.Ş.	Afyon, Bilecik, Eskişehir, Kütahya, Uşak	1.277.300	06.11.2008
Yeşilırmak Elektrik Dağıtım A.Ş.	Amasya, Çorum, Ordu, Samsun, Sinop	1.466.700	06.11.2008
Vangölü Elektrik Dağıtım A.Ş.	Muş, Bitlis, Van, Hakkari	401.400	12.02.2010
Çamlıbel Elektrik Dağıtım A.Ş.	Sivas, Tokat, Yozgat	734.700	12.02.2010
Fırat Elektrik Dağıtım A.Ş.	Malatya, Elazığ, Tunceli, Bingöl	663.700	12.02.2010
Uludağ Elektrik Dağıtım A.Ş.	Çanakkale, Bursa, Balıkesir, Yalova	2.278.500	12.02.2010
Dicle Elektrik Dağıtım A.Ş.	Diyarbakır, Ş.Urfa, Mardin, Batman	1.044.300	09.08.2010

Table 12. Companies with Distribution Licenses Granted (continued)

Distribution Company	**Region**	**Total No. of Customers**	**Date of Privatization**
Gediz Elektrik Dağıtım A.Ş.	İzmir, Manisa	2.331.500	09.08.2010
Trakya Elektrik Dağıtım A.Ş.	Edirne, Kırklareli, Tekirdağ	767.800	09.08.2010
Boğaziçi Elektrik Dağıtım A.Ş.	İstanbul (European Side)	3.832.800	09.08.2010
Göksu Elektrik Dağıtım A.Ş.		487.456	
Ayedaş	İstanbul Anadolu Yakası	2.102.284	07.12.2010
Toroslar Elektrik Dağıtım A.Ş.	Adana, Mersin, G.Antep, Hatay, Osmaniye, Kilis	2.597.355	07.12.2010
Akdeniz Elektrik Dağıtım A.Ş.	Antalya, Burdur, Isparta	1.469.794	07.12.2010
Total		31.490.891	

C.4 Retail

The sale of power to end users will be undertaken by retailers, who require retail licenses granted by EMRA. At the outset, the 21 Distribution Companies will also have retail businesses. These are required to be separated in accounting terms from the distribution businesses and hold two licenses (distribution and retail). There is scope, therefore, for a future split of retail from distribution.

Retail licenses may be granted maximum for 49 years. The Distribution and Retail Licenses granted to the distribution companies to be privatized were granted for 10 years starting from 13 March 2003. These licenses were later extended to 30 years.

One point to note is that EMRA and the Privatization Administration, until recently did not appear to be in complete agreement with the Competition Board about the bundling of distribution and retail.

Although there used to be, until July 2008, no restriction in the Electricity Market Law preventing a company from holding both retail and a distribution license, the Competition Board has expensed the opinion that the distribution and retail operations should be subjected to full ownership separation. The Electricity Market Law was amended in July 2008 and now allows distribution companies to carry out power generation and retail activities on the condition that, starting from 1 January 2013, they carry out each of these activities through separate legal entities (i.e. separate companies).

The Competition Board has also stated that it may refuse to approve the Distribution Company share sale transactions if it determines that the arrangements do not comply with the competition legislation. This issue (of conflicting regulatory jurisdictions) is discussed further below.

There will be two types of customer: eligible customers (able to choose among suppliers) and non-eligible customers. In order to qualify as an eligible customer, an individual customer needs to have power off take requirements in excess of a threshold established and reviewed annually by EMRA or be directly connected to the transmission system. The present threshold is 100,000 kWh per year.

There are presently no independent retailers. The retail business of the 21 Distribution Companies each currently has a monopoly right within their zone to supply non-eligible customers. Eligible customers are free to choose their suppliers (i.e. companies that hold retail licenses for other zones provided that their licenses authorize them to sell to different zones; generation companies, wholesale companies, auto producers and auto producer groups).

The Customer Services Regulation provides that independent retailers will not be able to obtain licenses until 2011. This prohibition was initially drafted to apply until 2008 but has been subject to one-year extensions three times. Although the

Customer Services Regulation provides that no retail license will be given to independent retailers that will serve non-eligible consumers, EMRA applies the prohibition more strictly and does not issue retail permits to any independent retailer.

It is anticipated that the eligible customer threshold will gradually be lowered so that, eventually, the entire retail market will be open to competition.

Initially the Distribution Companies would purchase their entire wholesale power needs from TETAŞ under the 5-year vesting contracts. Distribution Companies are currently able to purchase from other generators and they may also establish generation facilities and acquire electricity from their own generation companies (starting from January 2013, they will carry out their generation and retail activities through separate legal entities -until such date, they will keep separate accounts) or their affiliate companies. However, the price at which they purchase power from affiliates must be determined on an arms-length basis. The Electricity Market Law is not entirely clear on purchase price levels.

Retail license holders' principal duties are:

- Proposal of tariffs for non-eligible consumers for approval by EMRA within the framework of the provisions of the Electricity Market Tariffs Regulation;
- Establishment of standard contracts for supplies to non-eligible consumers on the basis of pre-set customer classes;
- Submission of information regarding the consumption of the eligible consumers they service to relevant distribution companies; and
- To purchase renewable energy for on-sale to non-eligible consumers, if the price of electricity generated at generation facilities based on renewable energy resources is equal to or lower than the wholesale price of TETAŞ, and if there is no cheaper alternative.

C.5 Main Bodies and Regulation of the Industry

The bodies with formal regulatory powers are:

- EMRA, the industry regulator, which is responsible for the grant, modification, administration and enforcement of all types of license; the promulgation of certain types of Regulations; the issuing of Communiqués; and the making of regulatory decisions. EMRA is intended to be the principal economic regulator; the other potential regulators below are not primarily responsible for the operation of the market or players within it;

- The Competition Board, which has general jurisdiction to take necessary actions and decisions to ensure the protection of competition in the goods and services markets, within the framework of the Law Concerning the Protection of Competition. In this respect, the Competition Board must approve the transactions (i.e. acquisitions, share transfer transactions) to be effected within the scope of privatization processes. The activities of all market players will be monitored by the Competition Board as well as EMRA.

In addition there are other bodies in the public sector which have significance in the functioning of the electricity market:

- TEDAŞ is the owner of the distribution systems. TEDAŞ has granted certain rights to Distribution Companies by transfer of operating rights (TOOR) agreements it signed with them. The TOOR agreements are in relation to the operation, maintenance and expansion of, and investment in and connection to the distribution systems. By virtue of the TOOR agreements, TEDAŞ retains ownership and maintains certain control over the distribution systems.

- TETAŞ buys electricity mostly from EÜAŞ under wholesale agreements and sells electricity to third parties.

TEİAŞ is the transmission operator and carrying out central market operation functions, running a balancing and settlement arrangement, enabling a wholesale market based on bilateral contracts.

APPENDIX D

OVERNIGHT COST BREAKDOWN STRUCTURE

Table 13. Advanced Coal Fired Power Plant

Items Deriving Power Plant Cost	Average Cost Distribution
Civil & Mechanical	20.89%
Project Development & Site Work	2.35%
Land Cost & Land Rights	2.85%
Plant Licensing & Plant Permits	0.70%
Excavation & Backfill	0.39%
On-site Transportation & Rigging	0.21%
Equipment Erection & Assembly	6.92%
Piping	2.69%
Structural Steel	1.90%
Concrete	1.62%
Staff Recruitment and Training	0.05%
Roads, Parking, Walkways	0.16%
Other Preconstruction Cost	1.04%
Special Equipment	44.66%

Table 13. Advanced Coal Fired Power Plant (continued)

Boiler	26.18%
Steam Turbine Package	6.15%
Feedwater Heaters	0.37%
Heller Cooling Tower with Auxiliaries	3.12%
Particulate Control	3.42%
SCR (Selective Catalytic Reduction)	4.00%
Continuous Emissions Monitoring System	0.05%
Distributed Control System	0.21%
Transmission Voltage Equipment	0.54%
Generation Voltage Equipment	0.61%
Other Equipment	20.44%
Pumps	0.50%
Tanks	0.11%
Auxiliary Heat Exchangers	0.06%
Auxiliary Boiler	0.37%
Water Treatment System	1.44%
Bridge Crane(s)	0.12%
Station / Instrument Air Compressors	0.06%
Reciprocating Engine Genset	0.02%
General Plant Instrumentation	0.05%
Coal Handling Equipment	10.81%
Ash Handling Equipment	5.06%
Safety Systems	0.39%
Special Materials	0.20%
Simulator	0.13%
Spare Parts	0.91%
Miscellaneous Equipment	0.20%

Table 13. Advanced Coal Fired Power Plant (continued)

Electrical Assembly & Wiring	1.74%
Controls	1.09%
Assembly & Wiring	0.65%
Auxiliary Buildings	2.68%
Boiler House and Turbine Hall, other technology hall	2.39%
Administration, Control Room, Machine Shop/Warehouse	0.20%
Auxiliary Buildings	0.08%
Security Building & Gatehouse	0.02%
Engineering & Plant Startup	3.19%
Engineering	2.49%
Start-up	0.54%
Demonstration Test Run	0.16%
Soft & Miscellaneous Costs	5.01%
Taxes & Insurance	0.65%
Construction Supervision	0.26%
Staff Salary-Related Costs	2.08%
Contractor's Soft Cost	0.99%
Contingency on Owner's Costs	0.78%
Other Owner's Capitalized Costs	0.26%
Shipping & Transportation Cost	1.39%

Table 14. Simple Cycle Gas Turbine

Items Deriving Power Plant Cost	Average Cost Distribution
Civil	24.24%
Project Development & Site Work	7.53%
Land Cost & Land Rights	1.50%
Plant Licensing & Plant Permits	1.25%
Excavation & Backfill	0.94%
On-site Transportation & Rigging	0.56%
Equipment Erection & Assembly	5.61%
Piping	2.23%
Structural Steel	1.37%
Concrete	1.12%
Staff Recruitment and Training	0.25%
Roads, Parking, Walkways	0.62%
Other Preconstruction Cost	1.25%
Special Equipment	45.85%
Gas Turbine Package	36.22%
SCR (Selective Catalytic Reduction)	4.62%
Gas Compressor	1.67%
Instrumental Control System	0.85%
Transmission Voltage Equipment	1.25%
Generation Voltage Equipment	1.25%
Other Equipment	4.39%
Reciprocating Engine Genset	0.06%
General Plant Instrumentation	0.17%
Safety Systems	0.94%

Table 14. Simple Cycle Gas Turbine (continued)

Special Materials	0.28%
Simulator	0.37%
Spare Parts	1.87%
Miscellaneous Equipment	0.69%
Electrical Assembly & Wiring	5.64%
Controls	1.25%
Assembly & Wiring	4.39%
Auxiliary Buildings	3.72%
Administration, Control Room, Machine Shop/Warehouse	2.53%
Auxiliary Buildings	0.37%
Technology Hall	0.75%
Security Building & Gatehouse	0.06%
Engineering & Plant Startup	5.69%
Engineering	4.99%
Start-up	0.57%
Demonstration Test Run	0.12%
Soft & Miscellaneous Costs	9.23%
Taxes & Insurance	1.25%
Construction Supervision	0.62%
Staff Salary-Related Costs	2.99%
Contractor's Soft Cost	2.50%
Contingency on Owner's Costs	1.25%
Other Owner's Capitalized Costs	0.62%
Shipping & Transportation Cost	1.25%

Table 15. Combined Cycle Gas Turbine

Items Deriving Power Plant Cost	Average Cost Distribution
Civil	20.97%
Project Development & Site Work	9.01%
Land Cost & Land Rights	0.75%
Plant Licensing & Plant Permits	0.55%
Excavation & Backfill	1.00%
On-site Transportation & Rigging	0.12%
Equipment Erection & Assembly	1.25%
Piping	3.27%
Structural Steel	2.82%
Concrete	1.62%
Staff Recruitment and Training	0.05%
Roads, Parking, Walkways	0.27%
Other Preconstruction Cost	0.25%
Special Equipment	52.83%
Gas Turbine Package	10.25%
Boiler	21.30%
Steam Turbine Package	10.94%
Heat Recovery Steam Generator (HRSG)	1.50%
Feedwater Heaters	0.31%
Cooling Tower	0.62%
SCR (Selective Catalytic Reduction)	3.35%
Instrumental Control System	3.07%
Transmission Voltage Equipment	0.75%
Generation Voltage Equipment	0.75%

Table 15. Combined Cycle Gas Turbine (continued)

Other Equipment	10.09%
Pumps	1.59%
Tanks	4.24%
Auxiliary Heat Exchangers	0.35%
Auxiliary Boiler	0.62%
Water Treatment System	1.25%
Station / Instrument Air Compressors	0.06%
Reciprocating Engine Genset	0.07%
General Plant Instrumentation	0.15%
Safety Systems	0.25%
Special Materials	0.12%
Simulator	0.12%
Spare Parts	0.75%
Miscellaneous Equipment	0.50%
Electrical Assembly & Wiring	2.77%
Controls	0.27%
Assembly & Wiring	2.50%
Buildings	4.89%
Boiler House and Turbine Hall, other technology hall	2.00%
Administration, Control Room, Machine Shop/Warehouse	2.75%
Auxiliary Buildings	0.12%
Security Building & Gatehouse	0.02%
Engineering & Plant Startup	3.07%
Engineering	2.87%
Start-up	0.12%
Demonstration Test Run	0.07%
Soft & Miscellaneous Costs	4.37%

Table 15. Combined Cycle Gas Turbine (continued)

Taxes & Insurance	0.62%
Construction Supervision	0.25%
Staff Salary-Related Costs	1.75%
Contractor's Soft Cost	0.75%
Contingency on Owner's Costs	0.75%
Other Owner's Capitalized Costs	0.25%
Shipping & Transportation Cost	1.00%

Table 16. Oil Fired Steam Plant

Items Deriving Power Plant Cost	**Average Cost Distribution**
Civil	25.79%
Project Development & Site Work	12.83%
Land Cost & Land Rights	0.60%
Plant Licensing & Plant Permits	0.24%
Excavation & Backfill	0.96%
On-site Transportation & Rigging	0.11%
Equipment Erection & Assembly	1.21%
Piping	3.64%
Structural Steel	2.94%
Concrete	2.36%
Staff Recruitment and Training	0.05%
Roads, Parking, Walkways	0.12%
Other Preconstruction Cost	0.72%
Special Equipment	44.60%

Table 16. Oil Fired Steam Plant (continued)

Boiler	20.57%
Steam Turbine Package	11.77%
Feedwater Heaters	0.30%
Cooling Tower	0.60%
SCR (Selective Catalytic Reduction)	4.05%
Instrumental Control System	5.86%
Transmission Voltage Equipment	0.72%
Generation Voltage Equipment	0.72%
Other Equipment	9.74%
Pumps	1.53%
Tanks	4.10%
Auxiliary Heat Exchangers	0.34%
Auxiliary Boiler	0.60%
Water Treatment System	1.21%
Station / Instrument Air Compressors	0.06%
Reciprocating Engine Genset	0.07%
General Plant Instrumentation	0.14%
Safety Systems	0.24%
Special Materials	0.12%
Simulator	0.12%
Spare Parts	0.72%
Miscellaneous Equipment	0.48%
Electrical Assembly & Wiring	4.36%
Controls	0.27%
Assembly & Wiring	4.10%
Buildings	5.06%
Boiler House and Turbine Hall, other technology hall	2.03%

Table 16. Oil Fired Steam Plant (continued)

Administration, Control Room, Machine Shop/Warehouse	2.89%
Auxiliary Buildings	0.12%
Security Building & Gatehouse	0.02%
Engineering & Plant Startup	5.50%
Engineering	5.31%
Start-up	0.12%
Demonstration Test Run	0.07%
Soft & Miscellaneous Costs	3.74%
Taxes & Insurance	0.60%
Construction Supervision	0.24%
Staff Salary-Related Costs	1.21%
Contractor's Soft Cost	0.72%
Contingency on Owner's Costs	0.72%
Other Owner's Capitalized Costs	0.24%
Shipping & Transportation Cost	1.21%

Table 17. Nuclear Power Plant

Items Deriving Power Plant Cost	**Average Cost Distribution**
Civil	18.62%
Project Development & Site Work	2.69%
Land Cost & Land Rights	2.09%
Plant Licensing & Plant Permits	0.30%
Excavation & Backfill	0.60%

Table 17. Nuclear Power Plant (continued)

On-site Transportation & Rigging	0.15%
Equipment Erection & Assembly	2.24%
Piping	2.09%
Structural Steel	4.48%
Concrete	2.99%
Staff Recruitment and Training	0.04%
Roads, Parking, Walkways	0.06%
Other Preconstruction Cost	0.90%
Special Equipment	49.56%
Reactor Plant Equipment	14.93%
Turbine Plant Equipment	23.89%
Electrical Plant Equipment	5.97%
Heat Rejection Equipment	0.90%
Nuclear Island/Protection Unit	1.34%
Radioactive Waste Processing System	0.75%
Fuel Handling System	0.30%
Advanced Control System	1.19%
Transmission Voltage Equipment	0.15%
Generation Voltage Equipment	0.15%
Other Equipment	5.88%
Pumps	0.49%
Tanks	0.81%
Auxiliary Heat Exchangers	0.15%
Auxiliary Boiler	0.07%
Water Treatment System	0.45%
Station / Instrument Air Compressors	0.09%
General Plant Instrumentation	0.30%

Table 17. Nuclear Power Plant (continued)

Safety Systems	0.45%
Special Materials	0.30%
Simulator	0.06%
Spare Parts	0.03%
Miscellaneous Equipment	2.69%
Electrical Assembly & Wiring	0.20%
Controls	0.13%
Assembly & Wiring	0.07%
Buildings	0.63%
Boiler House and Turbine Hall, other technology hall	0.25%
Administration, Control Room, Machine Shop/Warehouse	0.36%
Auxiliary Buildings	0.01%
Security Building & Gatehouse	0.00%
Engineering & Plant Startup	21.29%
Design & Engineering	20.60%
Start-up	0.60%
Demonstration Test Run	0.09%
Soft & Miscellaneous Costs	3.52%
Taxes & Insurance	0.75%
Construction Supervision	0.30%
Staff Salary-Related Costs	0.75%
Contractor's Soft Cost	0.54%
Contingency on Owner's Costs	0.30%
Other Owner's Capitalized Costs	0.15%
Decommissioning Cost	0.75%
Shipping & Transportation Cost	0.30%

Table 18. Biomass Power Plant

Items Deriving Power Plant Cost	Average Cost Distribution
Civil	16.11%
Project Development & Site Work	6.33%
Land Cost & Land Rights	1.57%
Plant Licensing & Plant Permits	0.52%
Excavation & Backfill	1.31%
On-site Transportation & Rigging	0.24%
Equipment Erection & Assembly	1.05%
Piping	1.62%
Structural Steel	0.94%
Concrete	1.02%
Staff Recruitment and Training	0.10%
Roads, Parking, Walkways	0.26%
Other Preconstruction Cost	1.15%
Specialized Equipment	53.06%
Gas Turbine Equipment	9.01%
Heat Recovery Steam Generator (HRSG)	4.18%
Steam Cycle	6.11%
Boost Compressor	0.62%
Combustion System	1.19%
BOP (Balance of the Plant) Equipment	10.52%
Gasification System	20.12%
Transmission Voltage Equipment	0.65%
Generation Voltage Equipment	0.65%
Other Equipment	12.46%
Wood Handling Unit	2.27%

Table 18. Biomass Power Plant (continued)

Wood Drying Unit	2.85%
Gas Cleanup Equipment	2.82%
Direct Quench System	0.02%
Auxiliary Heat Exchangers	0.42%
Auxiliary Boiler	0.52%
Water Treatment System	1.05%
General Plant Instrumentation	0.16%
Safety Systems	0.52%
Special Materials	0.26%
Simulator	0.26%
Spare Parts	0.78%
Miscellaneous Equipment	0.52%
Electrical Assembly & Wiring	1.51%
Controls	0.20%
Assembly & Wiring	1.31%
Buildings	1.57%
Boiler House and Turbine Hall, other technology hall	0.73%
Administration, Control Room, Machine Shop/Warehouse	0.52%
Auxiliary Buildings	0.26%
Security Building & Gatehouse	0.05%
Engineering & Plant Startup	7.71%
Engineering	6.33%
Start-up	1.39%
Soft & Miscellaneous Costs	6.28%
Taxes & Insurance	1.31%
Construction Supervision	0.52%
Staff Salary-Related Costs	2.62%

Table 18. Biomass Power Plant (continued)

Contractor's Soft Cost	0.78%
Contingency on Owner's Costs	0.52%
Other Owner's Capitalized Costs	0.52%
Shipping & Transportation Cost	1.31%

Table 19. Hydroelectric Power Plant

Items Deriving Power Plant Cost	**Average Cost Distribution**
Civil	11.94%
Project Development & Site Work	1.70%
Land Cost & Land Rights	1.44%
Plant Licensing & Plant Permits	0.62%
Excavation & Backfill	2.12%
On-site Transportation & Rigging	0.25%
Equipment Erection & Assembly	2.37%
Structural Steel	0.50%
Concrete	0.94%
Staff Recruitment and Training	0.12%
Road Relocation and Work Site Roads	0.77%
Other Preconstruction Cost	1.09%
Specialized Equipment	63.76%
Coffer Dams	0.32%
Derivation Tunnel, Sluice Outlet and Valve Room	1.42%
Rockfill Dam With Clay Core	0.73%
Spillway	1.58%

Table 19. Hydroelectric Power Plant (continued)

Inlet Structure	1.06%
Conveyance and Approach Tunnels	36.47%
Surge Tank	0.83%
Electromechanical Equipment	17.05%
Electrical Connections	1.17%
Instrumental Control System	0.62%
Transmission Voltage Equipment	1.25%
Generation Voltage Equipment	1.25%
Other Equipment	4.02%
Penstock and Penstock Supports	1.79%
General Plant Instrumentation	0.14%
Safety Systems	0.41%
Special Materials	0.62%
Simulator	0.31%
Spare Parts	0.69%
Miscellaneous Equipment	0.06%
Electrical Assembly & Wiring	2.81%
Controls	1.56%
Assembly & Wiring	1.25%
Buildings	1.88%
Administration, Control Room, Power House	1.17%
Auxiliary Buildings	0.31%
Security Building & Gatehouse	0.40%
Engineering & Plant Startup	6.79%
Engineering	6.73%
Start-up	0.06%
Soft & Miscellaneous Costs	6.93%

Table 19. Hydroelectric Power Plant (continued)

Taxes & Insurance	0.62%
Construction Supervision	0.62%
Staff Salary-Related Costs	3.43%
Contractor's Soft Cost	0.94%
Contingency on Owner's Costs	0.62%
Other Owner's Capitalized Costs	0.69%
Shipping & Transportation Cost	1.87%

Table 20. Wind Power Plant (Land Based)

Items Deriving Power Plant Cost	**Average Cost Distribution**
Civil	17.27%
Project Development & Site Work	5.32%
Land Cost & Land Rights	2.17%
Plant Licensing & Plant Permits	0.93%
Excavation & Backfill	0.62%
On-site Transportation & Rigging	0.25%
Equipment Erection & Assembly	2.35%
Structural Steel	1.08%
Concrete	0.31%
Staff Recruitment and Training	0.12%
Roads, Parking, Walkways	3.03%
Other Preconstruction Cost	1.08%
Specialized Equipment	64.81%
Rotor	14.67%

Table 20. Wind Power Plant (Land Based) (continued)

Drive Train	10.52%
Gearbox	9.47%
Tower	9.10%
Hydraulic, Cooling System	1.11%
Generator	6.07%
Electrical Connections	3.71%
Variable Speed Electronics	5.51%
Instrumental Control System	2.17%
Transmission Voltage Equipment	1.24%
Generation Voltage Equipment	1.24%
Other Equipment	2.10%
General Plant Instrumentation	0.07%
Safety Systems	0.15%
Special Materials	0.31%
Simulator	0.31%
Spare Parts	1.24%
Miscellaneous Equipment	0.02%
Electrical Assembly & Wiring	6.93%
Controls	1.05%
Assembly & Wiring	5.88%
Buildings	0.74%
Administration, Control Room, Machine Shop/Warehouse	0.62%
Auxiliary Buildings	0.06%
Security Building & Gatehouse	0.06%
Engineering & Plant Startup	2.04%
Engineering	1.98%
Start-up	0.06%

Table 20. Wind Power Plant (Land Based) (continued)

Soft & Miscellaneous Costs	4.24%
Taxes & Insurance	0.62%
Construction Supervision	0.62%
Staff Salary-Related Costs	1.55%
Contractor's Soft Cost	0.77%
Contingency on Owner's Costs	0.31%
Other Owner's Capitalized Costs	0.37%
Shipping & Transportation Cost	1.86%

Table 21. Wind Power Plant (Off-shore)

Items Deriving Power Plant Cost	**Average Cost Distribution**
Civil	27.43%
Project Development & Site Work	1.79%
Land Cost & Land Rights	0.15%
Plant Licensing & Plant Permits	0.23%
On-site Transportation & Rigging	0.68%
Excavation & Backfill	2.16%
Monopile Foundation & Support Structure	15.94%
Equipment Erection & Assembly	3.41%
Structural Steel	1.86%
Concrete	0.54%
Staff Recruitment and Training	0.09%
Other Preconstruction Cost	0.58%
Specialized Equipment	42.06%

Table 21. Wind Power Plant (Off-shore) (continued)

Rotor	7.35%
Drive Train	5.38%
Gearbox	6.29%
Tower	6.40%
Hydraulic, Cooling System	0.63%
Generator	3.25%
Electrical Connections	2.31%
Variable Speed Electronics	4.10%
Instrumental Control System	0.77%
Marinization of Turbine and Tower System	4.95%
Transmission Voltage Equipment	0.31%
Generation Voltage Equipment	0.31%
Other Equipment	6.18%
Port and Staging Equipment	1.14%
Scour Protection	3.15%
Personnel Access Equipment	0.99%
General Plant Instrumentation	0.03%
Safety Systems	0.12%
Special Materials	0.35%
Simulator	0.08%
Spare Parts	0.31%
Miscellaneous Equipment	0.01%
Electrical Assembly & Wiring	14.59%
Controls	0.31%
Assembly & Wiring	14.28%
Buildings	0.19%
Administration, Control Room, Machine Shop/Warehouse	0.15%

Table 21. Wind Power Plant (Off-shore) (continued)

Auxiliary Buildings	0.02%
Security Building & Gatehouse	0.02%
Engineering & Plant Startup	1.76%
Engineering	1.74%
Start-up	0.02%
Soft & Miscellaneous Costs	4.54%
Offshore Warranty Premium	2.71%
Taxes & Insurance	0.15%
Construction Supervision	0.23%
Staff Salary-Related Costs	1.00%
Contractor's Soft Cost	0.19%
Contingency on Owner's Costs	0.15%
Other Owner's Capitalized Costs	0.09%
Shipping & Transportation Cost	3.25%

Table 22. Photovoltaic Power Plant

Items Deriving Power Plant Cost	**Average Cost Distribution**
Civil	11.04%
Project Development & Site Work	3.91%
Land Cost & Land Rights	3.10%
Plant Licensing & Plant Permits	0.40%
Excavation & Backfill	0.20%
On-site Transportation & Rigging	0.12%
Equipment Erection & Assembly	1.61%

Table 22. Photovoltaic Power Plant (continued)

Piping	0.64%
Structural Steel	0.30%
Concrete	0.10%
Staff Recruitment and Training	0.04%
Roads, Parking, Walkways	0.10%
Other Preconstruction Cost	0.50%
Specialized Equipment	77.34%
Heliostat System	36.86%
Tower/Receiver System	9.06%
Thermal Storage System	12.08%
Steam Generation System	3.42%
Transmission Voltage Equipment	0.40%
Generation Voltage Equipment	0.40%
Master Control System	15.10%
Other Equipment	1.61%
Reciprocating Engine Genset	0.01%
General Plant Instrumentation	0.03%
Safety Systems	0.16%
Special Materials	0.20%
Simulator	0.10%
Spare Parts	1.01%
Miscellaneous Equipment	0.10%
Electrical Assembly & Wiring	0.75%
Controls	0.50%
Assembly & Wiring	0.25%
Buildings	0.09%
Administration, Control Room, Machine Shop/Warehouse	0.05%

Table 22. Photovoltaic Power Plant (continued)

Auxiliary Buildings	0.02%
Security Building & Gatehouse	0.02%
Engineering & Plant Startup	6.99%
Engineering	6.97%
Start-up	0.02%
Soft & Miscellaneous Costs	1.58%
Taxes & Insurance	0.20%
Construction Supervision	0.30%
Staff Salary-Related Costs	0.50%
Contractor's Soft Cost	0.25%
Contingency on Owner's Costs	0.20%
Other Owner's Capitalized Costs	0.12%
Shipping & Transportation Cost	0.60%

Table 23. Geothermal Power Plant

Items Deriving Power Plant Cost	**Average Cost Distribution**
Civil	19.74%
Project Development & Site Work	1.73%
Steamfield Cost & Land Rights	12.76%
Plant Licensing & Plant Permits	0.59%
Well Testing	0.27%
Excavation & Backfill	0.59%
On-site Transportation & Rigging	0.36%
Equipment Erection & Assembly	1.48%

Table 23. Geothermal Power Plant (continued)

Structural Steel	0.89%
Concrete	0.30%
Staff Recruitment and Training	0.12%
Roads, Parking, Walkways	0.30%
Other Preconstruction Cost	0.36%
Specialized Equipment	52.46%
Steamfield Generation Equipment	36.19%
Steamfield Piping	14.54%
Control and Instrumentation System	0.25%
Transmission Voltage Equipment	0.74%
Generation Voltage Equipment	0.74%
Other Equipment	2.85%
General Plant Instrumentation	0.18%
Safety Systems	0.47%
Special Materials	0.59%
Simulator	0.30%
Spare Parts	0.71%
Miscellaneous Equipment	0.59%
Electrical Assembly & Wiring	1.71%
Controls	0.23%
Assembly & Wiring	1.48%
Drilling	15.78%
Rig Mob/Demob	1.48%
Production Wells	7.77%
Injection Wells	6.53%
Buildings	0.20%
Administration, Control Room, Machine Shop/Warehouse	0.09%

Table 23. Geothermal Power Plant (continued)

Auxiliary Buildings	0.06%
Security Building & Gatehouse	0.05%
Engineering & Plant Startup	2.73%
Engineering	2.67%
Start-up	0.06%
Soft & Miscellaneous Costs	3.65%
Taxes & Insurance	0.59%
Construction Supervision	0.44%
Staff Salary-Related Costs	1.07%
Contractor's Soft Cost	0.59%
Contingency on Owner's Costs	0.59%
Other Owner's Capitalized Costs	0.36%
Shipping & Transportation Cost	0.89%

Table 24. Diesel Generator

Items Deriving Power Plant Cost	**Average Cost Distribution**
Civil	10.84%
Project Development & Site Work	4.13%
Land Cost & Land Rights	2.58%
Plant Licensing & Plant Permits	1.94%
Equipment Erection & Assembly	1.29%
Staff Recruitment and Training	0.26%
Other Preconstruction Cost	0.65%
Specialized Equipment	54.45%

Table 24. Diesel Generator (continued)

Generation Module Equipment	44.39%
BOP (Balance of the Plant) Equipment	4.90%
Transmission Voltage Equipment	2.58%
Generation Voltage Equipment	2.58%
Other Equipment	10.97%
General Plant Instrumentation	1.29%
Safety Systems	1.29%
Special Materials	1.29%
Simulator	3.23%
Spare Parts	2.58%
Miscellaneous Equipment	1.29%
Electrical Assembly & Wiring	4.52%
Controls	0.65%
Assembly & Wiring	3.87%
Buildings	7.74%
Administration, Control Room, Machine Shop/Warehouse	7.74%
Engineering & Plant Startup	2.58%
Engineering	1.94%
Start-up	0.65%
Soft & Miscellaneous Costs	8.90%
Taxes & Insurance	2.58%
Construction Supervision	1.29%
Staff Salary-Related Costs	2.97%
Contractor's Soft Cost	1.29%
Contingency on Owner's Costs	0.13%
Other Owner's Capitalized Costs	0.65%

APPENDIX E

ALTERNATIVE METHOD OF GENERATION CAPACITY COST

Capacity cost of power plants shall be alternatively calculated by Microsoft Office Excel instead of comprehensive mathematical calculations. The “Loan Amortization” tool is dedicated to find the required net payment of borrowed loan with respect to years with specific interest rates and within the life time of the power plants.

If the below illustration is considered,

The annual fixed cost of a 1000 MW nuclear power plant with 20 year life time, 8 years amortization period and overnight cost of 1.950 million \$ / MW by assuming 10 % annual depreciation rate shall be found by calculating the loan amount (1000 MW x 1.950 million \$ / MW = 1.950.000.000 \$) and then solving the problem as seen in Table 25;

Table 25. Loan Amortization of a Power Plant in 8 Years

Enter Values	
Loan Amount	$ 1,950.00
Annual Interest Rate	10,00 %
Loan Period in Years	8
Number of Payments per Year	1
Start Date of Loan	01.01.2011

Table 26. Loan Amortization Summary for 8 Years

Loan Summary	
Scheduled Payments	$ 365,52.00
Scheduled Number of Payments	8
Actual Number of Payments	8
Total Early Payment	$ -
Total Interest	$ 974.13

Pmt. No	Payment Date	Beginning Balance	Scheduled Payment	Total Payment	Principal	Interest	Ending Balance
1	01.2012	1,950.00	365.52	365.52	170.52	195.00	1,779.48
2	01.2013	1,779.48	365.52	365.52	187.57	177.95	1,591.92
3	01.2014	1,591.92	365.52	365.52	159.19	159.19	1,385.64
4	01.2015	1,385.59	365.52	365.52	138.56	138.56	1,158.64
5	01.2016	1,158.59	365.52	365.52	115.86	115.86	908.98
6	01.2017	908.98	365.52	365.52	90.90	90.90	634.37
7	01.2018	634.37	365.52	365.52	63.44	63.44	332.29
8	01.2019		365.52	332.29	33.23	33.23	0.00
		332.2					

If the same illustration is considered for an amortization period of 20 years, then the results seen in Table 27 is found.

Table 27. Loan Amortization of a Power Plant in 20 Years

Enter Values	
Loan Amount	$ 1,950.00
Annual Interest Rate	10,00 %
Loan Period in Years	20
Number of Payments per Year	1
Start Date of Loan	01.01.2011

Table 28. Loan Amortization Summary for 20 Years

Loan Summary	
Scheduled Payments	$ 229,05.00
Scheduled Number of Payments	20
Actual Number of Payments	20
Total Early Payment	$ -
Total Interest	$ 2,630.93

Pmt. No	Payment Date	Beginning Balance	Scheduled Payment	Total Payment	Principal	Interest	Ending Balance
1	01.2012	1,950.00	229.05	229.05	34.05	195.00	1,915.95
2	01.2013	1,915.95	229.05	229.05	37.45	191.60	1,878.50
3	01.2014	1,878.50	229.05	229.05	41.20	187.85	1,837.31
4	01.2015	1,837.31	229.05	229.05	45.32	183.73	1,791.99
5	01.2016	1,791.99	229.05	229.05	49.85	179.20	1,742.14
6	01.2017	1,742.14	229.05	229.05	54.83	174.21	1,687.31
7	01.2018	1,687.31	229.05	229.05	60.32	168.73	1,627.00
8	01.2019	1,627.00	229.05	229.05	66.35	162.70	1,560.65
9	01.2020	1,560.65	229.05	229.05	72.98	156.07	1,487.67
10	01.2021	1,487.67	229.05	229.05	80.28	148.77	1,407.39
11	01.2022	1,407.39	229.05	229.05	88.31	140.74	1,319.08
12	01.2023	1,319.08	229.05	229.05	97.14	131.91	1,221.94
13	01.2024	1,221.94	229.05	229.05	106.85	122.19	1,115.09
14	01.2025	1,115.09	229.05	229.05	117.54	111.51	997.56
15	01.2026	997.56	229.05	229.05	129.29	99.76	868.27
16	01.2027	868.27	229.05	229.05	142.22	86.83	726.05
17	01.2028	726.05	229.05	229.05	156.44	72.60	569.60
18	01.2029	569.60	229.05	229.05	172.09	56.96	397.52
19	01.2030	397.52	229.05	229.05	189.29	39.75	208.22
20	01.2031	208.22	229.05	229.05	187.40	20.82	0.00

By the comparison of the results of Table 25 and Table 27, one shall observe that the loan period gives rise to the interest payment which is an undesirable fact for the investors. Generally, the loaning period of 8-10 years is considered to be the optimum period for the amortization in fact the investors to claw back their investment.

APPENDIX F

ICBP MODEL

F.1 Inputs

ICBP model calculates the required marginal investment cost on transmission system due to generation increments on network node points[18]. In this manner, the model takes peak point demands as reference. The model minimizes the total cost, which is the marginal investment cost over MWkm and then calculates the variance of additional 1 MW capacity with respect to cost. As a result, basis transmission cost coefficient is applied to marginal cost (with respect to MWkm) and the total money is calculated.

Model needs the required data at peak conditions such as;

- Injected power to the system at each network node points,
- Consumption at each network node points,
- Categorization of transmission line types between node points,
- Length between the node points,
- Transmission cost coefficients and their ratio with respect to basis transmission cost coefficient[19].

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[18] Network node point is the point where more than two transmission lines are connected to the same point or just simply an interconnection point.

[19] This ratio reflects the difference between the cost of different types of lines.

In addition, the model uses the maximum power supply capacity of the generators at node points varying from summer to winter periods[20]. Transmission routes and related line types as well as their lengths are defined using the existing data.

F.2 Outputs

The model assumes infinite capacity in all routes and computes the optimum MWkm of the transmission line at the node points where the total consumption is met by the total generation.

$$\min T^*_{MWkm} = \sum_{i<j} |f_{ij}| l_{ij} \quad \text{with respect to } \forall_i \sum_j f_{ij} = G_i^S - D_i \, ; \sum_i G_i^S = \sum_i D_i \qquad \text{(Eq. 13)}$$

where

- T^*_{MWkm} is the minimum transmission in MWkm,
- f_{ij} flow between the node points i and j (if there is no route then it is taken as zero),
- l_{ij} total length between the node points i and j in km,
- G_i^S generation at the node point i,
- D_i depletion (consumption) at the node point i.

After the determination of optimal network size, model calculates the marginal investment cost at the node point in the case of 1 MW increment in generation (or

[20] The peak demand is reached in summer or winter in different regions of the country. Therefore two different marginal cost models are used for summer (1 April – 30 September) and winter (1 January – 31 March, 1 October – 31 December).

consumption since they are equal as the model's assumption). This marginal investment cost is the increment or decrement of all transferred MWkm in the network and it is the Lagrange multiplier in the optimization model ($\frac{\partial T^*_{MWkm}}{\partial G^s_i}$ and $\frac{\partial T^*_{MWkm}}{\partial D_i}$). For the production it is denoted as λ_i^G . An illustration of this method is explained in the latter steps of Appendix E.

F.3 Determination of the Final TL/MW Tariffs

ICBP model algorithm and the calculated marginal investment cost are taken as the basis in order to determine the final tariffs in terms of TL/MW. The determination steps are summarized below:

- Calculation of "unprocessed" cost of regional generation and the related sub-revenues,
- Calculation of the required total production revenue with respect to the total revenue cap for the transmission services,
- Calculation of the "additional cost", which is added to the regional prices according to TEİAŞ's revenue cap in order to acquire revenue.

F.4 Determination of the Increasing Regional Costs for the Generation

Weighted average cost of summer and winter periods, for each region, is calculated with the reference of installed capacity.

$$g_I^{Z,W} = \frac{\sum_{i\,in\,Z} G_i\, S\lambda_i^{G,W}}{\sum_{i\,in\,Z} G_i} \qquad g_I^{Z,S} = \frac{\sum_{i\,in\,Z} G_i\, S\lambda_i^{G,S}}{\sum_{i\,in\,Z} G_i} \qquad \text{(Eq. 14)}$$

where,

- $g_I^{Z,W}$, increasing “unprocessed” cost of generation in z region at winter peaks (TL),
- $g_I^{Z,S}$, increasing “unprocessed” cost of generation in z region at summer peaks (TL),
- G_i , maximum power supply limit at node point i (MW),
- s , network cost coefficient.

F.5 Calculation of Sub-Revenues

$$ZIRG_Z = S\% \times \sum_{i\,in\,Z} G_i\, g_I^{Z,S} + (1 - S\%) \times \sum_{i\,in\,Z} G_i\, g_I^{Z,W} \qquad \text{(Eq. 15)}$$

where,

- $ZIRG_Z$, sub-revenue in z region due to generation (TL)
- $S\%$, weighted percentage of cost, which is calculated for summer peaks
- Total sub-revenues for generation is calculated by the summation of all regional sub-revenues.

$$IRG = \sum_{Z} ZIRG_Z \qquad \text{(Eq. 16)}$$

where,

- IRG , total sub-revenue due to generation (TL)

In addition, in order to calculate total revenue due to generation, the following formula is derived.

$$TRG = RTUOS_R \times \frac{1}{1+k} \qquad \text{(Eq. 17)}$$

where,

- TRG, total revenue due to generation
- $RTUOS_R$, for the related tariffs, total revenue cap that is being covered by the system utilization costs (except system interconnection costs)

$$k = \frac{prefered\_payment\_rate\_held\_by\_the\_users\,\%}{prefered\_payment\_rate\_held\_by\_the\_producers\,\%} \qquad \text{(Eq. 18)}$$

In order to compensate the difference between the revenue cap and sub-revenues, addition costs are added for each MW for generation.

$$g_U = \frac{TRG - IRG}{\sum_i G_i} \qquad \text{(Eq. 19)}$$

where,

- g_U; additional costs related with generation (TL)

For each region, system utilization tariffs are determined by the addition of "unprocessed" regional costs and additional costs and combining with summer/winter peak calculated tariffs.

$$g^z = (g_l^{z,w} + g_U) \times (1 - S\%) + (g_l^{z,s} + g_U) \times S\% \qquad \text{(Eq. 20)}$$

where,

- g^z, system utilization tariffs for generation in z region.

F.6 Total System Utilization Costs

Total system utilization costs for a system utilization point [21] can be calculated as;

$$C_{put}^{G} = G_{put}^{A} \times g^{Z} \qquad \text{(Eq. 21)}$$

where;

- C_{put}^{G}, system utilization cost (TL) that is applied for the generator u on the condition of maximum power supply capacity at system utilization point p along t periods,
- G_{put}^{A}, maximum power supply capacity (MW) that is based on generation system utilization tariffs for the generator u along t periods at system utilization point p,
- g^{Z}, system utilization tariffs for generation in system utilization point of region z.

[21] System utilization point is the basis geographical point that is used to determine the system utilization costs according to regional tariffs. System utilization point is related with system utilization tariffs. System utilization points are specified in accordance with the transformer centers (where generation/consumption is connected to the transmission system).

F.7 Illustration of IBCP Model

Below, a network with three node points is schematized.

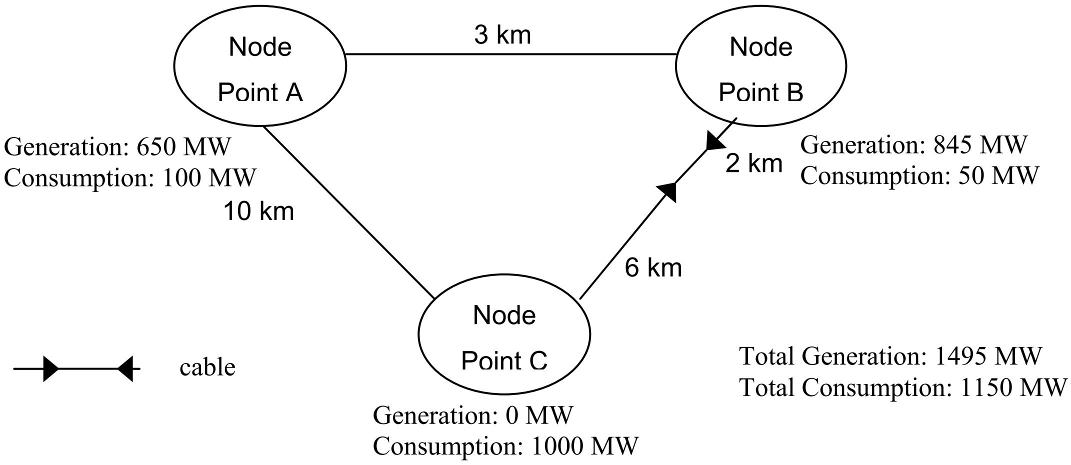

Figure 22. Network with Three Node Points

The first process is to balance the generation and the consumption. In this illustration, generation at each node points is decreased according to the same constant and the generation/consumption balance is satisfied.

Generation in Node Point A = 1150/1495 * 650MW = 500MW

Generation in Node Point B = 1150/1495 * 845MW = 650MW

As a result, the below diagram is observed.

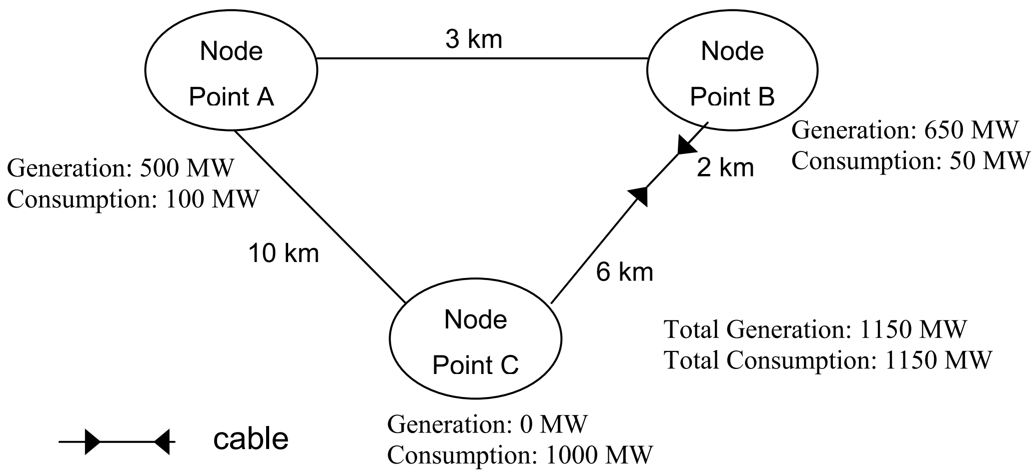

Figure 23. Energy Flow

Transmission cost coefficient of underground cables is assumed as 10 times more expensive than overhead lines. In addition, node point A is taken as the reference point (reference point does not affect the results). IBCP model makes the required adjustment in the network and calculates the energy flows as seen below:

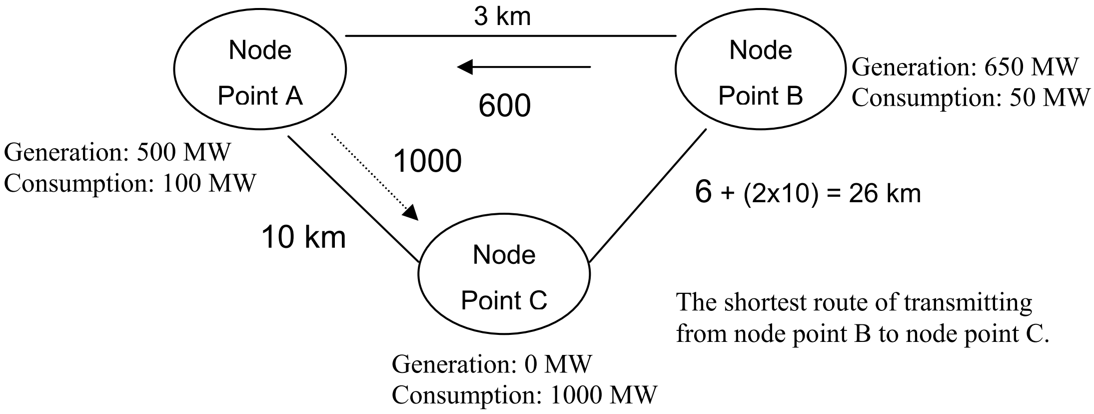

Figure 24. ICBP Model Adjustments (Base Case)

Total Cost = (600 x 3) + (1,000 x 10) = 11,800 MWkm (Base Case)

Then, in order to calculate marginal cost, 1MW generation is added to node points and 1MW consumption is added to the reference node point; and total MWkm cost is recalculated. The difference between the basis cost with the new cost gives the marginal km cost. This case is summarized below:

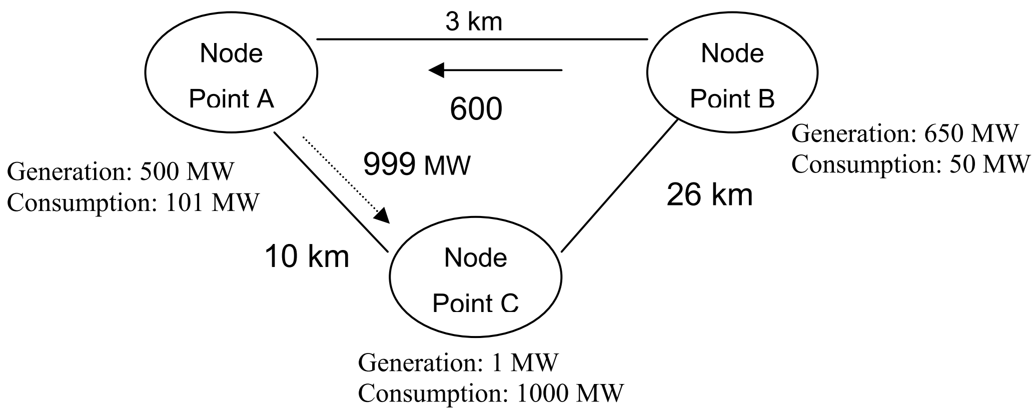

Figure 25. Marginal Cost Calculation Model

Calculation of marginal km cost at node point C:

Total Cost = (600 x 3) + (999 x 10) = 11,790 MWkm

Total cost is decreased 10 units. (marginal km cost= -10).

IBCP model simultaneously calculates the lowest marginal costs in each node points of the network.

APPENDIX G

TRANSMISSION SYSTEM INVESTMENT COST CALCULATION

The cost of transmitting 1 MW power in a transmission line for 1 km (TL/MWkm) is calculated as;

$$A = \frac{r \text{ x } c}{1 - \dfrac{1}{(1+r)^n}} \qquad \text{(Eq. 22)}$$

where,

c: Network expansion coefficient; represents the transmission infrastructure investment cost in order to transmit 1 MW power for 1 km. The magnitude of this coefficient depends on the investment that is planned and handled by TEİAŞ. Network expansion coefficient is determined according to below steps:

- Investment costs related with the existing projects are analyzed via investment programs with respect to each transmission line type (154kV, 380kV overhead and underground transmission lines) in order to obtain total investment cost. These costs except the system assets are summed and the total investment cost is found. These investment cost contains also the transformer costs of the existing projects. In ICBP model, the lowest cost line (380kV overhead line, 154 kV overhead line or underground line) is taken as the reference line and the cost of other type of lines are derived from that basis.

- These calculated investment cost is divided to the total MWkm value (related with each transmission line type) and the final value is reflected to the generators.

n: Total effective life-time of the transmission assets, adjusted to 20 years by TEİAŞ.

r: Depreciation rate of the assets and is adjusted as 12 % by TEİAŞ.

APPENDIX H

TRANSMISSION SYSTEM AREAS

Table 29. Transmission System Transformer Centers [34]

City	Transformer Center	Area
AYDIN	AYDIN	101
AYDIN	AYDIN MOBİL TM	101
AYDIN	BATI SÖKE	101
AYDIN	BOZDOĞAN	101
AYDIN	ÇİNE	101
AYDIN	GERMENCİK	101
AYDIN	GERMENCİK JTS	101
AYDIN	KEMER HES	101
AYDIN	KUŞADASI GİS	101
AYDIN	NAZİLLİ	101
AYDIN	SÖKE	101
BALIKESİR	ALTINOLUK	101
BALIKESİR	AYVALIK	101
BALIKESİR	BALIKESİR I	101
BALIKESİR	BALIKESİR II	101
BALIKESİR	BALIKESİR OSB	101
BALIKESİR	BALIKESİR SEKA	101
BALIKESİR	BANDIRMA III RES	101
BALIKESİR	BİGADİÇ	101
BALIKESİR	DURSUNBEY	101
BALIKESİR	EDREMİT	101
BALIKESİR	GÖNEN	101
BALIKESİR	ŞAMLI RES	101

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
BİLECİK	AKENERJİ BOZÜYÜK DGKÇS	101
BİLECİK	BOZÜYÜK	101
BİLECİK	TCDD KARAKÖY	101
BURSA	ASİLÇELİK	101
BURSA	BEŞEVLER	101
BURSA	BOSEN DGKÇS	101
BURSA	BURSA DGKÇS 154	101
BURSA	BURSA I	101
BURSA	BURSA III	101
BURSA	BURSA SANAYİ	101
BURSA	DEMİRTAŞ	101
BURSA	DEMİRTAŞ OSB	101
BURSA	EGEMEN 1 HES	101
BURSA	ENTEK DEMİRTAŞ OSB DGKÇS	101
BURSA	GEMLİK	101
BURSA	İNEGÖL	101
BURSA	KELES	101
BURSA	KESTEL	101
BURSA	ORHANELİ TES	101
BURSA	ORHANGAZİ	101
BURSA	OTOSANSİT	101
ÇANAKKALE	BİGA	101
ÇANAKKALE	ÇAMSEKİ RES	101
ÇANAKKALE	ÇAN	101
ÇANAKKALE	ÇAN ONSEKİZMART TES	101
ÇANAKKALE	ÇANAKKALE	101
ÇANAKKALE	ÇANAKKALE ÇİMENTO	101
ÇANAKKALE	ENERJİ-SA ÇANAKKALE DGKÇS	101
ÇANAKKALE	EZİNE	101
ÇANAKKALE	İNTEPE RES	101
ESKİŞEHİR	GÖKÇEKAYA HES	101
ESKİŞEHİR	KIRKA	101
İZMİR	AKENERJİ KEMALPAŞA DGKÇS	101
İZMİR	ALAÇATI	101
İZMİR	ALÇUK	101

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
İZMİR	ALİAĞA I	101
İZMİR	ALİAĞA II	101
İZMİR	ALMAK	101
İZMİR	ALOSBİ	101
İZMİR	ALSANCAK GİS	101
İZMİR	ASLANLAR	101
İZMİR	ATAER	101
İZMİR	BAHRİBABA GİS	101
İZMİR	BERGAMA	101
İZMİR	BORNOVA	101
İZMİR	BOSTANLI GİS	101
İZMİR	BOZYAKA	101
İZMİR	BUCA	101
İZMİR	ÇAKMAKTEPE TES	101
İZMİR	DÜZOVA RES	101
İZMİR	EBSO	101
İZMİR	EREGE METAL	101
İZMİR	GÜZELYALI GİS	101
İZMİR	HABAŞ	101
İZMİR	HABAŞ İZMİR DGKÇS	101
İZMİR	HATAY GİS	101
İZMİR	HİLAL GİS	101
İZMİR	HİLAL KLASİK	101
İZMİR	ILICA GİS	101
İZMİR	IŞIKLAR	101
İZMİR	İZMİR DGKÇS	101
İZMİR	KARABAĞLAR	101
İZMİR	KARŞIYAKA GİS	101
İZMİR	KEMALPAŞA	101
İZMİR	KORES KOCADAĞ RES	101
İZMİR	MARE MANASTIR RES	101
İZMİR	MAZI-3 RES	101
İZMİR	ÖDEMİŞ	101
İZMİR	ÖZKAN DEMİR ÇELİK	101
İZMİR	PETKİM	101

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
İZMİR	PİYALE GİS	101
İZMİR	ŞEMİKLER GİS	101
İZMİR	TAHTALI	101
İZMİR	TCDD HİLAL	101
İZMİR	TCDD MENEMEN	101
İZMİR	TİRE	101
İZMİR	ULUCAK	101
İZMİR	URLA	101
İZMİR	UZUNDERE	101
İZMİR	ÜNİVERSİTE	101
İZMİR	VİKİNG	101
İZMİR	YUNTDAĞI RES	101
İZMİR	ALİAĞA RES	101
İZMİR	SEYİTALİ RES	101
KÜTAHYA	AZOT	101
KÜTAHYA	EMET	101
KÜTAHYA	ETİ GÜMÜŞ	101
KÜTAHYA	KÜTAHYA	101
KÜTAHYA	SEYİTÖMER TES	101
KÜTAHYA	TUNÇBİLEK ŞALT	101
KÜTAHYA	TUNÇBİLEK TES	101
MANİSA	AKHİSAR	101
MANİSA	AKRES	101
MANİSA	AKSA-MANİSA	101
MANİSA	DERBENT	101
MANİSA	MANİSA	101
MANİSA	MANİSA (MORSAN)	101
MANİSA	MANİSA OSB TES	101
MANİSA	SARUHANLI	101
MANİSA	SAYALAR RES	101
MANİSA	SOMA A TES	101
MANİSA	SOMA B TES	101
MANİSA	SOMA RES	101
ADANA	FEKE HAVZA	102
ADIYAMAN	ADIYAMAN	102

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
ADIYAMAN	ADIYAMAN ÇİMENTO	102
ADIYAMAN	ADIYAMAN GÖLBAŞI	102
ADIYAMAN	KAHTA	102
ADIYAMAN	TCDD GÖLBAŞI	102
AMASYA	AMASYA	102
AMASYA	KAYABAŞI	102
DİYARBAKIR	DİCLE HES	102
DİYARBAKIR	DİYARBAKIR II	102
DİYARBAKIR	DİYARBAKIR III	102
DİYARBAKIR	DİYARBAKIR IV	102
DİYARBAKIR	ERGANİ ÇİMENTO	102
DİYARBAKIR	KARAKAYA HES	102
DİYARBAKIR	KARAKAYA ŞALT	102
DİYARBAKIR	KRALKIZI HES	102
ELAZIĞ	DSİ KUZOVA	102
ELAZIĞ	HAZAR I HES	102
ELAZIĞ	HAZAR II HES	102
ELAZIĞ	KEBAN	102
ELAZIĞ	KEBAN HES	102
ELAZIĞ	KEBAN ŞALT	102
ELAZIĞ	MADEN	102
ERZİNCAN	REFAHİYE	102
ERZİNCAN	YENİ ÇÖPLER GOLD TM	102
G.ANTEP	BELKIS (NİZİP)	102
G.ANTEP	ÇİMKO	102
G.ANTEP	FEVZİPAŞA	102
G.ANTEP	GAZİANTEP I	102
G.ANTEP	GAZİANTEP II	102
G.ANTEP	GAZİANTEP III	102
G.ANTEP	GAZİANTEP V	102
G.ANTEP	POMPA 3	102
G.ANTEP	PS 4B	102
G.ANTEP	TCDD FEVZİPAŞA	102
GİRESUN	ŞEBİNKARAHİSAR HAVZA GEÇİCİ TM	102

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
KAHRAMANMARAŞ	AFŞİN ELBİSTAN A TES	102
KAHRAMANMARAŞ	AFŞİN ELBİSTAN B TES	102
KAHRAMANMARAŞ	ANDIRIN	102
KAHRAMANMARAŞ	ANDIRIN HES	102
KAHRAMANMARAŞ	CEYHAN HES	102
KAHRAMANMARAŞ	ÇAĞLAYAN GEÇİCİ MOBİL	102
KAHRAMANMARAŞ	ÇÖLLOLAR	102
KAHRAMANMARAŞ	DOĞANKÖY	102
KAHRAMANMARAŞ	GÖKSUN	102
KAHRAMANMARAŞ	GÖKSUN SKM	102
KAHRAMANMARAŞ	KAHRAMANMARAŞ II	102
KAHRAMANMARAŞ	KALEALTI HES	102
KAHRAMANMARAŞ	KARGILIK HES	102
KAHRAMANMARAŞ	KILAVUZLU	102
KAHRAMANMARAŞ	KILILI	102
KAHRAMANMARAŞ	KISIK HES	102
KAHRAMANMARAŞ	MENZELET HES	102
KAHRAMANMARAŞ	NARLI	102
KAHRAMANMARAŞ	PS 5	102
KAHRAMANMARAŞ	SIR HES	102
KAHRAMANMARAŞ	TCDD NARLI	102
KAHRAMANMARAŞ	TKİ	102
KAYSERİ	KAYSERİ KAPASİTÖR	102
KAYSERİ	PINARBAŞI	102
MALATYA	DARENDE	102
MALATYA	HASANÇELEBİ	102
MALATYA	MALATYA I	102
MALATYA	MALATYA II	102
MALATYA	MALORSA	102
MALATYA	TCDD AKGEDİK	102
MALATYA	TCDD DOĞANŞEHİR	102
MALATYA	TCDD HEKİMHAN	102
MALATYA	TCDD YAZIHAN	102
MALATYA	TCDD YAZLAK	102
OSMANİYE	BAHÇE	102

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
OSMANİYE	BERKE HES	102
OSMANİYE	KADİRLİ	102
OSMANİYE	OSMANİYE RES	102
OSMANİYE	TCDD NOHUT	102
SAMSUN	ALTINKAYA HES	102
SAMSUN	BAFRA	102
SAMSUN	ÇARŞAMBA	102
SAMSUN	DERBENT HES	102
SAMSUN	HASAN UĞURLU HES	102
SAMSUN	ONDOKUZMAYIS	102
SAMSUN	SAMSUN I	102
SAMSUN	SAMSUN I MOBİL SANTRALİ	102
SAMSUN	SAMSUN II	102
SAMSUN	SAMSUN II MOBİL SANTRALİ	102
SAMSUN	SAMSUN III	102
SAMSUN	SUAT UĞURLU HES	102
SİVAS	ÇAMLIGÖZE HES	102
SİVAS	DEÇEKO	102
SİVAS	DEMİRDAĞ	102
SİVAS	KANGAL TES	102
SİVAS	KILIÇKAYA HES	102
SİVAS	KOYULHİSAR HES	102
SİVAS	SIZIR	102
SİVAS	SİVAS	102
SİVAS	SİVAS OSB	102
SİVAS	SUŞEHRİ	102
SİVAS	ŞARKIŞLA	102
SİVAS	TCDD CÜREK	102
SİVAS	TCDD ÇETİNKAYA	102
SİVAS	YEŞİL HES	102
SİVAS	ZARA	102
Ş.URFA	ATATÜRK	102
Ş.URFA	ATATÜRK HES	102
Ş.URFA	HİLVAN	102
Ş.URFA	KARACA	102

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
Ş.URFA	KARAKEÇİLİ	102
Ş.URFA	SİVEREK	102
Ş.URFA	ŞANLIURFA HES	102
Ş.URFA	ŞANLIURFA I	102
Ş.URFA	ŞANLIURFA II	102
Ş.URFA	TATARHÖYÜK	102
Ş.URFA	URFA ÇİMENTO	102
TOKAT	ALMUS HES	102
TOKAT	ARTOVA ÇİMENTO	102
TOKAT	ERBAA	102
TOKAT	KÖKLÜCE HES	102
TOKAT	REŞADİYE HES	102
TOKAT	TOKAT	102
TOKAT	TOKAT OSB	102
TOKAT	TURHAL	102
YOZGAT	AKDAĞMADENİ	102
AĞRI	AĞRI	103
AĞRI	AĞRI II	103
AĞRI	DOĞUBEYAZIT	103
AĞRI	PATNOS	103
ARDAHAN	ARDAHAN	103
ARTVİN	ARTVİN	103
ARTVİN	BORÇKA HES	103
ARTVİN	ÇAKMAKKAYA	103
ARTVİN	HOPA F/O	103
ARTVİN	MURATLI HES	103
BATMAN	BATMAN HES	103
BATMAN	BATMAN I	103
BATMAN	BATMAN II	103
BATMAN	BATMAN MOBİL SANTRALİ	103
BAYBURT	BAYBURT	103
BİNGÖL	BİNGÖL	103
BİTLİS	ADİLCEVAZ	103
BİTLİS	TATVAN	103
DİYARBAKIR	BİSMİL	103

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
DİYARBAKIR	KULP HES	103
DİYARBAKIR	KULP I- IV HES	103
DİYARBAKIR	LİCE	103
DİYARBAKIR	SİLVAN	103
ELAZIĞ	ELAZIĞ FERROKROM	103
ELAZIĞ	ELAZIĞ II	103
ELAZIĞ	ELAZIĞ III (HANKENDİ)	103
ELAZIĞ	ÖZLÜCE HES	103
ELAZIĞ	ÖZLÜCE ŞALT	103
ELAZIĞ	SEYRANTEPE HES	103
ERZİNCAN	ERZİNCAN I	103
ERZİNCAN	ERZİNCAN OSB	103
ERZİNCAN	TERCAN	103
ERZURUM	AŞKALE	103
ERZURUM	AŞKALE ÇİMENTO	103
ERZURUM	ERZURUM I	103
ERZURUM	ERZURUM II	103
ERZURUM	ERZURUM III	103
ERZURUM	HINIS	103
ERZURUM	HORASAN	103
ERZURUM	KALETEPE HES	103
ERZURUM	KONAK	103
ERZURUM	KUZGUN HES	103
ERZURUM	OLTU	103
ERZURUM	TORTUM	103
ERZURUM	TORTUM HES	103
ERZURUM	UZUNDERE	103
GİRESUN	ÇIRAKDAMI HES	103
GİRESUN	DERELİ HES	103
GİRESUN	DOĞANKENT HES	103
GİRESUN	GİRESUN	103
GİRESUN	TİREBOLU	103
GÜMÜŞHANE	AKKÖY II HES	103
GÜMÜŞHANE	GÜMÜŞHANE	103
GÜMÜŞHANE	KÜRTÜN HES	103

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
GÜMÜŞHANE	TORUL HES	103
HAKKARİ	BAĞIŞLI	103
HAKKARİ	HAKKARİ	103
IĞDIR	IĞDIR	103
KARS	ÇILDIR HES	103
KARS	KARS	103
KARS	NARİNKALE HAVZA	103
MUŞ	ALPARSLAN HES	103
MUŞ	MUŞ	103
ORDU	DARICA HES	103
ORDU	FATSA	103
ORDU	GÖLKÖY	103
ORDU	ORDU	103
ORDU	ÜNYE	103
RİZE	ARDEŞEN	103
RİZE	ÇAYELİ	103
RİZE	İKİZDERE HES	103
RİZE	İYİDERE	103
RİZE	RİZE	103
RİZE	UZUNDERE HES	103
RİZE	YOKUŞLU KALKANDERE	103
SİİRT	SİİRT ÇİMENTO (KURTALAN)	103
TRABZON	ARSİN	103
TRABZON	GÜNAYŞE HES	103
TRABZON	SARMAŞIK I	103
TRABZON	SARMAŞIK II	103
TRABZON	TRABZON	103
TRABZON	VAKFIKEBİR	103
TRABZON	YUKARI MANAHOZ HES	103
TUNCELİ	KONAKTEPE HES	103
TUNCELİ	MERCAN HES	103
TUNCELİ	PÜLÜMÜR	103
TUNCELİ	TUNCELİ	103
TUNCELİ	UZUNÇAYIR HES	103
VAN	BAŞKALE	103

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
VAN	BAŞKALE 380	103
VAN	ENGİL	103
VAN	ERCİŞ	103
VAN	VAN	103
ADANA	ADANA	104
ADANA	ADANA ÇİMENTO	104
ADANA	BATI ADANA	104
ADANA	CEYHAN I	104
ADANA	CEYHAN II	104
ADANA	CİHADİYE	104
ADANA	ÇATALAN HES	104
ADANA	DOĞU ADANA	104
ADANA	ENERJİ-SA ADANA DGKÇS	104
ADANA	GÜNEY ADANA	104
ADANA	İNCİRLİK	104
ADANA	İNCİRLİK HAVAALANI	104
ADANA	KARAHAN	104
ADANA	KARAİSALİ	104
ADANA	KOZAN	104
ADANA	MENTAŞ HES	104
ADANA	MİHMANDAR	104
ADANA	MİSİS	104
ADANA	SEYHAN	104
ADANA	SEYHAN I HES	104
ADANA	SEYHAN II HES	104
ADANA	TOROSLAR	104
ADANA	YEDİGÖZE HES	104
ADANA	YENİ ŞEHİTLİK	104
ADANA	YUMURTALIK	104
ADANA	YÜREĞİR	104
ADANA	YÜREĞİR HES	104
ADANA	ZEYTİNLİ	104
AKSARAY	TÜMOSAN	104
ANKARA	ŞEREFLİKOÇHİSAR	104
HATAY	ANTAKYA I	104

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
HATAY	ANTAKYA II	104
HATAY	ANTAKYA III	104
HATAY	BELEN RES	104
HATAY	ERZİN	104
HATAY	İKİZLER	104
HATAY	İSDEMİR	104
HATAY	İSKENDERUN I	104
HATAY	İSKENDERUN II	104
HATAY	İSKENDERUN III	104
HATAY	NURSAN	104
HATAY	PAYAS	104
HATAY	SEBENOBA RES	104
HATAY	SUGÖZÜ TES	104
HATAY	TCDD PAYAS	104
HATAY	YAZICI DEMİR ÇELİK	104
İSKENDERUN	MMK-ATAKAŞ	104
MERSİN	AKBELEN	104
MERSİN	AKKUYU	104
MERSİN	ANAMUR	104
MERSİN	CAMİŞ ELEKTRİK MERSİN DGKÇS	104
MERSİN	ÇİMSA	104
MERSİN	ENERJİ-SA MERSİN DGKÇS	104
MERSİN	ERDEMLİ	104
MERSİN	KADINCIK I HES	104
MERSİN	KADINCIK II HES	104
MERSİN	MERSİN I	104
MERSİN	MERSİN II	104
MERSİN	MERSİN III	104
MERSİN	MERSİN TERMİK	104
MERSİN	NACARLI	104
MERSİN	TARSUS	104
MERSİN	TAŞUCU	104
MERSİN	YAKAKÖY	104
NİĞDE	BOR	104
NİĞDE	NİĞDE OSB	104

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
OSMANİYE	ASLANTAŞ HES	104
OSMANİYE	OSMANİYE	104
OSMANİYE	OSMANİYE OSB	104
OSMANİYE	TCDD OSMANİYE	104
OSMANİYE	TOSÇELİK	104
OSMANİYE	YOLBULAN BAŞTUĞ	104
AMASYA	MERZİFON	105
ANKARA	BAĞLUM	105
ANKARA	ESENBOĞA	105
ANKARA	HİRFANLI HES	105
ANKARA	KALECİK	105
ANKARA	KESİKKÖPRÜ HES	105
ANKARA	OVACIK	105
BARTIN	BARTIN II	105
ÇANKIRI	ÇANKIRI	105
ÇORUM	ALACA	105
ÇORUM	ÇORUM I	105
ÇORUM	ÇORUM II	105
ÇORUM	KARGI	105
ÇORUM	OBRUK HES	105
ÇORUM	SUNGURLU OSB	105
DÜZCE	AKÇAKOCA	105
KARABÜK	İSMETPAŞA	105
KARABÜK	KARABÜK	105
KARABÜK	KARABÜK OSB	105
KASTAMONU	CİDE	105
KASTAMONU	İNEBOLU	105
KASTAMONU	KASTAMONU	105
KASTAMONU	KASTAMONU OSB	105
KASTAMONU	KÜRE	105
KASTAMONU	TAŞKÖPRÜ	105
KASTAMONU	TOSYA	105
KIRIKKALE	BAŞTAŞ	105
KIRIKKALE	HACILAR	105
KIRIKKALE	KAPULUKAYA HES	105

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
KIRIKKALE	KIRIKKALE	105
KIRIKKALE	KIRIKKALE MOBİL SANTRALİ	105
KIRŞEHİR	KIRŞEHİR	105
KIRŞEHİR	PETLAS	105
KONYA	KULU	105
SAMSUN	LADİK ÇİMENTO	105
SAMSUN	VEZİRKÖPRÜ	105
SİNOP	AYANCIK	105
SİNOP	BOYABAT	105
SİNOP	SİNOP	105
YOZGAT	SORGUN	105
YOZGAT	YERKÖY	105
YOZGAT	YİBİTAŞ	105
YOZGAT	YOZGAT	105
ZONGULDAK	ÇATALAĞZI TES	105
ZONGULDAK	ÇAYCUMA I	105
ZONGULDAK	ÇAYCUMA II	105
ZONGULDAK	ERDEMİR I	105
ZONGULDAK	ERDEMİR II	105
ZONGULDAK	EREĞLİ I	105
ZONGULDAK	EREĞLİ II (BÖLÜCEK)	105
ZONGULDAK	KANDİLLİ	105
ZONGULDAK	KARADON	105
ZONGULDAK	KOZLU	105
ZONGULDAK	SAFRANBOLU	105
ZONGULDAK	ZETES	105
ZONGULDAK	ZONGULDAK I	105
ZONGULDAK	ZONGULDAK II	105
AKSARAY	AĞAÇÖREN SKM	106
ANKARA	AKKÖPRÜ	106
ANKARA	ANKARA DGKÇS	106
ANKARA	ANKARA DGKÇS	106
ANKARA	ANKARA SANAYİ	106
ANKARA	BALGAT	106
ANKARA	BEYPAZARI	106

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
ANKARA	ÇAYIRHAN TES	106
ANKARA	ÇİMPOR YİBİTAŞ HASANOĞLAN	106
ANKARA	DDY 1	106
ANKARA	EMİRLER	106
ANKARA	ETİ-SODA	106
ANKARA	GÖLBAŞI	106
ANKARA	HASKÖY GİS	106
ANKARA	İMRAHOR	106
ANKARA	KAZAN	106
ANKARA	MACUNKÖY	106
ANKARA	MALTEPE GİS	106
ANKARA	MAMAK	106
ANKARA	OSTİM OSB	106
ANKARA	POLATLI	106
ANKARA	SARIYAR HES	106
ANKARA	SİNCAN	106
ANKARA	TCDD HİPODROM	106
ANKARA	TCDD NENEK	106
ANKARA	TEMELLİ	106
ANKARA	ÜMİTKÖY	106
ANKARA	YILDIZ	106
ANKARA	ZORLU ENERJİ SİNCAN DGKÇS	106
BALIKESİR	BANDIRMA DGKÇS	106
BOLU	BOLU	106
BOLU	BOLU ÇİMENTO	106
BOLU	BOLU II	106
BOLU	GERKONSAN	106
BOLU	GÖYNÜK	106
BOLU	MUDURNU	106
BURSA	BURSA DGKÇS 380	106
ÇANAKKALE	KARABİGA TES (İÇDAŞ)	106
ÇANKIRI	KURŞUNLU	106
DÜZCE	KAYNAŞLI	106
DÜZCE	OSMANCA	106
ESKİŞEHİR	TCDD MALIKÖY	106

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
KAYSERİ	ÇAMLICA I HES (AYEN)	106
KAYSERİ	ÇİNKUR	106
KAYSERİ	KAYSERİ I	106
KAYSERİ	KAYSERİ II	106
KAYSERİ	KAYSERİ III	106
KAYSERİ	SENDİREMEKE	106
KAYSERİ	TAKSAN	106
KAYSERİ	YAMULA HES	106
KAYSERİ	YEŞİLHİSAR	106
KAYSERİ	ZORLU ENERJİ KAYSERİ DGKÇS	106
KOCAELİ	TCDD KALBURLU	106
KOCAELİ	YARIMCA II	106
KONYA	DDY 2	106
KONYA	DDY 3	106
KONYA	DDY 4	106
KONYA	KIZÖREN	106
KONYA	KONYA IV	106
NEVŞEHİR	AVANOS	106
NEVŞEHİR	DERİNKUYU	106
NEVŞEHİR	KALABA	106
NEVŞEHİR	NEVŞEHİR II	106
NEVŞEHİR	ÜRGÜP SKM	106
NİĞDE	MİSLİOVA	106
NİĞDE	NİĞDE II	106
SAKARYA	ADAPAZARI	106
SAKARYA	ADAPAZARI DGKÇS	106
SAKARYA	DOKURCUN SKM	106
SAKARYA	GEBZE DGKÇS	106
SAKARYA	HENDEK	106
SAKARYA	KARASU	106
SAKARYA	KAYNARCA	106
SAKARYA	KUZULUK	106
SAKARYA	MELEN	106
SAKARYA	MOBİL I (KUZULUK)	106
SAKARYA	SAKARYA	106

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
SAKARYA	TCDD ARİFİYE	106
SAKARYA	TOYOTASA	106
YOZGAT	BOĞAZLIYAN	106
ÇANAKKALE	BURGAZ RES	107
ÇANAKKALE	GELİBOLU	107
ÇANAKKALE	KUMLİMANI	107
EDİRNE	BOREAS RES	107
EDİRNE	CAN ENERJİ	107
EDİRNE	ENEZ	107
EDİRNE	KEŞAN	107
EDİRNE	TCDD HALKALI	107
EDİRNE	TCDD KABAKÇA	107
EDİRNE	TCDD MURATLI	107
EDİRNE	TCDD VELİMEŞE	107
EDİRNE	UZUNKÖPRÜ	107
İSTANBUL	AKÇANSA ÇİMENTO	107
İSTANBUL	AKSARAY	107
İSTANBUL	ALİBEYKÖY	107
İSTANBUL	ALTINTEPE GİS	107
İSTANBUL	AMBARLI	107
İSTANBUL	AMBARLI F/O	107
İSTANBUL	AMBARLI DGKÇS	107
İSTANBUL	ATIŞALANI	107
İSTANBUL	BAĞCILAR GİS	107
İSTANBUL	BAHÇELİEVLER GİS	107
İSTANBUL	BAHÇEŞEHİR	107
İSTANBUL	BEYKOZ GİS	107
İSTANBUL	BEYLİKDÜZÜ	107
İSTANBUL	BÜYÜKBAKKALKÖY	107
İSTANBUL	BÜYÜKÇEKMECE	107
İSTANBUL	ÇATALCA RES	107
İSTANBUL	DAVUTPAŞA GİS	107
İSTANBUL	DUDULLU	107
İSTANBUL	ESENYURT DGKÇS	107
İSTANBUL	ETİLER	107

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
İSTANBUL	GÖZTEPE GİS	107
İSTANBUL	HABİBLER	107
İSTANBUL	HADIMKÖY	107
İSTANBUL	İÇMELER	107
İSTANBUL	İKİTELLİ	107
İSTANBUL	İSAKÖY	107
İSTANBUL	KARTAL	107
İSTANBUL	KASIMPAŞA GİS	107
İSTANBUL	KURTKÖY	107
İSTANBUL	KÜÇÜKBAKKALKÖY GİS	107
İSTANBUL	KÜÇÜKKÖY	107
İSTANBUL	LEVENT GİS	107
İSTANBUL	MASLAK	107
İSTANBUL	PAŞAKÖY	107
İSTANBUL	SAĞMALCILAR	107
İSTANBUL	SELİMİYE GİS	107
İSTANBUL	SİLAHTAR	107
İSTANBUL	SİLİVRİ	107
İSTANBUL	SOĞANLIK GİS	107
İSTANBUL	SULTANMURAT GİS	107
İSTANBUL	ŞİLE	107
İSTANBUL	ŞİŞLİ GİS	107
İSTANBUL	TAŞOLUK	107
İSTANBUL	TCDD İDEALTEPE	107
İSTANBUL	TEPEÖREN	107
İSTANBUL	TOPKAPI GİS	107
İSTANBUL	ÜMRANİYE GİS	107
İSTANBUL	VANİKÖY GİS	107
İSTANBUL	VELİEFENDİ GİS	107
İSTANBUL	YENİBOSNA	107
İSTANBUL	YENİBOSNA TES (İÇDAŞ)	107
İSTANBUL	YENİKAPI GİS	107
İSTANBUL	YILDIZTEPE GİS	107
İSTANBUL	ZEKERİYAKÖY GİS	107
KIRKLARELİ	BÜYÜKKARIŞTIRAN	107

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
KIRKLARELİ	DELTA ENERJİ	107
KIRKLARELİ	KIYIKÖY	107
KIRKLARELİ	ZORLU ENERJİ LÜLEBURGAZ DGKÇS	107
KOCAELİ	ASLANBEY	107
KOCAELİ	ÇOLAKOĞLU DGKÇS	107
KOCAELİ	DİLER ÇELİK	107
KOCAELİ	DİLİSKELESİ	107
KOCAELİ	DİLOVASI OSB	107
KOCAELİ	ENTEK KÖSEKÖY DGKÇS	107
KOCAELİ	FORD OTOSAN	107
KOCAELİ	GEBZE OSB	107
KOCAELİ	GÖLCÜK (YENİKÖY)	107
KOCAELİ	HYUNDAI	107
KOCAELİ	İZMİT GİS	107
KOCAELİ	KARAMÜRSEL	107
KOCAELİ	KENTSA DGKÇS	107
KOCAELİ	KİMYA OSB	107
KOCAELİ	KÖSEKÖY	107
KOCAELİ	KROMAN ÇELİK	107
KOCAELİ	NUH ÇİMENTO	107
KOCAELİ	NUH ENERJİ	107
KOCAELİ	TCDD OSMANGAZİ	107
KOCAELİ	TUZLA	107
KOCAELİ	TÜPRAŞ İZMİT RAFİNERİ TES	107
KOCAELİ	YARIMCA I	107
TEKİRDAĞ	BOTAŞ MARMARA EREĞLİSİ	107
TEKİRDAĞ	ÇERKEZKÖY	107
TEKİRDAĞ	ÇERKEZKÖY ENERJİ DGKÇS	107
TEKİRDAĞ	ÇORLU	107
TEKİRDAĞ	KAPTAN DEMİR ÇELİK	107
TEKİRDAĞ	MALKARA	107
TEKİRDAĞ	MARMARA PAMUKLU	107
TEKİRDAĞ	MODERN ENERJİ DGKÇS	107
TEKİRDAĞ	MODERN KARTON	107

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
TEKİRDAĞ	SARAY RES	107
TEKİRDAĞ	TEGESAN	107
TEKİRDAĞ	TEKİRDAĞ	107
TEKİRDAĞ	TRAKYA ELEKTRİK DGKÇS	107
TEKİRDAĞ	UĞUR TES	107
TEKİRDAĞ	ULAŞ	107
TEKİRDAĞ	UNİMAR DGKÇS	107
YALOVA	AKENERJİ YALOVA GİS	107
YALOVA	YALOVA	107
BİLECİK	BİLORSA	108
BİLECİK	PAŞALAR	108
BİLECİK	SÖĞÜT	108
BİLECİK	TCDD OSMANELİ	108
BURSA	YENİŞEHİR	108
BURSA	YENİŞEHİR OSB	108
ESKİŞEHİR	ÇİFTELER	108
ESKİŞEHİR	ESKİŞEHİR I	108
ESKİŞEHİR	ESKİŞEHİR II	108
ESKİŞEHİR	ESKİŞEHİR III	108
ESKİŞEHİR	TCDD ALPU	108
ESKİŞEHİR	TCDD KARAGÖZLER	108
ESKİŞEHİR	YENİCE HES	108
SAKARYA	PAMUKOVA	108
AYDIN	AKBÜK	109
DENİZLİ	ADIGÜZEL HES	109
DENİZLİ	BOZKURT	109
DENİZLİ	DENİZLİ ÇİMENTO	109
DENİZLİ	DENİZLİ II	109
DENİZLİ	DENİZLİ III	109
DENİZLİ	DENİZLİ IV	109
DENİZLİ	SARAYKÖY	109
DENİZLİ	TAVAS	109
MUĞLA	BODRUM	109
MUĞLA	DATÇA	109
MUĞLA	DATÇA RES	109

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
MUĞLA	KEMERKÖY TES	109
MUĞLA	MARMARİS	109
MUĞLA	MİLAS	109
MUĞLA	MUĞLA	109
MUĞLA	YATAĞAN TES	109
MUĞLA	YENİKÖY TES	109
AFYONKARAHİSAR	AFYON I	110
AFYONKARAHİSAR	AFYON II	110
AFYONKARAHİSAR	ÇAYSEKA	110
AFYONKARAHİSAR	EMİRDAĞ	110
AFYONKARAHİSAR	SANDIKLI	110
ANKARA	BEYLİKKÖPRÜ	110
ANKARA	TCDD BEYLİKKÖPRÜ	110
ANTALYA	AKORSAN	110
ANTALYA	AKSA-ANTALYA	110
ANTALYA	AKSEKİ	110
ANTALYA	ALANYA I	110
ANTALYA	ALANYA-II	110
ANTALYA	ALARA	110
ANTALYA	ANTALYA ENERJİ	110
ANTALYA	ANTALYA FERROKROM	110
ANTALYA	ANTALYA KEMER	110
ANTALYA	ANTALYA SERBEST BÖLGE	110
ANTALYA	ANTBİRLİK	110
ANTALYA	AS ÇİMENTO	110
ANTALYA	DİM HES	110
ANTALYA	FİNİKE	110
ANTALYA	GAZİPAŞA	110
ANTALYA	KAŞ	110
ANTALYA	KEPEZ I HES	110
ANTALYA	KEPEZ II HES	110
ANTALYA	KIZILDÜZ-ŞAHMALLAR HES	110
ANTALYA	KORKUTELİ	110
ANTALYA	LARA I	110
ANTALYA	LARA-II	110

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
ANTALYA	MANAVGAT	110
ANTALYA	MANAVGAT HES	110
ANTALYA	MANCARLIK GİS	110
ANTALYA	OYMAPINAR HES	110
ANTALYA	SERİK	110
ANTALYA	VARSAK	110
ANTALYA	GÜNDOĞDU	110
BURDUR	BUCAK	110
BURDUR	BURDUR	110
BURDUR	KARACAÖREN I HES	110
BURDUR	KARACAÖREN II HES	110
BURDUR	TEFENNİ	110
DENİZLİ	ACIPAYAM	110
DENİZLİ	ÇİVRİL	110
DENİZLİ	KIZILDERE JTS	110
ESKİŞEHİR	MOBİL II SİVRİHİSAR	110
ESKİŞEHİR	TCDD SAZAK	110
ISPARTA	BARLA	110
ISPARTA	EĞİRDİR	110
ISPARTA	GÖLTAŞ	110
ISPARTA	ISPARTA	110
ISPARTA	KEÇİBORLU	110
ISPARTA	KOVADA I HES	110
ISPARTA	KOVADA II HES	110
ISPARTA	KULEÖNÜ	110
ISPARTA	ŞARKİKARAAĞAÇ	110
KARAMAN	KARAMAN	110
KARAMAN	KARAMAN OSB	110
KARAMAN	KEPEZKAYA HAVZA	110
KONYA	AKŞEHİR	110
KONYA	ALİBEYHÖYÜĞÜ	110
KONYA	BEYŞEHİR	110
KONYA	CİHANBEYLİ	110
KONYA	ÇUMRA	110
KONYA	DEDELER	110

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
KONYA	GÜNEYSINIR	110
KONYA	KARAPINAR	110
KONYA	KARASINIR	110
KONYA	KONYA EREĞLİ	110
KONYA	KONYA I	110
KONYA	KONYA II	110
KONYA	KONYA III	110
KONYA	LADİK	110
KONYA	SEYDİŞEHİR	110
KONYA	YUNAK	110
KÜTAHYA	ALTINTAŞ	110
KÜTAHYA	SİMAV	110
KÜTAHYA	YENİGEDİZ	110
MANİSA	ALAŞEHİR	110
MANİSA	DEMİRCİ	110
MANİSA	DEMİRKÖPRÜ HES	110
MANİSA	SALİHLİ	110
MERSİN	AZMAK HES	110
MERSİN	BİRKAPILI HES	110
MERSİN	GEZENDE HES	110
MERSİN	GÖKSU HES	110
MERSİN	MERSİN RES	110
MUĞLA	AKKÖPRÜ	110
MUĞLA	DALAMAN	110
MUĞLA	EŞEN II HES	110
MUĞLA	FETHİYE	110
UŞAK	SÖNMEZ ENERJİ DGKÇS	110
UŞAK	UŞAK	110
UŞAK	UŞAK OSB	110
UŞAK	UŞAK RES	110
G.ANTEP	GAZİANTEP IV	111
G.ANTEP	KARKAMIŞ HES	111
KİLİS	KİLİS	111
Ş.URFA	AKÇAKALE	111
Ş.URFA	BİRECİK	111

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
Ş.URFA	BİRECİK HES	111
Ş.URFA	PEKMEZLİ	111
Ş.URFA	SURUÇ	111
Ş.URFA	ŞANLIURFA OSB	111
Ş.URFA	YARDIMCI	111
EDİRNE	EDİRNE	112
EDİRNE	EDİRNE ÇİMENTO	112
EDİRNE	HAVZA	112
EDİRNE	TCDD EDİRNE	112
EDİRNE	TCDD MANDIRA	112
KIRKLARELİ	ALTEK ALARKO KIRKLARELİ DGKÇS	112
KIRKLARELİ	BABAESKİ	112
KIRKLARELİ	HAMİTABAT DGKÇS	112
KIRKLARELİ	KIRKLARELİ	112
KIRKLARELİ	LÜLEBURGAZ	112
KIRKLARELİ	PINARHİSAR	112
KIRKLARELİ	TRAÇİM	112
MARDİN	ÇAĞ ÇAĞ HES	113
MARDİN	DİKMEN	113
MARDİN	ETİFOSFAT	113
MARDİN	KIZILTEPE	113
MARDİN	KIZILTEPE 380	113
MARDİN	MARDİN	113
MARDİN	NUSAYBİN (ÇAĞ ÇAĞ)	113
MARDİN	PS 4	113
SİİRT	ALKUMRU HES	113
SİİRT	DODAN	113
SİİRT	SİİRT	113
Ş.URFA	ÇIRÇIP	113
Ş.URFA	ELGÜN	113
Ş.URFA	KIRLIK	113
Ş.URFA	PS 4A	113
Ş.URFA	TELHAMUT	113
Ş.URFA	VİRANŞEHİR	113

Table 29. Transmission System Transformer Centers (continued)

City	Transformer Center	Area
ŞIRNAK	CİZRE	113
ŞIRNAK	KARKEY MOBİL SANTRALİ	113
ŞIRNAK	PS 3	113
ŞIRNAK	PS 3A	113
ŞIRNAK	SİLOPİ I F/O	113
ŞIRNAK	SİLOPİ II F/O	113
ŞIRNAK	SİLOPİ III F/O	113
ŞIRNAK	SİLOPİ IV F/O	113
ŞIRNAK	SİLOPİ V F/O	113
ŞIRNAK	ŞIRNAK	113
ŞIRNAK	ULUDERE	113
BALIKESİR	BANDIRMA II	114
BALIKESİR	BANDIRMA III	114
BALIKESİR	BANDIRMA RES	114
BALIKESİR	ERDEK	114
BALIKESİR	GÖBEL	114
BALIKESİR	KAPIDAĞ RES	114
BURSA	AKÇALAR	114
BURSA	EKİNLİ RES	114
BURSA	GÖRÜKLE	114
BURSA	KARACABEY	114
BURSA	MUSTAFA KEMAL PAŞA	114
AĞRI	DOĞUBEYAZIT - MAKO (İRAN)	115
ARTVİN	HOPA	115
HAKKARİ	İRAN-BAŞKALE	115
IĞDIR	IĞDIR (NAHÇIVAN-BABEK)	115
KARS	KARS-LENİNAKAN (ERMENİSTAN)	115
KIRKLARELİ	MARİTSA (BULGARİSTAN)	115
KIRKLARELİ	BABAESKİ- KEHROS	115
KIRKLARELİ	BABAESKİ -MARİTSA	115
ŞANLIURFA	BİRECİK HES -HALEP (SURİYE)	115
ŞIRNAK	IRAK (ZAKHO)-KARKEY MOBİL SANTRALİ	115