A DYNAMIC ANALYSIS OF RENEWABLE ENERGY SOURCES TO MEET TURKEY'S FUTURE ELECTRICITY NEED

by

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A DYNAMIC ANALYSIS OF RENEWABLE ENERGY SOURCES TO MEET TURKEY'S FUTURE ELECTRICITY NEED

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ABSTRACT

A DYNAMIC ANALYSIS OF RENEWABLE ENERGY SOURCES TO MEET TURKEY’S FUTURE ELECTRICITY NEED

This research deals with energy planning policies in electric power sector in Turkey. There is an important electricity generation potential of renewable sources which has not been sufficiently exploited yet in energy planning process. Most of the investments are allocated to power plants using fossil-fuels, whose combustion increases the harmful emission levels. The only renewable source which has a big share in total electricity generation of Turkey is hydropower sector. The goal of this research is to find a balance between the electricity demand and total installed capacity, through different policies. To this end, a system dynamics model of the national electricity planning system is constructed. The model includes the main non-renewable and renewable sources as sectors; lignite, hard coal, oil, natural gas, hydropower, small-scale hydropower, wind, solar and geothermal. The results obtained from the simulation show that historical allocation policies will yield electricity imports, if continued in the future. However, if capacity investments are made by renewable oriented policies, there will not be any electricity import in the long term, although high installation and operation costs will occur, while yearly emission levels will decrease. On the other hand, a non-renewable oriented allocation does not result in electricity import either and all the electricity generation capacity is completely used in the long term, but the fuel imports, especially natural gas import, considerably increase. This situation creates supply-dependence which is undesirable in the energy sector. Furthermore, this policy generates relatively low costs whereas the released emissions are quite high. In case the renewable and non-renewable sectors are given equal priority, there will not be electricity import in the long term if investment for each renewable source within whole renewable sector is allocated according to its yearly electricity generation potential in the total potential. It is hoped that the dynamic simulation model will be the basis of a dynamic electricity planning system and will serve as a laboratory to analyze different policy alternatives.
ÖZET

YENİLENEBİLİR ENERJİ KAYNAKLARININ TÜRKİYE’NİN GELECEKTEKİ ELEKTRİK GEREKSİNİMİNİ KARŞILAMASI ÜZERİNE DINAMİK BİR ANALİZ

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LIST OF ABBREVIATIONS

BO
Build and Operate

BOT
Build-Operate and Transfer

DMI
State Meteorology Institute

DPT
State Planning Organization

EIEI
General Directorate of Electrical Power Resources Survey and Development Administration

GDP
Gross Domestic Product

GNP
Gross National Product

MAED
Model for Analysis of the Energy Demand

OECD
Organization for Economic Co-operation and Development

TPAO
Turkish Petroleum Corporation

TÜBİTAK
The Scientific and Technical Research Council of Turkey

WASP
Wien Automatic System Planning Package

WEC TNC
World Energy Council, Turkish National Committee
1. INTRODUCTION

System modeling has become a noteworthy tool in the investigation of energy-economy interactions, conservation, environmental effects of energy planning policies, and the impact of privatization (Naill, 1973; Ford, 1983; Bunn and Larsen, 1992; Amlin and Backus, 1996).

After 1990s, through the stimulation of global warming, the attentions were directed to policies and energy planning models although there has been a great modeling tradition in energy sector. Since each country has its own unique considerations of energy resources, economic demand patterns, and energy security concerns, the approaches in the search of best strategy can be different. On the other hand, the increase in environmental sensitivity caused the renewables to get at a crossroads throughout the world, and it is claimed that renewables will be the future of the energy.

The main cause of global warming is attributed to the increasing emissions of CO$_2$, SO$_2$ and NO$_x$, which are mainly occurred in the energy generation process by the combustion of fossil fuels. Erdoğan (2000) states that “During the last 150 years, the quantity of CO$_2$ in the atmosphere has increased 25 per cent; the temperature has risen so the hottest eight years have been lived in the last decade. It is determined that the rise in the temperature is positively correlated to the pollution, and that CO$_2$ which increases the greenhouse effect is mostly released by the combustion of fossil fuels”.

Energy is essential both as means of production and for its contribution to quality of life. It is commonly accepted that the energy consumption is an indicator of development level of the countries. However, this assumption is under debate in the frame of modern social life (Tuna, 2001). On the eve of the 21$^{st}$ century, some of the most challenging environmental problems are directly linked with the production, transport, storage and the use of energy. IEA (2002a) defines energy’s environmental effects as “Oil-damaged coastlines, poor urban air quality, global climate change, energy's environmental effects include a wide range of pollutants, hazards and eco-system degradation with local, regional and global implications”.
Since the oil shock of 1970s, energy efficiency has improved considerably in response to energy price increases and supply uncertainties, government policies, and the independent technology improvements. As a consequence of sharp increases in petroleum and other energy prices in the 70’s, most countries have initiated policies and programs to reduce the cost of imported energy. In the developing world, particularly the oil-importing countries, most of the initial efforts focused principally on increasing the domestic energy supply. It is a fact that significant energy savings through energy demand management can be achieved. During the oil crisis years, industrial countries made appreciable savings even in the face of easing petroleum prices. “The current environment gives developing countries the time needed to take stock of existing policies and to grasp the opportunity to improve energy efficiency through realization of energy use” (Gamba et al., 1986).

In 20th century, fossil fuels (coal, oil, and more recently gas) and nuclear fuels have been the most important sources of energy in the electricity generation. On the other hand, hydropower was almost the unique renewable technology which made a significant contribution in the sector. After the oil crisis of the 1970s, the importance of renewable energy for electricity generation has increased so that they now provide nearly 20 per cent of the world’s primary energy requirement in this sector. The environmental benefits of power generation by renewables rather than combustion of fossil fuels were the major driving force of this development. Particularly, in reducing the greenhouse and acid gas emissions associated with fossil fuel power generation renewables are proved to be a vehicle (IEA, 2002a).

Some of the renewable energy technologies have made a great progress in terms of reliability and costs (Janssen, 2001). Many studies on future energy supply shows that renewables will grow proportionally faster than any other method of electricity generation and that governmental and institutional policy can greatly increase in the role of renewables in the future (IEA, 2002c).

Since electricity can not be stored efficiently and cheaply, it has to be generated parallel to demand. As a concept, electricity planning is to allocate the resources to meet the demand while optimizing some determined parameters. It is quite important to project the demand accurately in this process as the first step of energy planning. Although energy
consumption is affected by many factors, the main economic ones are population size; gross domestic product per capita; prices charged for energy, including the energy intensity of different sectors; and climate, particularly the length and average temperature of the winter season. In the electricity sector, the size and the location of plants depend on the location of resources and environmental factors (Yiğit, 1999).

Since Turkey has a rapidly growing population and a dynamic social and economic development, Turkey’s energy demand has grown up year by year. The yearly average population growth rate of Turkey, which is the highest rate among OECD countries, is 1.6 per cent in 1990 to 1998 (WEC TNC, 2000b). Turkey constitutes a major energy market. Domestic energy generation is less than half of energy demand. It is expected that a huge gap will occur between energy consumption and energy generation in the future according to existing demand scenarios. Güngör and Bozkurt (1999) and Güngör and Ankan (2000) state that “Turkey's existing energy sources, which are in use, are both insufficient and of poor quality”.

There are a lot of challenges that Turkey faces like other countries do. These can be listed as follows:

- To meet the energy need via its national resources
- To reduce the cost of energy imports
- To protect the environment
- To improve the socio-economic life

Demirbaş (2001) denotes that recent long term plans of industrialized countries replace the classical energy sources with renewable and sustainable energy source.

Turkey’s energy policy is mainly to provide energy in time, reliably, sufficiently, while protecting the environment and improving the social and economic development. Energy planning studies are done for short, medium and long terms by Ministry of Energy and Natural Resources (ETKB). In planning process, studies especially focus on raising the share of national sources in energy generation as soon as possible (WEC TNC, 2000b).
In Turkey, it is argued that investments in energy sector are not managed properly, so that the balance between supply and demand couldn't be reached in the past. This situation is caused mainly by wrong resource allocation policies. Although increasing the efficiency of energy use is normally more attractive than investing additional resource to increase the domestic supply, it is apparent that energy planning in Turkey ignores the polices on energy use side. Furthermore, energy conservation and demand management can produce results faster than increasing supply.

In this thesis, the aim is to analyze electricity supply and demand conditions and to investigate the alternative ways of meeting Turkey's electricity need via renewable sources for medium and long terms. While seeking the balance in electricity supply and demand, CO₂ equivalent emission rates of the sources used in electricity generation process are considered as an indicator of environmental and ecological destruction in resource allocation policies. System dynamics modeling and simulation is used in the investigation of the potential of renewable sources to meet Turkey's electricity need in this thesis. System dynamics methodology is an effective tool in resource planning in the electric power industry.
2. LITERATURE SURVEY

The main purpose of this chapter is to give an overview on the energy models throughout the world. In the first section, well-known energy models in the literature and their main structures are explained. In the second section, energy-modeling applications in system dynamics literature are illustrated. The third section gives the main characteristics of the energy models which are used in Turkey.

2.1. Energy Models in the World

Analytical energy models have been used since 1950. These models examine the energy sector in isolation from economic relationships. Kavrakoğlu (1987) reports that the petroleum crisis in 1973 brought about bigger concentration on energy models and the number of energy models almost tripled up to thousands. The rise in energy prices affected many countries and draw attentions to the energy-economy relationships. Thus, combined models regarding energy-economy relationships replaced with those simple models.

The first energy-economy models considered energy intensity and investment levels and models integrating energy and economy have developed thereafter. Since 1980, growth in environmental consciousness and increase in CO₂, SO₂, NOₓ emissions caused models to take environmental and social parameters into account. Representative models made for energy planning are listed in Table 2.1 whereas the system dynamics applications to electric power are listed in Table 2.2.

2.1.1. Primary Energy Models

These models consider the energy sector neglecting the economic relations. The first group listed in Table 2.1 gives the Primary Models. Two models amongst others that approach the system in detail are ETA and EFOM and such models are used for technology selection, investment-planning and the forecast of demand. TESOM added forecast of elasticity-of-fuel-substitution into these models. These models also accepted as a basis of energy-environment models. In this category, Arıkan and Kumbaroğlu (2000)
have classified models into two groups; Equilibrium and Optimization Models.

Table 2.1. Representative energy models (Compiled from: Arıkan and Kumbaroğlu, 2000)

<table>
<thead>
<tr>
<th>MODELS</th>
<th>Scope</th>
<th>Roots</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A. Primary Models</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ETA (Manne, 1976)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>EFOM (Bayraktar et al., 1981)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>TESOM (Lev, 1983)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>A.1. Equilibrium Models</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GEMINI (Cohan et al., 1994)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>ERB (Edmonds and Barns, 1994)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td>ICF (William, 1994)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td><strong>A.2. Optimization Models</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MARKAL (Holllins, 1995)</td>
<td>National Analysis</td>
<td>MARKAL</td>
</tr>
<tr>
<td>MRMM (Büeler, 1997)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td>EFOM-ENV (Lueth et al., 1997)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>PERSEUS-GWI (Ardone et al., 1996)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>WATEMS-GDL (Chung and Fuller, 1997)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>B. Energy-Economy Models</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ETA-MACRO (Manne et al., 1981)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>B.1. Single Sector Equilibrium Models</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GLOBAL 2100 (Manne, 1994)</td>
<td>Multi-Regional Analysis</td>
<td>GLOBAL2100</td>
</tr>
<tr>
<td>CETA (Peck, 1994)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td>MERGE (Manne, 1995)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td>MIS (Kuckshinrichs, 1996)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>RICE (Nordhaus, 1996)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td>IIAM (Harrison, 1997)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td>MEEET (Arıkan, 1997)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td>METAX (Arıkan, 1999)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td><strong>B.2. Multiple Sector Equilibrium Models</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MOBI-DK (Böhringer, 1998)</td>
<td>Multi-Regional Analysis</td>
<td></td>
</tr>
<tr>
<td>GOULDER (Gould, 1994)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>PESTES (Beaumais, 1995)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>JW (Jorgenson, 1994)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>MULTI (Nagurney, 1997)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>DREAM (Vennemo, 1995)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td><strong>B.3. Energy-Economy-Environmental Models</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WARM (Carraro, 1997)</td>
<td>National Analysis</td>
<td></td>
</tr>
<tr>
<td>PAGE (Plambeck, 1997)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>INTERA (Hope, 1996)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

In equilibrium models, price determines the supply and demand of primary and secondary energy and the net consumption level. GEMINI, ERB and ICF are included in this group.

Optimization-models aim to minimize the cost of energy while meeting the demand. MARKAL, MRMM, EFOM-ENV, PERSEUS-GWI and WATEMS-GDL are contained in
this group (Arkan and Kumbaroğlu, 2000).

2.1.2. Energy-Economy Models

Models inevitably undertook the energy-economy relationship since national energy policies are influenced by social and economic developments, by fluctuations of energy prices and constraints on energy resources. These models either emphasize the economy side of the mutual relationship, while simplifying energy sector as in the model HJ (Hudson and Jorgenson, 1974) or construct a single sector economy as in ETA-MACRO (Manne et al., 1981). In 1990s, environmental side of the system has been introduced into the models and the energy-economy-environment links have been examined.

Single Sector Equilibrium Models are the first type of models in this category. In these models, GDP is taken as a combined single factor representing economy side whereas energy sector has been analyzed thoroughly. Arkan and Kumbaroğlu (2000) list the models GLOBAL 2100, CETA, MERGE, MIS, RICE, IIAM, MEEET and METAX in this category. These models work with two markets, one being for the electrical energy and the other for non-electrical energies. Many types of fuels and technologies compete in order to raise their market share. Since supply technologies are quite detailed in these models, the costs of each policies and emission rates can be determined by examining different scenarios.

Second category contains Multiple Sector Equilibrium Models. In the contents of these models, production of each sector is separately constructed, sector relationships are defined and a general equilibrium regarding to every product is simulated. Although economic structure is analyzed in depth, energy system is not thoroughly examined. This drawback arises from the fact that it is quite difficult to find the empirical data on the mutual relationships among the sectors. Arkan and Kumbaroğlu (2000) classify the models MOBI-DK, GOULDER, PESTES, JW, MULTI and DREAM in this category. MOBI-DK, GOULDER and JW have been used in investigating the effect of different tax systems on the sector. JW is also used for examining the effects of carbon tax.

WARM, by its different structure, constitutes the third category. The basic strategy
of this model is to derive parameters exposing the motives underlying the behavioral relationship, by econometric methods (Ankan and Kumbaroğlu, 2000).

2.1.3. Environmental Factor in Energy Models

Decisions made under United Nation's Climate Change Act (1992), Berlin Manifest (1995), Kyoto Protocol (1997) and Buenos Aires Conference (1998) require nations to consider climate change in their social, economical and environmental policies. Therefore, recent models have introduced the issue of climate change. Most of these models mainly make use of the same structure; especially Wigley's Carbon Transformation Model (Wigley, 1996) is used. Moreover, some damage-functions are constructed to show the damage of climate change into the climate models. Ankan and Kumbaroğlu (2000) state that PAGE and INTERA have distinctive places in this area. Each model gives different results since they use different assumptions and methodology.

Although RICE, MERGE and CETA have such kind of damage functions, there are debates on their reliability. Using variables representing the damage to environment and the quality of environment in utility functions has been discussed and examined among scientists (Ankan and Kumbaroğlu, 2000).

2.1.4. General Characteristics of Energy Models

Models, especially seeking environmental effects of policies, have 100 year-term of planning scale. Minimum planning period is accepted as 25-30 years (e.g. MIS, EFOM, MARKAL, GOULDER, GEMINI, WARM, 2AM).

Ankan and Kumbaroğlu (2000) state that most of the models were built for national analysis. Some are MIS, DREAM, MARKAL, PESTES, JW, WARM, GOULDER, GEMINI, EFOM, ENV, PERSEUS-GWI. The models seeking environmental effects are designed for multi-regional examinations such as MERGE, GLOBAL2100, CETA, 2AM, RICE, ICF, ERB, MOBI-DK, and MRMM.
2.2. Energy Models in System Dynamics

System dynamics has been widely used in energy modeling. The research at MIT and Dartmouth was primarily concerned with world dynamics in the early 1970s. These models generally seek the limit of the growth in economy and population, depletion of the resources and causes of the pollution. Table 2.2 lists modeling projects and publications on the applications of system dynamics to electric power industry. Note that "*" stated in the first column in Table 2.2 remarks the extensions.

The first application of system dynamics to electric power begins with Roger Naill's national energy modeling project. In his project, he was interested in exploration and production of natural gas (Naill, 1973). Then he expanded the model, called FOSSIL2, to include oil, coal and other fuels (Naill and Backus, 1977; Naill et al., 1992; Naill, 1992). The aim of the model is to analyze national policies of U.S.A to reduce its dependence on foreign oil.

The second system dynamics model, listed in Table 2.2, Energy 2020 was developed to deliver multi-fuel model into the hands of individual energy companies and state agencies in U.S.A (Backus and Amlin, 1985).

Andrew Ford has applied system dynamics to a number of issues in the electricity sector of US since 1980s. Some of the most important researches of Andrew Ford are on policy evaluation (Ford, 1983), investments and uncertainty (Ford, 1985), and conservation analysis (Ford and Bull, 1989).

Conservation Policy Analysis Model (CPAM) and the Resource Policy Screening Model (RPSM) were developed for the Pacific Northwest Hydroelectric System (Ford et al., 1987). CPAM, the third application in Table 2.2, is a powerful tool for the conservation planners to project the likely savings and costs of the package of conservation policies via cost-efficiency curves. CPAM was valued for its integrated representation of the regional electric system as a whole, and its automatic representation of information feedback. Price feedback loop evaluating the interaction between price and demand is the most common feature of the system dynamics models. Planners have to involve both indirect effects as
well as direct ones in the construction of price feedback loop. CPAM models have changed
time. By including non-utility generators into the model a major improvement has
been realized. The new model was called as Non-Utility Generation Model (NUGM)
(Geinzer et al., 1990). The combination of CPAM and NUGM, namely RPSM, provides
the planners to analyze the resource issues.

A number of models have been developed to investigate the European Electricity
Industry, one of which is an inter-fuel substitution model for OECD countries (Moxnes,
1990).

There are three articles on automobile purchase decisions and their impacts on an
electricity utility company (Ford, 1994; 1995; 1996) which are listed in Table 2.2, grouped
as D. This model integrates vehicle choice and the model of the power company. There are
two choices for consumers, to buy gasoline cars or electric cars.

The growing attention on liberalization and privatization led to the utilization of
strategic tools within the system thinking tradition. Strategic business simulation models
are used as a tool to provide some broad insights into the dynamics of investments, pricing
and regulation. There are system dynamics investigations on the privatization of the
government owned power industry in U.K. and the deregulation of the privately owned
power industry in U.S.A, shown in Table 2.2, group E (Bunn and Larsen, 1992; Bunn et
al., 1993; Amlin and Backus, 1996).

The recent worldwide trend in system dynamics modeling area is especially on
electric power industry and water resource planning. Table 2.2, group F illustrates the
related applications in this area. There are applications in Pakistan, China, Colombia,
Indonesia, Australia and Jordan.

In all these application areas, system dynamics has proved its power with its policy
supporting feature under complex policy environments (Ford, 1997).

Furthermore, system dynamics forum and workshop reports practically give the key
features on the models. Group G in Table 2.2 provides a gateway to some of them.
<table>
<thead>
<tr>
<th>A</th>
<th>The National Model (Fossil2, Ideas)</th>
<th>Publications</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Naill</td>
<td>Managing the Energy Transition</td>
<td>1977</td>
</tr>
<tr>
<td></td>
<td>Naill and Backus</td>
<td>Technology Review</td>
<td>July 1977</td>
</tr>
<tr>
<td></td>
<td>Naill et al.</td>
<td>System Dynamics Review</td>
<td>Wint. 1992</td>
</tr>
<tr>
<td></td>
<td>Naill</td>
<td>System Dynamics Review</td>
<td>Sum. 1992</td>
</tr>
<tr>
<td></td>
<td>The AES Corp.</td>
<td>An Overview of the Ideas Model</td>
<td>Oct 1993</td>
</tr>
<tr>
<td>B</td>
<td>Individual Companies and State Agencies (Energy 2020)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Systematic Solutions Inc.</td>
<td>Introduction to Energy 2020</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Central Maine Power Company</td>
<td>The Energy 2020 Users Conference</td>
<td>June 1980</td>
</tr>
<tr>
<td>C</td>
<td>The Pacific Northwest Hydroelectric System (CPAM, RPSTM)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ford, Bull and Naill</td>
<td>Energy Policy</td>
<td>April 1987</td>
</tr>
<tr>
<td></td>
<td>Ford and Bull</td>
<td>System Dynamics Review</td>
<td>Wint. 1989</td>
</tr>
<tr>
<td></td>
<td>Ford and Geinzer</td>
<td>Energy Policy</td>
<td>May 1990</td>
</tr>
<tr>
<td></td>
<td>Ford</td>
<td>Operations Research</td>
<td>July 1990</td>
</tr>
<tr>
<td>D</td>
<td>Electric Cars and Electric Utility</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ford</td>
<td>Energy Policy</td>
<td>1994</td>
</tr>
<tr>
<td></td>
<td>Ford</td>
<td>System Dynamics Review</td>
<td>Spr. 1995</td>
</tr>
<tr>
<td></td>
<td>Ford</td>
<td>Public Utilities Fornightly</td>
<td>April 1996</td>
</tr>
<tr>
<td></td>
<td>Ford</td>
<td>System Dynamics Review</td>
<td>Spr. 1997</td>
</tr>
<tr>
<td>E</td>
<td>Privatization (UK) and Deregulation (USA)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Bunn and Larsen</td>
<td>Energy Policy</td>
<td>May 1992</td>
</tr>
<tr>
<td></td>
<td>Bunn, Larsen and Vlahos</td>
<td>Journal of the Operational Research Society</td>
<td>1993</td>
</tr>
<tr>
<td></td>
<td>Bunn and Larsen</td>
<td>System Dynamics Modeling for Energy Policy</td>
<td>1996</td>
</tr>
<tr>
<td></td>
<td>Amin and Backus</td>
<td>Utility Models for the New Competitive Electric Markets</td>
<td>1996</td>
</tr>
<tr>
<td>F</td>
<td>Regional/National Electricity&amp;Water Planning Models</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Asham and Saeed</td>
<td>Proceedings of the 1995 System Dynamics Conference</td>
<td></td>
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<td></td>
<td>Dyner and Bunn</td>
<td>Proceedings of the 1996 System Dynamics Conference</td>
<td></td>
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<td></td>
<td>Burton and Pumanda</td>
<td>Proceedings of the 1996 System Dynamics Conference</td>
<td></td>
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<tr>
<td></td>
<td>Ford</td>
<td>System Dynamics Review</td>
<td>Wint. 1996</td>
</tr>
<tr>
<td></td>
<td>Shawwash and Russell</td>
<td>Proceedings of the 1996 System Dynamics Conference</td>
<td></td>
</tr>
<tr>
<td>G</td>
<td>System Dynamics Models at Forums and Workshops</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

2.3. Energy Models and Applications in Turkey

2.3.1. Energy Demand and Planning Models

In Turkey, the models, namely MAED and WASP, provided by International Atom Agency for developing countries are used by Ministry of Energy and Natural Resources (ETKB) in energy planning process. ETKB uses the model MAED to generate projections for general energy and electricity demand. Projections obtained from MAED are used in WASP as the data for energy demands. WASP plans the timing, amount and composition of investments with respect to demand under given constraints and reliability by optimizing the cost.

This methodology being used since 1980s has not been changed after using ENPEP (Conzelmann, 1996) in the last few years since ENPEP's basic structure, especially data transportation, is the same as MAED and WASP. Furthermore, ENPEP has a technical module containing load projection, technical data bank, reliability calculations, and alternative demand projections. It also has an alternative energy demand projection module based on macroeconomic growth projections and equilibrium module calculating supply-demand equilibriums. However, this model does not have innovative characteristics through its methodology, which should be parallel to the progress in modeling area. Energy-economy relationship is defined by restricted parameters and feedback to the economy is neglected.

ENPEP's last module, IMPACT, calculates the amount of emission, based on the results obtained from WASP, and determines the control system in order to keep the
emission within limits. Since there is no feedback to planning module, there is again one-way relationship between energy and environment like between energy and economy in this model.

There are also some models built in Turkey for scientific research. Turan (2000) studied on modeling energy needs and investments. Kılıç (2001) also studied on the energy foresight in Turkey. ESM (Energy Simulation Model) and EOM (Energy Optimization Model) are built up by Ankara University Energy Group. In the model ESM, energy need is calculated as follows (TÜSİAD, 1998).

\[
\text{Energy Need} = \sum_j \left( \frac{\text{Energy Consumption}}{\text{GDP}} \times \frac{\text{GNP}}{\text{Population}} \right) \times \text{Population}
\]  

(2.1)

The indicators used in energy planning by ETKB are shown in Table 2.3. The energy demand strongly depends on Gross Domestic Product (GDP) and Gross National Product (GNP). The Purchasing Power Parity (PPP) is another indicator that has a powerful effect on energy demand.

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Primary Energy Demand (PED) (TOEx10³)</td>
<td>91030</td>
<td>124748</td>
<td>175074</td>
<td>233296</td>
<td>314353</td>
<td>367780</td>
<td>407106</td>
</tr>
<tr>
<td>GDP ($x10⁹)</td>
<td>238.11</td>
<td>321.56</td>
<td>458.32</td>
<td>666.85</td>
<td>994.82</td>
<td>1272.27</td>
<td>1499.01</td>
</tr>
<tr>
<td>PED/GDP</td>
<td>0.38</td>
<td>0.39</td>
<td>0.38</td>
<td>0.35</td>
<td>0.32</td>
<td>0.29</td>
<td>0.27</td>
</tr>
<tr>
<td>Population</td>
<td>65864</td>
<td>70271</td>
<td>74677</td>
<td>78633</td>
<td>82588</td>
<td>84555</td>
<td>85867</td>
</tr>
<tr>
<td>GDP per capita ($)</td>
<td>3615</td>
<td>4576</td>
<td>6137</td>
<td>8481</td>
<td>12046</td>
<td>15047</td>
<td>17457</td>
</tr>
<tr>
<td>GDP per capita (PPT)</td>
<td>7317</td>
<td>9975</td>
<td>13600</td>
<td>19299</td>
<td>27386</td>
<td>33875</td>
<td>38862</td>
</tr>
</tbody>
</table>

Population is another critical input. The yearly average population growth between 1990 and 1998 is 1.6 per cent (WEC TNC, 2000b). The growth rate of GDP forecasts made by DPT is given in Table 2.4.
Table 2.4. DPT’s GDP growth rate assumptions

<table>
<thead>
<tr>
<th>Rate of Growth (%)</th>
<th>1998</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2.8</td>
<td>2.9</td>
<td>4.7</td>
<td>5.0</td>
<td>5.7</td>
</tr>
</tbody>
</table>

The technological and industrialization levels of the countries are the main determining factors of energy intensity. Energy intensity is the amount of the energy consumed to earn a unit of income. The increase in productivity in energy sector causes energy intensity to decrease. "In Turkey, between the years 1970 and 1993 energy intensity level is around 0.99. This means a unit increase in GDP was realized by a unit increase in energy consumption in those years. Average energy intensity by 1989 in OECD countries is 0.40 while 0.71 in India, 0.25 in Hong Kong, 0.77 in Argentine. The high energy intensity level of Turkey can also be interpreted as most of energy generated is extremely wasted" (Ekrem et al., 1997).

From gross generation to net consumption, there is a series of calculations in the Electricity Balance Sheet. The structure of the electricity balance sheet is given in Figure 2.1.

![Electricity balance sheet structure diagram](image)

Figure 2.1. Electricity balance sheet structure

The realized gross and net electricity consumptions of Turkey from 1980 to 1998 are depicted in Figure 2.2. The future gross and net electricity consumptions are forecasted by
ETKB and also by DPT. The available data are illustrated in Figures 2.3 and 2.4.

![Figure 2.2. Electricity consumption of Turkey (WEC TNC, 2000a)](image)

![Figure 2.3. ETKB electricity demand forecast of Turkey (WEC TNC, 2000a)](image)
2.3.2. Energy Planning Policies

In 1938, small and local power plants were common and the local transition systems were isolated from each other. 1953 was a turning point to change the system. The government made some decisions according to which regional and big hydraulic and coal power plants would be installed with interconnecting transition systems. In the 90’s most of the goals have been realized (WEC TNC, 2002b).

Till 1970 it was expected that the energy demand will grow rather fast like other general economic parameters. However, the 1973 oil crisis caused the cost of energy generation to rise. There were a common thought before the crisis that petroleum is infinite and cheap, but it was not. After the crisis, new research and development studies started on renewable resources, such as wind, geothermal and solar, whereas the importance of effective consumption was accepted. Moreover, it is recognized that the priority in energy planning has to be given to the national resources. At the same time, environmental factors in energy planning started to take attention.

In order to meet the electricity demand, Turkish government has a great effort to increase the investments by the participation of private sector and foreigner investors. Especially, to meet the need by the utilities except of public ones, some applications have
been developed; Build-Operate and Build-Operate-Transfer systems are developed and promoted. Within this frame, some short term governmental policies have been developed. Some are listed as follows (WEC TNC, 2000b).

- Besides the existing resources, the new ones have to be searched as soon as possible.
- In the energy importing issue, the dependence to one country and one source should be hindered. The variety of the sources should be increased while considering the costs.
- Privatization should be promoted.
- The demand should be met by regional resources if possible.
- The network losses should be declined to the lowest level while efficiency is increased. The conservation programs should be supported.
- The share of electricity generation by new and renewable resources should be raised as soon as possible.
- While meeting the demand, the environment and the public health should be considered.

Consequently, in the sector of electricity, there are mainly four parameters that are taken into account in energy plans of Turkey given as follows:

- Cost minimization
- Meeting the demand
- Reliability
- Quality

Energy planning regards three periods; short, medium (5 years) and long terms (15 years). Short term planning is based on the installed capacity and its elasticity whereas medium term planning examines on raising the capacity via reliable technology. Long term planning seeks the allocation of resources to install new power plants while regarding the changes in the demand through different scenarios.
3. ENERGY RESOURCES AND ELECTRICITY GENERATION
IN TURKEY

According to the structure of energy production process, energy is defined in two
groups as Primary Energy and Secondary Energy. Primary Energy is the energy that has
not been subjected to any conversion or transformation process (TEAŞ, 1999). Turkey’s
primary energy resources are hard coal, lignite, asphaltit, oil, natural gas, hydropower,
wind, and geothermal, solar, wood, animal and plant wastes. Coke, briquette and electricity
are involved in Secondary Energy group. Primary energy resources are generally used as
fuel in generation of electricity and heat.

From 1970 to 1997, primary energy production has increased 90 per cent, while
electricity consumption has grown yearly 9.9 per cent in average. The lowest increase in
consumption realized in 1983 with 4.4 per cent whereas the highest increase realized in
1976 with 18.4 per cent (TÜSİAD, 1998).

There is a noticeable growth in the demand of electricity by the influence of growing
economy and population in Turkey. It is also expected that this growth will continue in
accordance with the trend of developing country. Therefore, resource planning in energy
sector became a vital issue with the draining of fossil fuels.

Since 1995 the yearly increase in electricity consumption is observed as around 10
per cent. The trend of installed capacities according to the power plant type between 1980
and 1998 is given in Figure 3.1. At the same period, electricity generation of these power
plants has occurred as in Figure 3.2. Each figure also gives related data under the graphs.

Hydropower and lignite power have big portions in electricity generation sector as it
can be seen in the figures mentioned above. It can also be seen that renewable resources
has recently been started to be used. Beside the hydropower, wind power and geothermal
power are the outstanding ones as new and renewable resources in electricity generation
sector in Turkey. Each of the main non-renewable and renewable resources in Turkey is
examined through their features and electricity generation potentials in this chapter.
Figure 3.1. Installed capacity of Turkey (WEC TNC, 2000a)

From 1990 to 1998, 7,037 MW capacity has joined the total installed capacity and total capacity reaches 23,352 MW. The share of thermal power plants’ capacity in total capacity is 56 per cent with 13,045 MW whereas 44 per cent of the capacity belongs to hydroelectric power plants with 10,307 MW. While the biggest share in the thermal power plants’ capacity has belonged to Lignite Power Plants until 1985, this share has decreased by the participation of Natural Gas Power Plants to the electricity sector in the recent years. 28 per cent of Turkey’s total installed capacity uses solid fuels while liquid fuels are used in the 7 per cent of total capacity as of 1998. 19 per cent of the total capacity generates electricity via natural gas as fuel.
In 1998 in Turkey, 62 per cent of the total gross electricity generation with 111,022 GWh is realized by thermal power plants whereas 38 per cent of total generation provided by hydroelectric power plants. Lignite Power Plants generate 29 per cent of total electricity generated while Natural Gas Power Plants have the share 22 per cent in total. The share of primary resources used in electricity generation as at 1998 is given in Figure 3.3.

The electricity balance sheet table is given in Table 3.1. It can be observed from Table 3.1 that gross electricity generation has increased 7.5 per cent from 1997 to 1998 while net electricity consumption raises 7.4 per cent. Form 1990 to 1996, Turkey was a net
electricity exporter country, but in 1997 and 1998 situation has changed and Turkey became a net electricity importer country.

![Pie chart showing energy sources](image)

**Figure 3.3.** The share of primary resources in electricity generation by 1998 (WEC TNC, 2000a)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Generation</td>
<td>57543</td>
<td>86248</td>
<td>94862</td>
<td>103296</td>
<td>111022</td>
</tr>
<tr>
<td>Internal Consumption</td>
<td>3311</td>
<td>4389</td>
<td>4777</td>
<td>5050</td>
<td>5523</td>
</tr>
<tr>
<td>Net Generation</td>
<td>54232</td>
<td>81859</td>
<td>90085</td>
<td>98246</td>
<td>105499</td>
</tr>
<tr>
<td>Import</td>
<td>176</td>
<td>270</td>
<td>2492</td>
<td>3299</td>
<td></td>
</tr>
<tr>
<td>Gross Consumption</td>
<td>54408</td>
<td>81859</td>
<td>90355</td>
<td>100738</td>
<td>108798</td>
</tr>
<tr>
<td>Network Losses</td>
<td>6680</td>
<td>13769</td>
<td>15855</td>
<td>18582</td>
<td>20795</td>
</tr>
<tr>
<td>Export</td>
<td>907</td>
<td>696</td>
<td>343</td>
<td>271</td>
<td>298</td>
</tr>
<tr>
<td>Net Consumption</td>
<td>46820</td>
<td>67394</td>
<td>74157</td>
<td>81885</td>
<td>87705</td>
</tr>
<tr>
<td>Gross Consumption per Capita</td>
<td>1013</td>
<td>1411</td>
<td>1540</td>
<td>1688</td>
<td>1797</td>
</tr>
</tbody>
</table>

**Table 3.1.** Electricity balance sheet (GWh) (WEC TNC, 2000b)

The CO₂ equivalent emission levels of the resources of Turkey are depicted in Figure 3.4 (TÜSİAD, 1998). TÜSİAD reports that CO₂ and CO₂ equivalent emission levels (NOx also included) of electric sectors are calculated by considering direct and indirect inputs of electricity generation processes. Only CO₂ emissions by source are 85.5 kg/GJ in coal, 64.4 kg/GJ in oil and 52 kg/GJ in natural gas.

It is observed in Figure 3.4 that lignite and hard coal power plants grouped as coal in
the figure have the highest level of emission. The emission levels of renewable power plants are quite small relative to non-renewable power plants.

![Figure 3.4. CO₂ equivalent emission levels (TÜSİAD, 1998)](image)

### 3.1. Non-Renewable Resources and Power Plants in Turkey

There are mainly four non-renewable fossil fuel resources in Turkey which are used in electricity generation process. These are hard coal, lignite, oil and natural gas. The heat content of each fuel determines the electricity generation capacity of 1 kg or 1 m³ of the fuel. Heat content is the amount of heat released during the combustion of 1 kg of solid fuel and 1 m³ of gaseous fuel at 0 C and under the pressure of 760 Torr.

#### 3.1.1. Lignite

Lignite is a fossil carbonaceous sedimentary deposit which is combustible, solid and black to brown colored. Its calorific value, with air at 30 C and 96 per cent relative humidity, is below 24 MJ/kg on the moist ash-free basis.

Lignite has an important place in the total reserve of Turkey. Turkey’s total lignite reserve was 8,374,372,000 tons in 1998. 7,339,046,000 tons of the total reserve are the proven lignite reserve of Turkey (WEC TNC, 2000a). Even if yearly production amount differs year by year, around 66,000,000 tons of lignite has been produced in the recent
years and approximately 85 per cent of it is used in thermal power plants to generate electricity (Besbelli, 2002). Table 3.2 gives the amounts of yearly domestic lignite production, total lignite consumptions of Turkey, and the amounts of lignite consumed by Lignite Power Plants from 1990 to 1998. The ratio of the amount of lignite used by power plants in total consumption is also illustrated.

Table 3.2. Yearly lignite production and consumption (1000 ton)

<table>
<thead>
<tr>
<th>Years</th>
<th>Domestic Lignite Production</th>
<th>Total Lignite Consumption</th>
<th>Lignite Consumed by Power Plants</th>
<th>Power Plant Consumption Ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>44407</td>
<td>45891</td>
<td>29884</td>
<td>65</td>
</tr>
<tr>
<td>1991</td>
<td>43207</td>
<td>48851</td>
<td>32293</td>
<td>66</td>
</tr>
<tr>
<td>1992</td>
<td>48388</td>
<td>50659</td>
<td>35318</td>
<td>70</td>
</tr>
<tr>
<td>1993</td>
<td>45286</td>
<td>46086</td>
<td>31917</td>
<td>69</td>
</tr>
<tr>
<td>1994</td>
<td>51533</td>
<td>51178</td>
<td>39701</td>
<td>78</td>
</tr>
<tr>
<td>1995</td>
<td>52758</td>
<td>52287</td>
<td>39815</td>
<td>76</td>
</tr>
<tr>
<td>1996</td>
<td>53889</td>
<td>54962</td>
<td>42441</td>
<td>77</td>
</tr>
<tr>
<td>1997</td>
<td>57387</td>
<td>59474</td>
<td>45694</td>
<td>77</td>
</tr>
<tr>
<td>1998</td>
<td>65204</td>
<td>64504</td>
<td>52115</td>
<td>81</td>
</tr>
</tbody>
</table>

The heat content of lignite used in power plants is around 2,000 Kcal/kg (WEC TNC, 2000a). The distribution of calorie groups of Turkey’s lignite reserves is depicted in Figure 3.5. The average heat content of lignite used in 1998 is 1,627 Kcal/kg and lignite’s electricity production potential is 1,593 gram/KWh and 2592 Kcal/KWh. In 1998, 92,497 tons Fuel Oil and 12,796 tons Diesel Oil are used as auxiliary fuels in lignite power plants (TEAŞ, 1999).

Total Installed Lignite Power Plant Capacity of Turkey is 6,213.9 MW in 1998 (WEC TNC, 2000a).

Average construction time of a lignite power plant can be assumed as 4 years, whereas its economic life can be accepted 30 years (Leventoğlu, 2001; Gençyılmaz, 2002).

Investment cost of installing a Lignite Power Plant is 1,600 $/KW while operation cost is 0.025 $/KWh (TMMOB, 2000; TÜBİTAK, 2001).
Figure 3.5. The distribution of calorie groups of Turkey’s lignite reserves 
(WEC TNC, 2000b)

The average CO₂ equivalent emission level released by Lignite Power Plants is accepted as 1,112.5 gram/KWh according to Figure 3.4. Note that the data given in Figure 3.4 provide only an emission range, but do not give the weight of electricity generation levels for each sector. As an assumption, the single average of the range is accepted as the emission level of power plant by its source. It is also important that Figure 3.4 gives a general coal power plants emission range. Since lignite and hard coal are generally called ‘coal’ in energy sector, the emission level of coal depicted in Figure 3.4 is assumed as the emission levels of both hard coal and lignite power plants.

3.1.2. Hard Coal

Hard coal is a fossil carbonaceous sedimentary deposit which is combustible, solid and black. Its calorific value, with air at 30 C and 96 per cent relative humidity, is over 24 MJ/kg on the moist ash-free basis.

Total hard coal reserve of Turkey was 1,124,000,000 tons in 1998. Proven reserve portion of this total is 423,000,000 tons (WEC TNC, 2000a). Recent yearly hard coal production is around 2,750,000 tons and approximately 16 per cent of the hard coal reserve is used in electricity generation (Bebelli, 2002; WEC TNC, 2000a). Table 3.3 gives the
amount of domestic hard coal production, total hard coal consumption of Turkey, and the amount of hard coal consumed by Hard Coal Power Plants from 1990 to 1998. The ratio of the amount of hard coal used by power plant in total consumption is also illustrated.

The heat content of hard coal is 6,100 Kcal/kg (WEC TNC, 2000a). Heat content of hard coal used in 1998 was 3,085 Kcal/kg and hard coal’s electricity production potential is 813 gram/KWh and 2,507 Kcal/KWh. In 1998, 17,527 tons Fuel Oil and 240 tons Diesel Oil were used as auxiliary fuels in lignite power plants (TEAŞ, 1999).

Table 3.3. Yearly hard coal production and consumption (1000 ton)

(WEC TNC, 2000a)

<table>
<thead>
<tr>
<th>Years</th>
<th>Domestic Hard Coal Production</th>
<th>Total Hard Coal Consumption</th>
<th>Hard Coal Consumed by Power Plants</th>
<th>Power Plant Consumption Ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>2745</td>
<td>8191</td>
<td>474</td>
<td>6</td>
</tr>
<tr>
<td>1991</td>
<td>2762</td>
<td>8824</td>
<td>782</td>
<td>9</td>
</tr>
<tr>
<td>1992</td>
<td>2830</td>
<td>8841</td>
<td>1339</td>
<td>15</td>
</tr>
<tr>
<td>1993</td>
<td>2789</td>
<td>8545</td>
<td>1298</td>
<td>15</td>
</tr>
<tr>
<td>1994</td>
<td>2839</td>
<td>8192</td>
<td>1441</td>
<td>18</td>
</tr>
<tr>
<td>1995</td>
<td>2248</td>
<td>8548</td>
<td>1246</td>
<td>15</td>
</tr>
<tr>
<td>1996</td>
<td>2441</td>
<td>10892</td>
<td>1476</td>
<td>14</td>
</tr>
<tr>
<td>1997</td>
<td>2513</td>
<td>12537</td>
<td>1828</td>
<td>15</td>
</tr>
<tr>
<td>1998</td>
<td>2156</td>
<td>13146</td>
<td>1885</td>
<td>14</td>
</tr>
</tbody>
</table>

Total Installed Hard Coal Power Plant Capacity is 335 MW in 1998 (WEC TNC, 2000a). Average construction time of a hard coal power plant can be assumed as 4 years, whereas its economic life can be accepted 30 years (Leventoğlu, 2001; Gençyılmaz, 2002).

Investment cost of installing Coal Power Plant is 1,450 $/KW while operation cost is 0.035 $/KWh (TMMOB, 2000; TÜBİTAK, 2001).

The average CO₂ equivalent emission level released by Hard Coal Power Plants is assumed as 1,112.5 gram/KWh according to Figure 3.4.

3.1.3. Crude Oil

Fuel oil and diesel oil, the products of crude oil, are used as input in electricity
generation process. Turkey’s total Crude Oil reserve is 977,185,000 tons and 43,685,000 tons of the total reserve is available reserve (WEC TNC, 2000a). Turkey’s recent yearly oil production is around 3,630,000 TOE (TPAO, 2002). Approximately 7 per cent of total oil production is used in power plants in Turkey. The heat content of crude oil is 10,500 Kcal/kg (WEC TNC, 2000a). In Table 3.4, the yearly domestic crude oil production and total crude oil consumption of Turkey are given. Total consumption of crude oil products and the consumption rate of power plants are also demonstrated in Table 3.4.

### Table 3.4. Yearly oil production and consumption (1000 ton) (WEC TNC, 2000a)

<table>
<thead>
<tr>
<th>Years</th>
<th>Domestic Crude Oil Production</th>
<th>Total Crude Oil Consumption</th>
<th>Total Oil Products Consumption</th>
<th>Oil Products Consumed by Power Plants</th>
<th>Power Plant Consumption Ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>3717</td>
<td>22700</td>
<td>21722</td>
<td>1155</td>
<td>5</td>
</tr>
<tr>
<td>1991</td>
<td>4451</td>
<td>22113</td>
<td>21161</td>
<td>762</td>
<td>4</td>
</tr>
<tr>
<td>1992</td>
<td>4281</td>
<td>23660</td>
<td>22856</td>
<td>1539</td>
<td>7</td>
</tr>
<tr>
<td>1993</td>
<td>3892</td>
<td>27074</td>
<td>26140</td>
<td>1658</td>
<td>6</td>
</tr>
<tr>
<td>1994</td>
<td>3686</td>
<td>25860</td>
<td>24885</td>
<td>1729</td>
<td>7</td>
</tr>
<tr>
<td>1995</td>
<td>3516</td>
<td>27918</td>
<td>27160</td>
<td>1871</td>
<td>7</td>
</tr>
<tr>
<td>1996</td>
<td>3500</td>
<td>29605</td>
<td>22281</td>
<td>1951</td>
<td>9</td>
</tr>
<tr>
<td>1997</td>
<td>3457</td>
<td>29176</td>
<td>28255</td>
<td>2120</td>
<td>8</td>
</tr>
<tr>
<td>1998</td>
<td>3224</td>
<td>29023</td>
<td>28203</td>
<td>2323</td>
<td>8</td>
</tr>
</tbody>
</table>

Fuel oil is hydro-carbon mixtures, that can be liquid or liquefiable oil products, with light boiling fraction that is used in burners. Composition and properties of fuel oil depends on national specifications. The average heat content of Fuel Oil used in power plants in 1998 was 9612 Kcal/kg while its electricity generation capacity was 277 gram/KWh and 2,659 Kcal/KWh. 1,656 tons of Diesel Oil was used as auxiliary fuel in electricity generation process in 1998 (TEAŞ, 1999).

Diesel oil is a liquid hydro-carbon mixture in the gas oil range which is used in compression-ignition internal combustion engines. Composition and properties of diesel oil depends on national specifications. The average heat content of Diesel Oil used in power plants in 1998 was 10,302 Kcal/kg while its electricity generation capacity was 247 gram/KWh and 2,540 Kcal/KWh (TEAŞ, 1999).

Turkey’s total installed capacity of fuel oil and diesel oil power plants were
1,225.4 MW and 219.2 MW respectively in 1998 (WEC TNC, 2000a).

Average construction time of an oil power plant can be assumed as 4 years, whereas its economic life can be accepted 30 years (Leventoğlu, 2001).

Installation cost of Oil Power Plants is 2,000 $/KW while operation cost is 0.06 $/KWh (TMMOB, 2000).

The average CO₂ equivalent emission level released by Oil Power Plants is calculated by taking the average of the data range given in Figure 3.4. Then it is observed that Oil Power Plants averagely release CO₂ equivalent emission around 825 gram/KWh.

3.1.4. Natural Gas

Natural gas mainly consists of methane and occurs naturally in underground deposits. Turkey's total Natural Gas reserve is 18,530 million m³, 8,800 million m³ of the total reserve is the available natural gas. Approximately 55 per cent of total natural gas production is used in power plants. Recent yearly natural gas production is around 565 million m³. Average heat content of natural gas is 9,100 Kcal/m³ (WEC TNC, 2000a).

The average heat content of natural gas used in power plants in 1998 is 8,467 Kcal/m³. In 1998, the electricity generation capacity of natural gas is 0.208 m³/KWh and 1,758 Kcal/KWh. 73,440 tons of Diesel Oil is used as auxiliary fuel in electricity generation process in 1998 (TEAŞ, 1999).

Table 3.5 demonstrates the amount of domestic natural gas production, total natural gas consumption of Turkey, and the amount of natural gas consumed by Natural Gas Power Plants from 1990 to 1998. The ratio of the amount of natural gas used by power plant in total consumption is also illustrated.

Turkey’s total installed capacity of natural gas power plants is 4,370.1 MW in 1998 (WEC TNC, 2000a). Even though technology changes so fast and decreases the construction time of plants, average construction time of a natural gas power plant can be
whereas its economic life is 40 years (Leventoğlu, 2001; Öner, 2002).

Installation cost for Natural Gas Power Plants is 680 $/KW whereas operation cost is 0.03 $/KWh (TMMOB, 2000).

The average CO₂ equivalent emission level released by Natural Gas Power Plants is illustrated as around 825 gram/KWh in Figure 3.4 if the average of the range is accepted as the emission level of this sector.

Table 3.5. Yearly natural gas production and consumption (million m³)
(WEC TNC, 2000a)

<table>
<thead>
<tr>
<th>Years</th>
<th>Domestic Natural Gas Production</th>
<th>Total Natural Gas Consumption</th>
<th>Natural Gas Consumed by Power Plants</th>
<th>Power Plant Consumption Ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>212</td>
<td>3418</td>
<td>2556</td>
<td>75</td>
</tr>
<tr>
<td>1991</td>
<td>203</td>
<td>4205</td>
<td>2868</td>
<td>68</td>
</tr>
<tr>
<td>1992</td>
<td>198</td>
<td>4612</td>
<td>2603</td>
<td>56</td>
</tr>
<tr>
<td>1993</td>
<td>200</td>
<td>5088</td>
<td>2530</td>
<td>50</td>
</tr>
<tr>
<td>1994</td>
<td>200</td>
<td>5408</td>
<td>2927</td>
<td>54</td>
</tr>
<tr>
<td>1995</td>
<td>182</td>
<td>6833</td>
<td>3602</td>
<td>53</td>
</tr>
<tr>
<td>1996</td>
<td>206</td>
<td>8113</td>
<td>3791</td>
<td>47</td>
</tr>
<tr>
<td>1997</td>
<td>253</td>
<td>10072</td>
<td>4569</td>
<td>45</td>
</tr>
<tr>
<td>1998</td>
<td>565</td>
<td>10648</td>
<td>5485</td>
<td>52</td>
</tr>
</tbody>
</table>

3.2. Renewable Resources and Power Plants in Turkey

Perpetuity is defined as the main characteristic of renewable resources. Technological development and competitive economy caused to keep the share of new and renewable resources lower than fuel oil, natural gas and coal. On the other hand, in many countries electricity production by geothermal, solar, wind and modern biomass energy has raised quite fast.

In Turkey, although studies on renewable energy started in 1960-1970, it has not progressed as expected. Recently, energy obtained from hydropower and biomass is used mostly. Although geothermal energy usage follows hydropower and biomass, it is not too much with respect to Turkey’s potential. Solar energy is almost symbolical even though Turkey is rich in its solar potential. Wind energy is recently begun to use whereas sea wave
energy is not considered yet. Although Turkey has a great modern biomass potential, energy plants are not known well and energy forestry is not utilized. It is expected that the progress in modern biomass will remove the classic one which is not economical. Total economical potential of these renewable resources in Turkey is 68,000 Btep/year. The share of each one in the potential is given in Figure 3.6. Turkey’s renewable energy potentials by source are given in Table 3.6 in detail.

![Graph showing renewable resource potentials](image)

Figure 3.6. The share of the renewable resource potentials in total renewable potential in Turkey

In the literature, there are three classes of 'potential' definition; gross potential, technical potential, and both technical and economical potential. These are classified according to their technical feasibility and economic feasibility. Technical feasibility is described as the condition that the project has no engineering problem technically, e.g. there shouldn’t be big and active earthquake lines in the field of a plant. Economic feasibility is described as the condition that yearly income of the project is greater than yearly cost of it.

### 3.2.1. Hydroelectric Power

Meteorological findings show that Turkey has average 644 mm rainfall yearly, which is equal to 501 billion m³ water of which 183 billion m³ flows into the seas or lakes through rivers. Building barrages does not permit to regulate flow of rivers in order to have maximum utility. Therefore, the reliability of hydroelectric power should be taken as 65 per cent (TÜBİTAK, 2001).
<table>
<thead>
<tr>
<th>RESOURCES</th>
<th>Gross Potential</th>
<th>Technical Potential</th>
<th>Economical Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydroelectric Power</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(MW)</td>
<td>107,500</td>
<td>53,750</td>
<td>34,862</td>
</tr>
<tr>
<td>(TWh/year)</td>
<td>430</td>
<td>215</td>
<td>124.5</td>
</tr>
<tr>
<td>Geothermal Energy</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heat (MW)</td>
<td>31,500</td>
<td>7,500</td>
<td>2,843</td>
</tr>
<tr>
<td>(MTOE/year)</td>
<td></td>
<td>5.4</td>
<td>1.8</td>
</tr>
<tr>
<td>Electricity (MW)</td>
<td>4,500</td>
<td>500</td>
<td>350</td>
</tr>
<tr>
<td>(TWh/year)</td>
<td></td>
<td></td>
<td>1.4</td>
</tr>
<tr>
<td>Solar Energy</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heat+Electricity (MW)</td>
<td>111,500 x 10^3</td>
<td>1,400,000</td>
<td>116,000</td>
</tr>
<tr>
<td>(TWh/year)</td>
<td>977,000</td>
<td>6,105</td>
<td>305</td>
</tr>
<tr>
<td>(MTOE/year)</td>
<td>80,000</td>
<td>500</td>
<td>25</td>
</tr>
<tr>
<td>Wind Energy (terrestrial)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity (MW)</td>
<td>220,000</td>
<td>55,000</td>
<td>20,000</td>
</tr>
<tr>
<td>(TWh/year)</td>
<td>400</td>
<td>110</td>
<td>50</td>
</tr>
<tr>
<td>Wind Energy (sea)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity (MW)</td>
<td></td>
<td>60,000</td>
<td>-</td>
</tr>
<tr>
<td>(TWh/year)</td>
<td></td>
<td>180</td>
<td>-</td>
</tr>
<tr>
<td>Sea Wave Energy</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity (MW)</td>
<td>75,000</td>
<td>9,000</td>
<td>-</td>
</tr>
<tr>
<td>(TWh/year)</td>
<td>150</td>
<td>18</td>
<td>-</td>
</tr>
<tr>
<td>Classical Biomass Energy</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel (MTOE/year)</td>
<td>30</td>
<td>10</td>
<td>7</td>
</tr>
<tr>
<td>Classical Biomass Energy</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel (MTOE/year)</td>
<td>90</td>
<td>40</td>
<td>25</td>
</tr>
</tbody>
</table>

Hydroelectric power is obtained by converting the potential energy of water to kinetic energy. Obtained energy through water falls from up codes to lower codes makes turbines work that makes the generators connected to turbines generate electricity.

In Turkey, gross potential of hydroelectric power is 430,000 GWh/year, while its technical potential is about 215,000 GWh/year. Both technical and economical potential of it is 124,500 GWh/year. Gross potential refers to theoretical upper limit of the potential. Technical potential represents the technological upper limit of the gross potential, and it is obtained by a function but mostly it is a ratio of gross potential. Economical potential is calculated by comparing the costs of different kind of power plants interconnected at the same system and meets the same amount of energy.
In 1998, total capacity of installed hydroelectric power plants is 10,306.5 MW that gives 36,341 GWh/year. 797 MW of this capacity providing 1,653 GWh/year reliable electricity belongs to small-scale hydroelectric power plants. The capacity of hydroelectric power plants under construction is 782 MW, providing 10,924 GWh/year electricity as of 1998.

Although installing a hydropower power plant takes too long time, its economic life is greater than other classic power plant types. According to feasibility studies, hydroelectric power plants are economically viable for 40-50 years. Furthermore, it can be increased to 75-100 years by rehabilitation of plants. Construction process can take four to six years.

Installation cost for Big-Scale Hydropower Plants is 1,200 $/KW whereas operation cost is 0.0005 $/KWh (TMMOB, 2000).

The average level of CO$_2$ equivalent emission releasing by hydroelectric power plants can be assumed as 200 gram/KWh referring to Figure 3.4.

The advantages of hydroelectric power can be listed as follows.

- Thermal and nuclear power plants need fuels such as oil, exported coal, natural gas and uranium whose costs can be easily affected by the economic crisis in the world. Moreover, the continuity in demand highly depends on the political relationships between the countries. However, the fuel of hydroelectric power plants, water, is a national resource and out of economical and political crises.

- Hydroelectric power plants can move in process in a few minutes in case of peak load whereas thermal power plants needs a few hours.

- Hydroelectric power is involved in renewable and clean energy.

The disadvantages of hydroelectric power can be listed as follows.

- Installation process of hydroelectric power plants takes longer time than other plants.

- During installation process and after economic life of hydroelectric power plants,
some environmental and social problems can occur.

3.2.2. Small-Scale Hydroelectric Power

While big hydroelectric power can be classified in ‘classic renewable, small ones are included in ‘new and renewable resources’ group as an alternative resource. Hydroelectric power plants whose capacities are between 101 KW and 10 MW are included in Small-Scale Hydroelectric Plants by EIEI.

Reliable small-scale hydroelectricity power potential of Turkey is technically 13.7 TWh/year, whereas in case of average flow producible energy could be 32,900 GWh/year.

Installed small-scale hydroelectric power plant capacity of Turkey is 797 MW that gives average 3,695 GWh electricity and reliable 1,653 GWh electricity.

Installation cost for small-scale hydroelectric power plants is 750 $/KW whereas operation cost is 0.0005 $/KWh (TMMOB, 2000).

The average level of CO₂ equivalent emission releasing by Small-Scale Power Plants can be assumed as 200 gram/KWh referring to Figure 3.4.

Besides the advantages of big-scale hydroelectric power plants, small-scale hydroelectric power plants’ advantages are as follows.

- Opposite to big-scale hydroelectric power plants, installation process doesn’t take long time.
- It doesn’t have any negative effect to the environment and social life.

3.2.3. Geothermal Energy

Geothermal energy is described as naturally stored heat in the deep levels of the ground, producing hot water, steam and gas, whose heat is greater than atmospheric heat. Furthermore, the heat of ‘hot and dry rocks’ can be used as geothermal energy by the help
of some technical methods (TÜBİTAK, 2001).

Geothermal energy is used in electricity generation, warming, cooling, thermal usage for health, process energy for industry, and in obtaining chemical substances.

Turkey is the seventh country in the world in regard to geothermal wealth. The installed power capacity of Turkey is 20.4 MW while its theoretical potential is 4,500 MW and investigated potential is 200 MW as at 1998.

Economic life of a geothermal power plant, which should be technically suitable, is minimum 30 years.

Installation cost for geothermal power plants is around 1,450 $/KW whereas operation cost is 0.0177 $/KWh (TMMOB, 2000).

The average level of CO\textsubscript{2} equivalent emission releasing by Geothermal Power Plants can be assumed as 75 gram/KWh referring to Figure 3.4.

The advantages of geothermal energy can be listed as follows.

- Since there is no need for fossil fuels to heat or steam the water, geothermal energy is an environmentally friend energy.
- It is produced by using national resources.
- Because of plants' long economic life, its investment cost is relatively lower with respect to its revenue and environmental advantages.

The disadvantage of geothermal energy is as follows.

- If re-injection method is not used, geothermal liquids cause corrosion and liming, damages agricultural watering. These liquids release carbon monoxide and hydrogen sulfur that cause greenhouse effect and increase global warming. But this can be eliminated by re-injection methods. Re-injection methods also keep the parameters of reservoir the same.
3.2.4. Solar Energy

Solar energy is a type of renewable energy. Its fixed power is 1,370 W/m² out of atmosphere and 0-1100 W/m² in the atmosphere. It can be used in warming, cooling, electricity generation, transportation, telecommunication, signalization and automation. Turkey’s geographical position is in the solar band and it is available to use solar energy. In order to use solar energy, it should be collected by solar heat collectors or photovoltaic cells.

Electricity is generated by direct or indirect methodologies. Direct methodology includes photovoltaic cells, thermoelectricity and thermo-ionic conversion. Indirect one includes solar batteries and thermal electricity generator that converts vapor or hydrogen provided by solar energy (TÜBİTAK, 2001).

Although there have been many studies on the investigation of Turkey’s solar energy potential done by different institutions and individuals, the results found are not similar because of different methodologies used and period of investigations. EIEI is still working on investigation of Turkey’s solar energy potential.

Installation cost for solar PV power plants is around 6,000 $/KW whereas operation cost is 0.25 $/KWh (Radikal, 2002; TMMOB, 2000).

The average CO₂ equivalent emission level released by Solar Power Plants can be accepted as 175 gram/KWh referring to Figure 3.4.

The advantage of solar energy is as follows.

- It is clean and renewable energy. Moreover, by the increase of usage of solar energy, like other new and renewable resources, it would make the usage of fossil fuels and so environmental pollution reduces. Its environmental cost is quite low.

The disadvantages of solar energy can be listed as follows.
• Price of solar batteries is still relatively high but it is expected that it will reduce in the following years.
• In Turkey, studies on potential of solar energy haven’t been completed yet. Therefore, it couldn’t be involved in national energy planning models.
• Extensive land use.

3.2.5. Wind Energy

Wind energy is an indirect, transformed solar power. The differences on heat of lands, seas and atmosphere and their pressure levels create wind. Wind is the relative movement of air due to the ground. It comes up with the replacement of air from high pressure levels to lower ones. The energy generated by wind depends on the speed of wind and its frequency. While the speed of wind is positively correlated to height, the power of wind is correlated to third power of wind’s speed (TÜBİTAK, 2001).

Around the world, especially in North Europe and USA, wind energy is widely used in generation of electricity, and its technology is growing quite fast while its cost is going down.

Economic life of wind turbines is around 20-25 years. Some in the literature claim that its life can be 30 years.

Average investment cost of wind power plants is approximately 1,450 $/KW whereas electricity generation cost is 0.045 $/KWh (TMMOB, 2000).

The average level of CO₂ equivalent emission releasing by Wind Power Plants is observed as 75 gram/KWh in Figure 3.4.

In Turkey, the potential of wind energy has been sought by DMI, EIEI and some other institutions.

The advantages of wind energy can be listed as follows.

• Wind energy is a clean and renewable energy. Wind power plants do not release CO₂
to the atmosphere. According to the literature, savings from CO₂ emission by using wind energy is 1000-2500 tonCO₂/MWyear. In Turkey, it is calculated that saving from releasing CO₂ is 3750 tonCO₂/MWyear with respect to coal power plants, 3000 tonCO₂/MWyear of oil power plants, and 2275 tonCO₂/MWyear of natural gas power plants. Furthermore, it prevents releasing of NOₓ and SOₓ.

- Although wind farms requiring wide fields seem causing problems, actually it does not since turbines use 1-1.2 per cent of total field and the remaining field can be used for agriculture.
- Wind power plants can also be installed in open-seas.

The disadvantages of wind energy are as follows.

- Turbines create visual and noise pollution. But, there are new designs reducing its visual pollution. The noise in wind farms is around 85 dB. It is recommended that the distance between settlements and wind farms should be 400 m. Thus, the noise reduces to 36.9-56 dB.
- They also may cause birds death. Therefore, wind power plants can not be installed in the national park areas.
- They may cause parasites in telecommunication around 2-3 km.

3.2.6. Biomass Energy

It is classified in two groups, classic and modern. Classic biomass energy is obtained from firewood, some plants and dried dung. Modern biomass energy is obtained from the products of energy forests and energy agriculture, wastes of forest and wood industry, agricultural and animal wastes, and urban wastes. Biomass materials are transformed to bio-fuels.

In Turkey, especially classic biomass resources are generally used for cooking and warming for many years.

The advantage of biomass energy is as follows.
• Biomass is a renewable and national resource. It is relatively more clean energy than the ones obtained from classic resources.

The disadvantages of biomass energy are as follows.

• In Turkey, wood consumption as a classic biomass resource destroys wood industry's raw material potential. Besides, it increases illegal wood cuts. Dried dung consumption for energy also decreases the manure potential for agriculture.
• It is argued that energy generated by biomass increases methane releasing which in turn causes greenhouse effect.

3.2.7. Sea-Based Renewable Energies

Sea-based renewable energies are sea wave energy, sea heat gradient energy, sea stream energy and tide energy. While Turkey does not have tide energy potential, sea wave energy is available. Even though Bosphorus is suitable with its sea stream potential, sea traffic does not permit to use this potential.

By using the 20 per cent of total shore of Turkey, 18,500 GWh/year of technical energy can be obtained. However, Turkey does not have sea observation units and measurement data. This energy source has not been evaluated yet in Turkey.
4. PROBLEM DEFINITION

The electricity need of Turkey is met by different kind of power plants using mostly non-renewable sources, such as lignite, natural gas, oil products. On the other hand, hydropower plant capacity is both one of the main electricity providers and almost the unique renewable source used in electricity sector. There is a lot of debate on Turkey’s declining fossil fuels opposite to the growing electricity demand as in the world. Frequently, it is claimed that in the near future installed capacity will not meet the electricity demand of Turkey. One perspective emphasizes the potential of renewable sources which is ignored by the existing political choices because of essentially high costs of its technology.

The world has come to a turning point after the recognition of global warming. One of the main reasons of global warming is combustion of fossil fuels. Combustion of fossil fuels causes the utilities to release many kinds of emissions. The Kyoto Protocol (1997) declared that especially industrialized and developing countries have to adjust their emission levels. That is directly related to the energy sector, so to the electricity sector. Recently, renewables are seen as the saver of the world. The potential for the renewables in Turkey will be taken into account sooner or later.

In this project, the general purpose is to analyze the potential of renewables to meet Turkey’s growing electricity demand. There are two important sides of the problem. The first one is the investment side in which investment decisions are made to allocate the capacity need to different sectors. The second one is the demand side in which some elements create the demand and some affect the demand forecasts.

The main purpose of this project is to investigate whether potential for renewables do have a significant contribution in total electricity generation to meet the electricity need of Turkey in the future with different allocation policies in case the renewable oriented policies are applied. It is also intended to examine the results of existing policies. The gap between total power capacity serviced and the current electricity need is one of the most important indicators in the model to figure out that in which scenario Turkey will fall in an
electricity bottleneck. At the same time, the investment and operation costs and CO₂ equivalent emission released can be observed for each scenario.

Each source constitutes a sector in the system. Different source allocation scenarios in the investment side will provide to screen the sector capacities and electricity generation amounts. Moreover, the amount of non-renewable sources used in the power plants year by year and the magnitude imported for each will be figured out.

On the demand side, the objective is to analyze the effect of the increase in the rate of energy savings and the decrease in the rate of network losses on demand and capacity. The effect of conservation oriented policies on the size of total capacity will be inspected. By implementation of the scenarios, CO₂ equivalent emission released, investment and operating costs can be observed. It is also aimed to analyze the results of using different demand scenarios produced by different institution and governmental offices.
5. RESEARCH METHODOLOGY

The System Dynamics Methodology was developed by a group of scientists at MIT in the 1970's and was called as "Industrial Dynamics". In the 1970's it became so popular and widespread and was used in many areas in the world by the name of "System Dynamics". "System Dynamics has been used extensively to aid in resource planning in the electric power industry. The many applications constitute a major body of work that has proven useful to large and small companies as well as government agencies at the local, state and federal level" (Ford, 1997).

System dynamics methodology as an effective tool in understanding socio-economic phenomena is used in this project to model energy planning system for electric power. The Systems Thinking and the Holistic approach constitute the philosophies of the simulation methodology through seeing the world as a whole of composed system. The System Dynamics Methodology takes the direct causality between variables as the basis of relationships, that is, a change in variable X causes a positive or negative change in variable Y. Referring to the principles of system thinking, the main structure of real system is constructed as a system dynamics model, different policies are analyzed and the behaviors of the system are observed via simulation. The dynamic behavior of the system over time is the core point of system dynamics. It does not aim to predict the values of the system variables point by point, but seeks the reasons that generate the observed behavior of the system.

Feedback principles constitute one of the important features of the methodology. Two-way relationships between variables constitute a feedback loop, that is, a change in variable X results in a change in variable Y, while in turn, a change in Y results in a change in X. The direction of feedback loop is determined by multiplying the directions of each relationship between variables in the loop. There are two kinds of feedback loops; positive and negative. Positive feedback loops exhibit growth pattern by reinforcing the initial change in one of the variables within the loop whereas negative ones expose a decay pattern by the draining process.
Since the fundamental variables change through time, mathematical base of the methodology involve the differential and difference equations. Most of the models are non-linear since there are interactive variables and equations. The non-linear relationships can be represented by graphical functions within the model. The behaviors of the system variables are observed by the operations of loops in the time frame. Some elementary behavior patterns in the System Dynamics are the Exponential Growth, the Exponential Decay, the S-shaped Growth and the Oscillatory Behavior.

There are various modeling packages used in system dynamics simulation. Some are STELLA, VENSIM, DYNAMO, ITHINK, POWERSIM, and DYSMAP. The basic building blocks of the System Dynamics packages are stocks, flows, converters and connectors. They are used to facilitate the mathematical expressions in writing. The stocks represent the condition and accumulations of the system and behave like material or non-material accumulators. The magnitude of a stock at a point in time tells how things “are” within the system at that point in time. Stocks are signified by rectangles. Flows represent the activities in the motion. Flows are directly connected to the stocks within the system. They fill and/or drain the stocks. Flows are generally signified by a pipe with a spigot, flow regulator, and one or two arrowheads attached. Converters convert inputs into outputs. They can represent either information or material quantities. The entire model is represented by a stock-flow diagram.

Modeling is a feedback process, not a linear sequence steps. Models go through constant iteration, continual questioning, testing and refinement (Sterman, 2000). There are five main steps in system dynamics modeling process which can not be distinguished totally from each other entirely.

The first step is “problem articulation”. It can be also called as boundary selection. The problem is explicitly stated with the reasons concerned. The boundaries of the system are described in detail with respect to the main characteristics and the purpose of the study. It is carefully considered that the borders of the system should not break any major links between elements.

The second step is a very important one, called “model conceptualization".
According to the real system data and the experiences gained from previous studies, the key variables and concepts are determined and the rules of the interactions of the variables are defined. Time horizon based on consistent arguments is identified. The historical behavior of the key concepts and variables are explained and the expected future behavior is described as the reference mode. Solutions generated depend on interpretation of the data. Therefore, correct data classification and interpretation is the first step in achieving correct solutions; otherwise efforts result in defective theories, models and recommendations (Perez and Byron, 1999). After figuring out the potential variables crucial to build the model, a tentative causal-loop diagram depicting the major variables of the system is constructed.

The third step is the model construction. The stocks, flows and the converters of the system are determined and their associated relationships are identified with respect to causal-loop diagram previously constructed. Generating the equations within the model is the last step of the model construction process. In equation writing, the form of each equation is specified and the coefficients are estimated according to the available data.

The next step is testing the validity of the model. Structural and behavioral validity are tested in this step via simulation runs. Simulation experiments are done by regarding different strategies. The results of each simulation experiments are analyzed.

The last step is the model implementation step. System Dynamics methodology provides the opportunity to seek how and why undesirable performance occurs by the analysis of the system's structure. Thereby, the behavior of the system can be improved by redesigning system's structure.
6. DESCRIPTION OF THE MODEL

The model structure is based to the following general settings and assumptions:

Although electricity planning is quite broad in the context of national energy planning, there are a number of activities that make up the core of the total electricity planning implementations. In the model, electricity sector is represented by a set of well-defined, concrete activities. The emphasis is especially given to the allocation of future capacity need to renewable sources and non-renewable sources under different policies. The whole system involves the future electricity need as an exogenous input or a function of current consumption. The model aims to display when the electricity shortage occurs if renewable oriented capacity planning is done. It is also aimed to analyze the results of non-renewable oriented policies.

Since the scope becomes too broad if all existing plants are included, the major electricity sources are taken into account as a sector. The selected sources are already the main ones in the sector and the ones possibly will have an important share in the future.

The STELLA 5 Software is used in this research, to model and analyze the renewables’ potential to meet Turkey’s electricity need (Richmond and Peterson, 2000).

6.1. Overview and Assumptions

The model is constructed and analyzed by using sector approach. The structure of the model is given in Figure A.1 as a whole. There are nine sectors representing the sources selected for electricity generation process. They can be classified as renewables and non-renewables. Non-renewable ones include Lignite Power Sector, Natural Gas Power Sector, Oil Power Sector and Hard Coal Power Sector. Renewables include Hydropower Sector, Wind Power Sector, Small-Scale Hydropower Sector, Geothermal Power Sector and Solar Power Sector. The sectors included in the model are the ones that compose 97.2 per cent of the total capacity and generate 99.5 per cent of the total electricity generated as of 1998. The LPG, Naphtha and Multi Fuel power plants are not involved in the model. Therefore,
analysis will be done for the determined sectors constituting the most of the capacity. The sectors diagram is illustrated in Figure 6.1.

![Sector diagram](image)

Figure 6.1. Sector diagram

The availability ratios are estimated as in the following table.

<table>
<thead>
<tr>
<th>Sector</th>
<th>Availability Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lignite Power Plants</td>
<td>90%</td>
</tr>
<tr>
<td>Hard Coal Power Plants</td>
<td>80%</td>
</tr>
<tr>
<td>Oil Power Plants</td>
<td>60%</td>
</tr>
<tr>
<td>Natural Gas Power Plants</td>
<td>85%</td>
</tr>
<tr>
<td>Hydropower Plants</td>
<td>45%</td>
</tr>
<tr>
<td>Small Scale Hydropower</td>
<td>60%</td>
</tr>
<tr>
<td>Geothermal Power Plants</td>
<td>69%</td>
</tr>
<tr>
<td>Wind Power Plants</td>
<td>30%</td>
</tr>
<tr>
<td>Solar Power Plants</td>
<td>30%</td>
</tr>
</tbody>
</table>

The year 1990 is accepted as the historical year. Since the available real data belonging to the electricity consumption and generation of Turkey are up to 1998, the validation of the major parameters is tested for eight years. The future electricity demand data available is up to 2010 and 2020. It is aimed that the model firstly will run for 25
years, from 1990 to 2015 as the medium term analysis, and the results will be examined. A long term, 55 year-simulation will also be done for a general analysis to examine the situation of the sources. Between the years 1990 and 1998, historical data validating the model are used in the model and after 1999 different parameters representing the policies is set to inspect the results. In the electricity consumption side, all realized consumption values are used for 1990-1998, and the demand forecasts made by governmental offices are set as the current gross electricity consumption data in the model.

Within each sector, the allocated future capacity need is compared to the existing capacity and then construction is started if there is a capacity gap found by the calculation of expected capacity and the desired level of under construction capacity. The non-renewable sources are depleted by the electricity generation of the related power plants. The depletion rate of the reserve is calculated by the average resource electricity generation capacity of a unit of the related source (KWh/gram). Yearly production amount of a non-renewable source is assumed as a fraction of the total reserve of Turkey. Although non-renewable sources are finite and depleted every year through the consumption of power plants for electricity generation, it is assumed that the capacity investment for non-renewable power plants does not consider the total reserve of Turkey since there is an opportunity to import related source without any constraint.

On the other hand, in the renewables, the potentials of the renewable sources restrict to make investment. A capacity investment can not be permitted if it exceeds the total remaining potential of the related renewable source. Renewable sources allow the retired capacity to join the potential again. For instance, if a wind power plant is retired then another wind power plant can be built up at the same wind farm. A new renewable power plant construction means that total potential of Turkey is allocated by that power plant with the rate of its electricity generation capacity. Consequently, installation orders are restricted by yearly potential of renewable sources that is not used yet.

There are also two sectors representing the demand side of the model. Current Electricity Need Sector involves the allocation of current electricity need to the existing power plants in respect of their capacities. Future Electricity Need Sector includes the calculation of the future electricity need for five years later by using the current electricity
consumption data and its allocation to the renewable and non-renewable sectors in regard of different parameters, which also constitute scenarios. In *Current Electricity Need Sector*, the gross installed capacity is transformed to the net installed capacity by dropping the average internal consumption rate of the power plants. After subtracting the network losses, which is the average ratio declared by the government, the available net electricity generation capacity can be obtained. At the same time, gross electricity consumption value is allocated to the sectors by considering their capacity ratios in the total after 1999. Before 1999, the historical allocation coefficients which are generated by taking the average share of the related sector’s electricity generation in the total electricity generated between 1990 and 1998 are used in meeting the current electricity need.

*Cost and Emission Sectors* includes total emission released by power plants during electricity generation and total cost occurring by the investment decisions and the operation costs of generated electricity by each sector.

The complete list of equations belonging to the model is given in Section A.1. Each sector’s equation set will be explained in detail in the following sections.

6.2. Model Sector Descriptions

6.2.1. Current Electricity Need Sector

The structure of *Current Electricity Need Sector* is depicted in Figure 6.2. This sector does not have any stock variables but uses the stock variables of the other sectors as inputs. Essential variables of the sector are the converters; namely Current Gross Electricity Consumption, Total Electricity Generation and Total Installed Capacity.

In the alphabetical order, the definitions of the major variables are as follows.

- *CurGrsElectConsGWh* : Current gross electricity consumption in terms of GWh/year.
- *CurGrsElectGenAllocbyNationICGWh* : Current gross electricity generation demand that can be met by National Installed
- CurGrsElectGenDmdGWh
  : Current gross electricity generation demand in terms of GWh/year.
- CurNetElectConsGWh
  : Current net electricity consumption in terms of GWh/year.
- GrsElectImpExpectedGWh
  : Gross electricity import which is expected in terms of GWh.
- GrsElectImpRealzdGWh
  : Gross electricity import realized in terms of GWh/year.
- InternalConsRatio
  : Average internal electricity consumption ratio that is used to generate electricity by power plants (per cent).
- NetworkLossRatio
  : The ratio of the net electricity loosed on distribution and transition lines (per cent).

Figure 6.2. The structure of current electricity need sector
- **TotDomNetElectConsGWh**: Total net electricity consumed through domestic power plants in terms of GWh/year.

- **TotGrsCapGWh**: Total gross electricity generation capacity of Turkey's installed power plants in terms of GWh/year.

- **TotGrsElectGenGWh**: Total gross electricity generated in terms of GWh/year.

- **TotGrsNRENElectGenGWh**: Total gross electricity generated by the power plants in the non-renewable sectors in terms of GWh/year.

- **TotGrsRENElectGenGWh**: Total gross electricity generated by the power plants in the renewable sectors in terms of GWh/year.

- **TotICMW**: Total installed capacity of Turkey in terms of MW.

- **TotNetCapAvlforEndUseGWh**: Total net electricity generation capacity of Turkey which is available to consume by end users in terms of GWh/year.

- **TotNetCapGWh**: Total net electricity generation capacity of Turkey in terms of GWh/year.

- **TotNetElectGenGWh**: Total net electricity generated in terms of GWh/year.

- **TotNRENICGWh**: Total gross electricity generation capacity of the power plants in the non-renewable sectors in terms of GWh/year.

- **TotNREN_IC_MW**: Total installed capacity of non-renewable sectors of Turkey in terms of MW.

- **TotRENICGWh**: Total gross electricity generation capacity of the power plants in the renewable sectors in terms of GWh/year.

- **TotREN_IC_MW**: Total installed capacity of renewable sectors of Turkey in terms of MW.
The critical input in this sector that also triggers the whole simulation is an external graphical function, namely Current Gross Electricity Consumption (CurGrsElectConsGWh). It will be explained in detail at the end of this section.

The variable Current Gross Electricity Generation Demand (CurGrsElectGenDmdGWh) is calculated by using the value of the variable CurGrsElectConsGWh and of the variable Internal Consumption Ratio (InternalConsRatio) through the formulation given as Equation (6.1). "Gross Electricity Generated" means the electricity measured at the generator terminals. In Chapter 3, Figure 3.1 explains the formulation. Internal Consumption Ratio is a constant, which is taken as 3.4 per cent given in Equation (6.2) (TMMOB, 2001). In the scenario analyses, especially in the conservation oriented policy based simulations, it will be taken as declining graphical function.

\[
\text{CurGrsElectGenDmdGWh} = \text{CurGrsElectConsGWh} \times (1 + \text{InternalConsRatio}) \quad (6.1)
\]

\[
\text{InternalConsRatio} = 0.034 \quad (6.2)
\]

This is the required electricity generation rate to meet the current gross need. If the gross capacity is enough to meet the required electricity generation, the amount of CurGrsElectGenDmdGWh is allocated to the sectors, representing national power plants, to get the demanded gross generation. If the gross capacity in terms of GWh/year is less then the gross electricity generation demand, electricity generation is ordered at the rate of total capacity. In the model, it is calculated as Equation (6.3).

\[
\text{CurGrsElectGenAllocbyNationICGWh} = \min(\text{CurGrsElectGenDmdGWh}, \text{TotGrsCapGWh}) \quad (6.3)
\]

The difference between the variables CurGrsElectGenAllocbyNationICGWh and CurGrsElectGenDmdGWh gives the expected amount of gross electricity that should be imported to satisfy the demand. In the model, the amount of expected imported electricity is represented by the converter GrsElectImpExpectdGWh. The formulation is given in Equation (6.4). Electricity generation policies giving the allocation decision of the CurGrsElectGenAllocbyNationICGWh to the sectors determines the gross electricity
generation amount of each sector. The electricity generation fraction of a sector can be either a constant ratio or the ratio of the installed capacity of the sector in the total. The structure of the decision process will be explained in the description of related sector. In summary, total gross electricity generated may not be equal to the allocated amount of gross electricity generation to that sector. Therefore, the realized electricity import can be different from the expected one. The formulation of the variable Gross Electricity Import Realized is given in Equation (6.5).

\[
\text{Gr} \text{sElectImpExpectedGWh} = \text{CurGr} \text{sElectGenDmdGWh} - \text{CorGr} \text{sElectGenAllocbyNationICGWh}
\]

(6.4)

\[
\text{Gr} \text{sElectImpRealzdGWh} = \text{CurGr} \text{sElectGenDmdGWh} - \text{TotGr} \text{sElectGenGWh}
\]

(6.5)

Total electricity generated is calculated by taking the sums of the generated electricity by the sectors classified as renewables and non-renewables. The formulations used in this process are given in Equations (6.6)-(6.8).

\[
\text{TotGr} \text{sElectGenGWh} = \text{TotGr} \text{sNRENElectricGenGWh} + \text{TotGr} \text{sRENElectricGenGWh}
\]

(6.6)

\[
\text{TotGr} \text{sNRENElectricGenGWh} = \text{Gr} \text{sElecGenbyHCPGWh} + \text{Gr} \text{sElecGenbyNGPGWh} + \text{Gr} \text{sElecGenbyOilGWh} + \text{Gr} \text{sElecGenbyLPGWh}
\]

(6.7)

\[
\text{TotGr} \text{sRENElectricGenGWh} = \text{Gr} \text{sElecGenbyWPGWh} + \text{Gr} \text{sElecGenbyGTPGWh} + \text{Gr} \text{sElecGenbyHPGWh} + \text{Gr} \text{sElecGenbySHPGWh} + \text{Gr} \text{sElecGenbySPGWh}
\]

(6.8)

Net electricity generated is the electricity which is the useful energy measured at the outlet of the power plants. In the model, the net electricity generated is calculated by dropping the rate of internal consumption as in the following way.

\[
\text{TotNetElecGenGWh} = \text{TotGr} \text{sElecGenGWh} \times (1 - \text{InternalConsRatio})
\]

(6.9)

Total net electricity consumed through the domestic capacity can be calculated from total net electricity generated by subtracting the electricity loosed on the network. The
related formulations and network losses ratio, which is accepted as 18 per cent (TMMOB, 2001) are given in Equations (6.10) and (6.11). In the scenario analyses made for the conservation oriented policy based simulations, it will be assumed that network losses ratio will show a declining behavior as internal consumption ratio assumed.

\[ \text{TotDomNetElectConsGWh} = \text{TotNetElectGenGWh} \times (1 - \text{NetworkLossRatio}) \]  
\[ \text{NetworkLossRatio} = 0.18 \]  

Total installed capacity is the sums of the electricity generation capacities of the installed power plants of Turkey involved in the model. Firstly, power plants are classified as non-renewables electricity generation capacity and renewables electricity generation capacity in terms of GWh, then total electricity generation is calculated by the formulations as in Equations (6.12), (6.13) and (6.14).

\[ \text{TotGrSCapGWh} = \text{TotNRENICGWh} + \text{TotRENICGWh} \]  
\[ \text{TotNRENICGWh} = \text{TotHCPICGWh} + \text{TotLPICGWh} + \text{TotNGICGWh} + \text{TotOPICGWh} \]  
\[ \text{TotRENICGWh} = \text{TotGTPICGWh} + \text{TotHPICGWh} + \text{TotSHPICGWh} + \text{TotSPICGWh} + \text{TotWPICGWh} \]

In the same way, total installed capacities are calculated by Equations (6.15)-(6.17).

\[ \text{TotICMW} = \text{TotNREN\_IC\_MW} + \text{TotREN\_IC\_MW} \]  
\[ \text{TotNREN\_IC\_MW} = \text{TotHCPIC\_MW} + \text{TotLPIC\_MW} + \text{TotNGPIC\_MW} + \text{TotOPIC\_MW} \]  
\[ \text{TotREN\_IC\_MW} = \text{TotGTPIC\_MW} + \text{TotHPIC\_MW} + \text{TotSHPIC\_MW} + \text{TotSPIC\_MW} + \text{TotWPIC\_MW} \]
Total Net Capacity of the installed power plants in terms of GWh/year is the maximum electricity generation capacity of Turkey’s power plants at the outlet of the power plants. This is the maximum electricity which can be generated by the installed capacity of the sectors and can reach the users, called as the Net Capacity Available for the End Use. This process is realized after the transition of electricity from the power plants to the users through the network. A ratio of the net generation is loosed on the network. It is accepted as 18 per cent as mentioned before. The formulations are given via Equations (6.18) and (6.19).

\[
\text{TotNetCapGWh} = \text{TotGrscapGWh} \times (1 - \text{InternalConsRatio}) \quad (6.18)
\]

\[
\text{TotNetCapAvlforEndUseGWh} = \text{TotNetCapGWh} \times (1 - \text{NetworkLossRatio}) \quad (6.19)
\]

Current Gross Electricity Consumption is set as a graphical function in the model. There are two gross electricity consumption forecasts for the future which are used as scenario inputs to build up alternative models. Firstly, in all scenarios the current electricity consumption data for 1990-1998 are constructed by using the historical data in terms of GWh/year given in Figure 6.3.

The gross electricity demand forecasts of ETKB and DPT constitute the scenarios in both current need and future need sides of the model. The graphs of each forecasts made by ETKB and DPT were given in Chapter 3 (see Figure 2.3 and Figure 2.4). DPT’s demand forecast data are for the years 1999 to 2010, whereas ETKB’s data are available for 1999 to 2020. In order to use them in long term simulation analysis, from 1990 to 2050, the curves of forecasts are analyzed and each forecast curve is extrapolated till 2050. Both exponential and quadratic trend regression functions are fitted and the extrapolations are figured in Figure 6.4 for ETKB and in Figure 6.5 for DPT. The quadratic ones are used in the model for an optimistic scenario analysis of long term simulation.

The exponential trend function given in Equation (6.20) is used in the calculation of ETKB’s gross electricity demand data from 2020 to 2050. The quadratic trend regression in ETKB data analysis uses the formulation as in Equation (6.21).
Figure 6.3. Real gross electricity consumption from 1990 to 1998 (GWh/year) (WEC TNC, 2000a)

\[ y(t) = 313835.1874 \exp(0.0634824t) \]  \hspace{1cm} (6.20)

\[ y(t) = 314274.4545+19146.59848t+847.310606t^2 \]  \hspace{1cm} (6.21)

While examining the data of ETKB in detail, it is observed that the trend of ETKB's demand forecast curve changes in the year 2011. Therefore, the regression analyses have been done by using the data of ETKB from 2011 to 2020.

Figure 6.4. Extrapolated gross electricity demand forecast of ETKB, by exponential and quadratic trends
The regression results for DPT's electricity demand forecasts are demonstrated in Figure 6.5.

The extrapolated gross electricity demand for DPT data is calculated by the following exponential trend regression and the quadratic trend regression formula.

\[ y(t) = 121338.5161 \times \exp(0.0736351t) \]  

\[ y(t) = 121001.4011 + 8794.977522t + 437.8946054t^2 \]

(6.22)  

(6.23)

Figure 6.5. Extrapolated gross electricity demand forecast of DPT, by exponential and quadratic trends

Some of the values of the each curve for ETKB and DPT from 2005 to 2045 are illustrated in Table 6.2.

In the model, for long term analysis, the exponential trend curve of ETKB and quadratic trend curve of DPT will form the basis of pessimistic and optimistic scenarios respectively.

The curves plotted in Figures 6.6 and 6.7 include the data of the realized gross electricity consumption for 1990-1998 and the forecasts of ETKB and DPT for 1999-2020 and 1999-2010 respectively. In the medium term analysis, these curves will be used as
different demand forecast scenarios. Note that, DPT's data for 2010-2020 are the extrapolated data of the quadratic trend.

Table 6.2. Comparative table for gross electricity demand curves (GWh)

<table>
<thead>
<tr>
<th>Demand Curves</th>
<th>Years</th>
<th>2005</th>
<th>2015</th>
<th>2025</th>
<th>2035</th>
<th>2045</th>
</tr>
</thead>
<tbody>
<tr>
<td>ETKB</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Exponential Trend</td>
<td>196,610</td>
<td>404,560</td>
<td>763,277</td>
<td>1,440,068</td>
<td>2,716,962</td>
<td></td>
</tr>
<tr>
<td>Quadratic Trend</td>
<td>196,610</td>
<td>404,560</td>
<td>748,400</td>
<td>1,261,844</td>
<td>1,944,750</td>
<td></td>
</tr>
<tr>
<td>DPT</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Exponential Trend</td>
<td>189,630</td>
<td>394,156</td>
<td>823,116</td>
<td>1,718,914</td>
<td>3,589,610</td>
<td></td>
</tr>
<tr>
<td>Quadratic Trend</td>
<td>189,630</td>
<td>373,822</td>
<td>645,688</td>
<td>1,005,132</td>
<td>1,452,155</td>
<td></td>
</tr>
</tbody>
</table>

For long term analysis, the extrapolated data given in Figures 6.4 and 6.5 will follow the data plotted in Figures 6.6 and 6.7 for the years 2020-2050 and 2010-2050 respectively. That is, the long term curves will be the combination of real data, forecast data and extrapolated data.

Figure 6.6. Current electricity consumption graph for ETKB demand forecast scenario in medium term analysis (GWh)

The formulation of the CurGrsConsGWh for ETKB demand forecast scenario used in the medium term analysis is given in Equation (6.24).

The formulation of the \textit{CurGrsConsGWh} for DPT demand forecast scenario for ETKB demand forecast scenario used in the medium term analysis is given in Equation (6.25).


Figure 6.7. Current electricity consumption graph for DPT demand forecast scenario in medium term analysis (GWh)
6.2.2. Future Electricity Need Sector

The structure of Future Electricity Need Sector is depicted in Figure 6.9. The distinguishing variables in the sector are Future Gross Electricity Consumption, Future Electricity Generation Demand, Total Potential of Renewables which is not used yet, Requested Priority of the Renewables and Priority of the Non-Renewables. The main purpose of this sector is to allocate the future gross electricity generation demand in terms of GWh to the sectors of renewables and non-renewables by considering the remaining electricity generation potential of the renewables. Structure of this sector is given in Figure 6.8.

![Diagram of Future Electricity Need Sector](image)

**Figure. 6.8. Structure of Future Electricity Need Sector**

The definitions of the major variables are as follows.

- **FutGrsElecConsGWh**: Future gross electricity consumption in terms of GWh/year.
- **FutGrsElectGenDmdGWh**: Future gross electricity generation demand in terms of GWh/year.
- **FutNRENNeedGWh**: Future gross electricity generation need that is supposed to be met by non-renewables in terms of GWh/year.
- **FutRENNeedGWh**: Future gross electricity generation need that is supposed to be met by renewables in terms of GWh/year.
- **NRENPriority**: Installation priority of non-renewables.
- **RENinitialPriority**: Initial installation priority of renewables for the years 1990-1998.
- **RENIstFracAdjust**: Adjustment of the installation priorities of the renewable sectors.
- **RENPriorityAdjusted**: Adjusted installation priority of renewables.
- **RENPriorityRequested**: The future requested installation priority for the, that is for 1999-2020 in the medium term analysis.
- **RENSmthPriorityReq**: The smoothed installation priority for the requested installation priority of the renewables.
- **TotRENPotGWh**: Total potential of renewables in terms of GWh/year.

The main input driving this sector is *FutGrsElectConsGWh*. This variable is a time based graphical function. While the simulation begins from the year 1990, the future investments made for the installation of new power plants considers the future gross electricity consumption, which is assumed as the consumption amount of five years later relative to the simulation year of the model. That is,

\[ 	ext{FutGrsElectConsGWh}(t) = \text{CurGrsConsGWh}(t+5) \]

According to this assumption, the graphical function is prepared by starting from the year 1990 with the 1995 value of *CurGrsConsGWh*. Therefore, for a medium term simulation run, there will be available data only for 15 years, for 1990 to 2015 with the data set of 1995-2020 current gross consumption. The formulation of *FutGrsElectConsGWh* used in ETKB demand forecast scenario is given in Equation (6.26).

(6.26)
The future gross electricity generation demand is calculated by the formulation given in Equation (6.27).

\[ \text{FutGrsElectGenDmdGWh} = \text{FutGrsElecConsGWh} \times (1 + \text{InternalConsRatio}) \]  \hspace{1cm} (6.27)

Other critical input of the sector given externally as a constant variable is \text{RENPriorityRequested}, which is also the main parameter for the scenario analyses. This variable refers that the needed investment is wanted to be made to the renewables at the rate of \text{RENPriorityRequested}. But, this variable becomes effective at the year 1999. Till 1999, the variable \text{RENinitialPriority} is used in this decision. \text{RENinitialPriority} is accepted as 0.65 per cent historically, which validates the model behavior for 1990-1999. In other words, for 1990 to 1998, 65 per cent of the needed capacity for the future is allocated to the renewables to make investments to construct new power plants. It is assumed that there will be a smooth transition from the initial priority of renewables to the required one in four years from 1999 to 2003. So, a transition effect (TransEff) is used in this process. The formulations given in the following pages will describe the usage of the transition effect in the model. Equation (6.36) gives the values of transition effect graph and its shape is illustrated in Figure 6.9.

![Transition Effect Graph](image_url)

**Figure 6.9. Transition effect**

On the other hand, there would be a potential problem in the renewable sectors. That
is, total potential of the renewables, namely TotRENPotGWh, which is the maximum available capacity to build up new power plants in terms of GWh/year, may not cover the allocated electricity generation demand to the renewables. If the rate of the future electricity generation need allocated to the renewables is greater than the potential of the renewables, the share of TotRENPotGWh in FutGrsElectGenDmdGWh determines the priority of the renewables (RENPriorityAdjusted). This process is called as adjustment. After the adjustment of the priority of renewables, the allocated amount of gross electricity generation need to the renewables (FutRENEnergyGWh) is calculated. The priority of non-renewables is calculated by considering the adjusted priority of renewables. All the calculations of this process are given in the following equations.

\[ RENInitialPriority = 0.65 \] (6.28)

\[ RENPriorityRequested = a \text{ given number between 0 and 1} \] (6.29)

\[ RENSmtthPriorityReq = RENPriorityRequested \times TransEff + RENInitialPriority \times (1 - TransEff) \] (6.30)

\[ RENPriorityAdjusted = \text{IF TIME} < 1999 \text{ THEN} \min(RENInitialPriority, (TotRENpotGWh/FutGrsElectGenDmdGWh)) \text{ ELSE} \min(RENSmthPriorityReq, (TotRENpotGWh/FutGrsElectGenDmdGWh)) \] (6.31)

\[ RENInstFracAdjusted = GTP_{Inst\_Frac} + HP_{Inst\_Frac} + SHP_{Inst\_Frac} + SPIInstFrac + WPInstFrac \] (6.32)

\[ NRENPriority = 1 - RENPriorityAdjusted \] (6.33)

\[ FutRENEnergyGWh = FutGrsElectGenDmdGWh \times RENPriorityAdjusted \] (6.34)

\[ FutNRENEnergyGWh = FutGrsElectGenDmdGWh \times NRENPriority \] (6.35)

\[ TotRENpotGWh = HP_{potNotUsed}GWh_{year} + WP_{potNotUsed}GWh_{Year} + SHP_{potNotUsed}GWh_{year} + GTP_{potNotUsed}GWh_{year} + SP\_potNotUsedGWh_{Year} \] (6.36)
\[ \text{TransEff} = \text{GRAPH}(\text{time})(1990, 0.00), (1991, 0.00), (1992, 0.00), (1993, 0.00), (1994, 0.00), (1995, 0.00), (1996, 0.00), (1997, 0.00), (1998, 0.00), (1999, 0.095), (2000, 0.245), (2001, 0.675), (2002, 0.88), (2003, 1.00) \] (6.37)

6.2.3. Sectors for Non-Renewable Resources and Power Plants

There are four sectors constituting the non-renewables. These are Lignite Power Sector, Hard Coal Power Sector, Oil Power Sector and Natural Gas Power Sector. The structure of each sector is generally the same. Only the abbreviations and units differ, so the differences will be introduced in the content of sub-sections. Only Lignite Power Sector will be explained in detail to give the draft structure of non-renewables in order to avoid repetition. Therefore, in the other sub-sections, the structures and sector equations will be demonstrated without giving any extra information. The data used in the non-renewable sectors of the model are based on the data given in Chapter 3 in the section Non-Renewable Resources and Power Plants in Turkey, and the data given in the previous sections of this chapter.

6.2.3.1. Lignite Power Sector. In Lignite Power Sector, gross electricity generation by Lignite Power Plants, lignite depletion from the reserves and capacity investments for the new ones are conducted. Figure 6.10 illustrates the structure of the Lignite Power Sector. In this section, firstly the variables of the sector seen whose names were abbreviated in the model will be introduced, and then equations will be explained.

The descriptions of the major equations are as follows.

**Stock Variables:**

- \( \text{LigniteReserveTON} \): The amount of lignite reserve in terms of ton that is available to be used in the Lignite Power Plants.

- \( \text{LPIC1\_MW,LPIC2\_MW,LPIC3\_MW} \): Total installed capacity of Lignite Power Plants (MW).

- \( \text{LPUNConsMW} \): Total capacity of the lignite power plants which are under construction (MW).
Figure 6.10. Structure of Lignite Power Sector
- \textit{LP\textunderscore TotalCost}: Total cost realized through installation of new lignite power plants and operation cost arising from electricity generation of the plants (USD).

\textbf{Flow Variables:}
- \textit{LP\_Installed}: The capacity whose installation order was given (MW/year).
- \textit{LP\_Online\_Rate}: The capacity whose construction process is completed (MW/year).
- \textit{LP\_Retire1, LP\_Retire2, LP\_Retire2}: Capacity retirement rate (MW/year).
- \textit{LP\_Install\_Cost}: The flow variable giving the rate of installation cost of LP (USD/year).
- \textit{LP\_Oper\_Cost}: The operation cost for the generated gross electricity by lignite power plants at time \( t \) (USD/year).
- \textit{YearlyLigDep\_TON}: The amount of yearly lignite depletion from the lignite reserve (Ton/year).

\textbf{Converters:}
- \textit{AT1}: Adjustment time for installation process (Year).
- \textit{AT2}: Adjustment time for under construction process (Year).
- \textit{CurLP\_Need\_Alloc\_GWh}: Current gross electricity generation need allocated to lignite power plants in terms of GWh/year.
- \textit{DesiredUC\_LP}: Desired under construction level of the stock LP\_UNCons\_MW (MW).
- \textit{DomGenbyLP\_GWh}: Gross electricity generation which is provided by domestic lignite reserves in terms of GWh/year.
- \textit{DomLigRes\_Pot\_GWh}: Yearly gross electricity generation potential
- **EmisRelbyLP**: of the domestic lignite reserves (GWh/year).

- **FutLPNeedAllocGWh**: The amount of CO₂ equivalent emission released by Lignite Power Plants during the electricity generation process (TON).

- **GrsElecGenbyLPGWh**: Future gross electricity generation need allocated to Lignite Power Sector (GWh/year).

- **InstallLP_MW**: Gross electricity generated by lignite power plants (GWh/year).

- **LigCapFract_Initial**: The lignite power installation need for a given capacity need (MW).

- **LigEmisTONperGWh**: Gross electricity generation ratio of lignite power plants within all sectors used in the allocation of CurLPNeedAllocGWh to Lignite Power Sector for the years 1990-1998 (per cent).

- **Lig Imported TON**: CO₂ equivalent emission release rate of lignite power plants which is given as a constant (TON/GWh).

- **LigProdFr**: The amount of lignite which is imported to be used in electricity generation process (TON).

- **LigResRateInTotal**: Lignite production fraction (per cent).

- **LigSmithCapFract**: The rate of lignite reserve’s electricity generation potential in total electricity generation potential of all non-renewable sectors.

- **LigTotalUsedTON**: Smoothed lignite power capacity installation fraction (per cent).

- **LigUseperGWh**: Total amount of lignite used in the electricity generation process at time t in terms of ton.

- **LigTotalUsedGWh**: The amount of lignite to generate a unit of electricity (TON/GWh).
- **Lig_CapFract**: Gross electricity generation ratio of lignite power plants within all sectors used in the allocation of CurLPNeedAllocGWh to Lignite Power Sector for the years 1999-2020 (per cent).

- **LigPPConsRatio**: The rate of the lignite consumption in the total lignite amount of production used in power plants (per cent).

- **LPAvailability**: The rate of the working hour of the lignite power plants in a year (per cent).

- **LPCapUtil**: Capacity utilization rate of lignite power plants (per cent).

- **LPIC_Delay**: The economical life of lignite power plants (Year).

- **LPInstCostperMW**: Lignite power plant installation cost (USD/MW).

- **LPOperCostperGWh**: Gross electricity generation cost of lignite power plants (USD/GWh).

- **LPUCDelay**: Under construction time of lignite power plants (Year).

- **LP.InstFract**: Installation fraction for lignite power plants within the non-renewables given as a constant for the years 1999-2020 (per cent).

- **LP_Priority**: Lignite power plant installation priority.

- **MaxWorkingHour**: Maximum working hour of power plants in a year (Hour).

- **NeedLP_MW**: The future capacity need allocated to the Lignite Power Sector in terms of MW.

- **TotalLigResGWh**: Lignite reserve’s total electricity generation potential in a determined process time (GWh/year).

- **TotalNonRenReserveGWh**: Total nonrenewable reserves’ electricity
• \textit{TotLPICGWh} \\
  \textit{TotLPIC \_MW} \\
• \textit{YearlyMaxLinProdGWhyear} \\
  \textit{YearlyMaxLigProdTON}

generation potential in a determined process time (GWh/year). \\
: Total gross electricity generation capacity of installed lignite power plants (GWh/year). \\
: Total installed capacity of lignite power plants (MW). \\
: Maximum electricity generation capacity by using the yearly maximum amount of domestic lignite produced (GWh/year). \\
: Maximum amount of domestic lignite production (TON).

There are two input variables driving the sector; \textit{CurLPNeedAllocGWh} and \textit{FutLPNeedAllocGWh}.

The first input of the sector, called \textit{CurLPNeedAllocGWh}, is a rate of the variable CurGrsElectGenAllocbyNationICGWh, the variable coming from the Current Need Sector. For the years 1990-1998, the historical average share of lignite power plants in electricity generation process, namely LigCapFract\_Initial, is used in computation of CurLPNeedAllocGWh. For the remaining period of the simulation, it is assumed that electricity generation need is provided by the sectors in the rate of the sector’s electricity generation capacity in the total after the historical period. Therefore, Lig\_CapFract starts to determine CurLPNeedAllocGWh after the year 1999. But, the transition from the LigCapFract\_Initial to Lig\_CapFract is supposed to be smooth. So, the transition effect (Equation (6.37)) is used in the sector as in all sectors.

The formulations on allocation process of CurGrsElectGenAllocbyNationICGWh to the Lignite Power Sector are given via Equations (6.38)-(6.40).

\[
\text{Lig\_CapFract} = \frac{\text{TotLPICGWh}}{\text{TotGrsCapGWh}}
\] 

(6.38)

\[
\text{LigSmthCapFract} = \text{Lig\_CapFract} \ast \text{TransEff} + \text{LigCapFract\_Initial} \ast (1 - \text{TransEff})
\]

where \text{LigCapFract\_Initial} = .316

(6.39)
\[
\text{CurLPNeedAllocGWh} = \begin{cases} 
\text{IF TIME}<1999 \text{ THEN} \\
(Cur\text{GrsElectGenAllocByNationICGWh}\times \text{LigCapFract}\_\text{Initial}) \text{ ELSE} \\
(Cur\text{GrsElectGenAllocByNationICGWh}\times \text{LigSmthCapFract})
\end{cases}
\] (6.40)

Current electricity generation demand allocated to the Lignite Power Sector can be met if there is sufficient capacity. This is controlled by the formulation given in Equation (6.41).

\[
\text{GrsElecGenbyLPGWh} = \text{MIN} (\text{TotLPICGWh}, \text{CurLPNeedAllocGWh})
\] (6.41)

The stock representing Total Installed Capacity is constructed in the form of third order delay structure. Therefore, there are three stocks, namely LPIC1\_MW, LPIC2\_MW and LPIC3\_MW whose aggregation composes total installed capacity of lignite power plants, symbolized by a converter called TotLPIC\_MW. The initial value of each stock is set by the division of initial installed capacity (WEC TNC, 2000a) by the number of the stocks, three. The same operation is applied to the flows of the stocks. That is, the delay is divided by three for each flow. The related computations are illustrated in Equation (6.42) for stock sets, Equation (6.43) for the flows and Equation (6.45) for the converter. There is also another stock variable, called LPUNCons\_MW, linked to LPIC1\_MW. The capacity of the completed construction flows to the stock LPIC1\_MW through the LP\_Online\_Rate. New installation flows into the stock LPUNCons\_MW through LP\_Installed. These variables are also stated in the following equations set.

**Stocks:**

\[
\begin{align*}
\text{LPIC1}\_\text{MW}(t) &= \text{LPIC1}\_\text{MW}(t - dt) + (\text{LP\_Online\_Rate} - \text{LPRetire1}) \times dt \\
\text{LPIC2}\_\text{MW}(t) &= \text{LPIC2}\_\text{MW}(t - dt) + (\text{LPRetire1} - \text{LPRetire2}) \times dt \\
\text{LPIC3}\_\text{MW}(t) &= \text{LPIC3}\_\text{MW}(t - dt) + (\text{LPRetire2} - \text{LPRetire3}) \times dt \\
\text{LPUNCons}\_\text{MW}(t) &= \text{LPUNCons}\_\text{MW}(t - dt) + (\text{LP\_Installed} - \text{LP\_Online\_Rate}) \times dt
\end{align*}
\]

where,

\[
\begin{align*}
\text{INIT LPIC1}\_\text{MW} &= 4896.2/3 \\
\text{INIT LPIC2}\_\text{MW} &= 4896.2/3 \\
\text{INIT LPIC3}\_\text{MW} &= 4896.2/3 \\
\text{INIT LPUNCons}\_\text{MW} &= 1212
\end{align*}
\] (6.42)
Flows:
\[ LPRetire1 = LPIC1\_MW/(LPIC\_Delay/3) \]
\[ LPRetire2 = LPIC2\_MW/(LPIC\_Delay/3) \]
\[ LPRetire3 = LPIC3\_MW/(LPIC\_Delay/3) \]

where,
\[ LPIC\_Delay = 30 \]
\[ LP\_Online\_Rate = LPUNConsMW/LPUCDelay \]
\[ LP\_Installed = \max(0,\text{InstallLP\_MW}) \] (6.43)

Converter:
\[ \text{TotLPIC\_MW} = LPIC1\_MW+LPIC2\_MW+LPIC3\_MW \] (6.44)

The electricity generation capacity of total installed capacity of lignite power plants (TotLPICGWh) is calculated by the following equation. The availability of lignite power plants is assumed as 90 per cent of the maximum working hour, which is the number of the hours in a year, 8760.

\[ \text{TotLPICGWh} = \text{TotLPIC\_MW}\times\text{LPAvailability}\times\text{LPCapUtil}\times\text{MaxWorkingHour}/1000 \] (6.45)

Electricity generation causes the reserve to reduce at the magnitude of the domestic lignite used in the power plants in terms of ton per year. The yearly domestic lignite usage directly restricted by the yearly lignite production. It is assumed that yearly lignite production can be realized at a fraction of the reserve. This fraction is accepted as 10 per cent. Furthermore, power plants consume the produced lignite at another rate, LigPPlConsRatio since they can be used in the other energy sectors such as in transportation, warming, or in industry etc. It is observed that the amount of lignite used in power plants increases year by year from 1990 to 1998. Therefore, a graphical function is built for this purpose. The value of LigPPlConsRatio for the year 1998 states constant in the following years whereas the shape of the graph LigPPlConsRatio is shown in Figure 6.11. If electricity generation by lignite power requires a lignite magnitude which is greater than yearly domestic lignite production, then the needed lignite is imported to satisfy the electricity generation demand. Related formulations are designated as in the following
equations grouped. Note that initial lignite reserve is calculated by adding the yearly lignite production amounts of 1990 to 1998 to the lignite reserve as of 1998 mentioned in Chapter 3 (see Table 3.2). The process time of the lignite production is accepted as one year.

Stock:

\[ \text{LigniteReserveTON}(t) = \text{LigniteReserveTON}(t - dt) + (- \text{YearlyLigDepTON}) \cdot dt \]

where \( \text{INIT LigniteReserveTON} = (8374372000 + 462457000) \) \hspace{1cm} (6.46)

Flow:

\[ \text{YearlyLigDepTON} = \text{DomGenbyLPGWh} \cdot \text{LigUseperGWh} \]

where \( \text{LigUseperGWh} = 1593 \) \hspace{1cm} (6.47)

Converters:

\[ \text{LigTotalUsedTON} = \text{GrsElecGenbyLPGWh} \cdot \text{LigUseperGWh} \]

\[ \text{DomLigResPotGWh} = \text{YearlyMaxLigProdTON} \cdot \text{LigPPConsRatio} \cdot \text{LigUseperGWh} \]

where,

\[ \text{LigPPConsRatio} = \text{GRAPH(time)}(1990, 0.65), (1991, 0.66), (1992, 0.685), (1993, 0.715), (1994, 0.755), (1995, 0.795), (1996, 0.825), (1997, 0.85), (1998, 0.85) \]

\[ \text{DomGenbyLPGWh} = \min(\text{GrsElecGenbyLPGWh}, \text{DomLigResPotGWh}) \]

\[ \text{YearlyMaxLigProdTON} = \text{LigniteReserveTON} \cdot \text{LigProdFr} \]

where \( \text{LigProdFr} = 0.10 \)

\[ \text{YearlyMaxLigProdGWhyear} = \]

\[ (\text{YearlyMaxLigProdTON} \cdot \text{LigUseperGWh}) / \text{ProcessTime} \]

where \( \text{ProcessTime} = 1 \)

\[ \text{LigImportedTON} = \max(0, (\text{LigTotalUsedTON} - \text{YearlyLigDepTON})) \] \hspace{1cm} (6.48)

The amount of \( \text{CO}_2 \) equivalent emission released electricity generation by lignite power plants are calculated as in Equation (6.49).

\[ \text{EmisRelbyLP} = \text{GrsElecGenbyLPGWh} \cdot \text{LigEmisTONperGWh} \]

where \( \text{LigEmisTONperGWh} = 1112.5 \) \hspace{1cm} (6.49)
Figure 6.11. Consumption ratio of lignite by lignite power plants for the years 1990 to 1998

The second input of the sector, called \( \text{FutLPNeedAllocGWh} \), is a rate of the variable \( \text{FutNRENNeedGWh} \) coming from the Future Need Sector. It signifies the expected capacity of the Lignite Power Sector for the future, that is, for the five year later. The variable \( LP_{InstFract} \) is the fraction which is given externally as a policy making variable. The total of installation fractions in non-renewable sectors is equal to one. In the scenario analysis, the installation fractions will be based on the costs and emissions released. In the essential model, the value of \( LP_{InstFract} \), like other sectors’ installation fractions, is based on the historical data. Priority of Lignite is equal to one. All priorities in the model are equal to one too. This variable is set in the model in order to give an independent priority despite the installation fractions of the sector. It represents the political priority given to the related resource. It may cause distortion in allocation of future electricity need. It means that total of the allocated future electricity needs may not be equal to total future electricity need because of the given priorities.

\[
\text{FutLPNeedAllocGWh} = \text{FutNRENNeedGWh} * LP_{InstFract} * LP_{Priority}
\]

where \( LP_{InstFract} = .53 \) and \( LP_{Priority} = 1 \) \( \text{(6.50)} \)

Firstly, the allocated capacity need to Lignite Power Sector is transformed from GWh/year to MW capacity. Then by considering the existing installed capacity, under
construction capacity and retired capacity, new capacity to be constructed is calculated in the name of variable InstallLP_MW. The following formulations are the models equations used in this process.

\[
NeedLP_{-}MW = \frac{FutLPNeedAllocGWh/LPAvailability/LPCapUtil/MaxWorkingHour*1000}{(6.51)}
\]

\[
InstallLP_{-}MW = (NeedLP_{-}MW-TotLPIC_{-}MW)/AT1 + \frac{(DesiredUC_{-}LP-LPUNConsMW)/AT2+LPRetire3}{6.52}
\]

where AT1=2 and AT2=2

\[
DesiredUC_{-}LP = LPRetire3*LPUCDelay\]

where \(LPUCDelay = 4\) (6.53)

If the value of InstallLP_MW is greater then zero, then installation initiates at the amount of the variable. In this case, the inflow LP_Installed whose formulation is stated in Equation (6.43) gets the value of InstallLP_MW.

Finally, in the cost calculation of the section, there is a stock accumulating the costs occurred during the installation and operation processes. The following equations give the formulations of the cost calculation.

**Stock:**

\[
LPTotalCost(t) = LPTotalCost(t - dt) + (LPInstallCost + LPOperCost) * dt
\]

where,

\[
INIT LPTotalCost = 0
\]

\[
LPInstCostperMW = 1600000
\]

\[
LPOperCostperGWh = 0.025*1000000
\]

(6.54)

**Flows:**

\[
LPInstallCost = LP_{-}Installed*LPInstCostperMW
\]

\[
LPOperCost = GrsElecGenbyLPGWh*LPOperCostperGWh
\]

(6.55)
6.2.3.2. Hard Coal Power Sector. Hard Coal Power Sector has the same structure with the Lignite Power Sector. The structure of this sector is illustrated in Figure 6.12 while all equations of the sector are given in Section A.1. Note that, the abbreviation of 'Hard Coal' is taken as HC in this sector while HCP reflects Hard Coal Power. There is a difference in the structure of the variable *Hard Coal Consumption Fraction* (HCPPConsRatio) from the equivalent variable of Lignite Power Sector. In Lignite Power Sector, it is assumed that the consumption ratio of the lignite produced by lignite power plants is increasing year by year. However, in the Hard Coal Power Sector it is taken as a constant variable with an average fraction, 16 per cent, since the historical behaviors do not show a significant change year by year. It is also assumed that the yearly maximum hard coal production rate will reduce because of the decrease in hard coal reserve by a constant *hard coal production fraction* (HCPProdFr) with the value of five per cent.

Moreover, historical behaviors also show that the yearly increase in Hard Coal Power Capacity can be assumed zero per cent. So, for the historical period of the simulation, 1990 to 1998, this fraction will be considered in the allocation of future electricity generation need to Hard Coal Power Sector.

6.2.3.3. Oil Power Sector. Oil Power Sector’s structure is given in Figure 6.13. The major formulations of the variables belonging to the sector are depicted in Section A.1. The abbreviation OP represents 'Oil Power' in this sector. The different structured variable is the Oil Power Plants’ consumption ratio from the produced oil. It is accepted as a graphical function demonstrated in Figure 6.14. As in Hard Coal Sector, it is also assumed that the yearly maximum oil production rate will reduce because of the decrease in oil reserve by a constant *oil production fraction* (OilProdFr) with the value of five per cent.
Figure 6.12: Structure of Hard Coal Power Sector
Figure 6.13. Structure of Oil Power Sector
Figure 6.14. Consumption ratio of oil by oil power plants from 1990 to 1998

Furthermore, as in the Hard Coal Sector, since the increase in Oil Power Capacity is almost zero in the historical period of the model, the installation fraction for new oil power plants is accepted as zero per cent.

6.2.3.4. Natural Gas Power Sector. Natural Gas Power Sector's structure is given in Figure 6.15. The major equations are shown in Section A.1. The abbreviation NGP means 'Natural Gas Power' in this sector. Note that, the units of the natural gas as a fuel is million m$^3$. The variable NGProdFr, the fraction of natural gas production, is taken as a graphical function illustrated in Figure 6.16. Since the real trend in domestic natural gas production shows a growing behavior, an S-shaped graphical function as production fraction is used in the calculation of yearly maximum natural gas production. On the other hand, the consumption ratio of natural gas produced by power plants (NGPPConsRatio) is assumed as a constant variable opposite to Lignite Power Sector. It is accepted as 60 per cent in average.
Figure 6.15. Structure of Natural Gas Power Sector
6.2.4. Sectors for Renewable Resources and Power Plants

There are five sectors involved under the title of the Renewables. These are Hydropower Sector, Small-Scale Hydropower Sector, Geothermal Power Sector, Wind Power Sector and Solar Power Sector. The structure of each sector is exactly the same. Only the abbreviations differ from sector to sector. In this section, the first sub-section will be explained in detail, all the relationships between the variables will be examined after the introduction of the variables which are classified as stocks, flows and converters. In the other sub-sections, only the structures and equation graphs will be illustrated. The data used in the renewables are explained in Chapter 3, in the section Renewable Resources and Power Plants in Turkey.

6.2.4.1. Hydropower Sector. The structure of the Hydropower Sector is given in Figure 6.17. There are five stocks in the model, three of which represent the installed capacity of hydropower plants, while one is the under construction capacity and the last one is the yearly hydropower potential which is not used. The whole equation set of this sector is given in Section A.1.

The major variables comprised in the Hydropower Sector are defined in the following way.
Figure 6.17. Structure of Hydropower Sector
**Stock variables:**

- **HPIC1MW, HPIC2MW, HPIC3MW**: Total hydropower installed capacity (MW).
- **HP_UC_MW**: Hydropower capacity under construction (MW).
- **HPpotNotUsedGWhyear**: The electricity generation potential of hydropower which has not been in use yet (GWh/year).
- **HPTotalCost**: The total cost realized through installation of hydropower plants and operation cost arising from electricity generation of the plants (USD).

**Flow variables:**

- **HP_Online_Rate**: The rate of the capacity changing its status from the under construction capacity to the installed capacity (MW/year).
- **HPRetire1, HPRetire2, HPRetire3**: The retired capacity of the installed hydropower capacity (MW/year).
- **HP_Pot_Added**: The potential which becomes available by the retirement of the capacity at the rate of outflow Retire3 in terms of GWh/year.
- **HPotUsage**: This is the allocated potential for the initiation of new hydropower plants in terms of GWh/year.
- **HPInstallCost**: The cost occurring by the installation of new capacities (USD/MW).

**Converters:**

- **DesiredUC_HP**: Desired under construction capacity (MW).
- **ElectGenbySmlBigHYDROICGWh**: Total electricity generated by both small and big scale hydropower plants (GWh/year).
- **EmisnRelbyHP**: CO₂ equivalent emission released by hydropower plants (TON).
- FutHPNeedAllocGWh: Future gross electricity generation need allocated to Hydropower Sector.
- GrsElectGenbyHPGWh: Gross electricity generated by hydropower plants.
- HPAvailability: Hydropower plants working hour in a year (per cent).
- HPCapFract_Initial: Historical electricity generation ratio of the hydropower sector within all sectors (per cent).
- HPcapFract: The ratio of the gross electricity generation capacity of hydropower plants within the total capacity of all sectors (per cent).
- HPCapUtil: Capacity utilization ratio for hydropower plants (per cent).
- HPEmisTONperGWh: CO₂ equivalent emission release rate of hydropower plants which is given as a constant (TON/GWh).
- HPFracInitial: The initial installation fraction of the hydropower sector within renewables that is based on the historical data (per cent).
- HPInsCostperMW: Hydropower plant installation cost (USD/MW).
- HPOperCostperGWh: Gross electricity generation cost of hydropower plants (USD/GWh).
- HPIC_Delay: The economical life of hydropower plants (Years).
- HPUC_Delay: Under construction time of hydropower plants (Years).
- HPInitiateGWh: New hydropower capacity initiation rate in terms of GWh/year.
- HP_Inst_Frac: Hydropower plant installation fraction (per cent).
- HPIInstFractRevised: Hydropower plant installation fraction revised.
• *HPSmthCapFrac*: Smoothed hydropower electricity generation fraction (per cent).

• *HPSmthInsFrac*: Smoothed hydropower plant installation fraction (per cent).

• **HP_Poten_Rate**: The share of the hydropower potential in the total renewable potential not used yet (per cent).

• **HP_Priority**: Hydropower plant installation priority.

• **InstallHP_MW**: This is the amount of installation needed to meet the future need in terms of GWh/year.

• **SmlBigHYDROICGWh**: The total of the small-scale and big-scale hydropower capacities in terms of GWh/year.

• **SmlBigHYDROIC_MW**: The total of the small-scale and big-scale hydropower capacities in terms of MW.

• **TotHPICGWh**: Total installed capacity of big-scale hydropower plants (GWh/year).

• **TotHPIC_MW**: Total installed capacity of big-scale hydropower plants (MW).

The starting point in the electricity generation process within the Hydropower Sector is the variable *GrsElectGenbyHPGWh*. The same logic of the non-renewable sectors is also valid for the renewable sectors in electricity generation step.

In the investment step of the sector, although the same structure with the non-renewable sector is used, there is a difference in the structure of installation fractions. In the sectors of the renewables, along the historical period of the simulation time, the initial installation fraction is used to determine the future hydropower electricity generation need. Then a smoothed transition is realized to a new installation fraction which composed of the revised multiplication of the variables **HP_Poten_Rate** and **HP_Priority**. The revision of the new calculated installation fraction **HP_Inst_Frac** is explained in the Future Need Sector. The calculation of *FutHPNeedAllocGWh* is done by using the following equations.
FutHPNeedAllocGWh = IF TIME<1999 THEN (HPFracInitial*FutRENNeedGWh) ELSE (FutRENNeedGWh*HPsmthInsFrac)  
(6.56)

HP_Poten_Rate = HPpotNotUsedGWhyear/TotRENPotGWh  
(6.57)

HP_Inst_Frac = HP_Poten_Rate*HP_Priority  
(6.58)

HPInstFractRevised = HP_Inst_FracRENNInstFracAdjust  
(6.59)

HPsmthInsFrac = (HPFracInitial*(1-TransEff))+(HPInstFractRevised*TransEff)  
(6.60)

Another important difference in the structure that only renewable sectors have is the structure of electricity generation potential of renewable sectors. In non-renewable sectors, there are reserves for each sector, which are waiting to be produced and depleted in the case of electricity generation. However, there are maximum limits on yearly gross electricity potentials for each renewable sector. The total of the installed capacity and under construction capacity is a part of total potential. Therefore, the potential of renewables is defined as the potential not used yet. The own nature of the renewables allows to re-use of the potential even though the utility ends its economic life. That is, a new plant can be constructed to generate electricity at the rate of the capacity of the utility. The following equations give relationships between the sector variables.

\[ HPpotNotUsedGWhyear(t) = \]
\[ HPpotNotUsedGWhyear(t - dt) + (HP_Pot_Added - HPotUsage) * dt \]
where INIT HPpotNotUsedGWhyear = (430000-23147.6)-691.2  
(6.61)

\[ HP_Pot_Added = HPRetire3*HPAvailability*HPCapUtil*MaxWorkingHour \]
(6.62)

\[ HPotUsage = HPinitateGWh \]
(6.63)

\[ HPinitateGWh = \text{MIN}(	ext{MAX}(0,(InstallHP_MW*HPAvailability*HPCapUtil*MaxWorkingHour/1000)), HPpotNotUsedGWhyear) \]
(6.64)
6.2.4.2. Small-Scale Hydropower Sector. The structure of this sector is depicted in Figure 6.18 and equations are given in Section A.1. The sector is almost identical to hydropower sector as in Figure 6.17 discussed above.

6.2.4.3. Geothermal Power Sector. The structure of this sector is given in Figure 6.19 and equations are listed in Section A.1. The sector is almost identical to hydropower sector as in Figure 6.17 discussed above.

6.2.4.4. Wind Power Sector. The structure of this sector is given in Figure 6.20 and equations are listed in Section A.1. The sector is almost identical to hydropower sector as in Figure 6.17 discussed above.

6.2.4.5. Solar Power Sector. Figure 6.21 shows the structure of this sector and equations are illustrated in Section A.1. The sector is almost identical to hydropower sector as in Figure 6.17 discussed above.
Figure 6.18. Structure of Small-Scale Hydropower Sector
Figure 6.21. Structure of Solar Power Sector
7. VERIFICATION AND VALIDATION

The model building step in the system dynamics approach is followed by verification and validation testing. Through verification, the model's consistency with the conceptual model is analyzed. The main purpose of the model validation is to examine whether the behavior of the key parameters of the model are acceptable with respect to the real behaviors.

The purpose of the verification is to confirm the set of variables and their relationships are correctly set in the model and the units of equations match on both sides. Regarding to this concept, relationships between the variables are checked and the dimensional consistency is ensured. There are also control parameters used in the model to control formulation errors. Allocation control variables, fraction control variables and installation control variables are built up in the model for this purpose.

7.1. Sector Isolated Runs and Verification

The aim of this chapter is to demonstrate the validity of the model sector by sector. The validity of the model is provided by obtaining the right behavior for the right reasons. This analysis refers to structural validity of the model. On the other hand, behavior validation tests are accepted as weak tests since they do not provide information on the structural validity of the model.

7.1.1. Lignite Power Sector Runs as Representative of Non-Renewable Sectors

In this sub-sector, extreme condition test is applied at the Lignite Power sector as representative of non-renewable sectors since all non-renewable sectors have the same structure. The inputs of the sector; the gross national electricity need, \textit{CurGrsElectAllocbyNationICGWh}, and the future gross electricity need, \textit{FutNRENNeedGWh}, are to be constant with their initial levels.

However, the capacity and installation fractions are taken as zero to test the
verification of the Lignite Sector. In this case, it is expected that there will be no electricity generation demanded and there will be no installation of new capacities for lignite power.

Note that, both initial and requested renewable priorities are accepted zero to analyze Lignite Power Sector more sensitive.

Figure 7.1 shows the critical variables which provide the verification of the structure. Since there will be no current and future electricity demand from Lignite Power Sector, any electricity generation or investment activity is not expected form the sector. Hence, there will not be any lignite consumption by power plants.

In the demand side, since there is not any future need for Lignite Power Sector, the system will not require any additional capacity to be installed. If there is not any new construction, the existing capacity will decline at the increasing rate of outflow retire3 while its level increases by the inflow coming from the under construction stock LPUUC MW. The inflow LP installed is zero as ordered. Since there is no electricity generation (curve 2), the lignite reserve (curve 5) is not depleted, so its level does not change.

Figure 7.1. Lignite Power Sector in isolated run in case of capacity and installation fractions with zero
If the capacity and installation fractions are taken as one, the highest value of the fraction, all of the current gross electricity generation need is allocated to the lignite power plants to be met and all future need investments are done for the new constructions of lignite power plants. It is expected that total installed capacity will increase gradually, as well as the electricity generation capacity. As a result, both electricity generation and the amount of lignite depleted will increase. Figure 7.2 shows the behaviors of the extreme condition test with capacity and installation fractions with zero.

![Figure 7.2. Lignite Power Sector in isolated run in case of capacity and installation fractions with one](image)

The model-generated behaviors are as expected and rational; thus the sector passes this extreme condition tests.

7.1.2. Hydropower Sector Runs as Representative of Renewable Sectors

In this sub-sector, extreme condition test is applied at the Hydropower sector as representative of renewable sectors since all renewable sectors have the same structure. The inputs of the sector; the gross national electricity need, CurGrsElectAllocbyNationICGWh, and the future gross electricity need, FutRENNeedGWh, are to be constant with their initial levels. However, the capacity and
installation fractions will be set to zero to test the verification of the Lignite Sector. In this case, it is expected that there will be no electricity generation demanded and there will be no installation of new capacities for lignite power. Note that, renewables priority is also taken as one for the extreme condition test.

In the first test, the capacity and installation fractions are set to zero for the entire simulation period. The behavior of the key parameters is given in Figure 7.3. It is expected that the capacity will firstly increase by outflow of under construction capacity while continuously decreasing by retirement. Retirement also causes the potential to increase. New investments can not be done in this analysis as seen in Figure 7.3 by curve 2.

![Graph showing Hydropower Sector in isolated run in case of capacity and installation fractions with zero](image)

Figure 7.3. Hydropower Sector in isolated run in case of capacity and installation fractions with zero

For the capacity and installation fractions with the value of one, all the generation and capacity installations are expected to be done in Hydropower Sector. Figure 7.4 depicts the behavior which is the expected one.

In conclusion, the extreme tests give meaningful results for both renewable and non-renewable sectors.
7.2. Reference Model Behavior and Validation

The base model is simulated under the mentioned set of assumptions, the model structure, graphical functions and defined parameter values. The reference year as the initial year for the simulation is selected as 1990. Since real data are available up to 1998, the validation of the model can be tested for the initial simulation period, 1990 to 1998. This is also accepted as a short term simulation. First of all, the analysis will begin with the general frame of the system, then gradually the scope of the analysis will be specialized and each sector will be examined. The reference model behavior is accepted as the behavior obtained by simulating the model with historical data extrapolated in medium term analysis. It will be described in Section 8.1 in detail.

7.2.1. Validation of Total Installed Capacity and Total Electricity Generation

Figure 7.5 demonstrates the real installed capacity of the years 1990 to 1998 and model variables behavior in the same period. Note that in the model, electricity generations of the sectors are calculated by using the initial capacity fractions which are assumed as the average electricity generation rates of the sectors in total generation between the years
1990 and 1998. This may cause a distortion in the simulation result. In the same way, initial investment fractions are accepted as the average proportions of the capacities in total capacity for each sector between the years 1990 and 1998. Although in the beginning years of the simulation, the model results and real data are close to each other, a little deviation is observed because of the initial fractions after the year 1994 (Figure 7.5). On the other hand, the trend is similar and the model is accepted as valid with respect to this behavior.

![Figure 7.5. Total installed capacity validation](image)

In the electricity generation side, the behaviors given in Figure 7.6 are obtained. It is seen in Figure 7.6 that both gross electricity generation and net electricity generation values obtained from the model are close enough to the historical data set and they have the same growing pattern. It is seen on the figure that the curve of the gross electricity generation demand is the same one of the gross electricity generated. It means that gross electricity need can be met for the years 1990 and 1998.

7.2.2. Validation of Total Installed Capacity and Total Electricity Generation of Non-Renewable and Renewable Sectors

The aggregate capacities of non-renewable sectors and renewable sectors patterns obtained from the model are illustrated in Figure 7.7 with the historical data of each one.
While the model-generated patterns of renewables and non-renewables were fitting to the historical data set, after 1995 an inconsistency occurs. The reason of this change in the behavior is the constant priority given to the renewables whose priority has changed historically year by year in reality.

The electricity generation patterns of all these sectors are demonstrated in Figure 7.8. The behaviors are close enough to the electricity generation, which is satisfactory for behavior validation.

7.2.3. Validation of Non-Renewable Sectors

The total magnitude of each non-renewable resource used in the electricity generation process is shown in Figure 7.13-Figure 7.16.

All figures illustrating the amount of the non-renewable resources used in electricity generation are acceptable according to the real data.

As a consequence, the model-generated behavior patterns of major variables can be accepted valid in the non-renewable sector.

Figure 7.6. Total electricity generation validation
Figure 7.7. Total installed capacity validation for non-renewable and renewable sectors

Figure 7.8. Total gross electricity generation validation for non-renewable and renewable sectors
Figure 7.9. Total installed capacity and gross electricity generation validation for Lignite Power Sector

Figure 7.10. Total installed capacity and gross electricity generation validation for Hard Coal Power Sector
Figure 7.11. Total installed capacity and gross electricity generation validation for Oil Power Sector

Figure 7.12. Total installed capacity and gross electricity generation validation for Natural Gas Power Sector
Figure 7.13. Amount of lignite used in electricity generation process (Ton)

Figure 7.14. Amount of hard coal used in electricity generation process (Ton)
Figure 7.15. Amount of oil used in electricity generation process (Ton)

Figure 7.16. Amount of natural gas used in electricity generation process (million m³)
7.2.4. Validation of Renewable Sectors

The validation of the key variables in renewable sectors can be examined in the following figures.

Note that total hydropower installed capacity is calculated by summing up big and small-scale capacities since the available data involve all hydropower plants in Turkey. The names of the variables representing the total capacity of aggregate hydropower capacity and its electricity generation are respectively \textit{SmlBigHYDRO ICMW} and \textit{ElectGenbySmlBigHYDROICGWh} in figures.

The results of the validation tests for renewables are also adequate with respect to the real data in the behavioral concept. Consequently, the validation tests for major variables for which historical data exist have been completed.

Figure 7.17. Total installed capacity and gross electricity generation validation for Hydropower Sector
Figure 7.18. Total installed capacity and gross electricity generation validation for Geothermal Power Sector

Figure 7.19. Total installed capacity and gross electricity generation validation for Wind Power Sector
8. SIMULATION EXPERIMENTS AND ANALYSIS OF RESULTS

A starting point in the model is the gross electricity consumption at current year. It determines the current electricity generation as well as the future need. It also affects the amount of the depletion and import of primary energy resources. There are two different gross electricity consumption forecasts discussed in the energy sector of Turkey. The first one is prepared by ETKB in 1998 while the other is revealed by DPT in 1993 (Figure 2.3, Figure 2.4). Each forecast has been extrapolated to the year 2050 for a long term analysis (Figure 6.5, Figure 6.6).

The model analysis will be based on the mentioned forecasts to be used in the model as the current and future electricity consumption in term of GWh/year. For the each forecast curve, a number of scenario analyses will be made. Firstly, a medium term simulation will be done, from 1990 to 2015. In the model, DT is accepted as 0.25.

In creation of the scenarios, some decision parameters are considered in the model listed as follows.

Decision parameters of the model:

1. Renewables Priority Requested (RENPriorityRequested) (see Section 6.2.2)
2. Non-Renewable Installation Fractions (see Section 6.2.3)
   2.1. Lignite Power Installation Fraction (Lig InstFract)
   2.2. Natural Gas Power Installation Fraction (NG InstFract)
   2.3. Oil Power Installation Fraction (OP InstFract)
   2.4. Hard Coal Installation Fraction (HC InstFract)
3. Conservation Scenario
   3.1. Network Losses (NetworkLossRatio)
   3.2. Savings (SavingRatio)

Each scenario will be analyzed by giving different values to the selected combinations of the variables. The scenario alternatives considered are given in Table 8.1.
In all model simulations, except the ones using historical parameters, the electricity generation decision is automatically changed by a transition from initial capacity fractions to the capacity proportion system at the year 1999. It means that, all sectors generate electricity in proportion to their electricity generation capacity within the total with respect to current gross electricity generation demand.

In the same way, initial installation fractions are phased out starting with year 1999 and different scenario fractions are started to be used.

In conclusion, implementations of the scenarios begin from the year 1999 in a smooth way. The term from 1990 to 1998 is called the historical period.

### 8.1. Future Projections of Historical Policies

In this section, both ETKB demand curve and DPT demand curve will be analyzed via historical installation fractions. That is, both installation fractions and capacity fractions will be the same as those of 1990-1998. These fractions are called as initial ones in the model. The initial capacity fractions whose sum is equal to one that determine the allocation of current gross electricity generation need to the sectors are assumed as in Table 8.2. The initial capacity investment fractions for the renewables and non-renewables separately are assumed as in Table 8.3.
Table 8.2. Initial capacity fractions of the sectors

<table>
<thead>
<tr>
<th>Lignite Power Plants</th>
<th>0.316</th>
<th>Hydropower Plants</th>
<th>0.393</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hard Coal Power Plants</td>
<td>0.024</td>
<td>Small Scale Hydropower Plants</td>
<td>0.011</td>
</tr>
<tr>
<td>Oil Power Plants</td>
<td>0.068</td>
<td>Geothermal Power Plants</td>
<td>0.001</td>
</tr>
<tr>
<td>Natural Gas Power Plants</td>
<td>0.187</td>
<td>Wind Power Plants</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Solar Power Plants</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 8.3. Initial capacity investment fractions of the sectors

<table>
<thead>
<tr>
<th>Lignite Power Plants</th>
<th>0.53</th>
<th>Hydropower Plants</th>
<th>0.971</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hard Coal Power Plants</td>
<td>0</td>
<td>Small Scale Hydropower Plants</td>
<td>0.027</td>
</tr>
<tr>
<td>Oil Power Plants</td>
<td>0</td>
<td>Geothermal Power Plants</td>
<td>0.002</td>
</tr>
<tr>
<td>Natural Gas Power Plants</td>
<td>0.47</td>
<td>Wind Power Plants</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Solar Power Plants</td>
<td>0</td>
</tr>
</tbody>
</table>

**ETKB demand forecast scenario:** Since the total renewable sector capacity has the biggest portion in total, most of the new capacity investments are done in this direction. Figure 8.1 illustrates capacity levels of total sectors (non-renewable and renewable capacity) while Figure 8.2 presents total gross electricity demands, generations and imports.

In Figure 8.2, it is observed that there are electricity imports after 1998. The import begins with the value 356.92 GWh and ends with 98,667.19 GWh/year in 2015. It is apparent that the total gross capacity (curve 1) is not completely used in (curve 2) to meet the demand (curve 3). Since the historical fraction taken as constant numbers are not affected by the electricity generation capacity of the sectors, current electricity generation allocation to the sectors via the historical data is not a robust one after the year 1998. Although total gross capacity is higher than the demand till year 2007, the electricity generation is smaller than the demand. While total electricity generation capacity and electricity generation demand are 237,168.38 GWh and 238,967.74 GWh respectively, electricity generation realizes with 199,526.58 GWh. This reveals a 39,441.16 GWh electricity import, although it should be 1,799.36 GWh. Furthermore, electricity import begins in 1998 with 356.92 GWh. This situation proves the problem with continuing the historical allocation.
Figure 8.1. Total installed capacity (MW) for ETKB demand forecast scenario

Figure 8.2. Gross electricity capacity, generation, demand and import (GWh) for ETKB demand forecast scenario

Since the reference behavior of the model is accepted as the behavior obtained by history based policy analysis, Figure 8.2 gives the reference behavior of the model for all ETKB demand forecast scenarios.
The gross capacities of renewable sectors are illustrated in Figure 8.3. As seen in the figure, most of the investments have been made to hydropower plants. The capacity levels of non-renewable sectors are presented in Figure 8.4. It is seen that natural gas and lignite power capacities grow while the others are decreasing.

Figure 8.3. Installed capacities of renewable sectors (GWh) for ETKB demand forecast scenario

Figure 8.4. Installed capacities of non-renewable sectors (GWh) for ETKB demand forecast scenario
Figure 8.5 shows the level of total of installation and operation costs and yearly total emission values. Figure 8.6 gives the amounts of fuel imports. It is apparent that, only natural gas is imported. It is reasonable since Turkey’s natural gas production is very low (see Table 3.5).

Figure 8.5. Total cost and emission for ETKB demand forecast scenario

Figure 8.6. Fuel imports (Ton) for ETKB demand forecast scenario
**DPT demand forecast scenario:** Figure 8.7 illustrates the patterns of total capacity, electricity generation and electricity import. The general patterns are similar to the previous scenario patterns. Only the levels of some variables are different but still quite close to each other. DPT forecast ends at a lower level demand than ETKB forecast of 2015. However, electricity import begins at the same year with the value 169.76 GWh/year in 1998. In 2015, electricity import reaches the value 9,036.37 GWh/year. These levels are lower than the ones in the previous scenario.

Total capacity reaches 366,862.86 GWh at 2015 whereas the level of capacity as of 2015 is 396,388.97 GWh in the first scenario. It is also observed that the gross electricity generation demand stays lower than the capacity until 2008. In that year, a 41,972.54 GWh electricity import occurs while the discrepancy between the capacity and generation is just 2,462.29 GWh. After 2008, the capacity can not satisfy the demand. The reference behavior of the model is accepted as the behavior demonstrated in Figure 8.7 for all DPT demand forecast scenarios. Other distinctive graphs are illustrated in Figure 8.8- Figure 8.12 for comparison.

![Image of Figure 8.7](image-url)
Figure 8.8. Total installed capacity (MW) for DPT demand forecast scenario

Figure 8.9. Installed capacities of renewable sectors (GWh) for DPT demand forecast scenario
Figure 8.10. Installed capacities of non-renewable sectors (GWh) for DPT demand forecast scenario

Figure 8.11. Total cost and emission for DPT demand forecast scenario
8.2. Policy Analysis

There are three main policies examined in this section. These are as follows:

1. **Renewable/ non-renewable equally weighted policy**
2. **Renewable oriented policy**
3. **Non-renewable oriented policy**

Each policy is analyzed by giving different non-renewable installation fractions. These are cost based non-renewable installation fractions, emission based non-renewable installation fractions and combined cost and emission non-renewable installation fractions.

8.2.1. Renewable/Non-Renewable Equally Weighted Policy

8.2.1.1. Cost Based Non-Renewable Installation Policies. Cost oriented scenario requires future electricity generation demand be allocated to non-renewables according to each sectors' cost fractions. Cost fractions are obtained by taking the ratios of each sectors' installation costs in their sum, then taking the inverse of each ratio. The cost fractions used as installation fractions in non-renewable sectors are computed as follows. The initial
allocation fractions are given in Table 8.3. The installation costs for each non-renewable sector were given in Section 3.1.

- Lignite Power Installation Fraction: 19%
- Hard Coal Power Installation Fraction: 21%
- Oil Power Installation Fraction: 15%
- Natural Gas Power Installation Fraction: 45%

In the model, it is assumed that there is a smooth transition from old to new fractions. This transition begins in 1999 and ends in 2003.

On the other hand, after 1998, renewable sectors make investments to construct new capacities according to proportional share of their potentials in total. There is also a smooth transition to the new potential-based installation fractions. The ratios of the potentials continuously change because of new installations and retirements.

The electricity generation need allocation system also changes by the usage of new capacity fractions. New capacity fractions are calculated by taking proportions of electricity generation capacity of each sector in the total of them. There is not any differentiation as renewables and non-renewables. All sector capacities are evaluated as a part of the whole. The smooth transition system is used to pass to new ones. The historical capacity fractions are given in Table 8.2.

**ETKB demand forecast scenario:** This scenario gives priority to renewables 50 per cent, the same as non-renewables after year 1999. The future gross need is allocated according to the priority levels of sectors. Then, within each sector group, the allocated future need is allocated to the sectors involved in the group.

Within this frame, the electricity generation results of the simulation can be observed in Figure 8.13 and Figure 8.14.

It is seen in Figure 8.13 that a huge investment has been made to the renewable sectors, so the capacity has increases sharply and reaches 128,091.89 MW in 2015. It is
also important that the renewable power plants work with a low availability. In order to generate the same amount of electricity, renewable sectors generally require higher capacity than the non-renewable ones. Therefore, electricity generation curves will not increase so sharp, as it can be seen in Figure 8.14. It is also seen that there is not any considerable electricity import.

![Graph](image1)

**Figure 8.13.** Total installed capacity (MW) for ETKB demand forecast scenario

![Graph](image2)

**Figure 8.14.** Gross electricity capacity, generation, demand and import (GWh) for ETKB demand forecast scenario
Since the new capacity investments are based on potential ratios after 1999 in renewable sectors, the ones who have the biggest proportion in total potential in terms of GWh/year, will be invested with the highest fraction. Hence, the allocation amount of future gross electricity need to renewable sectors will cause high investments with respect to installed capacities of each sector. Note that, most of the renewable sectors have very low level initial installed capacities. As a result, we observe that there is excess installed capacity after year 2002, gradually increasing and reaching to about 25 per cent in year 2010.

Figure 8.15 shows that total capacity of renewable sectors increases and electricity generation is mostly met by renewables. On the other hand, investments to non-renewable sectors go on while electricity generations by non-renewable sectors decrease through this policy.

Figure 8.15. Installed capacities and electricity generations by renewables and non-Renewables (GWh) for ETKB demand forecast scenario

Figure 8.16 demonstrates total cost generated and emission released. It is seen that total cost is rather higher than the result of reference model. Its value is almost four times of the reference runs value. Total emission released at 2015 is approximately 13 per cent higher than the reference run emission level at the same year.
**DPT demand forecast scenario**: The same analysis has been done by using DPT future gross electricity need projections. The results are more optimistic than the previous scenario. That is, lower capacity has installed, so lower costs and emissions have come out, and the need has been met during the simulation time. But as in the previous scenario, there is again excess installed capacity. Figure 8.17 shows the outputs of the simulation runs for this scenario.
8.2.1.2. Emission Based Non-Renewable Installation Policies. Emission based fractions are generated for the non-renewable sectors and assigned as installation fractions which are computed from emission figures given in Figure 3.4 as follows:

- Lignite Power Installation Fraction: 21%
- Hard Coal Power Installation Fraction: 21%
- Oil Power Installation Fraction: 29%
- Natural Gas Power Installation Fraction: 29%

**ETKB demand forecast scenario:** If the future non-renewable capacity need allocation to non-renewable sectors with emission based fractions, Oil Power Sector and Natural Gas Power Sector get the highest investments within the non-renewable group. Therefore, electricity generation level of natural gas is the highest one in non-renewables.

![Graph](image)

Figure 8.18. Non-renewable sector installed capacities (GWh) for ETKB demand forecast scenario

Total emission and non-renewable sector emissions released are shown in Figure 8.19. If we compare total emission level with the reference model results, it is seen that this policy results in higher emission level. Figure 8.19 shows that most of the emissions are released by electricity generation in lignite power plants.
Figure 8.19. Emission levels of whole system and non-renewable sectors for ETKB demand forecast scenario

The total cost of whole system and the non-renewable sector costs are illustrated in Figure 8.20. We observe that total cost is quite higher than the reference model’s cost level. Total cost of lignite power sector has the biggest share in total cost.

Figure 8.20. Cost levels of whole system and non-renewable sectors for ETKB demand forecast scenario
**DPT demand forecast scenario**: To compare the cost and emission results with the others, the following figures are examined. The same behavior as the previous run is obtained in this analysis.

Figure 8.21. Emission levels of whole system and non-renewable sectors for DPT demand forecast scenario

Figure 8.22. Cost levels of whole system and non-renewable sectors for DPT demand forecast scenario
8.2.1.3. Combined Cost & Emission Non-Renewable Installation Policies. In this stage, both installation and operation costs and emission levels are standardized, and combined effects are obtained as installation fractions used in the non-renewable sectors. The assigned fractions listed in Table 8.4.

The calculation system of each operation cost based installation fractions is the same as installation cost based fractions. Operations costs are given in Section 3.1. The fractions obtained are given in Table 8.4. This table also shows the order of calculations of combined effect fractions.

Table 8.4. Combined cost and emission based installation fractions

<table>
<thead>
<tr>
<th>NON-RENEWABLES</th>
<th>INSTALLATION COST FRACTIONS %</th>
<th>OPERATION COST FRACTIONS %</th>
<th>EMISSION FRACTIONS %</th>
<th>product</th>
<th>COMBINED FRACTIONS %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lignite Power Plants</td>
<td>19</td>
<td>34</td>
<td>21</td>
<td>0.01357</td>
<td>20</td>
</tr>
<tr>
<td>Natural Gas Power Plants</td>
<td>45</td>
<td>28</td>
<td>29</td>
<td>0.03654</td>
<td>55</td>
</tr>
<tr>
<td>Oil Power Plants</td>
<td>15</td>
<td>24</td>
<td>21</td>
<td>0.01058</td>
<td>16</td>
</tr>
<tr>
<td>Coal Power Plants</td>
<td>21</td>
<td>24</td>
<td>21</td>
<td>0.06678</td>
<td>100</td>
</tr>
<tr>
<td>TOTAL</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

From the combined cost and emission effect fractions listed in Table 8.4 that the natural gas sector is the most optimum sector to make investment relative to the other sectors within non-renewables. Then lignite follows the hard coal sector, and so on so forth.

**ETKB demand forecast scenario:** It is seen in Figure 8.23 that the scenario does not yield electricity import. The capacity is too high with respect to reference behavior and there is a big gap between capacity and generation. Total emission released, shown in Figure 8.24, is a little higher than reference behavior result. The levels of the fuel imports are also depicted in Figure 8.25 for this scenario.

**DPT demand forecast scenario:** The levels of the cost and emission depicted in Figure 8.26 are compared with the levels of the variables of emission based scenario shown in Figure 8.21 and Figure 8.22. It is observed that emission levels get almost the same values at the end of the simulation whereas this scenario gives better result in the cost
side. Fuel import levels are also illustrated in Figure 8.25.

Figure 8.23. Total capacity, electricity generation, demand and import for ETKB demand forecast scenario

Figure 8.24. Emission levels of whole system and non-renewable sectors for ETKB demand forecast scenario
Figure 8.25. Fuel imports for ETKB demand forecast scenario

Figure 8.26. Total cost and emission for DPT demand forecast scenario
8.2.2. Renewable Oriented Policy

Renewable Oriented Scenario aims to give all the priority for new investments to the renewable sectors in the future from 1999 to 2015. The future need sector has been revised for this purpose. Figure 8.28 shows the structure of the revised Future Electricity Need Sector.

Figure 8.27. Fuel imports for DPT demand forecast scenario

Figure 8.28. The structure of the revised future electricity need sector for renewable oriented scenarios
If the value of the variable *GlobalPotInvestment* is greater than zero, then future investments can be made after 1999. At 1999, the allocation system also changes and all future needs are supposed to be met by renewables. But, new allocation system comes to scene in a smooth way. The amounts of future investments made to the sectors are calculated via the following equations.

\[
FutRENNeedGWh = \text{IF time<1999 THEN} \\
(FutGrsElectDmdGWh - FutRENNeedGWh) \text{ ELSE} \\
((FutGrsElectDmdGWh-FutRENNeedGWh)*(1-TransEff)+0*TransEff) \\
\text{(8.1)}
\]

\[
FutRENNeedGWh = \text{IF TIME<1999 THEN} \\
\text{min(InitRENFutGrsDmdAlloc,TotRENPotGWh) ELSE} \\
\text{min(SmithRENFutGrsDmdAllocGWh,TotRENPotGWh)} \\
\text{(8.2)}
\]

\[
GlobalPotInvestment = \\
(FutGrsElectDmdGWh-TotGrsCapGWh)/AT1+TotRetirementGWh \\
\text{(8.3)}
\]

\[
InitRENFutGrsDmdAlloc = FutGrsElectDmdGWh*RENinitialPriority \\
\text{(8.4)}
\]

\[
RENinitialPriority = 0.65 \\
\text{(8.5)}
\]

\[
ReqRENFutGrsDmdAlloc = FutGrsElectDmdGWh-TotNRENCGWh \\
\text{(8.6)}
\]

\[
\text{SmithRENFutGrsDmdAllocGWh = if (GlobalPotInvestment>0) then} \\
(ReqRENFutGrsDmdAlloc*TransEff+ InitRENFutGrsDmdAlloc*(1-TransEff)) \text{ else 0} \\
\text{(8.7)}
\]

\[
\text{TotRetirementGWh =} \\
\text{GTPRetire3GWh+HCPRetire3GWh+HPRetire3GWh+LPRetire3GWh+} \\
\text{NGPRetire3GWh+OPRetire3GWh+SHPRetire3GWh+SPRetire3GWh+WPRetire3GWh} \\
\text{(8.8)}
\]

8.2.2.1. Cost Based Non-Renewable Installation Policies.

*ETKB demand forecast scenario:* In Figure 8.29, the curve 5 (GlobalPotInvestment)
illustrates the discrepancy between the future need and the expected capacity. Total electricity generated (curve 2) and the current electricity generation demand (curve 3) are showing exactly the same output behavior.

Figure 8.30 gives the costs and emissions with the amounts of generated electricity by renewables and non-renewables. It is apparent that accumulated cost through this policy is rather higher than the cost of the reference behavior, although emission level is a little lower than the reference model.

It is observed that, installed capacity of solar power sector increases quite fast. Since solar potential has the greatest proportion in the total renewable potentials, most of the investments have been made in this sector. It is also important that solar power plants work with only 30 per cent availability rate. Figure 8.32 presents the change in total capacities and electricity generation levels of renewable and non-renewable sectors while renewable sectors' capacity can be observed in Figure 8.31. As policy requires, there is no investment to non-renewable sectors after 2003.

![Figure 8.29. Gross electricity capacity, generation, demand and import (GWh) for ETKB demand forecast scenario](image-url)
Figure 8.30. Total cost and emission for ETKB demand forecast scenario

Figure 8.31. Installed capacities of renewable sectors (MW) for ETKB demand forecast scenario
Figure 8.32. Installed capacities and electricity generations (GWh) by Renewables and Non-Renewables for ETKB demand forecast scenario

**DPT demand forecast scenario:** The same analysis done previously for ETKB demand forecast scenario is evaluated by taking DPT's gross electricity consumption forecasts in this scenario. The results follow the same behavior of previous scenario's result with lower variable levels. The outputs can be observed in Figure 8.33. Comparing to reference behavior, total gross capacity becomes 464,579.38 GWh where reference model's capacity is 366,862.86. There is no electricity import with the application of this policy. But, a huge capacity excess occurs as it can be seen from the gap between curve 1, curve 2 and curve 3. The cost is also higher then the cost obtained in reference model. However, total emission is 46,000,000 tons lower than the reference model emission as of 2015.

**8.2.2.2. Emission Based Non-Renewable Installation Policies.**

**ETKB demand forecast scenario:** This scenario is supposed to reveal the minimum total emission level amongst the other scenarios which use ETKB's demand forecast. It is observed in Figure 8.34 that total emission level is lower than the reference run level. This scenario also reveals the one of the lowest total cost within the scenario results with respect to reference model.
Figure 8.33. Gross electricity capacity, generation, demand (GWh) and total cost and emission for DPT forecast scenario.

Figure 8.34. Emission levels of whole system and sector groups for ETKB demand forecast scenario.
Figure 8.35. Cost levels of whole system and sector groups for ETKB demand forecast scenario

**DPT demand forecast scenario:** This scenario is also supposed to result in minimum total emission amongst the other scenarios which use DPT's demand forecast. The results seen in Figure 8.36 are lower than the reference model results.

Figure 8.36. Total cost and emission for DPT demand forecast scenario

8.2.2.3. Combined Cost & Emission Based Non-Renewable Installation Policies.

**ETKB demand forecast scenario:** Total capacity and generation variables behave in the
same way of previous policy results shown in Figure 8.37. This policy only causes total capacity to get a little higher level. Renewable sectors generate almost the total of the cost in this scenario as seen in Figure 8.38. The total emission released as at the end of simulation (Figure 8.39) is quite lower than the one obtained in the previous policy run as seen in Figure 8.24.

Figure 8.37. Total electricity capacity, generation, demand and imports (GWh) for ETKB demand forecast scenario

Figure 8.38. Cost levels of whole system and sector groups for ETKB demand forecast scenario
Figure 8.39. Emission levels of whole system and sector groups in ETKB demand forecast scenario

**DPT demand forecast scenario:** Total cost and emission results are rather similar to Figure 8.37 results as seen in Figure 8.40.

Figure 8.40. Total electricity capacity, generation, demand, and total cost and emission for DPT demand forecast scenario
8.2.3. Non-Renewable Oriented Policy

Non-Renewable Oriented Scenario uses the same mentality of the Renewable Oriented Scenario. It gives all priority for new investments to the non-renewable sectors in the future, from 1999 to 2015. The future need sector has been also revised for this purpose. Figure 8.41 demonstrates the new diagram of Future Need Sector. If the value of \( \text{GlobalPotInvestment} \) is greater than zero, then future investments can be done after 1999. At 1999, all future needs are supposed to be met by non-renewable sectors. But, the change in allocation system realizes in a smooth way. The amounts of future investment made to the sectors are calculated via the following equations. Some revisions have also been made in the equations of Future Need Sector.

\[
\text{FutRENNeedGWh} = \begin{cases} 
\text{InitNRENFutGrsDmdAlloc} + \\
\text{FutRenNotAllocated} \end{cases} \text{ ELSE } \text{SmtNRENFutGrsDmdAllocGWh} 
\]

(8.9)

\[
\text{FutRENNeedGWh} = \begin{cases} 
\text{TIME} < 1999 \text{ THEN } \\
\min(\text{InitRENFutGrsDmdAlloc}, \text{TotRENPotGWh}) \text{ ELSE } \\
\min((\text{InitRENFutGrsDmdAlloc} \times (1-\text{TransEff}) + 0^*\text{TransEff}), \text{TotRENPotGWh}) 
\end{cases} 
\]

(8.10)

Figure 8.41. The structure of the revised future electricity need sector for non-renewable oriented scenarios.
\[
\text{FutRenNotAllocated} = \text{InitRENFutGrdsDmdAlloc} - \text{FutRENNeedGWh} \tag{8.11}
\]

\[
\text{GlobalPotInvestment = (FutGrdsElectDmdGWh - TotGrdsCapGWh)/AT1 + TotRetirementGWh} \tag{8.12}
\]

\[
\text{InitRENFutGrdsDmdAlloc} = \text{FutGrdsElectDmdGWh} \times (1 - \text{RENInitialPriority}) \tag{8.13}
\]

\[
\text{InitRENFutGrdsDmdAlloc} = \text{FutGrdsElectDmdGWh} \times \text{RENEnergyPriority} \tag{8.14}
\]

\[
\text{RENEnergyPriority} = 0.65 \tag{8.15}
\]

\[
\text{RENInstFracAdjust} = \frac{\text{GTP}_\text{Inst}_\text{Frac} + \text{HP}_\text{Inst}_\text{Frac} + \text{SHP}_\text{Inst}_\text{Frac} + \text{SPIInstFrac} + \text{WPIInstFrac}}{\text{ReqRENFutGrdsDmdAlloc} - \text{FutGrdsElectDmdGWh} - \text{TotRENICGWh}} \tag{8.16}
\]

\[
\text{SmthRENFutGrdsDmdAllocGWh} = \begin{cases} 
\text{(ReqRENFutGrdsDmdAlloc} \times \text{TransEff} + \text{InitRENFutGrdsDmdAlloc} \times (1 - \text{TransEff})) & \text{if} \ (\text{GlobalPotInvestment} > 0) \\
0 & \text{else} 
\end{cases} \tag{8.17}
\]

\[
8.2.3.1. \text{ Cost Based Non-Renewable Installation Policies.}
\]

**ETKB demand forecast scenario:** The responses given by this simulation run are illustrated in the following figures. Figure 8.42 shows that total capacity (curve 1) will be barely sufficient to meet the electricity generation demand (curve 3) after year 2013. The final level of electricity import is 5,603.23 GWh which is lower than the reference model’s import level in 2015.

The electricity generation levels of non-renewable and renewable sectors are also illustrated in Figure 8.42 with curve 4 and 5 to see the behaviors. Total electricity generation level of renewable sectors decreases by the decrease in their capacity. Since there is no investment made to the renewable sectors, future need is assumed to be met by non-renewables.
Figure 8.42. Gross electricity capacity, generation, demand, non-renewable and renewable sector generations (GWh) for ETKB demand forecast scenario

Figure 8.43. Total installed capacities of non-renewables and renewables, total cost and emission for ETKB demand forecast scenario

The cost level as of 2015 is 45 per cent higher than the reference cost level. Moreover, total emission is 67 per cent higher than the reference emission level.

The behaviors of each sector's fuel imports are also given in Figure 8.63. In the
reference model, only natural gas is imported. But, this policy also results in the imports of hard coal and oil beside natural gas.

![Diagram](Figure 8.44. Fuel Imports for ETKB demand forecast scenario)

**DPT demand forecast scenario:** DPT forecast curves depicting total installed capacities for each sector groups are shown in Figure 8.45. In the same figure, total cost and total emission levels are also depicted in order to compare to the previous scenario and reference model behaviors. Figure 8.45 displays that gross electricity generation capacity will be insufficient to meet the demand after the year 2013 with 109.83 GWh capacity gap.

8.2.3.2. Emission Based Non-Renewable Installation Policies.

**ETKB demand forecast scenario:** Opposite to the previous renewable oriented scenario analysis, this scenario results in the highest emission level within the emission based policy as seen in Figures 8.46 and 8.47.

**DPT demand forecast scenario:** This scenario results in lower cost and emission levels than the previous scenario. It reveals almost two time higher emission and cost levels than the reference model results as seen in Figure 8.48.
Figure 8.45. Total electricity capacity, generation and demand, and total cost and emission for DPT demand forecast scenario

Figure 8.46. Cost levels of whole system and sector groups for ETKB demand forecast scenario
Figure 8.47. Emission levels of whole system and sector groups for ETKB demand forecast scenario

Figure 8.48. Total cost and emission for DPT demand forecast scenario

8.2.3.3. Combined Cost & Emission Based Non-Renewable Installation Policies.

*ETKB demand forecast scenario*: Through this policy, it is seen in Figures 7.50 and 7.51 that while total cost as at the end of simulation year is lower than the result of renewable-
oriented policy, emission level released by this policy is quite higher. The levels of fuel imports are illustrated in Figure 8.52. Note that, total gross electricity demand and generation behaviors (Figure 8.49) are almost the same as in Figure 8.42.

Figure 8.49. Total electricity capacity, generation, demand, and total cost and emission for ETKB demand forecast scenario

Figure 8.50. Cost levels of whole system and sector groups for ETKB demand forecast scenario
**Figure 8.51.** Emission levels of whole system and sector groups for ETKB demand forecast scenario

**Figure 8.52.** Fuel imports for ETKB demand forecast scenario

**DPT demand forecast scenario:** Total cost and emission levels are illustrated in Figure 8.53 as informative curves ending with different results at the end of simulation term. With respect to the reference behavior, both total cost and emission levels get high
values at the end of simulation. The import amounts of non-renewable fuels are also illustrated in Figure 8.54.

![Graph of Total Cost vs. Emission for DPT demand forecast scenario](image)

**Figure 8.53.** Total cost and emission for DPT demand forecast scenario

![Graph of Fuel Imports for DPT demand forecast scenario](image)

**Figure 8.54.** Fuel imports for DPT demand forecast scenario

The comparison of the values of final major variables of each run discussed in Sections 8.1 and 8.2 is illustrated in Table 8.5. As a summary, at the end of simulation, in
year 2015, it is observed that gross electricity demand can be satisfied by total install
capacity with negligible electricity imports for all policies. But, there are capacity excesses
occurring with renewable/non-renewable equally weighted policy, renewable oriented
policy and historical policy. In Table 8.5, it is observed that the minimum level of
accumulated emission can be obtained by renewable oriented policy with emission based
non-renewable installation. Furthermore, non-renewable oriented policy with combined
cost and emission non-renewable installation policy gives the minimum level of
accumulated cost as at 2015. But, note that in non-renewable oriented policies there is
significant fuel imports (as seen already in the graphs discussed) not included in the above
cost figures, implying that these latter underestimate the total costs of non-renewable
policies. Also note that "electricity import" is shown as a separate variable in the table, and
its cost is not included in the accumulated cost entry. Therefore, cumulative costs in the
base run significantly underestimate the actual total cost in cases where there are electricity
imports (i.e. BASE RUN)

8.3. Conservation Scenario

In this section, it assumed that a conservation policy will be applied throughout the
country. Two aspects of conservation policies will be examined.

The first assumption is based on consumption efficiency. Electricity saving by all
consumers will be promoted via different methods and a 10 per cent saving is assumed to
be realized in total. For this purpose a "savings effect" has been developed and presented
in Figure 8.55. There are two curves as current savings effect and future savings effect. It is
assumed that current savings effect plays its role on current consumption after the year
2000. Its value reaches 10 per cent in 2015. 15 year-delay to have a stable saving ratio is
assumed to be an acceptable time since the social attitudes may not change so easily. On
the other hand, technological development has different aspects. It may affect electricity
consumption both in compounding way and in draining way. So, to estimate the dynamics
of savings is a broad and complex issue.

In this project, it is assumed that 10 per cent saving can be realized in 15 years from
2000 to 2015. When calculating the future investments, savings effect has to be considered.
<table>
<thead>
<tr>
<th></th>
<th>Historical Policy Continued (BASE RUN)</th>
<th>Renewable and Non-Renewable Equally Weighted Policy</th>
<th>Renewable Oriented Policy</th>
<th>Non-Renewable Oriented Policy</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Yearly Gross Electricity Demand (GWh)</strong></td>
<td>418,315</td>
<td>418,315</td>
<td>418,315</td>
<td>418,315</td>
</tr>
<tr>
<td><strong>Yearly Total Gross Capacity (GWh)</strong></td>
<td>396,388</td>
<td>501,404</td>
<td>501,351</td>
<td>412,711</td>
</tr>
<tr>
<td>Cost Based Non-Renewable Installation</td>
<td>499,544</td>
<td>495,285</td>
<td>499,944</td>
<td>408,168</td>
</tr>
<tr>
<td>Emission Based Non-Renewable Installation</td>
<td>499,944</td>
<td>501,418</td>
<td>408,168</td>
<td>414,901</td>
</tr>
<tr>
<td><strong>Yearly Gross Electricity Generation (GWh)</strong></td>
<td>319,647</td>
<td>418,315</td>
<td>418,315</td>
<td>412,711</td>
</tr>
<tr>
<td>Cost Based Non-Renewable Installation</td>
<td>418,315</td>
<td>418,315</td>
<td>408,168</td>
<td>414,901</td>
</tr>
<tr>
<td>Emission Based Non-Renewable Installation</td>
<td>418,315</td>
<td>418,315</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost&amp;Emission Based Non-Renewable Installation</td>
<td>418,315</td>
<td>418,315</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Capacity Utilization (%)</strong></td>
<td>81</td>
<td>84</td>
<td>83</td>
<td>100</td>
</tr>
<tr>
<td>Cost Based Non-Renewable Installation</td>
<td>84</td>
<td>84</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emission Based Non-Renewable Installation</td>
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<td>83</td>
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<td></td>
</tr>
<tr>
<td>Cost&amp;Emission Based Non-Renewable Installation</td>
<td>84</td>
<td>83</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Accumulated Electricity Import (GWh)</strong></td>
<td>676,578</td>
<td>1,001</td>
<td></td>
<td>9,279</td>
</tr>
<tr>
<td>Cost Based Non-Renewable Installation</td>
<td>968</td>
<td>1,001</td>
<td></td>
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</tr>
<tr>
<td>Emission Based Non-Renewable Installation</td>
<td>978</td>
<td>1,013</td>
<td></td>
<td>28,661</td>
</tr>
<tr>
<td>Cost&amp;Emission Based Non-Renewable Installation</td>
<td>966</td>
<td>996</td>
<td></td>
<td>4,411</td>
</tr>
<tr>
<td><strong>Accumulated Emission (TON)</strong></td>
<td>2,494,745,945</td>
<td>2,530,792,503</td>
<td>2,077,950,814</td>
<td>3,148,299,523</td>
</tr>
<tr>
<td>Cost Based Non-Renewable Installation</td>
<td>2,518,259,709</td>
<td>2,076,055,485</td>
<td></td>
<td>3,131,547,098</td>
</tr>
<tr>
<td>Emission Based Non-Renewable Installation</td>
<td>2,518,857,427</td>
<td>2,078,248,515</td>
<td></td>
<td>3,132,302,283</td>
</tr>
<tr>
<td>Cost&amp;Emission Based Non-Renewable Installation</td>
<td>2,518,857,427</td>
<td>2,078,248,515</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Accumulated Cost (USD)</strong></td>
<td>181,998,202,073</td>
<td>903,577,816,723</td>
<td>1,319,034,250,869</td>
<td>264,914,478,716</td>
</tr>
<tr>
<td>Cost Based Non-Renewable Installation</td>
<td>920,722,722,471</td>
<td>1,320,243,730,763</td>
<td></td>
<td>288,889,548,266</td>
</tr>
<tr>
<td>Emission Based Non-Renewable Installation</td>
<td>895,648,108,291</td>
<td>1,318,435,346,773</td>
<td></td>
<td>252,628,869,496</td>
</tr>
<tr>
<td>Cost&amp;Emission Based Non-Renewable Installation</td>
<td>895,648,108,291</td>
<td>1,318,435,346,773</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Therefore, current savings effect is transformed to future savings effect by shifting the beginning year to five year earlier. That is, while computing the future electricity generation demand the value of current savings effect as of 2000 will be taken into account in 1995.

![Graph showing current and future savings effect](image)

Figure 8.55. Current and future savings effect

The second aspect of the conservation policies is about the network losses. It is assumed that network losses can be reduced to 10 per cent from 18 per cent in ten years. Figure 8.56 demonstrates the assumed change in network losses. The change begins in 2000 and ends in 2010, and then the network losses ratio stays stable at 10 per cent. 10 year-delay is assumed sufficient to improve the network. Note that, the variable network losses is used in the calculation of total available net electricity generation capacity for end use (TotNetCapAvlforEndUseGWh), total domestic net electricity consumption (TotDomNetElecConsGWh) and current electricity consumption (CurNetElecConsGWh).

In the following parts of this section, the conservation policy will be applied through different resource priority scenarios on the base of cost and emission oriented scenario for a long term analysis, from 1990 to 2045. The extrapolated demand forecasts of ETKB and DPT demand curves will be used in this analysis. To construct a Pessimistic Scenario the exponential trend regression results of ETKB demand forecast is used, whereas the
quadratic trend regression curve of DPT demand forecast is selected as *Optimistic Scenario* (see Figures 6.4 and 6.5). Note that the existing demand forecast values as well as historical ones are included within the demand forecast curves, regenerated as optimistic and pessimistic for 1990 to 2050.

![Network Losses Ratio](image)

**Figure 8.56.** Network losses effect

### 8.3.1. Future Projections of Historical Installation Policies

The reference model behaviors are examined by long term simulation.

**Pessimistic demand forecast scenario:** It is observed in Figure 8.57 that the existing policies with pessimistic scenario yield a growing electricity import (curve 4) even though conservation policies are applied after 1999. In 2045, the gross electricity import becomes 689,040.34 GWh which is 27 per cent of the gross electricity demand. Total cost and emission levels are illustrated in Figure 8.58.

Figure 8.59 shows the historical policy behaviors without savings for long term simulation. It is observed that 765,890.71 GWh electricity import occurs if existing policy continued. Note that, total cost and emission levels reach $1.37 \times 10^{12}$ USD and $1.17 \times 10^9$ Tons respectively.

Consequently, the conservation scenario under historical policy yields 90 per cent reduction in total cost level, emission level and electricity import for each with respect to
historical policy without savings as of 2045.

Figure 8.57. Total electricity capacity, generation, demand and import (GWh) with savings for pessimistic demand forecast scenario.

Figure 8.58. Total cost and emission with savings for pessimistic demand forecast scenario.
Figure 8.59. Total electricity capacity, generation, demand and import (GWh) without savings for pessimistic demand forecast scenario

**Optimistic demand forecast scenario:** Figure 8.60 demonstrates that there will be 355,243.1 GWh electricity import in 2045, while gross electricity generation demand is 1,352,126.21 GWh.

Compared to the pessimistic demand forecast scenario, it is observed that electricity import in the optimistic scenario is 51.5 per cent of the amount of electricity import that obtained in the pessimistic scenario in 2045.

Total cost and emission levels are illustrated in Figure 8.61. In 2045, total cost with the value 7.31x10^{11} USD is 58 per cent of total cost obtained in the pessimistic scenario, whereas total emission with the value 5.69x10^{8} Tons is 53.6 per cent of total emission obtained in pessimistic scenario. It is apparent that optimistic scenario gives better results with respect to electricity import, cost and emission.

Figure 8.62 presents the future projections of the historical policies without savings. The level of electricity import is 395,730.61 GWh in 2045. Note that total cost and total emission levels reach 8.055x10^{11} USD and 6.311x10^{8} Tons.
Figure 8.60. Total electricity capacity, generation, demand and import with savings (GWh) for optimistic demand forecast scenario

Figure 8.61. Total cost and emission without savings for optimistic demand forecast scenario
Figure 8.62. Total electricity capacity, generation, demand and import without savings (GWh) for optimistic demand forecast scenario

8.3.2. Renewable/Non-Renewable Equally Weighted Policy Combined Cost and Emission Based Non-Renewable Installation.

Pessimistic demand forecast scenario: It is seen in Figure 8.63 that electricity need is met by the capacity. Since the installation policy changes in 1998, firstly a capacity excess occurs but after 2012 the capacity balances itself in the long term. It is also important that the decrease in network losses also decreases the discrepancy between capacity and electricity generation. It is apparent that there is no electricity import. Figure 8.64 shows the levels of total cost and emission.

Figure 8.65 gives the fuel imports. It is observed that natural gas imports start in 2001 and grows after 2004. Note that, lignite imports start in 2043.

Without savings, pessimistic scenario gives the behavior given in Figure 8.66. It is observed that if conservation policies are not applied, total gross capacity level will be 299,000 GWh more than the run conservation policy applied (Figure 8.63).
Figure 8.63. Total electricity capacity, generation, demand and import with savings for pessimistic demand forecast scenario.

Figure 8.64. Total cost and emission with savings for pessimistic demand forecast scenario.
Figure 8.65. Fuel imports with savings for pessimistic demand forecast scenario

Figure 8.66. Total electricity capacity, generation, demand, and total cost and emissions without savings for pessimistic demand forecast scenario

**Optimistic demand forecast scenario:** Figure 8.67 shows that the capacity is enough to meet the demand, and allocation allows sectors to generate the required energy. But it seems, after 2045 electricity import will occur. Total cost and released emission levels are
below the results of previous run. It is seen in Figure 8.68 that lignite is not imported in this scenario. Without savings, the behaviors given in Figure 8.69 are obtained.

Figure 8.67. Total electricity capacity, generation, demand, and total cost and emissions with savings for optimistic demand forecast scenario

Figure 8.68. Fuel imports with savings for optimistic demand forecast scenario
Figure 8.69. Total electricity capacity, generation, demand, and total cost and emissions without savings for optimistic demand forecast scenario

8.3.3. Renewable Oriented Policy Combined Cost and Emission Based Non-Renewable Installation

**Pessimistic demand forecast scenario:** It is observed in Figure 8.70 that the capacity obtained in this scenario is higher than the pessimistic scenario with a 1,720,000 GWh (Figure 8.63). Total installed capacities are given in Figure 8.71.

Total cost and emission levels are given in Figure 8.72. The cost obtained in this scenario is $1.40 \times 10^{13}$ USD whereas the cost given in Figure 8.84 is $8.3 \times 10^{12}$ USD. On the other hand, emission level with $5.02 \times 10^8$ Tons as of 2045 is lower than the level of the emission with $1.34 \times 10^9$ Tons shown in Figure 8.64.

This scenario reveals that only natural gas import occurs but it gives a decreasing behavior as seen in Figure 8.73.

The behavior of the model is obtained as in Figure 8.74 if conservation is not applied.
Figure 8.70. Total electricity capacity, generation, demand and import with savings for pessimistic demand forecast scenario

Figure 8.71. Total installed capacity, non-renewable and renewable sector capacities with savings for pessimistic demand forecast scenario
Figure 8.72. Total cost and emission with savings for pessimistic demand forecast scenario

Figure 8.73. Fuel imports with savings for pessimistic demand forecast scenario
Figure 8.74. Total installed capacity, non-renewable and renewable sector capacities without savings for pessimistic demand forecast scenario

**Optimistic demand forecast scenario:** The same behaviors are given by this scenario with lower level of variables with respect to previous run. Moreover, the comparison of the results of renewable oriented and equal priority policies gives the similar comments as in the previous run. Following results are the outputs of this scenario run.

Figure 8.75. Total electricity capacity, generation, demand and import with savings for optimistic demand forecast scenario
Figure 8.76. Total installed capacity, non-renewable and renewable sector capacities with savings for optimistic demand forecast scenario

Figure 8.77. Total cost and emission with savings for optimistic demand forecast scenario
Figure 8.78. Fuel imports with savings for optimistic demand forecast scenario

The behavior of the model is obtained as in Figure 8.79 if conservation is not applied in the long term.

Figure 8.79. Total installed capacity, non-renewable and renewable sector capacities without savings for optimistic demand forecast scenario
8.3.4. Non-Renewable Oriented Policy Combined Cost and Emission Based Non-Renewable Installation

**Pessimistic demand forecast scenario:** It is observed in Figures 8.80-8.82 that total capacity is completely used to meet the demand. The behavior in Figure 8.80 designates that there would be a growing electricity import after 2045.

Total cost is the medium one within the pessimistic scenario runs with the level $1.71 \times 10^{12}$ USD. But this scenario gives the highest emission level with $2.3 \times 10^9$ Tons as it can be seen in Figure 8.82.

It is observed in Figure 8.83 that lignite import starts earlier than the other pessimistic scenario runs.

**Optimistic demand forecast scenario:** It is apparent that the same behaviors and the comments given in the previous scenario are also valid for this scenario run, only within optimistic demand forecast scenarios. Figures 8.85-8.88 give the behaviors of this run in detail. Note that Figure 8.89 illustrates the model behavior analyzed without savings.

Figure 8.80. Total electricity capacity, generation, demand and import with savings for pessimistic demand forecast scenario.
Figure 8.81. Total installed capacity, non-renewable and renewable sector capacities with savings for pessimistic demand forecast scenario

Figure 8.82. Total cost and emission with savings for pessimistic demand forecast scenario
Figure 8.83. Fuel imports with savings for pessimistic demand forecast scenario

Figure 8.84. Total electricity capacity, generation, demand and total cost and emission without savings for pessimistic demand forecast scenario
Figure 8.85. Total electricity capacity, generation, demand and import with savings for optimistic demand forecast scenario

Figure 8.86. Total installed capacity, non-renewable and renewable sector capacities with savings for optimistic demand forecast scenario
Figure 8.87. Total cost and emission with savings for optimistic demand forecast scenario

Figure 8.88. Fuel imports with savings for optimistic demand forecast scenario
Figure 8.89. Total installed capacity, non-renewable and renewable sector capacities without savings for optimistic demand forecast scenario

In conclusion, Table 8.6 and Table 8.7 summarize the final values of main variables examined in this section for pessimistic and optimistic demand scenarios with and without savings in the long term. The tables also illustrate base run results for each scenario for comparison. It is seen that renewable oriented policy has the second lowest capacity utilization, after the base run, with 89 per cent under pessimistic scenario and 94 per cent under optimistic scenario. The minimum accumulated emission level is obtained by renewable-oriented scenario, which is 42 per cent lower than the level of base run in pessimistic demand scenario and 35 per cent lower in optimistic demand scenario with savings. On the other hand, lower accumulated costs are realized by non-renewable oriented policy at 2045, both in the pessimistic and the optimistic demand forecast scenarios. Just as in Table 8.5, observe again that costs of electricity import are not included in the cumulative cost figures, so that cumulative costs in the BASE RUN (involving large imports) significantly underestimate the actual costs.

Also observe that when all policies are compared under with and without savings scenarios (upper and lower halves of Table 8.6 and 8.7) installed capacities, gross electricity generation, cumulative costs and emissions are all reduced in the savings case.
### Table 8.6. Comparative values of main variables at year 2045 for pessimistic (very high) demand forecast scenario

<table>
<thead>
<tr>
<th></th>
<th>Historical Policy Continued (BASE RUN)</th>
<th>Renewable and Non-Renewable Equally Weighted Policy</th>
<th>% change relative to base run</th>
<th>Renewable Oriented Policy</th>
<th>% change relative to base run</th>
<th>Non-Renewable Oriented Policy</th>
<th>% change relative to base run</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Without Savings</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Yearly Gross Electricity Demand (GWh)</td>
<td>2,809,338</td>
<td>2,809,338</td>
<td>2,809,338</td>
<td>2,809,338</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Yearly Total Gross Capacity (GWh)</td>
<td>2,602,731</td>
<td>2,970,358</td>
<td>3,163,656</td>
<td>2,795,393</td>
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</tr>
<tr>
<td>Yearly Gross Electricity Generation (GWh)</td>
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<td>2,809,338</td>
<td>2,809,338</td>
<td>2,795,393</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Capacity Utilization (%)</td>
<td>79</td>
<td>95</td>
<td>89</td>
<td>100</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accumulated Electricity Import (GWh)</td>
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<td>-100</td>
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<td>-96</td>
</tr>
<tr>
<td>Accumulated Cost (USD)</td>
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<td>15,721,991,293,058</td>
<td>1,046</td>
<td>1,898,757,227,591</td>
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</tr>
<tr>
<td><strong>With Savings</strong></td>
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<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Yearly Gross Electricity Demand (GWh)</td>
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<td>2,529,809</td>
<td>2,529,809</td>
<td>2,529,809</td>
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</tr>
<tr>
<td>Yearly Total Gross Capacity (GWh)</td>
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<td>Yearly Gross Electricity Generation (GWh)</td>
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<td>2,529,809</td>
<td>2,529,809</td>
<td>2,515,024</td>
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</tr>
<tr>
<td>Capacity Utilization (%)</td>
<td>79</td>
<td>95</td>
<td>89</td>
<td>100</td>
<td></td>
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<tr>
<td>Accumulated Electricity Import (GWh)</td>
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<td>-100</td>
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</tr>
<tr>
<td>Accumulated Emission (TON)</td>
<td>16,680,081,913</td>
<td>20,243,447,316</td>
<td>21</td>
<td>9,729,129,559</td>
<td>-42</td>
<td>32,212,823,513</td>
<td>93</td>
</tr>
<tr>
<td>Accumulated Cost (USD)</td>
<td>1,240,717,418,284</td>
<td>8,025,681,996,049</td>
<td>547</td>
<td>13,970,948,914,251</td>
<td>1,026</td>
<td>1,714,442,356,681</td>
<td>38</td>
</tr>
</tbody>
</table>
Table 8.7. Comparative values of main variables at year 2045 for optimistic (very low) demand forecast scenario

<table>
<thead>
<tr>
<th>Without Savings</th>
<th>Historical Policy Continued (BASE RUN)</th>
<th>Renewable and Non-Renewable Equally Weighted Policy</th>
<th>% change relative to base run</th>
<th>Renewable Oriented Policy</th>
<th>% change relative to base run</th>
<th>Non-Renewable Oriented Policy</th>
<th>% change relative to base run</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yearly Gross Electricity Demand (GWh)</td>
<td>1,501,528</td>
<td>1,501,528</td>
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<td>1,501,528</td>
<td>1,501,528</td>
<td></td>
<td>1,501,528</td>
</tr>
<tr>
<td>Yearly Total Gross Capacity (GWh)</td>
<td>1,420,951</td>
<td>1,533,403</td>
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<td>1,590,207</td>
<td>1,476,057</td>
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<td>1,476,057</td>
</tr>
<tr>
<td>Yearly Gross Electricity Generation (GWh)</td>
<td>1,105,797</td>
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<td>1,501,528</td>
<td>1,476,057</td>
<td></td>
<td>1,476,057</td>
</tr>
<tr>
<td>Capacity Utilization (%)</td>
<td>78</td>
<td>98</td>
<td>94</td>
<td>100</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accumulated Electricity Import (GWh)</td>
<td>7,371,804</td>
<td>1,297</td>
<td>-100</td>
<td>1,412</td>
<td>-100</td>
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<td>587,710</td>
</tr>
<tr>
<td>Accumulated Emission (TON)</td>
<td>13,540,711,546</td>
<td>16,407,529,094</td>
<td>21</td>
<td>8,490,454,871</td>
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<td></td>
<td>25,082,438,190</td>
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<tr>
<td>Accumulated Cost (USD)</td>
<td>805,473,888,495</td>
<td>5,484,268,474,385</td>
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<td>9,279,686,328,850</td>
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<td>1,237,725,731,971</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>With Savings</th>
<th>Historical Policy Continued (BASE RUN)</th>
<th>Renewable and Non-Renewable Equally Weighted Policy</th>
<th>% change relative to base run</th>
<th>Renewable Oriented Policy</th>
<th>% change relative to base run</th>
<th>Non-Renewable Oriented Policy</th>
<th>% change relative to base run</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yearly Gross Electricity Demand (GWh)</td>
<td>1,352,126</td>
<td>1,352,126</td>
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<td>1,352,126</td>
<td>1,352,126</td>
<td></td>
<td>1,352,126</td>
</tr>
<tr>
<td>Yearly Total Gross Capacity (GWh)</td>
<td>1,280,081</td>
<td>1,379,085</td>
<td></td>
<td>1,429,623</td>
<td>1,327,630</td>
<td></td>
<td>1,327,630</td>
</tr>
<tr>
<td>Yearly Gross Electricity Generation (GWh)</td>
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<td>1,352,126</td>
<td></td>
<td>1,352,126</td>
<td>1,327,630</td>
<td></td>
<td>1,327,630</td>
</tr>
<tr>
<td>Capacity Utilization (%)</td>
<td>78</td>
<td>98</td>
<td>95</td>
<td>100</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Accumulated Electricity Import (GWh)</td>
<td>6,576,103</td>
<td>1,494</td>
<td>-100</td>
<td>1,625</td>
<td>-100</td>
<td></td>
<td>550,976</td>
</tr>
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<td>Accumulated Emission (TON)</td>
<td>12,391,102,780</td>
<td>14,915,439,602</td>
<td>20</td>
<td>7,994,882,560</td>
<td>-35</td>
<td></td>
<td>22,559,635,043</td>
</tr>
<tr>
<td>Accumulated Cost (USD)</td>
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<td>4,902,961,936,587</td>
<td>571</td>
<td>8,203,130,670,341</td>
<td>1,022</td>
<td></td>
<td>1,119,037,155,027</td>
</tr>
</tbody>
</table>
9. CONCLUSION AND FURTHER RESEARCH

The electricity need of Turkey has been met mostly by non-renewable sources. The major ones are lignite, completely produced from national resources, and natural gas, whose portion is growing in the sector year by year. But, the use of fossil fuels decreases the domestic reserves and causes the sectors to import fuel. Hydropower, as a renewable energy source, is one of the main electricity providers in the electric power sector in Turkey. There are other new and clean renewable resources with their considerable potentials.

The main goal of this study is to investigate whether renewable sectors can play an important role in the total electricity generation, to meet the electricity need of Turkey in the future, with different allocation policies. This question is investigated by constructing a dynamic simulation model which represents the energy planning dynamics in electric power sector in Turkey. There are two main electricity demand forecasts, generated by Ministry of Energy and National Resources (ETKB) and State Planning Agency (DPT). Since these forecasts are different, all scenario analyses are done for both of them. The validation tests are mostly based on information published by World Energy Council Turkish National Committee in 1998. Since much of the data on technological aspects of power plants and fuel production rates differ year by year, the averages of the related parameters are used in the model. Nevertheless, validity tests show that the model-generated behavior is consistent with the literature and available data and the model adequately represents the electricity generation, power plant installation and reserve depletion structures of Turkey.

Extensive scenario analysis is done with four strategic policies in new capacity installation: use of historical installation fractions; renewable oriented installation, non-renewable oriented installation and renewable/non-renewable equal priority. Simulations are done for medium term (until 2015) and long term (until 2045). In the medium term simulation analysis, at the end of simulation period it is observed that gross electricity demand can be satisfied by total installed capacity with negligible electricity imports in all
policies. On the other hand, there is excess capacity occurring with renewable/non-renewable equally weighted policy, renewable oriented policy and historical policy.

Renewable oriented policy emission based non-renewable installation gives the minimum level of accumulated emission. This policy has the second lowest capacity utilization, after the base run. New renewable sectors join electric power sector through significant investments. Especially the capacity of solar power sector increases amongst the renewables, and hydropower follows it.

The minimum level of accumulated cost by the end of medium simulation term can be obtained by non-renewable oriented policy with combined cost and emission non-renewable installation criterion. It is important that in non-renewable oriented policies there are significant fuel imports.

If the renewable and non-renewable sectors have equal priorities for future investments, electricity import does not occur and renewable sectors capacity grows significantly. There will be a balanced investment allocation among renewable sectors.

In case of emission oriented scenarios, the same fundamental behavior emerges with different costs and emissions. Generally, emission-based allocation scenarios create lower emission level, but high installation and operation costs. With respect to the emission level, the best results are obtained from renewable-oriented scenarios, but they produce high capacity installation costs.

The emission level and installation and operation costs of non-renewable sectors are finally averaged to form a combined installation criterion. Renewable and non-renewable policies result in different levels of capacity, cost and emission. Renewable oriented allocation yields the highest installed capacity, but it creates excess capacity as in the cost based policy results.

A conservation oriented scenario is implemented by assuming a gradual reduction in network losses and an increase in consumption efficiency. Long term analysis, until year 2045 is done with or without conservation assumptions over a period of 10 years.
Combined cost and emission based non-renewable installation policy is used under two projections; optimistic and pessimistic ones. In the analysis of pessimistic scenario, it is observed that only non-renewable oriented policy carried risk of not meeting the demand. Both renewable-oriented and equal priority assignment provide adequate electricity import. In the optimistic scenario, the risk of not meeting the demand is less than the pessimistic one. However, the installed capacity, hence the costs are lower in the pessimistic scenario. The installed capacity in optimistic scenario is almost half of that in the pessimistic scenario, even though there is no electricity import in either case. Furthermore, some fuel imports in pessimistic scenario do not occur in the optimistic one. On the other hand, lower accumulated costs are incurred by non-renewable oriented policy in 2045, for both the pessimistic and the optimistic demand forecast scenarios. When all policies are compared under with and without savings scenarios, it is seen that installed capacity, gross electricity generation, cumulative costs and emissions are all reduced with the savings case.

Since energy production is a very broad and complex issue, the model can be extended in different aspects. The demand side of the model can be influenced by the capacity excess and a feedback loop can be constructed between installed capacity and demand. Furthermore, the demand can be enhanced in itself. Moreover, emission and cost levels can directly influence the capacity installation and electricity generation fractions, constituting further feedback loops that allow more adaptive installation and allocation decision.
APPENDIX A: MODEL STRUCTURE AND EQUATIONS

The complete model and all equations of the model are provided in this appendix. Model structure includes nine sectors as energy sources; Lignite Power, Natural Gas Power, Oil Power, Hard Coal Power, Hydropower, Small-Scale Hydropower, Wind Power, Geothermal Power and Solar Power. There are also three sectors; Current Need, Future Need and Cost and Emissions Sector. Each of them can be observed on Figure A.1. Section A.1 gives the equations of the whole model.
A.1. Equation Set of Model

Costs and Emissions

\[ \text{TotalCost} = \text{TotalCostoNREN} + \text{TotalCostoREN} \]
\[ \text{TotalCostoNREN} = \text{HCPTotalCost} + \text{LPTotalCost} + \text{NGPTotalCost} + \text{OPTotalCost} \]
\[ \text{TotalCostoREN} = \text{GTPTotalCost} + \text{HPTotalCost} + \text{SHPTotalCost} + \text{SPTotalCost} + \text{WPTotalCost} \]
\[ \text{TotEmisNREN} = \text{EmisRelbyHCP} + \text{EmisRelbyLP} + \text{EmisRelbyNGP} + \text{EmisRelbyOP} \]
\[ \text{TotEmisREN} = \text{EmisRelbyGTP} + \text{EmisRelbyHP} + \text{EmisRelbySHP} + \text{EmisRelbyWP} + \text{EmisRelbySP} \]
\[ \text{TotEmission} = \text{TotEmisNREN} + \text{TotEmisREN} \]

CURRENT ELECTRICITY NEED

\[ \text{CurActGrsElectConsGWh} = \text{CurGrsElectConsGWh} \times (1 - \text{CurSavingsEffect}) \]
\[ \text{CurGrsElectGenAllocbyNationICGWh} = \text{MIN} (\text{CurGrsElectGenDmdGWh}, \text{TotGrsCapGWh}) \]
\[ \text{CurGrsElectGenDmdGWh} = \text{CurActGrsElectConsGWh} \times (1 + \text{InternalConsRatio}) \]
\[ \text{CurNetElectConsGWh} = \text{CurActGrsElectConsGWh} \times (1 - \text{NetworkLossRatio}) \]
\[ \text{GrsElectImpExpectedGWh} = \text{CurGrsElectGenDmdGWh} - \text{CurGrsElectGenAllocbyNationICGWh} \]
\[ \text{GrsElectImpRealizdGWh} = \text{CurGrsElectGenDmdGWh} - \text{TotGrsElectGenGWh} \]
\[ \text{InternalConsRatio} = 0.034 \]
\[ \text{TotDomNetElectConsGWh} = \text{TotNetElectGenGWh} \times (1 - \text{NetworkLossRatio}) \]
\[ \text{TotGrsCapGWh} = \text{TotNRENICGWh} + \text{TotRENICGWh} \]
\[ \text{TotGrsElectGenGWh} = \text{TotGrsNENElecGenGWh} + \text{TotGrsRENElecGenGWh} \]
\[ \text{TotGrsNNElecGenGWh} = \text{GrsElectGenbyHCPGWh} + \text{GrsElectGenbyNGPGWh} + \text{GrsElectGenbyOilGWh} + \text{GrsElectGenbyLPGWh} \]
\[ \text{TotGrsRENElecGenGWh} = \text{GrsElectGenbyGTPGWh} + \text{GrsElectGenbyHPGWh} + \text{GrsElectGenbySHPGWh} + \text{GrsElectGenbySPGWh} \]
\[ \text{TotCMW} = \text{TotREN_IC_MW} + \text{TotREN_IC_MW} \]
\[ \text{TotNetCapAvlforEndUsGWh} = \text{TotNetCapGWh} \times (1 - \text{NetworkLossRatio}) \]
\[ \text{TotNetCapGWh} = \text{TotGrsCapGWh} \times (1 - \text{InternalConsRatio}) \]
\[ \text{TotNetElecGenGWh} = \text{TotGrsElectGenGWh} \times (1 - \text{InternalConsRatio}) \]
\[ \text{TotNRENICGWh} = \text{TotHCPICGWh} + \text{TotLPICGWh} + \text{TotNGICGWh} + \text{TotOPICGWh} \]
\[ \text{TotREN_IC_MW} = \text{TotHPCIC_MW} + \text{TotLPIC_MW} + \text{TotNGPIC_MW} + \text{TotOPIC_MW} \]
\[ \text{TotRENICGWh} = \text{TotGTPI CGWh} + \text{TotHPCICGWh} + \text{TotSHPICGWh} + \text{TotSPICGWh} + \text{TotWPI CGWh} \]
\[ \text{TotREN_IC_MW} = \text{TotGTPI M_W} + \text{TotHPI M_W} + \text{TotSHPIC_MW} + \text{TotSPIC_MW} + \text{TotWPI M_W} \]

\[ \text{CurSavingsEffect} = \text{GRAPH(time)} \]
\[ (1990, 0.00), (1991, 0.00), (1992, 0.00), (1993, 0.00), (1994, 0.00), (1995, 0.00), (1996, 0.00), (1997, 0.00), (1998, 0.00), (1999, 0.00), (2000, 0.0025), (2001, 0.0055), (2002, 0.009), (2003, 0.012), (2004, 0.0155), (2005, 0.0215), (2006, 0.0295), (2007, 0.0375), (2008, 0.0465), (2009, 0.0575), (2010, 0.072), (2011, 0.0825), (2012, 0.089), (2013, 0.093), (2014, 0.0965), (2015, 0.0995), (2016, 0.0995), (2017, 0.0995), (2018, 0.0995), (2019, 0.0995), (2020, 0.0995) \]
\[ \text{NetworkLossRatio} = \text{GRAPH(time)} \]
FUTURE ELECTRICITY NEED

FutActGrsConsGWh = FutGrsElcConsGWh*(1-FutSavingsEffect)

FutGrsElectDmdGWh = FutActGrsConsGWh*(1+InternalConsRatio)

FutRENNeedGWh = FutGrsElectDmdGWh*NERNPriority

FutRENNeedGWh = FutGrsElectDmdGWh*NERNPriorityAdjusted

NERNPriority = 1-RENPriorityAdjusted

RENInitialPriority = 0.65

RENIInstFracAdjusted = GTP_Last_Frac*HP_Last_Frac+SHP_Inst_Frac+SPInstFrac+WPIInstFrac

NERNPriorityAdjusted = IF TIME<1999 THEN min(RENInitialPriority,(TotRENPotGWh/FutGrsElectDmdGWh)) ELSE
min(RENSmithPriorityReq,(TotRENPotGWh/FutGrsElectDmdGWh))

RENSmithPriorityReq = RENPriorityRequested*TransEff+RENIInstPriority*(1-TransEff)

TotRENPotGWh = HPnotNotUsedGWhYear+WPotnotNotUsedGWhYear+SHPnotNotUsedGWhYear+GTPnotNotUsedGWhYear+SPnessNotNotUsedGWhYear

FutSavingsEffect = GRAPH(time)

(1990, 0.00), (1991, 0.00), (1992, 0.00), (1993, 0.00), (1994, 0.00), (1995, 0.003), (1996, 0.006), (1997, 0.009), (1998, 0.012), (1999, 0.016), (2000, 0.022), (2001, 0.03), (2002, 0.038), (2003, 0.047), (2004, 0.058), (2005, 0.072), (2006, 0.083), (2007, 0.099), (2008, 0.093), (2009, 0.097), (2010, 0.1), (2011, 0.1), (2012, 0.1), (2013, 0.1), (2014, 0.1), (2015, 0.1)

GEOTHERMAL POWER

GTPIC1_MW(t) = GTPIC1_MW(t - dt) + (GTP_Online_Rate - GTPRetire1) * dt

INIT GTPIC1_MW = 15/3

INFLOWS:

GTP_Online_Rate = GTPUC_MW/GTPUC_Delay

OUTFLOWS:

GTPRetire1 = GTPIC1_MW/(GTPIC_Delay/3)

GTPIC2_MW(t) = GTPIC2_MW(t - dt) + (GTPRetire1 - GTPRetire2) * dt

INIT GTPIC2_MW = 15/3

INFLOWS:

GTPRetire1 = GTPIC1_MW/(GTPIC_Delay/3)

OUTFLOWS:

GTPRetire2 = GTPIC2_MW/(GTPIC_Delay/3)

GTPIC3_MW(t) = GTPIC2_MW(t - dt) + (GTPRetire2 - GTPRetire3) * dt

INIT GTPIC3_MW = 15/3

INFLOWS:

GTPRetire2 = GTPIC2_MW/(GTPIC_Delay/3)
OUTFLOWS:

\[ \text{GTPRetire3} = \text{GTPIC3} \div (\text{GTPIC}\_\text{Delay} \div 3) \]

\[ \text{GTPotNotUsedGWhyear}(t) = \text{GTPotNotUsedGWhyear} (t - dt) + (\text{GTP\_Pot\_Added} - \text{GTPotUsage}) \times dt \]

INIT GTPotNotUsedGWhyear = 18750-85

INFLOW:

\[ \text{GTP\_Pot\_Added} = \text{GTPRetire3} \times \text{GTPAvailability} \times \text{GTPCapUtil} \times \text{MaxWorkingHour} \]

OUTFLOWS:

\[ \text{GTPotUsage} = \text{GTPInitiateGWh} \]

\[ \text{GTPTotalCost}(t) = \text{GTPTotalCost}(t - dt) + (\text{GTPInstallCost} + \text{GTPOperCost}) \times dt \]

INIT GTPTotalCost = 0

INFLOW:

\[ \text{GTPInstallCost} = \text{GTPInstalled} \times \text{GTPInstCostperMW} \]

\[ \text{GTPOperCost} = \text{GrsElectGenbyGPGWh} \times \text{GTPOperCostperGWh} \]

\[ \text{GTPUC\_MW}(t) = \text{GTPUC\_MW}(t - dt) + (\text{GTPInstalled} - \text{GTP\_Online\_Rate}) \times dt \]

INIT GTPUC\_MW = 0

INFLOW:

\[ \text{GTPInstalled} = \text{GTPotUsage} \times (\text{GTPCapUtil} \times \text{GTPAvailability} \times \text{MaxWorkingHour}) \times 1000 \]

OUTFLOWS:

\[ \text{GTP\_Online\_Rate} = \text{GTPUC\_MW} \times \text{GTPUC\_Delay} \]

\[ \text{DesiredUC\_GTP} = \text{GTPRetire3} \times \text{GTPUC\_Delay} \]

\[ \text{EmisRelbyGTP} = \text{GrsElectGenbyGPGWh} \times \text{GTPEmisTONperGWh} \]

\[ \text{FutGTPNeedAllocGWh} = \begin{cases} \text{FutRENNeedGWh} & \text{IF TIME} < 1999, \text{THEN} \hspace{1cm} (\text{GTPFracInitial} \times \text{FutRENNeedGWh}) \hspace{1cm} \text{ELSE} \hspace{1cm} (\text{FutRENNeedGWh} \times \text{GTPSmthInstFrac}) \\ \text{GrsElectGenbyGPGWh} & \text{IF TIME} \geq \text{1999} \hspace{1cm} \text{THEN} \hspace{1cm} (\text{CurGrsElectGenAllocbyNationCGWh} \times \text{GTPCapFrac\_Initial}) \hspace{1cm} \text{ELSE} \hspace{1cm} (\text{CurGrsElectGenAllocbyNationCGWh} \times \text{GTPSmthCapFrac}) \end{cases} \]

\[ \text{GTPAvailability} = 0.69 \]

\[ \text{GTPcapFrac} = \frac{\text{TotGTPICGWh}}{\text{TotGrsCapGWh}} \]

\[ \text{GTPCapFrac\_Initial} = 0.001 \]

\[ \text{GTPCapUtil} = 1 \]

\[ \text{GTPEmisTONperGWh} = 75 \]

\[ \text{GTPFracInitial} = 0.002 \]

\[ \text{GTPIC\_Delay} = 30 \]

\[ \text{GTPInitiateGWh} = \text{MIN} (\text{MAX }(0, (\text{InstGTP\_MW} \times \text{GTPAvailability} \times \text{GTPCapUtil} \times \text{MaxWorkingHour} \div 1000)), \text{GTPotNotUsedGWhyear}) \]

\[ \text{GTPInstCostperMW} = 1450000 \]

\[ \text{GTPInstFracRevised} = \frac{\text{GTP\_Inst\_Frac}}{\text{RENNInstFracAdjust}} \]

\[ \text{GTPOperCostperGWh} = 0.0177 \times 1000000 \]
GTPSmothCapFract = GTPcapFract*TransEff+GTPCapFract_Initial*(1-TransEff)
GTPSmothInsFrac = (GTPFracInitial*(1-TransEff))+(GTPInstFractRevised*TransEff)
GTPUC_Delay = 2
GTP_Inst_Frac = GTP_Poten Rate*GTP_Priority
GTP_Poten Rate = GTPnotUsedGWh/Year/TotRENPotGWh
GTP_Priority = 1

InstallGTP_MW = (NeedGTP_MW-TotGTPIC_MW)/AT1+(DesiredUC_GTP-GTPUC_MW)/AT2+GTPRetire3
NeedGTP_MW = ProdGTPNeedAllocGWh/GTPAvailability/GTPCapUtil/MaxWorkingHour*1000
TotGTPICGWh = TotGTPIC_MW*GTPAvailability*GTPCapUtil/MaxWorkingHour/1000
TotGTPIC_MW = GTPIC1_MW+GTPIC2_MW+GTPIC3_MW

HARD COAL POWER
HCPIC1_MW(t) = HCPIC1_MW(t - dt) + (HCP_Online_Rate - HCPRetire1) * dt
INIT HCPIC1_MW = 332/3

INFLOWS:
HCP_Online_Rate = HCPUC_MW/HCUCDelay

OUTFLOWS:
HCPRetire1 = HCPIC1_MW/HCPIC_Delay/3
HCPIC2_MW(t) = HCPIC2_MW(t - dt) + (HCPRetire1 - HCPRetire2) * dt
INIT HCPIC2_MW = 332/3

INFLOWS:
HCPRetire1 = HCPIC1_MW/HCPIC_Delay/3

OUTFLOWS:
HCPRetire2 = HCPIC2_MW/HCPIC_Delay/3
HCPIC3_MW(t) = HCPIC3_MW(t - dt) + (HCPRetire2 - HCPRetire3) * dt
INIT HCPIC3_MW = 332/3

INFLOWS:
HCPRetire2 = HCPIC2_MW/HCPIC_Delay/3

OUTFLOWS:
HCPRetire3 = HCPIC3_MW/HCPIC_Delay/3
HCPTotalCost(t) = HCPTotalCost(t - dt) + (HCPInstallCost + HCPOperCost) * dt
INIT HCPTotalCost = 0

INFLOWS:
HCPInstallCost = HCP_Installed*HCPInsCostperMW
HCPOperCost = GrsElecGenbyHCPGWh*HCPOperCostperGWh
HCPUC_MW(t) = HCPUC_MW(t - dt) + (HCP_Installed - HCP_Online_Rate) * dt
INIT HCPUC_MW = 150

INFLOWS:

\[
\text{HCP\_Installed} = \max(0, \text{InstallHCP\_MW})
\]

OUTFLOWS:

\[
\text{HCP\_Online\_Rate} = \frac{\text{HCPUC\_MW}}{\text{HCUCDelay}}
\]

\[
\text{HCR\_Reserve\_TON}(t) = \text{HCR\_Reserve\_TON}(t - dt) + (\text{YearlyHCDep} \times \text{TON}) \times dt
\]

INIT HCR\_Reserve\_TON = (112400000+23232000)

OUTFLOWS:

\[
\text{YearlyHCDep} = \text{DomGenbyHCPGWh} \times \text{HCUseperGWh}
\]

\[
\text{CurHCP\_Need\_AllocGWh} = \text{IF TIME} < 1999 \text{ THEN} (\text{Cur\_Grs\_Elect\_Gen\_Alloc\_by\_National\_CGW}\times \text{HCCap\_Fract\_Initial}) \text{ ELSE} (\text{Cur\_Grs\_Elect\_Gen\_Alloc\_by\_National\_CGW}\times \text{HCSmith\_Cap\_Fract})
\]

\[
\text{Desired\_UC\_HC} = \text{HCR\_Retire\_3+HCUCDelay}
\]

\[
\text{DomGenbyHCPGWh} = \min(\text{Grs\_Elect\_Gen\_by\_HCPGWh}, \text{Dom\_HCR\_Res\_PotenGWh})
\]

\[
\text{Dom\_HCR\_Res\_PotenGWh} = \text{YearlyMax\_HCP\_Prod} \times \text{HCPPCons\_Ratio} \times \text{HCUseperGWh} \div \text{Process\_Time}
\]

\[
\text{EmisRelbyHCP} = \text{Grs\_Elect\_Gen\_by\_HCPGWh} \times \text{HCEmis\_TON\_per\_GWh}
\]

\[
\text{FutHCP\_Need\_AllocGWh} = \text{IF TIME} < 1999 \text{ THEN} (\text{Fut\_RE\_Need\_GWh} \times \text{HCP\_Inst\_Fract\_Initial}) \text{ ELSE} (\text{Fut\_RE\_Need\_GWh} \times \text{HCSmith\_last\_Fract} \times \text{HCP\_Priority})
\]

\[
\text{Grs\_Elect\_Gen\_by\_HCPGWh} = \text{MIN} (\text{Tot\_HCP\_IC\_GWh}, \text{Cur\_HCP\_Need\_AllocGWh})
\]

\[
\text{HCAvailability} = 0.80
\]

\[
\text{HCCap\_Fract\_Initial} = 0.024
\]

\[
\text{HCCap\_Util} = 1
\]

\[
\text{HCEmis\_TON\_per\_GWh} = 1112.5
\]

\[
\text{HClImported\_TON} = \max(0, (\text{HCTotal\_Used\_TON} - \text{YearlyHCDep} \times \text{TON}))
\]

\[
\text{HCP\_IC\_Delay} = 30
\]

\[
\text{HCP\_Ins\_Cost\_per\_MW} = 1450000
\]

\[
\text{HCP\_Oper\_Cost\_per\_GWh} = 0.035 \times 1000000
\]

\[
\text{HCPPCons\_Ratio} = 0.16
\]

\[
\text{HCP\_Prod\_Fr} = 0.05
\]

\[
\text{HCSmith\_Inst\_Fract} = \text{HCP\_Inst\_Fract} \times \text{Trans\_Eff} + \text{HCP\_Inst\_Fract\_Initial} \times (1 - \text{Trans\_Eff})
\]

\[
\text{HCP\_Inst\_Fract} = 0.16
\]

\[
\text{HCP\_Inst\_Fract\_Initial} = 0
\]

\[
\text{HCR\_Res\_Rate\_In\_Total} = \frac{\text{Total\_Pot\_HCEnergy\_GWh}}{\text{Total\_Non\_Res\_Reserve\_GWh}}
\]

\[
\text{HCSmith\_Cap\_Fract} = \text{HCP\_Cap\_Fract} \times \text{Trans\_Eff} + \text{HCP\_Cap\_Fract\_Initial} \times (1 - \text{Trans\_Eff})
\]

\[
\text{HCTotal\_Used\_TON} = \text{Grs\_Elect\_Gen\_by\_HCPGWh} \times \text{HCUseperGWh}
\]

\[
\text{HCUCDelay} = 4
\]

\[
\text{HCUseperGWh} = 813
\]

\[
\text{HC\_Cap\_Fract} = \frac{\text{Tot\_HCP\_IC\_GWh}}{\text{Tot\_Grs\_Cap\_GWh}}
\]
HC_Priority = 1
InstallHCP_MW = (NeedHCP_MW-TotHCPIC_MW)/AT1+(DesiredUC_HC-HCPUC_MW)/AT2+HCPRetire3
NeedHCP_MW = FutHCPNeedAllocGWh/HCAvailability/HCCapUtil/MaxWorkingHour*1000
TotalPotHCEnergyGWh = HCRerveTQN*HCPPConsRatio/HCUseperGWh/ProcessTime
TotHCPICGWh = (HCPIC1_MW+HCPIC2_MW+HCPIC3_MW)*HCAvailability*HCCapUtil/MaxWorkingHour*1000
TotHCPIC_MW = HCPIC1_MW+HCPIC2_MW+HCPIC3_MW
YearlyMaxHCPProd = HCRerveTQN*HCPProdFr

HYDROPOWER

HPIC1MW(t) = HPIC1MW(t - dt) + (HP_Online_Rate - HPRetire1) * dt
INIT HPIC1MW = (6764.3-186.05)/3

INFLOWS:
HP_Online_Rate = HP_UC_MW/HPUC_Delay

OUTFLOWS:
HPRetire1 = HPIC1MW/(HPIC_Delay/3)

HPIC2MW(t) = HPIC2MW(t - dt) + (HPRetire1 - HPRetire2) * dt
INIT HPIC2MW = (6764.3-186.05)/3

INFLOWS:
HPRetire1 = HPIC1MW/(HPIC_Delay/3)

OUTFLOWS:
HPRetire2 = HPIC2MW/(HPIC_Delay/3)

HPIC3MW(t) = HPIC3MW(t - dt) + (HPRetire2 - HPRetire3) * dt
INIT HPIC3MW = (6764.3-186.05)/3

INFLOWS:
HPRetire2 = HPIC2MW/(HPIC_Delay/3)

OUTFLOWS:
HPRetire3 = HPIC3MW/(HPIC_Delay/3)

HPPotNotUsedGWhyear(t) = HPPotNotUsedGWhyear(t - dt) + (HP_Pot_Added - HPPotUsage) * dt
INIT HPPotNotUsedGWhyear = (430000-23147.6)-691.2

INFLOWS:
HP_Pot_Added = HPRetire3*HPAvailability*HCPCapUtil*MaxWorkingHour

OUTFLOWS:
HPPotUsage = HPPotInitiateGWh

HPTotalCost(t) = HPTotalCost(t - dt) + (HPInstallCost + HPOperCost) * dt
INIT HPTotalCost = 0
INFLOWS:

\[ \text{HPIInstalCost} = \text{HPInstal} \times \text{HPI} \times \text{CostperMW} \]

\[ \text{HPOperCost} = \text{GrS ElectGenby HPGWh} \times \text{HPOperCostperGWh} \]

\[ \text{HP_UC_MW}(t) = \text{HP_UC_MW}(t-1) + (\text{HPInstal} - \text{HP_OnlRate}) \times dt \]

\[ \text{INIT HP_UC_MW} = 2806.7 \]

OUTFLOWS:

\[ \text{HPInstal} = \frac{\text{HPPotUsage} \times \text{HPAvailabiltiy} \times \text{MaxWorkingHour} \times 1000}{\text{HP CapUtil} \times \text{HP Availabiltiy} \times \text{MaxWorkingHour}} \]

\[ \text{HP OnlRate} = \frac{\text{HP UC_MW}}{\text{HPUC Delay}} \]

\[ \text{Desired UC} \times \text{HP} = \text{HP Retire} \times \text{HP UC Delay} \]

\[ \text{Elect Genby Smh Big HYDRO IC GW} = \text{Grs Elect Genby HPGWh} + \text{Grs Elect Genby SHPGWh} \]

\[ \text{Eminn Rel} \times \text{HP} = \text{Grs Elect Genby HPGWh} \times \text{HEmis TONperGWh} \]

\[ \text{FuHNeed Alloc GW} = \text{IF TIME<1999 THEN (HP Frac Initial + Fut REN Need GWh) ELSE (Fu REN Need GWh + HPSmth Frac)} \]

\[ \text{Grs Elect Genby HPGW} = \text{IF TIME<1999 THEN (Cur Grs Elect Gen Alloc by Nation IC GW * HP Cap Fract Initial) ELSE (Cur Grs Elect Gen Alloc by Nation IC GW * HP Smth Cap Fract)} \]

\[ \text{HP Availabiltiy} = 0.45 \]

\[ \text{HP Cap Fract} = \frac{\text{Tot HPI C GWh}}{\text{Tot Grs Cap GWh}} \]

\[ \text{HP Cap Fract Initial} = 0.393 \]

\[ \text{HP Cap Util} = 1 \]

\[ \text{HP Ems TON per GWh} = 200 \]

\[ \text{HP Frac Initial} = 0.971 \]

\[ \text{HP IC Delay} = 45 \]

\[ \text{HP Initiate GW} = \min(\max(0, (\text{Install HP_MW} \times \text{HP Availabilty} \times \text{HP Cap Util} \times \text{MaxWorkingHour} \times 1000), \text{HPPotNotUsedGW} \times \text{Year})) \]

\[ \text{HP Inst Cost per MW} = 1200000 \]

\[ \text{HP Inst Fract Revised} = \text{HP Inst Fract} \times \text{REN Inst Fract Adjust} \]

\[ \text{HP Oper Cost per GWh} = 0.0005 \times 1000000 \]

\[ \text{HP Smth Cap Fract} = \text{HP Cap Fract} \times \text{Trans Eff} + \text{HP Cap Fract Initial} \times (1 - \text{Trans Eff}) \]

\[ \text{HP Smth Frac} = (\text{HP Frac Initial} \times (1 - \text{Trans Eff})) + (\text{HP Inst Fract Revised} \times \text{Trans Eff}) \]

\[ \text{HP UC Delay} = 6 \]

\[ \text{HP Inst Fract} = \text{HP Poten Rate} \times \text{HP Priority} \]

\[ \text{HP Poten Rate} = \frac{\text{HP pot Not Used GW} \times \text{Year}}{\text{Tot REN Pot GWh}} \]

\[ \text{HP Priorit} = 1 \]

\[ \text{Install HP_MW} = \frac{\text{(Need HP_MW} - \text{Tot HPI C_MW}) \times \text{AT1} + \text{(Desired UC} \times \text{HP} - \text{HP UC_MW}) \times \text{AT2} + \text{HP Retire 3}}{} \]

\[ \text{Need HP_MW} = \text{Fut HN Need Alloc GWh} \times \text{HP Availabilty} \times \text{HP Cap Util} \times \text{MaxWorkingHour} \times 1000 \]

\[ \text{Sml Big HYDRO IC GW = Tot HPI C GWh} + \text{Tot SHPI C GWh} \]

\[ \text{Sml Big HYDRO IC_MW = Tot HPI C_MW} + \text{Tot SHPI C_MW} \]

\[ \text{Tot HPI C GWh} = \text{Tot HPI C_MW} \times \text{HP Availabilty} \times \text{HP Cap Util} \times \text{MaxWorkingHour} \times 1000 \]
TotalPIC_MW = HPIC1MW + HPIC2MW + HPIC3MW

TransEff = GRAPH(time)

(1990, 0.00), (1991, 0.00), (1992, 0.00), (1993, 0.00), (1994, 0.00), (1995, 0.00), (1996, 0.00), (1997, 0.00), (1998, 0.00), (1999, 0.095),
(2000, 0.245), (2001, 0.675), (2002, 0.88), (2003, 1.00)

LIGNITE POWER

LigniteReserveTON(t) = LigniteReserveTON(t - dt) + (- YearlyLigDepTON) * dt

INIT LigniteReserveTON = (8374372000 + 462457000)

OUTFLOWS:

YearlyLigDepTON = DomGenbyLPWGWh * LijUseperGWh

LPIC1_MW(t) = LPIC1_MW(t - dt) + (LP_Online_Rate - LPRetire1) * dt

INIT LPIC1_MW = 4896.2/3

INFLOWS:

LP_Online_Rate = LPUNConsMW/LPUCDelay

OUTFLOWS:

LPRetire1 = LPIC1_MW/LPIC_Delay/3

LPIC2_MW(t) = LPIC2_MW(t - dt) + (LPRetire1 - LPRetire2) * dt

INIT LPIC2_MW = 4896.2/3

INFLOWS:

LPRetire1 = LPIC1_MW/LPIC_Delay/3

OUTFLOWS:

LPRetire2 = LPIC2_MW/LPIC_Delay/3

LPIC3_MW(t) = LPIC3_MW(t - dt) + (LPRetire2 - LPRetire3) * dt

INIT LPIC3_MW = 4896.2/3

INFLOWS:

LPRetire2 = LPIC2_MW/LPIC_Delay/3

OUTFLOWS:

LPRetire3 = LPIC3_MW/LPIC_Delay/3

LPTotalCost(t) = LPTotalCost(t - dt) + (LPInstallCost + LPOperCost) * dt

INIT LPTotalCost = 0

INFLOWS:

LPInstallCost = LP_Installed*LPInstCostperMW

LPOperCost = GrsElecGenbyLPWGWh*LPOperCostGWh

LPUNConsMW(t) = LPUNConsMW(t - dt) + (LP_Installed - LP_Online_Rate) * dt

INIT LPUNConsMW = 1212
INFLOWS:

LP_Installed = max(0, InstallLP_MW)

OUTFLOWS:

LP_Online_Rate = LPUNCconsMW/LPUCDelay

AT1 = 2

AT2 = 2

CurlLPNeedAllocGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationCGWh*LigCapFract_Initial) ELSE (CurGrsElectGenAllocbyNationCGWh*LigSmthCapFract)

DesiredUC_LP = LPRetire3*LPUCDelay

DomGenbyLPGWh = min(GrsElecElecbyLPGWh,DomLigResPotGWh)

DomLigResPotGWh = YearlyMaxLigProdTON/LigPPConsRatio/LigUseperGWh

EmisRelbyLPGWh = GrsElecElecbyLPGWh*LigEmisTONperGWh

FutLPNeedAllocGWh = IF TIME<1999 THEN (FutNRENNeedGWh*LP.InstFractInitial) ELSE (FutNRENNeedGWh*LigSmthInstFract*LP_Priority)

GrsElecElecGenbyLPGWh = MIN (TotLPICGWh,CurLPNeedAllocGWh)

InstallLP_MW = (NeedLP_MW-TotLPIC_MW)/AT1+(DesiredUC_LP-LPNConsMW)/AT2+LPRetire3

LigCapFract_Initial = .316

LigEmisTONperGWh = 1112.5

LigImportedTON = Max(0,(LigTotalUsedTON-YearlyLigDepTON))

LigProdFr = 0.10

LigResRateInTotal = TotalLigResGWh/TotalNonRenReserveGWh

LigSmthCapFract = Lig_CapFract*TransEff+LigCapFract_Initial*(1-TransEff)

LigSmthInstFract = LP.InstFract*TransEff+LP.InstFractInitial*(1-TransEff)

LigTotalUsedTON = GrsElecElecGenbyLPGWh*LigUseperGWh

LigUseperGWh = 1593

Lig_CapFract = TotLPICGWh/TotGrsCapGWh

LPAvailability = 0.90

LP CapUtil = 1

LPIC_Delay = 30

LPInstCostperMW = 1600000

LPOperCostperGWh = 0.025*1000000

LPUCDelay = 4

LP.InstFract = .20

LP.InstFractInitial = .53

LP_Priority = 1

MaxWorkingHour = 365*24

NeedLP_MW = FutLPNeedAllocGWh/LPAvailability/LPCapUtil/MaxWorkingHour*1000

ProcessTime = 1
TotalLigResGWh = (LigniteReserveTON*LigPPConsRatio*LigUseperGWh)/ProcessTime
TotalNonRenReserveGWh = TotalLigResGWh+TotalPotNGEnergyGWh+TotalPotOilEnergyGWh+TotalPotHCEnergyGWh
TotLPICGWh = TotLPIC_MW*LPAvailability*LPCapUtil*MaxWorkingHour/1000
TotLPIC_MW = LPIC1_MW+LPIC2_MW+LPIC3_MW
YearlyMaxLigProdTON = LigniteReserveTON*LigProdFr
YearlyMaxLinProdGWhyear = (YearlyMaxLigProdTON/LigUseperGWh)/ProcessTime
LigPPConsRatio = GRAPH(time)
(1990, 0.65), (1991, 0.66), (1992, 0.685), (1993, 0.715), (1994, 0.755), (1995, 0.795), (1996, 0.825), (1997, 0.85), (1998, 0.85)

NATURAL GAS POWER

NGPIC1_MW(t) = NGPIC1_MW(t - dt) + (NGP_Online_Rate - NGPRetire1) * dt
INIT NGPIC1_MW = 2210/3

INFLOWS:
NGP_Online_Rate = NGPUC_MW/NGUCDelay

OUTFLOWS:
NGPRetire1 = NGPIC1_MW/NGPIC_Delay/3
NGPIC2_MW(t) = NGPIC2_MW(t - dt) + (NGPRetire1 - NGPRetire2) * dt
INIT NGPIC2_MW = 2210/3

INFLOWS:
NGPRetire2 = NGPIC2_MW/NGPIC_Delay/3

OUTFLOWS:
NGPRetire3 = NGPIC3_MW/NGPIC_Delay/3
NGPTotalCost(t) = NGPTotalCost(t - dt) + (NGPInstallCost + NGPOperCost) * dt
INIT NGPTotalCost = 0

INFLOWS:
NGPInstallCost = NGP_Installed*NGinsCostperMW
NGPOperCost = GrsElecGenbyNGPGWh*NGPOperCostperGWh
NGPUC_MW(t) = NGPUC_MW(t - dt) + (NGP_Installed - NGP_Online_Rate) * dt
INIT NGPUC_MW = 345.4
INFLOWS:

NGP_Installed = max(0,InstallNGP_MW)

OUTFLOWS:

NGP_Online_Rate = NGPUC_MW/NGUCDelay

NGResermm3(t) = NGResermm3(t - dt) + (- YearlyNGDepmm3) * dt

INIT NGResermm3 = (18530-3537+2219)

OUTFLOWS:

YearlyNGDepmm3 = DomGenbyNGPGWh*NGUseperGWh

CurtNGNeedAllocGWh = IF TIME<1999 THEN (CurGrsElecGenAllocbyNationICGWh*NGCapFract_Initial) ELSE (CurGrsElecGenAllocbyNationICGWh*NGSmthCapFract)

DesiredUC_OP = NGPRetire3*NGUCDelay

DomGenbyNGPGWh = min(GrsElecGenbyNGPGWh,DomNGResPotenGWh)

DomNGResPotenGWh = YearlyMaxNGProd*NGPPConsRatio/NGUseperGWh/ProcessTime

EmisRelbyNGP = GrsElecGenbyNGPGWh*NGEmisin3perGWh

FutNGPNeedAllocGWh = IF TIME<1999 THEN (FutNRENEngWh*NG_InitFractInitial) ELSE (FutNRENEngWh*NGSmthInitFract*NG_Priority)

GrsElecGenbyNGPGWh = MIN (TotNGCICWh,CurtNGNeedAllocGWh)

InstalNGP_MW = (NeedNGP_MW-TotNGPIC_MW)/AT1+(DesiredUC_OP-NGPUC_MW)/AT2+NGPRetire3

NeedNGP_MW = FutNGPNeedAllocGWh/NGAvailability/NGCapUtil/MaxWorkingHour*1000

NGAvailability = 0.85

NGCapFract_Initial = .187

NGCapUtil = 1

NGEmisin3perGWh = 825

NGImportedmm3 = Max (0,(NGTotalUsedmm3-YearlyNGDepmm3))

NGInsCostperMW = 680000

NGPIC_Delay = 40

NGPOperCostperGWh = 0.03*1000000

NGPPConsRatio = .60

NGP_InitFract = .55

NG_Priority = 1

NGResRateInTotal = TotalPotNGEnergyGWh/TotalNonRenReserveGWh

NGSmthCapFract = NG_CapFract*TransEff+NGCapFract_Initial*(1-TransEff)

NGSmthInstFract = NG_InitFract*TransEff+NG_InitFractInitial*(1-TransEff)

NGTotalUsedmm3 = GrsElecGenbyNGPGWh*NGUseperGWh

NGUCDelay = 3

NGUseperGWh = 0.238

NG_CapFract = TodNGICGWh/TotGrsCapGWh
NG_InstFracInitial = .47
TotalPotNGEnergyGWh = NGReservemm3*NGPPConsRatio*NGUseperGWh/ProcessTime
TotNGICGW = TotNGPIC_MW*NGAvailability*NGCapUtil*MaxWorkingHour/1000
TotNGPIC_MW = NGPIC1_MW+NGPIC2_MW+NGPIC3_MW
YearlyMaxNGProd = NGReservemm3*NGProdFr
NGProdFr = GRAPH(time)
(1990, 0.01), (1991, 0.0115), (1992, 0.017), (1993, 0.0285), (1994, 0.0605), (1995, 0.0755), (1996, 0.0845), (1997, 0.0935), (1998, 0.1)

OIL POWER
CrudeOilReserveTON(t) = CrudeOilReserveTON(t - dt) + (- YearlyOilDepTON) * dt
INIT CrudeOilReserveTON = (977185000-106586000+33725000)

OUTFLOWS:
YearlyOilDepTON = DomGenbyOPGW*OilUseperGWh
OPIC2MW(t) = OPIC2MW(t - dt) + (OPRetire1 - OPRetire2) * dt
INIT OPIC2MW = (1552+546)/3

INFLOWS:
OPRetire1 = OPICMW/OPIC_Delay/3
OUTFLOWS:
OPRetire2 = OPIC2MW/OPIC_Delay/3
OPIC3MW(t) = OPIC3MW(t - dt) + (OPRetire2 - OPRetire3) * dt
INIT OPIC3MW = (1552+546)/3

INFLOWS:
OPRetire2 = OPIC2MW/OPIC_Delay/3
OUTFLOWS:
OPRetire3 = OPIC3MW/OPIC_Delay/3
OPICMW(t) = OPICMW(t - dt) + (OP_Online_Rate - OPRetire1) * dt
INIT OPICMW = (1552+546)/3

INFLOWS:
OP_Online_Rate = OPUNConsMW/OPUCDelay
OUTFLOWS:
OPRetire1 = OPICMW/OPIC_Delay/3
OPTotalCost(t) = OPTotalCost(t - dt) + (OPInstallCost + OPerCost) * dt
INIT OPTotalCost = 0

INFLOWS:
OPInstallCost = OP_installed*OPInsCostperMW
OPOperCost = GrsElecGenbyOilGWh*OPOperCostperGWh

OPUNConsMW(t) = OPUNConsMW(t - dt) + ((OP_Installed - OP_Online_Rate) * dt

INIT OPUNConsMW = 0

INFLOWS:

OP_Installed = max(0, InstallOP_MW)

OUTFLOWS:

OP_Online_Rate = OPUNConsMW/OPUCDelay

CurOPNeedAllocGWh = IF TIME<1999 THEN (CurGrsElecGenAllocbyNationLCGWh*OilCapFract_Initial) ELSE (CurGrsElecGenAllocbyNationLCGWh*OilSmthCapFract)

DesiredUCOil = OPRetire3*OPUCDelay

DomGenbyOPGWh = min(GrsElecGenbyOilGWh, DomOilResPotenGWh)

DomOilResPotenGWh = YearlyMaxOilProd*OilPPConsRatio/OilUseperGWh/ProcessTime

EmisRelbyOP = GrsElecGenbyOilGWh*OilEmisTONperGWh

FutOPNeedAllocGWh = IF TIME<1999 THEN (FutRENNeedGWh*OP_InstFractInitial) ELSE (FutRENNeedGWh*OPSmthInstFract*Oil_Priority)

GrsElecGenbyOilGWh = MIN (TotalOPICGWh,CurOPNeedAllocGWh)

InstallOP_MW = (NeedOP_MW-TotOPIC_MW)/AT1+(DesiredUCOil-OPUNConsMW)/AT2+OPRetire3

NeedOP_MW = FutOPNeedAllocGWh/OPAvailability/OPCapUtil/MaxWorkingHour*1000

OilCapFract_Initial = .068

OilEmisTONperGWh = 825

OilImportedTON = Max(0,(OilTotalUsedTON-YearlyOilDepTON))

OilProdFr = 0.05

OilResRateInTotal = TotalPotOilEnergyGWh/TotalNonRenReserveGWh

OilSmthCapFract = Oil_CapFract*TransEff+OilCapFract_Initial*(1-TransEff)

OilTotalUsedTON = GrsElecGenbyOilGWh*OilUseperGWh

OilUseperGWh = 277

Oil_CapFract = TotOPICGWh/TotGrsCapGWh

Oil_Priority = 1

OPAvailability = .60

OPCapUtil = 1

OPIC_Delay = 30

OPInstCostperMW = 20000000

OPOperCostperGWh = 0.06*1000000

OPSmthInstFract = OP_InstFract*TransEff+OP_InstFractInitial* (1-TransEff)

OPUCDelay = 4

OP_InstFract = .09

OP_InstFractInitial = 0

TotalPotOilEnergyGWh = CrudeOilReserveTON*OilPPConsRatio/OilUseperGWh/ProcessTime
\[ \text{TotOPICGWh} = \text{TotOPIC\_MW} \times \text{OPAvailability} \times \text{OPCapUtil} \times \text{MaxWorkingHour} / 1000 \]

\[ \text{TotOPIC\_MW} = \text{OPICMW} + \text{OPIC2MW} + \text{OPIC3MW} \]

\[ \text{YearlyMaxOilProd} = \text{CrudeOilReserveTON} \times \text{OilProdFr} \]

\[ \text{OilPPConsRatio} = \text{GRAPH(time)} \]

(1990, 0.05), (1991, 0.0532), (1992, 0.057), (1993, 0.066), (1994, 0.0795), (1995, 0.0907), (1996, 0.0968), (1997, 0.099), (1998, 0.1)

**SMALL SCALED HYDROPOWER**

\[ \text{SHPIC1\_MW(t)} = \text{SHPIC1\_MW(t - dt)} + (\text{SHP\_Online\_Rate} \times \text{SHPRetire1}) \times dt \]

INIT SHPIC1\_MW = 186.05/3

**INFLOWS:**

\[ \text{SHP\_Online\_Rate} = \text{SHPUC\_MW} \times \text{SHPUC\_Delay} \]

**OUTFLOWS:**

\[ \text{SHPRetire1} = \text{SHPIC1\_MW} / (\text{SHPIC\_Delay}/3) \]

\[ \text{SHPIC2\_MW(t)} = \text{SHPIC2\_MW(t - dt)} + (\text{SHPRetire1} - \text{SHPRetire2}) \times dt \]

INIT SHPIC2\_MW = 186.05/3

**INFLOWS:**

\[ \text{SHPRetire1} = \text{SHPIC1\_MW} / (\text{SHPIC\_Delay}/3) \]

**OUTFLOWS:**

\[ \text{SHPRetire2} = \text{SHPIC2\_MW} / (\text{SHPIC\_Delay}/3) \]

\[ \text{SHPIC3\_MW(t)} = \text{SHPIC3\_MW(t - dt)} + (\text{SHPRetire2} - \text{SHPRetire3}) \times dt \]

INIT SHPIC3\_MW = 186.05/3

**INFLOWS:**

\[ \text{SHPRetire2} = \text{SHPIC2\_MW} / (\text{SHPIC\_Delay}/3) \]

**OUTFLOWS:**

\[ \text{SHPRetire3} = \text{SHPIC3\_MW} / (\text{SHPIC\_Delay}/3) \]

\[ \text{SHPotNotUsedGYear(t)} = \text{SHPotNotUsedGYear(t - dt)} + (\text{SHP\_Pot\_Added} - \text{SHPotUsage}) \times dt \]

INIT SHPotNotUsedGYear = 32900-3695

**INFLOWS:**

\[ \text{SHP\_Pot\_Added} = \text{SHPRetire3} \times \text{SHP\_Availability} \times \text{SHPCapUtil} \times \text{MaxWorkingHour} \]

**OUTFLOWS:**

\[ \text{SHPotUsage} = \text{SHPInitGWh} \]

\[ \text{SHPTotalCost(t)} = \text{SHPTotalCost(t - dt)} + (\text{SHPInstallCost} + \text{SHPOperCost}) \times dt \]

INIT SHPTotalCost = 0

**INFLOWS:**

\[ \text{SHPInstallCost} = \text{SHPInstalled} \times \text{SHPInstCostperMW} \]

\[ \text{SHPOperCost} = \text{GrsElecGenbySHPGWh} \times \text{SHPOperCostperGWh} \]
SHPUC\_MW(t) = SHPUC\_MW(t - dt) + (SHPInstalled - SHP\_Online\_Rate) \times dt

INIT SHPUC\_MW = 8.8

INFLOWS:

SHPInstalled = SHPotUsage/(SHPCapUtil*SHPAvailability*MaxWorkingHour)*1000

OUTFLOWS:

SHP\_Online\_Rate = SHPUC\_MW/SHPUC\_Delay

DesiredUC\_SHP = SHPRetire3*SHPUC\_Delay

EmisRelbySHP = GrsElectGenbySHPGWh*SHPEmisTONperGWh

FutSHPNeedAllocGWh = IF TIME<1999 THEN (SHPFracInitial+FutRENNeedGWh) ELSE (FutRENNeedGWh*SHPSmthFrac)

GrsElectGenbySHPGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*SHPCapFrac\_Initial) ELSE (CurGrsElectGenAllocbyNationICGWh*SHPSmthFrac)

InstallSHP\_MW = (NeedSHP\_MW-TotSHPIC\_MW)/AT1+(DesiredUC\_SHP-SHPUC\_MW)/AT2+SHPRetire3

NeedSHP\_MW = FutSHPNeedAllocGWh/SHPAvailability/SHPCapUtil/MaxWorkingHour*1000

SHPA availability = 0.60

SHPcapFrac = TotSHPICGWh/TotGrsCapGWh

SHPcapFrac\_Initial = .011

SHPCapUtil = 1

SHPEmisTONperGWh = 200

SHPFracInitial = .027

SHPIC\_Delay = 45

SHPInitiateGWh = MIN(MAX(0,(InstallSHP\_MW*SHPAvailability*SHPCapUtil*MaxWorkingHour/10000)),SHPpotNotUsedGWhyear)

SHPInstCoperMW = 750000

SHPInstFracRevised = SHP\_Inst\_Frac/RENInstFracAdjust

SHPOpCoperGWh = 0.0005\times1000000

SHPSmthCapFrac = SHPcapFrac\times TransEff\times SHPcapFrac\_Initial\times(1-TransEff)

SHPSmthInsFrac = (SHPFracInitial\times(1-TransEff))+(SHPInstFracRevised\times TransEff)

SHPUC\_Delay = 1

SHP\_Inst\_Frac = SHP\_Poten\_Rate\times SHP\_Priority

SHP\_Poten\_Rate = SHPpotNotUsedGWhyear/TotRENPotGWh

SHP\_Priority = 1

TotSHPICGWh = TotSHPIC\_MW*SHPAvailability*SHPCapUtil*MaxWorkingHour/1000

TotSHPIC\_MW = SHPIC1\_MW+SHPIC2\_MW+SHPIC3\_MW

SOLAR POWER

SPIC1\_MW(t) = SPIC1\_MW(t - dt) + (SP\_Online\_Rate - SPRetire1) \times dt

INIT SPIC1\_MW = 0
INFLOWS:
SP_Online_Rate = SPUC_MW/SPUC_Delay

OUTFLOWS:
SPRetire1 = SPIC1_MW/(SPIC_Delay/3)
SPIC2_MW(t) = SPIC2_MW(t - dt) + (SPRetire1 - SPRetire2) * dt
INIT SPIC2_MW = 0

INFLOWS:
SPRetire1 = SPIC1_MW/(SPIC_Delay/3)

OUTFLOWS:
SPRetire2 = SPIC2_MW/(SPIC_Delay/3)
SPIC3_MW(t) = SPIC3_MW(t - dt) + (SPRetire2 - SPRetire3) * dt
INIT SPIC3_MW = 0

INFLOWS:
SPRetire2 = SPIC2_MW/(SPIC_Delay/3)

OUTFLOWS:
SPRetire3 = SPIC3_MW/(SPIC_Delay/3)
SPTotalCost(t) = SPTotalCost(t - dt) + (SPInstallCost + SPOperCost) * dt
INIT SPTotalCost = 0

INFLOWS:
SPInstallCost = SPInstalled*SPInsCostperMW
SPOperCost = GrsElectGenbySPGWh*SPOperCostperGWh
SPUC_MW(t) = SPUC_MW(t - dt) + (SPInstalled - SP_Online_Rate) * dt
INIT SPUC_MW = 0

INFLOWS:
SPInstalled = SPotUsage*(SPAavailability*SPCapUtil*MaxWorkingHour)*1000

OUTFLOWS:
SP_Online_Rate = SPUC_MW/SPUC_Delay
SP_PotNotUsedGWhYear(t) = SP_PotNotUsedGWhYear(t - dt) + (SP_Pot_Added - SPotUsage) * dt
INIT SP_PotNotUsedGWhYear = 8000000

INFLOWS:
SP_Pot_Added = SPRetire3*SPAavailability*SPCapUtil*MaxWorkingHour

OUTFLOWS:
SPotUsage = SPInitiateGWhyear
DesiredUC_SP = SPRetire3*SPUC_Delay
EmisRelbySP = GrsElectGenbySPGWh*SPEmisTONperGWh
FutSPNeedAllocGWhyear = IF TIME<1999 THEN (SPInstFracInitial*FutRENNeedGWh) ELSE (FutRENNeedGWh*SPSmthInsFrac)

GrsElectGenbySPGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*SPCapFract_initial) ELSE (CurGrsElectGenAllocbyNationICGWh*SPSmthCapFract)

InstallSP_MW = (NeedSP_MW-TotSPIC_MW)/AT1+(DesiredUC_SP-SPUC_MW)/AT2*SPRetire3

NeedSP_MW = FutSPNeedAllocGWhyear/SPAvalilability/SPCapUtil/MaxWorkingHour*1000

SPAvalilability = .30

SPCapFrac = TotSPICGWh/TotGrsCapGWh

SPCapFract_initial = 0

SPCapUtil = 1

SPEmisTONperGWh = 175

SPIC_Delay = 25

SPInitiateGWhyear = MIN(MAX(0,(InstallSP_MW*SPAvalilability*SPCapUtil*MaxWorkingHour/1000)),SP_potNotUsedGWhYear)

SPInsCostperMW = 6000000

SPInstFrac = SP_Poten_Rate*SP_Priority

SPInstFracInitial = 0

SPInstFracRevised = SPInstFrac/RENSpecFracAdjust

SPCostperGWh = 0.20*1000000

SPSmthCapFract = SPCapFrac*TransEff+SPCapFract_initial*(1-TransEff)

SPSmthInsFrac = (SPInstFracInitial*(1-TransEff))+(SPInstFracRevised*TransEff)

SPUC_Delay = 1

SP_Poten_Rate = SP_potNotUsedGWhYear/TotRENPotGWh

SP_Priority = 1

TotSPICGWh = TotSPIC_MW*SPAvalilability*SPCapUtil*MaxWorkingHour/1000

TotSPIC_MW = SPIC1_MW+SPIC2_MW+SPIC3_MW

WIND POWER

WPIC1_MW(t) = WPIC1_MW(t - dt) + (WP_Poten_Rate - WPRetire1) * dt

INIT WPIC1_MW = 0

INFLOWS:

WP_Poten_Rate = WPUC_MW/SPUC_Delay

OUTFLOWS:

WPRetire1 = WPIC1_MW/(WPIC_Delay/3)

WPIC2_MW(t) = WPIC2_MW(t - dt) + (WPRetire1 - WPRetire2) * dt

INIT WPIC2_MW = 0

INFLOWS:

WPRetire1 = WPIC1_MW/(WPIC_Delay/3)

OUTFLOWS:
\[ \text{WPRetire2} = \text{WPIC2}_{-\text{MW}}/(\text{WPIC}_\text{Delay}/3) \]
\[ \text{WPIC3}_{-\text{MW}}(t) = \text{WPIC3}_{-\text{MW}}(t - dt) + (\text{WPRetire2} - \text{WPRetire3}) \times dt \]
\[ \text{INIT WPIC3}_{-\text{MW}} = 0 \]

**INFLOWS:**
\[ \text{WPRetire2} = \text{WPIC2}_{-\text{MW}}/(\text{WPIC}_\text{Delay}/3) \]

**OUTFLOWS:**
\[ \text{WPRetire3} = \text{WPIC3}_{-\text{MW}}/(\text{WPIC}_\text{Delay}/3) \]
\[ \text{WPotNotUsedGWhYear}(t) = \text{WPotNotUsedGWhYear}(t - dt) + (\text{WP_{Pot_{Added}} - WP_{Pot_{Usage}}}) \times dt \]
\[ \text{INIT WPotNotUsedGWhYear} = (400000+180000) \]

**INFLOWS:**
\[ \text{WP_{Pot_{Added}}} = \text{WPRetire3} \times \text{WP Availability} \times \text{WP Cap Util} \times \text{Max Working Hour} \]

**OUTFLOWS:**
\[ \text{WPotUsage} = \text{WP Initiate GWh} \]
\[ \text{WPTotalCost}(t) = \text{WPTotalCost}(t - dt) + (\text{WP Install Cost} + \text{WP Oper Cost}) \times dt \]
\[ \text{INIT WPTotalCost} = 0 \]

**INFLOWS:**
\[ \text{WP Install Cost} = \text{WP Installed} \times \text{WP Inst Cost per MW} \]
\[ \text{WP Oper Cost} = \text{Grs Elect GWh by WP GWh} \times \text{WP Oper Cost per GWh} \]
\[ \text{WPUC}_{-\text{MW}}(t) = \text{WPUC}_{-\text{MW}}(t - dt) + (\text{WP Installed} - \text{WP Online Rate}) \times dt \]
\[ \text{INIT WPUC}_{-\text{MW}} = 0 \]

**INFLOWS:**
\[ \text{WP Installed} = \text{WPotUsage}/(\text{WP Availability} \times \text{WP Cap Util} \times \text{Max Working Hour}) \times 1000 \]

**OUTFLOWS:**
\[ \text{WP Online Rate} = \text{WPUC}_{-\text{MW}}/\text{WPUC}_{-\text{Delay}} \]
\[ \text{DesiredUC}_{-\text{WP}} = \text{WPRetire3} \times \text{WPUC}_{-\text{Delay}} \]
\[ \text{EmisRelbyWP} = \text{Grs Elect GWh by WP GWh} \times \text{WP Emis TON per GWh} \]
\[ \text{FutWPNeedAllocGWh} = \text{IF TIME < 1999 THEN (WFRactInitial} \times \text{FutRENNeedGWh) ELSE (FutRENNeedGWh} \times \text{WPSmthfInsFrac}) \]
\[ \text{GrsElectGWh by WP GWh} = \text{IF TIME < 1999 THEN (CurGrscElectGen Allocby Nation ICCW} \times \text{WP Cap Fract Initial) ELSE (CurGrscElectGen Allocby Nation ICCW} \times \text{WPSmth Cap Fract}) \]
\[ \text{Install WP}_{-\text{MW}} = (\text{NeedWP}_{-\text{MW}} \times \text{TotWPIC}_{-\text{MW}}) / \text{ATT1} + (\text{DesiredUC}_{-\text{WP}} \times \text{WPUC}_{-\text{MW}}) / \text{ATT2} + \text{WPRetire3} \]
\[ \text{NeedWP}_{-\text{MW}} = \text{FutWPNeedAllocGWh} \times \text{WP Availability} \times \text{WP Cap Util} \times \text{Max Working Hour} \times 1000 \]
\[ \text{TotWPIC GWh} = \text{TotWPIC}_{-\text{MW}} \times \text{WP Availability} \times \text{WP Cap Util} \times \text{Max Working Hour} \times 1000 \]
\[ \text{TotWPIC}_{-\text{MW}} = \text{WPIC1}_{-\text{MW}} + \text{WPIC2}_{-\text{MW}} + \text{WPIC3}_{-\text{MW}} \]
\[ \text{WP Availability} = 0.30 \]
\[ \text{WP cap Frac} = \text{TotWPIC GWh} / \text{Tot Grs Cap GWh} \]
\[ \text{WP Cap Fract Initial} = 0 \]
WPCapUtil = 1
WPemisTONperGWh = 75
WPFracInitial = 0
WPIC_Delay = 25
WPInitiateGWh = MIN(MAX(0,(InstallWP_MW*WP Availability*WPCapUtil*Max Working Hour/1000)),WP potNotUsedGWhYear)
WPInstCostperMW = 1450000
WPInstFrac = WP_Poten_Rate*WP_Priority
WPInstFracRevised = WPInstFrac/RENInstFracAdjust
WPOperCostperGWh = 0.045*1000000
WPSmthCapFrac = WPcapFrac*TransEff+WPcapFrac_Initial*(1-TransEff)
WPSmthInstFrac = (WPFracInitial*(1-TransEff)+(WPInstFracRevised*TransEff)
WPUC_Delay = 1
WP_Poten_Rate = WPpotNotUsedGWhYear/TotRENPotGWh
WP_Priority = 1
REFERENCES


Bespelli, B., 2002, General Directorate of Mineral Research and Exploration (MTA), Personal Conversation, April.


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