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Abbreviations

Abbreviations	Words (Original)
AC	Alternating Current
AGC	Automatic Generation Control
APK	Research Planning and Coordination
ASTM	American Society for Testing and Materials
ADUAS	Private Generation Company
AVR	Automatic Voltage Regulator
AZE	Alliance of Zero Extinction
B/C	Benefit by Cost
BO	Build Operate
BOT	Build Operate Transfer
BOTAS	Petroleum Pipeline Corporation
BROT	Build Rehabilitate Operate Transfer
BTU	British Thermal Unit
CAES	Compressed Air Energy Storage
CBD	Convention on Biodiversity
CBKPCL	CBK Power Company Ltd.
C/C	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CFRD	Concrete Face Rockfill Dam
CGD	Concrete Gravity Dam
CH4	Methane
CITES	Convention on International Trade in Endangered Species of Wild Fauna and Flora
CO2	Carbon Dioxide
C/P	Counterpart
CSR	Corporate Social Responsibility
DC	Direct Current
DD	Doga Dernegi
DE	Diesel Engine
DFR	Draft Final Report
DGP	Balancing Power Market
DO	Diesel Oil
DPT	State Planning Organization
DSI	General Directorate of State Hydraulic Works
DSM	Demand Side Management
DTS	Dispatcher Training Simulator
EBRD	European Bank for Reconstruction and Development
EEX	European Energy Exchange
EHSS	Extra High Strength
EIA	Environmental Impact Assessment
EIB	European Investment Bank
EIE	General Directorate of Electric Power Resources Survey and Development Administration
EMP	Environmental Management Plan
EMRA	Energy Market Regulatory Authority
EMS	Energy Management System
ENCC	Emergency National Control Center
ENPEP	Energy & Power Evaluation Program (Software name)
ENTSO-E	European Network of Transmission System Operators for Electricity
EOJ	Embassy of Japan

EPDK	Energy Market Regulatory Authority
ETKB	Ministry of Energy and Natural Resources
EU	Europe Union
EUAS	Electric Generation Company
FFC	Flat Frequency Control
FGD	Flue Gas Desulfurization
FOH	Forced Outage Hour
FR	Final Report
FS	Feasibility Study
GDP	Gross Domestic Product
G/H	Guest House
GHG	Greenhouse Gas
GME	Gestore dei Mercati Energetici S.p.A
GT	Gas Turbine
HES	Hydro Electric Station
HH	Household
HPP	Hydro Power Plant
HWL	High Water Level
IcR	Inception Report
IEA	International Energy Agency
IEE	Initial Environmental Examination
IMF	International Monetary Fund
IMPSA	Industrias Metalurgicas Pescarmona S.A.I.C.& F
IPP	Independent Power Producer
ItR	Interim Report
IUCN	International Association for Conservation of Nature
JEPX	Japan Electric Power Exchange
JICA	Japan International Cooperation Agency
KBA	Key Biodiversity Area
KCETAS	Kayseri Region Electricity Company
LDC	Load Dispatch Center
LOLE	Loss of Load Expectation
LOLP	Loss Of Load Probability
LWL	Low Water Level
MAED	Model for Analysis of Energy Demand
MCM	Million Circular Mil
MENR	Ministry of Energy and Natural Resources
MFSC	Market Financial Settlement Center
MOEF	Ministry of Environment and Forest
MOH	Maintenance Outage Hour
MP	Master Plan
MTA	General Directorate of Mineral Research & Exploration
N2O	Nitrous oxide
NA	Naphtha
NAS	Sodium-sulfur
NCC	National Control Center
NDP	National Development Plan
NGO	Non Governmental Organization
NLDC	National Load Dispatch Center
NOx	Nitrogen oxides
NPC	National Power Corporation
NPSH	Net positive suction head
NSO	Neutral System Organization

NWL	Normal Water Level
OECD	Organization for Economic Co-operation and Development
OIB	Privatization Administration
OJT	On the Job Training
O&M	Operation and Maintenance
PAP	Project-Affected People
PC	Personal Computer
PDF	Portable Document Format
PDP	Power Development Planning
PDPAT II	Power Development Planning Assist Tool (Software name)
PLC	Power Line Communication
PMUM	Market Financial Settlement Center
PP	Power Plant
PPA	Power Purchase Agreement
PPS	Power Producer and Supplier
P/S	Power Station
PSALM	Power Sector Assets & Liabilities Management Corporation
PSPP	Pumped Storage Power Plant
PSS	Power System Stabilizer
PSS/E	Power System Simulation for Engineering (Software name)
PV	Photovoltaic
PYS	Market Management System
RAP	Resettlement Action Plan
RCC	Regional Control Center
RE	Renewable Energy
REDA	Regional Electricity Distribution Company
RETICS	Reliability Evaluation Tool for Interconnected Systems (Software name)
RH	Reservoir Hydro
RTU	Remote Terminal Unit
RWE	RWE (Company name)
SCADA	Supervisory Control And Data Acquisition
SCC	Substation Control Center
SEO	Société Electrique de l'Our
SOx	Sulfur oxides
SPO	State Planning Organization
SPS	Special Protection System
SPV	Special Purpose Vehicle
S/S	Substation
ST	Steam Turbine
SVC	Static Var Compensator
SW	South West
S/W	Scope of Work
TAEK	Turkish Atomic Energy Authority
TBC	Tie-line Bias Control
TBM	Tunnel Boring Machine
TDP	Transmission Development Planning
TEAS	Turkish Electricity Generation and Transmission Company
TEDAS	Turkish Electricity Distribution Company
TEIAS	Turkish Electricity Transmission Corporation
TEK	Turkish Electricity Authority
TEPCO	Tokyo Electric Power Company, Inc
TEPSCO	Tokyo Electric Power Services Co., Ltd.
TETAS	Turkish Electricity Trading and Contracting Co.Inc.

TKI	Turkish Coal Enterprises
TL	Türk Lirası
TOOR (or TOR)	Transfer of Operating Right
TOR	Terms Of Reference
TOU	Time-of-Use
TPP	Thermal Power Plant
TSO	Transmission System Operator
TTK	Turkish Hardcoal Authority
UCTE	Union for the Coordination of Transmission of Electricity
UGPH	Under Ground Power House
UN	United Nations
US	United States
USC	United States Cent
USD	United States Dollar
WASP IV	Wien Automatic System Planning (Software name)
WESM	Wholesale Electricity Spot Market
WNW	West Northwest
WS	Workshop
XRD	X-Ray Diffraction

Abbreviations	Words (Original)	Words (Turkish)
APK	Research Planning and Coordination	Araştırma Planlama Koordinasyon
BOTAS	Petroleum Pipeline Corporation	Boru Hatları ile Petrol Taşıma A.Ş.
DPT	State Planning Organization	Devlet Planlama Teşkilatı Müsteşarlığı
DSI	General Directorate of State Hydraulic Works	Devlet Su İşleri
DGP	Balancing Power Market	Dengeleme Güç Piyasası
EIE	General Directorate of Electric Power Resources Survey and Development Administration	Elektrik Isleri Etüt Idaresi Genel Müdürlügü
ETKB	Ministry of Energy and Natural Resources	Enerji ve Tabii Kaynaklar Bakanl
EPDK	Energy Market Regulatory Authority	Enerji Piyasası Düzenleme Kurumu
EUAS	Electric Generation Company	Elektirik Üretim Anonim Şirketi
KCETAS	Kayseri Region Electricity Company	Kayseri ve Civari Elektrik T.A.S
MTA	General Directorate of Mineral Research & Exploration	Maden Tetkik ve Arama Genel Müdürlüğü
OIB	Privatization Administration	Özelleştirme İdaresi Başkanlığı
PMUM	Market Financial Settlement Center	Piyasa Mali Uzlastirma Merkezi
PYS	Market Management System	Piyasa Yönetim Sistemi
TAEK	Turkish Atomic Energy Authority	Türkiye Atom Enerjisi Kurumu
TEAS	Turkish Electricity Generation and Transmission Company	Türkiye Elektrik Anonim Şirketi
TEDAS	Turkish Electricity Distribution Company	Türkiye Elektrik Dağıtım Anonim Şirketi
TEIAS	Turkish Electricity Transmission Corporation	Türkiye Elektrik İşleri Anonim Şirketi
TEK	Turkish Electricity Authority	Türkiye Elektrik Kurumu
TETAS	Turkish Electricity Trading and Contracting Co.Inc.	Türkiye Elektrik Ticaret ve Taahhüt A.Ş.
TKI	Turkish Coal Enterprises	Türkiye Kömür İşletmeleri
TTK	Turkish Hardcoal Authority	Türkiye Taşkömürü Kurumu

Chapter 1 Introduction

1.1 Background of the Study

The Turkish government has shown a power development scenario in which the power consumption and the maximum power demand will annually increase by 7 % on average by 2015. Given such a steep increase in the demand and the generation capacity, number of construction plans, etc., it is projected that the country would be unable to cope with the peak demand by 2015. In line with such an increase in the power demand, the peak demand will also increase. Therefore, it is urgently required to carefully study an appropriate method for providing sufficient electricity during peak hours in the future.

For the supply of electricity during peak hours, pumped storage power generation is considered as the most appropriate method since it is capable of raising the output in short time and allows the surplus electricity during off-peak hours to be utilized if a certain level of base power source is secured. Pumped storage power generation requires advanced technologies not only in construction but also for operation due to its particularity. However, the Turkish government has no experience in constructing or operating a pumped storage power plant (PSPP). The Turkish government has a plan to proceed with PSPP development until around 2015, and has requested the Japanese government to provide support for their PSPP development since 2006.

1.2 Purpose of the Study and Implementation Details

1.2.1 Purpose of the Study

The purpose of the Study is to conduct the following operations in accordance with the designated schedule:

- Formulate an optimal power development plan designed to meet the peak demand growth (from 2010 to 2030).
- Review the development plan of pumped storage power projects (herein after referred to PSPPs) as a peak power supplier, which the Turkish side is currently studying.
- Transfer the technologies related to the above study to the counterpart.

1.2.2 Area in Which to Conduct the Study

This Study is to be conducted throughout Turkey.

1.2.3 Implementation Details (TOR)

This Study is made of roughly three operation elements. Summaries of the individual operation elements are shown in the following:

(1) Basic Investigation

The related data for analyzing the current status and the future planning of the electricity supply system in Turkey will be collected and analyzed. The power demand forecast method and the electricity system development planning conducted by the current implementing agencies will also be reviewed, and areas to be improved will be proposed as appropriate.

(2) Case Study of Possible Plans for Peak Power Sources to Meet the Peak Demand Growth (Including PSPP)

Pumped storage generation candidate sites which are independently investigated or extracted by the Turkish-side counterpart will be reviewed, while desk research will also be conducted by the Study Team to select development candidate sites. Priority projects will be ranked among all development candidate sites selected by the both parties, and concept designing including studies in Turkey for the extracted and optimal pumping sites will be made. Proposal will be made on investigation contents

regarding the development possibility to support a future independent study to be conducted by the Turkish side.

(3) Studying an Optimal Power Development Plan to Meet the Peak Demand

Based on the results from the two operation elements as described above, the optimal development size of measures will be proposed, such as by setting a long-term power development scenario taking into consideration the electricity supply during peak hours.

1.3 Study Implementation Policy

1.3.1 Scope of the Study Works

The Study will be conducted mainly on the following items in the respective years. This Study will be conducted over two fiscal years in accordance with S/W signed between the conducting organizations of the partner country and the Japan International Cooperation Agency on June 22, 2009.

Table 1. 1 Scope of the Study Operation

First year (fiscal 2009)	Second year (fiscal 2010)
STAGE 1: Basic investigation	STAGE 2: Case study of possible plans for peak power sources STAGE 3: Study on an optimal power development plan to meet the peak demand growth
· Preparation work in Japan · 1st study in Turkey · 1st work in Japan	· 2nd study in Turkey · 2nd work in Japan · 3rd study in Turkey · 3rd work in Japan · 4th study in Turkey · 4th work in Japan · Preparation/submission of final report in Japan

STAGE 1: Basic Investigation

a. Collecting, checking, and analyzing related data (Preparation work in Japan, 1st study in Turkey, and 1st work in Japan)
b. Reviewing and analyzing the power development plan (Preparation work in Japan, 1st study in Turkey, and 1st work in Japan)
c. Holding a 1st workshop (2nd study in Turkey)
d. Studying comparative advantages of the peaking power source (2nd study in Turkey and 2nd work in Japan)

STAGE 2: Case Study of Possible Plans for Peak Power Sources to Meet the Peak Demand Growth (Including PSPP)

a. Investigation of basic information (1st study in Turkey)
b. Selecting possible PSPP sites and narrowing down the list to priority sites (1st work in Japan and 2nd study in Turkey)
c. Conceptual design and proposal for a next-step investigation (3rd work in Japan and 4th study in Turkey)
d. Second and third workshops/seminars (2nd and 3rd study in Turkey)

STAGE 3: Studying an Optimal Power Development Plan to Meet the Peak Demand

a. Improving/sophisticating the works for formulating a long-term power demand and supply plan (2nd to 4th work in Japan and 2nd to 4th study in Turkey)
b. Setting a scenario for peak power demand and supply and studying optimization (2nd to 4th work in Japan and 3rd and 4th study in Turkey)

1.3.2 Formulation of a Plan for Developing a Power Source

Figure 1. 1 shows an investigation flow for formulating a plan for developing a power source designed to cope with the peak demand (for the period between 2010 and 2030) based on the Turkish national energy policy and power source development plan.

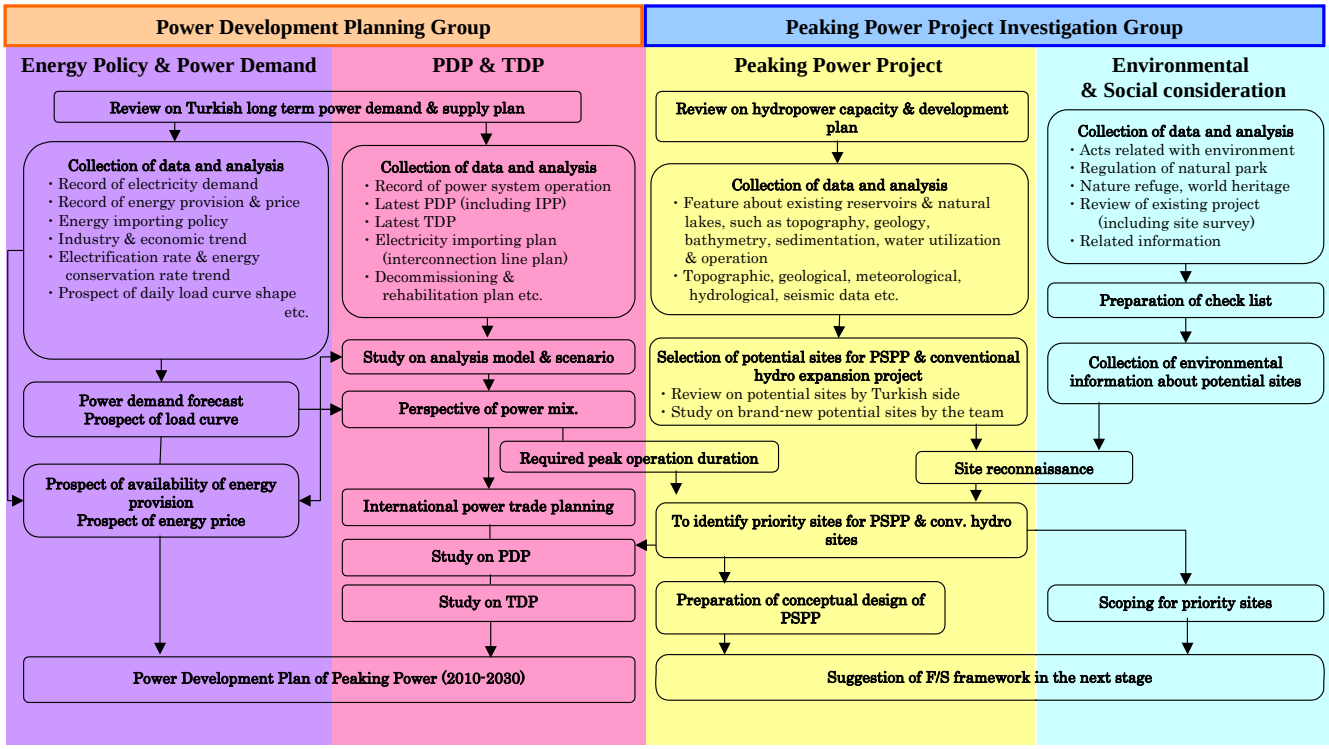


Figure 1. 1 Outline of Investigation Flow

1.4 Study Organization and Study Achievements

1.4.1 Conducting Organizations of the Partner Country

- Turkish Electricity Transmission Co.: hereinafter referred to as “TEIAS”
- General Directorate of Electric Power Resources Survey and Development Administration: hereinafter referred to as “EIE”

1.4.2 Composition of Study Group and Their Study Schedule

This Study will be executed with the members and system as shown in Figure 1. 2.

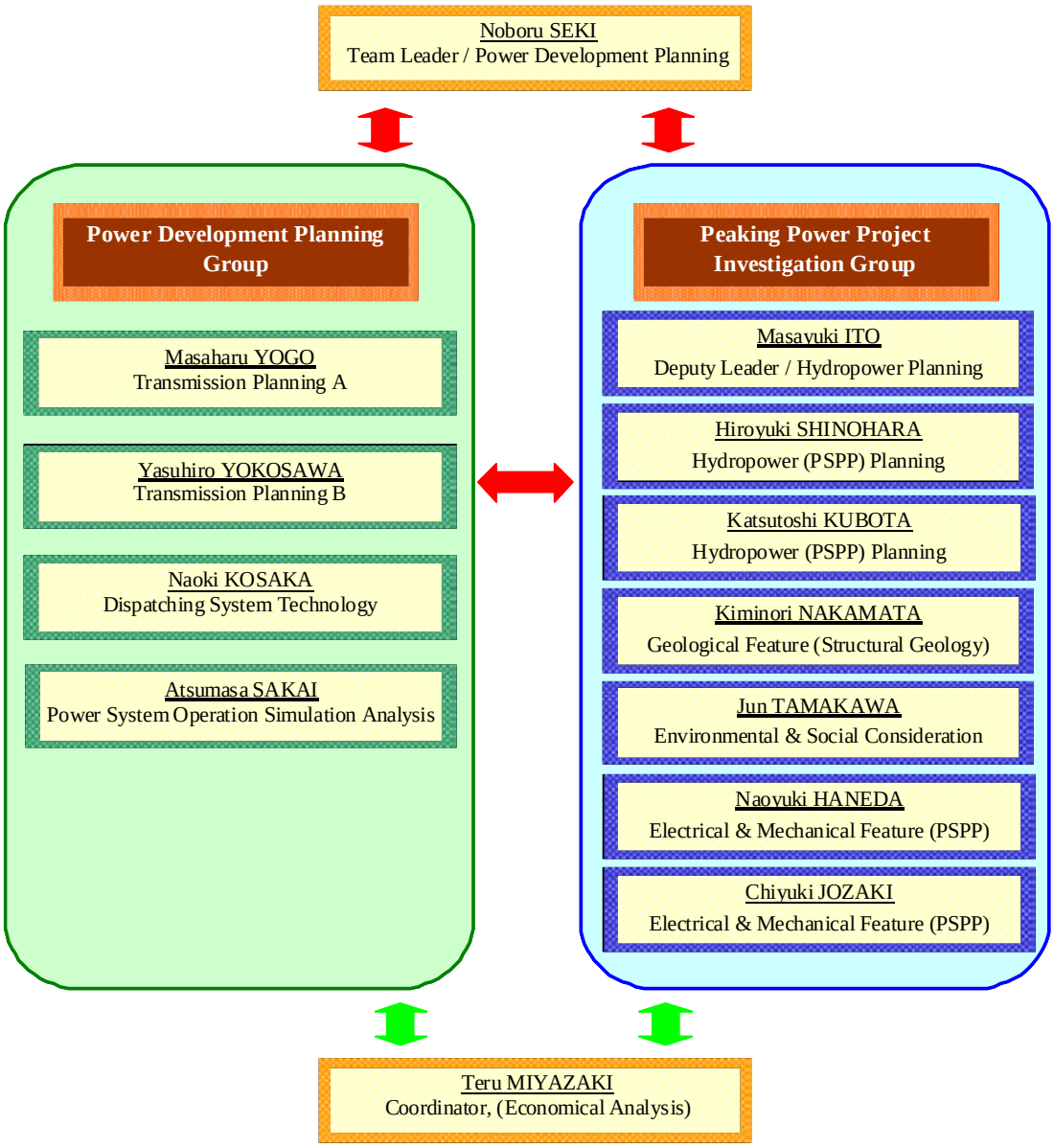


Figure 1. 2 Organization of Study Team

Note that Naoyuki HANEDA and Chiyuki JOZAKI have been participating since the second year as an Electrical & Mechanical (PSPP) specialist. Katsutoshi KUBOTA has also been participating since the second year as Hydropower (PSPP) specialist.

1.4.3 Study Achievements

The first study in Turkey was conducted in February 2010.

The first steering committee was held.

1) The inception report was briefed and discussed.
2) Related data were confirmed and evaluated.
3) Peak power optimization was preliminarily studied.
   ① Power development planning was reviewed and analyzed.
   ② Data for demand and supply operation simulation were collected and formulated.
4) Selection criteria for development candidate sites for pumped storage generation were set.
5) Development candidate sites for pumped storage generation were selected.
   ① Collection of basic information (on geography, geology, and environment)

② Review of candidate sites for pumped storage generation planned by the Turkish side

The second study in Turkey was conducted in May and June 2010.

The second steering committee was held.

1) Peak power optimization was studied.
   ① Demand and supply operation simulation was implemented (basic case).
   ② The system analysis was implemented.
2) Development candidate sites for pumped storage generation were selected.
   ① Candidate sites for new pumped storage generation were selected.
   ② Candidate sites for pumped storage generation were studied in Turkey, and prosperous candidate sites were narrowed down.
   ③ Geographical information on priority projects was acquired.
3) The first workshop was held.
4) Training on power development planning and basic technologies for pumping was conducted.
5) Seminar on power development planning and basic technologies for pumping was conducted.

The third study in Turkey was conducted in August and September 2010.

The third steering committee was held.

1) The contents of Interim Report on the study were discussed.
2) Development candidate sites for pumped storage generation were selected.
   ① The results of candidate site survey for new pumped storage generation were explained.
   ② The results of site survey for expanding existing power plant were explained.
3) The second workshop was held.
   ① Long-term supply/demand plan
   ② Evaluation of PSPP in terms of power system operation
   ③ Selection and evaluation of potential sites of PSPP
   ④ Geological investigation for PSPP
   ⑤ Methodology of cost estimation
   ⑥ Environmental and social considerations
4) Training on power development planning and basic technologies for pumping was conducted.

The forth study in Turkey was conducted in November and December 2010.

The forth steering committee was held.

1) The contents of Draft Final Report on the study were explained and discussed.
2) The third workshop for PDP was held.
   ① Long-term Power Development Planning (2011-2030)
   ② Feasibility of Extension Plan of Existing Reservoir Type Hydropower Plant
   ③ PSPP Operation Scheme in Europe
   ④ Ownership and Contract Condition of PSPP
3) The third workshop for PSPP was held
   ① Outline of Priority PSPPs, Altınkaya PSPP and Gökçekaya PSPP
   ② Topographic and geologic feature of the Priority PSPP sites
   ③ Results of Initial Environmental Examination
   ④ Conceptual Design (Civil structures of Priority PSPPs)
   ⑤ Conceptual Design of Priority PSPPs (Electrical & Mechanical Equipment)
   ⑥ Proposal and Recommendation of Further Step

Chapter 2 Energy Sector and Electricity Sector

2.1 Energy Sector

2.1.1 Energy Policy

The Turkish government published the ninth national development plan (2007-2013) (hereinafter "the NDP") and laid out the basic policy and visions for development with strong growth, fair redistribution of income, and strengthening of international competitiveness to shift to an information-oriented society and complete assimilation into the EU society. The target for the energy sector in the NDP is to supply the required energy stably for Turkey's economical growth at minimum cost through the diversification of fuel and its suppliers and the reduction of public expenditures by privatization of the national generating and distribution companies. Environmental consideration for the limitation of environmental impact in the energy development is also mentioned in NDP

The Turkish government also published quarterly and annual action plans for the NDP, and the focus in energy sector for 2010 is on the energy security through diversification of the fuel portfolio. Since Turkey presently depends on imported natural gas for nearly half of its fuel for electric power generation, Turkey will face problems of uncontrolled electricity costs and the increase of payment in foreign currency in the future. To improve the situation, Turkey gives priority to energy security and makes decisions on active utilization of the renewable energy and domestic primary energy (lignite) resources, and the development of nuclear power. For the utilization of renewable energy, the "Law on utilization of Renewable Energy Resources for the Purpose of generating Electrical Energy (law no. 5346)" became effective and electricity generation from wind and geothermal increased by 70% in the last year (2009). The Turkish government also recently made an agreement with the Russian government regarding the construction of a 4,800 MW nuclear power plant and its PPA.

The policy and action plan for the power sector is announced with specific numerical targets, in "Electricity Energy Market and Supply Security Strategy Paper" by the State Planning Organization, which is the revised paper of "Electricity Sector Reform and Privatization Strategy Paper" published in 2004. Numerical targets for the best mix of fuel portfolio and utilization of domestic fuel in the strategy paper are as follows:

- It is targeted for the share of nuclear power plants in electricity energy to increase up to at least 5% by the year 2020. To realize that, it is planned to install nuclear power stations, total capacity of 5,000 MW, by 2020, and Akkuyu/Mersin are mentioned as the candidate sites.
- Target of the share of renewable resources in electricity energy is to increase up to at least 30% by 2023. Especially, the installed capacity of wind energy power is targeted to increase to 20,000 MW, which is a half of the present total installed capacity in Turkey.
- Through measures for utilization of domestic and renewable resources, the share of natural gas in electricity generation will be reduced to below 30%.
- Proven lignite deposits and hard coal resources will be put to use by 2023 in electricity energy generation activities. To that end, efforts will continue for making good use of exploitable domestic lignite and hard coal fields in electricity generation projects.
- Power plants based on high-quality imported coal will also be made use of, taking into consideration supply security and developments in utilization of such resources.

2.1.2 Energy Demand and Supply Status

The status of production, import, and export of fossil fuels (coal, oil, gas) in 2007 is shown in Table 2. 1.

Table 2. 1 Status of Production, Import, and Export of Fossil Fuels in 2007

Unit: ktoe (kiloton of oil equivalent)

	Coal and Peat	Crude Oil + Petroleum Products	Gas
Production	14,794	2,109	735
Import	14,640	37,621	29,784
Export	0	-6,094	-26
Stock changes, etc.	-48	-2,933	-79
Total	29,385	30,703	30,415

Source: Created by the Study Team based on the IEA data

The three types of fossil fuels are used in almost equal amounts. Although half of the coal consumed is produced in Turkey, the domestic production amounts of oil and gas account for 10% or less of their respective consumption amounts. In this way, Turkey relies on import for most of the energy resources.

Although domestic resources, namely hydropower (3,083 ktoe), geothermal (1,498 ktoe), and renewable energy (5,055 ktoe), are also produced in Turkey, the total production amount of these resources, that is, approx. 9,600 ktoe, accounts for only 10% of the total domestic energy consumption.

The use status of fossil fuels (coal, oil, gas) in 2007 is shown in Table 2. 2.

Table 2. 2 Status of Use of Fossil Fuels in 2007

Unit: ktoe (kiloton of oil equivalent)

	Coal and Peat		Crude Oil + Petroleum Products		Gas	
	ktoe	%	ktoe	%	ktoe	%
Electricity Plant	13,119	44.6	1,152	3.8	13,931	45.8
CHP Plant	183	0.6	264	0.9	1,876	6.2
Industry	11,229	38.2	1,419	4.6	3,717	12.2
Transport	0	0	15,692	51.1	167	0.5
Residential	2,750	9.4	1,745	5.7	6,901	22.7
Commercial	0	0	0	0	3,066	10.1
Non-Energy Use	0	0	5,634	18.3	203	0.7
Others	2,105	7.2	4,796	15.6	556	1.8
Total	29,385	100	30,703	100	30,415	100

Source: Created by the Study Team based on the IEA data

Though about half of each of coal and gas is consumed for electricity, more than half of the oil is used for transportation, and electricity accounts for about 4%.

2.1.3 Situations Surrounding Energy

(1) Natural gas

Gas is exclusively sold by a governmental institution, BOTAS. A power purchase agreement has been made between BOTAS and EUAS for gas to be used by thermal power plants owned by EUAS. Private power generators purchase natural gas from regional gas distribution companies. These gas distribution companies are then supplied with gas from BOTAS, while they are selling the gas to general customers including private power generators after charging a certain commission (e.g., 15%).

(2) Coal

TKI conducts sales operations for lignite and TTK for hard coal. On top of that, EUAS, which owns the interest of Afsin-Elbistan lignite mine, mines by itself and supplies lignite to its own power plants.

(3) Oil

Although not much oil is used for electricity, EUAS procures oil from the general market.

(4) Nuclear

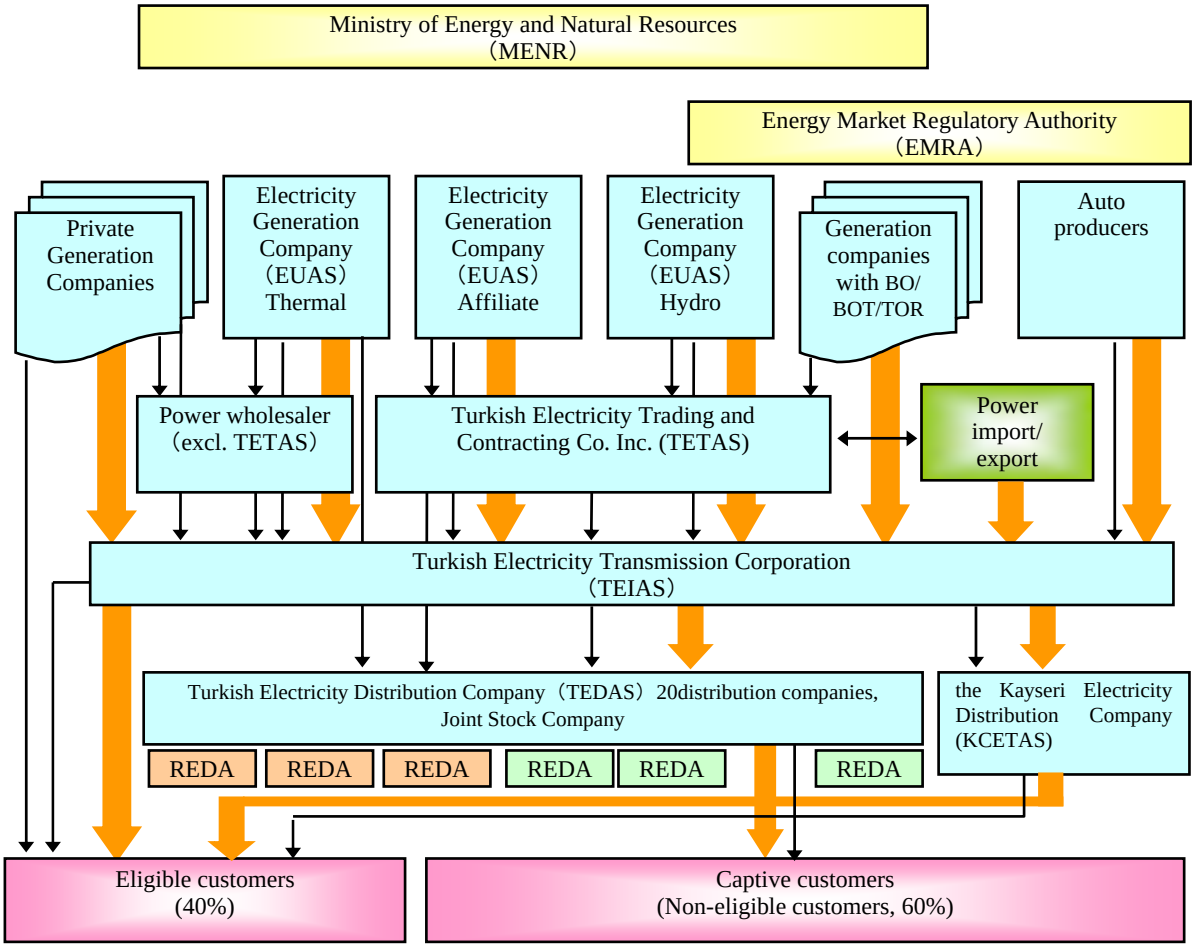
The Turkish Atomic Energy Authority (TAEK) solicited a bid for Unit No. 1 nuclear power plant operation in September 2008, and a consortium between Russian nuclear construction and export company Atomstroyexport and Turkish enterprises bids for that. TAEK completed technical examination in December 2008, and Turkish Electricity Trade and Contracting Company (TETAS) is currently (as of February 2009) examining the wholesale electricity prices of the power plant. The power plant is planned to be built near Mersin along the Mediterranean Sea (at Akkuyu), with the total installed capacity of 4800 MW of the four units.

Apart from this project, Korea Electric Power Corp. is planning development for 4,000 MW (pressurized water reactor: type APR 1400) in Sinop along Black Sea in the north.

2.2 Electricity Sector

2.2.1 Institutional Arrangement and Sector Overview

This subsection summarizes the institutional arrangement of Turkey's power industry. The arrangement is in transition because of the sector reform started in 1994 and accelerated by Electricity Market Law (No. 4628) in 2001. The former government entity Turkish Electricity Authority (TEK) has been divided into entities in accordance with electricity supply stages, namely generation, transmission, and distribution stages. While its transmission business continues to be run by the state, its generation and distribution businesses are planned to be privatized. Figure 2. 1 shows the institutional arrangement as of the end of 2008.



Legend: Orange arrow: physical power flow, Black arrow: traded power flow. REDA stands for regional distribution companies.

Note: Currently, the customers with their annual electricity consumption with and over 0.1 GWh, set by EMRA, or those who are directly connected to the transmission system are qualified as eligible customers as of 2010, the ones who have the right to choose their own electricity supplier.

Figure 2. 1 The Institutional Arrangement of Turkish Power Sector

The major government organizations are the Ministry of Energy and Natural Resources (MENR) and the Energy Market Regulatory Authority (EMRA). MENR is responsible for general matters related to energy including electricity industry, while EMRA is in charge of the energy industry's regulatory matters. EMRA issues six types of licenses for electricity business: generation, transmission, distribution, wholesale, retail, and auto production (generation of electricity for own needs).

For the power business entities, transmission business is operated by the state-owned monopoly Turkish Electricity Transmission Corporation (TEIAS), while generation market is a liberalized competitive market. TEIAS owns assets related to electricity transmission activities. National Load Dispatch Center and Market Financial Settlement Center (MFSC) are created within TEIAS' organization. MFSC is the market operator and is planned to be independent from TEIAS in future.

Electric Generation Company (EUAS), the state generation company, owns and operates publicly owned hydropower plants (HPPs) and thermal power plants (TPPs). The company is supposed not to develop new power plants, except the case required due to electricity supply security.

The unique state-owned company is TETAS (Turkish Electricity Trading and Contracting Co. Inc.). The company is established to carry out wholesale activities specifically with generators constructed

under the build-operate (BO) and build-operate-transfer (BOT) models and those operated under the transfer of operating rights (TOOR) model. The company has taken over the power purchase contracts by public with the above-mentioned generators. TETAS also purchases electricity from EUAS and sells the electricity to the state distribution company, Turkish Electricity Distribution Company (TEDAS), through a purchase agreement. Besides the above main role, TETAS deals with electricity trading business with neighboring countries, which is allowed under the wholesale license. Further, in accordance with the MENR's energy policies to decrease the dependency on foreign energy resources for electricity generation, TETAS has been assigned the duty to purchase electricity generated by the nuclear power plants and by the lignite-fueled Afsin C and D power plants.

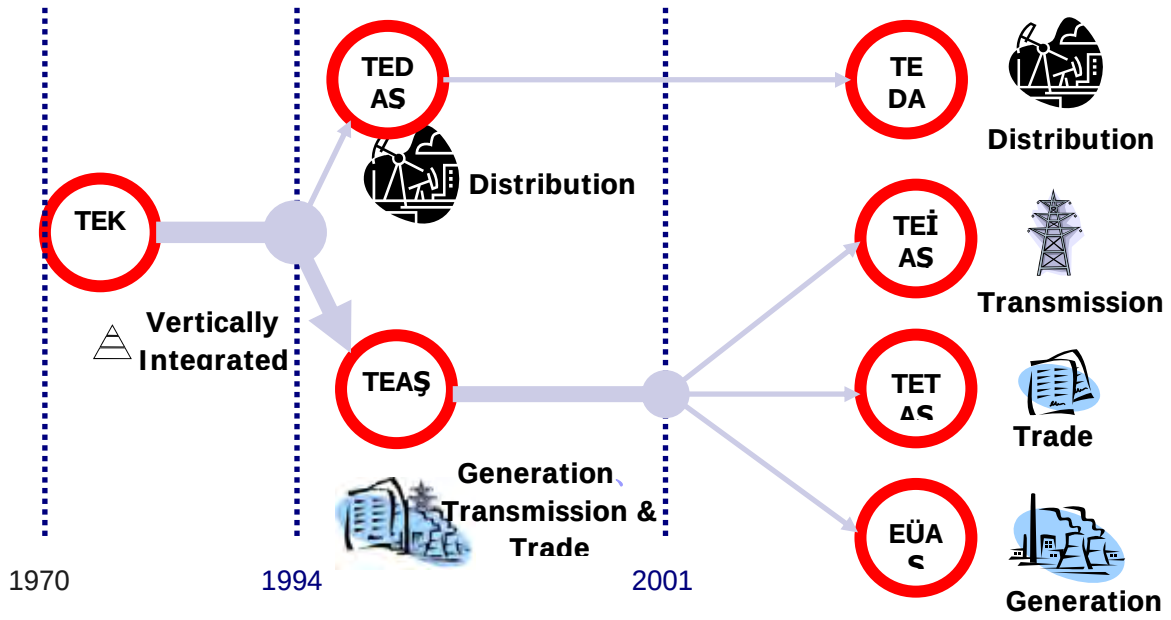
Distribution business is operated by 21 regional monopolies. Currently most of them are under a joint-stock company, TEDAS, a state-owned enterprise, while the others are privatized. With the government's plan, all the distribution companies are to be privatized under TOOR scheme. Around 40% of electricity retail market is deregulated. The customers with annual electricity consumption over 0.1 GWh are qualified as eligible customers (as of June 2010). By 2012, customers except residential customers are planned to be deregulated. During the transition period between 2006 and 2010 (recently extended to 2012), the distribution companies need to purchase 85% of electricity for non-eligible customers from TETAS and EUAS. After the transition period, the distribution companies will be able to select sources to procure electricity.

Table 2. 3 and Figure 2. 2 summarize the liberalization progress of Turkish electricity industry.

Table 2. 3 Liberalization Progress of Turkish Electricity Industry

1970	The establishment of TEK (Turkish electricity Authority), which was a publicly owned and vertically integrated statutory monopoly
1984	1st movement of market liberalization with the Law No: 3096 (Transfer of Operating Rights). The private sector participation to the power market has been permitted. 2 different laws, Law No: 3996 (Build Operate-Transfer) in 1994 and Law No: 4283 (Build Own Operate) in 1997, followed the law.
1994	TEK was divided into two state-owned enterprises; Turkish Electricity Generation-Transmission Corporation (TEAŞ) and Turkish Electricity Distribution Company (TEDAS).
2001	2nd movement: With the Law No:4628; Electricity Market Law, liberalization was initiated. TEAS was unbundled into three companies responsible for different sub-sectors, namely EÜAS (generation), TEIAŞ (transmission) and TETAŞ (wholesale). Around 30 % of the electricity retail market has been open to competition. An independent regulatory body, EMRA, has been established.
2004	"The Strategy Paper concerning Electricity Market Reform & Privatization" has been issued: • State-owned distribution companies and generation companies are to be privatized by 2012. • Privatization Administration is in charge of privatization activities. ➢ Privatization of distribution sector is to start in 2005. ➢ Privatization of generation sector is to start in 2006.
2006	The Balancing & Settlement System started. The Market Financial Settlement Center (MFSC or PMUM) by TEIAS
2009	Day Ahead Market and Privatization of Distribution started. The strategy paper of 2004 has been updated as "Electricity Energy Market and Supply Security Strategy Paper."

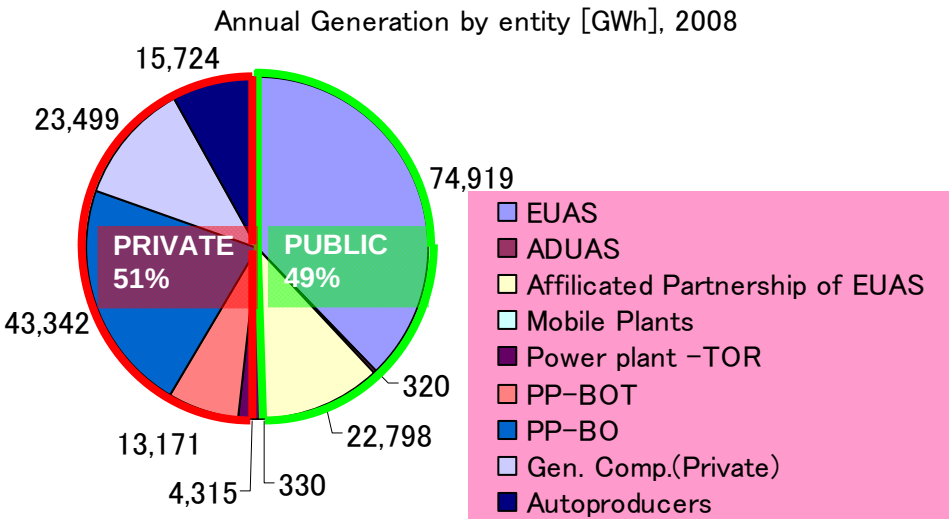
Source: Developed by the Study Team based on the following materials: the website of Privatization Administration; "Energy Policies of IEA Countries: Turkey 2005 Review" by IEA; and "Privatization of Turkey's Electricity Distribution Industry" Privatization Administration, Mar. 2009)



Note: The privatization of EUAS' plants would result in its market share decrease from 60% to 20% in terms of installed capacity.

Figure 2. 2 Step of Liberalization

Figure 2. 3 shows the current generation market share by entity.



Source: "Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018)", June 2009, by TEIAS.

Figure 2. 3 Annual Power Generation by Entity

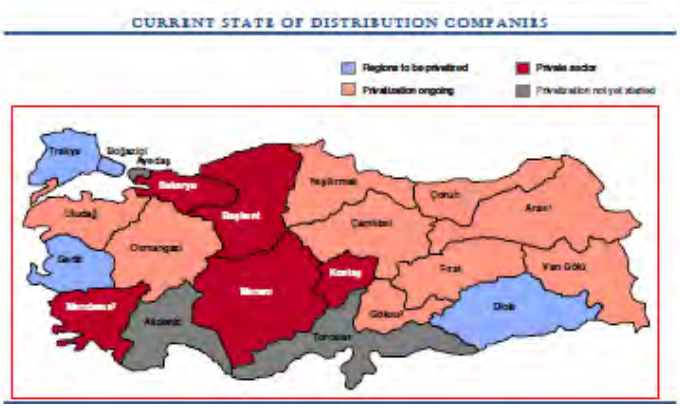
Table 2. 4 shows the expansion of liberalized market in Turkey.

Table 2. 4 The Share of Eligible Customers.

Annual Electricity consumption [GWh]	Valid date	Share of total market
9.9 <	2003	-
7.8 <	2004.Jan.27	28%
7.7 <	2005.Jan.27	30%
6.0 <	2006.Jan.25	32%
3.0 <	2007. Jan.25	38%
1.2 <	2008.Jan.24	-
0.1 <	(as of June 2010)	-

Source: "Privatization of distribution companies in Turkey (Toruko haiden jigyo no mineika)", Kaigai Denryoku 2008.6. referring to EMRA's annual report.

Figure 2. 4 shows the privatization progress of regional distribution companies.



: Regions to be privatized, Private sector,
: Privatization ongoing, Privatization not yet started.

(Source: "Privatization of Turkey's Electricity Distribution Industry" Privatization Administration, Mar.2009)

Figure 2. 4 Privatization Progress of Distribution Companies

2.2.2 Electricity Tariff System

The current Turkish electricity tariff system is classified into the following four categories:

(1) Wholesale tariff
  a. Wholesale tariff through bilateral contract (regulated)
  b. Wholesale tariff through PMUM (power exchange)
  c. Wholesale tariff among EUAS, TETAS, and TEDAS during transition period (regulated)

(2) Transmission tariff (regulated)
(3) End-user tariff (regulated)
(4) Import/export tariff: based on negotiation between TETAS and neighboring countries.

(1) Wholesale

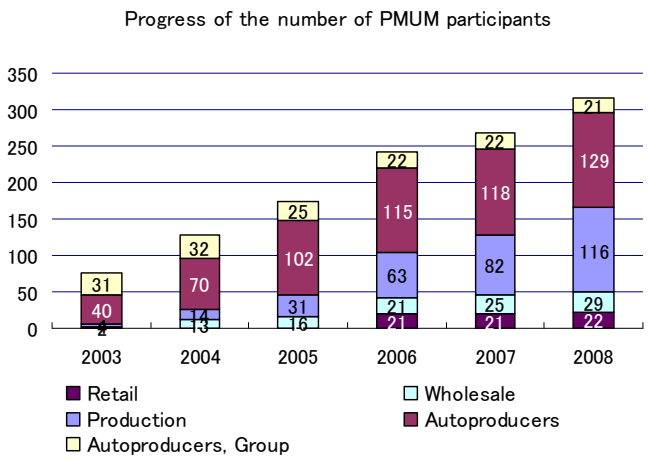
Wholesale tariff through bilateral contract as well as the one through power exchange, MFSC (or PMUM), is set through bilateral negotiation. The wholesale tariff between private power generation

companies and TETAS varies in accordance with the prices agreed upon in the previous power purchasing arrangements under the BO, BOT, and TOOR models. The prices are set generally higher than the other wholesale tariffs, though they have declined close to Turkey's average wholesale tariff level. The average purchased and sold electricity prices by TETAS in 2008 were US cents 8.88 per kWh and US cents 8.53 per kWh, respectively. The TETAS' wholesale tariffs toward distribution companies including TEDAS are published on EMRA's website. The tariffs toward consumers directly connected to the transmission system are also published on the same website. There, the tariffs are categorized by customer group and by region.

[The Structure of Turkish Electricity Market]

There are two types of electricity markets in Turkey. One is the market based on bilateral contracts mainly among generation companies, distribution companies, and eligible customers, and the other is the market through power exchange called MFSC (or PMUM) which is operated by TEIAS. The ratio of traded electricity amount is 8 for the former to 2 for the latter currently. Both can be said as liberalized market because traded prices can be determined based on market principle.

The bilateral contracts have been made between EUAS and TETAS, between TETAS and TEDAS, and between private generation companies and privatized distribution companies/eligible customers. Most of the players in power exchange are private power companies and distribution companies. This situation has resulted from the fact that the average wholesale tariff at which generation companies sell to distribution companies through bilateral contracts is regulated, i.e. capped by EMRA, and the tariff is generally lower than the traded prices in PMUM. Because the Turkish government does not intend to make additional power purchase agreements with private power generation companies, the share of electricity traded in PMUM is estimated to increase. Figure 2. 5 shows the growth of the number of PMUM participants.



Source: TEIAS annual report 2008.

Figure 2. 5 The Number of PMUM Participants by License Type

(2) Transmission charge

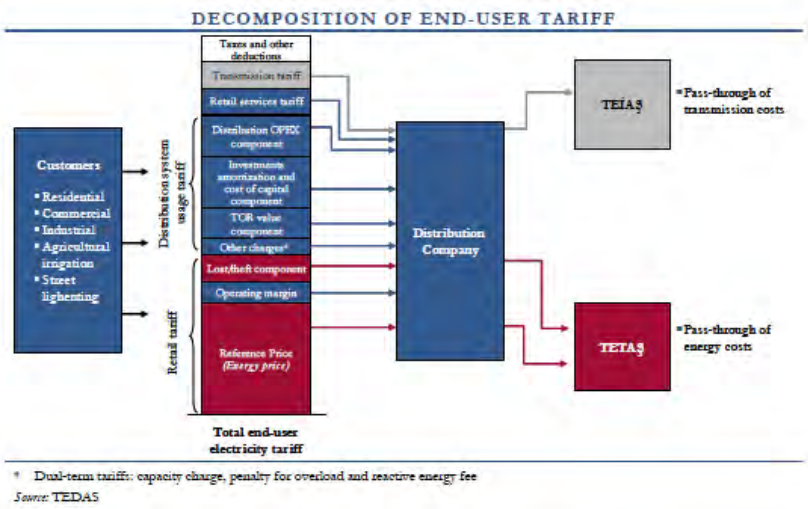
In Turkey's electricity market, TEIAS operates and owns the power system composed of transmission lines and substations. Therefore, distribution companies pay the access fee or transmission charge to TEIAS. The transmission charge differs among 22 regions of the country. The charge consists of two parts: use of system tariff and system operation tariff.

(3) End-user tariff system

Deregulated eligible consumers can either keep regulated tariffs or switch to deregulated tariff agreed upon with private generation generators. Non-eligible customers keep regulated tariffs. The tariffs shall be kept uniform during the transitional period, and are calculated by a so-called "price equalization mechanism."

The end-user tariff is composed of four components: retail sales tariff, transmission tariff, retail services tariff, and distribution tariff.

Figure 2. 6 summarizes the decomposition of end-user tariff.



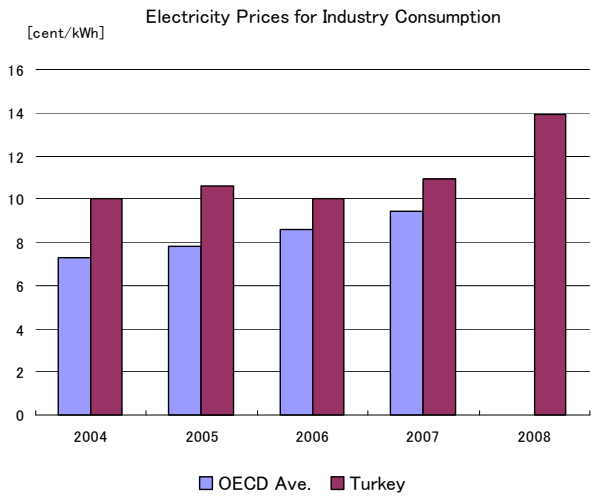
Source: TEASER: Privatization of Turkey's Electricity Distribution Industry, 2005, Lazard, Privatization Administration

Figure 2. 6 Decomposition of End-user Tariff

Retail services tariff differs between TEDAS on behalf of not-yet-privatized regional distribution companies and privatized regional distribution companies. The tariff structure varies by customer category, such as industry customers and residential customers. While two-term tariff is prepared for some customer groups, single-term tariff is prepared for most customer groups like residential customers. Customers can also choose TOU (time-of-use) rate.

Likewise, distribution tariff differs between TEDAS and privatized regional distribution companies.

The Turkish average retail electricity tariff level for industry is higher than that of OECD countries (Figure 2. 7).



Source: "2010 Annual Programme" Undersecretariat of State Planning Organization, 2010

Figure 2. 7 Comparison of Turkey's Retail Tariff with Those of OECD Countries

2.2.3 Role of Key Entities

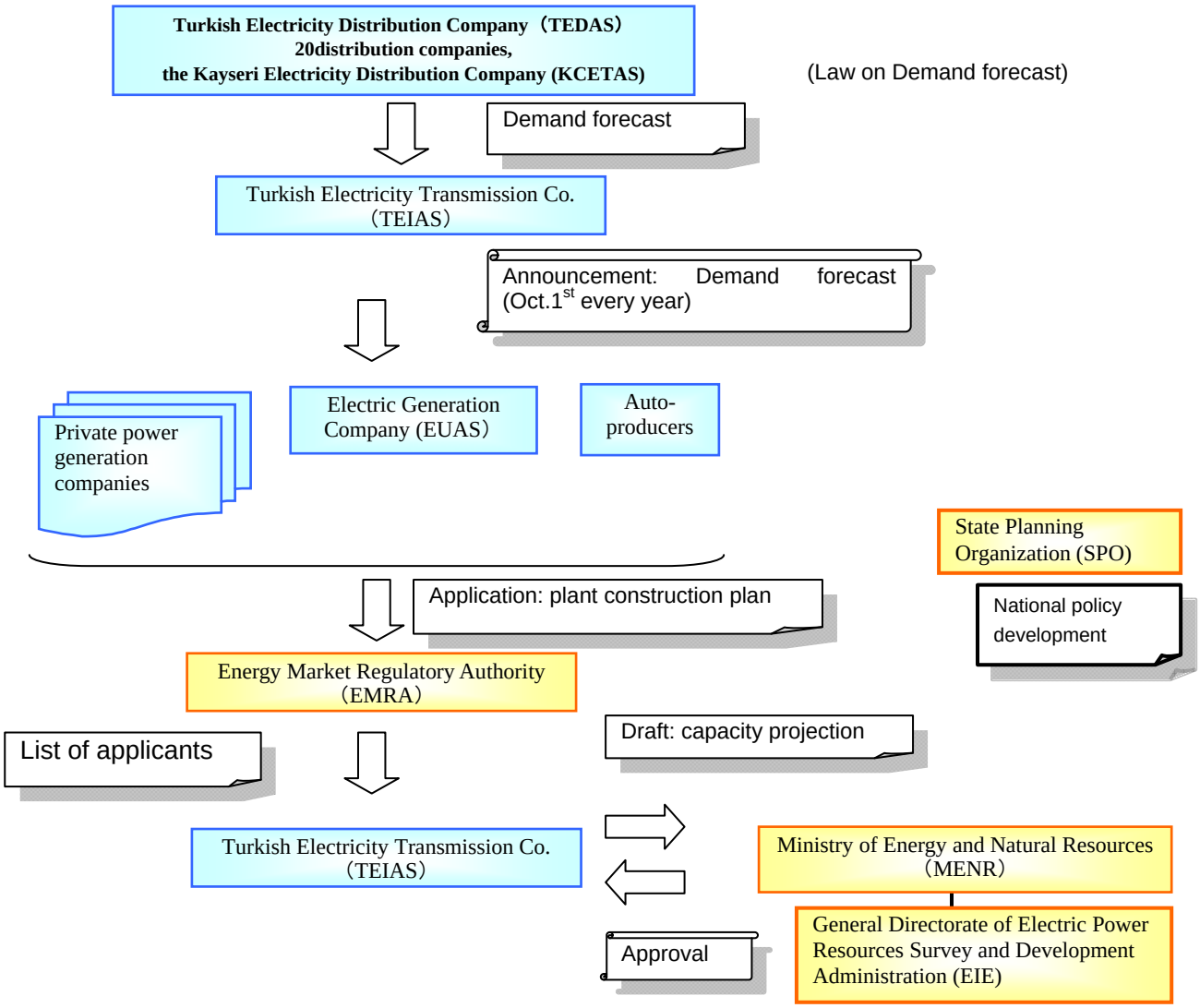
(1) The formulation of power development plan

a. Overview

Similar to "System Adequacy Forecast" of ENTSO-E, the European grid organization, TEIAS annually develops Turkey's 10-Year generation capacity projection. The projection does not necessarily secure future power supply.

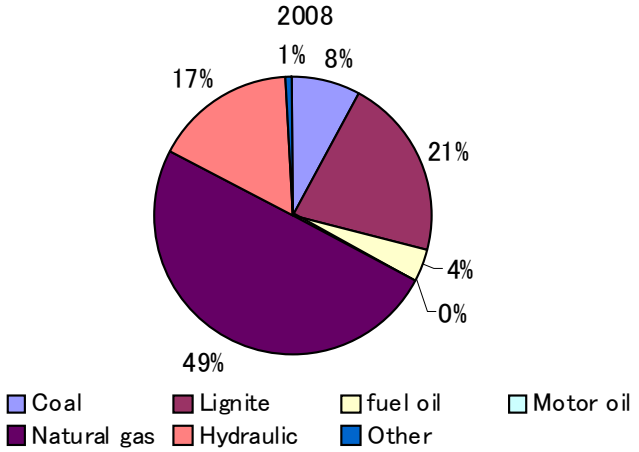
Electricity demand forecast to be used in the projection is supposed to be prepared by distribution companies, though the forecast is still prepared by the Ministry of Energy and Natural Resources (MENR) due to the transitional period.

For the existing generation system, TEIAS obtains data mainly from EUAS, TETAS, and EMRA. EMRA collects the data of private power companies, including their construction plans. For the newly developed generation system, the data are obtained mainly from DSI (State Hydraulic Works) in addition to the above entities. Figure 2. 8 shows the formulation process of power development planning in Turkey.



Source: 10-year Generation Capacity Projection: 2009-2018, TEIAS

Figure 2. 8 Formulation Process of Power Development Planning



Note: Other: Geothermal, wind, liquid sulfur, wood wastes, etc.
Source: "Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018)", June 2009, by TEIAS; Turkey in statistics 2009, referring to TETC Electricity Generation - transmission Statistics of Turkey.

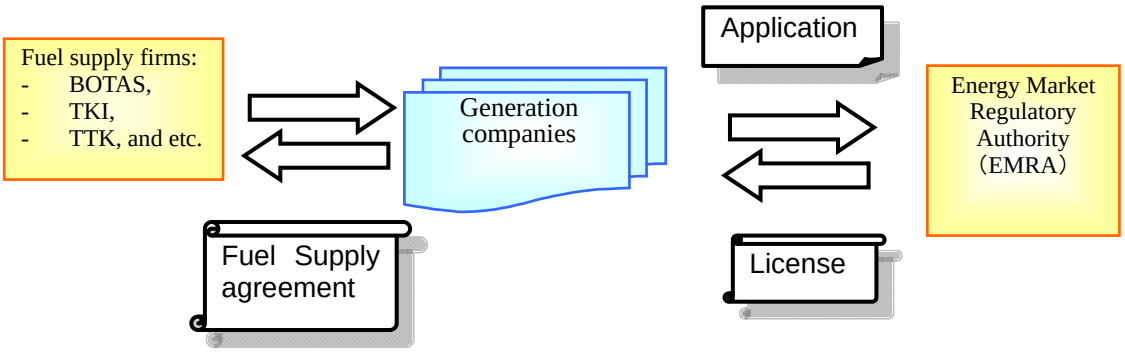
Figure 2. 9 Power Generation by Primary Resource

Before the enforcement of the Electricity Market Law, General Directorate of Electric Power Resources Survey and Development Administration (EIE) had conducted feasibility studies of planned power plants. Consequently, engineering and construction activities had been implemented by DSI for dams and by EUAS for power generation facilities. Currently, neither EIE nor DSI is engaged in new power development projects because such activities by state-owned-enterprises are not allowed now. Instead, private enterprises submit application for power development to MENR. EIE assists the ministry's evaluation of those applications. DSI has been engaged in activities related to the construction of dams whose purpose excludes power generation

State Planning Organization (SPO) is responsible for national policy development. Regarding the organization's involvement in energy sector, SPO has participated in the development of the country's long-term energy policy. For example, the country's Ninth Development Plan 2007-2013 proposes the diversification of energy resource types in order to secure stable energy supply. SPO also assists MENR to develop "Electricity Energy Market and Supply Security Strategy Paper. (2009)," proposing further use of domestic primary energy resources.

(2) Power plant development

In accordance with the national liberalization policy, public sector organizations such as EUAS, DSI, and EIE do not have a future plan to construct a new large-scale hydropower plant except in an emergency case. Only hydropower plants with installed capacity of less than 100 MW are planned, mainly led by EIE. Investors from private sector who are interested in power plant development are to submit their applications to EMRA. It is not allowed to develop power plants with schemes such as Build, Operate (BO)/Build, Operate, Transfer (BOT)/Transfer of Operating Right (TOOR) any longer.



Source: Developed by the Study Team based on the interview with EMRA and TEIAS

Figure 2. 10 Application Process of Power Plant Development

The maximum construction period is not clearly stated in existing law and regulation, though standard construction period is described in a relevant document of Electricity Market Licensing Regulation's Article 10. According to the document "Reference periods of regarding the completion of the generation plant (Board Decree 1855/20.11.2008)," the standard preparation period prior to construction period for coal-fired thermal power plants (including lignite) and reservoir-type hydropower plants is 24 months, while that for other type of plants is 16 months.

The period of construction itself varies by fuel type and the installed unit's capacity. For example, in case of thermal power plants with combined-cycle system, the standard construction period is 32 months for plants with installed capacity of less than 50 MW, while the period is extended to 48 months for those with capacity of more than 500 MW. In case of reservoir-type hydropower plants, the period is 36 months for plants with its reservoir capacity of less than 1,000,000 m^3, while the period is extended to 66 months for those with the capacity of over 10,000,000 m^3. Likewise, in the case of wind power generation, the construction period is 16 months for plants of installed capacity of less than 10 MW, while the period is extended to 40 months for those of over 100 MW. The total period from license issuance to the commission of the plant is the sum of the preparation period and the construction period. In principle, if licensees fail to keep the standard period, their license will expire unless EMRA Board accepts the excuses for the extension.

2.2.4 Power Demand and Supply

(1) Electric power demand

When Turkey's power consumption is compared with those of EU countries, Germany consumes the most, followed by U.K., France, Italy, Spain, and then Turkey. On the other hand, electric energy consumption per capita is 2,217 kWh in Turkey, while it amounts to 6,602 kWh as the EU average, as of 2008.

Turkey's gross consumption (generated energy + imported energy - exported energy) in 2007 increased by 8.8% over the previous year to 190 TWh, and by 4.2% to reach 198.1 TWh in 2008. Out of this, the net consumption (including transmission and distribution loss and stolen power) was 155.1 TWh in 2007 and 161.9 TWh in 2008.

Table 2. 5 Breakdown of Net Consumption in 2008

Unit: TWh

	Electric energy	Total
Generate	198.4	
Import	0.8	
		199.2
Export	-1.1	
(Gross consumption)		198.1
In-house used	-8.7	
Transmission loss	-4.4	
Distribution loss	-23.1	
(Net consumption)		161.9
Industrial	74.9	(50%)
Residential	39.6	(24%)
Commercial	23.9	(15%)
Public	7.3	
Other	16.3	

Source: TEIAS, TEDAS

Gross consumption grew by the average of 7.4% per year between 1988 and 2008, which is a fourfold increase in 21 years and a twofold growth in 12 years. Furthermore, although the figure for 2009 has not been finalized, it is somewhat lower than in 2008 due to the effect of the economic crisis.

The maximum demand has grown from 9964 MW in 1991 to 15,231 MW in 1996, to 21,006 MW in 2002, to 25,174 MW in 2005, and to 30,516 MW in 2008. Until a few years ago, maximum demand was recorded in winter, but since 2007, it has been recorded in summer mainly due to the increase in the air-conditioning load. Demand is relatively low in spring and fall, and minimum demand has taken place in October in recent years. In addition, the gap between maximum and minimum demand has been growing.

Table 2. 6 Maximum Demand and Gross Consumption from 1988 to 2008

Year	Maximum Demand (MW)	Increase rate (%)	Gross Consumption (GWh)	Increase rate (%)
1988			48,430	7.8
1989			52,602	8.6
1990			56,812	8.0
1991	9,964	8.54	60,499	6.5
1992	11,113	11.5	67,217	11.1
1993	11,921	7.3	73,432	9.2
1994	12,760	7.0	77,783	5.9
1995	14,165	11.0	85,552	10.0
1996	15,231	7.5	94,789	10.8
1997	16,926	11.1	105,517	11.3
1998	17,799	5.2	114,023	8.1
1999	18,938	6.4	118,485	3.9
2000	19,390	2.4	128,280	8.3
2001	19,612	1.1	126,871	-1.1

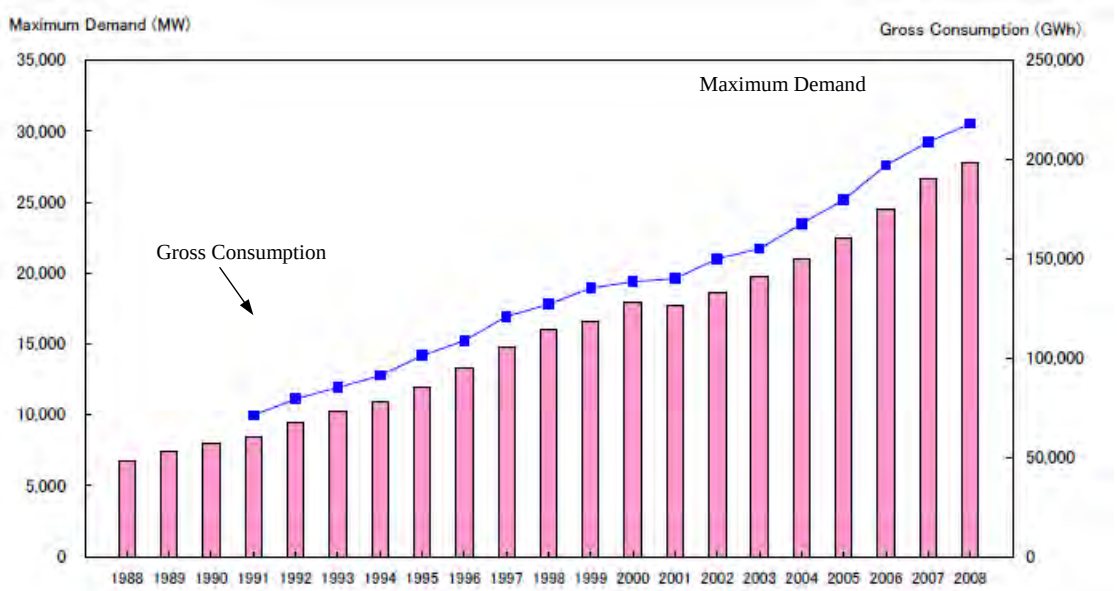
2002	21,006	7.1	132,553	4.5
2003	21,729	3.4	141,151	6.5
2004	23,485	8.1	150,018	6.3
2005	25,174	7.2	160,794	7.2
2006	27,594	9.6	174,637	8.6
2007	29,249	6.0	190,000	8.8
2008	30,517	4.3	198,085	4.3

Source: TEAS

Table 2. 7 Maximum and Minimum Demand from 2006 to 2008

Year	Maximum Demand	Minimum Demand	Maximum - Minimum
2006	27,594MW	10,545MW	17,049MW
2007	29,249MW	11,100MW	18,149MW
2008	30,157MW	10,409MW	19,748MW

Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2008-2017), TEIAS, July 2008, Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009 and TEAS



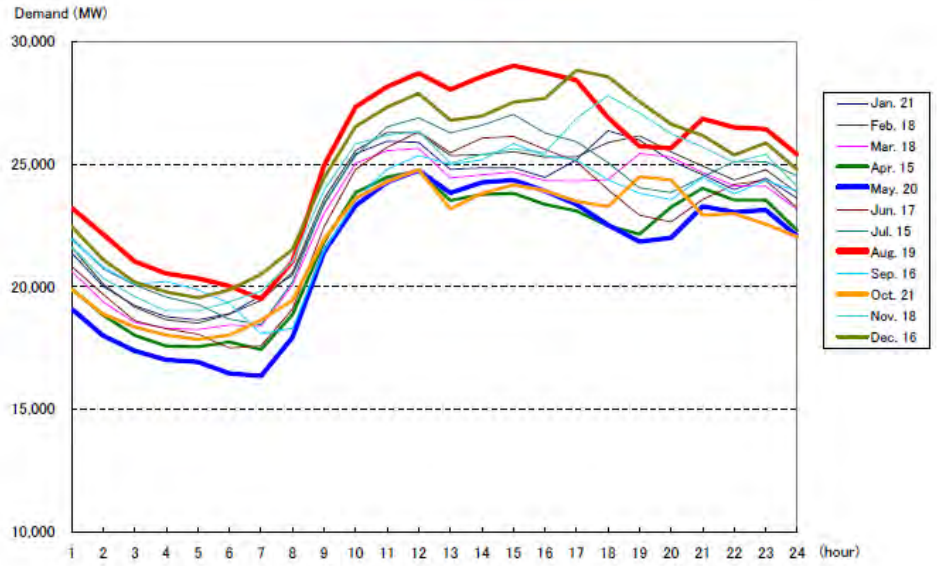
Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009

Figure 2. 11 Transition of Maximum Demand and Gross Consumption

In order to have an overall look at the seasonal change of demand curve, the daily load curve of third Wednesday of each month in 2009 is illustrated as follows. As was mentioned earlier, high demand is seen in summer and winter while demand in spring and fall is relatively low.

In summer the peak appears at around 15:00 due to air-conditioning demand, whereas the peak in winter is seen at 17:00 because of the demand of lighting and cooking. The annual peak demand was shifted to summer a few years ago and now the peak demands in summer and winter are at comparable levels.

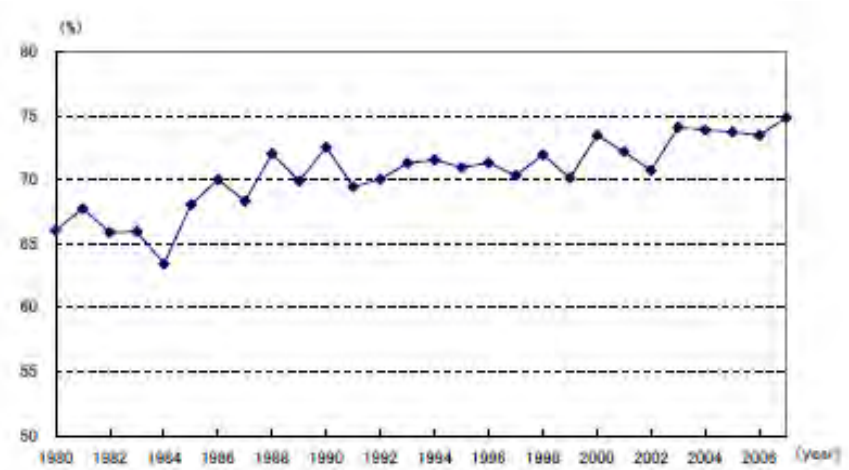
Given the future prospect of even wider use of air-conditioning and electrical heating systems, the seasonal gap between summer/winter demand and spring/fall demand is expected to grow further.



Source: TEIAS

Figure 2. 12 Load curve of third Wednesday of each month in 2009

The chart in Figure 2. 13 represents the trend of annual load factor. With the growing electrification rate as a result of the rising living standards and expanding use of industrial and residential electricity consumption due to economic development, the annual load factor has been on the rise. Power consumption is expected to continue to grow, but depending on the growth of the tertiary industry and the increase in cooling demand, the load factor could go down due to the expanding difference between high demand and low demand.



Source: TEIAS Web Page

Figure 2. 13 Transition of annual load factor

(2) Power generation facility

Power producers in Turkey include nationally owned EUAS and private generation companies. Also, as a nationally owned wholesaler, TETAS purchases power from power plants built in the 1990s via BOT (build-operate-transfer) or BO (build-operate) contracts with operational contracts of certain periods (such as 20 years), and supplies it. Many of BOT power stations are natural gas fired, while

many of BO plants are coal fired; many private power plants are fueled by natural gas.

As of June 2010, Turkey's national power generation capacity was 45,502 MW, and 45% of that, 20,369 MW, is owned by EUAS, 7% of that is owned by auto producers, equipped with their generation facilities. Some of the auto producers are connected to the grid and supply a part of the generated power to other companies. In addition, the capacity of thermal power generation has reached 29,604 MW, accounting for 65%. Capacities of hydro and wind are 14,802 MW (33%) and 1002 MW (2.2%), respectively. Wind power generation was 146 MW at the end of 2007, 364 MW at the end of 2008 and 1,002 MW in June 2010, showing a rapid increase of nearly three times increase per year.

Table 2. 8 Generation Capacity by Owner from 2007 to 2010

Unit: MW

Owner		End of 2007	End of 2008	June 2010	Ratio (%)
EUAS	Thermal	8,,90.9	8,690.9	8,690.9	
	Hydro	11,350.3	11,455.9	11,667.9	
	Total	20,041.2	20,146.8	20,368.8	44.8
Affiliated Partnership of EUAS	Thermal	3,834.0	3,834.0	3,834.0	
	Total	3,834.0	3,834.0	3,834.0	8.4
ADUAS	Thermal	30.0	---	---	
	Hydro	111.3	---	---	
	Total	141.3	---	---	
TOR	Thermal	620.0	620.0	620.0	
	Hydro	30.1	30.1	30.1	
	Total	650.1	650.1	650.1	1.4
Mobile Plants	Thermal	262.7	262.7	262.7	
	Total	262.7	262.7	262.7	0.6
BO	Thermal	6,101.8	6,101.8	6,101.8	
	Total	6,101.8	6,101.8	6,101.8	13.4
BOT	Thermal	1,449.6	1,449.6	1,449.6	
	Wind	17.4	17.4	17.4	
	Hydro	982.0	982.0	972.4	
	Total	2,449.0	2,449.0	2,439.4	5.4
Generation Companies	Thermal	3,130.3	3,687.3	6,070.3	
	Geothermal			94.2	
	Wind	127.7	345.1	938.8	
	Hydro	363.0	807.2	1,577.4	
	Total	3,621.0	4,839.6	8,725.7	19.2
Auto producers	Thermal	3,175.2	2,978.5	2,574.5	
	Wind	1.2	1.2	1.2	
	Hydro	363.0	553.5	544.2	
	Total	3,621.0	3,533.2	3,119.9	6.9
Total	Thermal	27,294.5	27,624.9	29,603.8	65.1
	Geothermal			94.2	0.2
	Wind	146.3	363.7	1,002.4	2.2
	Hydro	13,394.9	13,828.7	14,802.0	32.5
	Total	40,835.7	41,817.2	45,502.3	

TOR: Power Plants under Transfer of Operational Right Contract
BO: Power Plants under Built-Operate Contract
BOT: Power Plants under Built-Operate-Transfer Contract
Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009 and TEIAS Web Page

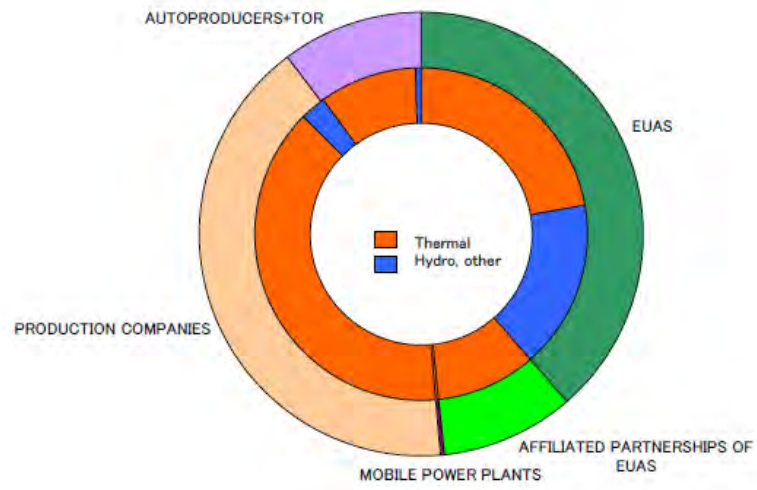
The generated energy by the type of generation company is tabulated and illustrated in Table 2. 9 According to the result in 2007, EUAS accounted for 38%, EUAS affiliated companies for 10%, while private generation companies including BO and BOT for 41%. Thermal generation accounted for 81%, and other generation such as hydro, geothermal, and wind accounted for 19%.

Table 2. 9 Planned and Record of Generated Electric Energy of Each Generation Company in 2007 and 2008

(Unit: GWh)

	Revised plan of 2007	Record of 2007	Plan of 2008	Record of 2008
EUAS	75,700	73,839	74,731	74,919
ADUAS		216	482	320
Affiliated Partnership of EUAS	19,098	18,488	20,472	22,798
Mobile Plants	138	797	1,800	330
TOR	4,480	4,268	4,203	4,315
BOT	14,455	14,256	13,758	13,171
BO	44,946	44,970	47,219	43,342
Generation Companies	17,927	19,399	25,600	23,499
Auto producers	16,324	15,325	17,118	15,724
Non-EUAS Generation	117,368	117,719	130,352	123,499
Total Generation of Turkey	**193,068**	**191,558**	**205,383**	**198,418**
Import	743	864	600	789
Turkey's Generation + Import	**193,811**	**192,422**	**205,983**	**199,207**
Export	2,873	2,422	1,983	1,122
Total Consumption of Turkey	**190,938**	**190,000**	**204,000**	**198,085**

TOR: Power Plants under Transfer of Operational Right Contract
BO: Power Plants under Built-Operate Contract
BOT: Power Plants under Built-Operate-Transfer Contract
Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009



Source: TEIAS Web Page

Figure 2. 14 Generated Electric Energy in 2007 by Generation Companies and Power Sources

(3) Trend of power sources

The power generation capacity and actual generated energy by power source are shown in Table 2. 10. In recent years, in order to meet the rapidly growing demand, and as power development by the private sector is being pushed forward, many natural gas-fired thermal power plants which have benefits in terms of development periods and fuel procurements have been built.

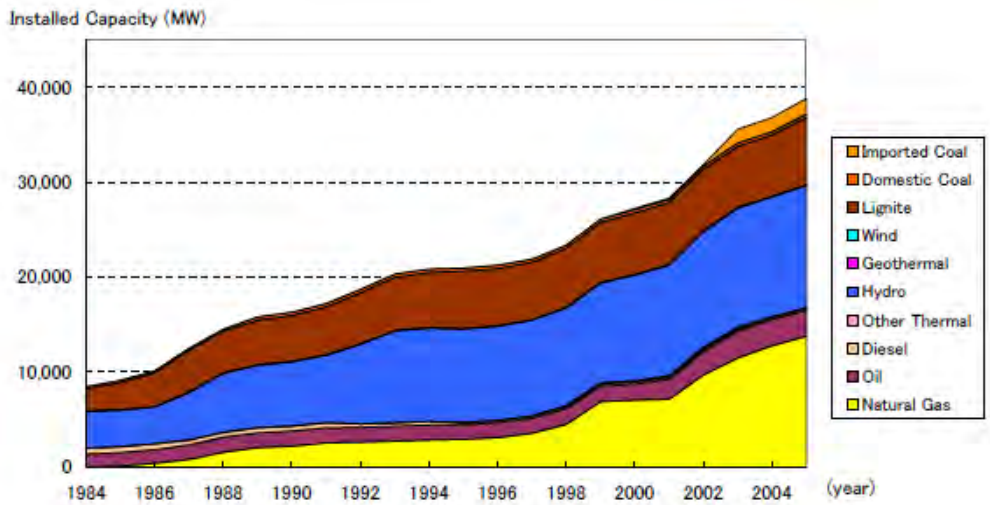
The ratio of generated energy by power source in 2008 is as follows: natural gas at 48.2%, coal at 29.0%, and hydro at 16.8%. This is because as 2008 experienced water shortage, power generated by hydro was relatively low. In 2010, therefore, hydro generating energy is expected to rise due to more ample water reserves.

Table 2. 10 Transition of Generation Capacity by Power Sources (unit: MW)

Year	Lignite	Domestic coal	Imported coal	Natural gas	Oil	Diesel	Other thermal	Hydro	Geo-thermal	Wind	Total
1985	2,864.3	219.9	-	100.0	1,417.8	627.3	0.0	3,874.8	17.5	-	9,121.6
1990	4,874.1	331.6	-	2,210.0	1,574.5	545.6	0.0	6,764.3	17.5	-	16,317.6
1995	6,047.9	326.4	-	2,924.5	1,557.2	204.2	13.8	9,862.8	17.5	-	20,954.3
2000	6,508.9	335.0	145.0	7,044.0	1,671.0	229.5	119.1	11,175.2	17.5	18.9	27,264.1
2005	7,130.8	335.0	1,651.0	13,773.5	2,708.3	215.9	87.8	12,906.1	15.0	20.1	38,843.5
2007	8,211.4	1,986.0	-	14,560.4	2,243.4	206.4	64.1	13,394.9	169.2	-	40,835.7

Source: TEIAS Web Page

Remark: Since data of imported coal and wind on 2006 and later are not explicitly described in above table, data until 2005 are illustrated in the following figure.



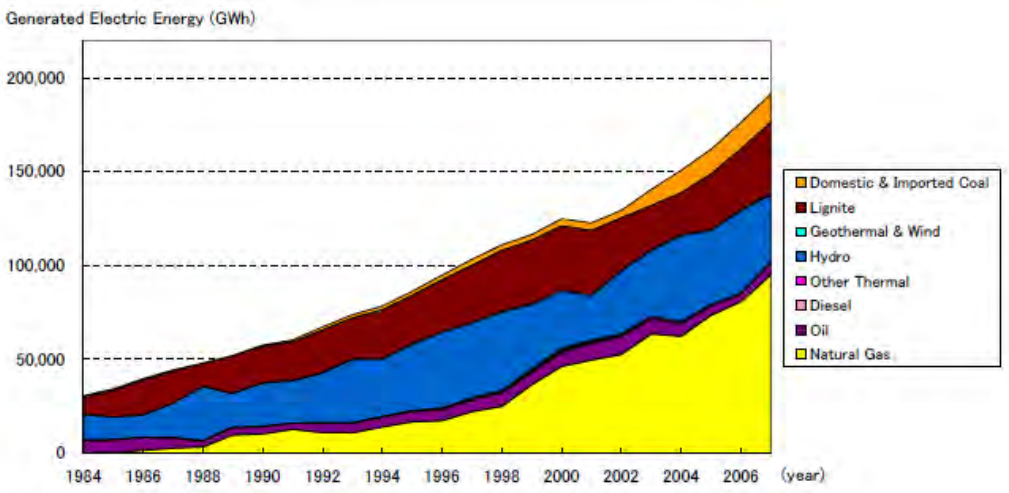
Source: TEIAS Web Page

Figure 2. 15 Transition of Generation Capacity by Power Sources

Table 2. 11 Transition of Generated Electric Energy by Power Sources (Unit: GWh)

Year	Lignite	Domestic+ Imported coal	Natural gas	Oil	Diesel	Other thermal	Hydro	Geothermal +Wind	Total
1985	14,317.5	710.3	58.2	7,028.6	53.4	0.0	12,044.9	6.0	34,218.9
1990	19,560.5	620.8	10,192.3	3,920.9	20.8	0.0	23,147.6	80.1	57,543.0
1995	25,814.8	2,232.1	16,579.3	5,498.2	273.8	222.3	35,540.9	86.0	86,247.4
2000	34,367.3	3,819.0	46,216.9	7,459.1	980.6	1,091.3	30,878.5	108.9	124,921.6
2005	29,946.3	13,246.2	73,444.9	5,120.7	2.5	481.7	39,560.5	153.4	161,956.2
2007	38,294.7	15,136.2	95,024.8	6,469.6	13.3	257.6	35,850.8	511.1	191,558.1

Source: TEIAS Web Page



Source: TEIAS Web Page

Figure 2. 16 Transition of Generated Electric Energy by Power Sources

Table 2. 12 Generation Capacity by Power Sources (as of June 2010)

Unit: MW

Generation Company	Thermal												Geothermal	Hydro			Wind	Total (Ratio (%))
	Oil	DE	Imported coal	Coal	Lignite	AS	Natural gas	NA	RE	Combo: solid+ liquid	Combo: liquid+ gas	**Thermal total**		Dam	Run-of -river	**Hydro total**		
EÜAŞ	680.0	1.0		300.0	4,747.0		2,962.9					**8,690.9**		11,215.3	462.6	**11,677.9**		**20,368.8 (44.8)**
Affiliated Partnership of EÜAŞ					2,714.0		1,120.0					**3,834.0**				**0.0**		**3,834.0 (8.4)**
TOR					620.0							**620.0**			30.1	**30.1**		**650.1 (1.4)**
Mobile Plants	262.7											**262.7**				**0.0**		**262.7 (0.6)**
BO			1,320.0				4,781.8					**6,101.8**				**0.0**		**6,101.8 (13.4)**
BOT							1,449.6					**1,449.6**		772.0	200.4	**972.4**	**17.4**	**2,439.4 (5.4)**
Generation Companies	390.2	15.0	405.0			135.0	3,570.6		58.4		1,496.2	**6,070.3**	**94.2**	154.4	1,423.0	**1,577.4**	**983.8**	**8,725.7 (19.2)**
Auto producers	207.8	10.4	196.0	35.0	58.7		839.1	21.4	29.7	551.5	625.0	**2,574.5**		540.0	4.2	**544.2**	**1.2**	**3,119.9 (6.9)**
Total	1,540.6	26.5	1,921.0	335.0	8,139.7	135.0	14,724.0	21.4	88.0	551.5	2,121.1	**29,603.8**	**94.2**	12,681.7	2,120.3	**14,802.0**	**1,002.4**	**45,502.3**
Ratio (%)	3.4	0.1	4.2	0.7	17.9	0.3	32.4	0.0	0.2	1.2	4.7	**65.1**	**0.2**	27.9	4.7	**32.5**	**2.2**	**100**

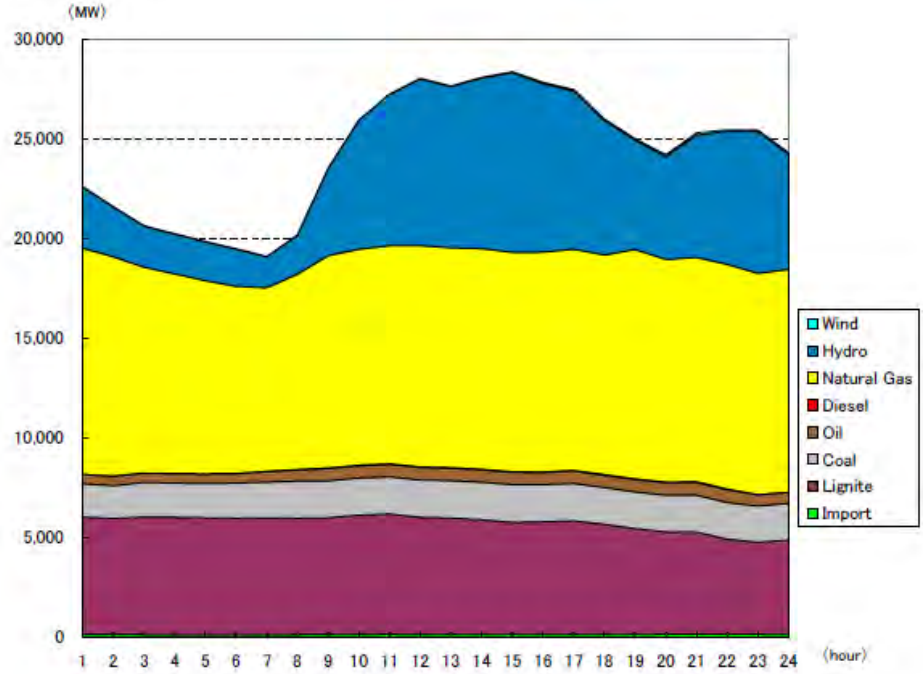
DE: Diesel, AS: Asphaltite, NA: Naphtha, RE: Renewable+waste

Source: TEIAS Web Page

(4) Status of generation by power sources

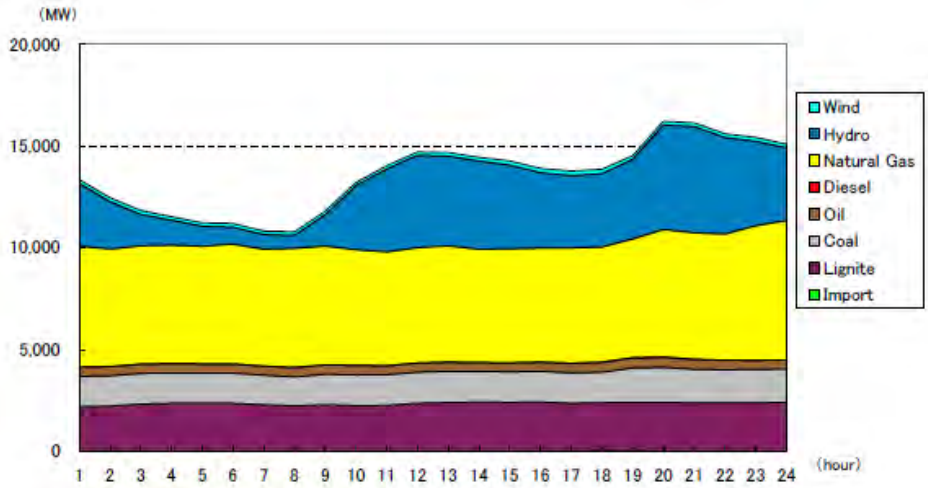
Demand curves and their breakdown by power source on August 5, 2009, the day of maximum demand, and September 21, the day of minimum demand in 2009, are illustrated in Figure 2. 17 and Figure 2. 18.

Basically, gas-fired thermal generation is used as a base supply operation in constant power output, while hydropower is used to deal with the peak demand. When peak demand is high, thermal power plants are also used to meet the demand. When there is ample power supply by hydropower plants during periods of abundant water reserves, gas-fired thermal power plants are operated on partial load.



Source: TEIAS

Figure 2. 17 Load Curve by Power Sources on August 5, 2009



Source: TEIAS

Figure 2. 18 Load Curve by Power Sources on September 21, 2009

(5) Power plant operation of EUAS

EUAS has 18 thermal power plants, four of which are natural gas fired, as well as 106 hydropower plants.

It has 45% of coal concessions in Turkey and consumes 60 million tons of coal annually, half of which is mined by EUAS itself and the other half is purchased from other companies in Turkey. It has supplier contracts with TKI (Turkish Coal Enterprise) for lignite and with TTK (Turkish Hardcoal Authority) for hard coal, and partial ones with private companies. "Take or pay" contracts are conducted for up to 85% of amount, where the obligation to pay takes place even when the contracted amount of purchase has not been met. However, there have been no cases where such an obligation was actually applied. For example, in a case where a sudden accident occurs and generators have become unusable, there is a clause that allows the contracted amount to be changed. Such flexible operations are made possible. Contracts with private companies are even more flexible. For example, even if there is a minimum requirement of 45% purchase, in some cases, if the contracted purchase is not fulfilled, the shortfall can be carried over to the next year.

The company purchases most of the natural gas from BOTAS and fuel purchase contracts of power plants under EUAS are made by EUAS with BOTAS. Contracts include potential penalties in case of low annual purchase as well as prices at addition purchases. Negotiations on 2011 contracts will be conducted later, and EUAS wishes to avoid "take or pay" contracts. Fuel prices between EUAS and BOTAS are determined by the secretary of treasury.

Oil-fired thermal power plants are supposed to be operated only when necessary, and oil is purchased from the general market.

While operations of dam water levels are determined through daily discussions with concerned agencies, with regard to annual operations, water levels have to be lowered before March when the rainy season starts. As rainfall was high in 2010, some of the thermal power plants were operated at lower power output at nighttime.

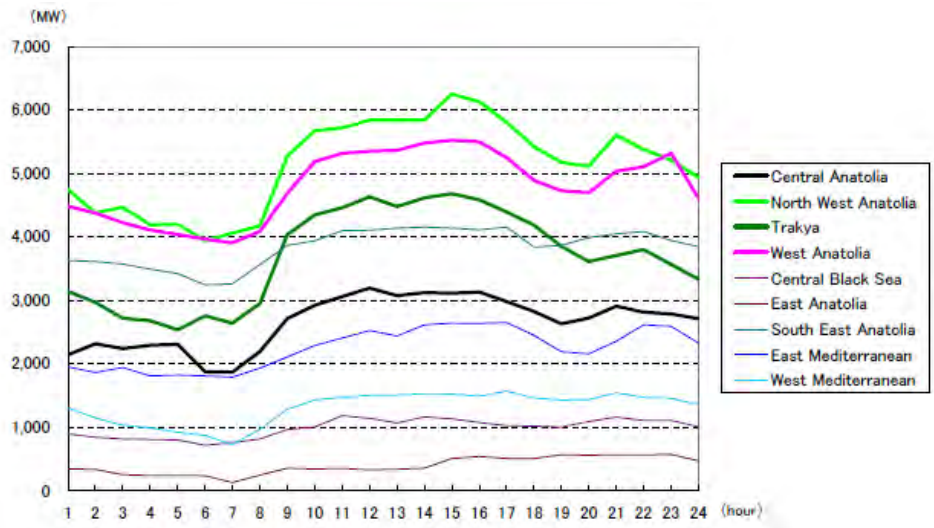
In the course of privatization, power plants of EUAS will be privatized. The OIB (Privatization Administration) plans the TOR (transfer of operation right) method, that is, hydropower plants will be granted the operational rights for 30 to 49 years, provided that the rights will be returned to EUAS after its expiration. Thermal power plants sell the ownership, and in a case of coal-fired thermal power plants, coal mines are combined with the power plant but the operation rights of mines are sold for the determined period, in accordance with the TOR method.

If supply shortage is foreseen in the future, the state-owned power producer, EUAS, will newly build power plants. However, since the liberalization was introduced in 2001, such a development has not happened yet.

(6) Characteristics of power demand by region

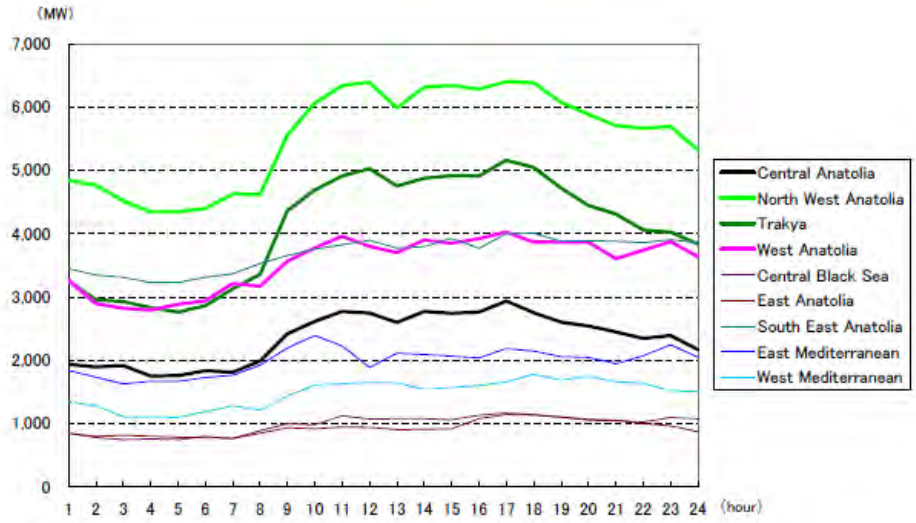
In order to have an overview of the demand characteristics by region, demand curves of August 5, 2009, the day of maximum demand in summer, and of December 17, the day of maximum demand in winter in 2009, by each responsible area of local load dispatch centers (LDCs) are shown in Figure 2. 19 and Figure 2. 20.

Northwestern Anatolia is a region including the Asian side of Istanbul (the demand is highest in this division). Peak demand and power consumption of the region are higher in winter than in summer. Trakya region includes the European side of Istanbul, and the European side of Turkey from the Bosphorus straits between Black Sea and Marmara Sea. This region also has high power demand; demands in summer and winter are generally comparable, but, at present, winter demand is slightly higher. West Anatolia is a coastal area of the Aegean Seas centering around Izmir. Since it has a warm climate and high energy demand by tourists from summer resort areas, as is described in Section 3.4, demand in summer is much higher than that in winter. Also, since there are many industrial plants in the area, the demand gap between daytime and nighttime is relatively small.



Source: TEIAS

Figure 2. 19 Load Curve of Each Region on August 5, 2009



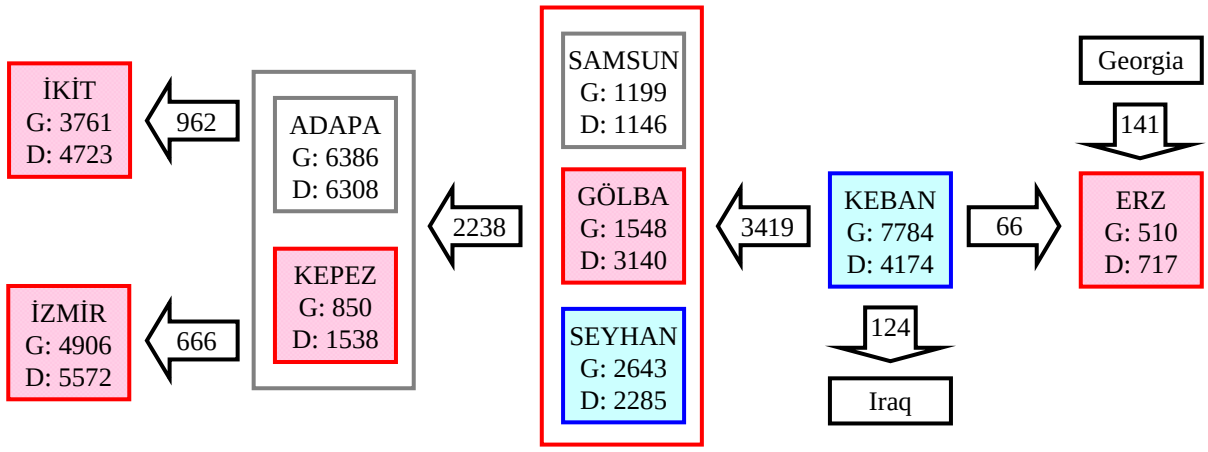
Source: TEIAS

Figure 2. 20 Load Curve of Each Region on December 17, 2009

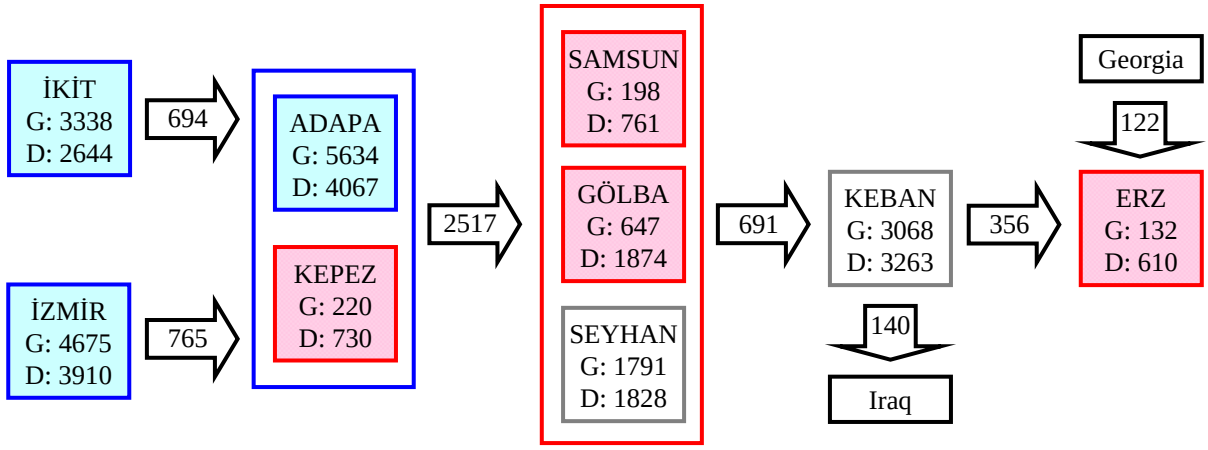
(7) Power flow between regions

With regard to the demands of August 5, the day of maximum demand in summer, and of December 17, the day of maximum demand in winter in 2009, the power flow between local load dispatch centers (LDCs) is described below.

The area shown in red is where power shortage was occurring, whereas the areas in blue are where there was power surplus.



Regional supply/demand balance（15:00　August 5th, 2009）：Total demand　29604MW

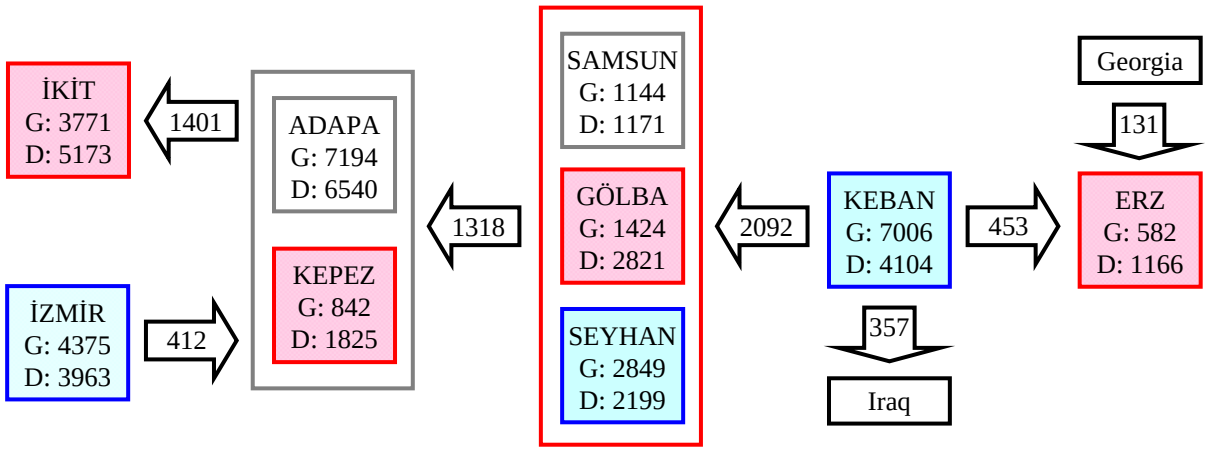


Regional supply/demand balance（7:00 August 5th, 2009）：Total demand 19,685MW

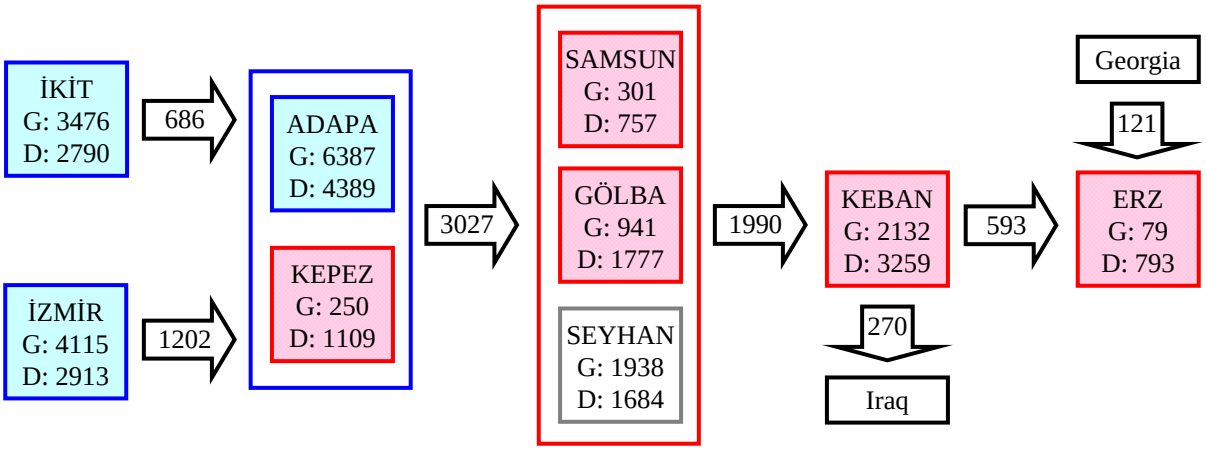
Source: TEIAS

Figure 2. 21　Power Flow between Regions on August 5, 2009

During the daytime in summer, power flows from the east side to the west side, whereas at night, since hydropower plants on the east side stop, the power flow is reversed, flowing from the western side to the eastern side.



Regional supply/demand balance（18:00 December 17th, 2009）：Total demand 28961MW



Regional supply/demand balance（05:00 December 17th, 2009）：Total demand 19470MW

Source: TEIAS

Figure 2. 22 Power Flow between Regions on December 17, 2009

As in the summer time, in winter as well, during the daytime, power flows from the eastern side to the western side and at night, from the western side to the eastern side. Only in Izmir, however, power surplus occurs both during the daytime and nighttime; thus power is transmitted to other regions.

(8) Transmission and distribution network

On land spanning 1500 km from the east to the west, Turkey has transmission systems comprising voltages of 380 kV (400kV), 154 kV, and 66 kV, which is the largest transmission system among EU countries.

The 380 kV transmission lines are 14,420 km long, 154 kV transmission lines are 31,654 km long, while underground cables of 380 kV are 13km long and 154 kV underground cables are 163 km long. Distances of the transmission lines by voltage are tabulated in Table 2. 13. The 220 kV transmission lines are used to interconnect with Georgia and Armenia. The 66 kV lines will be abolished in the near future.

During daytime, power flows from the large-scale hydropower plants in the southeastern area (Keban, Karakaya, Ataturk, Birecik) via 380 kV long-distance transmission lines (Yesilhisar-Ataturk, Keban-Kayseri-Golbasi, Sincan-Elbistan A/B, two lines each) to the demand areas in the central and

western regions. Supply/demand power system control is conducted at the National Load Dispatch Center (NLDC) near Ankara and at nine local load dispatch centers (LDCs) (refer to Section 3.4).

Table 2. 13 Length of Transmission Lines (as of 2008, unit: km)

380kV	220kV	154kV	66kV	Total
14,420.2	84.5	31,653.9	508.5	46,667.1

Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009

Table 2. 14 Substations

	380kV	154kV	66kV	Total
TEIAS	67	527	26	620
EUAS	13	50	6	69
Other	5	135	3	143
Total	85	712	35	832

Source: TEIAS

Table 2. 15 Transformers in Transmission Substations

	Number	Total capacity (MVA)
380/154kV	166	33,818
380/33kV	26	3,325
154/MV	1,550	55,000

*MV: voltage between 36kV and 31.5kV

Source: TEIAS

Operational voltages of transmission line systems are 380-420 kV for 380 kV lines（360-420 kV at emergencies）and 145-165 kV for 154 kV lines (140-170 kV at emergencies).

On the sending end of the power plants to the transmission network, voltage fluctuation during the parallel in/off operations should stay within a range of ±3% of the nominal voltage, and the voltage fluctuations which are caused by the control of the compensation equipment should remain within a range of ±5% of the nominal voltage.

Reactive power is measured for industrial customers and if it exceeds the reference value controlled by EMRA, penalties will be imposed.

Voltages of transmission network are controlled by the generators and by the compensation equipment installed in the substation bus bar and the transmission lines (indicated in Table 2.13). The transformer tap is manually operated through on-load tap changer.

In addition, serial capacitors are installed at a total of 16 locations of long-distance transmission lines in order to improve stability and to adjust power flow and voltage.

Table 2. 16 Compensation Equipment

	Total capacity
Shunt reactor	
380kV transformer tertiary	528 MVar
380kV network	4,486 MVar
154kV bus bar	75 MVar
Shunt capacitor	
154kV network	442 MVar
MV bus bar	1,825MVar
Serial capacitor	
380kV network	3,800MVar

Source: TEIAS

Capacity of distribution substations and distances of distributions lines are tabulated in Table 2. 17 and Table 2. 18.

Table 2. 17 Length of Distribution Lines (as of 2008, unit: km)

33kV	15.8kV	10.5kV	6.3kV	Other	0.4kV	Total
339,691	30,848	5,573	7,792	101	556,918	940,922

Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009

Table 2. 18 Number and Capacity of Distribution Substations (as of 2008, unit: MVA)

		15.8kV	10.5kV	6.3kV	Other	0.4kV	Total
33kV	Number	491	219	445	56	267,572	268,782
	Capacity	4,090	3,528	3,344	268	71,663	82,893
15.8kV	Number			5	3	31,233	31,241
	Capacity			15	3	9,202	9,220
10.5kV	Number			1		8,227	8,228
	Capacity			4		7,019	7,023
6.3kV	Number				5	8,100	8,105
	Capacity				141	3,611	3,752
Other	Number				9	1,920	1,930
	Capacity				59	365	424
Total	Number	491	219	451	74	317,052	318,286
	Capacity	4,090	3,528	3,363	471	91,859	103,312

Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009

The transmission loss remains at low levels of around 2%, as shown in Table 2. 19. Although the loss rate including stolen power declined from 25% in 2002 to 14% in 2009, it is the highest among OECD countries next to Mexico, and further improvements are desired.

Table 2. 19 Transition of Transmission Loss Rate

Year	%	GWh
2001	2.8	3,374.4
2002	2.7	3,440.7
2003	2.4	3,330.7
2004	2.4	3,422.8
2005	2.4	3,695.3
2006	2.7	4,543.8
2007	2.5	4,523.0
2008	2.3	4,388.4

Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009

(9) Situation of power supply

Table 2. 20 Available Generation Capacity, Demand Forecast, Reserve Margin, Interrupted Supply Energy on third Wednesday in 2010

2010	Available generation capacity (MW)	Demand forecast (MW)	Reserve margin (%)	Interrupted supply energy (MWh)
January 20	31,908	28,500	10.7	0
February 17	30,464	26,800	12.0	600
March 17	28,850	26,750	7.3	122
April 21	29,009	26,250	9.5	197
May 12*	29,863	26,700	10.6	572
June 16	32,771	29,800	9.1	61
July 21	34,520	31,820	7.8	1,886
August 18	32,746	32,600	0.4	5,376**
September 15	32,376	29,000	10.4	0
October 20	29,720	26,550	10.7	0
November 10*	31,084	28,600	8.0	42

*: data of second Wednesday, due to national holiday

**: includes load shedding

Source: JICA Study Team based upon data from TEIAS

Turkey's electrification rate has reached at 100% around the year 2000, and there exists no non-electrified area since then. In 2010, total capacity of around 46GW power plants are operated with appropriate generation planning and output control in order to supply the demand with around 33GW at maximum.

In recent years, the annual maximum power demand occurs in summer and periodic maintenance plans of power plants are coordinated so that the supply capability shall be prepared for the demand in each time of the year. In some cases, however, shutdown or output decrease of power plants occur due to the reasons other than maintenance, which causes the power shortage for a few days in a year and load shedding cannot be avoided. In the high demand days in August of 2010, load sheddings were executed at 2 days and energies of 2,150MWh and 2,300MWh could not be supplied respectively.

"Shutdown or output decrease of power plants due to the reasons other than maintenance" include plant troubles and other reasons such as output decrease of coal fired thermal power plant by using low calories coal, efficiency decrease of gas combined cycle power plant by operating in high humidity atmosphere, output decrease of hydro power plant in operating at close to the lower water level of reservoir in dry season, and so on. In average, supply capability decreases commonly occur by 2GW due to plant troubles, and 8GW due to reasons other than troubles.

Following table shows available generation capability, demand forecast, reserve rate, and interrupted supply energy, on third Wednesday of each month by November in 2010.

Considering daily supply incapability of 12 to 17GW in average due to maintenance and reasons other than maintenance, available supply capability would be 29 to 34GW, and reserve rate in high demand days in summer greatly decreases. Causes of interrupted supply energy are mainly troubles in power network facilities besides the load shedding, which leads to necessity of improvement of reliability of network facility, as well as of power generation facility.

2.2.5 Interconnection with Other Countries

Although Turkey's power system is interconnected with other Asian neighboring countries such as Georgia, Armenia, Azerbaijan, Iran, Iraq, and Syria, they are not synchronized. For example, in the interconnection with Syria, the transmission lines to which Turkey sends power are not connected to the Syrian grid.

Power imports and exports are conducted by TETAS based on an agreement between governments. The import/export record for 2008 is as follows.

A contract has been signed with a Georgian power company of Adjarian, which will expire at the end of 2010. Based on this contract, Turkey has imported 216 GWh and exported 54 GWh of power. Turkey exported power to the Azerbaijian enclave of Nakhichevan between 1991 and 2007, but imported 94 GWh in 2008. It has imported power from Turkmenistan, with which Turkey shares no border, via Iran since 2003 and imported 450 GWh in 2008. In its transaction with Turkmenistan, the country's scope of responsibility has been set to cover up to its border with Turkey. Turkey started exporting to Syria in 2006 and exported 97 GWh in 2008. Turkey transmitted 100MW of power from the Turkish side, and 100 MW from a power producer at an interconnecting point, exporting 1.6 GWh of power to Iraq.

In the past, Turkey interconnected with EU's UCTE/ENTSO-E system by separating Turkey's domestic power system. Between 2001 and 2003, Turkey interconnected with the Bulgarian system for the capacity of approximately 600 MW, but it is disconnected at present. Turkey exported 89 GWh of power to Greece in 2008 and imported 30 GWh.

Currently, the project of interconnection and synchronized operation with Bulgarian network by 2 circuits and with Greek network by 1 circuit, each of 380kV, is underway. On September 18th, 2010, Turkey transmission network was interconnected and the frequency control of Turkey was changed from FFC (Flat Frequency Control) to TBC (Tie Line Biased Control). Capacity of interconnection is 1,800MW in total and NLDC takes responsibility of power trade through interconnection.

Initially, interconnection is controlled at 0MW for a month, and limited in 500MW for a year, with 250MW for both directions. 65% of power trade will be with Bulgaria and 35% with Greece, and 46 companies will participate in the trade. After 1 year of interconnection, power trade with other EU countries is planned.

In interconnecting ENTSO-E network through Greece and Bulgaria, while stability analyses were completed, there existed a problem in frequency control. To deal with it, governor system of large scale power plants were improved, and network separation tests at maximum load in January 2010, network separation tests at minimum load in March and April 2010, and other tests were conducted. Currently, power fluctuation in interconnected operation is studied. Also, a special protection system (SPS) is planned to install to control Turkey's generation and load in order to defend ENTSO-E network from influences of faults and disturbances in Turkey side, and to prevent interconnection trip as much as possible.

Table 2. 21 International Interconnection Lines with Neighboring Countries

Country	Substation	Substation in Turkey	Voltage	Distance	Transmission capacity (summer)
Bulgaria	Maritsa East	Babaeski	380 kV	136km	832MVA
	Maritsa East	Hamitabat	380 kV	150km	1,268MVA
Georgia	Batum	Hopa	220kV	28km	240MVA
Armenia	Gumri	Kars	220kV	78km	480MVA
Azerbaijian	Babek	Igdir	154kV	87km	110MVA
Iran	Bazargan	Dogubeyazit	154kV	73km	171MVA
	Khoy	Baskale	380 kV	100km	488MVA
Iraq	Zakho	PS3	380 kV	16km	342MVA
Syria	Aleppo	Birecik HES	380 kV	124km	845MVA
Greece	Filippi	Babaeski	380 kV	200km	1,268MVA

Source: MEVCUT ENTERKONNEKSIYON HATLARNIN NET TRANSFER KAPASITELERI DUYURUSU

Table 2. 22 Transition of Electricity Export

Unit: GWh

	2001	2002	2003	2004	2005	2006	2007
Georgia	0.0	0.0	0.0	0.0	9.3	106.7	117.5
Greece	0.0	0.0	0.0	0.0	0.0	0.0	90.2
Azerbaijan	432.8	435.1	401.6	378.7	384.1	325.7	14.9
Iraq	0.0	0.0	186.0	765.6	1,404.7	1,668.8	1,237.2
Syria	0.0	0.0	0.0	0.0	0.0	134.5	962.4
Total	**432.8**	**435.1**	**587.6**	**1,144.3**	**1,798.1**	**2,235.7**	**2,422.2**

Source: TEIAS Web Page

Table 2. 23 Transition of Electricity Import

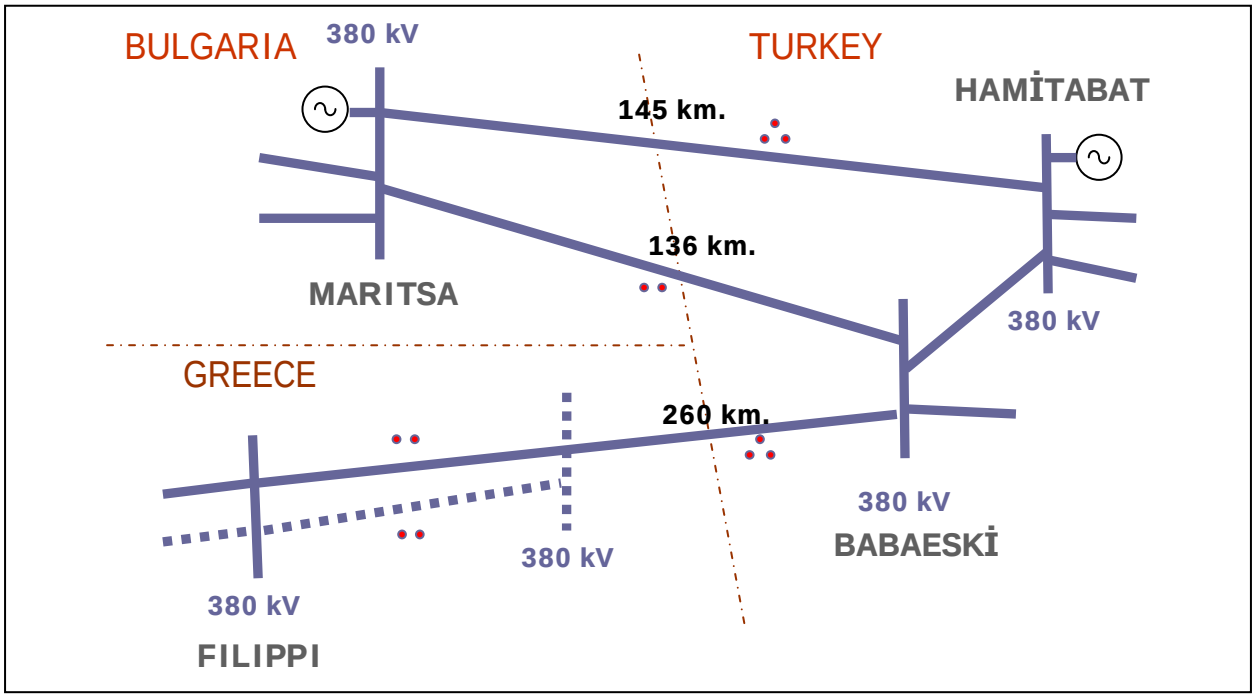
Unit: GWh

	2001	2002	2003	2004	2005	2006	2007
Bulgaria	3,775.5	3,445.4	1,134.5	0.0	0.0	0.0	0.0
Georgia	523.0	92.7	0.0	0.0	101.1	40.5	215.6
Azerbaijan	0.0	0.0	0.0	0.0	0.0	0.0	15.3
Iran	280.9	50.1	0.0	0.0	0.0	0.0	0.0
Turkmenistan	0.0	0.0	23.5	463.5	534.8	532.7	633.4
Total	**4,579.4**	**3,588.2**	**1,158.0**	**463.5**	**635.9**	**573.2**	**864.3**

Source: TEIAS Web Page

Source: TEIAS

Figure 2. 23 Outline of international interconnection



Source: TEIAS

Figure 2. 24 Interconnection with ENTSO-E network

400 kV Network

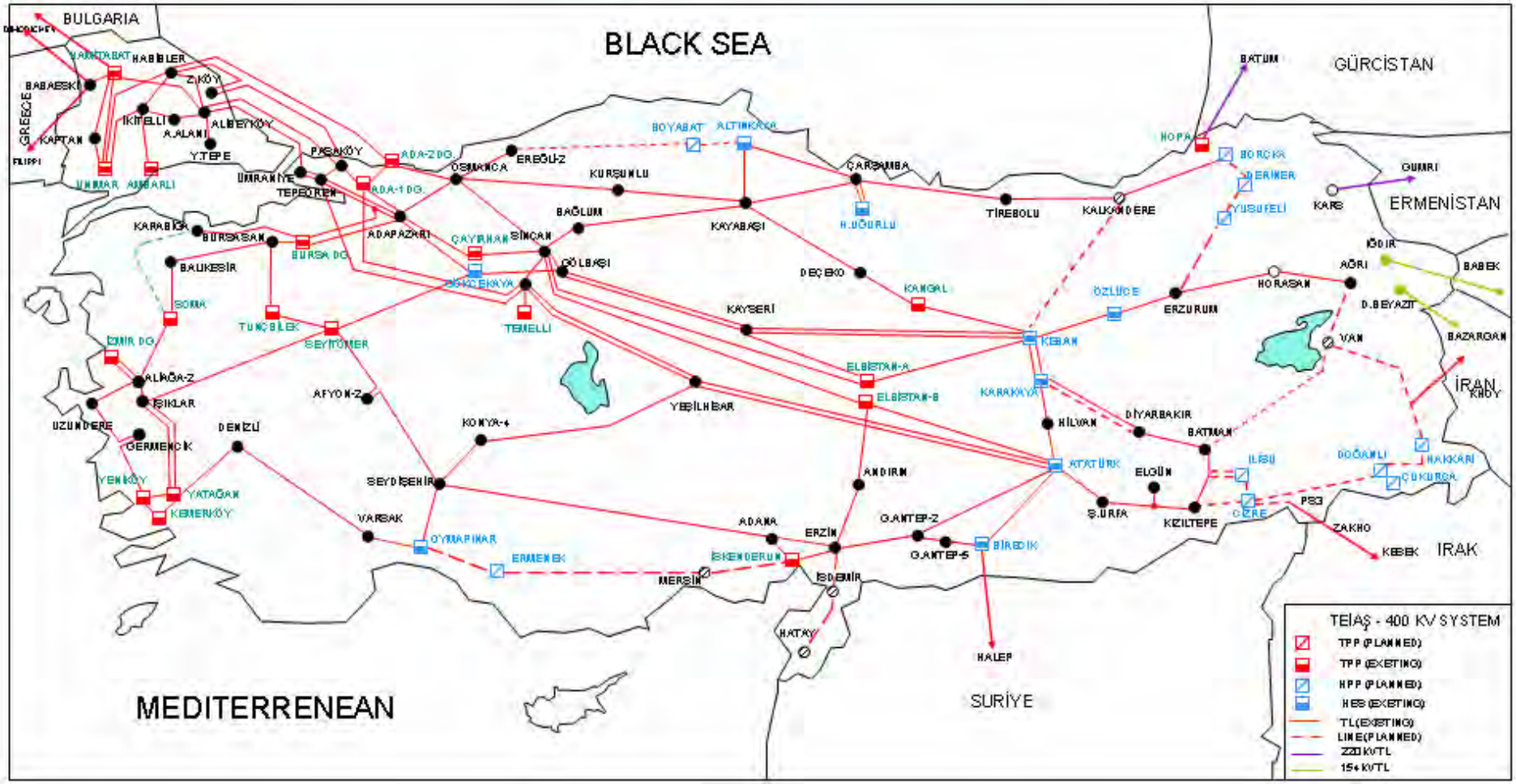


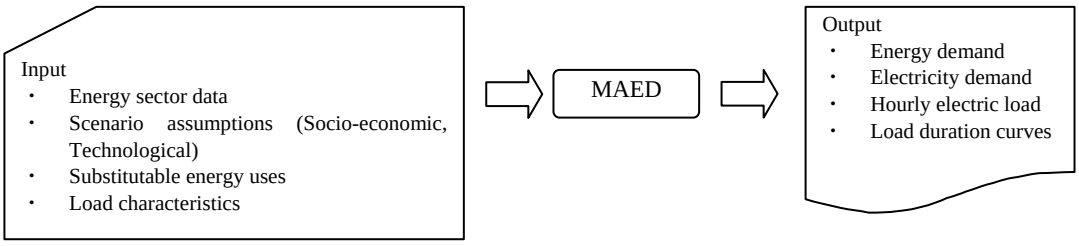
Figure 2. 25 380 kV Network of TEIAS

Chapter 3 Review of Long-term Demand/Supply Plan

3.1 Current status of Power Demand Forecast

Demand forecast is made by the Ministry of Energy and Natural Resources, ETKB, by using the Energy & Power Evaluation Program (ENPEP), Model for Analysis of Energy Demand (MAED) module, and Balance module.

MAED makes the assumption of overall energy demand based on the growth rates of population and industrial sectors as well as the development scenario on the socioeconomic and technological fronts, and then calculates the future power demand. However, at the moment, there is a huge margin of error even in population surveys. Therefore, the forecast is not necessarily reliable. There is a plan to develop a new demand forecast software with support of the United States, in which conditions such as energy savings will be incorporated. The results of such demand forecasts are made public in the "Turkish Electrical Energy 10-Year Generation Capacity Projection" jointly issued by ETKB and TEIAS.



Source: Model for Analysis of Energy Demand (MAED-2) User's Manual, IAEA, 2006

Figure 3. 1 Input and Output of MAED

The APK, Research Planning and Coordination Division of TEIAS, used to make simulations of power development plans by using WASP modules based on the demand forecast calculated by MAED. However, since the enactment of Electricity Market Law No. 4628 (regulation 4628), it has become difficult for TEIAS to gather necessary information. Therefore, since 2003, plans as to by whom, when, and where power plants using what fuel will be built have become difficult to grasp.

Therefore, the current "Capacity Projection 2009-2018" was compiled based on the power generation plan on plants under construction or with license granted, but it is not possible to analyze the necessary development capacity volume or optimal power sources composition based on appropriate supply reliability. As for network facilities such as transmission lines (mainly 380 kV), new construction plans are projected based on the past trend. It is considered that such a situation will not be a bottleneck as there is some reserve capacity for the time being.

On the other hand, among distribution companies which are required to make demand forecast in recent years, TEDAS makes forecast on both macro and micro levels by using demand forecast software developed by a consulting firm, McKenzie. At present, however, since some of statistical data which must be input are unavailable and there are frequent changes in contracts with eligible consumers, making forecast remains quite difficult.

Below is the content of demand forecast described in the "Capacity Projection 2009-2018" issued in June, 2009. Although demand forecast is supposed to be made up to 10 years ahead by the local power distribution companies according to the above-mentioned regulation 4628, since it is not available at present, high demand and low demand forecast made by ETKB are used.

The demand forecast was made by ETKB in May 2008, and "high demand" was projected via DPT (SPO). It is based on contribution by agriculture, construction, mining, manufacturing, energy, and service sectors on the GDP growth rate, while the "low demand" is based on the assumed 4.5% GDP growth of 2009 and after.

Table 3. 1 Growth Rates in High Demand and Low Demand Cases

Period	Growth Rate in High Demand Case (%)	Growth Rate in Low Demand Case (%)
2000-2005	4.6	4.6
2005-2010	5.8	5.3
2010-2015	5.5	4.5
2015-2030	5.5	4.5

Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2008-2017), Turkish Electricity Transmission Corporation, Research Planning and Coordination Department, July 2008

Table 3. 2 GDP Classified by Type of Business

	2000	2005	2010	2015	2020	2025	2030
Agriculture	12.2	10.6	8.5	7.5	6.5	5.7	5.0
Construction	5.7	5.8	5.7	5.5	5.5	5.5	5.5
Mining	0.9	0.7	0.6	0.5	0.5	0.5	0.5
Manufacturing	23.5	23.5	23.5	24.0	24.1	24.2	24.3
Energy	1.9	1.9	2.3	2.8	3.3	3.7	4.1
Services	55.7	57.5	58.9	59.6	60.1	60.4	60.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2008-2017), Turkish Electricity Transmission Corporation, Research Planning and Coordination Department, July 2008

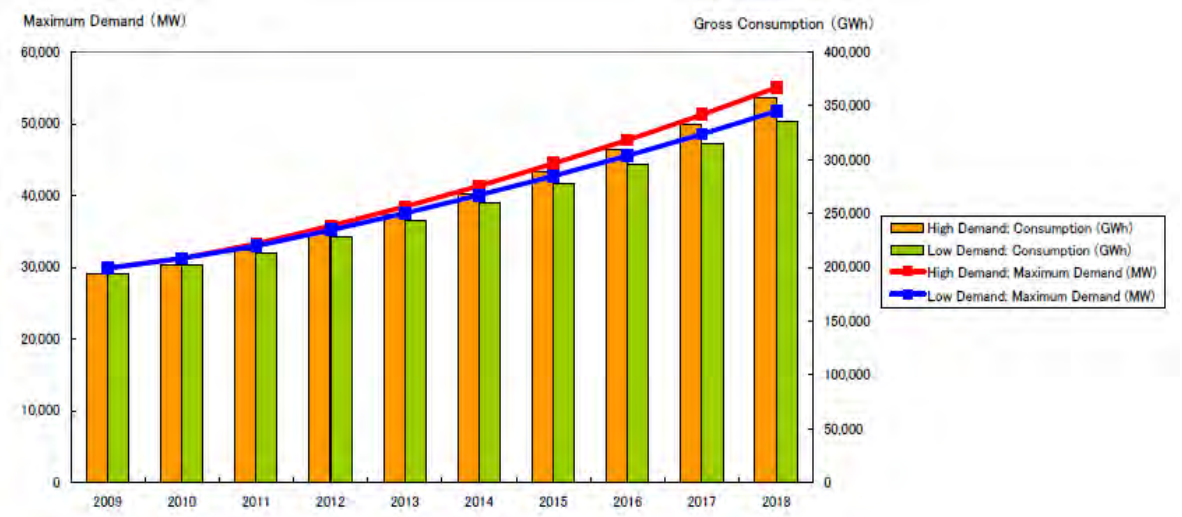
The demand forecast made in June 2009 was based on the projection of 2008, setting power consumption level for 2009 lower by 2% due to the economic crisis, while setting low increase rates for 2010 and 2011, and setting the values in line with the MAED model for later years.

The following figures are those of gross consumption including transmission/distribution loss, in-house power consumption, and stolen power.

Table 3. 3 Load Forecast in High Demand and Low Demand Cases

	High Demand				Low Demand			
Year	Maximum Demand (MW)	Increase Rate (%)	Gross Consumption (GWh)	Increase Rate (%)	Maximum Demand (MW)	Increase Rate (%)	Gross Consumption (GWh)	Increase Rate (%)
2009	29,900		194,000		29,900		194,000	
2010	31,246	4.5	202,730	4.5	31,246	4.5	202,730	4.5
2011	33,276	6.5	215,907	6.5	32,964	5.5	213,880	5.5
2012	35,772	7.5	232,101	7.5	35,173	6.7	228,210	6.7
2013	38,455	7.5	249,508	7.5	37,529	6.7	243,500	6.7
2014	41,339	7.5	268,221	7.5	40,044	6.7	259,815	6.7
2015	44,440	7.5	288,338	7.5	42,727	6.7	277,222	6.7
2016	47,728	7.4	309,675	7.4	45,546	6.6	295,519	6.6
2017	51,260	7.4	332,591	7.4	48,553	6.6	315,023	6.6
2018	55,053	7.4	357,202	7.4	51,757	6.6	335,815	6.6

Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009



Source: Turkish Electrical Energy 10-year Generation Capacity Projection (2009-2018), TEIAS, June 2009

Figure 3. 2 Load Forecast in High Demand and Low Demand Cases

Although the growth rate up to 2011 was revised downward, it is expected to make steady growth afterwards. Even in the low-demand scenario, the growth level of the high 6% range is expected from 2012 onward.

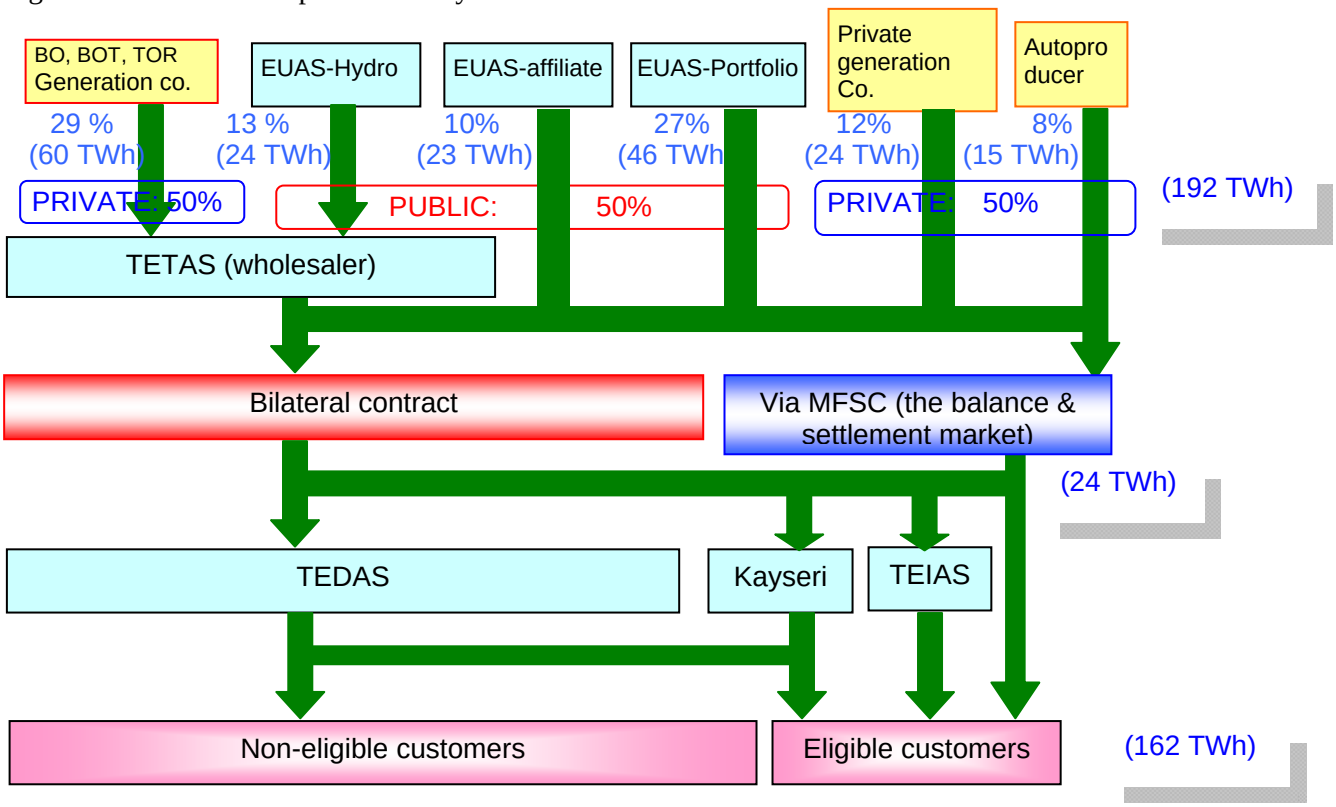
As of May 2009, according to the forecast made by ETKB, demand was forecast at 499 TWh in the high-demand scenario (7.5% growth) and 406 TWh in the low-demand scenario (5.96% growth). If it is extrapolated to 2020, the figures are projected at around 410 TWh and 380 TWh, respectively.

In the next section, development plans for generation facilities based on these forecasts will be evaluated.

3.2 Current Power Development Plan and Its Review

3.2.1 Power Development Plan Liberalized Electricity Market

This subsection describes the current power development plan in Turkish liberalized electricity market. Figure 3. 3 shows the map of electricity-related entities.



NOTE: MFSC: Market Financial Settlement Center
(1) Figures in parentheses stand for the annual amount of electricity traded in fiscal year 2008.
(2) TETAS deals with power trading with neighboring countries.
(Source: Developed by the Study Team based on interview with relevant entities; "Turkish Electricity Market Structure" Navitas Enerji. 2009; "Capacity projection 2009-2018" TEIAS; and "TEIAS 2008 Annual Report" TEIAS.)

Figure 3. 3 Image of Electricity Flow among Entities

After the privatization of EUAS' portfolio power plants as well as affiliate plants, the market share of EUAS would decrease from the current 60% to around 20% in terms of installed capacity.

(1) The formulation of power development plan of Turkey; the measure to secure power supply.

The latest Turkish power development plan is the one developed by TEIAS in 2004 employing power development simulation software, WASP (Wien Automatic System Planning). Since then, the plan has not been updated due to difficulty in collecting necessary information for TEIAS. As reference, the government's national energy policy has been updated since 2004, for example, delay in the nuclear power plant development and increase in the installed capacity of wind power generation.

The following explains the details.

(a) Demand forecast and power development planning before 2004.

MENR's Energy Affairs Department had conducted the energy demand forecast employing a software, MAED (Model for Analysis of the Energy Demand), until 2003. TEIAS had conducted

its power development planning employing WASP, based on the demand forecast result led by MENR. The situation has changed since 2001, the year of the enactment of Electricity Market Law (no. 4628). It has become harder for the TEIAS to force generation companies to provide their power development plans, which has resulted in uncertainty in the national power development plan. That is, it has become harder for TEIAS to know by whom, when, where, and with what type of fuel power plants would be developed.

(b) Demand forecast and power development planning after 2004

Electricity demand forecast to be used in the TEIAS' 10-year capacity projection is supposed to be prepared by distribution companies, though the forecast is updated by the Ministry of Energy and Natural Resources (MENR) due to the transitional period.

Most of the newly added power plants have been/will be constructed by private generation companies which obtained licenses from EMRA. Private investors who plan the power plant development are to submit their application to the EMRA, which is the market regulatory authority. The issue is that the majority of the development plans have uncertainty. For example, EMRA issues one and a half times as many licenses as that necessary for the estimated supply capacity. Furthermore, it is not certain whether the plans would be commissioned as scheduled. Such a situation might be attributed to the fact that EMRA would not take responsibility for power supply security, while the authority issues the power development licenses (refer to Table 3. 4).

Table 3. 4 Licensing Activity by EMRA

Fuel/ resource type	Application		Evaluation		Qualified		Total	
	Number	Capacity [MW]	Number	Capacity [MW]	Number	Capacity [MW]	Number	Capacity [MW]
Wind	3	27.8	722	75,154.1	12	850.9	737	76,032.8
Hard coal	7	5,101.7	12	6,890.0	3	1,006.0	22	12,997.7
Natural gas	8	1,083.3	22	9,509.1	5	1,699.3	35	12,261.6
Hydraulic	102	1,432.8	220	3,509.3	163	2,938.7	485	7,880.9
Fuel oil			2	115.1			2	115.1
Geothermal	4	74.4					4	74.4
Biofuel	1	2.0			2	15.6	3	17.6
Biogas	2	5.5	2	2.9			4	8.4
biomass	1	4.0	1	3.4			2	7.4
Total	128		982		18	6,480.5	1,295	109,395.9

Source: a handout obtained from EMRA at interview in February 2010

The current administration system where EMRA issues power generation licenses enables TEIAS to forecast the national power development plan only for the next 5-6 years. Due to such reasons, the Turkish national long-term (10-20 years ahead) power development plan, which tries to secure supply capacity so as to meet the forecasted demand, has not been updated since 2004. Besides the fact, no one is sure that even the power plants planned to be commissioned in the next 5-6 years would really be commissioned. Therefore, TEIAS, the owner of the national grid, cannot help expanding the grid based on a rough estimate. Such investment seems inefficient because the investment could turn out to be unnecessary if the actual power development comes out to be largely different from the initial estimate. TEIAS has made efforts to avoid such inefficiency as well as future supply shortages by closely communicating with relevant entities like MENR to obtain up-to-date information.

(c) Issue: power supply security

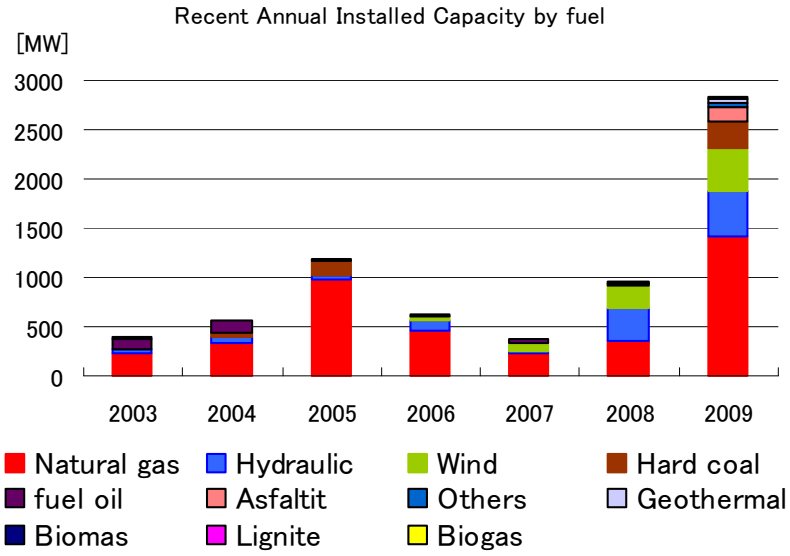
Under the current environment, it is not realistic to place the full responsibility of electricity supply security to TEIAS only. A similar story also applies to BOTAS (Petroleum Pipeline Corporation) in the gas sector. While EUAS is to construct power plants in an emergency case –

supply shortage – such a potential crisis has been avoided since the start of the liberalization program in 2001.

Different from US and Western European countries, whose demand growth has slowed down, Turkey's electricity demand is expected to grow to be twice as large as the current demand in capacity in the next 20 years. Under such circumstances, some concerns remain: (1) whether additional supply capacity of 40 GW would be fully fulfilled in the Turkish liberalized market and (2) whether a balanced mixture of generation fuel would be achieved from fuel supply security points of view.

For the first concern, in theory of market principle, if there is demand (or electricity trading price increases), the corresponding amount of supply would be provided (or new entrants would participate in the generation market). Its consequence could, however, be the outflow of industry which consumes large amount of electricity out of Turkey, leading to slowdown of the nation's economic growth. The Turkish government's ninth development plan also raises the issue of expensive domestic electricity retail tariff, which is higher than that of the average among OECD countries.

For the second concern, in a completely liberalized market without government's intervention, market participants generally tend to pursue short-term profit. One of the typical consequences is the choice of an economically competitive fuel - currently natural gas (Figure 3. 4). It is not preferred in terms of national energy security to depend on single type of fuel, as historically shown, e.g. skyrocketing energy price during the oil crisis in 1970s in Japan (Box 3.1). The Turkish government aims to avoid such a crisis, setting its goal in their policy to reduce the share of natural gas-fired power generation from the current 50% to less than 30% by 2023, and to increase the share of nuclear power generation to at least 5%. The government's involvement would be one of the key factors to secure energy supply for sustainable economic development; at the same time, it is also important that the involvement does not sacrifice the power companies' financial independence.



Source: Developed by the Study Team based on the material obtained from EMRA at interview.

Figure 3. 4 Annual Installed Capacity by Fuel.

Box 3.1 Oil Crisis and power industry

The rise of oil price in Middle East oil-producing countries, so called first oil crisis which was triggered by the Yom Kippur War in October 1973, had caused trouble to nations like Japan which were heavily depend dent on imported natural resources. The impact of the crisis was severe not only in automobile industry, but also in power industry which had largely relied on fuel oil for power generation. Japan has changed her policy to reduce the share of oil in power generation fuel so that the impact of possible future oil crisis would be mitigated (Figure Box 3.1). Such change has also resulted in the promotion of energy conservation activities as well as the development of new forms of energy. Likewise, after the oil crisis, the shift from oil-dependent society has been attained worldwide (Figure Box 3.2).

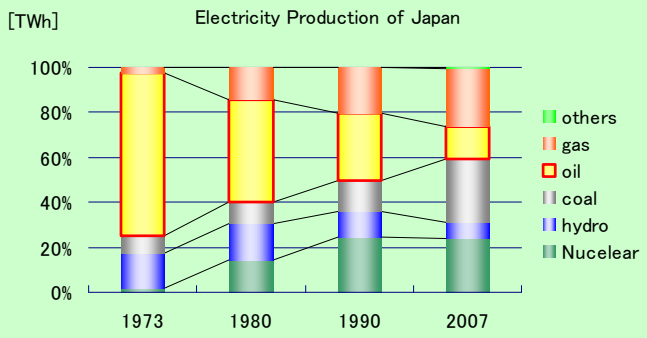


Figure Box 3.1 Transition of Electricity Production Composition by Fuel

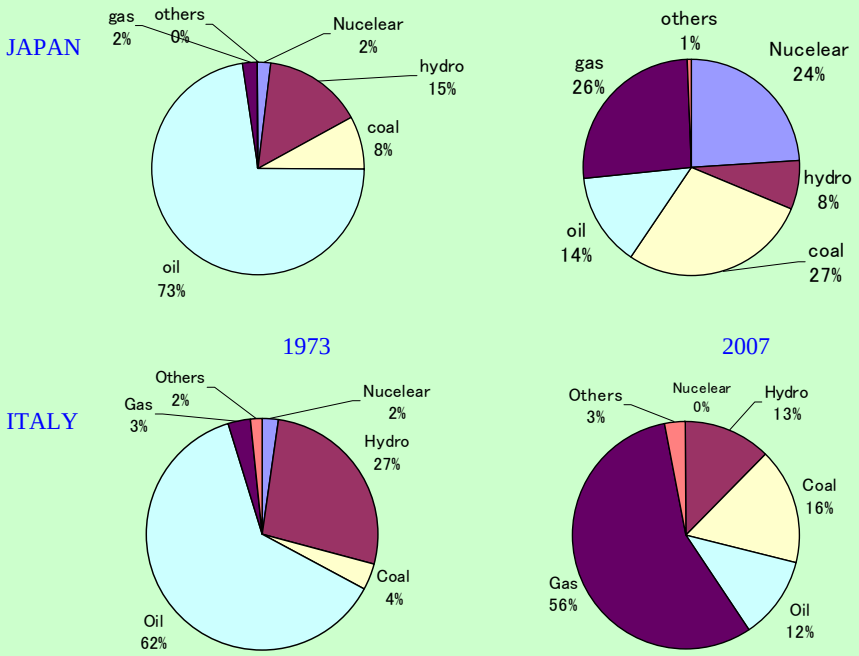


Figure Box 3.2 Shift of Oil Share in Power Generation in Japan and Italy.

Source: IEA "Electricity Information (2009 Edition)

(2) The role of "Turkish Electrical Energy 10-Year Generation Capacity Projection"

TEIAS develops national power generation capacity projection annually under the above-mentioned circumstances. As mentioned earlier, the capacity projection only aggregates information from the market participants such as EUAS, TETAS, and EMRA. EMRA collects the data of private power companies, including the construction plans. For a newly developed generation system, the data are obtained mainly from DSI (State Hydraulic Works) in addition to the above entities. The projection covers the development plan of power plants under construction of those with licenses obtained from EMRA. What makes TEIAS' projection development challenging is the fact that plants which obtained licenses do not always keep their commissioning schedule as expected. To summarize, the projection does not necessarily secure future supply amount to meet the forecasted demand. The latest capacity projection (2009-2018) was also developed under the circumstance where power generation plan is uncertain, and it does not show the power development plan meeting the demand fully.

Box 3.2 Power Development Plan in Europe

UCTE/ ENTSO-E develops an annual report on the demand and supply result of its area. Besides the report, it has published "System Adequacy Forecast 2009-2020," a long-term power plan in its area. The report estimates the supply security sufficient for growing peak demand and compares the growth of demand with that of supply capacity. Under the uncertain circumstance where investors see it challenging to catch the signal for necessary capital investment while liberalization has been promoted, the report aims to secure future power supply by providing power market participants with necessary information to assist their decision. The report shows two scenarios shown below:

Scenario-A: this scenario takes into account the confirmed plan of power plants' development and retirement.

Scenario-B: besides the plan adopted in Scenario-A, this scenario takes into account the plan of power plants' development and retirement which are not confirmed but seem highly feasible.

(Source: Kaigai Denryoku (Overseas Electricity) 2009.4)

(3) Future Power Development Planning and National Policy (including nuclear and renewable energy)

The national energy policy has been described in Section 2.1.1. EMRA plays a screening role, easing the development of renewable energy (RE) power plants, while restricting that of gas-fired thermal power plants. Investors make a decision whether to enter the generation market with signal from MFSC.

For the environmental aspects, Turkey has been included in Annex-I country group of Kyoto Protocol since August 2009. The Turkish carbon dioxide (CO_2) emission per capita was 3.3 ton as of 2003, which was significantly lower than the average of OECD countries (11.1 ton) as well as that of EU-15 countries (9.0 ton), and even the world average (4.0 ton). Regarding the composition of Turkish greenhouse gas (GHG) emissions, CO_2 occupies the majority, 81.6% of total as of year 2004. It is followed by methane (CH_4) with a share of 15.6% and nitrous oxide (N_2O) with a share of 1.9%. The emission amount almost doubled from 1990 to 2006, excluding the amount related to forest activities. The largest GHG emitter of Turkey in 2006 was the energy sector, whose share was about 35%, amounting to 258,206.6 $GgCO_2eq$. The second was the manufacturing industries and construction sector with about 30%, followed by the transport sector with around 17 %, and the residential and services sector with around 17%.

The Turkish government has collaborated with the United Nations since January 2007 with "First National Communication of Turkey on Climate Change" (United Nations Framework Convention on Climate Change). The report has been updated in 2009 as "Report of the In-Depth Review of the First National Communication of Turkey." According to the report, the Turkish government has formulated energy policies enhancing the following aspects: (1) energy supply security (diversification of primary energy resources and the promotion of domestic resources), (2) combined heat and power generation, (3) renewable energy sources, and (4) energy efficiency improvements. The UN report

shows concern against these government policies, specifically those on the energy supply security aspect, because the relevant policies aim to promote the use of domestic lignite for power generation, which might lead to higher levels of GHG emissions. Therefore, the report recommends to employ some measurement such as the construction/retrofit of flue gas desulfurization (FGD) plants.

The UN report estimates aggregated GHG emissions in 2020 under two different scenarios, namely the one without measures and the other with measures. Compared with the GHG emission amount of 246,122 $GgCO_2eq$ in its base year of 2005, the amount of "without measures" scenario is estimated as 539,025 $GgCO_2eq$ (increase almost by 120%) while that of "with measures" scenario is estimated as 615,667 $GgCO_2eq$ (increase almost by 150 %). Emissions from the electricity sector account for 30-40% of the total in the above cases.

Box 3.3 Extension of Vianden Pumped Storage Power Plant, Luxembourg.

The Vianden Pumped Storage Power Plant (PSPP) is one of the largest PSPPs in Europe with output of 1,100 MW, which was commissioned in 1964. The plant's first to tenth units are operated in power generation mode for 4 hours and in pump mode for 7 hours. After the addition of 11th unit, the plant will be operated in power generation mode for 4.4 hours.

The expansion to 1,300 MW aims to meet the growing peak demand with more flexibility. RWE Power (Germany) and the Société Electrique de l'Our (SEO, Luxembourg) finance the project, amounting to 150 million Euro. The construction period is estimated to be 4 years.

In Europe, PSPP has been utilized as countermeasure against the voltage fluctuation of power grid over 80 years, because PSPPs are superior to base- and middle-load power plants in output control speed. Moreover, PSPPs have been key power source which stores surplus electricity during off-peak hours to prepare for peaking demand coming next.

Thanks to the national policy promoting the spread of wind power generation both in Luxembourg and Germany, the amount of installed capacity of wind power generation there is estimated to increase further. Pumped storage power plants have contributed to the stabilization of the power system by absorbing such output fluctuation caused by wind power generation.

In summary, Vianden PSPP contributes to stable power supply in Europe not only in its frequency control aspect and in voltage stabilization aspect but also in prompt response to fluctuating demand.

(SOURCE: Kaigai Denryoku (Overseas Electricity) 2009.5)

3.2.2 License Issuance Status

EMRA publishes its license issuance status on the Internet.
http://www.epdk.gov.tr/lisans/elektrik/ilerleme_proje.htm

(1) Thermal

As of January 2010, EMRA has issued licenses for 68 thermal sites. The license issuance status is summarized in Table 3. 4.

Table 3. 5 License Issuance Status (Thermal)

Fuel type		Capacity		Percentage of completion	
Natural Gas	38	More than 1,,000MW	4	More than 90%	10
Import Coal	15	600MW – 1,000MW	10	50% - 90%	8
Lignite	10	200MW – 600MW	11	10% - 50%	6
Fuel Oil	1	50MW – 200MW	12	0% - 10%	14
Others	4	Less than 50MW	31	0%	30
Total	68	Total	68	Total	68

Among the above, 12 sites with the installed capacity of 50 MW or more and the percentage of completion of 10% or more are shown in Table 3. 6.

Table 3. 6 Large-Scale Sites with Percentage of Completion 10% or More (Thermal)

Name	Fuel type	Supply output (MW)	Percentage of completion (%)
Delta Enerji Üretim ve Ticaret A.Ş.	Natural Gas	64.2	90.6
Eren Enerji Elektrik Üretim A.Ş.	Import Coal	165.0	90.4
Aliağa Çakmaktepe Enerji Üretim A.Ş.	Natural Gas	216.1	83.4
Aksa Enerji Üretim A.Ş.	Natural Gas	257.0	63.6
İçdaş Çelik Enerji Tersane ve Ulaşım San. A.Ş.	Import Coal	410.3	62.1
Enerjisa Enerji Üretim A.Ş.	Natural Gas	1,025.0	61.2
Camiş Elektrik Üretim A.Ş.	Natural Gas	130.0	53.6
AS Enerji Elektrik Üretim San. Ve Tic. A.Ş.	Natural Gas	67.0	36.9
Borasco Elektrik Üretim San. Ve Tic. A.Ş.	Natural Gas	886.9	29.3
Eren Enerji Elektrik Üretim A.Ş.	Import Coal	1,213.3	27.6
İÇDAŞ Elektrik Enerjisi Üretim ve Yatırım A.Ş.	Import Coal	607.9	24.9
İçdaş Çelik Enerji Tersane ve Ulaşım San. A.Ş.	Import Coal	607.9	10.3

(2) Hydro

As of January, 2010, EMRA has issued licenses for 477 hydro sites. The license issuance status is summarized in Table 3. 7. Despite a large number of sites having acquired licenses, 40% or more of the all sites are small-scale hydro plants with an output of 10 MW or less.

Table 3. 7 License Issuance Status (Hydro)

Capacity		Percentage of completion	
More than 200MW	11	More than 90%	22
100MW – 200MW	18	50% - 90%	36
50MW – 100MW	33	10% - 50%	85
10MW – 50MW	206	0% - 10%	213
Less than 10MW	209	0%	121
Total	477	Total	477

Among the above, 24 sites with the installed capacity of 50 MW or more and the percentage of completion of 10% or more are shown in Table 3. 8.

Table 3. 8 Large Scale Sites with the Percentage of Completion 10% or More (Hydro)

Name	Supply output (MW)	Percentage of completion (%)
Darıca I HES	99.0	94.6
Uzunçayır HES	84.0	81.2
Akocak HES	90.1	80.1
Çırakdamı HES	58.7	78.3
Uluabat Kuvvet Tüneli HES	110.3	75.6
Cevizlik HES	102.4	71.0
Dereli HES	58.8	66.3
Ceyhan HES	63.5	65.5
Erenler HES	51.1	64.7
Alkumru Barajı ve HES	247.4	45.1
Hacınınoğlu HES	144.4	40.3
Yedigöze HES	317.0	38.8
Sarıgüzel HES	105.1	29.1
Kandil Enerji Projesi HES	217.6	22.6
Akköy 2 HES	233.6	22.2
Tatar HES	115.8	21.4
Göktaş HES	292.5	20.8
Feke II HES	71.0	20.5
Güllübağ HES	99.0	18.3
Menge Barajı ve HES	86.8	15.6
Akıncı HES	102.3	12.5
Pembelik HES	122.4	12.2
Daran HES	54.6	10.5
Toros HES	51.2	10.4

(3) Other renewable energy (wind, etc.)

As of January 2010, EMRA has issued licenses for 90 renewable energy sites other than hydro. The license issuance status is summarized in Table 3. 9.

Table 3. 9 License Issuance Status (Renewable Energy)

Fuel type		Capacity		Percentage of completion	
Wind	77	More than 100MW	5	More than 90%	5
Geothermal	3	50MW – 100MW	10	50% - 90%	10
Bio gas	6	20MW – 50MW	36	10% - 50%	8
Biyokütle	2	10MW – 20MW	24	0% - 10%	56
Çöp Gazı	2	Less than 10MW	15	0%	11
Total	90	Total	90	Total	90

3.3 Current Status and Evaluation of System Planning

3.3.1 The Existing and Planned Transmission Lines and Substations up to 2012

The voltages 380 kV and 154 kV are applied as the nominal voltages for the power network system in Turkey and 66 kV is partly applied for the system. The nominal voltages not less than 380 kV will be needed to transmit the power from the pumped storage power stations targeted in this study because their power outputs are expected to be more than 1,000 MW.

Table 3. 11 shows the list of the power transmission lines with 380 kV as of 2009. Table 3. 12 shows the list of them that is scheduled to be commissioned from 2010 to 2012.

Table 3. 10 lists the conductors used for 380 kV transmission lines. Double bundled 954 MCM or triple bundled and triple bundled 1,272 MCM are used.

Table 3. 10 Conductors used for 380 kV Transmission Lines

Name of conductors	Size	Summer Capacity (MVA)	Spring/Autumn Capacity (MVA)	Thermic Capacity (MVA)
2B, Rail	2 x 954 MCM	832	1,360	995
2B, Cardinal	2 x 954 MCM	845	1,360	1,005
3B, Cardinal	3 x 954 MCM	1,268	2,070	1,510
3B, Pheasant	3 x 1,272 MCM	1,524	2,480	1,825

Sets of series capacitors are installed at the ends of the 380 kV transmission lines with large distance from the eastern area where hydropower stations are located to the central area in order to maintain system stability. The allowable fault current is 50 kA for the 380 kV power network systems.

Table 3. 11 Existing 380 kV Transmission Lines (2009)

	Nominal Voltage (kV)	From	to	Distance (km)	Conductor	No.of Circuits	No.of Conductors
1	380	Adana	Erzin	68.13	954	1	2
2	380	Adana	İskenderun	45.8	1272	1	3
3	380	Adana	Seydişehir	354	954	1	2
4	380	Adapazarı	Bursa DGKÇS	139.9	954	1	2
5	380	Adapazarı	Çayırhan	134	954	1	2
6	380	Adapazarı	Gökçekaya	101.9	954	1	2
7	380	Adapazarı	Paşaköy	103.5	954	1	3
8	380	Adapazarı	Osmanca	63.7	954	1	2
9	380	Adapazarı	Tepeören (K.)	86.9	954	1	2
10	380	Adapazarı	Tepeören (G.)	86.4	954	1	2
11	380	Ada I DGKÇS	Ada II TM	19.5	1272	1	3
12	380	Ada I DGKÇS	Ada II DGKÇS	0.5	954	1	3
13	380	Afyon II	Seydişehir	183.4	954	1	2
14	380	Aliağa II	İzmir DGKÇS I	0.9	1272	1	3
15	380	Aliağa II	İzmir DGKÇS II	0.9	1272	1	3
16	380	Aliağa II	İzmir (Işıklar)	47.5	954	1	2
17	380	Aliağa	Soma	81.9	954	1	2
18	380	Aliağa	Uzundere	69.5	954	1	3
19	380	Aliağa	Manisa	38.8	954	1	3
20	380	Alibeyköy	Hamitabat	149.6	954	1	3
21	380	Alibeyköy	İkitelli	19.9	954	1	3
22	380	Alibeyköy	Ümraniye	21.8	954	1	3
23	380	Alibeyköy	Paşaköy	45.7	954	1	3
24	380	Alibeyköy	Yıldıztepe	5.3	954	1	2
25	380	Ambarlı DGKÇS	İkitelli	15.8	954	1	2
26	380	Ankara II (Sincan)	Çayırhan	78	954	1	2
27	380	Ankara II (Sincan)	Gölbaşı	33.8	954	1	2
28	380	Ankara II	Kayabaşı	289.4	954	1	3
29	380	Ankara II (Sincan)	Osmanca	174.3	954	1	3
30	380	Ankara II	Temelli	26.3	1272	1	3
31	380	Altınkaya	Çarşamba	93	954	1	3
32	380	Altınkaya	Kayabaşı	99.5	954	1	2
33	380	Atatürk	Birecik	61.1	954	1	2
34	380	Atatürk	Elbistan B	178	954	1	3
35	380	Atatürk	Gaziantep II	102.9	954	1	3
36	380	Atatürk	Karakaya	158.5	954	1	3
37	380	Atatürk	Şanlıurfa II	63.8	954	1	1
38	380	Atatürk	Göksun-Y.Hisar(G.)	320.4	954	1	2
39	380	Atatürk	Göksun-Y.Hisar(K.)	316.9	954	1	2
40	380	Babaeski	Hamitabat	25.1	954	1	2
41	380	Babaeski	Maritsa (Bulg.)	77.3	954	1	2
42	380	Birecik	Gaziantep II	59.6	954	1	3
43	380	Birecik	Suriye	68	954	1	2
44	380	Balıkesir	Bursa Sanayii	109.5	954	1	2
45	380	Balıkesir	Soma	65.4	954	1	2
46	380	Borçka	Kalkandere	128.7		1	
47	380	Botaş (ME)	Habibler	84.1	954	1	3
48	380	Başkale	İran	53.2	954	1	3
49	380	Batman	Diyarbakır-III	92.8	954	1	3
50	380	Batman	Kızıltepe-II	105	954	1	3
51	380	Bursa Sanayii	Tunçbilek	87.9	954	1	2
52	380	Bursa DGKÇS	Karabiga	174.3	954	1	3
53	380	Bursa DGKÇS	Tepeören	138.3	954	1	2
54	380	Bursa DGKÇS	Bursa TM	16.2	954	1	3
55	380	Çarşamba	H.Uğurlu-I	18.6	954	1	2
56	380	Çarşamba	H.Uğurlu-II	18.6	954	1	2
57	380	Çarşamba	Kayabaşı	125.8	954	1	2
58	380	Çarşamba	Tirebolu-II	193.3	1272	1	3
59	380	Deçeko	Kangal	61.1	954	1	3
60	380	Deçeko	Kayabaşı	168.2	954	1	3
61	380	Denizli	Varsak (1-10 ve 363-387=ÇD, 10-363=TD)	177	954	1 - 2,	3
62	380	Denizli	Yatağan	119.6	954	1	3
63	380	Dokurcun	Paşaköy	151.4	1272	1	3
64	380	Diyarbakır- III	Karakaya	94.5	954	1	3
65	380	Elbistan A	Elbistan B	11.5	954	1	3

	Nominal Voltage (kV)	From	to	Distance (km)	Conductor	No.of Circuits	No.of Conductors
66	380	Elbistan B TM	Elbistan B (TES)(kuzey)	6.2	954	1	2
67	380	Elbistan B TM	Elbistan B (TES)(güney)	6.1	954	1	2
68	380	Elbistan A	Ürgüp-sincan	455.6	954	1	3
69	380	Elbistan B	Ürgüp-sincan	455.7	954	1	3
70	380	Elbistan A	Kayseri kap	143.2	954	1	2
71	380	Elbistan A	Keban Şalt-II	169.2	954	1	1
72	380	Elbistan	Andırın	102.6	954	1	2
73	380	Erzin	Andırın	71.5	954	1	2
74	380	Ereğli	Osmanca	48.6	954	1	2
75	380	Erzin	Gaziantep II	118.2	954	1	3
76	380	Erzin	İskenderun-II	36.9	1272	1	3
77	380	Erzurum-II	Horosan	108	954	1	3
78	380	Erzurum-II	Özlüce	203.4	954	1	3
79	380	Etibank	Seydişehir-I	2.4	954	1	2
80	380	Etibank	Seydişehir-II	2.2	954	1	2
81	380	Etibank	Seydişehir-III	2.3	954	1	2
82	380	Gökçekaya	Gölbaşı	161.2	954	1	2
83	380	Gökçekaya	Seyitömer	110.8	954	1	2
84	380	Hamitabat	Kaptançelik	96	954	1	3
85	380	Hamitabat	Bulgaristan	90.2	954	1	3
86	380	Hamitabat	İkitelli(Unimar Giriş)	23.6	954	1	2
87	380	Hamitabat	İkitelli (Unimar Çıkış)	22.8	954	1	2
88	380	Hamitabat	Unimar	85.5	954	1	3
89	380	Habibler	İkitelli	9.6	954	1	2
90	380	Habibler	Paşaköy	47.3	954	2	3
91	380	Unimar-Botaş DGKÇS	Habibler	83.5	954	1	3
92	380	Işıklar	Seyitömer	287.6	954	1	2
93	380	Işıklar	Yatağan-I	144.5	954	1	2
94	380	Işıklar	Yatağan-II	144.6	954	1	3
95	380	İkitelli	Unimar	85.5	954	1	2
96	380	Kangal	Şalt-II	130.4	954	1	3
97	380	Kaptançelik	Unimar	1.3	954	2	2
98	380	Karakaya	Şalt-I (batı)	87.7	954	1	2
99	380	Karakaya	Şalt-II (doğu)	87.8	954	1	2
100	380	Kayabaşı	Kurşunlu	216.9	954	1	3
101	380	(Kayabaşı-Sincan) Brş.N	Bağlum-I	0.6	954	1	3
102	380	(Kayabaşı-Sincan) Brş.N	Bağlum-II	0.6	954	1	3
103	380	Kayseri Kap.	Şalt-II (güney)	258.5	954	1	2
104	380	Kayseri Kap.	Şalt-II (kuzey)	258.4	954	1	2
105	380	Kayseri Kap.	Gölbaşı (G)	265.8	954	1	2
106	380	Kayseri Kap.	Gölbaşı (K)	265.9	954	1	2
107	380	Keban Şalt-II	Özlüce	263.6	954	1	3
108	380	Kemerköy	Yatağan	45.6	954	1	2
109	380	Kemerköy	Yeniköy	12.5	954	1	2
110	380	Konya-IV	Seydişehir	97.3	954	1	2
111	380	Konya-IV	Yeşilhisar	224.4	954	1	3
112	380	Kurşunlu	Osmanca	217.7	954	1	3
113	380	Manisa	Işıklar	26.9	954	1	3
114	380	Osmanca-Ada.2 DGKÇS	Habibler	231.3	954	1	3
115	380	Oymapınar	Seydişehir	84.2	954	1	2
116	380	Oymapınar	Varsak	74.5	954	1	2
117	380	Paşaköy	Tepeören	19.5	1272	1	2
118	380	PS/3	Irak	15.5	954	1	2
119	380	Seyitömer	Afyon-II	110.6	954	1	2
120	380	Seyitömer	Tunçbilek Şalt-B	42	954	1	2
121	380	Şalt 2	Şalt-I (1)	6.8	954	1	2
122	380	Şalt 2	Şalt-1 (2)	6.7	954	1	2
123	380	Şalt 2	Şalt-1 (3)	6.7	954	1	2
124	380	Şanlıurfa	Kızıltepe	148.2	954	1	3
125	380	Tirebolu	Kalkandere	133		1	
126	380	Temelli	Kargı-Dokurcun	215.2	1272	1	3
127	380	Temelli	A.Ören-Yeşilhisar (G)	287.5	1272	1	3
128	380	Temelli	A.Ören-Yeşilhisar (K)	287.7	1272	1	3
129	380	Temelli	Gürsöğüt-Tepeören	304.7	954	1	3
130	380	Tepeören	Ümraniye (güney)	30.5	1272	1	3
131	380	Tepeören	Ümraniye (kuzey)	30.3	954	1	3
132	380	Tutes B	Tutes Şalt	1.3	954	1	2
133	380	Yatağan	Yeniköy	40.5	954	1	2
134	380	Yeniköy	Uzundere	152.6	954	1	3

* * The unit of the conductor sizes is MCM

Table 3. 12 Planned 380 kV Transmission Lines from 2010 to 2012

Nominal Voltage (kV)	From	to	Distance (km)	Conductor	No.of Conductors	No. of Circuits
380	Borçka HPP-Deriner HPP	Yusufeli HPP	75	954	3	1
380	Yusufeli HPP	Erzurum	125	954	3	1
380	Karabiga 380 TM - Çan	Soma TES	160	954	3	1
380	Gercüş-Ilısu-Cizre	Sınır	30	954	3	2
380	Gercüş-Ilısu-Cizre	Sınır	100	954	3	1
380	Mersin	İskenderun İKS	110	1272	3	1
380	İsdemir 380 TM	Hatay 380 TM	65	954	3	1
380	Oymapınar HPP	Ermenek HPP	128	1272	3	1
380	Karakaya	Diyarbakır 380	18	954	3	1
380	Ümraniye	Küçükbakkalköy 380	6.3	2000	1	1
380	Mersin	Ermenek HPP	160	1272	3	1
380	Ağrı	Van	180	954	3	1
380	Batman - Siirt	Van	65+205	1272	3	1
380	Van	Başkale	105	954	3	1
380	Boyabat	Altınkaya	50	1272	3	1
380	Seydişehir	Varsak	130	954	3	1
380	Temelli	Afyon 2	214	1272	3	1
380	Afyon 2	Denizli	180	1272	3	1
380	Davutpaşa	Yeni Bosna GIS TM	6	2000	1	1
380	(Bursa DGKÇS-İçdaş Karabiga)Brş.N	Bursa San.	13	954	3	2
380	Soma	Manisa	4	1272	3	2
380	Soma	Manisa	46	1272	3	1
380	Viranşehir 380 İrtibatları ETL	ŞANLIURFA	1	954	3	2
380	Özlüce	Diyarbakır 380	100	1272	3	1
380	Başkale 380 İrtibatları ETL	VAN	5	954	3	1
380	Borçka	Sınır (Gürcistan)	130	954	3	1
380	Gölbaşı	Kayaş 380 TM	30	1272	3	2
380	(Işıklar - Yatağan)Brş.N	Germencik	5	954	3	2
380	Gelibolu	Unimar	145 (2 Hat)	1275	3	1
380	İçdaş 2	Lapseki	36	1272	3	2
380	Lapseki	Gelibolu Denizaltı Kablosu	5	2000	1	2
380	Unimar (Mevcut hat yerine)	İkitelli	86	1272	3	2
380	Menemen 380 TM irtibatları	İZMİR	5	954	3	2
380	K.Maraş	G.Antep2 380	50	1272	3	1
380	Kayabaşı	Akıncı	120	1272	3	1
380	Uşak 380 TM İrtibatları	UŞAK	25	954	3	2
380	Eren TES	Osmanca	104	1272	3	2

** The unit of the conductor sizes is MCM. The red colored data indicate underground cables.

3.3.2 Power Flow of 380 kV Power Network System

The power flow on the 380 kV power network system was calculated for 2015 using the PSS/E data obtained from TEIAS. Figure 3. 5 shows the results of this calculation. The data contained the system model covering 380 kV and 154 kV.

The power demand at the load side was around 47,070 MW and the system loss of 380 kV and 154 kV was around 1,060 MW. The capital city, Ankara, is located around TEMELLI, SINCAN, and GOLBASI. It was found out that the power flows occur from the eastern mountainous area and the Black Sea seaside coast in the northeastern area to the capital city, Ankara, and Istanbul.

However, those power flows resulted based on the model considering all the expected IPPs; therefore the total capacity of power stations was much more than the power demand. TEIAS set out the condition of generators as follows to adjust the power outputs from them for the power flow calculation.

- The operation of hydropower stations was assumed as the mode of restoring the water in their reservoirs in preparation for peak power demand.
- The full outputs of IPP thermal power stations were assumed as much as possible.

The power flow diagram also indicates the location of two following pumped storage hydropower stations.

- PSPP 27 connected to Altınkaya hydropower station
- PSPP 32 connected to Gökçekaya hydropower station

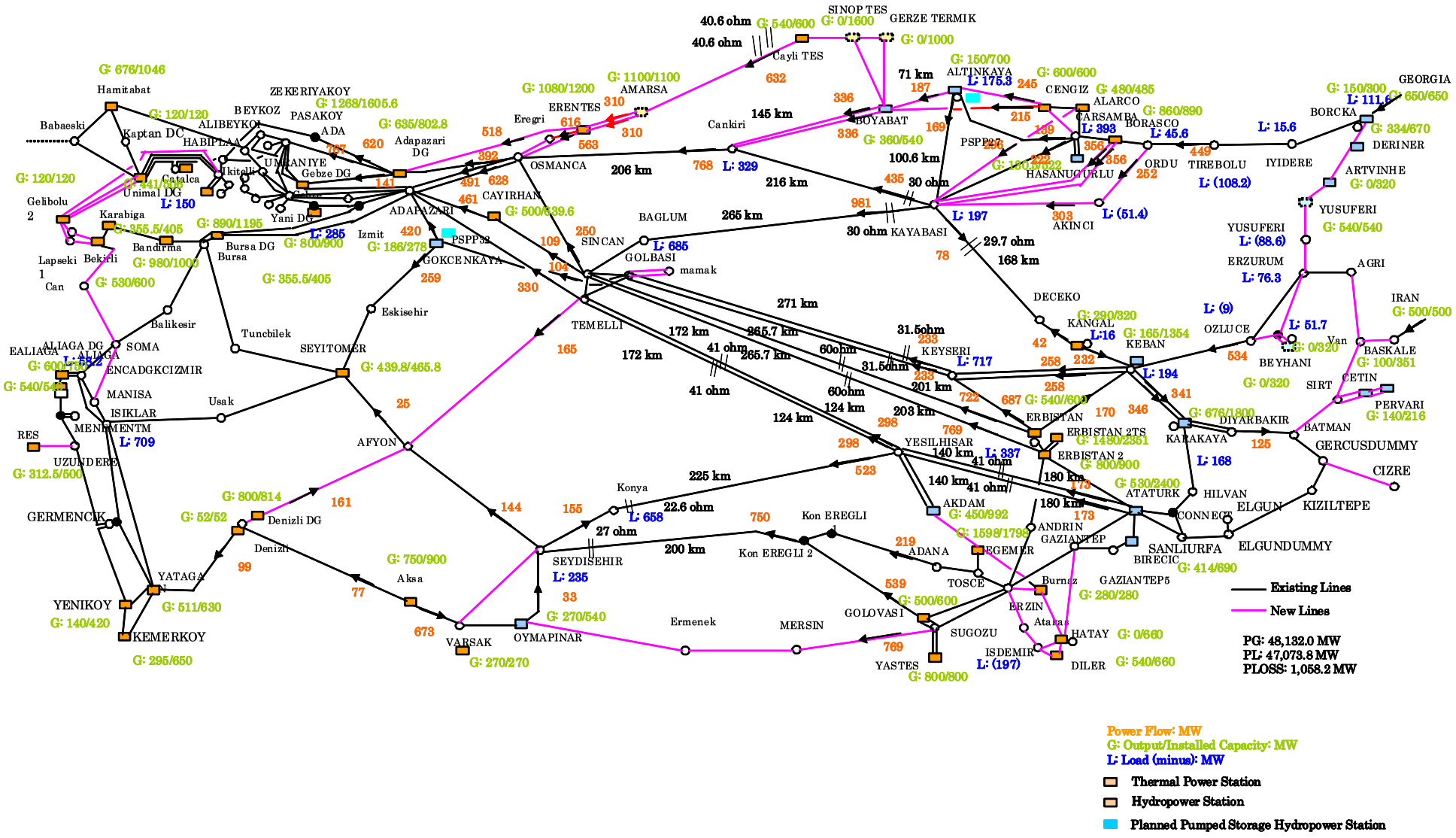


Figure 3. 5 Results of Power Flow Calculation for 380 kV System of Turkey in 2015

3.3.3 Methodology of Power Network System Planning

TEIAS establishes the criteria of transmission system, which show the preconditions for power network system planning and the technical requirements for power stations and power consumers to realize these preconditions.

These criteria determine the following items regarding the power network system planning:

- Methodology of power network system configuration
  - To make plans so as to keep the adequate capacities of power transmission lines and transformers even when a single circuit or a transformer is removed from the system (the N-1 fault occurs) while all the thermal and hydropower stations are fully operated.

- Main specifications of power system facilities
  - Descriptions of the main specifications are as follows:
    - maximum number of the feeders connected to substations, bus configurations, numbers and capacities of transformers, neutral grounding, voltage regulators, installation of high-voltage to medium-voltage transformers, connections of loads, connections of transformers, 380 kV series capacitors, capacities of shunt capacitors and reactors, conductors, phase twisting, voltage steps, load levels of distribution lines, basic specifications of generators such as power factor, types of protection relays, high-speed single-phase reclosing method, etc.
    - target power frequency level
    - target voltage level
    - power factor of generators
    - fault clearing time: 380 kV – 120 ms, 154 kV – 140 ms
    - fault current level: 380 kV – 50kA, 154 kV – 31.5 kA

The requirements for main specifications of generators, their control system, and the facilities of power consumers to be connected to the grids are determined as follows:

- Power generator control system
  - The specifications of the governors have to be reported to TEIAS when they are commissioned or modified. The main specifications of the governor, auto voltage regulator, and power system stabilizer (PSS) have to be described in the connection agreement between TEIAS and the power station company.

- Frequency control
  - The power generation unit designated as the secondary frequency control unit has to be equipped with facilities to treat the signals sent from the central dispatching center.
  - The functions or the specifications of the governors to take roles in the primary and the secondary frequency control have to obey the standards adopted for UCTE in consideration with the international connections.
- The modifications of the specifications that would affect the power network system have to be made under the technical supervision of TEIAS.
  - The specifications of the protection system installed by the network users have to obey the standards regarding the power supply reliability and its quality and the connection agreement between TEIAS and the power station company.
  - Power factors of power consumers and power generators have to be kept in the range of the predetermined levels.
- TEIAS may request for countermeasures for the sub-synchronous resonance of power generators.
- TEIAS may do load shedding by under-frequency relays.

According to these criteria, the power network plans have to be made so as to keep the adequate capacities of power transmission lines and transformers even when the N-1 fault occurs while all the thermal and hydropower stations are fully operated. However, the power system model obtained from TEIAS contains the power generation units that are not fully operated as previously mentioned.

Some power stations are not clearly planned such as IPPs. There is some uncertainty about the power network system planning that is several years away.

TEIAS will start to make the plans of the transmission lines required for the nuclear power stations located in the southern region, the Sinop nuclear power plant located in the Black Sea area, and the thermal power stations to reflect the power network system plans that will be established in 2012-2013. However, there are no specific plans of these power transmission lines as yet.

3.4 Current Status of Power System Operation

3.4.1 Overview of Power Market

Power transactions in Turkey can take two forms: based on a bilateral contract and through the power trading market. Transactions based on a bilateral contract, which is mainly a contract between a power generation company and distribution company/customers, account for over 80% of the total trading. TEIAS, a state-owned transmission company, owns and operates transmission systems while operating the power trading market via Market Financial Settlement Center, PMUM. Transactions through it account for about 20% of the total. In a sense that prices are determined by bilateral contracts or on the market, both types of transactions are made in liberalized markets.

Bilateral contracts are made between EUAS and a distribution company, between power plants built on BO, BOT, or TOR and TETAS, between TETAS and a distribution company, between a private power producer (IPP) and a private distribution company and eligible consumers, etc. TETAS is a power trading company which purchases power from generation companies privatized by BO, BOT, or TOR schemes or from the state-owned EUAS, and sells power to distribution companies such as TEDAS. Its transactions account for 45% of the entire power market. Auto producers can sell up to 5% of their generated power to others in addition to supplying to their own facilities.

The criterion for eligible consumer is those who consume 100 MWh or higher in a year. (The figure is revised in January every year. It was previously 480 MWh.) Although it is possible to choose to not to be an eligible consumer, potentially nearly 60% of power users are now eligible. In the energy strategy formulated by SPO in 2009 as well, the plan was set to encompass all consumers to be eligible except for household consumers by 2012. Household consumers are also scheduled to be eligible by 2015.

Under the policy of distribution business privatization officially decided in 2004, 20 distribution companies out of 21 distribution districts in Turkey were reorganized under TEDAS by March 2005, while the remaining one was an originally private distribution company in Kayseri district. By August 2010, tender was announced for all distribution companies with some exceptions, and the operation rights for five companies were transferred by September 2010. Privatization is conducted by transferring operation rights for the determined period (TOR method), while the ownership of its asset is retained by TEDAS and the exclusive operation right for distribution and electricity sales in the district is approved by EPDK. It is planned that the distribution license and the electricity sales license are divided by 2013 and the retail market of electricity will be deregulated.

At present, due to regulation 4628, 15 distribution companies under TEDAS must purchase 85% of power consumption of non-eligible consumers from power plants, in which there is a specified composition (6 portfolios) of TETAS and EUAS, and 15% from the power trading market. Therefore, TEDAS contracts with EUAS and TETAS as a representative of its 15 distribution companies to make up 85% of the total. In the beginning, regulation 4628 was supposed to be enforced for five years from 2004, but a 2-year extension was decided upon in 2008 to last until 2012.

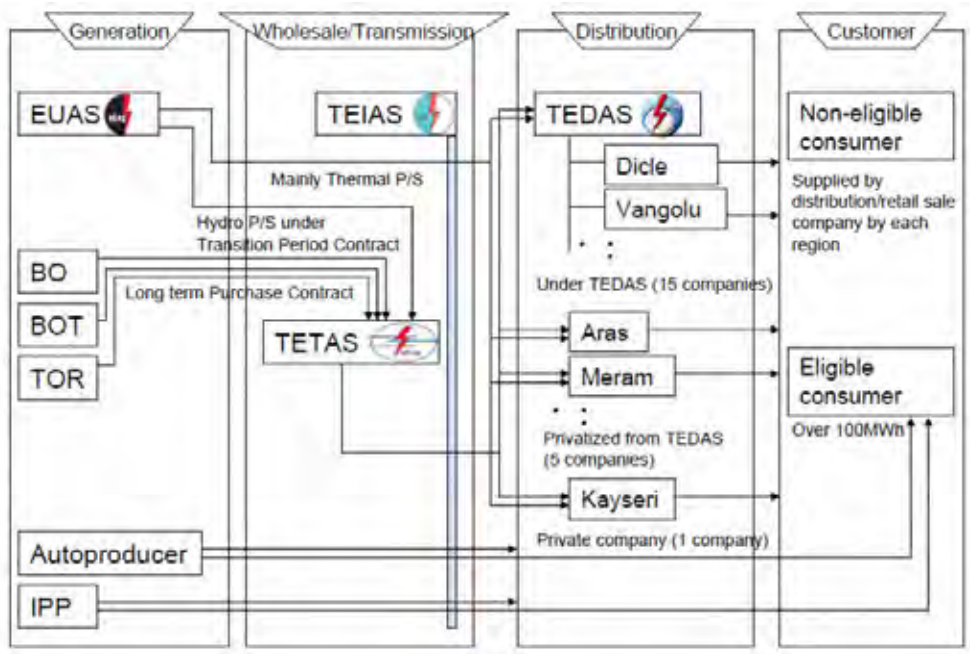
TETAS must purchase power at prices decided upon in contracts with power generation companies built by BO, BOT, or TOR schemes before the liberalization in 2001, which are rather high prices. Therefore, TETAS strikes a good balance by buying power from hydropower plants in transition period contract with EUAS (which are not immediately subject to privatization but are to be privatized after the transition period). Recently, prices from the power trading market are getting higher than these prices.

On the other hand, key players of the power trading market are independent power producers, or IPPs, and distribution companies. At present, distribution companies under TEDAS are not allowed to contract with IPPs, while private distribution companies can be supplied by IPPs via TETAS. However, prices at which TETAS purchases power shall not exceed the upper limit set by EMRA, so currently IPPs can sell at higher prices through the power trading market. Consequently, IPPs did not bid for the tender offered by TETAS. Therefore, from the viewpoint of energy security, under a new regulation, IPPs are required to make bilateral contracts as much as possible. In the Baskent Distribution Company, the distribution company for Central Anatolia around Ankara and its operation right was transferred to the Sabanci Group, one of the two big business groups in Turkey, the source of power purchase has not

changed since before privatization, and is the determined portfolio of TETAS and EUAS, at the time of August 2010.

The power trading market started on August 1, 2006. At the outset, trading was made on a daily basis. Then, in order to more accurately strike a good balance between supply and demand, hourly based transactions started on December 1, 2009. The hourly based transactions are comprised of the Day Ahead Market operated by PMUM using PYS, and the Balancing Power Market (DGP) managed on the current day by the NLDC. Prices are posted on the PMUM system.

PMUM is one unit of TEIAS, made up of 48 staff members. Its functions are diverse, ranging from operation of the Day Ahead Market to the planning and development of regulations, making and sending invoices and receipts, etc.



Source: EIE, TEIAS, TETAS, TEDAS

Figure 3. 6 Relations of Power Purchase-Supply Contracts (Bilateral Contracts)

3.4.2 Demand and Supply Operation

(1) Annual generation plan

All power plants submit their annual generation plans (monthly and daily) to TEIAS by August of the previous year. During September-December, the ETKB consults with EUAS, TEIAS, TETAS, TEDAS, fuel sales companies (coal, natural gas), and the government (ETKB and secretary of treasury) to discuss the annual generation plans for the following year.

With regard to the flow of riverine systems, DSI, a national organization, makes a decision by taking into account international cross-border water flow. A plan of maintenance outages of power plant is made by taking into consideration the annual supply/demand plan. For example, thermal power plants are often shut down between March and May and between September and November for maintenance, when hydropower plants operate at higher utilization rates.

After the formulation of the annual generation plan, generation, wholesale, and distribution companies sign mutual contracts for 1 year. In the contract, the volume by slot of the annual 8,760 hours is decided. Once the volume is finalized, monthly power trading volume can no longer be changed, but the breakdown of the daily volume of the next month can be adjusted at the end of the month to the extent that the monthly total volume does not change.

(2) Day Ahead Market

Supply/demand adjustment of the following day is made on the Day Ahead Market by using PYS managed by PMUM.

Demand forecast and supply capability of each power plant of the following day are input into PYS by 11:30. Conventionally, demand forecast of the next day was made by NLDC, but since December 1, 2009, distribution companies in regions have been required to input their demand forecasts. At the moment, however, since it is considered to be a transition period, distribution companies make no demand forecast; thus NLDC makes the actual entries. Distribution companies under TEDAS are required to input the demand in their region based on the demand forecast TEDAS sends to them every month.

With regard to supply capability of each power plant, power plants under EUAS, power plants built on BO, BOT, or TOR and contracted with TETAS, and private generation companies input their contracted power generation plans (in cases of bilateral contracts, only the amount is input, not the prices), prices when output is raised, and prices of lowered output at each time zone. In order for this, power plants under EUAS send the following day's generation plans to EUAS by 9:00 and EUAS makes their entry. TETAS makes entry on behalf of its contracted power plants of BO, BOT, and TOR while it gives approval of entered values regarding hydropower plants under EUAS with which TETAS has contracts.

The average of these prices at this point is made public as the early average price. Based on the price, the discrepancy between the demand forecast and supply plan is adjusted and the transaction closes at 14:00.

Then, from 14:00 to 16:00, entered values are checked, and at 16:00, the daily production program and the daily price are determined and the generation plan of the next day is posed on PMUM.

(3) Current day market

Once generation plans are determined for the following day in the Day Ahead Market, adjustments are made in the current day market by DGP managed by NLDC. If the output of a generator exceeds or goes below the amount determined on the Day Ahead Market, the price and changeable range are input (by 16:00) and the transaction closed at 18:30.

With regard to the supply operation on the current day, the operator determines the generator from the list of operation orders posted on PMUM, posts the determined values on PMUM at least 15 minutes before the operation starts, and informs the related LDC of the values.

If an accident/trouble breaks out at a power plant which makes it unable to supply the planned power, the alternative amount is purchased by PMUM from the current day market at the cost of the power plant which had been scheduled to supply the power. Therefore, in order to avoid paying the penalty, some power plants have operational reserve capacity as emergency backup.

(4) Frequency control

The standard frequency is 50.0 Hz and the actual frequency is controlled to stay within 49.8-50.2 Hz.

Ancillary services offered include primary frequency control to adjust the fluctuation due to demand changes in several seconds or minutes, secondary frequency control to adjust the demand changes in several minutes to 15 minutes, and tertiary frequency control for demand change for 15 minutes or longer.

The primary frequency control changes the output of the generator in accordance with the change in frequencies through the governor of the generator. With the exception of renewable energy power plants (run-off river-type hydro is included), it is applied to power stations with units of output of 50 MW or higher, or to power plants with total output of 100 MW or higher. It is required to reserve 2% of those generators' capacity for governor-free portion to enable it to respond to the frequency change, and payments are made for the reserve as part of the contract (three-month fixed price by unit price control). As a whole, a total of 110 power plants with the total capacity of 700 MW are reserved for this. Out of primary control reserves, 50% must start up within 15 seconds and the entire reserve must start within 30 seconds and continue for 15 minutes. If plants subject to this control find it technically

difficult to conduct such quick adjustments, as in the case of coal-fired thermal plants, they can purchase 2% reserve from other companies or have their other generation facilities to take its place.

The secondary frequency control is conducted through the AGC function of EMS/SCADA system at NLDC. Similar to the primary frequency control, it is applied to power stations with units of output of 50 MW or higher, or to power plants with total output of 100 MW or higher. The reserves for this control are determined to be kept 700 MW in total, apart from the reserve for the primary control. The applicable power stations are selected from power producers which bid for the possible input increase/decrease capabilities on the Day Ahead Market and offered the lowest prices. Therefore, its prices change day by day.

As for the tertiary frequency control, plants which are able to start up in about 15 minutes are selected from outaged power stations. Since they are selected from the current day market, no amount is set in advance.

3.4.3 Network Operation

(1) Load dispatching center's organizations

With the enforcement of Turkey's Power Market Act in 2001, three companies, TEIAS (transmission), TETAS (wholesale), and EUAS (generation), were established. TEIAS is engaged in network operation and management of the power trading market.

Supply/demand and grid control are conducted by the National Load Dispatch Center, NLDC, and nine local LDCs. NLDC is responsible for supply/demand control, management of the 380 kV network, and interconnecting lines with the neighboring countries, while local LDCs are in charge of the operation of 154 kV and 66 kV networks.

The planning of maintenance outage of transmission network facilities is coordinated and determined by an LDC in the region and maintenance of these facilities is carried out by the 22 field offices of TEIAS.

Table 3. 13 Area of Each Regional LDC

Local Dispatch Center	Location	Area
Thrace LDC	Istanbul (İkitelli)	Trakya (TRAKYA YTM)
North West Anatolia LDC	Adapazari (Adapazarı)	North West Anatolia (KBA YTM)
North East Anatolia LDC	Samsun (Çarşamba)	Central Black Sea (O. KARADENIZ YTM)
West Anatolia LDC	Izmir (İzmir)	West Anatolia (BA YTM)
West Mediterranean LDC	Antalya (Kepez)	West Mediterranean (B. AKDENIZ YTM)
East Mediterranean LDC	Adana (Çukurova)	East Mediterranean (D. AKDENIZ YTM)
Central Anatolia LDC	Ankara (Gölbaşı)	Central Anatolia (OA YTM)
East Anatolia LDC	Erzurum (Erzurum)	East Anatolia (DA YTM)
South East Anatolia LDC	Elazig (Keban)	South East Anatolia (GDA YTM)

Source: TEIAS

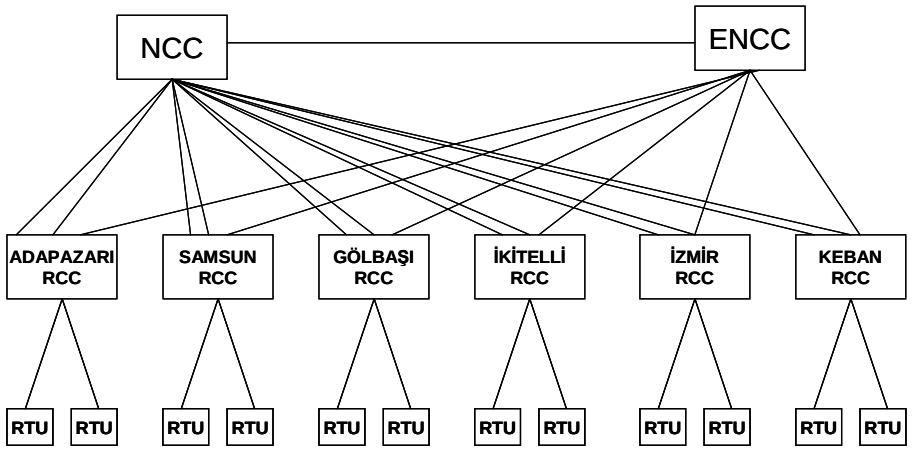
(2) Situation of SCADA system

The SCADA/EMS systems were introduced at NLDC and five LDCs along with 50 locations of RTU in the middle of the 1980s. Then, in 2004, they were replaced/installed at NLDC and six LDCs (Adapazari, Samsun, Keban, Izmir, Ikitelli, and Golbasi) and have been in operation to date. All systems are manufactured by Siemens.

Table 3. 14 Outline of SCADA and Related Systems

NLDC	SCADA/EMS system
Emergency NLDC	SCADA/EMS system
Regional LDC (9 centers)	SCADA system: installed in 6 centers
RTU	205 units are installed
Remote control substation	11 substations
AGC (Automatic Generation Control)	Installed in more than 25 power stations

Source: TEIAS



(NCC=NLDC, ENCC=Emergency NLDC)
Source: TEIAS

Figure 3. 7 Data Transmission Route among EMS/SCADA Systems

Six local LDCs equipped with the SCADA system are able to monitor the power system they are responsible for, while LDCs without the SCADA system have temporarily installed the NLDC's network monitoring terminals to be able to grasp the situation of the national power systems.

Power systems subject to monitoring are currently the 380 kV transmission network and power stations of 50 MW or higher. RTUs are installed at 205 locations, which collect 80% of ON/OFF and numerical online data. A plan is to expand the subjects of monitoring further and install RTUs at about 100 locations a year.

All the substations are manned and local LDCs give operational command to them via telephone. There are 11 substations which can be remotely controlled in the area of Istanbul LDC and are composed of gas insulated equipment.

A dispatcher training simulator (DTS) for LDC operators is located in the same building as NLDC and connected to LDCs via telecommunication line. At present, however, due to low capacity of the telecommunication line, local LDC operators receive training at the NLDC. NLDC for emergency is located in the basement of TEIAS head office and can substitute the function of NLDC at emergency.

(3) Situation of NLDC

- NLDC is responsible for power system operation, supply/demand control, and supply quality management. Operation work is conducted by three shift teams, with one team composed of four to five operators and a chief. Out of four to five operators, two are engineers, who are responsible for selecting generators from PMUM.
- Real-time clock and frequency time clock are set on the upper section of the network monitoring board in the control room, with several minutes of discrepancy. There is no standard to match frequency time with real time (i.e. no requirement for adjusting frequency time to match real

time).

- The target for frequency adjustments is in the range of 49.95 - 50.05 Hz.
- In supply/demand control, NLDC selects the most economical power plant from the currently available power plants, and contacts the selected plant via PMUM system and telephone to give command on change in generating output.
- N-1 criteria are used for supply reliability.

Photo 3.1 NLDC Control Room

Photo 3.2 NLDC Control Room (Monitoring Board)

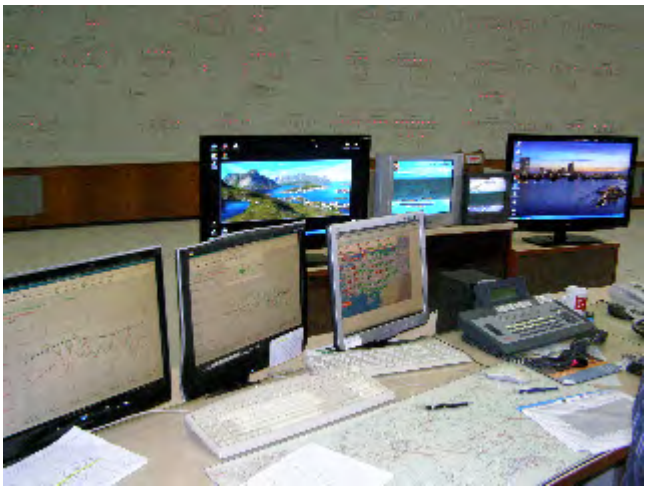


Photo 3.3 NLDC Control Room (Console)

(4) Situation of Central Anatolia LDC

- Central Anatolia LDC covers 13 provinces, which includes 380 kV substations at 11 locations and 154 kV substations at 93 locations.
- It is operated in three shifts, with each shift consisting of three operators and a chief.

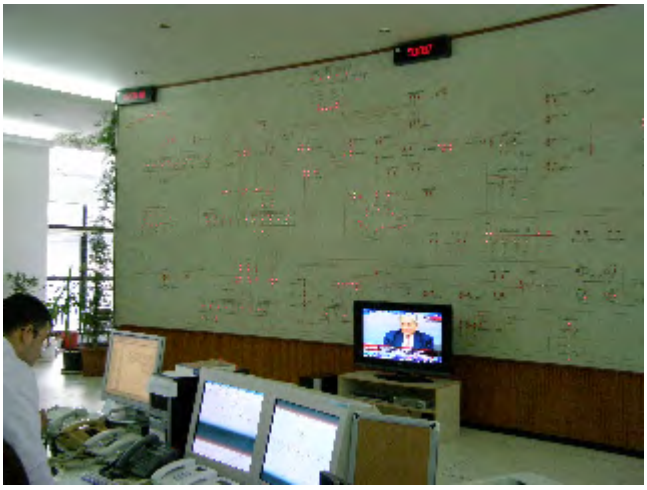


Photo 3.4 Central Anatolia LDC Control Room

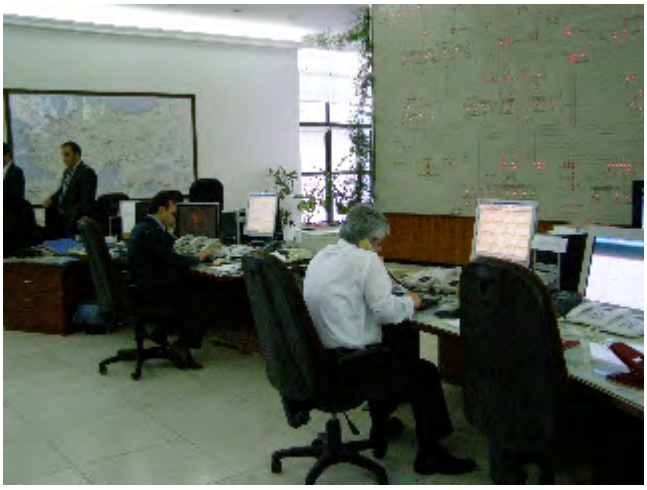


Photo 3.5 Central Anatolia LDC Control Room

(5) Situation of Istanbul (Trakya) LDC

- The Istanbul LDC is responsible for power systems in provinces on the European side of Istanbul from the Bosphorus and Dardanelles straits and other provinces on the European side of Turkey. Power demand in these areas is 5,500 MW, accounting for one-sixth of the entire demand of Turkey.
- Recent (mid-May 2010) demand is 2,500 MW (minimum) to 4,500 MW (maximum) on weekdays, and 2,050 MW (minimum) to 3,100 MW (maximum) on Sundays.
- There are four transmission lines of 380 kV and two transmission lines of 154 kV across the Bosphorus Straits. The capacity of four 380 kV lines is 4,500 MW in total. Power usually flows in from the Asian side at 1,000 MW (low demand) to 2,000 MW (peak demand).
- The LDC monitors 380 kV substations at 12 locations and 154 kV substations at 59 locations in a total of 71, more than half of which collect information online. The LDC collects operational data six times a day via telephone.
- Regional characteristics: On the European side of Istanbul, in particular, major conglomerates are concentrated and 95% of financial institutions are located in the region. It is one of the most important areas in Turkey. Most of the transmission lines have been already undergrounded. There are substation control centers which remotely control GIS facilities. Supply capacity is almost equal to demand, most of which are gas-fired thermal power plants.
- Voltage is controlled by transformer tap and compensators. When voltage deviates from the specified range, the LDC contacts the substation to make adjustments. Usually based on the communication from a substation and monitoring from LDC, voltage adjustment is determined. No voltage adjustments are necessary at normal demand increase, and most adjustments are to curb the increase in voltage during low demand hours.
- A project to interconnect the Dardanelles Straits with a 380 kV transmission line is scheduled to be complete in 2014.
- The LDC has 29 employees (10 engineers, 15 technicians, and 3 general affairs and finance staff members).
- Operation work is conducted in three shifts by four units, with each unit composed of four members.
- Adjacent to Istanbul LDC is the Ikitelli substation, one of the most important substations in the country with two units of 380/154 kV, two units of 380/33 kV, and two units of 154/33 kV.
- The bus bar of the substation consists of double bus bars and a bus bar for switching.
- The telecommunication systems are optical fibers and PLC (wireless telecommunication is not used).

- Downstairs of Istanbul LDC is a substation control center, SCC, from which 11 substations are remotely controlled. The SCC control room has no monitoring board, and monitoring/control is done only from the console.
- SCC's monitoring console has the identical configuration as that of LDC (manufactured by Siemens) and remote control functions are added. At the SCC, two operators take turns.

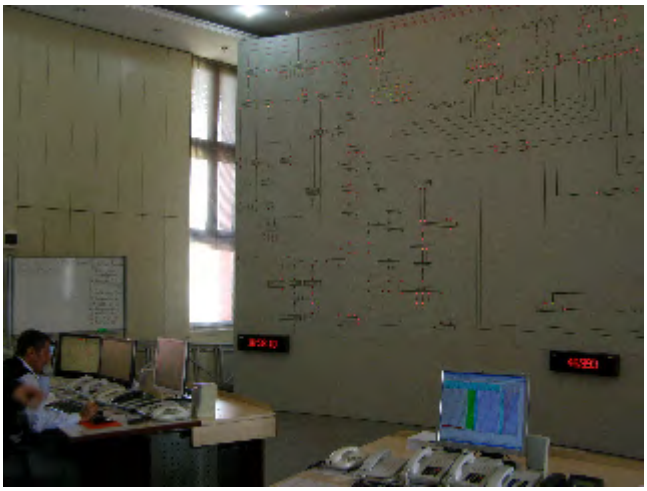


Photo 3.6 Istanbul LDC Control Room

Photo 3.7 Istanbul LDC Control Room

(6) Situation of Izmir (West Anatolia) LDC

- It covers six provinces of Aegean region, west of Turkey.
- There are 76 power plants with the existing generation capacity of 7,500 MW. Energy supply capability for 2010 is 46,000 GWh. The energy consumption in 2009 was 31,000 GWh against the target of 35,000 GWh. Peak demand of 2009 was 5,777 MW.
- Due to regional characteristics, the shift to the summer peak was early compared with the other regions. Until 2000 peak demand occurred in winter (18:00 to 19:00 in December and January), but since 2000 peak demand has been seen in summer (14:00 to 15:00 in July and August).
- The number of covered substations is eight locations of 380 kV and 83 locations of 154 kV. The number of power plants is six locations of 380 kV and 21 locations of 154 kV. The total capacity of substations is 17,750 MVA。
- The number of power plants monitored by SCADA system is 22 locations of 380 kV and 48 locations of 154 kV. This includes substations in the Antalya region. There is a plan to install RTUs in all of the above-mentioned substations in the future.
- SCADA system was introduced in Izmir LDC in 1989. Antalya LDC (which used to be covered by Izmir LDC and has separated in recent years) is yet to be equipped with SCADA.
- Transmission lines which are interconnected with neighboring regions include 380 kV transmission line (600 MW) 3cct (Adapazari (northwest) 2cct, Mediterranean Sea 1cct), 154 kV transmission line (60 MW) 16cct (Adapazari 10cct, Mediterranean Sea 6cct).
- Generators of Demirkopru hydro, Kemer hydro, and Aria thermal (all of which belong to EUAS) are operated as synchronous compensators. In addition, reactive power compensation equipment is in place at the substations.
- On-load tap changers equip all 380 kV transformers and are manually operated. Operation command is made by operators at this LDC.
- Allowable voltage range is 10%, but the operational target for control is within 5%. In 380 kV systems, 340 - 420kV is set to be the operational range.
- Wind power accounts for around 12%, but has little effect such as voltage fluctuations so far.

Problems may arise in 2015 when the ratio of wind power is expected to grow. The Izmir LDC independently makes wind condition forecast as a countermeasure.

- Compensation for reactive power using generators shall be also made by private generation companies other than EUAS. Since August 1, the cost for it shall be paid as well. This is a "must" ancillary service, and if it is not fulfilled, penalty will be imposed.
- There was a disturbance which affected the entire Aegean region in 2006. Transmission line faults occurred regularly.
- As regional characteristics, Izmir and Manisa are industry-centered whereas Aydin and Mugla are tourism-centered. Since coastal regions are summer resorts, there is a great gap of 1.5 or 2 times between summer and winter. When compared to the situation 10 years ago, the use of air conditioners has been spreading and today almost all households are equipped with air conditioners.
- Hydropower plants in the region are developed for irrigation, and thus cannot be used for peak demand. Therefore, peak demand is basically fulfilled by power from outside the region. Interchange capability is: 380 kV × 3cct : 600 MW × 3 = 1,800 MW, 154 kV × 16 cct : 60 MW × 16 = 960 MW.
- There are automobile factories at two locations in Adapazari and three locations in Bursa, generating night demand.
- Izmir LDC has 35 staff members, having four shift units with each having four operators.
- As measures against short-circuit capacity, increasing capacity of circuit breakers and splitting bus bar of substations are undertaken.
- Isikla substation is located adjacent to Izmir LDC.

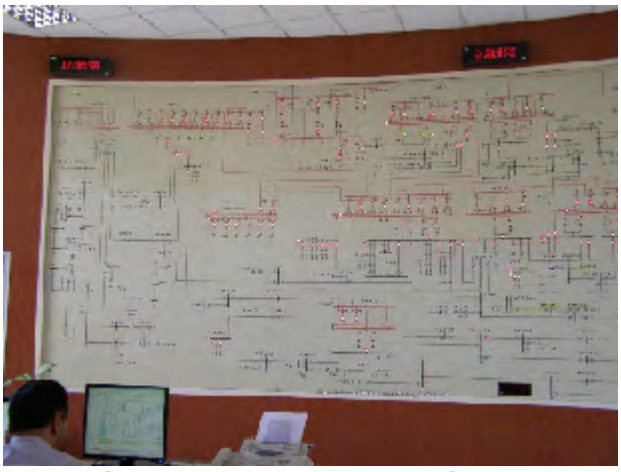
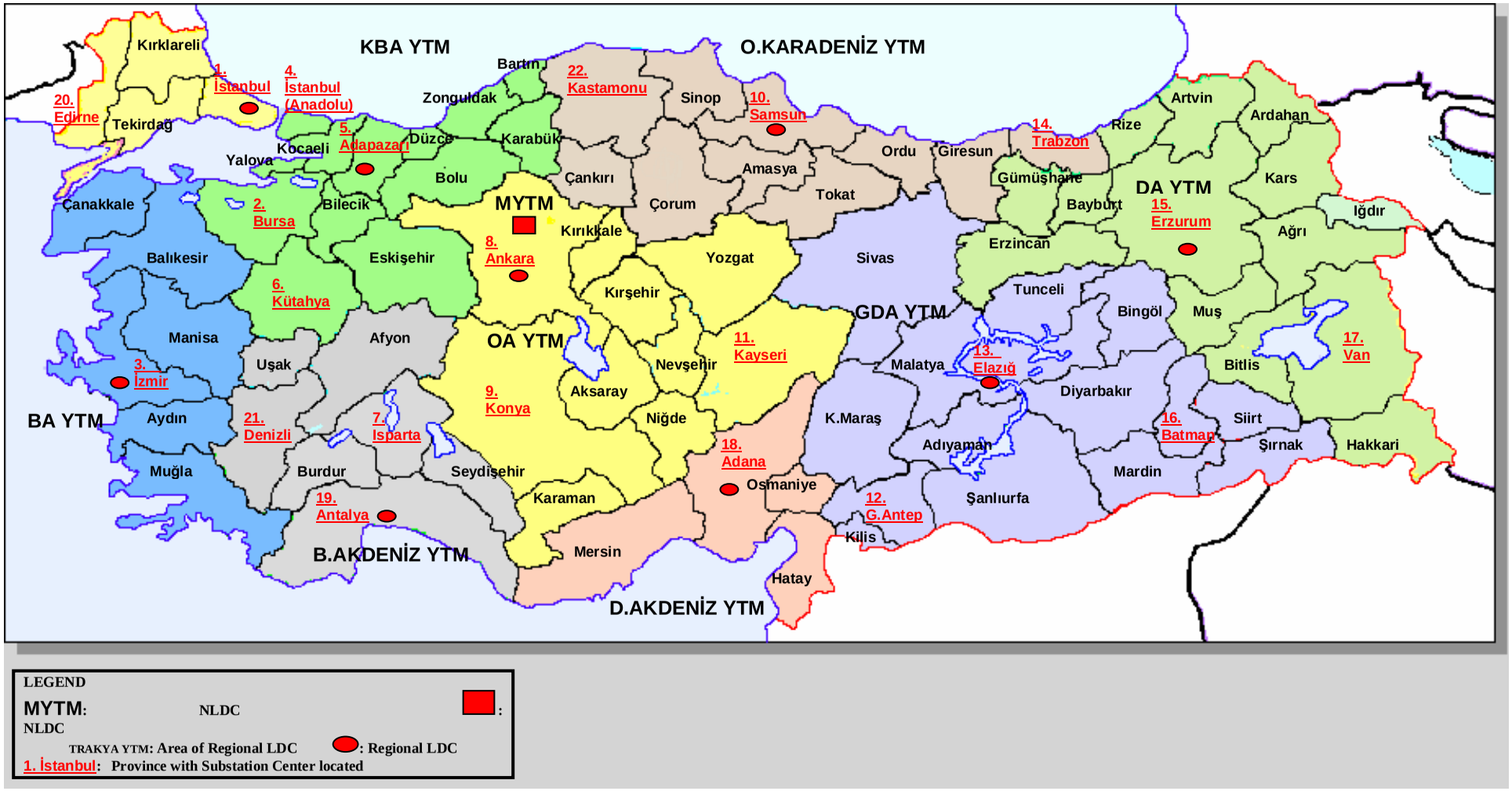


Photo 3.8 Izmir LDC Control Room

Photo 3.9 Izmir LDC Control Room



Source: TEIAS

Figure 3. 8 Area of Each Regional LDC

Chapter 4 Optimal Power Generation for Peak Demand

4.1 Preliminary Analysis

4.1.1 Review of Existing Power Development Analysis by WASP4

TEIAS had conducted the Turkey's power development analysis employing software WASP-4 until 2004 (hereafter WASP study). The latest version was issued in November 2004 ("Turkish Power Development Planning 2005-2020"). The analysis has not been updated since then. This subsection reviews the approach of the analysis by TEIAS. This JICA study cites figures/values of specific items from the WASP study, like the technical data of existing power plants.

According to the latest version of WASP study in 2004, the analysis was conducted in the following manner: (1) demand forecast by the Ministry of Energy and Natural Resources (MENR) employing a software MAED; (2) supply capacity projection by TEIAS based on meeting the demand projection by MENR; (3) TEIAS employing of a software, WASP4, by TEIAS for the economically most optimal mixture of power plant development.

The main premises are summarized as shown below:

- Planning period: Years 2005 to 2020
- Demand forecast: Scenario 1: 7.9%, Scenario 2: 6.4% for peak demand.
- Major policies:
  - Fuel: the use of natural gas for power generation is limited below 30 billion m^3/year, while the supply of gas is guaranteed equal to or over 20 billion m^3/year. The use of import coal for power generation is limited below 15 million ton/year (equivalent to 6,000 MW).
  - Annual operation (power generation) hour: the hour for existing thermal plant is assumed to be 6,500 hour (equivalent to capacity factor of 75%), while that for candidate thermal plant is assumed to be 7,000 hour except for coal-fired plant, for which it is 6,500 hour (equivalent to capacity factor of 80% and 75%, respectively).
  - Primary resource reserve: the reserves by fuel type are assumed in the following manner:
    - Domestic lignite: 18,790 MW (120 billion kWh), of which 6,520 MW (42 billion kWh) are in operation; 2,200 MW (11 billion kWh) are under construction or license obtained; and 10,070 MW (67 billion kWh) are considered as candidate.
    - Coal: 1,755 MW (11 billion kWh), of which 555 MW (3.1 billion kWh) are in operation and 1,200 MW (7.8 billion kWh) are candidate.
    - Hydraulic capacity: 36,355 MW (129 billion kWh), of which 12,578 MW (45 billion kWh) are in operation; 3,254 MW (11 billion kWh) are under construction or license obtained; and 20,423 MW (74 billion kWh) are candidate.
  - Precipitation: The probability of an average rainy year is set as 65%, that of an ample rainy year is set as 20%, and that of a dry year is set as 15%, based on the statistics in the past 30 years. The amount of precipitation of dry year is as low as around 40% of that of the average rainy year.
  - LOLP (loss of load probability): set as 2%, is equivalent to 175 hours per year of LOLE (loss Of load expectation). The power shortage cost is set as 1 USD/kWh.

Table 4. 1 shows the detail setting of existing thermal power plants. The data shown stand for the values as of the end of year 2006.

Table 4. 1 Existing Thermal Plants Data

Plant's name	Unit power		# of unit	Plant's installed power [MW]	Yearly generation [GWh]	Heat consumption [kcal/ kWh]			Maint. duration [day/ year]	Forced outage rate [%]	Average calorific value [kcal/kg]	Fuel cost		O&M cost		Fuel type	Emission Factor [%of fuel]	
	Min. [MW]	Max [MW]				At Base load	Ave. Incremental	At max load				[USD /ton]	[USC/ 10^6kcal]	Fixed [USD/kW/Mo]	Variable [USD /MWh]		SOx	CO2
Catalagzi B	90	150	2	300	1,950	2,641	2,383	2,538	60	10	3,200	38.6	1,205	2.86	1.20	Hard coal	0.66	124.91
Elbistan A 1-4	221	339	4	1,356	2,203	2,803	2,641	2,747	60	10	1,050	10.4	995	1.94	0.93	Lignite	1.99	66.28
Cayirhan	90	155	4	620	4,30	2,665	2,473	2,584	60	10	1,184	14.0	1,181	4.77	4.11	Lignite	0.21	85.85
Kangal	94	152	3	456	2,694	2,753	2,690	2,729	60	10	1,300	10.3	789	3.46	0.99	Lignite	3.11	64.74
Kemerkoy	126	210	3	630	4,095	2,656	2,137	2,448	60	10	1,689	9.6	566	1.36	1.11	Lignite	3.53	73.39
Orhaneli	126	210	1	210	1,365	2,421	2,164	2,318	60	10	2,350	28.7	1,221	3.26	3.28	Lignite	0.12	99.99
Seyitomer	97	150	4	600	3,900	2,796	2,328	2,631	60	10	1,750	10.4	592	2.28	0.77	Lignite	1.55	74.71
Soma B	132	172	6	1,032	6,708	2,731	2,571	2,694	60	10	2,300	22.4	975	1.17	0.50	Lignite	1.08	82.15
Tuncbilek	105	122	3	366	2,379	2,808	2,072	2,707	60	10	2,350	34.3	1,459	3.63	1.00	Lignite	2.36	97.5
Yatagan	126	210	3	630	4,095	2,900	2,219	2,628	60	10	1,906	14.6	766	2.92	0.88	Lignite	2.64	82.08
Yenikoy	126	210	2	420	2,730	2,667	2,041	2,417	60	10	1,647	10.5	639	2.57	0.69	Lignite	2.83	72.59
Ambarli DG	100	450	3	1,350	8,775	2,061	1,670	1,757	60	10	8,383	166.3	1,984	0.35	2.33	Natural gas	0	220.87
Hamitabat	90	280	4	1,120	7,280	2,977	1,368	1,885	60	10	8,116	171.7	2,115	0.65	0.07	Natural gas	0	220.87
Bursa	360	716716	22	1,432	9,308	1,806	1,319	1,564	60	10	8,347	171.0	2,049	0.47	0	Natural gas	0	220.87
Ambarli + Hopa	100	170	4	680	4,420	2,390	2,204	2,3113	60	10	9,600	218.0	2,271	0.77	0.11	Fuel oil	2	312.44
Aliaga GT	30	30	6	180	1,170	2,660	0	2,660	60	10	9,600	427.4	4,452	2.54	0.11	Motor	2	312.44
Yi D.Gas	340	679	7	4,753	30,895	1,806	1,322	1,564	60	10	8,347	171.0	2,049	0.47	0	Natural gas	0	220.87
Auto producer	260	260	6	1,560	10,140	3,500	0	3,500	60	10	9,600	218.0	2,271	0.7	0.11	Fuel oil	2	312.44
Yeni Autoproducer	122	244	14	3,416	22,204	1,806	1,322	1,564	60	10	8,347	171.0	2,049	0.47	0	Natural gas	0	220.87
YiD	360	725	2	1,450	9,425	1,806	1,322	1,562	60	10	8,347	171.0	2,049	0.47	0	Natural gas	0	220.87
EUAS others	24	24	1	24	156	2,660	0	2,638	60	10	10,300	458.6	4,452	2.54	0.11	Motor	2	312.44
Yi iTH.Kom	380	758	2	1,516	9,85	2,556	2,155	2,356	60	10	6,000	50.0	833	4.98	2.38	Import coal	0.08	227.17
Can	75	160	2	320	2,080	1,973	1,853	1,909	60	10	2,600	49.3	1,896	3	1.00	Lignite	0.2	64.74
Elbistan B	103	344	4	1,376	8,944	2,399	2,322	2,352	60	10	1,050	10.4	995	3.31	5.06	Lignite	0.1	66.28
Mobile	124	265	3	795	5,168	2,390	2,245	2,313	60	10	9,600	218.0	2,271	1.53	0.29	Fuel oil	2	312.44

Hydrological projects are separated into two different parts according to capacity factors titled HYDA and HYDB. In both parts, hydrological candidates are classified according to basin, priority, and cost. Data shown in Table 4. 2 were calculated from data as of the end of year 2006.

Table 4. 2 Existing Hydropower Plants Data

	HYDA				HYDB			
	Installed capacity: 11,202 MW				Installed capacity: 3,173 MW			
	O&M (FIX) cost: 0.33 USD/kW-Mo.				O&M (FIX) cost: 0.33 USD/kW-Mo.			
	Average year's operation				Average year's operation			
	Project 1: 5,606 MW Regulated energy: 677 GWh				Project1: 1,366MW Regulated energy: 187 GWh			
	Base [MW]	Peak [MW]	Peaking Energy [GWh]	Hours / day (working days)	Base [MW]	Peak [MW]	Peaking Energy [GWh]	Hours / day (working days)
Q1	885	3,824	1,650	6.6	245	902	457	7.8
Q2	2,130	3,196	1,316	6.3	589	709	364	7.9
Q3	1,065	3,868	2,850	6.3	295	908	789	13.3
Q4	1,092	3,673	2,592	11.3	302	859	717	12.8
	Project 2: 5,606 MW Regulated energy: 677 GWh				Project2: 297MW Regulated energy: 29 GWh			
Q1	885	3,824	1,650	6.6	37	212	68	4.9
Q2	2,130	3,196	1,316	6.3	90	193	53	4.2
Q3	1,065	3,868	2,850	6.3	45	217	112	8
Q4	1,092	3,673	2,592	11.3	46	207	110	8.1
					Project3: 800MW Regulated energy: 687 GWh			
				Q1	114	523	235	6.8
				Q2	275	456	190	6.4
				Q3	138	540	389	11.1
				Q4	141	513	355	10.6
					Project 4: 710MW Regulated energy: 271 GWh			
				Q1	93	504	212	6.5
				Q2	224	449	188	6.4
				Q3	112	512	345	10.3
				Q4	115	488	322	10.1
	TOTAL				TOTAL			
	Base [MW]	Peak [MW]	Peaking Energy [GWh]	Available [MW]	Base [MW]	Peak [MW]	Peaking Energy [GWh]	Available [MW]
Q1	1,770	7,684	3,300	9,418	489	2,151	972	2,640
Q2	4,260	6,392	2,632	7,904	1,178	1,806	795	2,985
Q3	2,141	7,735	5,700	9,866	589	2,177	1,635	2,766
Q4	2,184	7,346	5,184	9,530	604	2,067	1,503	2,671

As reference, Table 4. 3 shows the values used in WASP study.

Table 4. 3 Input Data for Calculation of Generation cost for Future Power Plant.

Item	Unit	Lignite	Lignite (Elbistan)	Hard coal	Imported coal	Natural gas-1 (NGY2)	Natural gas-2 (NGYE)	Nuclear	Hydro-A/B
Installed capacity per unit	MW	160	360	300	500	275	700	1500	
Unit power (Min.)	MW	75	103	147	244	150	350	750	
Life time	Year	30	30	30	30	25	25	30	50
Unit construction cost (w/o interest)	USD /kW	1,400			1,200	750	600	1,750	1,000-1,200
Foreign	USD /kW	L15A: 1,498	L350: 1,551	HC30: 1,467	CIMP: 1,290	749	599	1,978	HYDA: 270-680 HYDB: 250-600
Domestic	USD /kW	L15A: 180	L350: 175	190	106	102	82	495	HYDA: 500-1,260 HYDB: 470-1,120
Discount rate	%	10	10	10	10	10	10	10	10
Annual operation hour	Hour	6,588	6,588	6,588	6,588	7,020	7,020	7,020	7,020
F.O.R	%	10	10	10	10	10	10	10	10
Annual Maintenance date	Date	60	60	60	60	60	60	60	60
Heat rate (at max)	Kcal/ kWh	1,909	2,352	2,456	2,356	1,593	1,566	2,620	
Heat rate (ave. incremental)	Kcal/ kWh	1,853	2,332	2,148	2,155	1,297	1,326	2,480	
Heat rate (at base load)	Kcal/ kWh	1,973	2,399	2,762	2,556	1,840	1,806	2,760	
Calorific value	Kcal/kg	2,470	1,128	3,500	6,000	8,100	8,100		
Fuel consumption	Gr/ kWh (*)	773	2,085	702	393	0.193	0.193		
Fuel cost	USC /10^6 kcal	868	445	1,293	833	1,966	1,966		
	USD/ton	21	5	45	50	180	180		
Fixed O&M cost	USD/kW/yr	36	31.44	44.28	53.64	5.64	5.64	54.6	0.33 USD /kW-Mo.
Variable O&M cost	Cent/kWh	0.1	0.295	0.148	0.203	0	0	0	
Construction period	Year	4	5	4	4	3	3	8	5

Note: Recently announced construction cost of Nuclear plant is 20 billion USD for 4,000MW, this means 5,000 USD/kW for nuclear power plants.

*: natural gas: Nm^3/kWh

Source: developed by the Study Team based on the data set used for WASP-4 and the power development plan in 2004 by TEIAS

4.1.2 Comparison between WASP and PDPAT

(1) Comparison of calculation methods of WASP and PDPAT

WASP and PDPAT are software with basically the same function of simulating supply/demand operation of power plants and evaluating power development plans from the viewpoint of economics. However, there are some differences in their respective calculation methods. Major differences between WASP and PDPAT are shown below.

Table 4. 4 Major Differences between WASP and PDPAT

Item	WASP	PDPAT
Output	・ Develop optimal power development plan for years subject to calculation	・ For a certain power development plan, simulate the most economical supply/ demand operation and calculate operational cost
Demand	・ Input annual maximum demand and period-specific maximum demand (up to 12) ・ Input annual Demand Duration Curve	・ Input hourly demand data for peak demand day, weekdays, and weekends & holidays for each month.
Operation simulation	・ Simulate by preset period (monthly, seasonally) ・ Dispatch load based on load order by using fuel cost at maximum load. ・ No simulation function on interconnection with power systems of other countries	・ Simulate monthly/weekly/daily operation ・ Dispatch load by using the equally incremental fuel cost method ・ Have simulation function on interconnection with power systems of other countries

In order to compare and understand the differences of calculation results of WASP and PDPAT, calculations were made via PDPAT on economical supply/demand operation of power development plans found to be optimum solution by the WASP calculation. WASP data provided from TEIAS were used for input data for PDPAT calculation in order to make calculation conditions consistent. However, because of disparity in input data due to the above-mentioned difference of calculation, some data processing becomes necessary. Major processing works are described below.

(a) Demand data

Because WASP data do not have hourly demand data, the hourly demand data were created from 2009 demand data obtained for this study and WASP yearly maximum demand data.

(b) Develop hydropower generation data

Since in the WASP data the year was divided into four periods, the monthly energy flow was developed based on the maximum demand ratio for each period.

(c) Operation of thermal power plants

In the PDPAT calculation, week-based operation was taken into account.

(2) Comparison of calculation result

The comparison of calculation results including operation cost and kWh balance of 2009, 2014, and 2019 is shown as follows. Despite differences in calculation methods, it was confirmed that results of supply/demand-based simulations were almost the same.

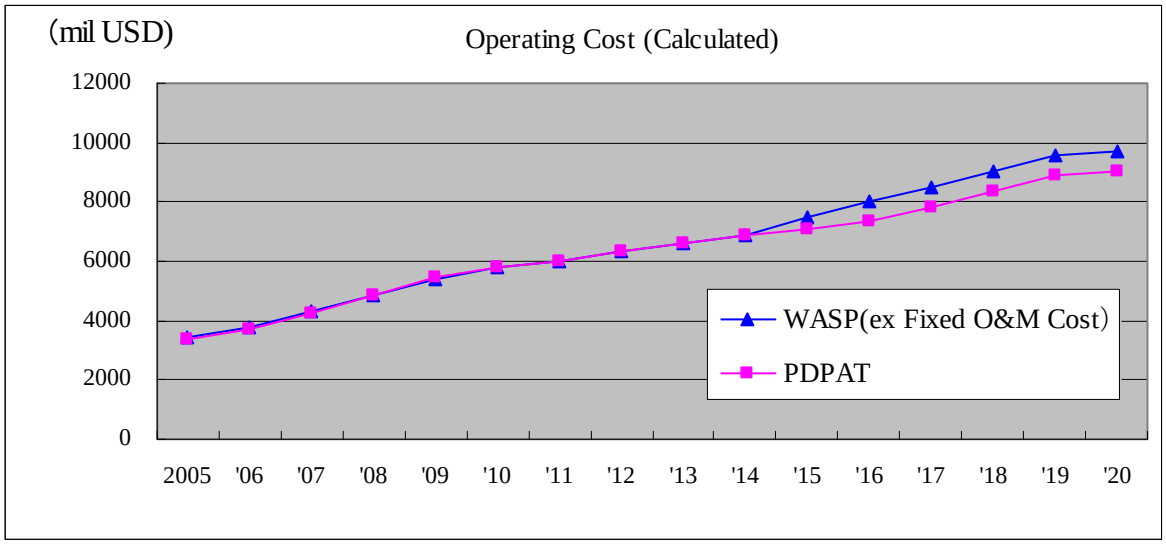


Figure 4. 1 Comparison of Calculated Operation Cost

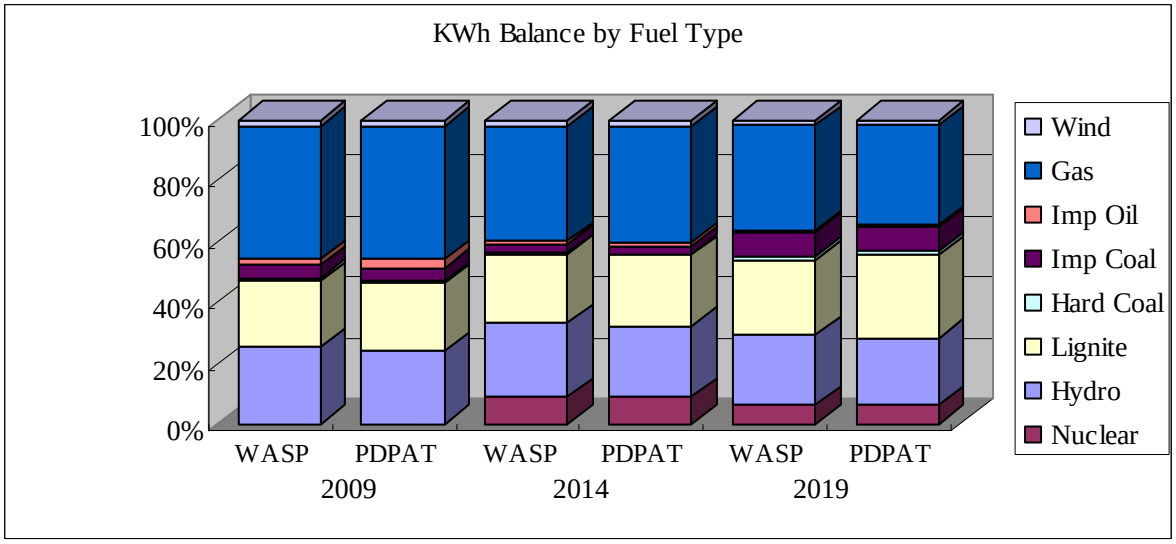


Figure 4. 2 Comparison of kWh Balance Calculated

4.2 Economic Comparison among Various Power Sources through Screening

A generating cost for each availability factor is calculated based on construction cost (fixed cost) and fuel cost (variable cost) of various power sources, and then which power source is optimal as each of base, middle and peak supply capacities are examined.

(1) Unit construction cost

Unit construction costs for various power sources provided from EIE are as in Table 4. 5.

Table 4. 5 Unit Construction Cost

	Unit construction costs provided by EIE
Natural gas-fired thermal	650 – 750 USD/kW
Lignite thermal	1,600 USD/kW
Import-coal fired thermal	1,450 – 1,700 USD/kW
Hydro (run-of-river type & reservoir type)	1,200 – 1,500 USD/kW
Nuclear	1,800 – 2,700 USD/kW

By reference to the above-described values, standard unit construction costs for various powers used for calculating the costs in the base case have been set as in Table 4. 6.

Table 4. 6 Standard Unit Construction Cost

	Values in the base case
Natural gas-fired thermal (C/C)	700 USD/kW
Natural gas-fired thermal (GT)	500 USD/kW
Oil-fired thermal (ST)	800 USD/kW
Oil-fired thermal (GT)	500 USD/kW
Lignite-fired thermal	1,600 USD/kW
Import-coal fired thermal	1,600 USD/kW
Hydro (run-of-river type & reservoir type)	1,400 USD/kW
Pumped Storage Power Plant	700 USD/kW
Nuclear	2,400 USD/kW

(2) Annual fixed cost

The annual fixed costs are calculated as shown in Table 4. 7 based on the unit construction costs described above. Generally speaking, the annual fixed costs differ depending on the depreciation methods, and are the highest just after the start of operation rather than being constant every year. In this case, equalized costs by lifetime are shown assuming that the interest rate is 10%. Note that the calculations were made assuming that the lifetimes for generation facilities are 40 years for hydro facilities where civil engineering facilities account for a large proportion, and 20 years for thermal and nuclear facilities, respectively.

Table 4. 7 Annual Fixed Cost

	Unit construction cost (USD/kW)	Annual expense rate (%)			Annual expense (USD/kW/ year)
		Interest rate, depreciation	O&M costs	Total	
Natural gas-fired thermal (C/C)	700	11.75	4.5	16.25%	113.8
Natural gas-fired thermal (GT)	500	11.75	5.0	16.75%	83.8
Oil-fired thermal (ST)	800	11.75	2.5	14.25%	114.0
Lignite thermal	1,600	11.75	3.5	15.25%	244.0
Import-coal fired thermal	1,600	11.75	3.5	15.25%	244.0
Conventional hydro	1,400	10.23	0.5	10.73%	150.2
Pumped Storage Power Plant	700	10.23	1.0	11.23%	78.6
Nuclear	2,400	11.75	3.0	14.75%	354.0

(3) Fuel cost

The fuel cost projection until 2030 published by IEA in 2009 has been used for the future fuel cost projection. The projected prices are shown in Table 4. 8.

Table 4. 8 IEA Projection

		2008	2015	2020	2025	2030
Oil	USD/bbl	97.19	86.67	100.00	107.50	115.00
Gas	USD/Mbtu	10.32	10.46	12.10	13.09	14.02
Coal	USD/tonne	120.59	91.05	104.16	107.12	109.40

Fuel costs in standard power plants in 2020 are calculated based on the price projection, as shown in Table 4. 9.

Table 4. 9 Fuel Cost

	IEA forecast (2020)		Fuel price (USC/kcal)	Efficiency	Fuel cost (USC/kWh)
Oil ST	100.0 USD/bbl	9,600 kcal/kg	7.3	38%	16.5
Oil GT	Ditto	Ditto	Ditto	29%	21.6
Gas C/C	12.10 USD/Mbtu	4.0 kcal/Btu	4.8	55%	7.5
Gas GT	Ditto	Ditto	Ditto	29%	14.2
Coal ST	104.16 USD/tonne	6,000 kcal/kg	1.7	41%	3.6

(4) Generating cost

Standard generating costs for various power sources in 2020 are calculated as shown in Figure 4. 3 based on the above-described projections of the unit construction costs and fuel costs. Note that the fuel cost for PSPP is based on the assumption that water is pumped by coal-fired thermal power and pumping efficiency is 70%. In addition, the fuel cost for nuclear power plants has been assumed to be 1 USC/kWh.

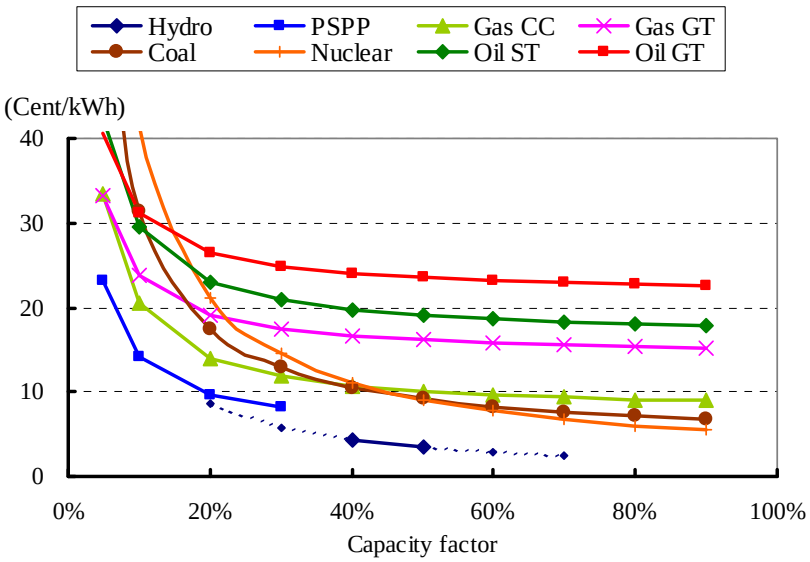


Figure 4. 3 Generating Cost

In the base supply capacity region (i.e., the range where the availability factor is 70% or more), nuclear and coal-fired thermal plants with lower fuel unit prices are economically advantageous. In the middle supply capacity region (where the availability factor is 30-60%), conventional hydro is the most excellent. This is because conventional hydro is developed preferentially in sites where the cost is lower than other power sources and economic efficiency is obtained when the availability factor is 40-50% (operation time: approx. 4000 hours).

Details of the generating costs for the peak supply capacity (i.e., the range where the availability factor is up to 20%) are as shown in Figure 4. 4.

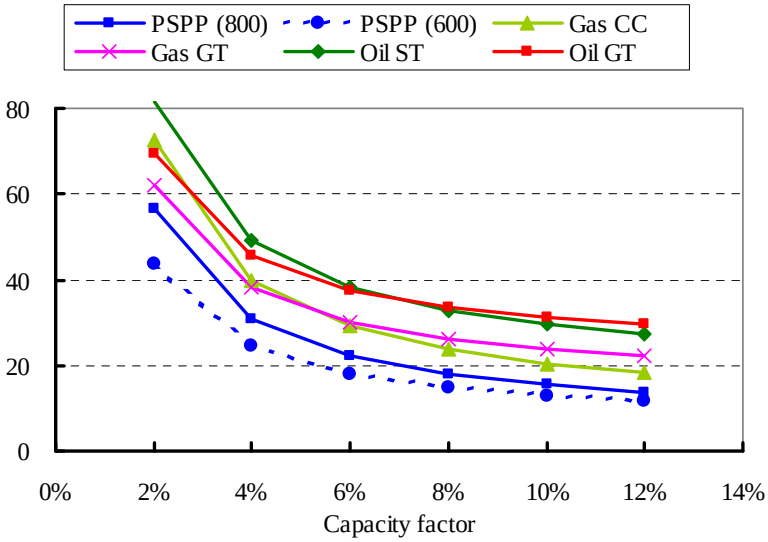


Figure 4. 4 Generating Cost (for peak supply)

The generating cost is as high as 30 cent/kWh in any facility when the availability factor is 4%. In the case where the unit construction cost for PSPP is 700USD/kW, the generating cost of PSPP is the lowest for peak supply capacity. In the case where the unit construction cost of PSPP exceeds 800USD/kW, the generating cost of gas GT is lower than that of PSPP when the availability factor is very low (with the availability factor being 2% or less).

4.3 Formulation of Data for Demand and Supply Operation Simulation

Data for PDPAT II was formulated for implementing demand and supply operation simulation by using PDPAT II.

4.3.1 Demand Forecast

(1) Future demand forecast in the capacity projection formulated by TEIAS

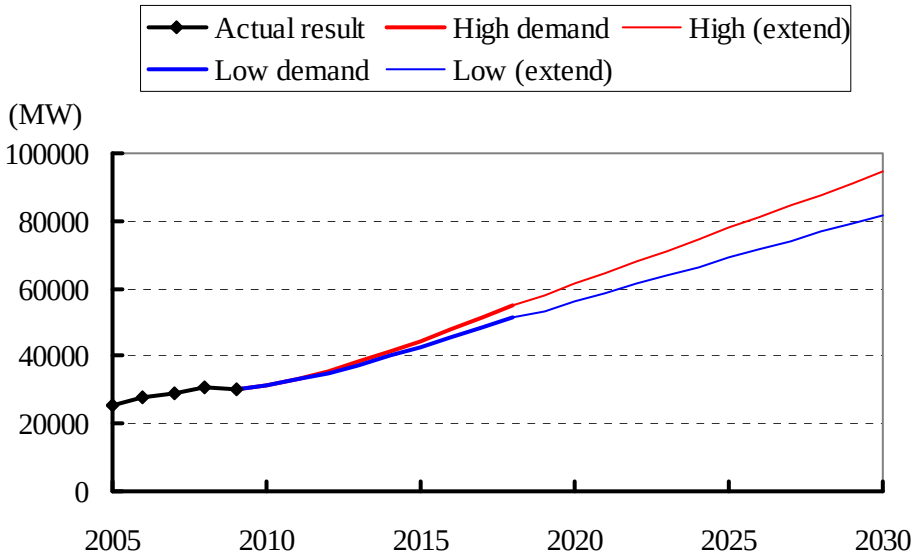
The future demand forecast in the 10-Year Generation Capacity Projection (2009–2018) formulated by TEIAS (until 2018) is as shown in Table 3. 3.

According to this projection, it is assumed that the future annual load factors will remain unchanged from the actual result of 74.1% in 2009 both for high demand and low demand. This means that the demand shape will hardly change.

(2) Peak demand forecast in 2019 and thereafter

No values published by authoritative institutions have been found regarding the demand forecast in 2019 and thereafter.

The values forecasted by the Study Team for 2019 and thereafter are shown in Figure 4. 5, expressed as extended straight lines by reference to the increase tendency until 2018 in TEIAS's projection. Since the lines are extended linearly, the rate of increase is forecasted to gradually decrease.



Formulated by the Study Team by reference to TEIAS's forecast values

Figure 4. 5 Demand Forecast until 2030

Based on this forecast, the peak load in 2030 will be approx. 80,000 MW (80 GW) for a low-demand case. The base case demand in this study is forecasted to reach the demand size of 80 GW in entire Turkey around 2030. Accordingly, the study for 2030 will be conducted for the demand size of 80 GW. Note that in a high-demand case, where the demand increases at a faster rate than forecast, the result of the study will be for about 2025, which is earlier than 2030.

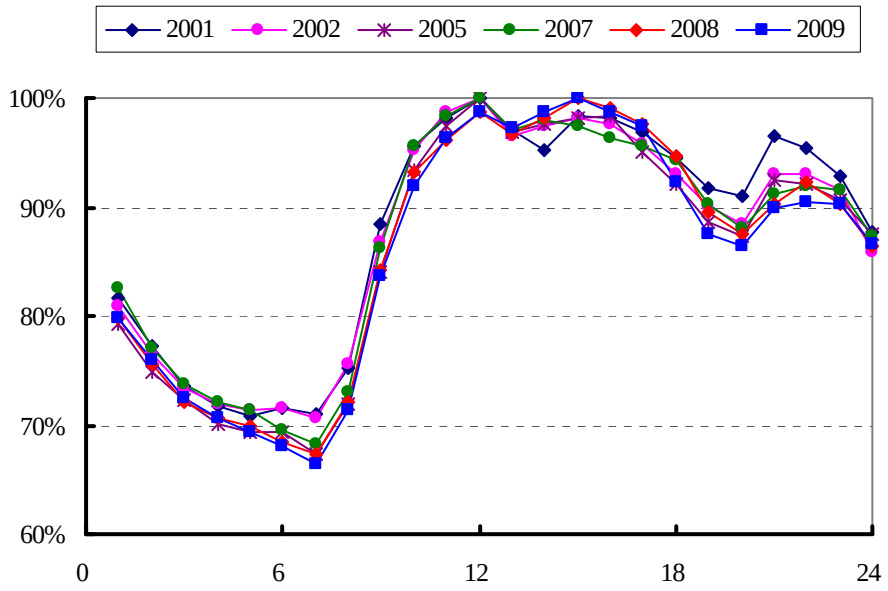
4.3.2 Current Status and Future Prospects for Peak Demand

In the demand forecast in the capacity projection formulated by TEIAS, it is forecasted that the annual load factor would be constant and the demand shape would hardly change until 2018. However, it is commonly recognized among involved parties that promoted introduction of air conditioners has led to great increase in the demand, mainly in summer daytime, recently.

On the basis of such situations, change in the future peak demand shape has been estimated.

(1) Demand shape of the maximum demand occurrence day in summer

The demand shape on the maximum demand occurrence days in summer from 2001 to 2009 is shown in Figure 4. 6.



Formulated by the Study Team based on the data provided from TEIAS

Figure 4. 6 Demand Shape on Maximum Demand Occurrence Days in Summer

Based on this, the following could be said as the trend of recent demand shapes. (The increase rate herein refers to the increase for 7 years between 2001 and 2008.)

- The maximum demand occurrence time is shifting from 12:00 to 15:00. (The annual demand increase rate at 15:00 is 8.0%, which is larger than the demand increase rate 7.5% at 12:00.)
- Lighting peak at around 20:00 and 21:00, the so-called evening lighting peak, has decreased. (The annual demand increase rate at 21:00 is 6.7%, which is the lowest among all time zones.)
- The midnight load (minimum demand/maximum demand) has been gradually decreasing. (The annual increase rate of the maximum demand is 8.0%, while the annual increase rate of the minimum demand is 6.9%.)

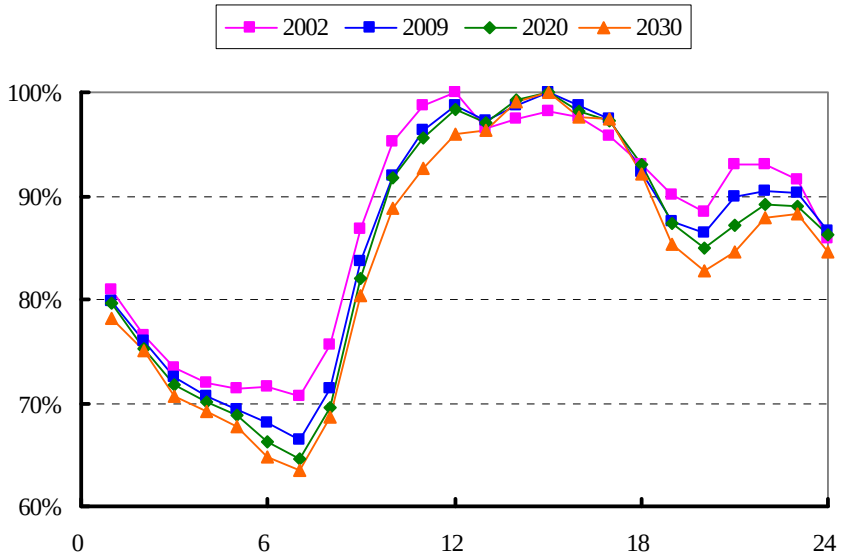
Demands when the maximum demand occurred (at 15:00) and when the minimum demand occurred (at 7:00) in individual years from 2001 to 2008 are shown in Table 4. 10.

Table 4. 10 Transition of Maximum Daily Demand and Minimum Daily Demand

	2001	2002	2003	2004	2005	2006	2007	2008	Average increase	
									(MW)	(%)
Maximum	17,839	18,427	19,680	21,484	23,457	25,945	27,962	30,482	1,806	8.0
Minimum	12,876	13,280	13,991	14,934	16,079	17,650	19,569	20,511	1,091	6.9

Formulated by the Study Team based on the data provided from TEIAS

Though the maximum demand has been increasing annually by 1806 MW on average, the minimum demand has been increasing annually by only 1,091 MW (60.4% of the maximum demand increase). If the increase tendency from 2001 to 2008 is assumed to continue until 2030 for all time zones, the demand shapes shown in Figure 4. 7 can be forecasted for 2020 (with the demand size of 56 GW) and 2030 (with the demand size of 80 GW).

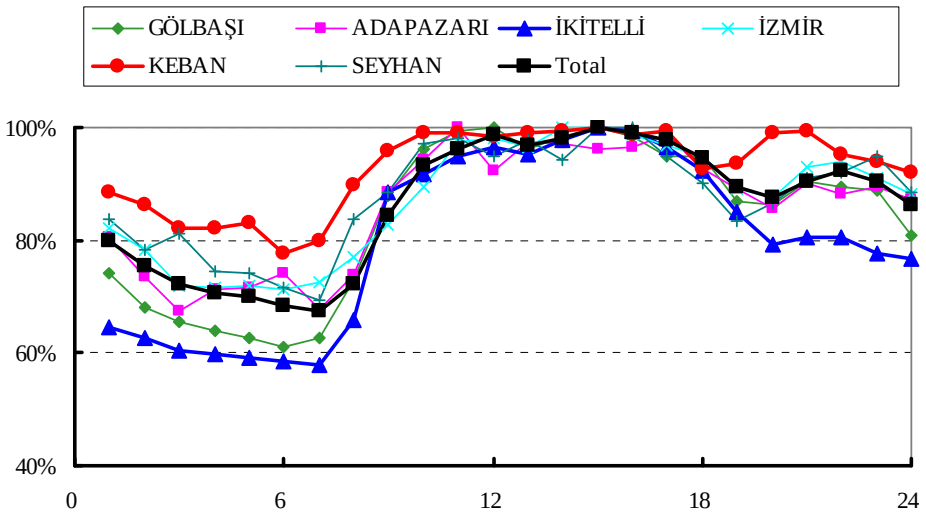


Formulated by the Study Team based on the data provided from TEIAS

Figure 4. 7 Demand Shape Forecasts in 2020 and 2030

(2) Difference of Demand Shapes by Region

The country of Turkey is divided into nine dispatch centers. Demand shapes at the individual dispatch centers on the maximum demand occurrence day (July 23, 2008) are shown in Figure 4. 8.



Formulated by the Study Team based on the data provided from TEIAS

Figure 4. 8 Demand Shapes on Maximum Demand Occurrence Day (by Dispatch Center)

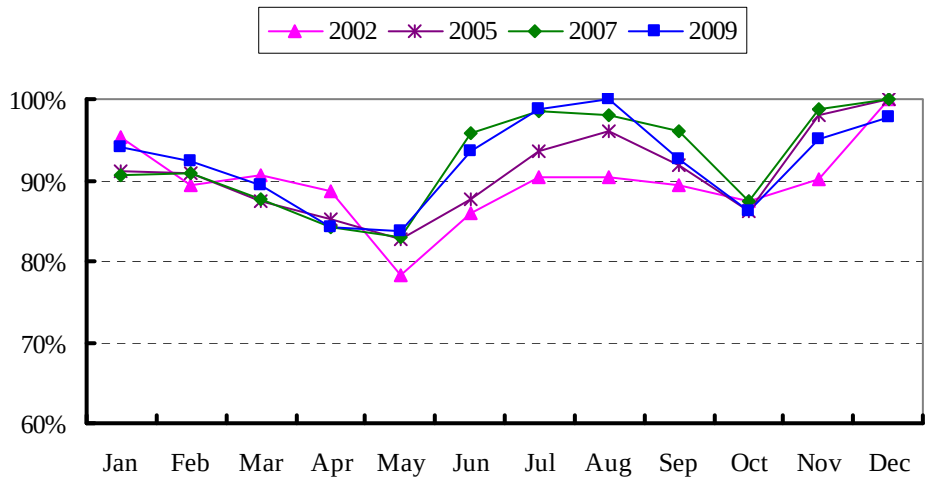
The demand shapes of the İKİTELLİ dispatch center in charge of the European side in Istanbul city and the GÖLBAŞI dispatch center in charge of Ankara city show the night load of approx. 60%. The peak time zones are about 10 hours from about 9:00 to 19:00, while the demand in the evening is not much large.

Meanwhile, the demand shape at the KEBAN dispatch center in charge of the eastern regional areas shows approx. night load of 80%, with not much difference between on-peak and off-peak. The peak time zone is as long as 15 hours from about 9:00 to about 24:00.

The demand shape for the entire country shows the night load of approx. 67%, which is very much like the demand shape of the ADAPAZARI dispatch center in charge of the Adapazari district having many industrial zones.

(3) Seasonal difference

The monthly maximum demands in the representative years in and after 2002 are shown in Figure 4. 9.

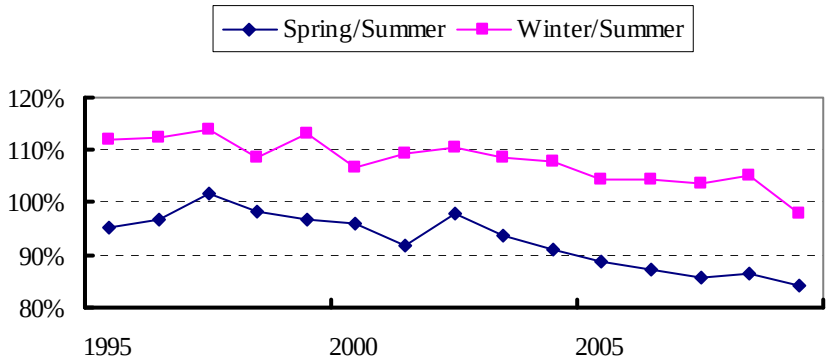


Formulated by the Study Team based on the data provided from TEIAS

Figure 4. 9 Monthly Maximum Demand

According to this, it could be said, as the recent demand shape trend, that the maximum demand occurrence season is shifting from winter (December) to summer (July or August).

Transitions of the ratio of the spring maximum demand with respect to the summer maximum demand and the ratio of the winter maximum demand with respect to the summer maximum demand in 1995 and thereafter are shown in Figure 4. 10.



Formulated by the Study Team based on the data provided from TEIAS

Figure 4. 10 Seasonal Difference (Turkey)

The recent trend (in 2000 and thereafter) shows that the demands in spring and winter have been gradually decreasing compared to that in summer and that the demand increase rate in summer has been increasing.

4.3.3 Data on Generation Facilities

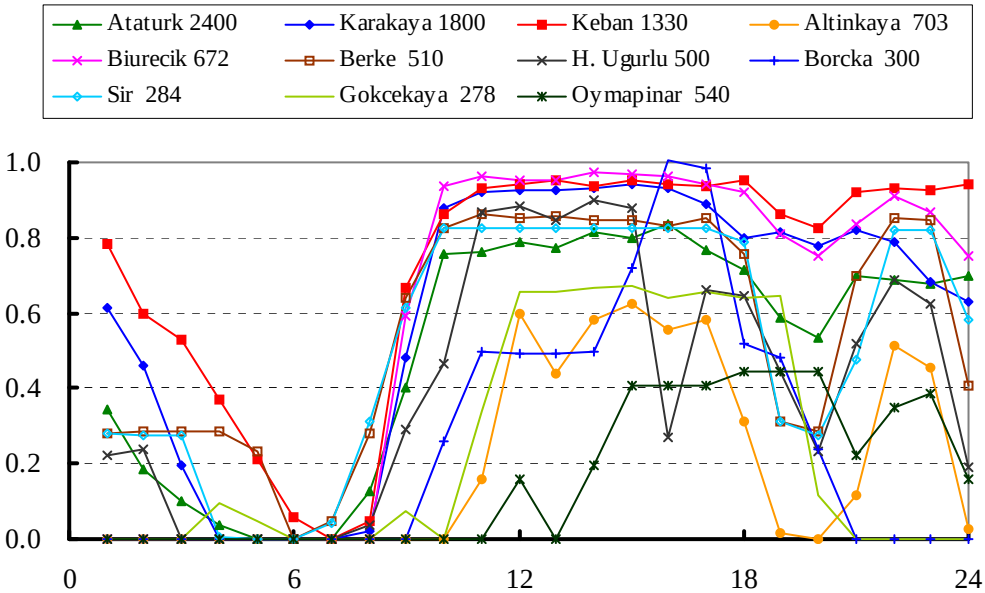
(1) Hydro-related data

For a power plant with installed capacity of 50 MW or more, monthly maximum outputs, minimum outputs, and generating energies have been inputted for each power plant. For a small-scale hydro with installed capacity of less than 50 MW, data for several power plants were collectively inputted, assuming the plants as a single power plant in the unit of 100 MW.

(a) Monthly maximum output and minimum output

Monthly maximum output and minimum output were determined by reference to the actual operation result at each power plant at each hour.

The operation status of hydropower plants of 200 MW or more on July 23, 2008 (maximum demand occurrence day in the past), is shown in Figure 4. 11.



Formulated by the Study Team based on the data provided from TEIAS

Figure 4. 11 Operation Status of Large Scale Hydro Power Plants (on July 23, 2008)

All power plants of 200 MW or more, outputting 0 MW during night, own regulating ponds and operate to meet the peak demand every day. Similarly, investigation on the past operation status for all power plants with the installed capacity of 50 MW or more showed that their maximum outputs are the same as the installed capacities and minimum outputs are 0. Accordingly, it is estimated that these power plants own regulating ponds, and operate to meet the peak demand every day.

With the possibilities that a small-scale hydro does not own a regulating pond taken into consideration, the maximum output was set to be 60% of the installed capacity and the minimum output to be 30% of the installed capacity in the rainy season from January to August. (The outputs further decrease in the dry season from September to December.)

(b) Monthly generating energy

The monthly generating energy of existing hydro generation facilities were calculated by averaging out the actual generation results in the past.

A facility that recently started operation or will start operation in the near future does not have sufficient actual operation results in the past. Therefore, the monthly generating energy for such a facility was determined by reference to the actual operation result of an existing hydro for which the river system is presumed to be close to that facility.

The monthly generating energy of a small-scale hydro was calculated by reference to the mean value of all power plants with installed capacity of 50 MW or more.

(c) Forced outage rate

A result of forced outage rates calculated from the past operational data is shown in Table 4. 11. The average of three hydropower plants is about 1.9%.

Table 4. 11 Actual Forced Outage Rates of Hydropower Plants

Power Stations	Unit size	Number of Units	Forced outage rate	
			2008	2009
Ataturk	300MW	8	0.4%	2.0%
Karakaya	300MW	6	2.8%	3.5%
Keban	170MW class	6	0.8%	1.6%

Formulated by the Study Team based on the data provided from TEIAS

Note: -The forced outages include events in which power plants were voluntarily shut down after faults were found.
-Days of forced outage include days required for repair after the forced outage took place.
-The definition of forced outage rate is the annual forced outage days divided by 365.

(d) Newly developed powers

Out of the sites to which license has been granted by EMRA, the sites of which the percentage of completion is 10% or more are expected to start operation in the near future. (Refer to Table 3. 8.) These sites are described as newly developed power plants also in the 10-Year Generation Capacity Projection (2009–2018) formulated by TEIAS.

Although EMRA granted license to many sites, 40% or more of all sites are small-scale hydro outputting 10 MW or less. Accordingly, it is forecasted that there will not be many large-scale developments in the future.

(2) Thermal-related data

For a power plant with installed capacity of 50 MW or more, the facility output and the classification number have been inputted for each power plant in accordance with the classification shown in Table 4. 13. For small-scale thermal power plants with installed capacity of less than 50 MW, the total output has been collectively inputted for each group the power plants fall in.

(a) Forced outage rate

A result of forced outage rates calculated from the past operational data is shown below.

Table 4. 12 Actual Forced Outage Rates of Thermal Power Plants

Power Stations	Fuel	Unit size	Number of Units	Forced outage rate	
				2008	2009
Ambarlı KÇ (C/C)	Gas	150MW class	9	4.6%	6.2%
Bursa KÇ (C/C)	Gas	240MW class	6	8.7%	5.2%
Hamitabat KÇ (C/C)	Gas	100MW class	12	7.1%	6.8%
Afşin-Elbistan A	Lignite	350MW	4	36.6%	27.6%
Afşin-Elbistan B	Lignite	350MW	4	21.3%	17.2%
Kemerköy	Lignite	210MW	3	16.9%	17.1%
Yatağan	Lignite	210MW	3	14.1%	12.4%
Yeniköy	Lignite	210MW	2	11.0%	12.2%
Orhaneli	Lignite	210MW	1	7.4%	5.2%
Cayirhan Park hold	Lignite	160MW	4	4.8%	5.5%
Soma B	Lignite	165MW	6	18.8%	15.1%
Seyitömer	Lignite	150MW	4	6.0%	6.2%
Kangal	Lignite	150MW	3	14.5%	14.2%
Tunçbilek	Lignite	150MW	2	17.4%	9.2%
Çan	Lignite	160MW	2	12.1%	10.4%
Çatalağzı	Bituminous	150MW	2	6.0%	3.8%

Formulated by the Study Team based on the data provided from TEIAS

Note: -The forced outages include events in which power plants were voluntarily shut down after faults were found.
-Days of forced outage include days required for repair after the forced outage took place.
-The definition of forced outage rate is the annual forced outage days divided by 365.

Although the overall average of forced outage rate of gas-fired thermal power plants is about 6%, figures of thermal power plants which use lignite as fuel are very high. The average rate of Afşin-Elbistan, Kemerköy, and Soma in particular are 15% or higher, while the figure for Cayirhan Park hold is low at around 5% on average. It is assumed that ownership by private companies has an impact on the figures.

(b) Classification of thermal power plants

Thermal power plants have been classified by fuel type, generation method, unit capacity, etc., as shown in Table 4. 13.

Table 4. 13 Classification of Thermal Power Plants

No.	Fuel type	Other information	Unit capacity (MW)	Efficiency (maximum output)	Mini. output	Mainte. duration	Forced outage rate	Power stations
7	Gas	New Gas C/C	700	55.0%	80%	40 days	4%	BOT, BO
8	Gas	C/C (EUAS)	700	55.0%	60%	60 days	6%	Bursa KÇ (C/C)
9	Gas	Gas (EUAS)	450	49.0%	60%	60 days	6%	Ambarlı KÇ (C/C)
10	Gas	Gas (EUAS)	280	45.6%	60%	60 days	6%	Hamitabat KÇ (C/C)
11	Gas	New Gas C/C	250	54.0%	80%	50 days	4%	BOT, BO
13	Gas		50	33.0%	80%	30 days	6%	Autoproducer
14	Gas	GT (for peak)	150	29.0%	20%	30 days	6%	
18	Oil	New Oil ST	250	38.0%	80%	50 days	4%	
19	Oil	New Oil GT	150	29.0%	20%	30 days	4%	
20	Oil	ST	150	37.2%	60%	60 days	10%	Ambarlı + Hopa
21	Oil		18	37.2%	60%	30 days	10%	Samsun
24	Diesel oil	DO C/C	90	39.0%	60%	40 days	10%	Aliağa GT+KÇ (CC)
25	Diesel oil	Diesel	30	32.6%	40%	30 days	8%	Denizli
27	Import coal	New Coal	600	41.0%	90%	50 days	4%	
28	Import coal	New Coal	600	36.5%	90%	50 days	4%	BO
29	Import coal		300	39.5%	90%	50 days	4%	Autoproducer
32	Lignite	New Lignite	350	38.5%	90%	45 days	4%	
33	Lignite		350	36.6%	70%	60 days	15%	Afşin-Elbistan B
34	Lignite		350	31.3%	70%	60 days	15%	Afşin-Elbistan A
36	Lignite		210	35.4%	70%	60 days	12%	Yeniköy, Kemerköy
37	Lignite		210	37.1%	70%	60 days	6%	Orhaneli
38	Lignite		210	32.7%	70%	60 days	12%	Yatağan
39	Lignite		170	31.9%	70%	60 days	15%	Soma B
40	Lignite		150	32.1%	70%	60 days	10%	Seyitömer, Kangal
41	Lignite		150	33.3%	70%	60 days	5%	Cayirhan Park hold
42	Lignite		150	31.8%	70%	60 days	10%	Tunçbilek
43	Lignite	Fluidized bed	160	38.0%	80%	60 days	10%	Çan
44	Lignite		50	31.0%	90%	30 days	5%	Autoproducer
46	Bituminous	New	600	39.0%	90%	50 days	4%	
47	Bituminous		150	33.9%	70%	60 days	5%	Çatalağzı

Formulated by the Study Team based on the data provided from TEIAS

The data on heat efficiency at the maximum output have been created by reference to the data inputted to WASP used in the TEIAS' study in formulating the long-term planning in 2004.

The minimum outputs have been determined with the actual operation result and standard performance of the applicable devices taken into consideration.

(c) Newly developed powers

In the 10-Year Generation Capacity Projection (2009–2018) formulated by TEIAS, newly developed thermal sites are described until 2013. Out of the sites to which license has been granted by EMRA, the sites of which the percentage of completion is 10% or more fall in the facilities that will start operation by 2013 (refer to Table 3. 6).

Note that EMRA has granted the license to 68 sites at present, and thus development is expected to continue in 2014 and thereafter.

(3) Nuclear power and renewable energy

(a) Nuclear power

The 2009 strategy paper published by the State Planning Organization (SPO) stipulates the target that nuclear power plants should account for 5% or more of the total generation amount by 2020 and 5,000 MW should be developed from 2010 to 2020. With this taken into consideration, it is assumed that the Russian-type reactors (1,200 MW × 4 units) that are currently being planned in Akkuyu/Mersin will be developed by 2020. It was also assumed that one more Project (1,200 MW × 4 units) will be developed by 2030.

(b) Wind

Since the size of each wind site is not very large, data for several sites were collectively inputted, assuming those sites as a single power plant of 100 MW. As the generation output, 30% of the maximum output can be constantly outputted regardless of seasons and hours. Therefore, power equivalent of 30% of the installed capacity is expected to be supplied.

The 2009 strategy paper published by SPO specifies that Turkey aims to introduce considerable amount of capacities, as much as 20,000 MW, by 2023. The license issuance status in Table 3. 4 shows that a wind site with the capacity of 75,000 MW is proposed to EMRA and it is now under examination, and thus the viability of the target is considered to be fairly high. However, the total capacity of all 90 renewable energy sites, which have been granted the license by EMRA, published on the Internet as of January 2010 would be 3000 MW. With this fact taken into consideration, it is forecasted as the base case that the installed capacity will increase through development of new power by 800 MW every year.

(c) Geothermal (including biomass thermal)

Like wind, the scale of a single geothermal site is not very large; data for several sites have been collectively inputted as a single power plant of 100 MW. It has been set that 80% of the maximum output can be constantly outputted as the generation output regardless of seasons and hours. Therefore, power equivalent of 80% of the installed capacity is expected to be supplied.

It is forecasted that the installed capacity will increase through development of new power plants by 100 MW in every 5 years.

(4) Summary

The generation facility list (2009) and the development planning from 2010 to 2016 are shown in Table 4. 14.

Table 4. 14 List of Generation Facilities and Development Planning

							2009	2010		2011		2012		2013		2014		2015		2016	
							33952		169		670		0		840		0		0		1200
							12992		469		670		0		0		0		0		1200
EUAS and affiliated TOR, BO, BOT, Mobile	Hydro	Ataturk	2400	Menzelet	124			ERMENEK	309	DERINER	670									ILISU	1200
		Karakaya	1800	Muratli	115			TOPCAM	60												
		Keban	1330	Dicel	110			small hydro	100												
		Altinkaya	703	Torul	103	Darica I	99														
		Birecik	672	Yamula	100	Uzuncayir	84														
		Berke	510	Kralkizi	94	Akocak	90														
		H. Uguzlu	500	Kiskluce	90	Cirakdami	59														
		Borcka	300	Kurtun	85																
		Sir	264	Kesikkopru	76	small hydro	200														
		Gokcekaya	278	Dogankent	75	small hydro	200														
		Batman	198	Kadinak	70	small hydro	200														
		Karkamis	189	Demirkopru	69	small hydro	300														
		Ozluce	170	S Uguzlu	69																
		Catalan	169	Adiguzel	62																
		Sanyar	160	Seyhan1	60																
		Dezende	159	Derbent	56																
		Aslantas	138	Kadinak2	56																
		Hirfanli	128	Kapulukaya	54																
		Kilickaya	120	Camlica	84																
							1123		(300)		0		0		0		0		0		0
	Oil	Aliaga+ Cevrim	180	Samsun 2	131			Ambarli Fuel-Oil	(300)												
		Ambarli Fuel-Oil	680	Samsun 1	131																
							8385		0		0		0		0		0		0		0
	Lignite, Hard coal	Afsin Elbistan B	1440	Tuncbilek B	365	Yatagan	630														
		Afsin Elbistan A	1355	18 Mart Can	320	Kemerkoy TS	630														
		Seydisehir	600	Orhaneli	210	Yenikoy	420														
		Kangal TS	457	Soma A-B	1038	Catalagzi TS	300														
						Park Termik	620														
							1320		0		0		0		0		0		0		0
	Import coal	Iskenderun Sugo	1320																		
							10132		0		0		0		840		0		0		0
	Gas	Bursa Dogalgaz	1432	Adapazari-1	1595	Unimar	504							Ambarli B DGKC	840						
		Ambarli Dogalgaz	1350	Adapazari-2	798	Enron	499														
		Hamitabat	1120	Izmir	1590	Ova Elektrik	258														
				Ankara Baymina	798	Esenyurt	189														
Auto. Generation company							9514		1350		2547		4970		1213		0		0		0
							1927		1008		1027		1842		0		0		0		0
	Hydro	Oymapinar	540	AKKOPRU	115	small hydro	200	Kigi	140	Yedigoze	317	Akkoy 2	234								
		Akkoy I	102	CIBRUK	200	small hydro	200	Cevizlik	102	Sanguzel	105	Goktas	293								
		ALPASLAN-I	160	Ulualat Kuwet Ti	110	small hydro	200	Derek	59	Kandil Enerji Pro	218	Gullubag	99								
						small hydro	100	Ceyhan	64			Menge Baraji ve	87								
								Eneller	51	Tatar	116	Akinci	102								
								Alkumru Baraji ve	247	Feke II	71	Pembelik	122								
								Haciminoglu	144	small hydro	200	Daran	55								
								small hydro	200			Toros	51								
												small hydro	800								
							1414		0		0		0		0		0		0		0
	Oil	Erdemir (Eregli)	75	Petkim Aliaga	170	Ken Kipas Elektr	43														
		Tupras Rafinen ('	84	Karkey (Silopi)	172	small (Autoprodu	600														
		Ataer Enerji	70			small (Private)	200														
							430		0		0		0		0		0		0		0
	Lignite, Hard coal	Isdemir (Iskeden	220	small (Autoprodu	210																
							495		0		410		1216		1213		0		0		0
	Import coal	Colakoglu	190	Eren Enerji Elekt	165					Icdas Celik Enerj	410	Icdas Celik Enerj	608	Eren Enerji Elekt	1213						
		Icdas Celik	130									ICDAS Elektrik E	608								
							4667		142		810		1912		0		0		0		0
	Gas	Bis Enerji Sanay	410	Entek (Demirtas)	146	Manisa Organize	65	Delta Enerji Uret	64	Aliaga Cakmakte	216	Borasco Elektrik	887								
		Zorlu Enerji	189	Enerji-Sa (Zeytin	130	Erdemir (Eregli)	60	Nuh Cimento Sa	48	Aksa Enerji Uret	257	Enerjisa Enerji U	1025								
		Entek Kosekoy	145	Ak Enerji (K.Pa	127	Nuh Enerji-2	73	small (Private)	30	AS Enerji Elektri	67										
		Bosen Enerji Ele	143	Ak Enerji (Bozuy	127	Modern Enerji (B	97			Camis Elektrik U	130										
		Cam Is Enerji (M	126	Enerji-Sa (Kentsi	120	Eskisehir End. E	69			small (Private)	140										
		Zorlu Enerji	90	Ak Enerji (Cerkes	98	Aksa Enerji (Ant	184														
		Alarko Altek	83	Enerji-Sa	65	small (Autoprodu	650														
		Zorlu Enerji (B.K	68	Enerji-Sa (CANA	64	small (Private)	740														
		Cebi Enerji	64	Habas(Aliaga)	225																
		Zorlu Enerji (Sinc	50	Colakoglu	123																
							700		200		300		0		0		0		0		0
	Wind, Geothermal, Others	Wind	100	Wind	100	Geothermal	50	Wind	100	Wind	100										
		Wind	100	Wind	100	Geothermal	50	Wind	100	Wind	100										
		Wind	100	Wind	100					Wind	100										
	Hydro			EUAS, TOR, BO, BOT			12992		13461		14131		14131		14131		14131		14131		15331
				Autoproducer, EMRA			1927		2935		3961		5804		5804		5804		5804		5804
				Total			14919		16396		18092		19935		19935		19935		19935		21135
	Oil			EUAS, TOR, BO, BOT			1123		823		823		823		823		823		823		823
				Autoproducer, EMRA			1414		1414		1414		1414		1414		1414		1414		1414
				Total			2537		2237		2237		2237		2237		2237		2237		2237
	Lignite, Hard coal			EUAS, TOR, BO, BOT			8385		8385		8385		8385		8385		8385		8385		8385
				Autoproducer, EMRA			430		430		430		430		430		430		430		430
				Total			8815		8815		8815		8815		8815		8815		8815		8815
	Import coal			EUAS, TOR, BO, BOT			1320		1320		1320		1320		1320		1320		1320		1320
				Autoproducer, EMRA			495		495		896		2111		3325		3325		3325		3325
				Total			1815		1815		2216		3431		4645		4645		4645		4645
	Gas			EUAS, TOR, BO, BOT			10132		10132		10132		10132		10972		10972		10972		10972
				Autoproducer, EMRA			4667		4700		5510		7422		7422		7422		7422		7422
				Total			14799		14832		15642		17554		18394		18394		18394		18394
	Wind, Geothermal, others			EUAS, TOR, BO, BOT			0		0		0		0		0		0		0		0
				Autoproducer, EMRA			700		900		1200		1200		1200		1200		1200		1200
				Total			700		900		1200		1200		1200		1200		1200		1200
	TOTAL			EUAS, TOR, BO, BOT			33952		34121		34791		34791		35631		35631		35631		36831
				Autoproducer, EMRA			9514		10864		13411		18381		19695		19695		19695		19695
				Total			43466		44985		48202		53172		55226		55226		55226		56426

4.3.4 Economic Efficiency-Related Data

See Section 4.2 .

4.4 Study of Appropriate Reserve Capacity Rate Based on Supply Reliability

4.4.1 Study of the Base Case

The relationship between loss of load expectation (LOLE) and the supply reserve capacity rate was obtained taking into consideration the facility composition forecast around 2020 (with the demand size of approx. 56 GW), and the appropriate reserve capacity rate was determined for the determined supply reliability criteria (LOLE value).

(1) Inputted data

(a) Demand shape

The maximum demands and the minimum demands for the respective seasons are shown in Table 4. 15.

Table 4. 15 Maximum Demands and Minimum Demands for Individual Seasons

	Maximum	Minimum	Min/Max
Jan-Mar	50,460MW	27,157MW	53.8%
Apr-Jun	53,018MW	29,754MW	56.1%
Jul-Sep	56,000MW	29,247MW	52.2%
Oct-Dec	53,425MW	30,673MW	57.4%

Formulated by the Study Team based on the data provided from TEIAS

(b) Error in demand forecast

Error in prediction of the demand forecast, which is 1% of the forecasted demand, is estimated as the standard deviation.

(c) Generation facility composition and forced outage rate

The generation facility composition and their forced outage rates are as shown in Table 4. 16. Forced outage rates were determined by reference to the actual results in 2008 and 2009.

Table 4. 16 Generation Facility Composition and Forced Outage Rate

	Capacity (GW)	Rate	Maximum unit capacity	Forced outage rate
Hydro (including PSPP)	23.9	32.1%	300MW	2%
Wind (including Geothermal)	8.0	10.7%	10MW	5%
Gas-fired thermal	20.6	27.7%	700MW	4% - 6%
Oil-fired thermal	2.2	3.0%	150MW	8% - 10%
Import-coal fired thermal	5.9	7.9%	600MW	4%
Domestic-coal fired thermal	9.0	12.1%	350MW	4% - 15%
Nuclear	4.8	6.5%	1,200MW	5%
Total	74.4			

Formulated by the Study Team based on the data provided from TEIAS

(d) Output fluctuation possibility of renewable energies

Approximately 2,000 MW, despite slight difference among seasons, is estimated as the standard deviation of output fluctuation possibility of renewable energies.

(2) Relationship between LOLE and supply reserve capacity rate

The relationship between LOLE and the supply reserve capacity rate determined based on the inputted data as described above is shown in Figure 4. 12.

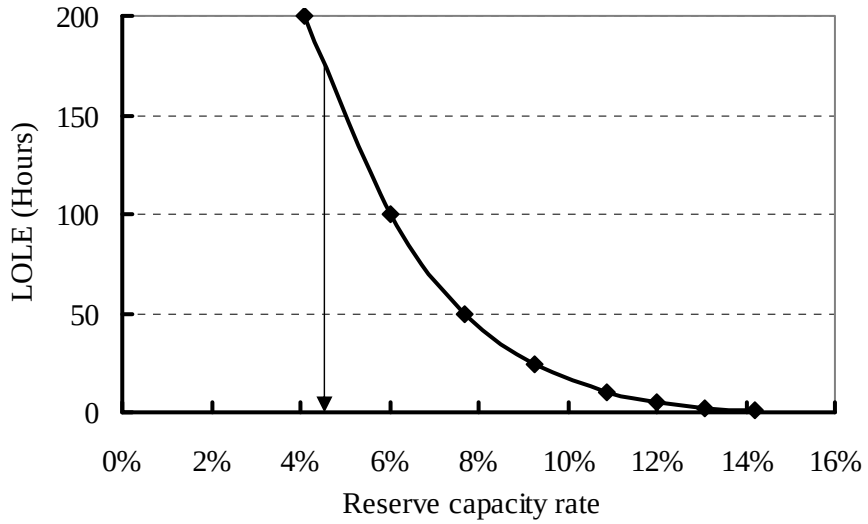


Figure 4. 12 Relationship between LOLE and Supply Reserve Capacity Rate

In the data inputted to WASP used in the TEIAS' study when establishing the long-term planning in 2004, the criteria of the supply reliability was set to be 2% in the LOLP value, which corresponds to 175 hours per year if the level is converted to an LOLE value. Accordingly, it is read from the above-described graph that only approx. 4% have to be secured for the supply reserve capacity rate. In the study in 2004, the electricity price when the supply capacity is not sufficient is set to be 1 USD/kWh.

When referring to examples in other countries, approx. 24 hours in LOLE value is targeted as the supply reliability criterion in Thailand and Vietnam as well. Given the economic situation in Turkey at this moment, damage to economic activities because of a power failure that occurs due to insufficient supply capacity would be large and the electricity price when supply capacity is insufficient would become 1 USD/kWh or more. Accordingly, 24 hours or less should be targeted in the LOLE value.

When the above-described viewpoint is taken into consideration, approx. 9% would be needed as the supply reserve capacity rate.

As a result of the study described above, the future study in this investigation should aim at securing the supply reserve capacity rate of 8-10% as the supply reliability level.

4.4.2 Sensitivity Analysis

(1) Sensitivity analysis

The base case under given conditions has been examined so far. The result of sensitivity analysis regarding the error on demand forecast, forced outage rates of facilities, output fluctuation probability of renewable energy power generation, etc., is shown in Figure 4. 13.

(a) Error on demand forecast

The study of the base case takes into account 1% of the assumed value as the margin of error on demand forecast of 1% (standard deviation). This means that in a one-day-ahead demand forecast, when the next-day maximum demand is forecast at 56,000 MW, the probability that the actual demand will be 1% higher than the forecast, at 56,560 MW or greater, is around 15.9%. (By the same token, it means the probability of demand becoming 2% higher than the forecast, at 57,120 MW or higher, is around 2.3%.)

Changes in the required supply reserve capacity rates to satisfy different predetermined LOLE values are shown in Figure 4. 13.

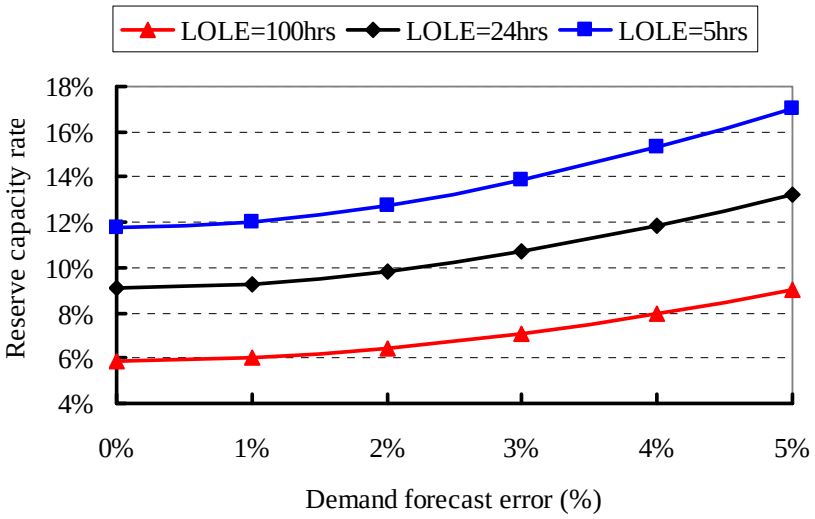


Figure 4. 13 Changes in supply reserve capacity rates due to changes in demand forecast margin of error

While margins of error between forecast and actual demand remain small, the increase in the required supply reserve capacity rate is not great. As the margin of error becomes greater, the required supply reserve capacity rate significantly increases. In other words, as the accuracy of demand forecast goes down, it is possible that the required supply reserve capacity rate would greatly increase. The higher the required supply reliability level is (lower predefined LOLE value), the greater the increase in the rate becomes, and thus more accurate demand forecast is needed.

(b) Forced outage rate of power plants

In the study of the base case, there is a great margin in the forced outage rates of power plants (as shown in Table 4. 16), which stand at between 2% and 15%. The forced outage rate of a power plant is defined as the hours in which power could not be generated due to accidents per year divided by the annual hours (8,760 hours). In other words, the plant forced outage rates are in proportion to hours in which power could not be generated.

Changes in the required supply capacity rates which satisfy predetermined LOLE values by changing hours in which power cannot be generated due to accidents are shown in Figure 4. 14.

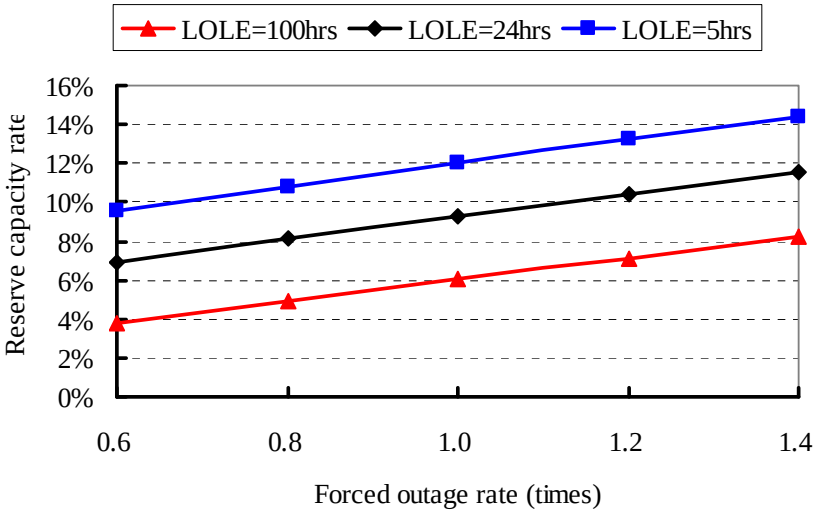


Figure 4. 14 Changes in the supply reserve capacity rates due to changes in forced outage rates

When the forced outage rate increases to 1.4 times that of the base case, the required supply reserve capacity rate goes up by 2 points. On the other hand, when the forced outage rate declines to 0.6 times that of the base case, the supply reserve capacity rate goes down by 2 points.

(c) Fluctuation range of power output via renewable energy sources

In the study of the base case, 2,000 MW is expected as a standard deviation of power output fluctuation of renewable energy sources. This means there is around a 15.9% or so probability that the expected supply capacity may decline by 2,000 MW or greater.

Changes in the supply reserve capacity rates which satisfy the predetermined LOLE values when the standard deviation is changed are shown in Figure 4. 15.

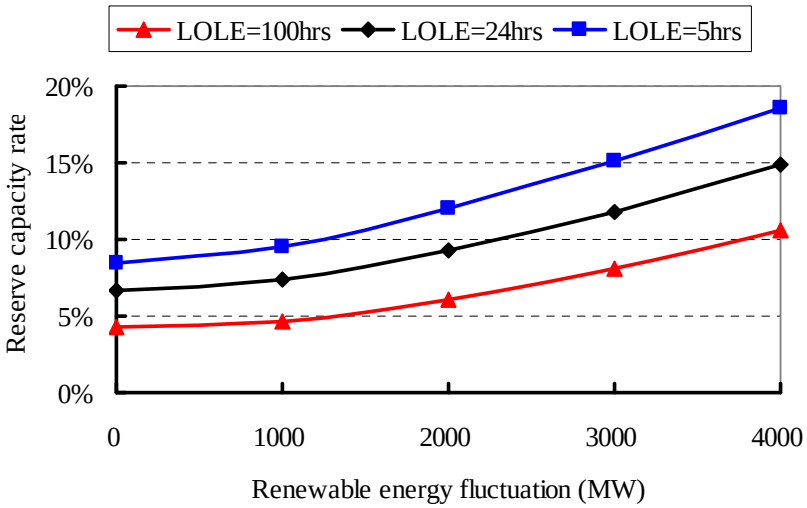


Figure 4. 15 Changes in supply reserve capacity rate due to renewable energy fluctuation

When the renewable energy fluctuation remains small, the increase in the reserve capacity rate will not be great. When the standard deviation of the fluctuation becomes 2 times as great as that in the base case to reach 4,000 MW, the reserve supply capacity will increase by 5-6%. As the number of wind turbines goes up rapidly, renewable energy fluctuation is expected to become greater, thus raising a possibility that the supply reserve capacity rate will significantly increase.

(2) Study of 2030

The result of studying the reserve supply capacity by using demand profile and composition of power plants expected for 2030 is shown in Figure 4. 16.

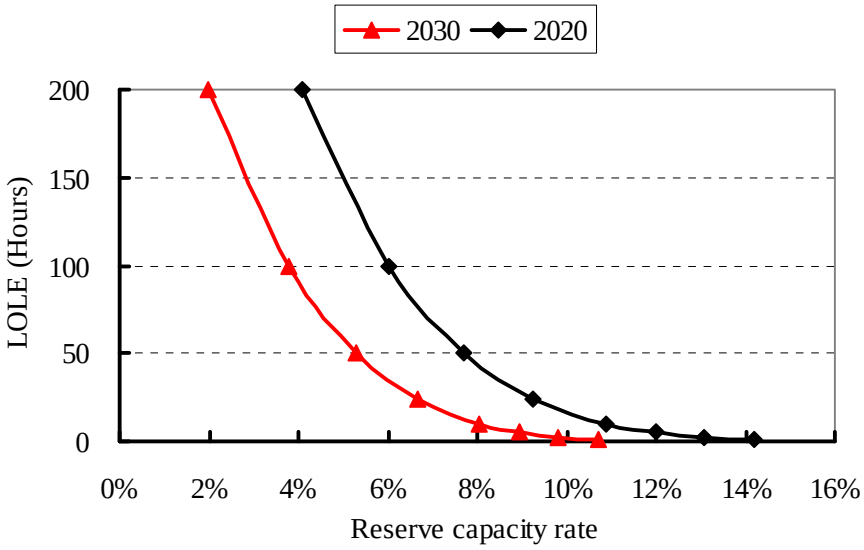


Figure 4. 16 Relationship between LOLE and reserve supply（2030）

In the study of 2030, the supply reserve capacity rate required to secure the comparable supply reliability level can be about 3% lower than the result of studying the projected status of 2020. This is due to the following reasons:

- As the demand profile takes a greater peak, peak hours with high demand will become shorter.
- The ratio of newer, more advanced equipment which has lower forced outage rates is on the rise.

For these reasons, it is expected that the supply reserve capacity rate required to secure a comparable supply reliability level will gradually decline from 2020 and onward. On the other hand, higher supply reliability levels will be gradually but increasingly required. After the Turkish power system gets interconnected to that of EU at a full scale, in particular, supply reliability comparable to the EU power system will be required. In other words, when the supply reserve capacity rate of 8-10% is secured, the LOLE value will be around 25 hours in 2020 while the figure for 2030 will be about 5 hours, which will win high supply reliability comparable with the EU power systems. From this perspective, it will become necessary to secure 8-10% supply reserve capacity rate in 2030 as well.

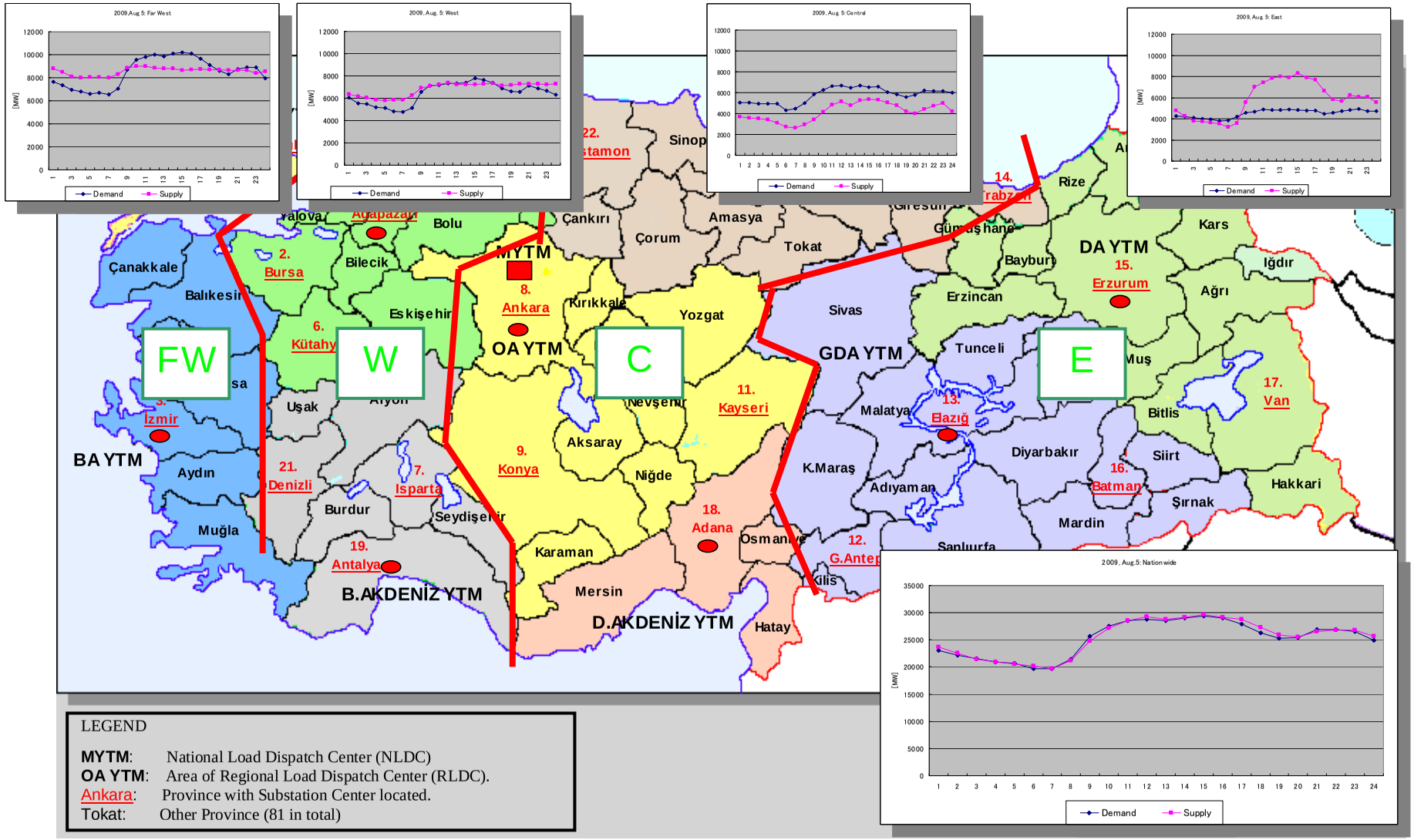
(3) Analysis on regional characteristics

This subsection analyzes the demand-supply balance of Turkey taking into account the country's regional characteristics. Its approach is to divide the country's national grid system into 4 zonal systems and to analyze the supply reliability of each system.

The national grid has been divided into four zonal systems, each of which consists of the areas of regional load dispatch centers (LDCs) with similar supply-demand characteristics. The zonal systems have been named, from west to east, the Far Western System, the Western System, the Central System, and the Eastern System. The Far Western System consists of Trakya LDC region (Istanbul) and West Anatolia LDC region (Izmir), while the Western System consists of Northwestern Anatolia LDC region (Bursa) and West Mediterranean LDC region (Antalya). The Central System is composed of Central Black Sea LDC region (Samsun), Central Anatolia LDC region (Ankara), and East Mediterranean LDC region (Adana). Finally the Eastern System consists of East Anatolia LDC region and South East Anatolia LDC region. The Study Team regards 380kV backbone transmission lines connecting the

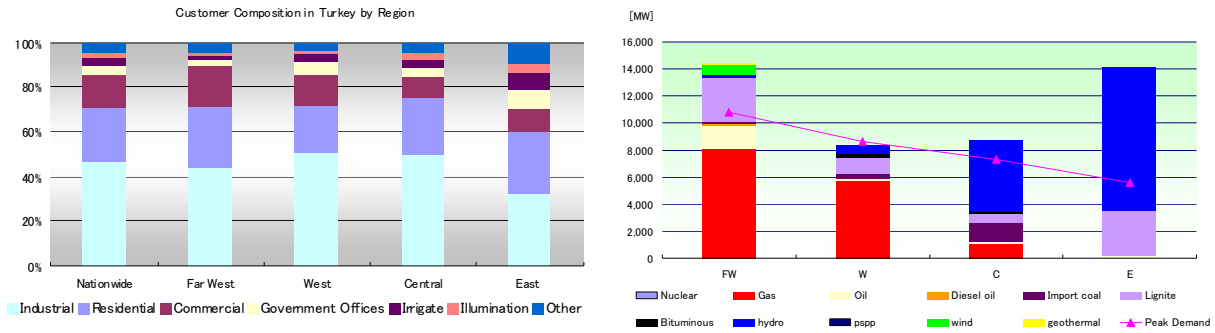
four zonal systems as regional interconnection lines. Figure 4. 17 summarizes the zoning and supply-demand balance of each zonal system as of August 2009.

It is obvious from the supply-demand balances that demand is tend to be larger in west than in east. Likewise, the shape of daily load curves become sharpened in west compared with the shape in east. Figure 4. 18 shows the composition of customer category by system in the four zone systems. As shown in Figure 4. 18, the Turkey's electricity demand is characterized as "higher in west, and lower in east". The Far Western System which covers high demand centers such as Istanbul and Izmir has larger share of residential and commercial demand categories than those in the Western System and the Central System. In terms of supply characteristics, while the Eastern System holds rich hydraulic resource capable of meeting peak load, the Far Western System is mainly composed of gas-fired power stations operated to supply base load (refer to Figure 4. 18). The Western System chronically suffers from negative balance of supply-demand in its closed system.



(Source: Developed by JICA Study Team based on the material provided by TEIAS)

Figure 4. 17 Daily load curve by system (August 2009)



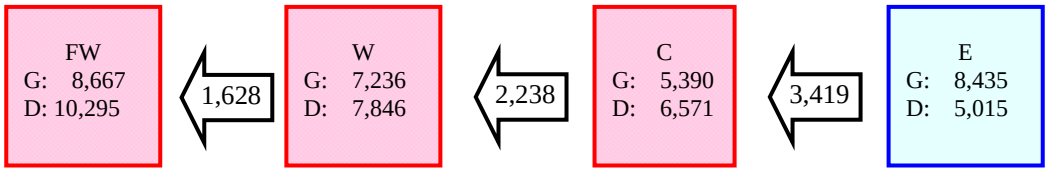
Source: Developed by JICA Study Team based on the material provided by Privatization Authority (left), and TEIAS (right)

Figure 4. 18 The share of demand type by system (left, 2008) and the composition of fuel type in power generation by system (right, 2010)

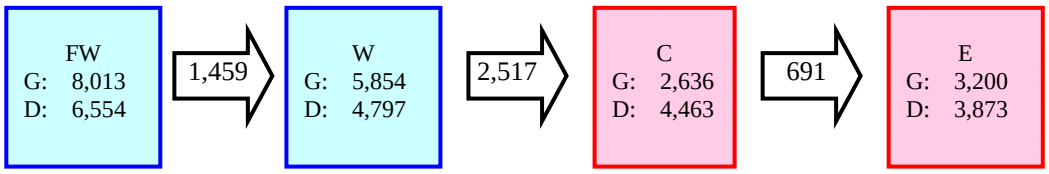
The characteristics of power flow reflect the above supply-demand structure. That is, during the daytime, power flows from the east to the west in order to meet the peak demand in the Far Western System, over 380 kV transmission lines along around 1,000 km distance, while power flows in reverse during the night time. Therefore, Turkish regional systems are characterized as dependent on one another. Because of such characteristics, the expansion of long transmission lines would be continued.

Figure 4. 19 shows the power flow among the zonal systems and supply-demand balance of each zonal system. All the data are as of August 5th, 2009, the date which recorded the year's maximum demand. The box in red stands for the zonal system suffering from power shortage, while the box in blue stands for the zonal system with surplus of power supply.

Regional balance (3pm, August 5, 2009): Total demand was 29,604 MW.



Regional balance (7am, August 5, 2009): Total demand was 19,685 MW.



Unit: MW.
Source: Developed by JICA Study Team based on material provided by TEIAS.

Figure 4. 19 Power flow between systems (August 5, 2009)

During the daytime in summer seasons, power flows from east to west, while the flow reverses in nighttime, reducing the output from hydropower plants in the eastern area.

The above has reviewed the current regional characteristics of Turkey's power demand-supply balance. As pointed out in Chapter 3, one of the main issues is that the country's backbone transmission lines could be reinforced more than necessary due to the uncertainty of power development plants. As proposed also in Chapter 3, such possible additional expenditure could be avoided if the sites of new power plants are planned closed to demand centers.

The next part analyzes the supply reliability in year 2030 based on the outcome of the current system analysis. The condition and assumption utilized in the analysis, specifically the policy to allocate nationwide demand and supply into the four zonal systems, are explained below.

Premise

(a) Demand assumption

It is presumed that the shape of the load curves in 2030 would be similar to those of actual load curves in 2009 for the four zonal systems - the same approach as the one for the analysis of the whole country. Therefore, the shape's difference of the load curves among the zonal systems of 2009 have been kept in those of 2030.

(b) Development plan

The employed approach is to allocate the power plants planned in the nationwide power development plan which used for this study's analysis ("the most optimal case") to the created four zonal systems. The planned new power plants whose locations are confirmed have been allocated to the system whose area covers the locations. The planned power plants whose locations are not confirmed have been allocated to systems according to rules set by fuel type whose details are shown below. As an example, thermal power plants have been allocated to systems so that the demand supply balance in each system would be kept in the system, because the location of thermal plants generally would not be limited by geographical factors like hydropower plants and wind power plants (This rule excludes the case of domestic coal-fired thermal power plants, which utilize adjacent coal mines).

- The potential sites of wind power generation have been spread over the nation. Since the wind power generation's potential map (Source: "Turkish Wind Atlas," Turkish State Meteorological Service) tells that the area of the Far Western System is the area which holds the most potential sites along coastal lines, this analysis assumed that the more wind power plants would be installed in the Far Western System than any other system.
- The scale of the planned hydropower plants would be small with the capacity of less than 100 MW for the most of the cases. Their potential sites are dispersed across the country, and the Study Team assumed that the coming hydropower plants would be installed intensively in the Central System and the Eastern System, whose total installed capacity during the period between 2011 and 2030 amounts to 8.3 GW.
- Because the development of gas-fired power plants would not be intensively promoted according to the government's energy policy, "Electricity Energy Market and Supply Security Strategy Paper (2009)," their current distribution pattern would be kept in 2030. Consequently, new gas-fired power plants would be installed evenly in the two systems, namely the Far Western System and the Western System. The expected total amount of installed capacity would be 10.5 GW during year 2011 and 2030.
- As for the imported-coal-fired thermal power plants, it would not be easy to identify their distribution pattern among the four systems because small number of imported-coal-fired thermal power plants have been operated currently. The analysis assumed that the plants would be installed evenly in the three systems with coastal sides, namely the Far Western System, the Western System, and the Eastern System, based on the fact that existing import-coal-fired power plants locate along coastal lines.
- Two nuclear power plants are planned to be installed in the Central System where their planned sites, Akkuyu/ Mersin and Sinop locate, reflecting "Electricity Energy Market and Supply Security Strategy Paper (2009)". The one in Akkuyu is set to start its operation by 2023 with its installed capacity of 4,800 MW, while the one in Sinop is set to start by 2030.
- The first candidate pumped storage power plant (PSPP) in Altınkaya is assumed to starts its operation in the area of the Central System by 2030 with its installed capacity of 1,800 MW based on the study's outcome. The second prioritized PSPP in Gokcekaya is also set to be developed in the Central System's area, though its location is almost on the border to the area of the Western System.
- The transmission capacity of interconnections between the zonal systems in year 2030 are set to be 20GW, reflecting the result of this study's system analysis.

Table 4. 17 shows the list of power plants in each zonal system as of year 2030.

Table 4. 17 The list of power plants by system (Year 2030)

The Far Western System

Unit: MW

FW	Thermal & Nuclear	Ambarli Dogalgaz	1,350	Enron	499	Private others (Gas)	740
		18 Mart Can	320	Esenyurt	189	Autoproducer others (Oil)	600
		New Soma A-B	1,250	Habas(Aliaga)	225	Private others (Oil)	200
		New Yatagan	740	Colakoglu	123	Autoproducer others (Lignite)	210
		Kemerkoy TS	630	Manisa Organize San.	85	Autoproducer (Gas)	30
		New Yenikoy	420	Modern Enerji (B:karistiran)	97	Autoproducer (Gas)	140
		Cam Is Enerji (Mersin)	126	Ataer Enerji	70	Autoproducer (Gas)	100
		Alarko Altek	83	Petkim Aliaga	170	Autoproducer (Gas)	100
		Zorlu Enerji (B.Karistiran)	66	Icdas Celik	130	Autoproducer (Gas)	100
		Cebi Enerji	64	Hamitabat	1,120	New Gas 700	4,900
		Ak Enerji (K.Pasa)	127	Icdas Celik Enerji Tersane ve Ulasim San. A.S.	410	New Coal 600	3,600
		Enerji-Sa (Kentsa)	120	Icdas Celik Enerji Tersane ve Ulasim San. A.S.	608		
		Ak Enerji (Cerkezkoy)	98	ICDAS Elektrik Enerjisi Uretim ve Yatirim A.S.	608		
		Enerji-Sa	65	Aliaga Cakmaktepe Enerji Uretim A.S.	216		
		Enerji-Sa (CANAKKALE)	64	Delta Enerji Uretim ve Ticaret A.S.	64		
		Izmir	1,590	Ambarli B Dogalgaz	840		
		Unimar	504	Autoproducer others (Gas)	650		
							24,440
	Hydro	Demirkopru (69MW)	69	Adiguzel (62MW)	62	TOPCAM (60MW)	60
		small hydro (100MW) x 1	100	small hydro (200MW) x 2	400		
							691
	Wind	Wind (100MW) x 11	1,100	Wind (800MW) x 9	7,200		
							8,300
	Geothermal	Geothermal (100MW) x 6	600				
							600
	TOTAL						34,031

The Western System

W	Thermal & Nuclear	Bursa Dogalgaz	1,432	Tupras Rafineri (Yarimca)	84	Autoproducer (Gas)	100
		New Seyitomer	720	Eskisehir End. Enerji(Eskisehir-2)	59	Autoproducer (Gas)	100
		New Tuncbilek B	440	Colakoglu	190	Autoproducer (Gas)	100
		Orhaneli	210	Aksa Enerji (Antalya)	184	Autoproducer (Gas)	100
		New Catalagzi TS	350	Eren Enerji Elektrik Uretim A.S.	165	Autoproducer (Gas)	100
		Bis Enerji Sanayi	410	Eren Enerji Elektrik Uretim A.S.	1,213	Autoproducer (Gas)	100
		Entek Kosekoy	145	Aksa Enerji Uretim A.S.	257	Autoproducer (Gas)	100
		Bosen Enerji Elektrik Uretim A.S	143	AS Enerji Elektrik Uretim San. Ve Tic. A.S.	67	New Gas 700	700
		Zorlu Enerji	90	Enerjisa Enerji Uretim A.S.	1,025	New Gas 700	700
		Entek (Demirtas)	146	Nuh Cimento Sanayi A.S.	48	New Coal 600	600
		Enerji-Sa (Zeytinli)	130	Autoproducer (Gas)	100	New Coal 600	600
		Ak Enerji (Bozuyuk)	127	Autoproducer (Gas)	100	New Coal 600	600
		Adapazari-1	1,595	Autoproducer (Gas)	100	New Coal 600	590
		Adapazari-2	798	Autoproducer (Gas)	100	New GT (Gas)	2,400
		Ova Elektrik	258	Autoproducer (Gas)	100		
		Erdemir (Eregli)	75	Autoproducer (Gas)	100		
		Erdemir (Eregli)	80	Autoproducer (Gas)	100		
		Nuh Enerji-2	73	Autoproducer (Gas)	100		
							18,204
	Hydro	Oymapinar (540MW)	540	small hydro (200MW) x 6	1,200		
		Uluabat Kuvvet Tuneli (110.3MW)	110				
							1,850
	Wind			Wind (800MW) x 3	2,400		
							2,400
	TOTAL						22,454

The Central System

C	Thermal & Nuclear	Zorlu Enerji	189	Nuclear I	1,200		
		Zorlu Enerji (Sincan)	50	Nuclear I	1,200		
		Ankara Baymina	798	Nuclear I	1,200		
		Iskenderun Sugozu (Isken)	1,320	Nuclear I	1,200		
		Isdemir (Iskederun)	220	Nuclear II	1,200		
		Park Termik	620	Nuclear II	1,200		
		Samsun 2	131	Nuclear II	1,200		
		Samsun I	131	Nuclear II	1,200		
		Borasco Elektrik Uretim San. Ve Tic. A.S.	887				
		Camis Elektrik Uretim A.S.	130				
							14,077
	Hydro	Altinkaya (703MW)	703	Kadinak (70MW)	70	Goktas (292.5MW)	293
		Berke (510MW)	510	S Ugurlu (69MW)	69	Feke II (71MW)	71
		H. Ugurlu (500MW)	500	Seyhan1 (60MW)	60	Menge Baraji ve (86.8MW)	87
		Sir (283.5MW)	284	Derbent (56.4MW)	56	Akinci (102.3MW)	102
		Gokcekaya (278.4MW)	278	Kadinak2 (56MW)	56	Daran (54.6MW)	55
		Catalan (168.9MW)	169	Kapulukaya (54MW)	54	Toros (51.2MW)	51
		Sanyar (160MW)	160	Camlica (84MW)	84	Akkoy I (101.9MW)	102
		Gezende (159.4MW)	159	ERMENEK (309MW)	309	PSPP (300MW) -1	300
		Aslantas (138MW)	138	AKKOPRU (115MW)	115	PSPP (300MW) -2	300
		Hirfanli (128MW)	128	OBRUK (200MW)	200	PSPP (300MW) -3	300
		Kilickaya (120MW)	120	Darica I (99MW)	99	PSPP (300MW) -4	300
		Torul (105.6MW)	103	Akocak (90.1MW)	90	PSPP (300MW) -5	300
		Yamula (100MW)	100	Cirakdami (58.7MW)	59	PSPP (300MW) -6	300
		Kokluce (90MW)	90	Dereli (58.8MW)	59	small hydro (200MW) x 9	1,800
		Kurtun (85MW)	85	Ceyhan (63.5MW)	64		
		Kesikkopru (76MW)	76	Yedigoze (317MW)	317		
		Dogankent (74.5MW)	75	Akkoy 2 (233.6MW)	234		
							10,032
	Wind	Wind (100MW)	100	Wind (800MW) x 5	4,000		
							4,100
	Total						28,209

The Eastern System

E	Thermal & Nuclear	Afsin Elbistan B	1440	New Coal 600	600		
		New Afsin Elbistan A	1670	New Coal 600	600		
		Kangal TS	457	New Coal 600	600		
		Karkey (Silopi)	171.9	New Coal 600	600		
		Ken Kipas Elektrik Uretim A.S.	43				
							6,182
	Hydro	Ataturk (2400MW)	2400	Dicel (110MW)	110	Hacininoglu (144.4MW)	144.4
		Karakaya (1800MW)	1800	Kralkizi (94MW)	94	Sariguzel (105.1MW)	105.1
		Keban (1330MW)	1330	DERINER (670MW)	670	Kandil Enerji Projesi (217.6MW)	217.6
		Biurecik (672MW)	672	ALPASLAN-I (160MW)	160	Tatar (115.8MW)	115.8
		Borcka (300MW)	300	Kigi (140MW)	140	Gullubag (99MW)	99
		Batman (198MW)	198	ILISU (1200MW)	1200	Pembelik (122.4MW)	122.4
		Karkams (189MW)	189	Uzuncayir (84MW)	84	small hydro (100MW) x 2	200
		Ozluce (170MW)	170	Cevizlik (102.4MW)	102.4	small hydro (200MW) x 14	2800
		Menzelet (124MW)	124	Erenler (51.1MW)	51.1		
		Muratli (115MW)	115	Alkumru Baraji ve (247.4MW)	247.4		
							13,961
	Wind			Wind (800MW) x 1	800		
							800
	Total						20,943

Based on the premise shown above, the analysis of the supply reliability in year 2030 has been conducted for the four systems. As a result, each zonal system's seasonal supply and demand are led as shown in Table 4. 18.

Table 4. 18 Seasonal supply-demand balance by system (Year 2030)

System	Demand (MW)				Supply (MW)			
	Jan.–Mar.	Apr.–Jun.	Jul.–Sep.	Oct.–Dec.	Jan.–Mar.	Apr.–Jun.	Jul.–Sep.	Oct.–Dec.
FW	25,149	26,897	27,910	22,356	23,144	25,975	26,592	22,442
W	17,819	20,119	20,845	21,938	17,623	17,929	19,844	19,982
C	15,530	17,301	18,418	16,808	18,671	22,177	23,851	21,645
E	13,065	12,292	13,730	14,091	16,778	16,254	16,114	16,486
Total	71,663	76,609	80,903	75,193	76,216	82,335	86,401	80,555
Nationwide	69,975	75,591	80,000	73,958	76,216	82,335	86,401	80,555

Note: Because the time when maximum demand appears would vary geographically, the simple sum of the four systems' values would not be necessarily identical with the value of nationwide.

The peak demand appears during July and September in the Far Western System and the Central System, similar to the case of the national system. For the Western and the Eastern Systems, their peak demand appear during October and December.

Table 4. 19 shows the result of supply reliability analysis for the four systems in year 2030, which has been conducted based on the condition shown above.

Table 4. 19 The supply reliability of the four zonal systems (Year 2030)

System	Demand [MW]	Supply Capability [MW]	Reserve Capacity [MW]	Reserve Capacity Rate [%]	LOLE [hours]
FW	27,910	26,592	-1,318	-4.7	77.8
W	21,938	19,982	-1,956	-8.9	80.7
C	18,418	23,851	5,433	29.5	2.7
E	14,091	16,486	2,395	17.0	10.7
Total	82,357	86,911	4,554		
Nationwide	80,000	86,400	6,400	8.0	10.2

Table 4. 20 summarizes the required reserve margin of each system in case aiming to secure a certain level of electric supply reliability, i.e. the loss of load expected (LOLE) of 24 hours.

Table 4. 20 The required reserve capacity to achieve LOLE of 24 hours (Year 2030)

System	Required Reserve Capacity to achieve LOLE of 24 hours [MW]	Reserve Capacity Rate [%]	LOLE [hours]
FW	568.8	2.0	24.0
W	-259.3	-1.2	24.0
C	3,433.7	18.6	24.0
E	1,808.1	12.8	24.0
Total	5,551.2		
Nationwide	5,336.2	6.7	24.0

The result in Table 4. 20 tells that the Central System and the Eastern System require around 19% and 13 % of reserve capacity rates respectively. By contrast, the Far Western System and the Western System require few reserve capacity rates. The possible reason for the case of the former two systems, the Central and the Eastern Systems, is summarized that these two systems would need more reserve capacity than the other systems because the degree of unexpected volatility is estimated to be larger in the two systems than the other systems. This is partly because that large-scale nuclear power plants with large unit capacity are installed (8 units with its installed capacity of 1,200 MW each), resulting in the possible tremendous damage in case of a breakdown/ accident from supply capability points of view, and partly because the supply capability could be dramatically reduced in dry years.

In case of a regional power supply shortage, other systems with remaining supply surplus would provide electricity to the system of power shortage within the capacity of interconnection lines. Figure 4. 20 shows the distribution of frequencies in which a certain amount of power flow on the regional interconnection lines appear.

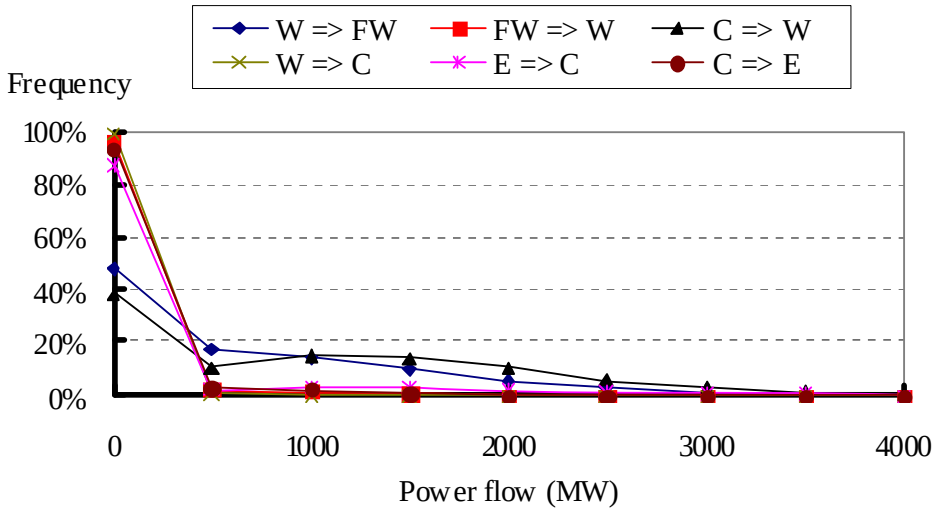


Figure 4. 20 Distribution of power flow amount over regional interconnection lines

As shown in Table 4. 19, the Central System retains large amount of reserve capacity, securing enough supply capability during normal time. Further, the transmission capacity of the regional interconnection linking the Central System and the Western System is large enough that the Western System and the Far Western System can expect to receive electricity from the Central and/ or the Eastern Systems in case of power shortage. Therefore, it is possible for the Western and the Far Western Systems to keep high supply reliability, even though those two systems do not hold large amount of reserve capacity.

4.5 Possibility of Introduction of Various Power Supplies as Peak Supply Capacity

4.5.1 Evaluation of Various Power Generations for Peak Demand

Large-scale reservoir type hydro power stations such as Keban, Karakaya, and Ataturk are currently operating to meet the peek demand in Turkey. Appropriate power generations are needed in future because the demand is expected to increase at around 7 % per year. In this section, possible power generations that are under necessity to meet the peak demand in future are evaluated.

(1) Characteristics of various power supplies for peak demand

Possible power generations to meet the peak demand are PSPP, expansion of existing reservoir-type hydro, development of new reservoir-type hydro, development of low load factor thermal (such as GT), and electricity purchasing from other countries. The characteristics of individual power generations are shown in Table 4. 21. Note that all below power plants have the feature as a power generation for peak demand, in common, that operation at the maximum output is possible within a short period (within 5 minutes) of the operation being activated.

Table 4. 21 Characteristics of Various Power Generations for Peak Demand

	Advantages	Disadvantages
PSPP	♦ Fixed cost is low. ♦ Frequency adjustment is possible also at night. (in the case of variable speed units) ♦ There are many sites where large-scale (1000 MW or more) development is possible.	♦ Operable time is restricted within the pondage volume. ♦ Motive power for pumping is needed.
Expansion of existing reservoir type hydro	♦ Fuel cost is not needed. ♦ There is possibility that increase in generating energy is expected.	♦ Fixed cost is high. ♦ Use of conventional hydro may be restricted due to decrease in water level during the construction work period
Development of new reservoir type hydro	♦ Fuel cost is not needed. ♦ Generating energy is greatly increased.	♦ Fixed cost is high. (It is higher than expansion of conventional reservoir type hydro.) ♦ Large-scale economic sites have already been developed.
Gas turbine (GT)	♦ Operation is always possible. ♦ The fixed cost is low.	♦ Fuel cost is high.
Electricity purchasing from other countries	♦ Special generation facility is not needed. (Demand can be met only by interconnected transmission lines.)	♦ Available amounts and prices are influenced by the partner country.

(2) Verification of advantages of reservoir-type hydro

Rough estimation was made on the unit construction costs for expansion of existing reservoir-type hydro and development of new reservoir-type hydro, which will create advantages as peak supply capacity over development of GT. (Refer to Section 4.2 for economical efficiency data.)

(a) Expansion of existing reservoir-type hydro

Expansion of an existing reservoir-type hydro facility has a benefit of eliminating the need for development of a gas turbine. However, this just changes the time and scale for operating existing power plants, and thus reduction effect in the fuel cost is hardly expected. Accordingly, expansion of the existing reservoir-type hydro facility will be considered to be economical, if the annual expense needed for expanding the existing reservoir-type hydro facility equals to or is less than the annual expense needed for canceling the development of a gas turbine. Based on the unit construction cost of a gas turbine, 500USD/kW, and its annual expense ratio, 16.75%, its annual expense should be 83.8 USD/kW/year. Since the lifetime of a conventional hydro is longer than that of a GT, the annual expense ratio of hydro is 10.73%, which is much lower than that of GT. Accordingly, the break-even unit construction cost should be 780 USD /kW.

(83.8 USD/kW/year/10.73% = approx. 780 USD/kW)

(b) Development of new reservoir-type hydro

A case where a reservoir-type hydro facility of 500 MW is to be newly developed is assumed. The annual availability factor is assumed to be 10%. In this case the annual generating energy should increase by 438 GWh (500 MW × 8,760 hours × 10%).

In addition to the reduction effect of the fixed cost obtained by canceling the development of a GT, it is possible to reduce the fuel cost corresponding to the annual generating energy. GT and CC are thought to be the thermal power plants for which combustion can be reduced by the development of a new reservoir-type HPP. If it is assumed that generation of these can be reduced half, the average unit price should be 10.8 USC/kWh based on the fuel unit prices 14.2 USC/kWh for GT and 7.5 USC/kWh for CC. Given the effect of reduction in the fuel cost, the break-even unit construction cost should be 1,660 USD/kW.

(Approx. 780 USD/kW + 10.8 USC/kWh × 438 GWh/10.73%/500 MW = approx. 1,660 USD/kW)

When the annual availability factor of a newly developed reservoir-type is large, the reduction of fuel cost is expected to be high. Thus, the break-even unit construction cost will be gradually higher and assumed to be 2,540 USD/kW and 3,430 USD/kW when the annual availability factor is 20 % and 30 %, respectively.

4.5.2 Feasibility of Expansion of Existing Reservoir-Type Hydropower Plant as a Peak Supplier

(1) Current situation of existing reservoir-type hydropower plants

In Turkey, there are three large-sized reservoir hydropower plants with over 1,000 MW (total output 5,535 MW) in operation that were constructed in series along the Euphrates river. Among the three plants, Keban hydropower plant is the uppermost. These three hydropower plants account for 49% in installed capacity and 56% in annual generation energy of all the hydropower plants in Turkey, as shown in Figure 4. 21.

The annual average capacity factor of all hydropower plants in Turkey is 40%. However, the capacity factor of the three hydropower plants of Keban power plant, Karakaya power plant, and Ataturk power plant is, respectively, 55.4%, 46.6%, and 38.5%, as shown in Table 4. 22.

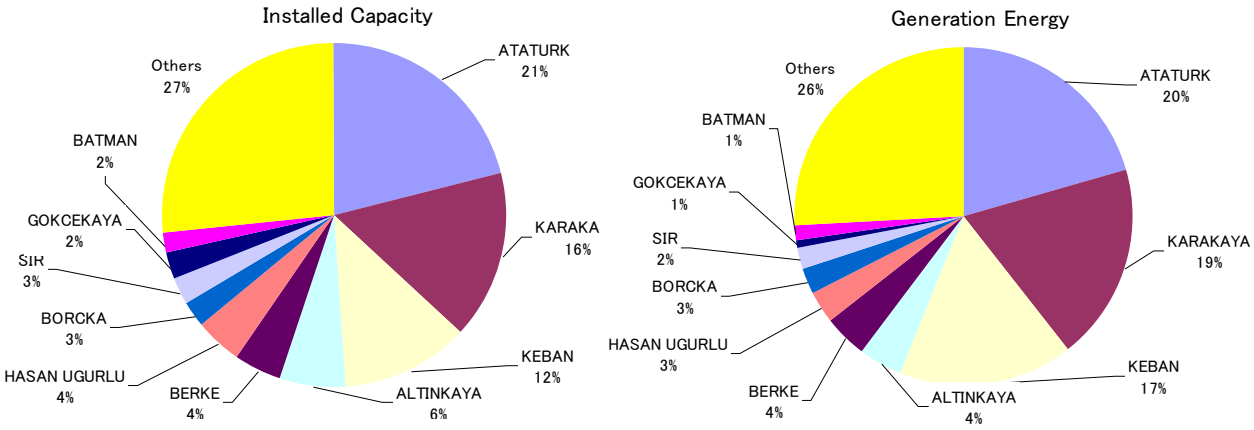


Figure 4. 21 Share of Each Hydropower Plant in Install Capacity and in Generation Energy

Table 4. 22 Outline of KEBAN, KARAKAYA and ATATURK HPPs

	Unit	KEBAN	KARAKAYA	ATATÜRK
H.W.L.	m	845	693	542
L.W.L.	m	813	670	526
Gross Head	m	152	151	158
Effective Head (*)	m	141	143	153
Max Power Discharge (*)	m3/s	1,100	1,450	1,800
Effective Storage Capacity (**)	$x10^6$m3	14,000	5,324	11,000
Installed Capacity	MW	1,360	1,800	2,400
Firm Energy	GWh/year	5,820	6,800	7,400
Annual Generation	GWh/year	6,600	7,350	8,100
Capacity Factor	%	55.4	46.6	38.5

(*) Calculated by EIE
(**) from EUAS

(2) Development of peak supply capacity by expansion of existing hydropower plants

Keban and Karakaya hydropower plants are currently operated as a middle supplier. Therefore, there is high possibility that Keban and Karakaya hydropower plants are expanded in order to meet the drastic increase of peak power demand in the future.

In consideration of expansion work of hydropower plants, the Study Team will examine change of water operation in line with expansion of hydropower plants in the same river system by reservoir operation simulation, and study comparative layouts of expansion plans such as location of intake, cofferdam, power station, and waterway route based on the existing topographical map of 1/25,000 on

the desk. Then, the Study Team will execute a site survey to investigate geographical and geological conditions as well as environmental conditions.

Based on the site survey results, the Study Team will review the expansion plan, estimate the project cost of several scales of expansion plan, and select the optimal scale of expansion plan.

The Study Team will evaluate the economical efficiency by B/C method considering gas turbine as an alternative peak supplier and assess feasibility of the optimal expansion plan.

(a) Desk study

Dam types of Keban and Karakaya are a combined type of fill dam and concrete gravity dam (Figure 4. 22) and arch concrete dam (Figure 4. 23), respectively. Since Karakaya dam is located in a precipitous valley, it is difficult to build a cofferdam and intake for expansion and to construct power station and switch yard.

Source: Google earth

Figure 4. 22 Keban Dam

Source: Google earth

Figure 4. 23 Karakaya Dam

Consequently, the Study Team decided to study the expansion feasibility of Keban hydropower plant, whose capacity factor is the largest at 55% and which has a gentle terrain around the dam.

The Study Team drafted expansion plans on the left bank and the right bank on a scale of 1/25,000 (refer to Appendix 4-5-1).

The right bank plan is drafted so that intake is installed by constructing cofferdam at the right bank upstream cove in the reservoir and waterway and powerhouse are situated underground.

The left bank plan is drafted so that intake is installed in the concrete gravity dam by constructing cofferdam at the left bank in the reservoir and the waterway and powerhouse are situated on the ground.

(b) Itinerary of site survey

An itinerary of site survey was drawn up discussing the site survey plan with C/P. The Study Team had prepared a questionnaire in advance in order to fulfill the survey without omission. Especially, data regarding river inflow, generation records of the existing power plant, and operation records of the reservoir were collected.

Participants of the site survey and actual itinerary are as listed in Table 4. 23.

（Participants）

EIE: Maksut Sarac, Mustafa G., Huseyin K., Burhan O.

JICA Study Team: H. Shinohara, J. Tamakawa, K. Nakamata,

Table 4. 23 Itinerary of Site Survey

Date	Activities	Stay
August 18	Ankara – Elazig Visit Circir Water fall and Micro hydropower plants	EUAS G/H
August 19	Visit EUAS Office of Keban HES Site Survey Right Bank, Left Bank Visit Keban HES Visit DSI Office of Keban Dam	EUAS G/H
August 20	Site Survey Right Bank, Left Bank Elazig – Ankara	

(c) Results of site survey and assessment

Results of the site survey on extension alternatives (right bank and left bank) are described in Appendix 4-5-2. The Study Team identified that there are no social and environmental issues for both extension alternatives and the extension alternative on the left bank is more likely than that on the right bank because it has fewer geological issues.

After the site survey, the latest topographical map of 1:25,000 was provided from EIE. Then, the Study Team revised the layout of the extension alternative on the left bank, taking into consideration the location of the existing dam, the power facilities, and topographical conditions. The revised layout is shown in Figure 4. 24.

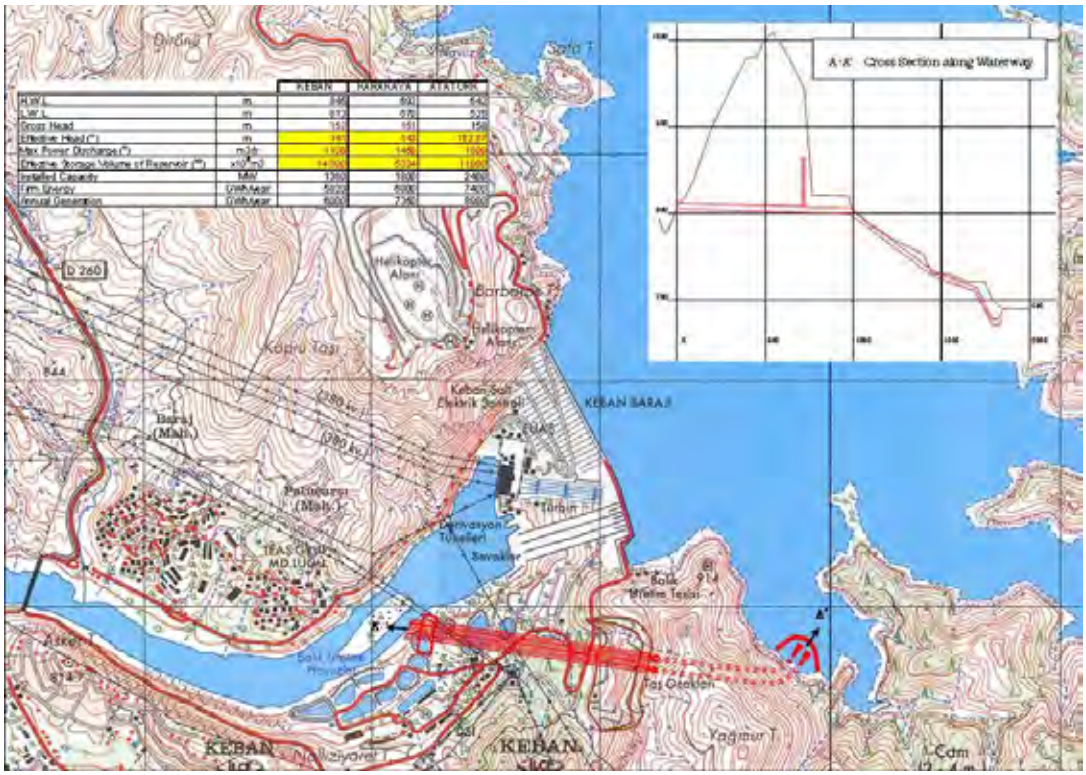


Figure 4. 24 Layout of Extension Plan of Keban HES

(d) Study on optimal scale of extension plan

The Study Team estimated project cost and firm peak capacity (Required peak duration hour in the power system is assumed as 7 hours) of each scale of extension plan by varying number of units from 2 to 8, and evaluated economical efficiency of each project scale by using B/C method applying gas turbine thermal power plant or pumped storage power plant as an alternative. Here, project profiles of the extension plan such as available water level of the reservoir, water level of outlet, effective head, unit capacity are set as the same as those of the existing power plant.

Besides, since no water has been spilled over from the Keban Dam so far, there is no additional generation energy by extension.

Assumptions of the study are shown below.

Table 4. 24 Assumptions of The Study on Extension Plan of Keban HES

Item	Preconditions
Unit Max. Output	183 MW
Unit Max. Discharge	135 m^3/s
Gross Water Head	152 m
Effective Water Head	145 m
Condition of Operation	Operating duration of all units comprising existing units and extended ones is 7 hours per day through a whole year. (This means that all units are operated as a peak power supplier)
Number of Existing Unit	8 units
Number of Extension Unit	2, 4, 6, 8 units

Before studying on economical efficiency of the extension project, the Study Team executed simulation of water level of the dam based on the river inflow data for 3 years from 2006 to 2008 when the extension is implemented, in order to examine whether or not the water level becomes lower than L.W.L.

Figure 4. 25 shows simulation results of the water level of Keban dam in the case that 6 or 8 units is extended. In the case of 6 unit extension, the water level is maintained between H.W.L and L.W.L. It indicates that the water amount is enough for making Keban HES including up to 6 extension units a peak power supplier. On the other hand, in the case of 8 extension units, the water level is lowered less than L.W.L in 2008.

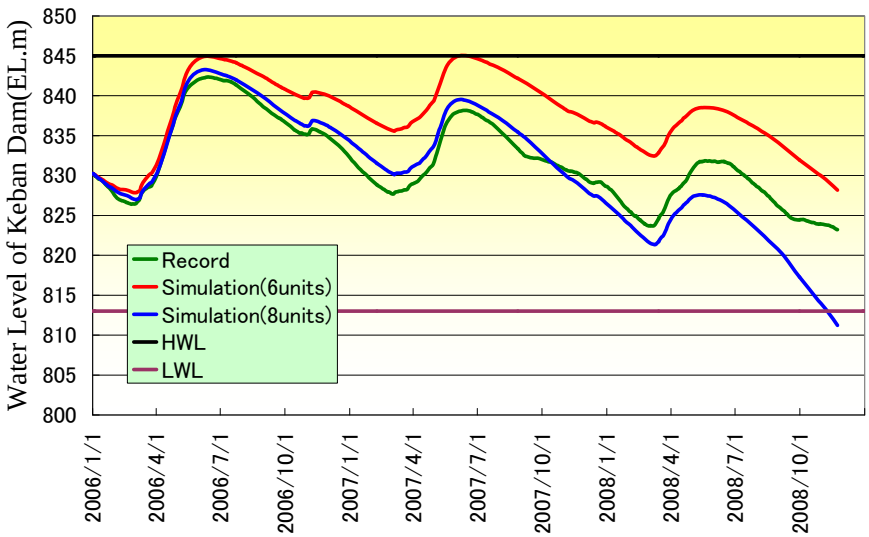


Figure 4. 25 Simulation Result of Reservoir Operation of Keban Dam

Meanwhile, the Study Team calculated the available supply capacity of each option of extension scale by dispatching it to the power system from 2025 to 2030, using PDPAT II. The results are shown below.

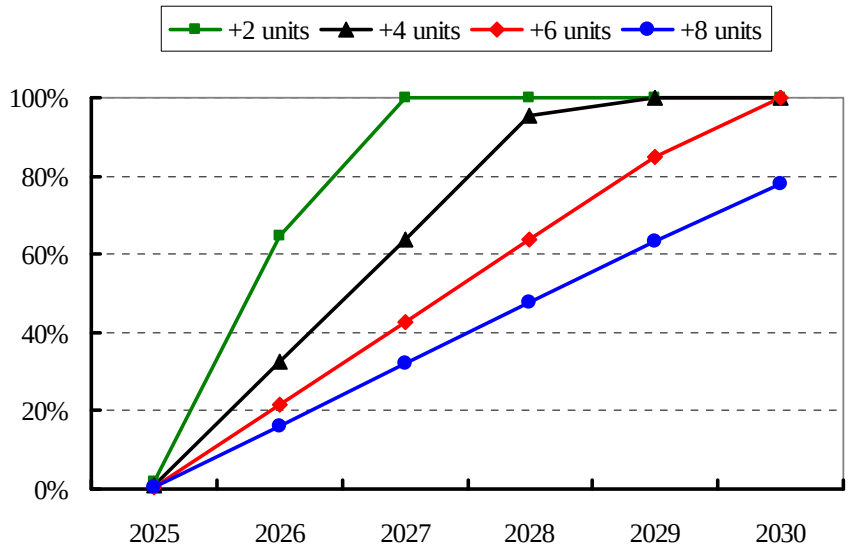


Figure 4. 26 Available Supply Capacity of Each Extension Scale of Keban HES

In 2025, the existing conventional type hydropower plants including Keban can meet peak power demand. Therefore, when Keban HES is extended before 2025, any extended capacity is useless for peak supply capacity. 2 units' extension is available after 2027, 4 units' extension is available after 2029 and 6 units' extension is available after 2030 for peak supplier in the power system. Furthermore, in the case of 8 units' extension plan, the available supply capacity in 2030 is reduced to 80% of the extended installed capacity.

It is judged from simulation of reservoir operation of Keban Dam and simulation of demand supply balance by dispatching Keban extension units that extension is feasible up to six (6) units without big problems. The Study Team estimated roughly extension cost of options of 2, 4, 6 and 8 units' extension. Table 4. 25 shows the results of rough estimate of each extension cost.

Though kW unit cost of the 2 units' extension is 727 USD/kW which is almost equal to that of PSPP, the kW unit costs are decreasing as the number of extension units is increasing due to scale economy, and the extension cost of 8 units is 543 USD/kW.

Table 4. 25 Rough Estimate of Extension Cost of Keban HES

Number of Extension Units	2	4	6	8
Unit Capacity (MW)	183	183	183	183
Unit Discharge (m3/s)	135	135	135	135
Total Extension Capacity (MW)	366	732	1,098	1,464
Total Extension Discharge (m3/s)	270	540	810	1,070
<Main Structures Features>				
No. of Headrace (D: 9.3m, L: 700m)	1	2	3	4
No. of Penstock (D: 4.6m, L: 1,113m)	2	4	6	8
No. of Surge Tank (D: 15.0m, L: 55.00m)	1	2	3	4
Length (m) of Power House (B: 19.0m, H: 30.0m)	38.00	76.00	114.00	152.00
Total Construction Costs（mil.USD)	**266**	**442**	**618**	**795**
Architecture Works	2	3	5	7
Civil Works	90	125	160	195
Waterway/Surge Tank	*20*	*40*	*59*	*79*
Penstock	*7*	*15*	*23*	*31*
Power House/Mech. Base	*8*	*13*	*19*	*24*
Temporary Works (Coffer Dam, others)	*55*	*57*	*59*	*61*
Electrical & Mechanical Works	93	187	280	374
Steel pipe, Gate and Others	81	127	173	219
Unit Costs (USD/kW)	**727**	**604**	**563**	**543**

(3) Feasibility of Extension Plan of Existing Reservoir Type Hydropower Plant

Cost-benefit analysis (B/C and B-C) was carried out based on the above extension costs. Gas turbine thermal power plant (GT) and pumped storage power plant (PSPP) are applied as an alternative power source respectively. Construction costs of the alternative power plants described in Section 4.2 are used for the analysis. Table 4. 26 shows the results of the cost-benefit analysis (B/C and B-C).

In the case of 2 unit extension, B/C becomes somewhat over 1.0 against both alternative power sources. Economical efficiency of the 2 units' extension plan is judged not high. Since either B/C value of 4 or 6 units' extension plan is over 1.2, it seems that both extension plans have high feasibility. However, in the case of 8 units' extension plan, B/C value becomes less than 1.2, since the available supply capacity in the power system in 2030 is reduced to 80% of the extended installed capacity.

In conclusion, the extension plan of 6 units (1,098MW) is the most economical. However, the peak supply capacity of 1,098MW is available after 2030 in the power system.

Table 4. 26 Cost-benefit Analysis（B/C, B-C)

Number of Extension Units			2	4	6	8
Total Extension Capacity (MW)			366	732	1,098	1,464
Supply Capacity (MW)			366	732	1,098	1,171
Unit Costs (USD/kW)			727	604	563	543
Alternative Power Source	Gas Turbine	B/C	1.07	1.29	1.39	1.15
		B-C (mil.USD)	2.1	13.9	25.6	12.8
	PSPP	B/C	1.01	1.21	1.30	1.08
		B-C (mil.USD)	0.2	10.1	20.0	6.8

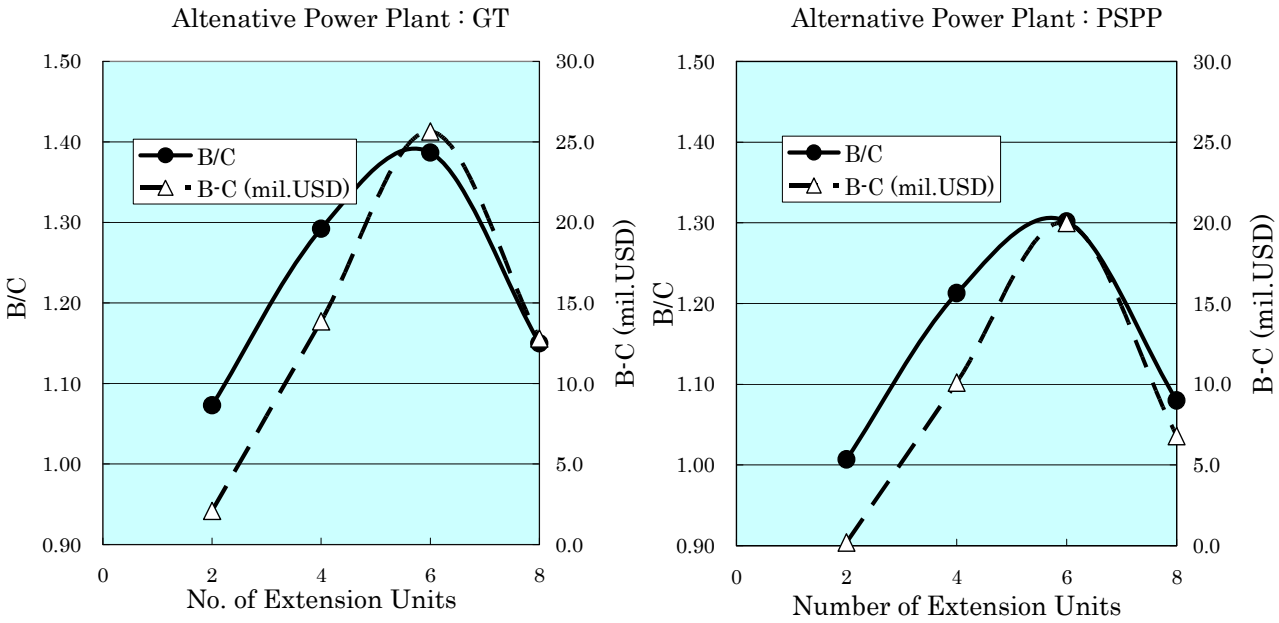


Figure 4. 27 Correlation between No. of Extension Unit & B/C or B-C

(4) Required Transmission Lines for Extension of Keban HES

In this section, the required transmission lines for extension of Keban HES are discussed. The base system is set out as the system that can transmit the power in case of increase in the power generation in the region of Black Sea coast area and also in the eastern mountainous area as described in Chapter 7. This system is the case with adding the circuits that would be needed even when no additional Keban units.

The required circuits of 380 kV were examined for the case of adding the units of Keban HES to this base power system by 1,080 MW (6 x 180 MW) to fulfill the criteria.

The increase in the power flow is shown in Figure 4. 29 when the power generation in the eastern mountainous area is increased and 1,080 MW power generation is added to Keban HES. Power flows after increased are shown in squares and increases in the power flow are shown in the parentheses.

The intervals with high increase in the power flow are listed as follows.

Keban-Kangal: Increase in power flow is 185 MW per circuit
Keban-Karakaya: Increase in power flow is 259 MW per double circuits
Keban-Erbistan: Increase in power flow is 196 MW per circuit

Increases in power flow in other intervals are approximately less than around 100 MW. Because of the large number of circuits around Keban, the increase in power flow by adding units of Keban HES is divided into the number of circuits, no intervals of transmission lines have the power flow exceeding the capacities of the transmission lines when a single circuit fault occurs.

Figure 4. 30 and Figure 4. 31 show the power angle swinging curves for the case of the increase in the power generation in the eastern mountainous area and the case with adding 1,080 MW to Keban HES respectively.

There are any large differences between two curves. The increase in the power generation of Keban HES does not impose significant impacts on the base system.

Thus, no additional circuits are required for the power transmission from Keban HES after the system is reinforced in order to transmit the increase in the power generation of power stations in 2015.

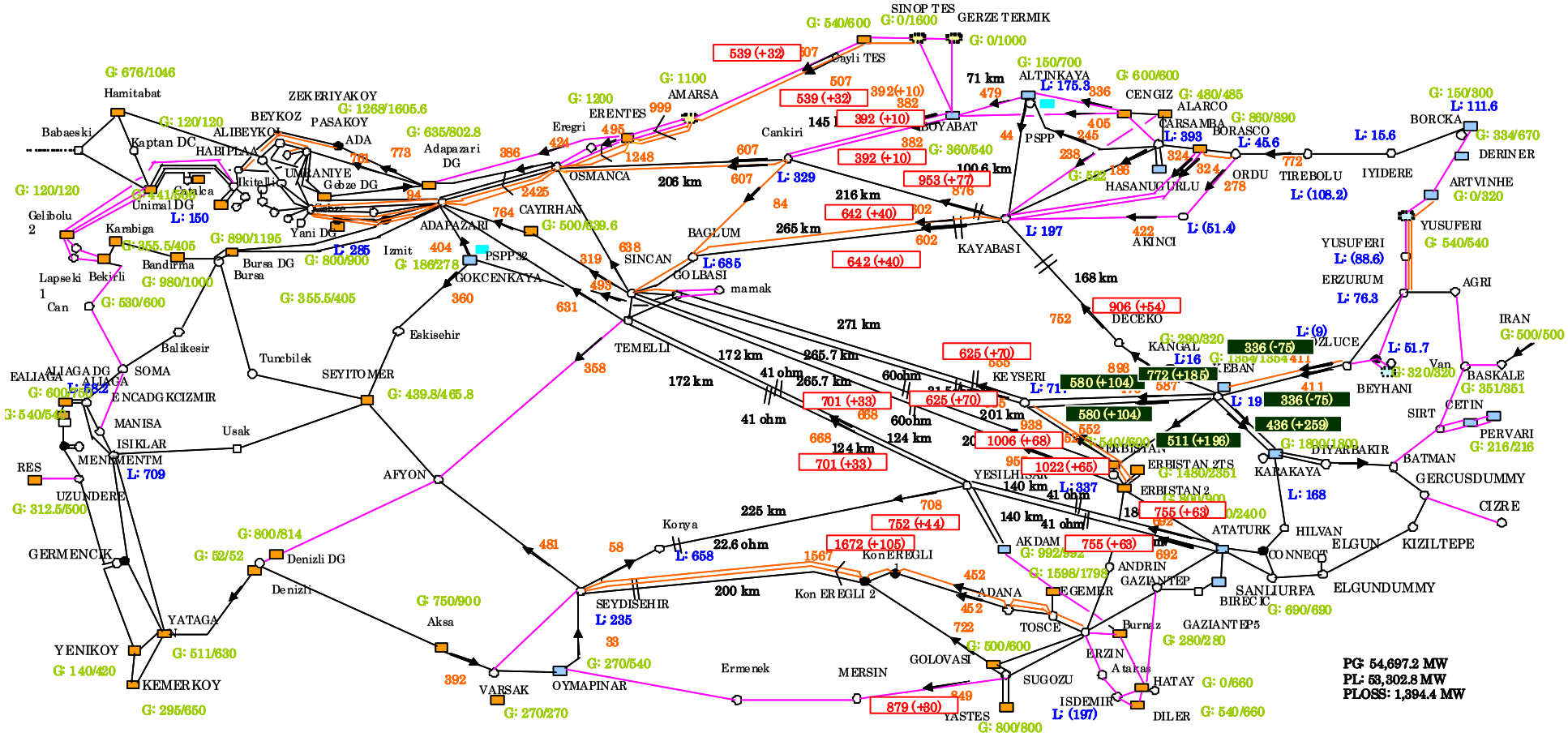
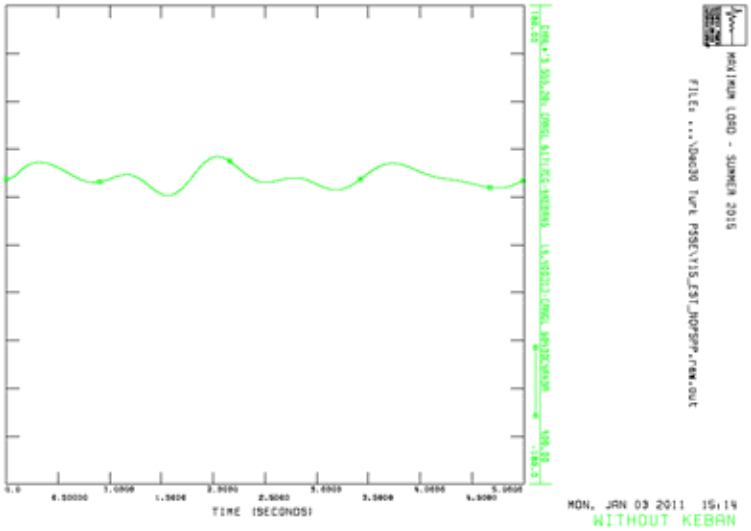
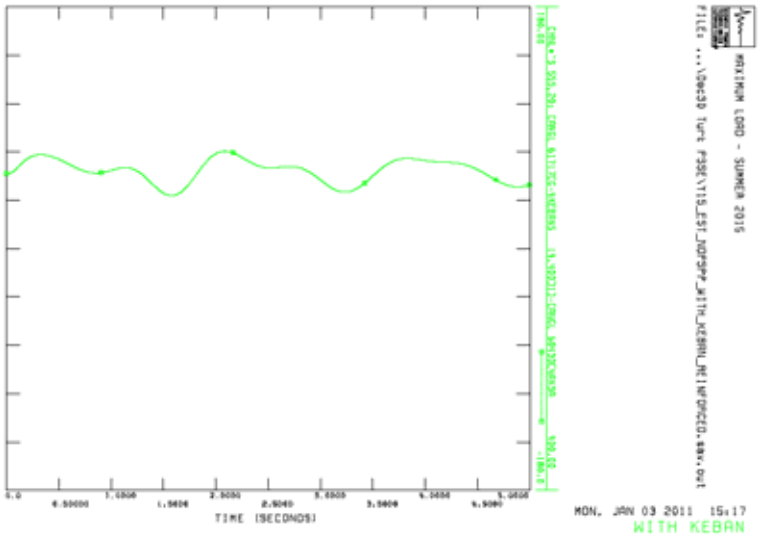


Figure 4. 28 Result of Power Flow Calculation when Adding Units of Keban HES to the Base System



- The case of the line tripping of the Erbistan- Sinkan
- The difference of the generator internal phase angle between Keban HES and Aksa power station located in the south western area (tripping at 120 ms after the occurrence of three-phase short-circuit of a single circuit)

Figure 4. 29 Stability Swing Curve (Generation Pattern B)



- The case of the line tripping of the Erbistan- Sinkan
- The difference of the generator internal phase angle between Keban HES and Aksa power station located in the south western area (tripping at 120 ms after the occurrence of three-phase short-circuit of a single circuit)

Figure 4. 30 Stability Swing Curve (Generation Pattern B + Adding Units of Keban HES)

4.5.3 Availability of Power Import from Neighboring Countries

There is a possibility that the supply reliability improvement and the reduction in fuel consumption are achieved in a Turkish system by interconnection with the ENTSO-E system. On the other hand, it is possible not to obtain those results, depending on the interconnection transmission line capacity restriction.

According to the information of ENTSO-E in 2008, Bulgaria, which was connected with Turkey's system, had surplus power export balance of trade (5,324 GWh), Greece had had exceeding power import of balance of trade (5,706 GWh).

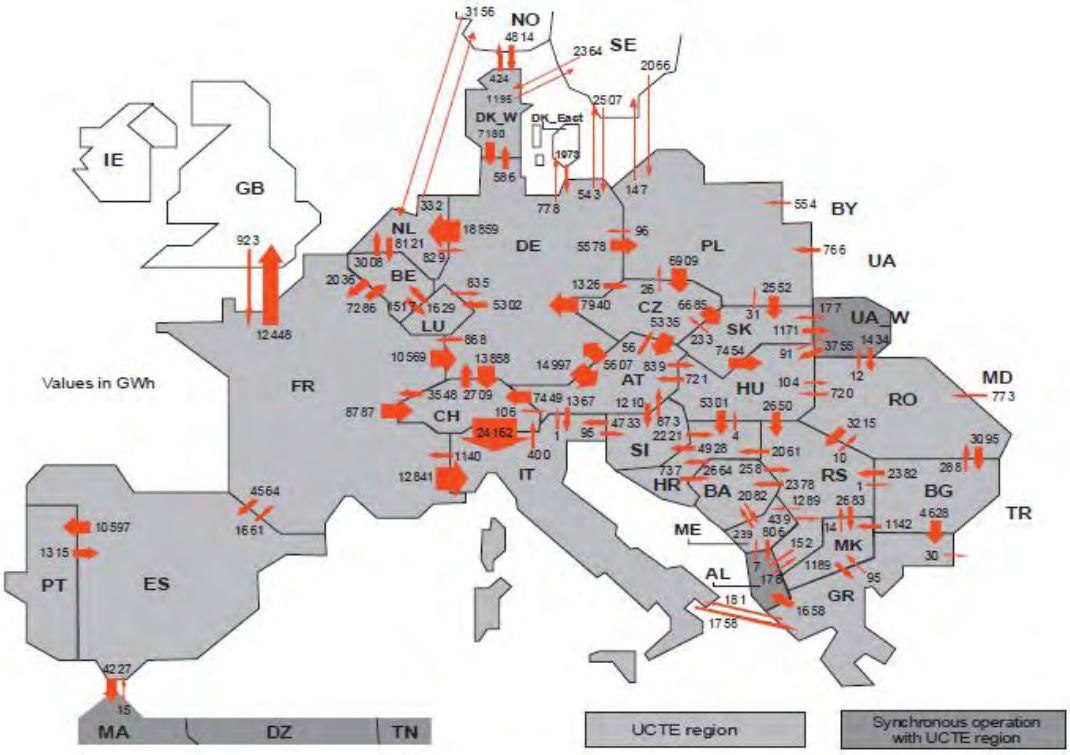


Figure 4. 31 International power flow in 2008(Physical energy flows 2008 in GWh)

Table 4. 27 Power Trade between Greece and Bulgaria in 2008 Unit: GWh

Greece			Bulgaria		
Country	Import	Export	Country	Import	Export
Bulgaria	4,628	-	Greece	-	4,628
Macedonia	1,189	-	Macedonia	-	1,142
Italy	1,758	181	Romania	3,095	268
Turkey	-	30	Yugoslavia	1	2,382
Albania	-	1,658	-	-	-
Total	7,575	1,869	Total	3,096	8,420

The annual capacity rate of interconnection lines from Bulgaria and Macedonia to Greece is over 80% and a congestion line. Therefore, the ability to obtain a necessary marginal supply capability in the Turkish system in peak periods depends on the congestion of interconnection lines during the peak demand period.

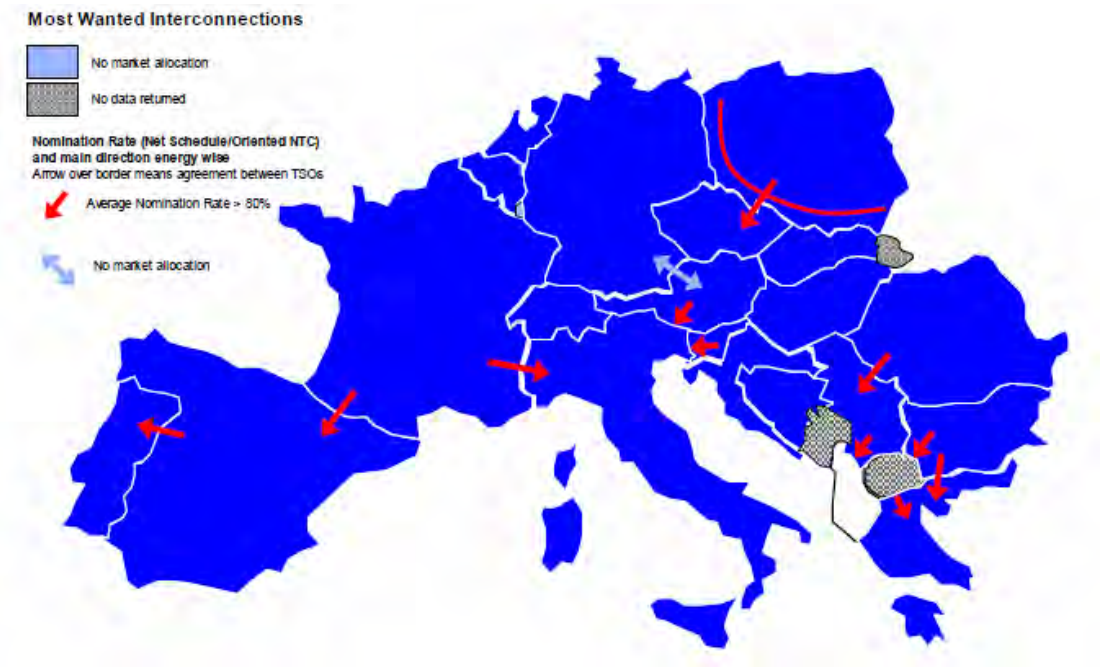


Figure 4. 32 Power Trade Congestions in 2008

4.6 Study of Optimal Power Supply Configuration in 2030

First, the optimal configuration ratio of the peak supply capacity was studied in a system with a demand size of 80 GW, which is estimated to be reached around 2030. Next, out of the necessary peak supply capacities, the optimal development amount of PSPP was studied.

Note that if the demand increases more than what is forecasted, the study should be conducted for a time earlier than 2030, while if the demand increases less than what is forecasted, the study should be conducted for a time later than 2030.

4.6.1 Study of the Necessary Amount of Peak Supply Capacity

(1) Comparison between gas turbine plant and combined cycle plant

The necessary amount of peak supply capacity was studied by comparing a gas turbine, which is economical as peak supply capacity, and combined cycle, which is economical as middle supply capacity.

Economic specifications for both are shown in Table 4. 28. Note that though both use natural gas as fuel and the fuel prices are the same, the difference in efficiency is large, which causes a great difference in the fuel unit price.

Table 4. 28 Comparison in Economic Efficiency between Gas Turbine and Combined Cycle

	Construction cost	Annual fixed cost	Fuel cost
Gas turbine (GT)	500 USD/kW	83.8 USD/kW/year	14.2 USC/kWh
Combined cycle (C/C)	700 USD/kW	113.8 USD/kW/year	7.5 USC/kWh

Though GT with a lower unit construction cost than C/C has a lower annual fixed cost, its fuel unit price will be higher due to poor efficiency.

The calculation results are shown below. As the supply reliability level, an 8% of reserve supply capacity against maximum demand shall be secured (LOLE values of 5-10 hours).

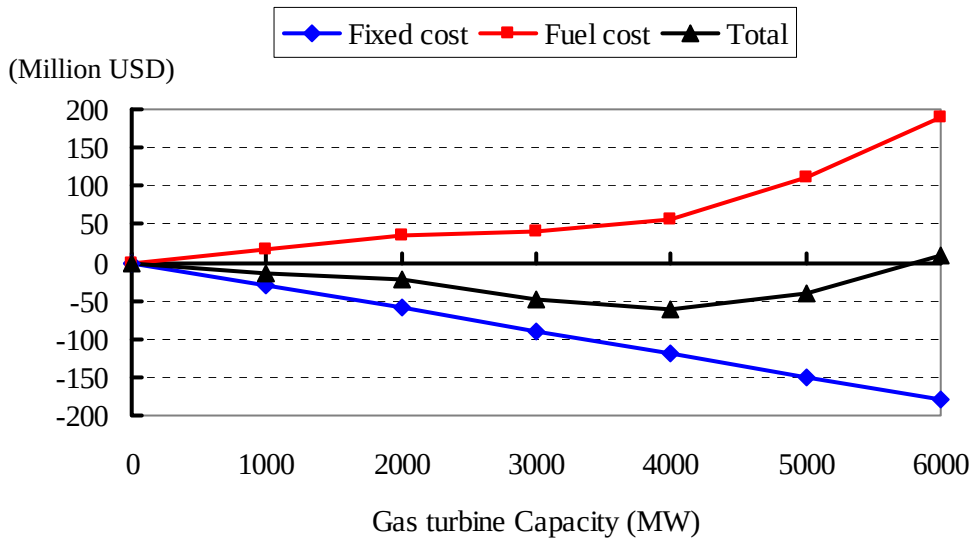


Figure 4. 33 Cost Comparison between Gas Turbine and Combined Cycle

If the installed capacity of GT is increased as peak supply capacity and the installed capacity of C/C equivalent to the GT's increase amount is decreased, the total fixed cost will decrease by 30 million USD per 1,000 MW due to its lower annual fixed cost than C/C. Meanwhile, since the fuel unit price of a GT is higher than that of a C/C, the total fuel cost will, generally speaking, increase in accordance with the increase in the installed capacity of GT. However, in the region where GT capacity is relatively small (4,000 MW or less), the increase rate is not so high.

An image of weekly operation in August 2030 in a case where 4,000 MW of GT has been developed is shown in Figure 4. 34. During the daytime when maximum demand takes place, GT is in operation, whereas during other hours GT is not in operation most of the time. Furthermore, in months other than August, there are cases where GT is not in operation at all even during hours when maximum demand is present.

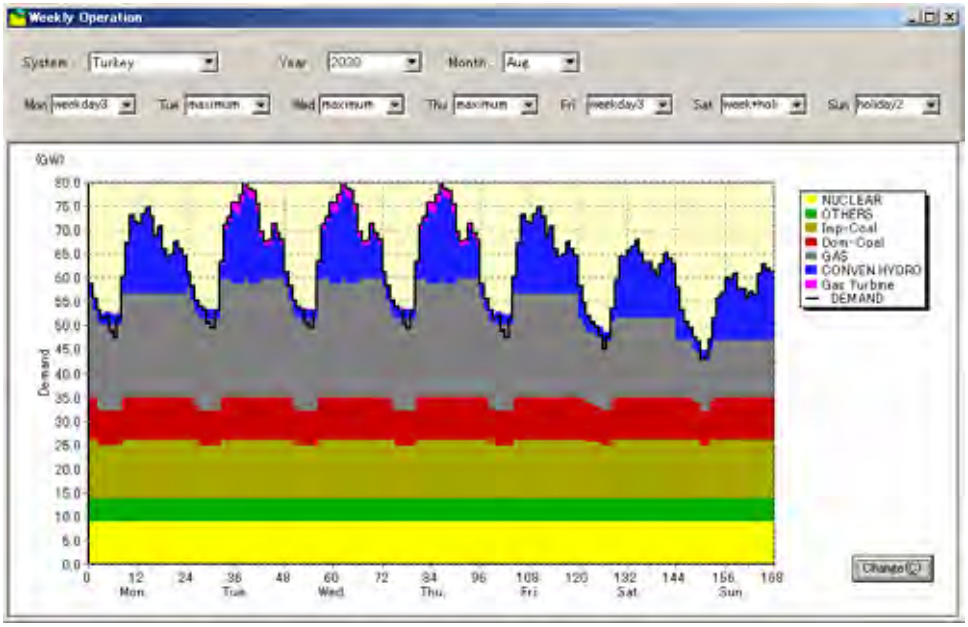


Figure 4. 34 Operational Image of Gas Turbine Thermal Power Plant（GT: 4000MW）

The economics of peak supply capacity largely depend on the supply reliability level. The result of changing supply reliability levels in the above-mentioned study is shown in Figure 4. 35.

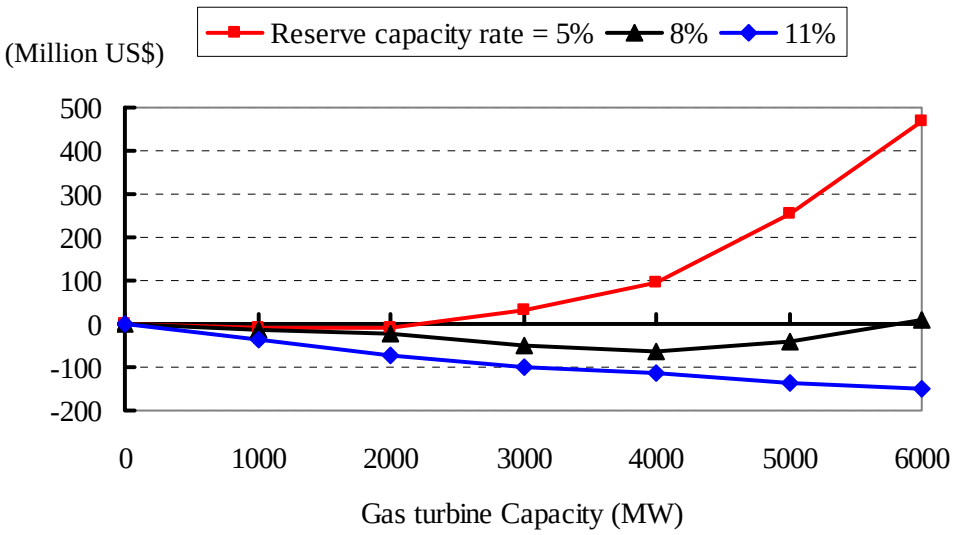


Figure 4. 35 Changes in Economics of Peak Supply Capacity due to Changes in Supply Reserve Capacity Rate

When the reserve capacity rate declines to 5%（the LOLE value of about 50 hours）the optimum development amount of the peak supply capacity will decline to 2,000 MW or lower. On the other hand, when the reserve supply capacity increases to 11%（the LOLE value of 1 hour or below） the optimum output of the peak supply capacity will increase to 6,000 MW or higher.

This is related to the actual operational output of GT which supplies power during peak hours. When the supply reserve capacity rate declines, even at stages when GT has been in operation only at small scales, there will be a greater opportunity for GT operation which has higher fuel cost. This will lead to higher fuel cost, which in turn will significantly reduce the advantage of GT. On the other hand, when the supply reserve capacity rate increases, even when the use of GT goes up, there will be few opportunities for GT operation. Since the fuel cost does not increase, GT with lower fixed cost will be advantageous.

As a result, although the optimal development amount of GT which supplies power at peak hours is largely dependent on supply reliability levels, in a case of appropriate supply reliability level (reserve capacity rate of 8%), the optimum GT development amount will be around 4,000 MW.

(2) Comparison between pumped storage power plant (PSPP) + GT and combined cycle

Next, the necessary amount of peak supply capacity was studied by comparing “PSPP + GT,” which is economical as peak supply capacity, and the combined cycle thermal in a similar method.

Economic specifications of PSPP and combined cycle are shown below.

Table 4. 29 Comparison of Economic Efficiency between PSPP and Combined Cycle

	Construction cost	Annual fixed cost	Fuel cost
PSPP	700 USD/kW	78.6 USD/kW/year	5.2 USC/kWh
Combined cycle (C/C)	700 USD/kW	113.8 USD/kW/year	7.5 USC/kWh

Though the unit construction cost of PSPP is 700 USD/kW, which is the same as that of C/C, the annual fixed cost of PSPP is low due to long lifetime because of many civil engineering facilities and because of low O&M cost. The fuel unit price of PSPP, which is calculated on the assumption that

water is pumped by increasing the generation from coal-fired thermal, is lower than the fuel unit price of C/C, even taking into consideration the pumping loss by 30%.

The calculation results are shown in Figure 4. 36.

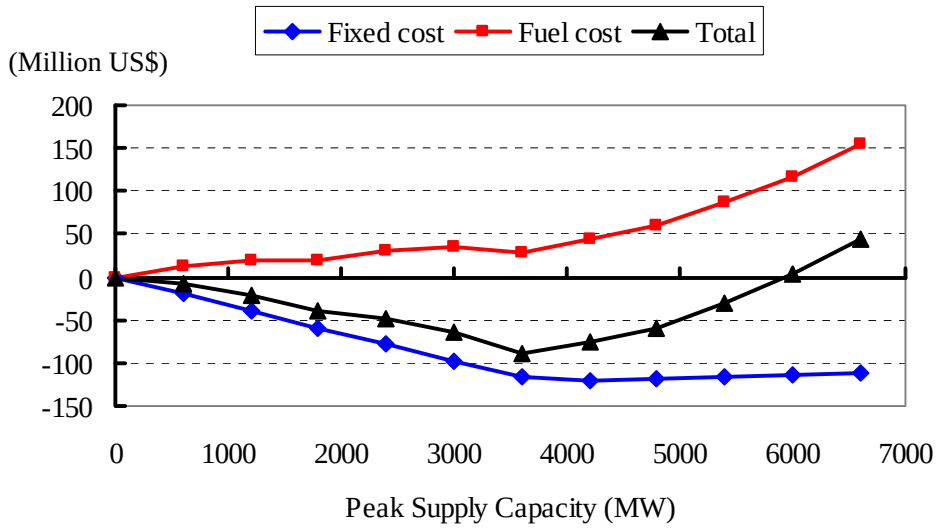


Figure 4. 36 Cost Comparison between PSPP+GT and Combined Cycle

If the installed capacities of PSPP and GT as peak supply capacity are increased by the same amount, and the installed capacity of C/C equivalent to the total increase amount of them is decreased, the fixed cost will decrease by 33 million USD per 1,000 MW, because the annual fixed cost for PSPP + GT is lower than C/C. If the development amount for peak supply capacity exceeds 4,000 MW (i.e., if the development amount of PSPP exceeds 2,000 MW), the same supply capacity as the installed capacity cannot be expected for PSPP. Accordingly, the decreasing trend of the fixed cost will slightly slow down. The fuel cost shows a similar trend as the case where only GT is installed, and will slightly decrease in the region where there is not much installation amount (1,000 MW or less).

As a result of this, the development would be optimal if the development amount of PSPP + GT as peak supply capacity is 2,000-2,500 MW.

(3) The necessary amount of peak supply capacity

The result of application of operations at various generation facilities to the demand on the maximum demand day in August in the case where the development amount of PSPP + GT is 3,000 MW (i.e., the development amount of PSPP is 1,500 MW) is shown in Figure 4. 37.

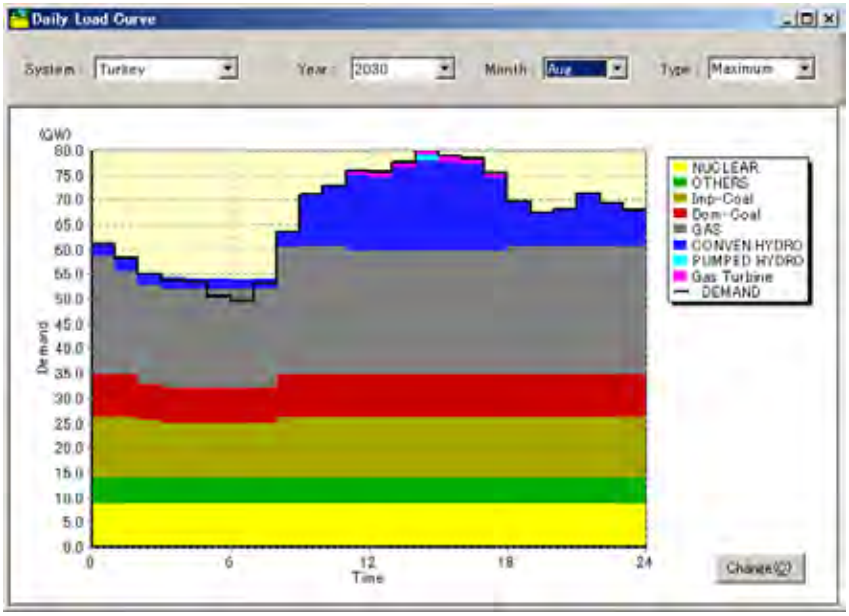


Figure 4. 37 Example of Application of Operation at Generation Facilities

Existing conventional hydro facilities as peak supply capacity have already met a large portion of the demand, and thus the necessity for further peak supply capacity will not be large unless the operation conditions of conventional hydro change in the future. However, the development of PSPP or GT as peak supply capacity in addition to the conventional hydro would also be economical, as long as its ratio is up to approx. 3% of the entire installed capacity.

4.6.2 Study on Necessary Amount of Pumped Storage Power Plants (Study in the Base Case)

(1) Study on the pondage volume of PSPP

Prior to the necessary amount of the PSPP, the optimal pondage volume for PSPP is studied. Generally speaking, the unit of the pondage volume of a hydro (the effective pondage volume) is cubic meters (m^3). However, the unit here is expressed by the time duration (hours) for which the operation of a PSPP at the maximum output can continue.

Generally speaking, if the pondage volume is to be increased, it is also necessary to increase the height of the dam as a matter of course. Accordingly, in the case where a large benefit is not expected, further expansion of the pondage volume would become inefficient due to its high construction cost.

The same amount of the development amount and the supply capacity are always expected for thermal power plants unless fuel supply is restricted. On the other hand, in case of hydro, the daily operable amount is restricted by the river inflow amount and the capacity of pond which regulates the inflow amount. (In the case of a PSPP, the operable amount is restricted by the capacity of the pond of the upstream dam since there is almost no river inflow amount to the dam.)

(a) Estimation for the case where there is no conventional hydro (i.e., the case that never happens in actual life)

The following shows an example where the supply capacity changes depending on the difference in the pondage volume of PSPP. This case is an example where the demand in a system (80 GW) in Turkey in 2030 will be met by developing 12,000 MW (12 GW) of PSPP, since there is no conventional hydro. (The estimation is made in a case that never happens in actual life in order to facilitate the readers' understanding.)

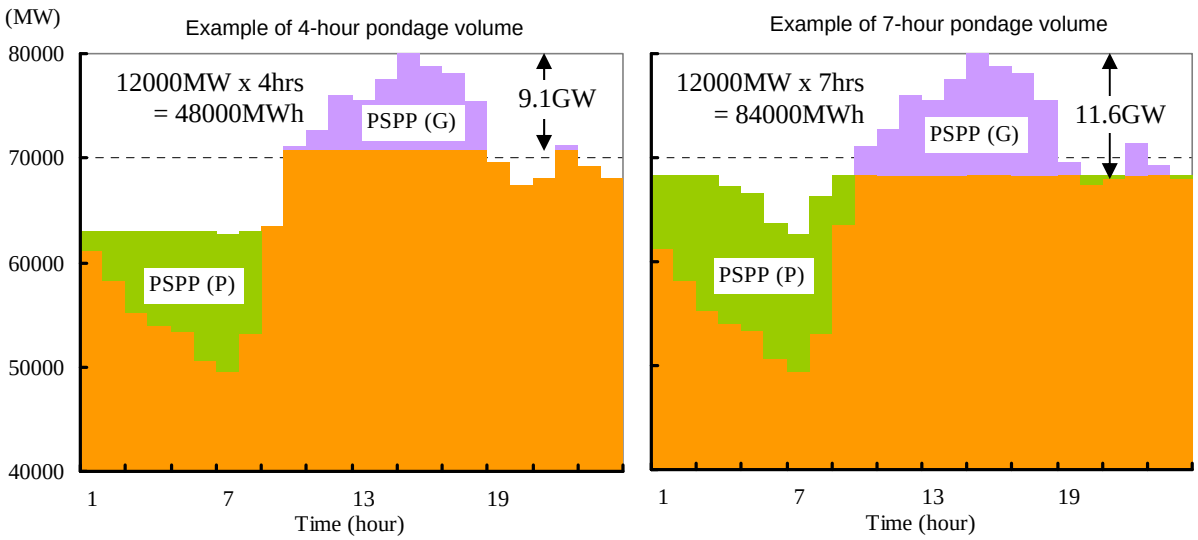


Figure 4. 38 Image Picture of PSPP dispatching to Demand

Dispatching of PSPP to the demand would be the most economical because this enables suppressing thermal operation requiring a high fuel cost if it is applied so that the post-application demand shape becomes as flat as possible. If the pondage volume is 4 hours, the applicable amount of PSPP is only 48,000 MWh. Therefore, if the PSPP is to be applied so that the post-application demand shape becomes as flat as possible, the supply capacity of only 9100 MW (9.1 GW) will be expected. On the contrary, in the case where the pondage volume is 7 hours, the capacity of the applicable amount of PSPP is 84,000 MWh. Accordingly, the supply capacity of 11,600 MW (11.6 GW), which is almost equal to the installed capacity of 12,000 MW, can be expected if PSPP is to be

applied so that the post-application demand shape becomes as flat as possible. In this way, difference in the supply capacity of PSPP is caused depending on the size of the pondage volume.

(b) Estimation in a realistic case

In the study in the previous paragraph, a case where there is no conventional hydro was estimated. In the actual system in Turkey, however, there are many conventional hydropower plants (HPPs). Since these conventional HPPs do not need fuel costs, it would be the most economical to accord conventional HPPs with top priority.

Most of the large-scale (50 MW or more) conventional HPPs in Turkey operate only in the daytime when the demand is large and stop operation during nighttime when the demand is small (refer to Section 4.1.5 (1)). In other words, currently, most of the demand peak areas can be supplied by conventional HPPs.

With the status as described above taken into consideration, the result applied to the demand is shown in Figure 4. 39.

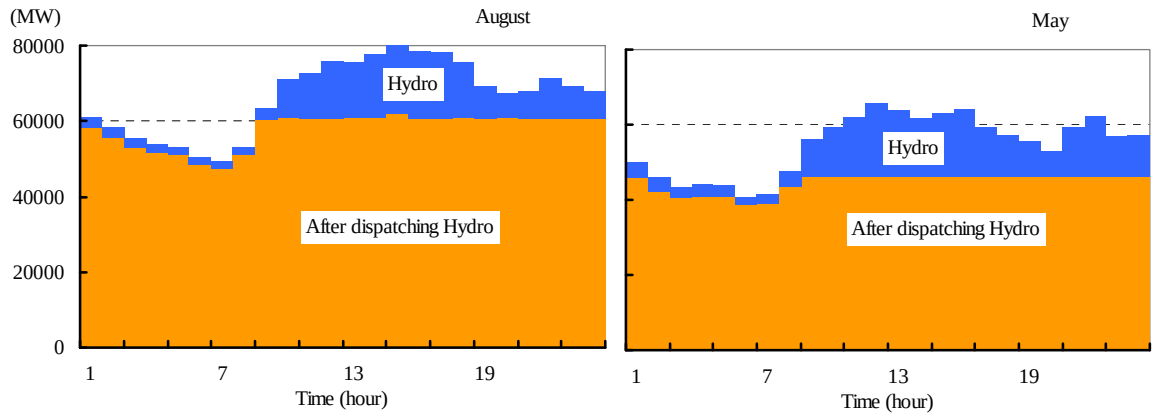


Figure 4. 39 Example of Dispatching of Conventional Hydro to Demand

When a conventional HPP is applied to the peak time zones of the demand, the post-application demand shape becomes very flat. While the peak shape remains only for 1 hour at 15:00 in August when the maximum demand is large, the shape becomes completely flat from 9:00 to 24:00 in May when the maximum demand is small.

The relationship between the installed capacity of the PSPP and the supply capacity of the PSPP in August in a system in 2030 (with the demand size of 80 GW) is shown in Figure 4. 40.

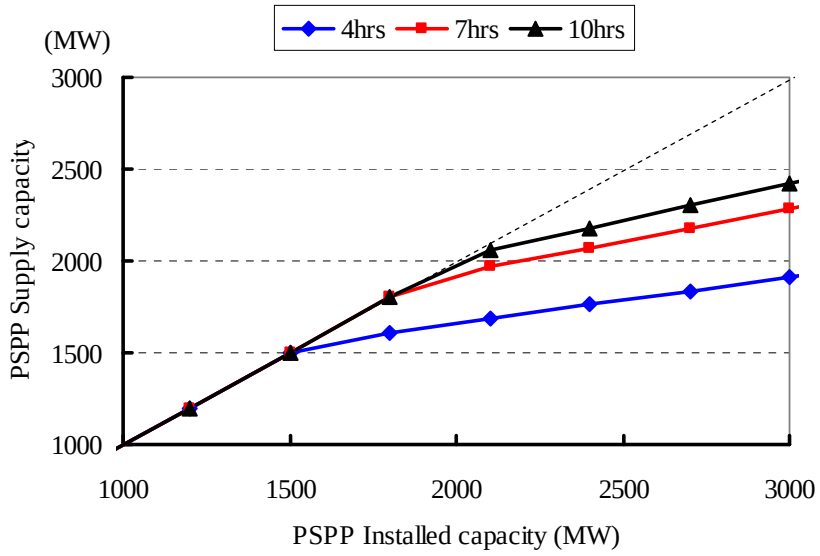


Figure 4. 40 Relationship between Installed Capacity and Supply Capacity of PSPP

Estimation was made for three cases where the pondage volumes (in the unit of the number of hours) are 4 hours, 7 hours, and 10 hours, respectively. The result showed that the installed capacity is the same as the supply capacity in August in any case, as long as the installed capacity of PSPP is 1,500 MW or less. In the case where the installed capacity of PSPP is 1,800 MW, the installed capacity will be the same as the supply capacity if the pondage volume (in the unit of the number of hours) is 7 hours or more; however, the expected supply capacity will decrease if the pondage volume is only 4 hours. In the case where the installed capacity of PSPP is 2,100 MW or more, the installed capacity will not be the same as the supply capacity if the pondage volume is 7 hours or more; however, the difference is small between the cases when the pondage volume is 7 hours and when it is 10 hours.

The reason for that could be as follows. Since the pumping efficiency is approx. 70%, in the case where the pondage volume is 10 hours, it takes 14.3 hours to pump from the lowest to the highest water level in the upper reservoir. In other words, it takes at least 24.3 hours for one cycle of generation and pumping where the entire pondage volume is effectively used, and thus it is not possible to operate the facility in a single day. In this way, even if the pondage volume is 10 hours, it is not possible to continuously operate for 10 hours at the maximum output every day. Given the fact that pumping and generation are conducted within a single day (24 hours) and that a time period when the facility stops without generation or pumping in the intermediate time zone between pumping and generation, if the pondage volume is as large as 7 hours or more, it will be difficult to utilize its pondage volume effectively every day.

Changes in the supply capacities of PSPP (August and annual average) when the pondage volume (in the unit of the number of hours) is changed in two cases where the development amount of the PSPP is 1,200 MW and 2,400 MW, respectively, are shown in Figure 4. 41.

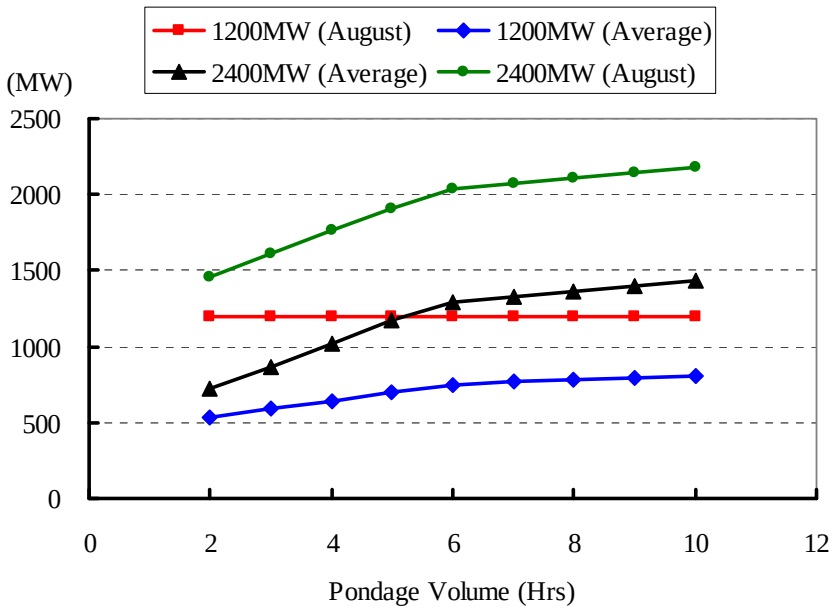


Figure 4. 41 Relationship between Pondage Volume and Supply Capacity of PSPP

In the case where the development amount of PSPP is 1,200 MW, the supply capacity of 1,200 MW is expected in August regardless of the size of the pondage volume. However, the average supply capacity except August, the supply capacity decreases in accordance with the decrease in the pondage volume. If the pondage volume becomes 6 hours or less, the rate of decline in the supply capacity will further increase. On the contrary, if the pondage volume becomes 7 hours or more, increase in the supply capacity will slow down. This trend is further remarkable when 2,400 MW of PSPP is developed, and increase in the supply capacity will slow down when the pondage volume is 7 hours or more even in August.

(c) Conclusion

As studied above, though increase in the pondage volume to approx. 6-7 hours produces the effect of a corresponding increase in the supply capacity, increase to 7 hours or more does not produce a very large benefit. Therefore, when investment efficiency is taken into consideration, the pondage volume of 7 hours would be appropriate.

(2) Study on optimal necessary amount of PSPP

In the study in Section 4.6.1 , it was concluded that the additional development peak supply capacity in the amount of approx. 4,000 MW is needed by PSPP and gas turbines, in addition to by conventional hydro.

Here, which of PSPP and gas turbine (GT) is more economical as peak supply capacity was studied. Figure 4. 42 shows how the expense for the entire system changes when the development amount of PSPP is increased. The cost represents the difference between the actual case and the reference level under which no PSPP has been developed. Furthermore, by basically stopping the development of GT with the same capacity in response to the development of PSPP, the supply reserve capacity rates are maintained at a constant level (8%) in all cases.

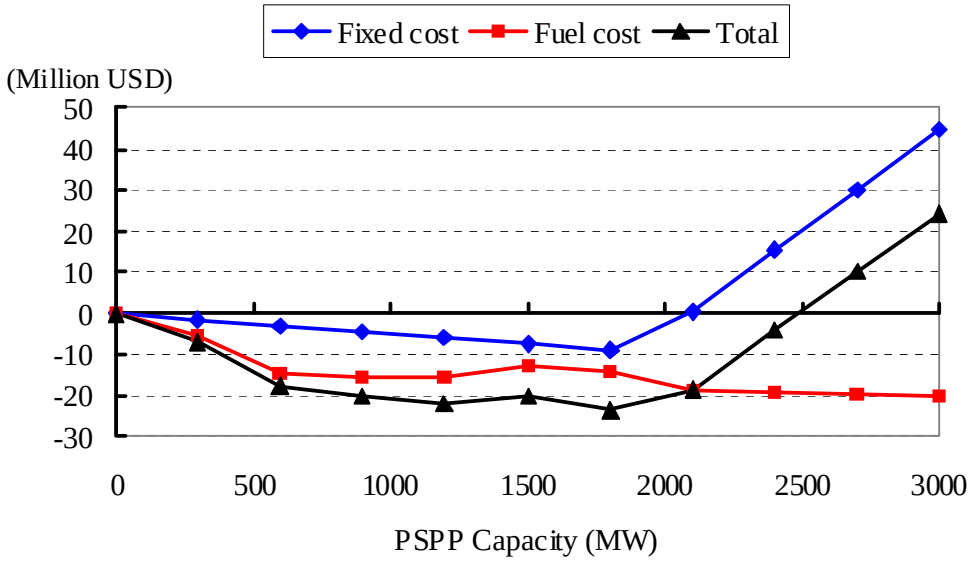


Figure 4. 42 Optimal Necessary Amount of PSPP

(a) Fixed cost

When the development amount of PSPP is increased, the corresponding development amount of GT will decrease. Since the annual fixed costs are 78.6 USD/kW/year for PSPP and 83.8 USD/kW/year for GT, respectively, the total annual fixed cost will gradually (5.2 million USD per 1,000 MW) decrease as the development amount of PSPP increases. This trend continues until the development amount of PSPP reaches 1,800 MW. However, if further development than 1,800 MW is implemented, the supply capacity will not become the same as the development amount. Accordingly, if the development amount of GT in the same amount as that of PSPP is decreased, it will cause insufficient supply capacity to maintain a certain supply reserve capacity rate. (The reason for this will be described later.) In order to maintain a certain supply reserve capacity rate, this situation needs be addressed by reducing the decrease in the development amount of GT which will be made possible by the development of PSPP, causing increase in the fixed cost. Specifically, in the case where the development amount of PSPP is 1,800 MW, it is possible to maintain a certain supply reserve capacity rate even if the development amount of GT decreases by an equal amount, 1,800 MW. However, in the case where the development amount of PSPP is 2,100 MW, it is necessary to suppress the decrease in the development amount of GT to 1,967 MW in order to maintain a certain supply reserve capacity rate.

Meanwhile, the fuel cost decreases as the development amount of PSPP increases. This is because the introduction of PSPP promotes effective utilization of less-expensive power for pumping at night. However, this trend continues only until the development amount of PSPP reaches approx. 600 MW, and even if the development amount of PSPP is further increased, the fuel cost will substantially remain unchanged.

In terms of the total expense of the fixed cost and the fuel cost, the total expense gradually decreases until the development amount of PSPP reaches 1,800 MW. However, if the development amount of PSPP is further increased, the entire expense will greatly increase due to dramatic increase in the fixed cost. In this way, it will be the most economical when the development amount of PSPP is 1,800 MW.

The reason the supply capacity does not match the development amount if development of 1,800 MW or more is implemented is thought to be as follows.

A picture of dispatching of PSPP to the demand when 2,100 MW of PSPP is developed is shown in Figure 4. 43.

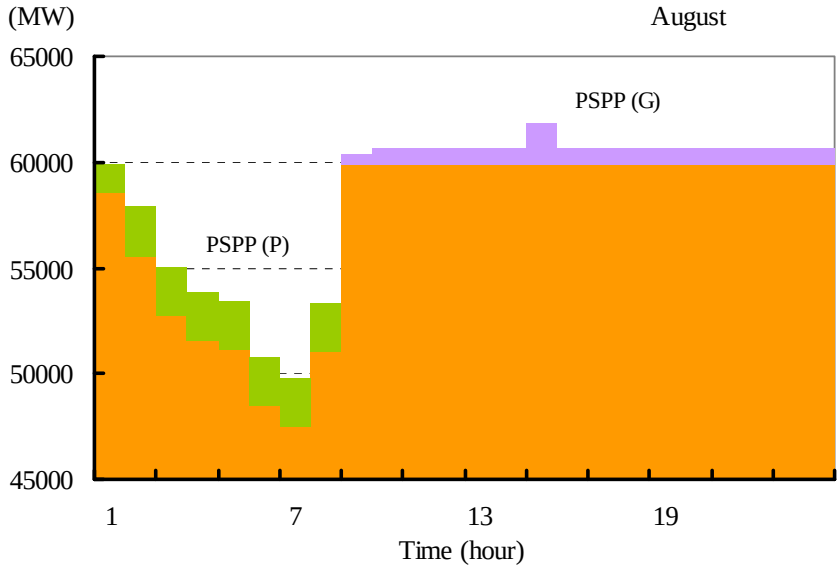


Figure 4. 43 Image Picture of Dispatching PSPP to Demand

The demand shape after application of conventional hydro is flat from 9:00 to 24:00 except at 15:00. Accordingly, when the development amount of PSPP is increased, the time period when the demand should be met by PSPP will increase to 16 hours. On the contrary, since the PSPP has the pondage volume only equivalent to 7 hours at the maximum output operation, it is not possible for the facilities to operate at the maximum output for the entire time period to be addressed, requiring the operation while suppressing the output.

(b) Fuel cost

The fuel cost will decline as the development amount of PSPP increases. This is because excess power generated during nighttime can be effectively used to power pumping. Although the fuel cost will steadily go down until the development amount of PSPP of around 600 MW, even if the development amount is raised further, no further reduction in fuel cost can be expected, thus remaining flat.

Expected changes in various fuel consumption and the overall efficiency of gas-fired power generation with the increase of development of PSPP are shown in Figure 4. 44.

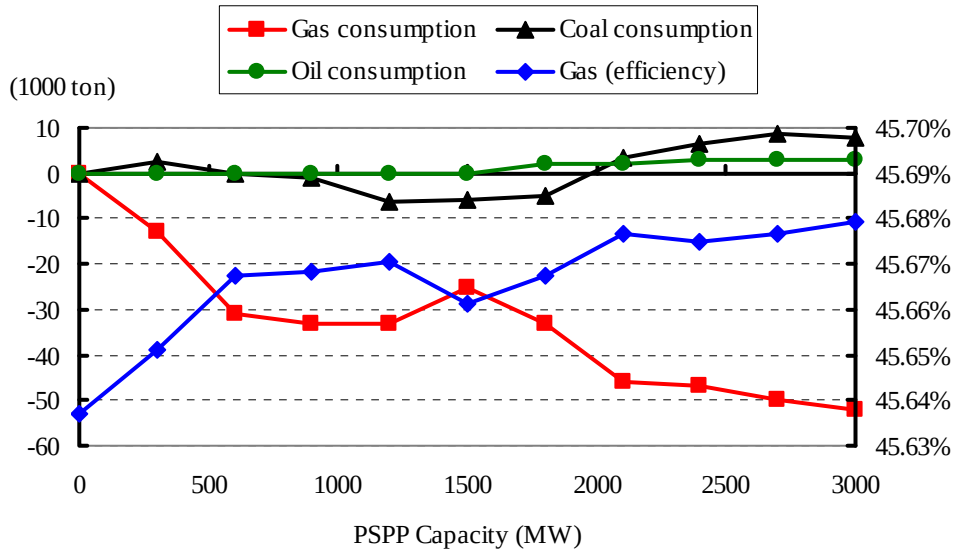


Figure 4. 44 Changes in Various Fuel Consumption and Overall Efficiency of Gas-fired Thermal

Although consumption of coal and oil will see little change, gas consumption will gradually decline as more and more PSPPs are developed. When the developed output of PSPPs reaches 2,100 MW, it will be possible to reduce gas consumption by 50,000 tons a year. While the overall efficiency of gas-fired thermal power was 45.64% when no PSPPs were introduced, when the developed output topped 2,100 MW and went higher, it increased by 0.04 points to 45.68%.

(c) CO_2 emissions

Expected changes in CO_2 emissions generated from the whole power system with the increase in the development amount of PSPP are shown in Figure 4. 45.

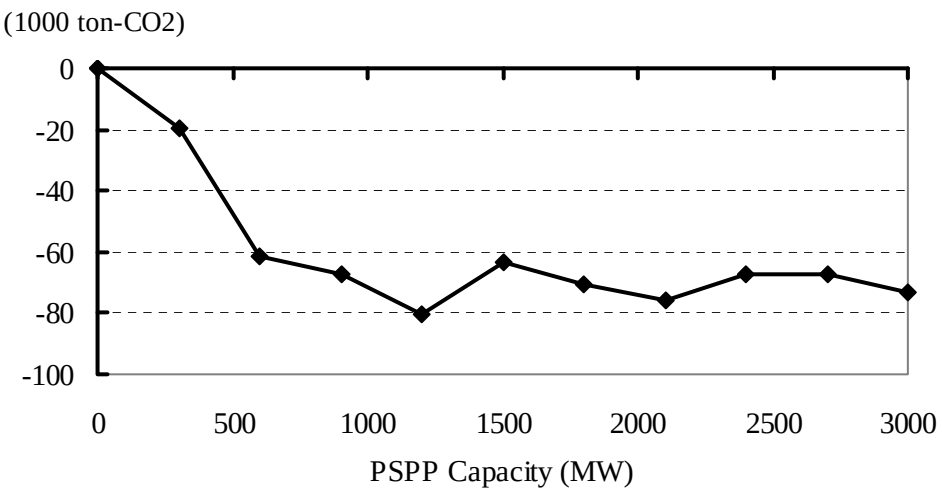


Figure 4. 45 Changes in CO_2 emissions

As mentioned above, it is possible to reduce CO_2 emissions generated from the whole power system as the development amount of PSPP is increased due to the reduction in gas consumption. When the development amount goes up to 600 MW or higher, it will become possible to reduce CO_2 emissions by around 70,000 tons a year.

(d) Overall evaluation

In terms of fixed and fuel costs combined, they will gradually decline until the development amount of 1,800 MW of PSPP. However, when the development amount of PSPP is increased, because of the significant incremental fixed cost, the overall costs will significantly go up as well. Furthermore, these costs include the supply incapable cost in a case of supply impossible.

On the environmental front, the development of PSPPs will enable efficient operation of thermal power plants, thus allowing the reduction in CO_2 emissions.

In the overall evaluation by taking into account the economical and environmental fronts, out of 4,000 MW of the optimal installed capacity at peak period, the development amount of 1,800 MW of PSPPs is optimal.

4.6.3 Sensitivity Analysis

(1) Changes in fuel prices

Fossil fuel prices in the base case use forecasted prices until 2030 announced by IEA in 2009.

Changes in the economics of PSPP in accordance with uniform changes in fossil fuel prices are shown as follows.

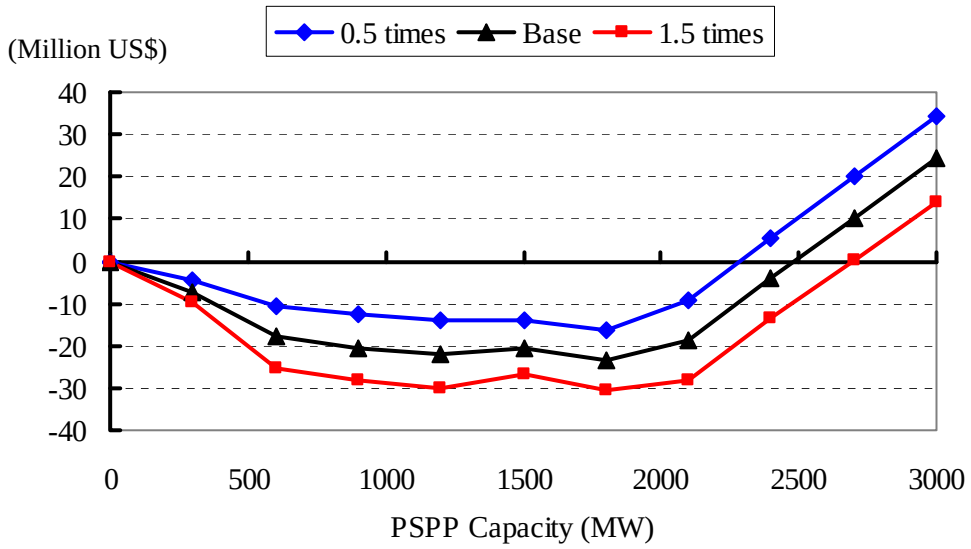


Figure 4. 46 Changes in Economics of PSPP due to Changes in Fuel Prices

When fossil fuel prices go up 1.5 times uniformly, even though the total advantage somewhat increases, the optimal development amount will change very little. Similarly, when fossil fuel prices go up by 0.5 times uniformly, although the total advantage somewhat declines, the optimal development amount of PSPP changes very little. In this way, significant changes in fuel prices have little impact on the optimum development amount of PSPP.

(2) Changes in construction cost of PSPP

The construction cost of PSPP in the base case uses the figure of 700 USD/kW as a rough construction cost calculated at the moment. Changes in the economics of PSPP in accordance with changes in the construction cost are shown in Figure 4. 47.

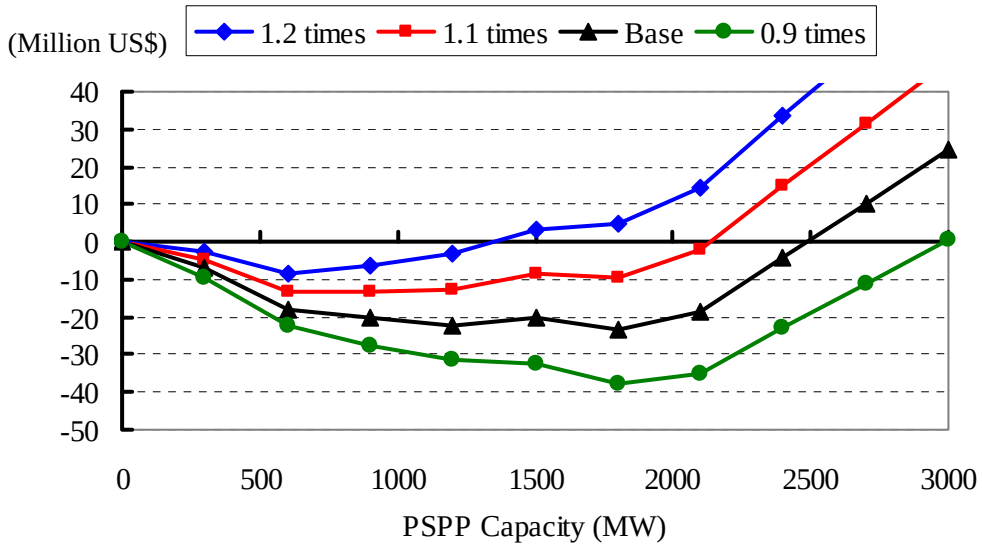


Figure 4. 47 Changes in Economics of PSPP due to Changes in Construction Cost

When the construction cost of PSPP goes up to 1.2 times (840 USD/kW), the total advantage declines and the optimal development amount will go down to about 600 MW. On the other hand, when the construction cost of PSPP go up to 0.9 times (630 USD/kW), although the total advantage somewhat declines, the optimal development amount of PSPP changes very little.

(3) Changes in supply reliability levels

In the base case, the supply reserve capacity rate of 8% is used as a supply reliability rate. This will be 5-10 hours by the LOLE value when the composition of power plants in 2030 is taken into account.

Changes in the economics of PSPP in accordance with changes in supply reserve capacity rates are shown in Figure 4. 48 when the optimal peak supply capacity is set at 4,000 MW.

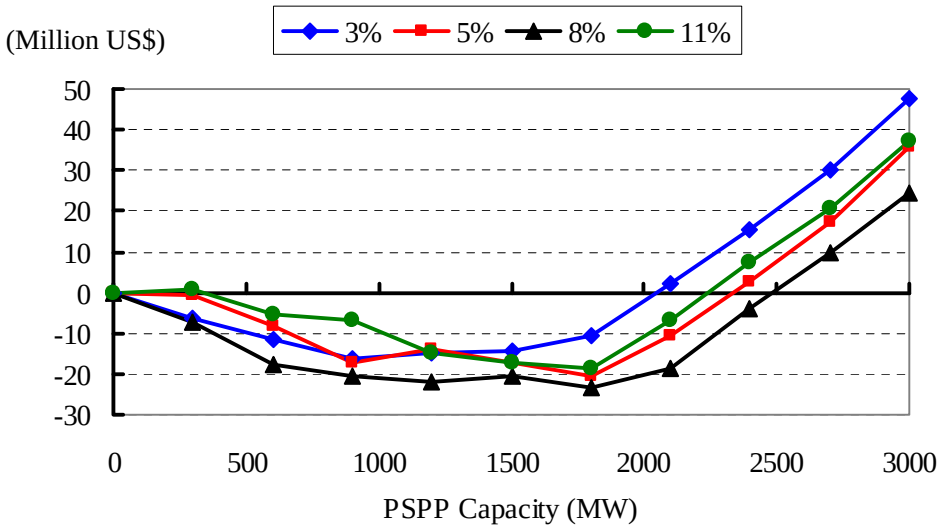


Figure 4. 48 Changes in Economics of PSPP in accordance with Changes in Supply Reserve Capacity Rates

Out of the 4,000 MW of the optimal installed capacity required under any circumstances during the peak period whose economics of PSPP does not change much even by changing the supply reserve capacity rate, 1,800 MW of the development amount of PSPP can be said as optimal. However, the required peak supply capacity of power plants such as PSPP and GT which have low fixed costs is changing by supply reliability level.

(4) Changes in demand profile

In the base case, it is assumed that the maximum power demand will reach 80 GW in 2030. This means the annual growth of 4.8% in 20 years from 2010 to 2030.

Even though it is very difficult to accurately predict the maximum demand and demand profile, it is assumed that the growth of daytime demand will be significant, centering on air conditioner demand, and the difference between daytime and nighttime will expand. On the other hand, another scenario can also be assumed, that the growth in peak demand will slow down due to economic slowdown or progress of demand side management (DSM) and the difference between daytime and nighttime will shrink.

The observation was made in a case where maximum power supply grows and declines by 5% maximum supply growth and decline to see how the changes impact the optimal development amount of PSPP.

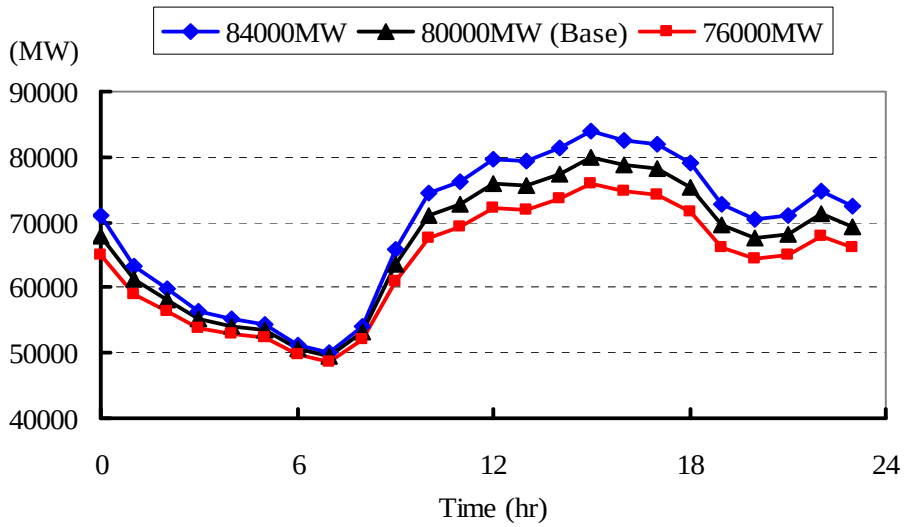


Figure 4. 49 Changes in demand profile

Changes in economics of PSPP in accordance with changes in demand profile are shown in Figure 4. 50.

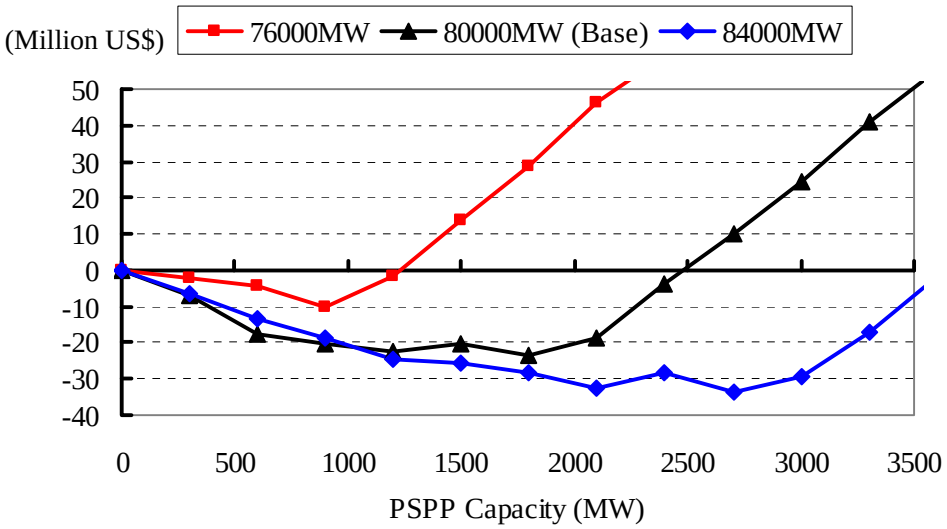


Figure 4. 50 Changes in Economics of PSPP in accordance with Changes in Demand Profile

When the maximum peak demand declines by 5% to 76,000 MW, at stages where the development amount of PSPP is low（1,200 MW or greater）the development amount and supply capacity become unmatched. Therefore, to carry over GT comparable to the development amount becomes impossible, in turn pushing up the overall fixed cost and bringing down the optimum development amount of PSPP to around 900 MW.

On the other hand, when maximum peak demand increases 5% to 84,000 MW, even when the development amount of PSPP reaches 2,700 MW, the development amount and supply capacity remain matched. Therefore, to carry over GT comparable to the development amount becomes possible, in turn bringing up the overall fixed cost and pushing up the optimum development amount of PSPP to around 2,700 MW. In this way, changes in demand profile significantly affect the optimal development amount.

(5) Changes in the ratio of renewable energy (wind in particular)

In the base case, the wind power installed capacity is assumed at 15,600 MW in 2030. This figure is rather large, 10 times as compared to the current installed capacity, but still small in comparison to the target set in the strategy paper (20,000 MW in 2023).

Changes in the economics of PSPP in accordance with the installed wind power capacity are shown in Figure 4. 51.

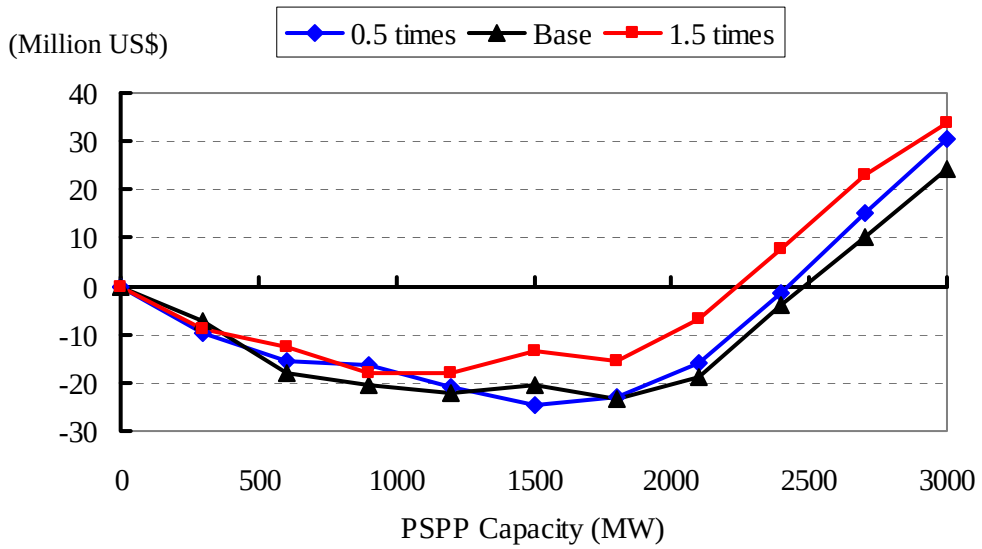


Figure 4. 51 Changes in Economics of PSPP in accordance with Installed Wind Power Capacity

Even though calculations were made by changing the wind power installed capacity at 23,400 MW (1.5 times the base case) and 7,800 MW (0.5 times the base case), no major differences were found.

Wind power generation is considered to show major changes in the output by short duration at each individual point. However, the assumption in this study is that as the number of locations goes up, changes in output on short duration mutually offset, constantly bringing about the average output. Since power plants are operated on this thinking, it is assumed that changes of wind power installation do not have a great impact. However, when wind power is introduced in large quantity, there will be a greater possibility that during the off-peak period, power generated via wind will become excessive; thus extremely cheap power for pumping can be secured in large quantity, thereby pushing up the advantage of PSPP.

4.6.4 Risk Assessment

Advantages of PSPP are largely influenced by external factors such as secured reserve supply capacity, daily demand curve profile, plant composition, and fuel prices. On the other hand, construction of a PSPP takes a long time, and it takes more than 10 years from decision making on development till the start of the operation. Therefore, if the situation dramatically changes, there is a risk that most of the intended advantages may disappear.

These external factors are associated as follows:

- Slow demand growth and increased reserve supply capacity weaken the need of peak supply capacity.
- Through active promotion of DSM and the like, demand profile does not become sharp and supply capacity comparable to plant maximum capacity cannot be expected.
- Power plants expected to power pumping have not been developed.
- Active promotion of the development of reservoir-type power plants as peak supply capacity (including expansion of existing hydropower plants) leads to the relative value of PSPP to decline.

Developers of PSPP need to take measures to avoid these risks when making development decisions. However, even with efforts by developers, these events cannot be avoided. Therefore, developers are

forced to take measures to minimize potential losses associated with these events.

One of the measures includes the postponement of operation starting period in response to changing situation. If it is before starting full-scale construction work, financial burden will not be too great, causing small amount of losses. The ratio of civil engineering work in PSPP construction is high. After starting full-scale construction work, postponing the operation starting period would cause significant losses. If all of these risks have to be borne by developers, it is thought that developers are very unlikely to make decisions to develop PSPPs. Therefore, in promoting development of PSPPs, measures must be considered to ensure costs associated with the above-mentioned risks be evenly borne by beneficiaries. (Refer to Section 8.3.4 ）

In thermal power plants as well, there is a risk that initially assumed benefits may reduce. For following reasons, however, developers are more likely to make development decisions on them than for PSPPs:

- Shorter duration from development decision making till operation starting period.
- Decline in benefits is not as extreme as with PSPPs.
- In cases of postponing the operation starting period, equipment can be sought to be transferred to other locations. (The ratio of equipment is higher than for a PSPP.)

4.7 Power Optimal Plan for Peak Demand

(1) Economics of power plants designed for peak demand

Power plants designed to meet peak demand are required to have the following functionality benefits:

- Generate power during peak hours with high demand
  Since during peak hours the marginal cost is high, even if variable cost (fuel cost) is somewhat high, it will not be a big problem.
- In case of emergencies such as supply capacity drop due to plant accidents or demand surge, power plants to be ready for operation at all times.
  Therefore, it is essential that the fixed cost (construction-related cost and operational and maintenance cost combined) is low.

Long-hours continuous operation is not expected of power plants designed for peak demand. Rather, they are expected to serve as a backup by being ready for operation at all times. Therefore, even if the variable cost is somewhat high, power plants whose fixed costs are low can be candidates. In this respect, the economics of peaking power plants are largely affected by the fluctuations of fixed cost. If the fixed cost of combined-cycle thermal power plants, which are positioned as middle-peak power plants, is lower than that of other peaking power plants, selecting combined-cycle thermal is more economical as a peaking power plant as well. This means that the fixed cost of peaking power plants must be at least lower than that of combined-cycle thermal.

The optimal required output of peaking power plants is largely affected by changes in supply reliability levels. When a supply reliability level is low and supply reserve capacity rate is low, there will be greater possibility of supply shortage in cases of sudden supply capacity drop due to a plant accident or demand surge or other emergencies, thus increasing the operational hours of peaking power plants. However, since peaking plants (GT in particular) have higher variable costs than other power plants, if operational hours become too long, combined-cycle thermal plants, which are positioned as middle demand response type, will become more economical. On the other hand, when supply reliability and supply reserve capacity rate are high, there will be a lower possibility of supply shortage in case of emergencies such as sudden supply drop due to a plant accident or demand surge, thus causing a peaking power plant to operate for not too long. Therefore, if the supply reliability goes up to certain levels, even if the variable cost is somewhat high, as long as the fixed cost is low, such power plants have an economic advantage as a peaking power plant.

(2) Comparison among multiple peaking power plants

(a) Comparison focusing on economics

Comparison was made among the three candidates listed in Table 4. 30 as peaking power plants.

Table 4. 30 Various Power Plants for Peaking Power Plants

	Construction cost	Annual fixed cost	Fuel cost	Remarks
PSPP	700 USD/kW	78.6 USD/kW/year	5.2 USC/kWh	
Reservoir type Hydro	1,800 USD/kW	193.1 USD/kW/year	0 USC/kWh	Capacity factor: 10%
Gas turbine (GT)	500 USD/kW	83.8 USD/kW/year	14.2 USC/kWh	

Furthermore, receiving power from other countries can be considered as one of the peaking power sources. However, during the peak period, other countries are likely to be short of power as well.

Therefore, depending on demand/supply conditions of other countries, there is a possibility that power cannot be received at the necessary time. Therefore, having excessive expectation poses a national security problem. Hence, it is desirable for Turkey to give priority to other measures to procure power domestically and place buying power from other countries as a supplementary option.

Figure 4. 52 represents a result of calculating what shares each of pumped storage power plant (PSPP), reservoir hydro (RH), and gas turbine (GT), which are three peaking power plants, should take to be economical to satisfy 4,000 MW of peak demand. Furthermore, based on the reference costs of combining PSPP (0 MW), RH (0 MW), and GT (4,000 MW), comparison is made with the reference values.

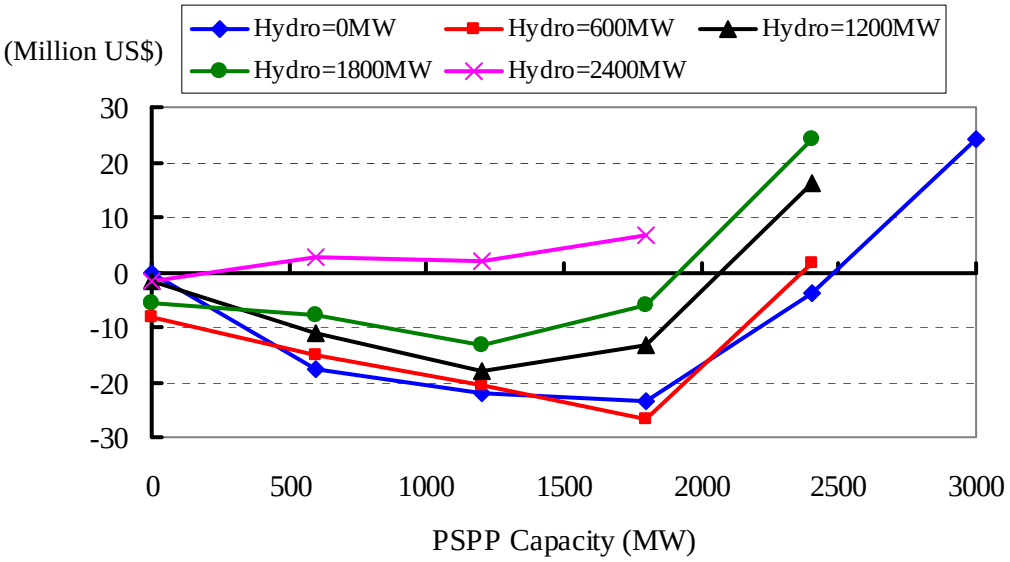


Figure 4. 52 Economics of Peaking Power Plants due to Changes in Development Amount- 1

What is thought to be the most economical combination is PSPP (1,800 MW), RH (600 MW), and GT (1,600 MW) or PSPP (1,800 MW), RH (0 MW), and GT (2,200 MW).

In the comparison among different peaking power plants, economic considerations are largely affected by values of fixed costs. In the above-mentioned study, 1800USD/kW (annual fixed cost of 193.1USD/kW) is taken as the construction unit cost of a reservoir-type hydro which runs at 10% of its capacity and the graph in Figure 4. 53 indicates that the construction cost declines to 1,600 USD/kW (annual fixed cost of 171.7 USD/kW) .

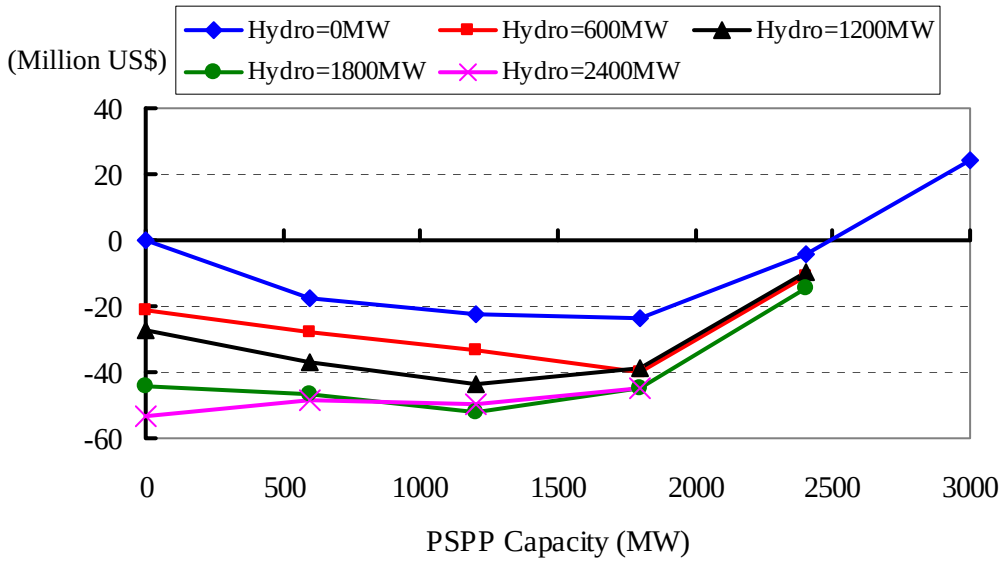


Figure 4. 53 Economics of Peaking Power Plants due to Changes in Development Amount- 2

In the case where the construction unit cost of a reservoir-type hydro declines to 1,600 USD/kW, what is thought to be the most economical combination is either PSPP (0 MW), RH (2,400 MW), and GT (1,600 MW) or PSPP (1,200 MW), RH (1,800 MW), and GT (1,000 MW). In other words, when there is a reservoir-type hydro (running at 10% of its capacity) which can be constructed at 1,600USD/kW or less, it is more economical to give it the development priority and postpone the development of PSPP instead.

(b) Comparison based on functionality

In the study in the last section, the comparison was made about the only sum of fixed and variable (fuel) costs by focusing on the economics. In other words, benefits deriving from the ability to provide ancillary service, which is one of the major features of various peaking power plants, are not incorporated. Whether ancillary service is available or not is a factor which has an important impact on the level of power quality. For Turkey, which is required to raise its power quality, it will be essential to appropriately evaluate the value of ancillary service.

The availability of various ancillary services for a variety of peaking power plants is described below.

Table 4. 31 Ancillary Service of Various Peaking Power Plants

		Frequency Control (Primary & Secondary reserve)		Stand-by operation (Tertiary reserve)
		Peak period	Off-peak period	
Pumped storage power plant		♦ Possible	♦ Possible via pumping operation (in a case of adopting variable-speed pump)	♦ Possible
Reservoir type hydro		♦ Possible	♦ Possible but very uneconomical during hours with low marginal cost	♦ Possible
Gas turbine (GT)		♦ Possible	♦ Possible but very uneconomical during hours with low marginal cost	♦ Possible (slower than hydro)
Buying power from other countries		♦ Possible	♦ Possible	♦ Possible (dependent on other countries)
Refer	Combined (C/C) thermal	♦ Possible by adding adjustment equipment, but need to lower output to operate and somewhat uneconomical.		♦ Possible (slower than GT)
	Coal-fired thermal	♦ Possible by adding adjustment equipment, but need to lower output to operate and considerably uneconomical.		♦ Impossible

Different peaking power plants have very similar ancillary functions, but only PSPP and system to buy power from other countries have frequency control function during off-peak periods. During off-peak period, if there are conditions under which conventional hydropower plants and combined-cycle thermal power plants can make frequency adjustments, the off-peak frequency adjustment functions that PSPPs have cannot be seen as greatly valuable. However, looking at the current status and future of Turkey, the country will face the following challenges, and system operators will likely to have considerable difficulty in adjusting frequencies during off-peak hours. This means frequency adjustment function during off-peak hours will be of high value.

- Issues in power plants to supply frequency adjustment function
  - A majority of conventional hydropower plants of large and medium capacity (50 MW or larger) are shut down during off-peak hours.
  - Combined-cycle thermal power plants owned by private companies aim to operate at the maximum output as much as possible rather than making output adjustment.

- Increasing needs of frequency adjustment
  - Large-scale introduction of wind turbines whose output largely fluctuate during short duration.
  - The introduction of nuclear power plants which constantly operate at the maximum output is planned.

The breakdown of the transmission tariffs of different European countries described in “ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2010” (September 2010) is shown in Figure 4. 54.

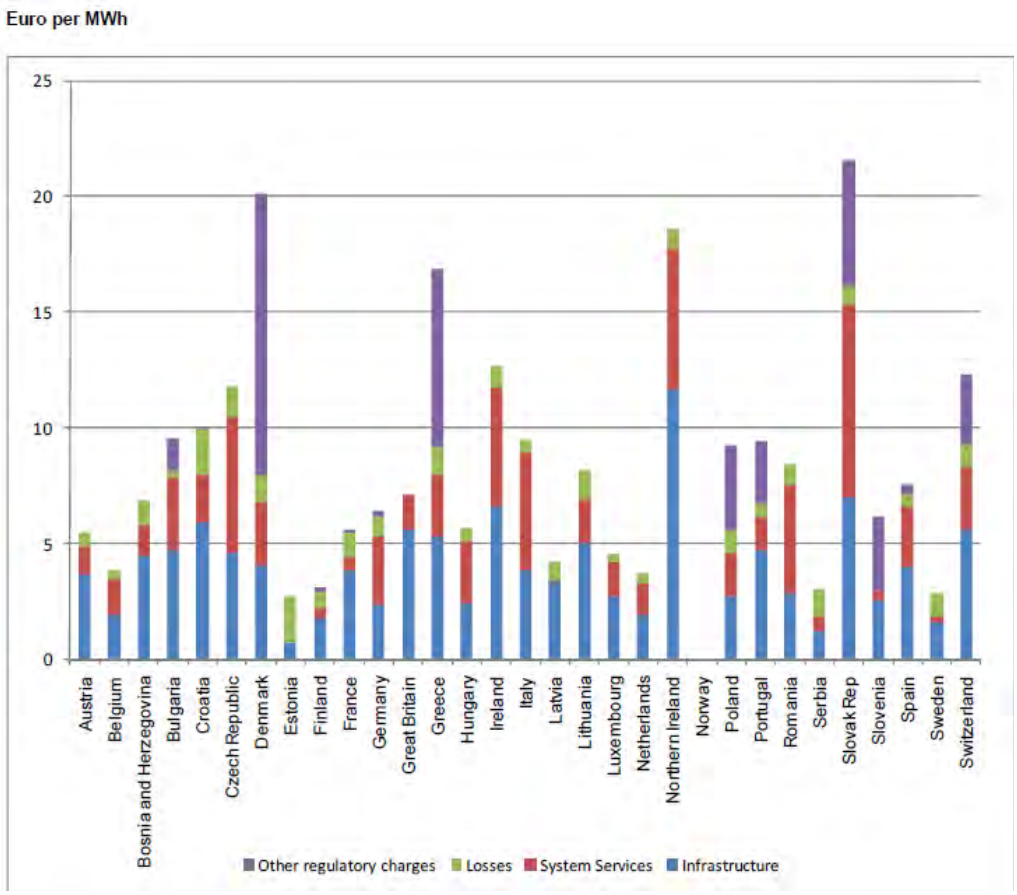


Figure 4. 54 Transmission Tariffs of European countries

Although prices for system service including primary reserve, secondary reserve, tertiary reserve, voltage control, and so on, vary from country to country, the average is around 3 Euro/MWh（4 USD/MWh）. By using this figure, the value of frequency adjustment function was calculated and the result is shown below:

- Off-peak power demand：50,000 MW
- System service charge necessary for implementation: 50,000 MW × 4USD/MWh = 200,000 USD/hour
- Frequency adjustment capacity necessary to implement the system（1% of demand）: 50,000 MW × 0.01 = 500 MW
- Frequency adjustment capacity per 300 MW pump: 50 MW (equivalent of 10% of required amount)
- This means frequency adjustment function per pump of 300 MW is equivalent of 20,000USD/hr.
  Assuming that annual off-peak operation time is 500 hours, the value is equivalent of 10 million USD a year.

(c) Conclusion

In terms of economics, what is thought to be the most economical combination is either <PSPP (1,800 MW), RH (600 MW), and GT (1,600 MW)> or <PSPP (1,800 MW), RH (0 MW), and GT (2,200 MW)>. However, that is largely influenced by the values of fixed cost. If a peaking power plant with low fixed cost emerges, it can be most economical to install the model for all of the locations.

On the other hand, in terms of functionality of peaking power plants, there are few differences in peak-time functions, whereas in terms of off-peak frequency adjustment function, PSPP is superior to other types of power plant. When this advantage is evaluated, it is judged that PSPP has an advantage enough to influence the economics. Therefore, even if the total economics of PSPP is somewhat inferior to some, overall, PSPP can be considered to have a higher value.

Based on the above-mentioned points, in areas where PSPP is expected to deliver supply capacity comparable to its installed capacity, it is considered the best to develop PSPP.

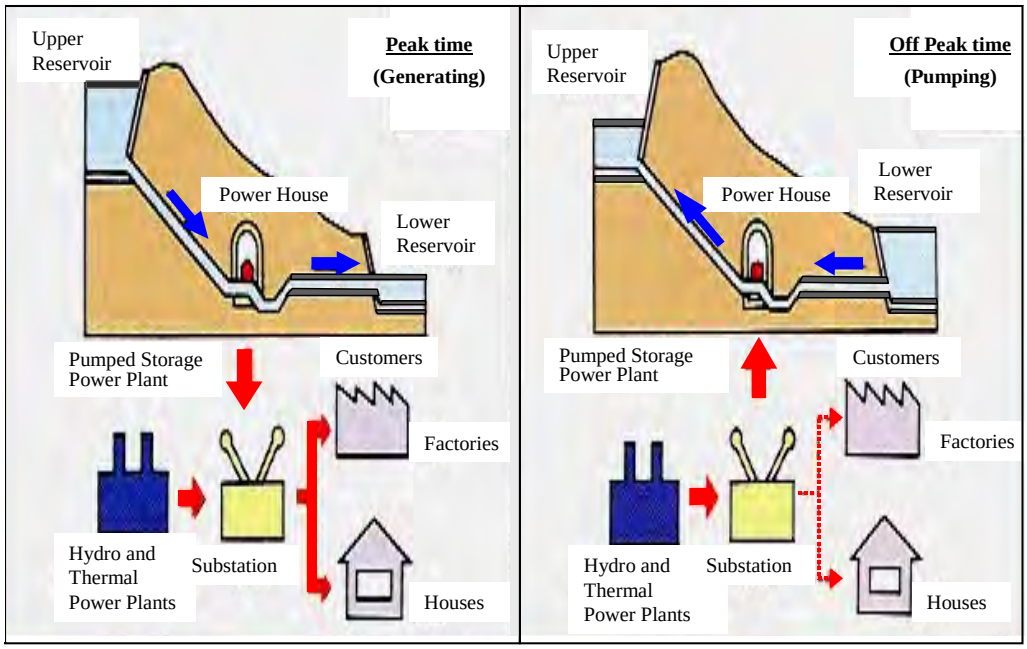
4.8 Roles and Functions of PSPP

(1) Operational mechanism of PSPP

The working of PSPP is shown in Figure 4. 55.

A PSPP is a power generation facility that utilizes water to generate and store electric power. PSPP consists of two regulating reservoirs of upper and lower dams, which are connected by an underground waterway, together with an underground powerhouse located midway along the waterway.

The plant pumps water from the lower reservoir to the upper reservoir at night, when demand for electric power is low (off-peak time), by using electric energy generated by other power plants, and then utilizes this water to generate electricity when demand becomes high at evening time (peak time).



Source: Leaflet of TEPCO

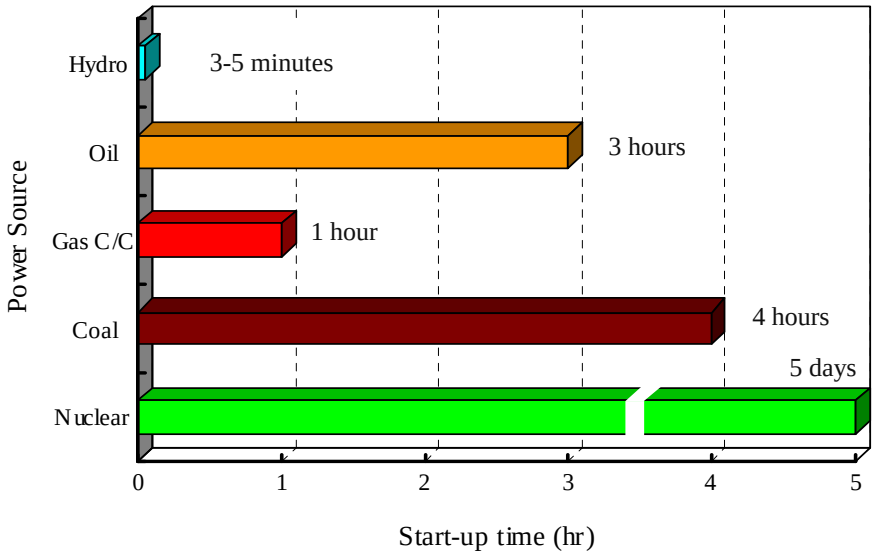
Figure 4. 55 Outline of Pumped Storage Power Plant

(2) Operational characteristics of PSPP

Comparing other power sources, PSPP has the features of quick startup and high output change rate (refer to Figure 4. 56, Table 4. 32).

In addition, since the water is utilized repeatedly between the reservoirs once it is filled at the time of starting its operation, PSPP has the capability of rated output throughout the year, regardless of rainy or dry seasons.

From these characteristics, PSPP has substantial advantages in power system operation, not only in supplying at the peak time hours as scheduled, but also in dealing with short-term demand changes.



Source: Leaflet of TEPCO

Figure 4. 56 Start-up Time after 8-hour Shutdown

Table 4. 32 Output Change Rate

Power Source	Output Change Rate
Hydro	50 – 60%/min
Oil	1 – 3%/min
Gas C/C	5%/min
Coal	1 – 3%/min
Nuclear	NA

(3) **Operational roles of PSPP**

In order to operate the power system stably and efficiently as well as keeping up the supply reliability, measures of (a) demand supply control, (b) economic dispatching, and (c) ancillary service should be conducted appropriately. A PSPP is utilized to implement these measures effectively.

(a) Demand supply control

The purpose of demand supply control is to prepare the output reserve for demand changes and keep supplying generation output corresponding to the demand. PSPP is utilized for this purpose as follows:

- Supply for peak demand
  Generating operation is scheduled in peak demand hours of the day. In order for this, the pumping-up operation is implemented in off-peak hours to prepare for the high demand of the following day, or occasionally in a couple of days.
- Supply for unscheduled power source outages
  PSPP can be the backup for unscheduled power outage by supplying power quickly, that is, quick startup from standby or pump-up shedding in pumping operation. By keeping the demand supply balance in a short time, unwanted load shedding can be avoided.
- Supply for large demand fluctuation
  From the characteristics of quick output changes as stated, PSPP can be used to adjust demand and supply effectively by generating operation in large demand rising hours such as in the morning (refer to Figure 4. 57).

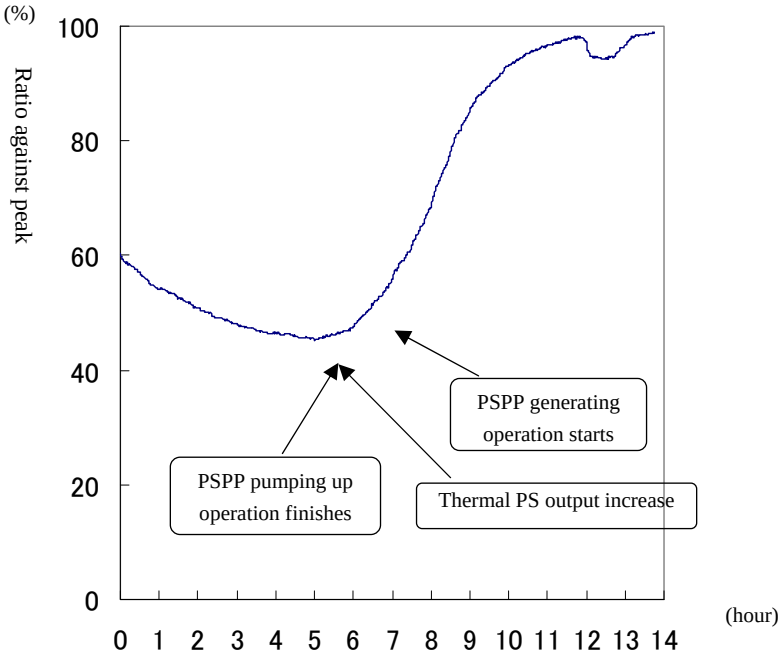


Figure 4. 57 Operations of generators in demand rising hours

(b) Economic dispatching

A PSPP stores electric energy when demand for electricity is low, as at nighttime, and uses this stored energy for peak hours; thus it can adjust the demand-supply balance and reduce the gap between the peak and off-peak hour's demand (refer to Figure 4. 58). That is, the PSPP plays a role of leveling the ever-changing electric power consumption and can be regarded as a kind of DSM.

Owing to PSPP's role of load leveling, the other power sources which frequently start up and shut down or adjustment of output can operate continuously for long time at stable output, so their fuel efficiency can increase. Moreover, the share of base power sources with low generation unit costs can be increased; thus the overall generation cost of the power system becomes lower, and economic efficiency increases.

- Pump-up using surplus supply
  Some power sources such as nuclear power plants and run-of-river hydropower plants are to keep their output constant for economic and efficient operation. In some cases, surplus power supply from these power plants has to be compensated for by the pumping-up operation of PSPP. For this function, a PSPP would be necessary for demand supply control during off-peak hours in the case that share of these power plants increases.
- Pump-up for economic operation of base supply
  In order to reduce the overall fuel cost and improve the generation efficiency, the pumping-up operation is implemented in nighttime by utilizing efficient and low-cost power sources and reducing less efficient power plants' operations in daytime.
- Pump-up for lowering lower reservoir's water level
  When it is necessary to suppress the downstream flow in the case that the river flows in a lower reservoir, pumping-up generation can be conducted so as not to raise the lower reservoir level and prevent ungenerated water in the lower reservoir from discharging.

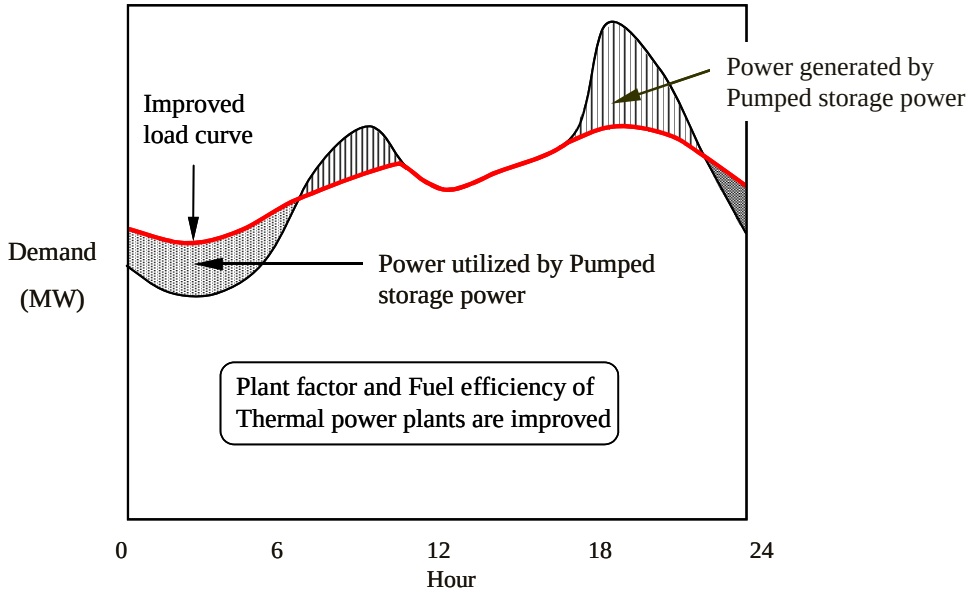


Figure 4. 58 Leveling Load Curve by Pumped Storage Power Plant

(c) Ancillary service

Since PSPP has an excellent adjustment capability like conventional hydropower plants, PSPP can provide the following ancillary services, which are indispensable to ensure the reliability of the power system:

- Frequency control capability
  In order to control the system frequency and adjust the demand supply unbalances in real time, it is required to reserve the necessary amount of reserves depending upon demand fluctuation periods, such as spinning reserve for some seconds of to per-minute fluctuations and the operational reserve for per-minute to some minutes of fluctuations. PSPP has the characteristics of flywheel effect to deal with fluctuations at periods of some seconds, the capability of governor control to deal with fluctuations at periods of some seconds to a minute, and the capability of load frequency control to deal with fluctuations at periods of a minute to some minutes (refer to Figure 4. 59).
- Power flow control in transmission network
  When network fault or unscheduled power outage leads to an overload of some part of the network or transient instability of the overall network, pumping-up or generating operation of PSPP is quickly shed or PSPP output is quickly controlled in order to relieve overload or prevent instability of the network.
- Voltage control in transmission network
  It is necessary to keep voltage of the network to appropriate ranges in order to transmit electricity stably and efficiently. PSPP can control the voltage of the network not only by controlling AVR like other power plants but also by supplying reactive power continuously in its “phase control operation” mode.
- “Black start” capability
  In the case of a wide-area blackout, power supply can be started from PSPP by its self-energizing capability.
- Pumping up as test load
  When a network test such as a large-capacity generator’s shedding test is conducted using commercial power network, pumping-up operation of PSPP can be used as a test load.
- Backup of thermal power plant in case of environmental restriction alert

For the example of Japan, when “Air Pollution Alert” is issued and output control of thermal power stations is restricted in that area, PSPPs are used for demand supply control as their backup.

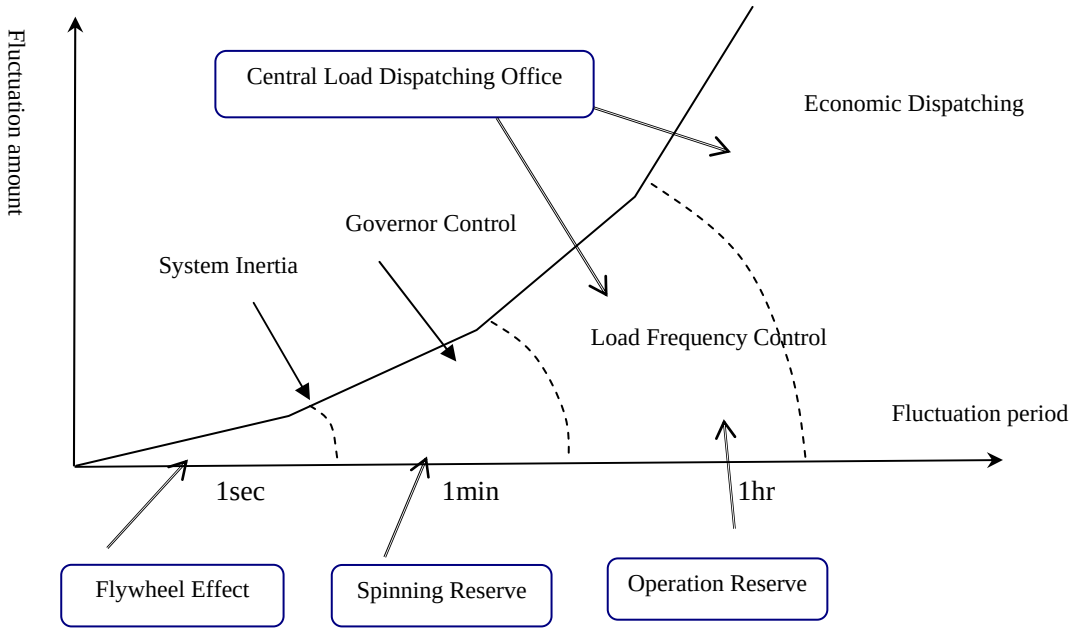


Figure 4. 59 Outline of Demand Supply Control