MAINTENANCE PLANNING

IN

POWER SYSTEMS OPERATION

by

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We hereby recommend that the thesis entitled "Maintenance Planning in Power Systems Operation" submitted by Varol Günyaşar to be accepted in partial fulfillment of the requirements for the Degree of Master of Science in Industrial Engineering in the Institute for Graduate Studies in Science and Engineering, Boğaziçi University.

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ABSTRACT

In this study, the optimal operation and maintenance schedules of integrated hydro-thermal power generating systems are searched under different demand levels and operating capacities. The modelling approach aims to handle the problem in two parts. In the first part, a linear programming model is constructed that investigates the optimal seasonal operation and maintenance policies subject to power demand satisfaction, capacity, water usage, energy generation, importation and maintenance requirement constraints. The objective function to be minimized constitutes of operating costs of generating units, and the costs of imported and unsatisfied energy demands.

In the second part, using the results obtained for different scenarios related to yearly peak power demand and the commissioning dates of planned investments in part one, a further attempt is made to distribute the planned capacity outages (capacities in maintenance) for each generating group and season into months in terms of single generating units. The objective here is considered as the levelization of monthly risks.

The risk level of some period is measured in terms of "expected number of shortage days" throughout that period which is calculated by comparing the distributions of available generating capacity and daily peak demands. The loss-of-load probability (LOLP) method is employed in this part of the study which is a widely used index of reliability.

The first part of the model, as applied to Turkish Interconnected Power System, contains 429 variables and 326 constraints. The generating units in the system are handled such that the model contains 5 thermal groups (lignite, fuel oil, coal, gas turbine type power plants and non-TEK thermal units) and 12 hydro groups (10 dams with reservoir, lake and river power plants and non-TEK hydro units). 1984 is considered as the target year for the model.

The study does not aim to perform statistical analysis on the operating rules of dams or on the distribution of water inflows. Therefore, from the data available, relevant to water inflows and reservoir operating schedules, all dams are assumed to have average water inflows throughout the periods of the year 1984.

The load demand pattern of the interconnected system for the year 1984 is obtained from the results of the hourly load forecasting package program developed by TEK in the present year. For each period, the load-duration curves are approximated by 3 average load levels: Base load, intermediate load and peak load.

Using the results of the cost minimization model for each scenario, a framework of optimal maintenance periods are obtained for each group. In addition, the effects of different load demand figures and the delays incurred in commissioning dates of new power plants on the maintenance policies can be observed. The results of this observation are combined with a risk levelization procedure in the second part, in order to obtain a proper distribution of the proposed maintenance capacities among the months of each period.

KISA ÖZET

Bu çalışmada, bütünleşik hidro-termal güç sistemlerinin farklı talep düzeyleri ve işletme kapasitelerine ilişkin en iyi işletme ve bakım çizelgeleri araştırılmıştır.

Modellemede benimsenen yaklaşım, problemin iki bölümde ele alınmasını öngörmektedir. Birinci bölümde; güç isteminin karşılanması, kapasite, su kullanımı, enerji üretimi, dış alım ve bakım gereksinmeleri kısıtları altında en iyi mevsimsel işletme ve bakım politikalarını araştıran bir doğrusal programlama modeli kurulmuştur. En küçüklenecek amaç işlevi, enerji üreten birimlerin işletme maliyetleri ile dışarıdan alınan ve karşılanamayan enerji maliyetlerinden oluşmaktadır.

İkinci bölümde ise, ilk bölümdeki yıllık maksimum güç talebi ve planlanmış yatırımların devreye giriş tarihlerine ilişkin farklı senaryoların sonuçları kullanılmıştır. Burada, mevsimler ve üretim grupları için elde edilen planlanmış bakım kapasitelerinin aylara ve üretim birimlerine dağıtımına yönelik olarak, aylık risk düzeylerinin dengelenmesini amaçlayan bir yöntem kullanılmıştır.

Bir dönemin risk düzeyi, o döneme ilişkin elverişli üretim kapasitesi ve günlük tepe yük dağılımlarının karşılaştırılmasıyla hesaplanan "Yokluk günlerinin beklenen sayısı"

ölçüsüyle belirlenmektedir. Çalışmanın bu bölümünde, oldukça yaygın bir güvenilirlik göstergesi olan "Yük kaybı olasılığı" (LOLP-Loss of Load Probability) kullanılmıştır.

Modelin ilk bölümü, Türkiye Enterkonekte sistemine uygulandığı şekliyle 429 değişken ve 326 kısıttan oluşmaktadır. Sistemdeki üretim birimleri, modelde 5 termik grup (linyit, fuel oil, taşkomörü, gaz türbinli santrallar ve TEK dışı termik birimler) ve 12 hidrolik grup (10 hazneli baraj, göl ve kanal santralları ve TEK dışı hidrolik birimler) olarak ele alınmış, model uygulaması 1984 yılı için yapılmıştır.

Çalışmanın amacı, baraj işletim kuralları veya su geliri dağılımlarına ilişkin istatistiksel bir analiz yapmak değildir. Bu yüzden, su gelirleri ve hazne işletim çizelgelerine ilişkin elde edilen veriler kullanılarak, tüm barajların 1984 yılı boyunca ortalama su gelirleriyle çalışacağı varsayılmıştır.

Enterkonekte sistemin 1984 yılı dönemlerine ilişkin güç istemi değerleri, TEK tarafından geliştirilen saatlik yük tahmini programının sonuçlarından yararlanılarak elde edilmiştir. Her dönem için oluşturulan yük-süre eğrileri, 3 farklı yük düzeyi (taban yük, ara yük ve tepe yük) yardımıyla yaklaştırılmıştır.

Maliyet en küçüklemesi modelinden farklı senaryolar için elde edilen sonuçlar kullanılarak, her bir üretim grubuna ilişkin en iyi bakım dönemlerinin genel çerçevesi oluşturulmuştur. Ayrıca, değişik yük istemlerinin ve planlanmış yeni üretim birimlerinin devreye giriş tarihlerinde oluşabilecek gecikmelerin bakım politikaları üzerindeki etkileri de gözlenmiştir. Bu gözlemin sonuçları, çalışmanın ikinci bölümünde bir risk düzleştirme yöntemiyle birleştirilerek dönemler için önerilen bakım kapasitelerinin en uygun aylık dağılımı elde edilmiştir.

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I. INTRODUCTION

1- POWER SYSTEM OPERATION AND MAINTENANCE

An electric power supply system consists of generation, transmission and distribution systems, whereby electricity is generated by a number of generating units in power stations, then transmitted at high voltage to major consumption areas, and then distributed to individual customers at progressively decreasing voltages. The entire system is often highly interconnected for economic and technical reasons. The important aspects of the industry are very large economies of scale in all phases of the operation and the fact that the finished product cannot be stored in economic quantities. Therefore, the nature of the industry is monopolistic. Another important aspect of the industry is that it is the most capital intensive of all industries in an economy, and requires an ever increasing capital outlay in the face of a constantly growing demand. All these factors complicate the planning and operation problems of utility managements who have to plan for and operate a total capacity larger than the maximum instantenous power demand at any time(13).

Electrical energy for power systems is normally generated by an electromechanical conversion process.

The mechanical energy used to drive electric generators is developed in two different ways:

1. Conversion of heat energy into mechanical energy by means of steam-turbines, gas turbines, diesel or gas engines,

2. Applying the force of falling water to drive hydraulic turbines.

Although work is under way on direct conversion methods of generating electricity, which include magnetohydrodynamics, thermoelectric and thermionic conversion, and chemical fuel-cell generation, present applications on power systems are almost universally of steam-turbine-driven or waterwheel driven generators with some applications of gas turbines.

Successful operation of power systems requires attention to safety for personnel and equipment and the provision of service to utility customers without interruption and at the lowest feasible cost. As far as the daily operation is concerned, the main problem is the economic selection and loading of generating units to satisfy a varying demand with reasonable supply reliability. Having forecast the system load for the coming hours, the operation planner must select the combination of units that will supply the expected demand from the system over this period in accordance with a suitable objective function. This is called the unit commitment problem. The total load must then be allocated to the committed units and this in turn is known as the load dispatch problem.

The overall objective is often taken as cost minimization. The generation scheduling problem is composed of these two problems.

The scheduling problem during daily operation of a power system must be handled in the framework of a longer term planning of generation. This relation arises from the limited availability of some primary energy resources and generating equipment. Existence of limits on the availability of water in a hydro-thermal system, and the need to overhaul generating equipment for preventive maintenance require that the total system resources must be programmed for periods of up to 12 months so as to best meet the demand from the system over that period of time. This use of generation scheduling has also an important bearing on system capacity expansion planning. Daily scheduling of generation can thus be seen to be part of the broader long term scheduling problem. This study aims to observe the operation and maintenance policies throughout the periods of the year under different conditions and to determine the framework for daily system operation plans.

As generating facilities increase in size, number and complexity, the impact of maintenance schedules on power system cost and reliability also increases. An electric utility with a fossil fuel capacity of 2000 Megawatts, for example, would spend in the neighborhood of $ 7,000,000 annually for plant maintenance(10). The reliability of operation generation costs and capital expenditures are affected by the methods used to schedule maintenance. Techniques of maintenance scheduling can increase system reliability and reduce costs simply by spreading maintenances more evenly throughout the year.

In general, maintenance down times vary from two to six weeks. During the down time of a unit, its capacity is not available, and the total installed capacity of the system is decreased. A reduction in installed capacity usually results in a deterioration of reliability; in instances where reliability drops too much, the system planner must either provide supplemental capacity or, if possible, rearrange the maintenance schedule. The need for schedule revisions could also result from unexpected forced outages of units or auxiliary equipment, unexpected delays in the installation of new units, unavailability of manpower and materials, work stoppages or delays, or changes in the load forecast. Although a schedule may have been carefully formulated at the beginning of the year, sudden revisions may degrade the schedule later. Especially for large systems, it is not uncommon for a maintenance schedule to be revised frequently during the year.

When developing the model, an underlying assumption is that the cyclical monthly maintenance required for each unit which increases that unit's availability and efficiency is established in advance. Although the generating reserves may be increased in the short run by postponing or avoiding maintenance, subsequent increases in forced outages and decreases in efficiency will eventually result. Increases in forced outages may lead to a more serious reserve shortage and a spiral of decreasing performance may be generated.

In addition to the cost and reliability of supply during system operation, two important factors that must be considered in scheduling of generating unit maintenances are:

a) Crew and manpower availability: Since manpower for maintenance is a limited resource for most utilities, it is essential to recognize that it is impossible to work on certain combinations of units at the same time.

b) Control of the time between outages: Certain maintenance should be performed such that the average time between outages is one year. By recognizing when the last scheduled, or actual outage took place and the possible time range of the present outage, the planner takes advantage of the flexibility in scheduling and insures that maintenance will take place at fairly regular intervals.

2- NATURE OF THE STUDY

As mentioned before, a prime requirement for any electric utility system is the ability to fulfill customer demands for power with some prescribed measure of reliability. So, a "Standard of supply", which is the extent to which a consumer can rely on his electricity supply being available at a useful voltage and frequency, must be maintained. On the other hand, successful operation of a power system requires the achievement of the lowest feasible cost.

Formulations concerning power system operation are generally stated in the format of mathematical programming models. Cost minimization is the main objective in these studies(2,5, 8,11,12,22,24,27,30). In addition, modelling approaches concerning the reliability of supply which reflect the uncertainities in load demands and generating unit availabilities are being developed(1,3,4,9,10,32). The stochastic nature of hydraulic systems in terms of water inflows and reservoir operating rules is modelled mainly in studies concerning the planning of reservoirs(7,23,29).

In this study, the optimal operation and maintenance schedules of integrated hydro-thermal power generating systems are searched under different demand levels and operating capacities. A linear programming model is constructed that investigates the optimal seasonal operation and maintenance policies subject to power demand satisfaction, capacity, water usage, energy generation, importation and maintenance requirement constraints. The objective function to be minimized constitutes of the operating costs of generating units, and the costs of imported and unsatisfied energy demands.

Using the results obtained for different scenarios related to yearly peak power demand and the commissioning dates of planned investments in the optimization model, a further attempt is made to distribute the planned capacity outages (i.e. capacities in maintenance) for each generating group and season into months in terms of single generating units. While doing this, the "inhibited" periods of maintenance implied by the optimization model, which reflect the economics of operation, are utilized when determining the feasible periods for generating unit maintenances. The objective here is considered as the levelization of monthly risks.

The risk level of some period is measured in terms of the "expected number of shortage days" throughout that period which is calculated by comparing the distributions of available generating capacity and daily peak demands. The loss-of load probability (LOLP) method is employed in this part of the study which is a widely used index of reliability.

The study does not aim to perform statistical analysis on the operating rules of dams or on the distribution of water inflows. So, by using the available data relevant to water inflows and reservoir level patterns, all dams are assumed to have average water inflows throughout the periods of the year 1984. As a further step, the effects of a dry period which could occur once in 20 years for all geographical regions are observed as an extreme case for each scenario in order to find out the variations in optimal operating and maintenance policies.

Before introducing the model, it will be useful to give a summary of historical developments and some characteristics of Turkish electric power system, from the viewpoint of analyzing the existing situation.

3- DEVELOPMENTS AND CHARACTERISTICS OF TURKISH POWER SYSTEM

The first power plant in our country has been installed in Tarsus in 1902 and electrification studies emerged with the commissioning of Silahtarağa power plant in 1913. Electricity generation services have been executed by foreign concessioned corporations and then by municipalities during the first two decades. The insufficient capacities of existing power plants forced the newly emerging large-scale state industrial enterprises such as Karabük Iron and Steel, İzmit Paperworks, and Sümerbank Textile to install their own power plants. As a consequence, in the electrical energy sector, the "auto-producer" institutions have emerged and some of these have helped to supply electrical energy for towns and cities in the periphery to a certain extent. In this period, which can be called the period of "isolated power plants", the desired rate of development in the electrification of Turkey has not been achieved due to the isolated, inefficient and small capacity units which were unable to answer the needs of increasing demand for electrical energy.

Etibank and E.İ.E.İ., being authorized in the fields of energy resources planning and electricity generation studies, have been founded in 1935. These institutions realized the second thermal power plant, Çatalagzı, in 1948 and the first transmission line between this power plant and Istanbul has been constructed in 1952. After 1950, there has been a return to the mediation of concessioned companies in electricity generation and "Kepez and Antalya Region Electric Power Plants Company" and "Çukurove Electricity Company" (of which Etibank has the biggest share) have been established.

Rapid developments in industry, agriculture and technology, and the ever increasing electrical energy demand, created the need to supply this demand by using primary natural resources and the necessity to unify the energy generations supplied by different institutions. For this reason, T.E.K. (Turkish Electricity Authority) was established in October 25, 1970 through the Law no.1312. Turkish Electricity Authority, by having proprieted the already existing generation units which for that time being controlled by the municipalities and autoproducers and incorporated them to the interconnected system, have been organized the generation, transmission and distribution of electrical energy in accordance with the development plan principles.

Development of installed power capacity of the Turkish electricity sector through the years of institutional structure changes is shown in the following table.

TABLE 1- Development of Installed Power Capacity

Year	Installed Capacity (MW)
1913	17.3
1935	126.2
1950	407.8
1957	939.4
1962	1370.8
1970	2234.9
1975	4186.6
1980	5118.7
1981	5554.4
1982	6640.4
1983*	6975.4

* By October 1st., 1983.

In parallel with the developments in total installed capacity, electricity supply and demand figures showed the pattern in Table 2 during the period 1970-1982. As seen from the table, the imported and restricted energy figures recorded an increasing trend during the last decade. In addition, the restrictions and cuts in energy demand in 1983 is expected to be above 2000 GWh mainly due to restricted water inflows incurred in the present water year.

TABLE 2- Electrical energy Supply-demand relationship (GWh)

Year	Generation	Import	Total Supply	Restriction	Actual Demand
1970	8623.0	-	8623.0	-	8623.0
1971	9781.1	-	9781.1	22.	9803.1
1972	11241.9	-	11241.9	5.	11246.9
1973	12425.2	-	12425.2	190.	12615.2
1974	13477.0	-	13477.	250.	13727.
1975	15622.8	96.2	15719.	175.	15894.
1976	18282.8	332.2	18615.	140.	18755.
1977	20564.6	492.2	21056.8	777.1	21833.9
1978	21726.1	621.	22347.1	1326.	23673.1
1979	22521.9	1042.9	23564.8	1625.3	25190.1
1980	23275.4	1341.1	24616.5	1753.4	26369.9
1981	24672.8	1616.2	26289.	1655.6	27944.6
1982	26551.5	1773.4	28324.9	1082.8	29407.7

In 1982, the total generation of 26551.5 GWh energy has been realized by the following institutions:

TABLE 3- Distribution of 1982 energy generation among institutions (GWh)

Institution	Generation	%
T.E.K.	23243.1	87.5
Concessioned Comp.	1589.7	6.0
Autoproducers	1659.	6.3
Municipalities	59.7	0.2
TOTAL	26551.5	100.

T.E.K. has the biggest share in total installed capacity, as well as in generation. In Table 4, the distribution of total installed capacity according to resources and institutions is illustrated (October 1, 1983).

TABLE 4- Distribution of total capacity (MW).

Institution	Thermal	Hydro	Total Capacity	%
T.E.K.	2929.7	2948.5	5878.2	84.3
Concessioned Comp.	106.0	219.8	325.8	4.7
Autoproducers	614.1	12.2	626.3	9.0
Municipalities	118.3	26.8	145.1	2.0
TOTAL	3768.1	3207.3	6975.4	100
%	54.	46.	100	

Turkish power system includes isolated (i.e. not interconnected) generating units of 89.2 MW total capacity which have generated 530.2 GWh energy in 1982 (These figures are included in respective columns of capacity and generation).

In the operation and maintenance planning model, all interconnected units are considered in terms of generation. In maintenance planning, only the generating groups being operated by T.E.K. are considered which in turn correspond to 84.3 percent of total capacity.

II. A MAINTENANCE PLANNING MODEL

1- MODELLING MAINTENANCE PLANNING

The electrical power system operation poses considerable difficulties through modelling since there are a variety of power plants with different generation costs, capacities, availabilities, etc. On the other hand, the system power demand is subject to changes at different seasons, months, days and even hours of the day.

The aim of this study is to derive a framework for the short term operation and maintenance of integrated hydro-thermal power systems. It is possible to formulate the problem by employing various kinds of quantitative techniques such as linear, non-linear and dynamic programming. Due to the flexibilities in modelling and solution stages, a linear programming model is developed which seeks to determine the optimal operation and maintenance policies while satisfying system constraints. In order to keep the model in reasonable sizes, the model is constructed so as to examine seasonal policies under different demand levels and operating capacities. While doing this, the maintenance schedules are handled as the average capacity outages during the seasons for each generating group.

A further attempt is made to distribute the planned maintenance capacities for each generating group and season into months in terms of single generating units. The objective here is considered as the levelization of monthly risks.

Therefore, it can be said that the main philosophy of the study is to combine the two objectives in power system operation, namely the costs through operation and the reliability of supply. This part will serve for the derivation of a general framework for the optimal maintenance schedules.

2. THE STRUCTURE OF THE MODEL

The model searches for the optimal seasonal operation and maintenance policies subject to power demand satisfaction, capacity, water usage, energy generation, importation and maintenance requirement constraints. The objective function to be minimized constitutes of operating costs of enerating units and the costs of imported and unsatisfied energy demands.

a. The constraints of the model:

i) Load Demand Satisfaction: For each load level and period, the supplied power (generation plus imported power) plus the unsatisfied power demand must be equal to the power demand.

$$\sum_{i=1}^{n} P_{ikt} + I_{kt} + U_{kt} = PD_{kt} \quad ; \quad \begin{array}{l} k=1,\ldots,m \\ t=1,\ldots,T \end{array}$$

where,

P_{ikt} : Average power generated by the power plant group i at load level k in period t.

I_{kt} : Imported power at load level k in period t.

U_{kt} : Unsatisfied power demand at load level k in period t.

PD_{kt} : Average power demand at load level k in period t.

ii) Relation of power generation and capacity: For each load level and period, power generated by a power plant group cannot exceed the available generation capacity.

$$P_{ikt} \leq a_{it} \cdot (P_i - M_{it}) \quad ; \quad \begin{array}{l} i=1,\ldots,n \\ k=1,\ldots,m \\ t=1,\ldots,T \end{array}$$

where,

a_{it}': Availability coefficient of power plant group i in period t representing the forced outage rates (break-down probabilities) and some losses in generation.

P_i : Installed capacity of power plant group i.

M_{it} : Average capacity of power plant group i taken into maintenance in period t.

iii) Water use in dams with reservoir: For each dam, the beginning reservoir volume plus the water inflow throughout a period must be equal to the end-of-period reservoir volume plus the water released for power generation at different load levels and the water overflow from the filled reservoir during that period.

$$S_{it} + X_{it} - \sum_{k=1}^{m} G_{ikt} - R_{it} - S_{i,t+1} = 0 \; ; \; t=1,\ldots,T \quad i \in \text{Dams with reservoir.}$$

where,

S_{it} : Reservoir volume of dam i at the beginning of period t.

X_{it} : Average water inflow of dam i in period t.

G_{ikt} : Amount of water released for generation purposes from reservoir of dam i at load level k in period t.

R_{it} : The water overflow from filled reservoir i in period t.

iv) Power generation in dams: For each load level and period, the average power generated by a dam is equal to the amount of water released for generation times the amount of energy that can be generated by one unit volume of water, divided by the duration of the load level.

$$P_{ikt} = \frac{k_i h_{it} \cdot G_{ikt}}{d_{kt}} \quad ; \quad t=1,\ldots,T$$
$$k=1,\ldots,m$$
$$i \in \text{Dams with reservoir.}$$

where,

k_i : A coefficient used to convert the water potential into energy.

h_{it} : Water level of the reservoir i during period t (m.)

($k_i \cdot h_{it}$ represents the amount of energy that can be generated by 1 unit volume of water)

d_{kt} : Duration (hours) of load level k in period t.

v) Maintenance Requirements: For each power plant group, the total installed capacity must be maintained throughout the year.

$$\sum_{t=1}^{T} M_{it} = \frac{P_i}{K} \quad ; \quad i=1,\ldots,n$$

where,

K is the number of months (duration of maintenance) in a period. For monthly maintenances and seasonal plans, K=3.

vi) Import Restrictions: The total energy imported throughout the year has an upper bound. Such a bound is valid for average power imports also.

$$\sum_{t=1}^{T} \sum_{k=1}^{m} d_{kt} . I_{kt} \leq EI_m$$

where, EI_m is the limitation on the yearly energy imports.

vii) Bounds on variables:

$$Si_{min} \leq S_{it} \leq Si_{max} \quad ; \quad \forall i,t$$

$$I_{kt} \leq I_m \quad ; \quad \forall k,t$$

where,

Si_{min} and Si_{max} are the minimum and the maximum permissible reservoir volumes during operation for dam i, and I_m is the maximum power import possible during any load level.

viii) Nonnegativities:

$$P_{ikt} , M_{it} , G_{ikt} , S_{it} , R_{it} , I_{kt} , U_{kt} \geq 0 \; ; \; \forall i,k,t.$$

b. The Objective Function

The objective is the minimization of the total of generation, import, and unsatisfied demand costs.

$$\text{Min. } Z = \sum_{t=1}^{T} \{ \sum_{k=1}^{m} d_{kt} \left[(\alpha_I . I_{kt}) + (\alpha_u . U_{kt}) \right]$$

$$+ \sum_{i=1}^{n} \sum_{k=1}^{m} (\alpha_{g_i} . d_{kt} . P_{ikt}) \}$$

where,

α_{g_i} is the unit cost of generation for power plant group i.

α_I and α_u are the unit costs of imported energy and unsatisfied energy demand, respectively.

3- APPLICATION OF THE MODEL TO THE TURKISH INTERCONNECTED SYSTEM

The model, as applied to the Turkish Interconnected Power System, contains 429 variables and 326 constraints. The generating units in the system are handled such that the model contains 5 thermal groups (lignite, fuel oil, coal, gas turbine type power plants and non-TEK thermal units) and 12 hydro groups (10 dams with reservoir, lake and river power plants and non-TEK Hydro units). In maintenance planning, only the generating groups being operated by TEK are considered which correspond to 85.4 percent of interconnected system installed capacity. 1984 is considered as the target year for the model.

The model is solved for various scenarios by using TEMPO (Techniques for Extreme Point Optimization) package in Burroughs B-6900 System at METU for each scenario, the process time varies between 1,5 to 2 minutes with a memory allocation of 1740 words.

3.1. THE STRUCTURE OF THE INTERCONNECTED SYSTEM

Turkish Interconnected Power System is composed of thermal (lignite, fuel oil, coal and motorine type generating units) and hydro (dams with reservoir and generating units in natural lakes and rivers) power plants which totally amount to 6886.2 MW. The distribution of the total installed capacity among institutions and systems is given in Table 5.

TABLE 5- Distribution of total capacity with respect to systems, institutions and resources(MW).

	Interconnected		Isolated	
Institution	Thermal	Hydro	Thermal	Hydro
TEK	2928.3	2948.5	1.4	-
Non-TEK	760.8	248.6	77.6	10.2
Total	3689.1	3197.1	79.	10.2
Systems Total	6886.2		89.2	

TEK has the biggest share, 5876.8 MW, in our interconnected system which corresponds to 85.4 percent of total system capacity. The general characteristics of power plants composing the TEK capacity are given in Table 6.

TABLE 6- Characteristics of TEK Interconnected Units

Power Plant	Installed Cap.(MW)	Unit Capacities(MW)
a) Lignite Group		
Yatağan	420	2x210
Soma-B	330	2x165
Seyitömer	450	3x150
Tunçbilek-B	300	2x150
Tunçbilek-A	129	2x32, 1x65
Soma A	44	2x22
İzmir	37.5	1x20,3x5,1x2,5
TOTAL	1710.5	
b) Fuel-Oil Group		
Anbarlı	630	2x150, 3x110
Hopa	50	2x25
TOTAL	680	
c) Coal Group		
Çatalağzı	129	6x21,5
Silahtar	82.5	2x30,1x22.5
TOTAL	211.5	
d) Gas Turbines		
Aliağa	120	4x30
Seydişehir	120	8x15
Bornova	30	2x15
Hazar	30	2x15
Engil	16.2	1x16.2
Others	10.1	
TOTAL	326.3	
Thermic Total	2928.3	

TABLE 6- (Continued)

Power Plant	Installed Cap.(MW)	Unit Capacities(MW)
e) Dams with reservoir		
Keban	1370	4x185, 4x157.5
H.Uğurlu	500	4x125
Gökçekaya	278.4	3x92.8
Sarıyar	160	4x40
Hirfanlı	96	3x32
Kesikköprü	76	2x38
Demirköprü	69	3x23
Kemer	48	3x16
S.Uğurlu	46	2x23
Almus	27	3x9
TOTAL	2670.4	
f) Lake and River Group		
Doğankent A+B	73.3	
Kovada I+II	59.5	
Hazar I+II	30.1	
Tortum	26.2	
Çıldır	15.4	
İkizdere	15.1	
Göksu	10.6	
Çağ-Çağ	14.4	
Other p.p.	33.5	
TOTAL	278.1	
Hydraulic Total	2948.5	
GENERAL TOTAL	5876.8	

The energy produced by generating units in interconnected system is subject to some losses such as consumption of plant auxiliaries and network losses. The net energy consumed is thus obtained by dropping these losses from gross plant generations. This relation can be seen in Figure 1.

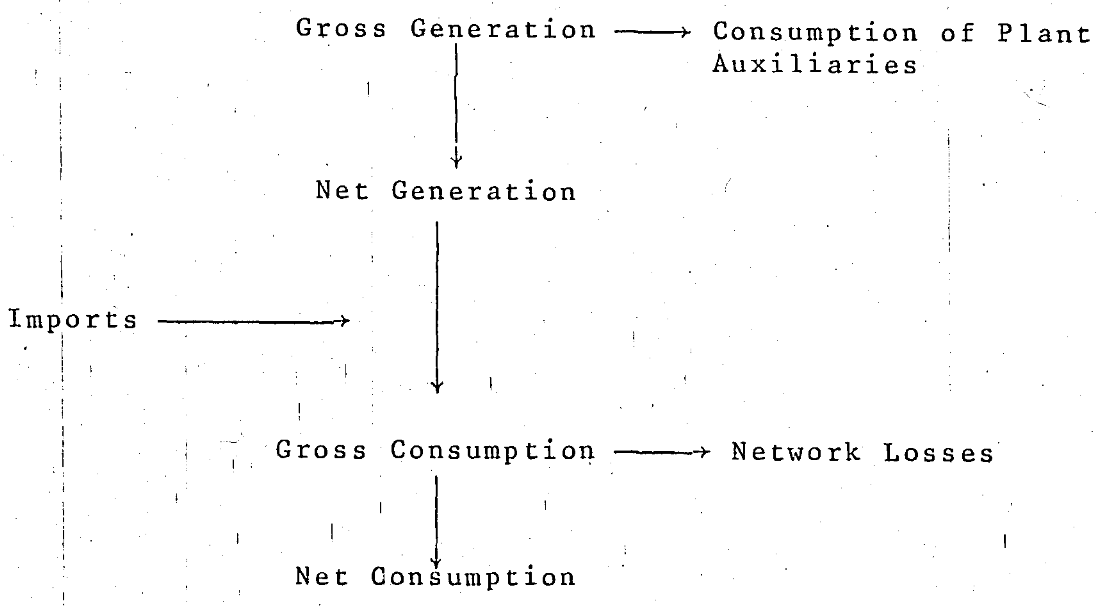

FIGURE 1- Interconnected System Generation-Consumption Relationship.

In addition to domestic generation, import possibilities exist by the interconnections with Bulgaria and USSR since 1975. The annual upper bound on energy import is determined as 1800 GWh through the agreements with these countries. On the other hand, the instantaneous maximum power that can be imported is taken as 350 MW.

3.2. GENERATION COSTS AND POWER PLANT AVAILABILITIES

Cost of energy generation consists of two parts: Fixed and variable. Fixed cost components are depreciation, interest charges on borrowed money, materials, labor, taxes, and other expenses that continue irrespective of the load on the power system. Variable part contains the costs affected by the loading of generating units of different fuel or water rates, and purchase or sale of power.

By analyzing the unit generation costs incurred for different power plants in the period 1970-1982 and by using unit fuel consumption rates, the gross generation costs for inter-connected system groups are determined as follows:

Group	Unit Cost of Generation (TL/kWh)
Lignite	8.-
Fuel Oil	19.-
Coal	22.-
Gas Turbine	60.-
Dams	1.-
Lake and River p.p.	2.-
Non-TEK Thermal	25.-
Non-TEK Hydro	2.-

The unit cost of import is taken as 10 TL/kWh by assuming the rates of exchange as 1 $ = 320 TL and 1 DM = 120 TL. The unit cost for the unsatisfied energy demand is taken as 200 TL/kWh.

For a power generation system composed of different types of power plants, estimation of the availability which can be expected from a given installed plant is clearly of great importance, since a change in this will be reflected closely in the plant margin and capital costs. Availability generally reflects the time for which the unit is not available because of breakdown related to the time for which the unit is needed to run. The rate of breakdown for a unit (i.e. the forced outage rate - FOR) is calculated as

$$\text{FOR} = \frac{\text{Duration of Breakdown}}{\text{Duration Subjected to Breakdown}}$$

where the duration subjected to breakdown is the sum of breakdown duration and the actual run time of that unit.

For all power plants considered in the model, FOR values are calculated and combined in order to obtain the group availabilities. Since the average generations are considered in the model, some proper allowances especially for the thermal units are included in the figures to represent the consumption rates in plant auxiliaries. The availability indices used in the planning model are given in Table 7.

TABLE 7- Availability Indices for generating groups.

i	Group	P_i(MW)	a_{it}
1	Lignite	1710.5	0.82
2	Fuel oil	680	0.87
3	Coal	211.5	0.78
4	Gas turbines	326.3	0.70
5	Keban	1370	0.96
6	H.Uğurlu-S.Uğurlu	546	0.95
7	Sarıyar-G.Kaya	438.4	0.94
8	Hirfanlı-K.Köprü	172	0.92
9	Demirköprü	69	0.95
10	Kemer	48	0.93
11	Almus	27	0.95
12	Lake and River p.p.	278.1	0.70

In the model, the non-TEK thermal and hydro power plant generations are handled by assuming average overall availabilities of 0.40 and 0.65, respectively:

$$P_{ikt} \leqq 0.40\ P_i \quad ; \quad \forall\ k,t$$

i = non-TEK thermal group

$$P_{ikt} \leqq 0.65\ P_i \quad ; \quad \forall\ k,t$$

i = non-TEK Hydro group

On the other hand, the lake and river group power plants are modelled with a load factor of 0.50 in each period. Also, in accordance with the operating strategy of T.E.K., the gas turbine group will be operated at most 3000 hours during 1984.

$$\sum_{k=1}^{m} P_{ikt}.d_{kt} \leq 0.50.P_i.D_t \quad ; \quad \forall t, \text{ i=Lake and River group}$$

$$D_t = \sum_{k=1}^{m} d_{kt}$$

$$\sum_{t=1}^{T} \sum_{k=1}^{m} P_{ikt}.d_{kt} \leq 3000 \; P_i \quad ; \quad \text{i=Gas turbine group.}$$

3.3. INTERCONNECTED SYSTEM POWER DEMANDS

The power demand patterns of the interconnected system for the year 1984 are obtained from the results of the fore-casting package program developed by TEK in the present year. The forecasting program utilizes the actual hourly loads supplied at each hour of the day during period 1970-1982. Each month is represented by its third week while the days of the week are classified into 5 groups: Monday, Wednesday, Saturday, Sunday and an equivalent day for Tuesday-Thursday and Friday. By comparing energy consumption figures through workdays and including the seasonal variation factors, the general trend of yearly peak load demand is obtained. Daily and hourly variation factors are employed to obtain the hourly loads for the representative week of each month for period 1983-1990 in terms of per-unit (i.e. as the percentage of yearly peak load demand) values.

From hourly load forecasting model, the load-duration curves for each month of 1984 are obtained. Since the model will consider seasonal planning, the monthly curves are combined in 3-month groups and seasonal load-duration curves are prepared.

Load-duration curves are approximated by 3 average load levels: Base load, intermediate load and peak load. Thus, for each period, the average load levels and corresponding durations in terms of hours are obtained. These are shown in Table 8.

TABLE 8- Average load levels and durations

Period	Load Level	Load(MW)	Duration(hours)
	1	3591	1760
1	2	4673	324
	3	5289	100
	1	3644	1819
2	2	4547	279
	3	5151	86
	1	3775	1785
3	2	4599	330
	3	5171	93
	1	3843	1775
4	2	4914	296
	3	5460	137

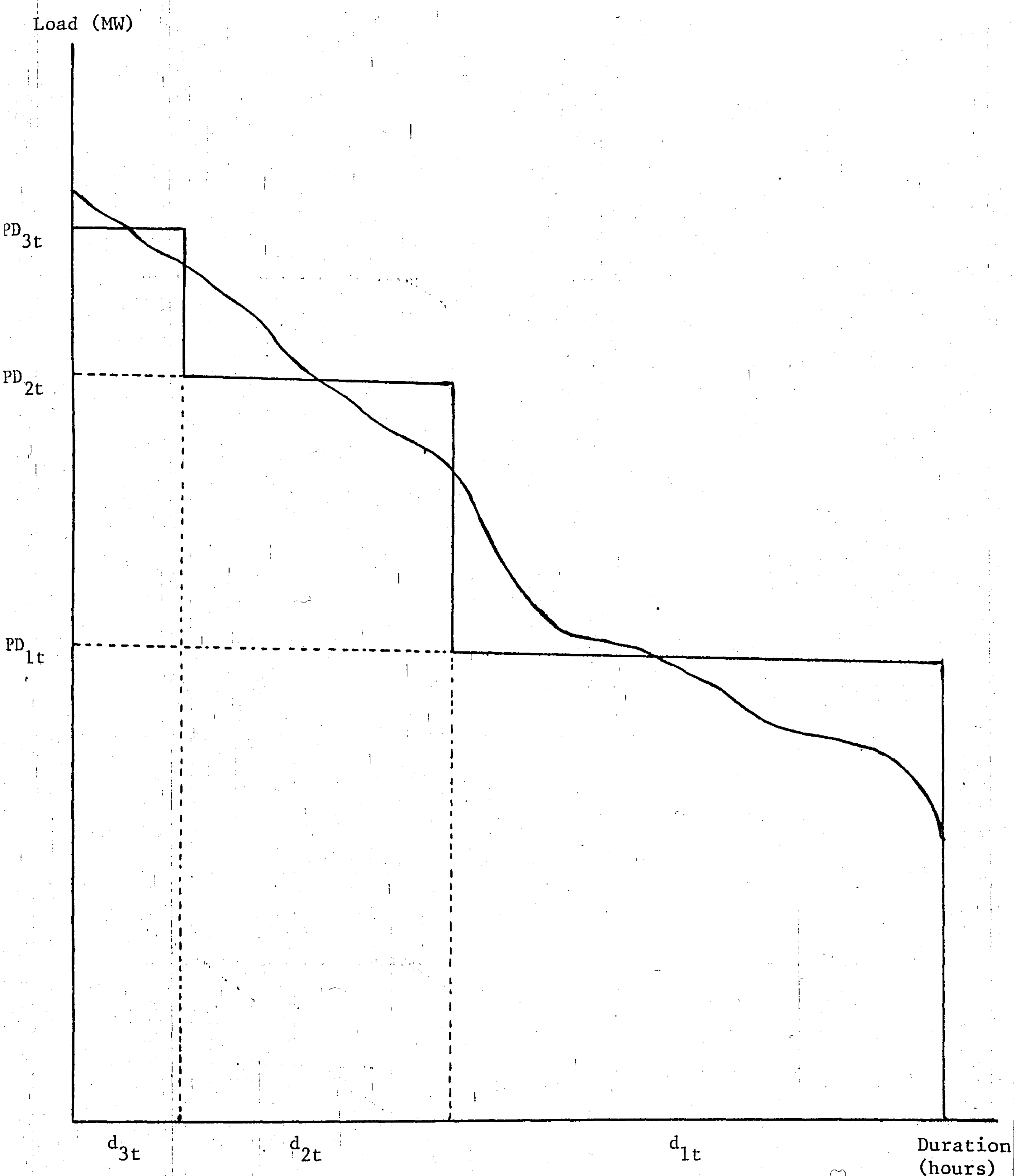

Figure 2. Approximation of the Load-duration Curve.

In Table 8, the yearly peak power demand is taken as the forecasted value of 5600 MW. The approximation of a load-duration curve by different load levels is shown in Figure 2.

The interconnected system energy demand for the year 1984 is accepted as 34,463.98 GWh in the model in accordance with load forecasting program results.

3.4. CHARACTERISTICS OF HYDRO OPERATION

There are many conditions connected with hydro operations, such as uncontrolled flows and required releases of water for irrigation or flood control, which take away from the system operator some of the alternatives that he might have if the water could be used entirely as desired for the benefit of power generation. The value of water changes from time to time, being lowered during periods of high flow, and increased during periods when flows are low or when reservoirs are being drafted at controlled rates of flow. Since each m^3 of water through a hydro plant will develop a definite amount of energy depending on the head of the reservoir, water is equivalent to fuel such as coal or oil for power generation purposes.

Water supplies for hydro generation can have different values from time to time, and the use of hydro power must be integrated into the system power supply so that the lowest overall cost results.

In the maintenance planning model developed, it is not aimed to perform statistical analysis on the operating rules of dams or on the distribution of water inflows. Using the available data relevant to water inflows and reservoir level patterns, all dams are assumed to have average water inflows throughout the periods of the year 1984. As a further step, the effects of a dry period which could occur once in 20 years for all geographical regions are observed as an extreme case for each scenario in order to find out the variations in optimal maintenance schedules.

The average annual water inflows for the dams with reservoir in interconnected system are given in Table 9.

TABLE 9- Average Inflows for the Dams

Dam	Average Annual Inflow m^3/sec.	Average Annual Inflow $10^6 m^3$/year
Keban	644.3	20318.64
H.Uğurlu	169.4	5342.20
Sarıyar	91.4	2882.39
Hirfanlı	79.7	2513.42
Demirköprü	29.2	920.85
Kemer	23.1	728.48
Almus	22.9	722.17

For each dam, the distribution of annual average water inflows into periods of the year is different. This is shown in Table 10.

TABLE 10- Percentage distribution of average annual inflows to periods

Dam	Operating Years	Periods 1	2	3	4
Keban	33	18.7	60.2	10.4	10.7
H.Uğurlu	23	30.4	48	8	13.6
Sarıyar	26	42.8	32.9	7.9	16.4
Hirfanlı	23	30	52.7	7.9	9.4
Demirköprü	23	54.5	22.6	5	17.9
Kemer	24	55.7	17.8	5.2	21.3
Almus	16	24	59.3	8	8.7

For each dam, the percentage values given in Table 10 are used to determine the period water inflows.

Gökçekaya is a "secondary" type dam since it's located on the same river with Sarıyar, and its water inflows are composed of releases from Sarıyar. S.Uğurlu and Kesikköprü have the similar characteristics as Gökçekaya, since they use the water releases of H.Uğurlu and Hirfanlı, respectively. These consecutive power plants are grouped together such as Sarıyar and Gökçekaya, H.Uğurlu and S.Uğurlu, Hirfanlı and Kesikköprü and used in this way in maintenance planning model.

Since their reservoirs are very small as compared to the primary plants, S.Uğurlu and Kesikköprü generations are simply related to H.Uğurlu and Hirfanlı, respectively, by the ratios of respective water usage efficiencies.

$$P_{jkt} \leq 0.092\ P_{ikt} \quad ; \quad \forall_{k,t} \quad ; \quad \begin{array}{l} j=\text{S.Uğurlu} \\ i=\text{H.Uğurlu} \end{array}$$

$$P_{jkt} \leq 0.65\ P_{ikt} \quad ; \quad \forall_{k,t} \quad ; \quad \begin{array}{l} j=\text{Kesikköprü} \\ i=\text{Hirfanlı} \end{array}$$

In general, the seasonal structure of hydraulic system operation can be considered in 3 periods(15):

a) Early Drawdown Season (October-December): Reservoirs are drawn down, and almost no forecasts of run-off are available.

b) Late Drawdown Season (January-March): Reservoirs are still being drawn, but run-off forecasts might make more storage available for use.

c) Refill-hold Season (April-September): The spring run-off allows filling, and mostly hydro resources are employed in the system.

So, by assuming average water inflows throughout the year, the pattern of reservoir water levels for each dam can be approximated. In the model, in accordance with the assumption of average water inflows, the reservoir water levels during different periods have been taken as average values utilizing the approximated normal operating curves for each dam. Also, end-of year target levels for reservoir volumes are imposed for each hydraulic power plant.

The amount of energy generated in a hydroelectric power plant is defined as

$$E_{it} = k_i \cdot h_{it} \cdot G_{it}$$

where,

k_i = A coefficient used to convert the water potential into energy,

h_{it} = Water level of the reservoir i during period t (m)

G_{it} = The amount of water released for energy generation during period t (m^3)

E_{it} = Energy generated in period t (kWh)

This relation can be converted to the following form in order to obtain the average power generation during a load level k.

$$P_{ikt} = \frac{k_i \cdot h_{it}}{d_{kt}} \cdot G_{ikt}$$

Where P_{ikt} is the average power output obtained during load level k in period t, G_{ikt} is the amount of water released for generation during load level k in period t and d_{kt} is the duration of load level k in period t.

The term ($k_i . h_{it}$) practically represents the amount of energy that can be generated by one unit volume of water. For each dam and period, these terms are obtained from the tables prepared by D.S.İ. for each dam showing the variation of water efficiency rates with altitude. This relation is shown in Table 11 for Keban.

TABLE 11- Water efficiency rates for Keban

Altitude (m)	m^3/kWh
795	3.70
800	3.50
805	3.35
810	3.22
815	3.08
820	2.98
825	2.82
830	2.69
835	2.58
840	2.48
845	2.40

Through the operation of a dam, the reservoir water level has lower and upper limits reflecting the operating efficiency and reliability. Operating a reservoir around its minimum critical level enchances the system risk resulting from the uncertainities related to the expected water inflows in future periods. Also, the efficiency in energy generation decreases due to the lowered reservoir level.

On the other hand, operating around the maximum reservoir capacity imposes a risk onto the system in terms of operating safety in cases of excess water inflows. Also, this situation can lead to the opportunity loss of the water inflow by overflowing from the filled reservoir. The upper and lower limits on reservoir operating water levels are given in Table 12.

TABLE 12- Operating limits for the dams ($h(m)$, $S(10^6\ m^3)$)

Dam	$h_{i_{min}}$	$S_{i_{min}}$	$h_{i_{max}}$	$S_{i_{max}}$
Keban	813	14199.57	845	31001.59
H.Uğurlu	178	777.50	199	1250.00
Sarıyar	460	756.60	477	1900.30
Gökçekaya	377.5	730.00	392	1018.80
Hirfanlı	842	3705.30	851	5750.00
Demirköprü	221.8	280.46	244.2	1105.40
Kemer	252.7	97.62	293	460.05
Almus	772.2	215.60	804.5	1006.83

3.5. SCENARIO SPECIFICATIONS

The maintenance planning model is solved for different scenarios related to the commissioning dates of planned investments and yearly power demand patterns in 1984.

The characteristics of the new investments which are planned to be in operation and the corresponding commissioning dates are given in Table 13.

TABLE 13- Characteristics of planned investments

Power Plant	Type	Unit Capacities (MW)	Planned commissioning Date (Months)
Oymapınar 1-4	Dam	4x135	1-4-7-10/1984
Aslantaş 1-3	Dam	3x46	4-7-10/1984
Elbistan A-1	Lignite	1x340	7/1984
Çevrim	Gas turbine	1x60	10/1983
Geothermal	Natural steam	1x15	1/1984

In the model, the maintenance requirements are employed only for groups already in operation by July 1983 and the planned capacity additions are handled with appropriate availabilities and load factors in suitable generating groups. Oymapınar and Aslantaş generating units are included in Lake and River power plant group with an average availability of 0.70 and an overall load factor of 0.50 in respective periods. Elbistan A-1 and Geothermal power plants are included in Lignite group with 0.70 availability whereas Çevrim is considered in Gas Turbine group with the same availability figure.

The maintenance planning model is solved first by assuming the realization of all investments at planned commissioning dates (Scenario code: IR). Then, the effects of possible delays in commissioning dates are considered in order to observe the shifts in maintenance schedules. This is performed by employing two more scenarios, namely "the case of six months delay" and "the case of one year delay". in commissioningdates for all investments (Scenario codes:

ID_1 and ID_2). The commissioning dates of planned investments assumed in different scenarios are given in Table 14.

TABLE 14- Commissioning dates of planned investments

Power Plant	Unit	Cap. (MW)	Scenario		
			IR	ID_1	ID_2
Oymapınar	1	135	1/1984	7/1984	1/1985
Oymapınar	2	135	4/1984	10/1984	4/1985
Oymapınar	3	135	7/1984	1/1985	7/1985
Oymapınar	4	135	10/1984	4/1985	10/1985
Aslantaş	1	46	4/1984	10/1984	4/1985
Aslantaş	2	46	7/1984	1/1985	7/1985
Aslantaş	3	46	10/1984	4/1985	10/1985
Elbistan A	1	340	7/1984	1/1985	7/1985
Çevrim	1	60	10/1983	4/1984	10/1984
Geothermal	1	15	1/1984	7/1984	1/1985

Using Table 14, the accumulated capacity additions in 1984 with respect to periods considered in the model are obtained as in Table 15.

TABLE 15- Development of capacity additions through periods (MW)

Scenario	Period			
	I	II	III	IV
IR	210	391	912	1093
ID_1	-	60	210	391
ID_2	-	-	-	60

On the other hand, the load demand forecasts have uncertainties related to yearly peak load. In Table 8, the approximated average load levels and durations were given for the forecasted yearly peak of 5600 MW(Case of forecasted load demands-FL). In order to observe the variations in operation and maintenance policies against the deviations from yearly peak load and corresponding energy forecasts, two other load demand patterns are employed. These include an overall decrease (lower loads) and an overall increase (upper loads) of 5 % in load demands for all load levels (Cases of LL and UL). By using the same per-unit distributions for representative weeks of each month, the approximated load-duration curves of each period are obtained, while keeping the load level durations as in FL case for simplicity. The yearly peak loads are 5320 and 5880 MW whereas energy demands are 32,733.86 and 36,181.63 GWh for LL and UL cases, respectively. The average load levels for these two scenarios are given in Table 16.

TABLE 16- Average load levels for load demand scenarios(MW).

Period	Load Level	LL	UL
1	1	3412	3771
	2	4439	4907
	3	4976	5501
2	1	3461	3826
	2	4319	4774
	3	4915	5432
3	1	3586	3964
	2	4369	4829
	3	4920	5438
4	1	3651	4035
	2	4668	5160
	3	5161	5705

As a result, a total of nine different scenarios have been tried including three power demand patterns and three different conditions for the new capacity additions as shown in Figure 3.

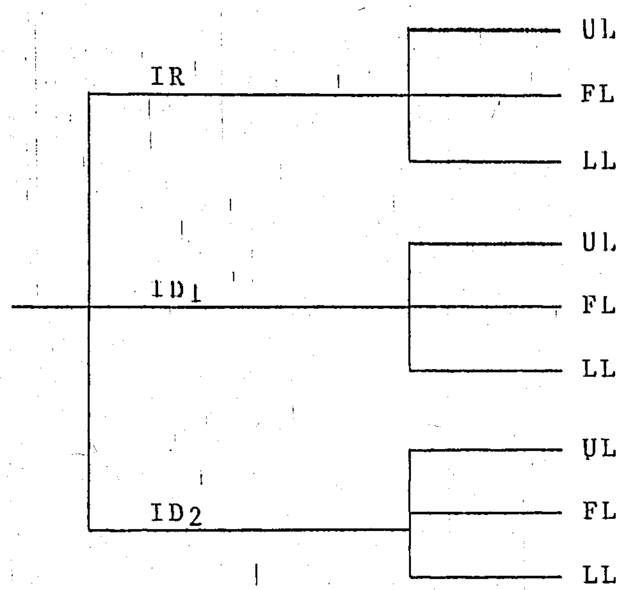

Figure 3. Outline of scenarios.

In addition, the same scenarios have been applied assuming the water inflows of a dry water year which could occur once in twenty years for all dams by making the necessary adjustments in water generation efficiencies and load factors for hydro resources.

4- RESULTS AND OBSERVATIONS

The main observation derived as a result of the model applications for different scenarios is related to the hydraulic nature of the power system. As can be seen through the analysis of operating results, the leading factor in planning the operation and maintenance of the power system is the usage of hydro facilities in regulating the system supply against different power demand levels while performing the required plant maintenances.

A second observation is that the first period of 1984 (January-March) will keep the highest risk since it incorporates the lowest hydro generation potential and since it's the period which is highly affected from the delays incurred in new capacity additions. The detailed operating results are given in following sections.

4.1. CASE OF AVERAGE WATER INFLOWS

The general framework obtained through the application of the planning model to all scenarios shows that the thermal power plant maintenances are scheduled to the third and second periods (April-September) where hydraulic generation potential is maximum due to the high reservoir levels resulting from the expected water inflows especially in the second period and the obligation of keeping relatively high reservoir levels during summer months for irrigation purposes. This obligation also emerges from the requirement of satisfying the demand during the month in which the highest energy and peak power demands occur, namely December.

It has been observed that, whatever the investment commissioningdates and power demand levels are, dams with reservoir must operate through the aim of maximizing hydro energy utilization, which is equivalent to generate when reservoir level is around its highest expected value.

The optimal maintenance schedules obtained for all normal (average) water year scenarios are given in Table 17.a, b,c. The corresponding operating results in terms of average generations for the generating groups are given in Appendix I-A.

In order to observe the variations in maintenance capacities more effectively, the percentage distribution of maintenance capacities with respect to resources and scenarios are given in Table 18.

TABLE 17.a. Capacities in Maintenance-Case of IR(MW)

SCENARIO: NORMAL WATER YEAR - INVESTMENTS REALIZED

Loads	Decreased by 5 %				Forecasted Loads				Increased by 5 %			
Lignite	-	-	1726	-	-	-	1726	-	-	-	1726	-
Coal	212	-	-	-	-	-	212	-	-	212	-	-
F.Oil	-	-	680	-	-	286	394	-	-	431	249	-
Gas Turbine	386	-	-	-	386	-	-	-	-	-	-	386
Thermal Tot.	598	-	2406	-	386	286	2331	-	-	642	1975	386
Keban	1083	182	-	107	620	487	-	263	908	-	-	463
H.Uğurlu S.Uğurlu	-	-	-	546	-	-	-	546	-	-	-	546
Sarıyar Gökçekaya	-	-	-	438	-	-	-	438	-	-	-	438
Hirfanlı Kesikköprü	-	172	-	-	-	172	-	-	-	172	-	-
Demirköprü	-	-	69	-	-	69	-	-	-	-	69	-
Kemer	-	-	48	-	-	-	-	48	-	-	-	48
Almus	27	-	-	-	27	-	-	-	27	-	-	-
Dams Total	1110	365	117	1079	647	728	-	1295	946	161	69	1495
Lake and River P.P.	-	-	14	265	-	-	-	278	-	-	-	278
Hydraulic Total	1110	365	131	1344	647	728	-	1573	946	161	69	1773
General Total	1707	365	2536	1344	1033	1015	2331	1573	946	803	2044	2159
PERIOD	I	II	III	IV	I	II	III	IV	I	II	III	IV

TABLE 17.b. Capacities in Maintenance-Case of TD_1 (MW)
SCENARIO: NORMAL WATER YEAR - INVESTMENTS DELAYED 6 MONTHS

Loads	Decreased by 5 %				Forecasted Loads				Increased by 5 %			
Lignite	-	576	1135	-	-	1283	427	-	-	1007	704	-
Coal	-	212	-	-	-	212	-	-	-	212	-	-
F.Oil	-	-	680	-	-	-	680	-	-	-	680	-
Gas Turbine	326	-	-	-	326	-	-	-	-	-	326	-
Thermal Tot.	326	787	1815	-	386	1506	1111	-	-	1227	1776	-
Keban	1305	65	-	-	1239	-	-	131	1292	-	-	78
H.Uğurlu S.Uğurlu	-	-	-	546	-	-	-	546	-	-	-	546
Sarıyar Gökçekaya	156	-	-	283	-	-	-	438	-	-	-	438
Hirfanlı Kesikköprü	-	172	-	-	-	172	-	-	-	172	-	-
Demirköprü	-	-	69	-	-	-	69	-	-	-	69	-
Kemer	48	-	-	-	-	-	10	38	-	-	-	48
Almus	27	-	-	-	-	-	-	27	27	-	-	-
Dams Total	1536	237	69	829	1239	172	79	1181	1330	-	69	1271
Lake and River P.P.	240	38	-	-	-	-	278	-	-	-	-	278
Hydraulic Total	1776	275	69	829	1239	172	357	1181	1330	-	69	1549
General Total	2102	1062	1884	829	1625	1678	1468	1181	1330	1227	1845	1549
PERIOD	I	II	III	IV	I	II	III	IV	I	II	III	IV

TABLE 17.c. Capacities in Maintenance-Case of ID_2(MW)

SCENARIO: NORMAL WATER YEAR - INVESTMENTS DELAYED 1 YEAR

Loads	Decreased by 5 %				Forecasted Loads				Increased by 5 %			
Lignite	-	889	822	-	-	920	790	-	-	1276	435	-
Coal	-	212	-	-	-	212	-	-	-	212	-	-
F.Oil	-	-	680	-	-	-	680	-	-	-	680	-
Gas Turbine	326	-	-	-	-	326	-	-	-	-	326	-
Thermal Tot.	326	1100	1502	-	-	1458	1470	-	-	1487	1441	-
Keban	1370	-	-	-	922	448	-	-	1370	-	-	-
H.Uğurlu S.Uğurlu	263	54	-	229	144	-	-	402	96	-	-	450
Sarıyar Gökçekaya	-	36	-	402	-	-	119	319	438	-	-	-
Hirfanlı Kesikköprü	12	144	12	5	12	144	12	5	-	-	-	172
Demirköprü	-	-	69	-	-	69	-	-	-	-	69	-
Kemer	-	-	-	48	-	-	48	-	48	-	-	-
Almus	27	-	-	-	-	-	-	27	-	-	-	27
Dams Total	1671	234	81	684	1077	661	179	754	1953	-	69	649
Lake and River P.P.	-	240	-	38	240	-	38	-	240	-	-	38
Hydraulic Total	1671	474	81	723	1317	661	217	754	2192	-	69	687
General Total	1997	1574	1583	723	1317	2119	1687	754	2192	1487	1510	687
PERIOD	I	II	III	IV	I	II	III	IV	I	II	III	IV

TABLE 18- Distribution of percentage capacities in maintenance

LOADS	PERIOD	THERMAL CAPACITY Scenario IR	ID_1	ID_2	HYDRO CAPACITY Scenario IR	ID_1	ID_2	TOTAL CAPACITY Scenario IR	ID_1	ID_2
Upper Loads	1	-	-	-	32.1	45.1	74.4	15.9	22.4	37.3
	2	21.4	40.9	50.8	5.4	-	-	13.5	20.6	25.3
	3	65.7	59.1	49.2	2.3	2.3	2.3	34.3	31.0	25.7
	4	12.9	-	-	60.1	52.5	23.3	36.3	26.0	11.7
Forecasted Loads	1	12.9	12.9	-	21.9	42.0	44.7	17.4	27.3	22.4
	2	9.5	50.1	49.8	24.7	5.8	22.4	17.0	28.2	36.1
	3	77.6	37.0	50.2	-	12.1	7.4	39.2	24.7	28.7
	4	-	-	-	53.4	40.1	25.5	26.4	19.8	12.8
Lower Loads	1	19.9	11.1	11.1	37.6	60.2	56.7	28.7	35.8	34.0
	2	-	26.9	37.6	12.4	9.3	16.1	6.1	18.0	26.8
	3	80.1	62.0	51.3	4.4	2.3	2.7	42.6	32.1	26.9
	4	-	-	-	45.6	28.1	24.5	22.6	14.1	12.3

The percentage distribution of capacities in maintenance in terms of major power plant groups for different scenarios is given in Table 19. It can be observed that, through the increasing load levels and delaying investments, the total maintenance capacity is being transferred from the fourth and third periods to the first two periods-especially to the first period-in order to meet the increased energy figures through those periods by the scenario developments. Finally, since the model aims for the overall minimization of operating system

TABLE 19- Percentage Capacities in Maintenance (Average Water Inflows)

		PERIOD															
		LIGNITE				COAL				FUEL OIL				KEBAN			
SCENARIO	LOADS	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
	UL	-	-	100	-	-	100	-	-	-	63.4	36.6	-	66.2	-	-	33.8
IR	FL	-	-	100	-	-	-	100	-	-	42.1	57.9	-	45.3	35.6	-	19.1
	LL	-	-	100	-	100	-	-	-	-	-	100	-	79	13.2	-	7.8
	UL	-	58.9	41.1	-	-	100	-	-	-	-	100	-	94.3	-	-	5.7
ID_1	FL	-	75	25	-	-	100	-	-	-	-	100	-	90.4	-	-	9.6
	LL	-	33.7	66.3	-	-	100	-	-	-	-	100	-	95.3	4.7	-	-
	UL	-	74.6	25.4	-	-	100	-	-	-	-	100	-	100	-	-	-
ID_2	FL	-	53.8	46.2	-	-	100	-	-	-	-	100	-	67.3	32.7	-	-
	LL	-	51.9	48.1	-	-	100	-	-	-	-	100	-	100	-	-	-

costs, the supply in the last two periods is improved at the expense of the first two periods. Thermal group maintenances begin to shift from the third period to the second and the hydro group from the fourth period to the first. This results in a high operating risk especially for the first period.

The variation of water usage in Keban reservoir is given in Figure 4 for the case of forecasted load demands. As seen from the figure, the delaying investments forced the dam to accumulate more water during the first two periods in order to fulfill the system demand where reservoir is at its highest average level (period 3) and where the system demand is the maximum (Period 4).

For the scenarios of average water inflows, unsatisfied power demand does not exist except the 370.4 Gwh deficit for the upper-load case when the investment delays are one year. But, it is highly possible for some deficits to occur because of limitations due to fuel supplies and unforeseen breakdowns especially in thermal power plants. In addition, there exists a high degree of uncertainty in assumed non-TEK availabilities and load factors.

The average and marginal costs of generation are given in Table 20, which shows the relatively higher risk of the first period resulting from the employment of expensive resources in generation.

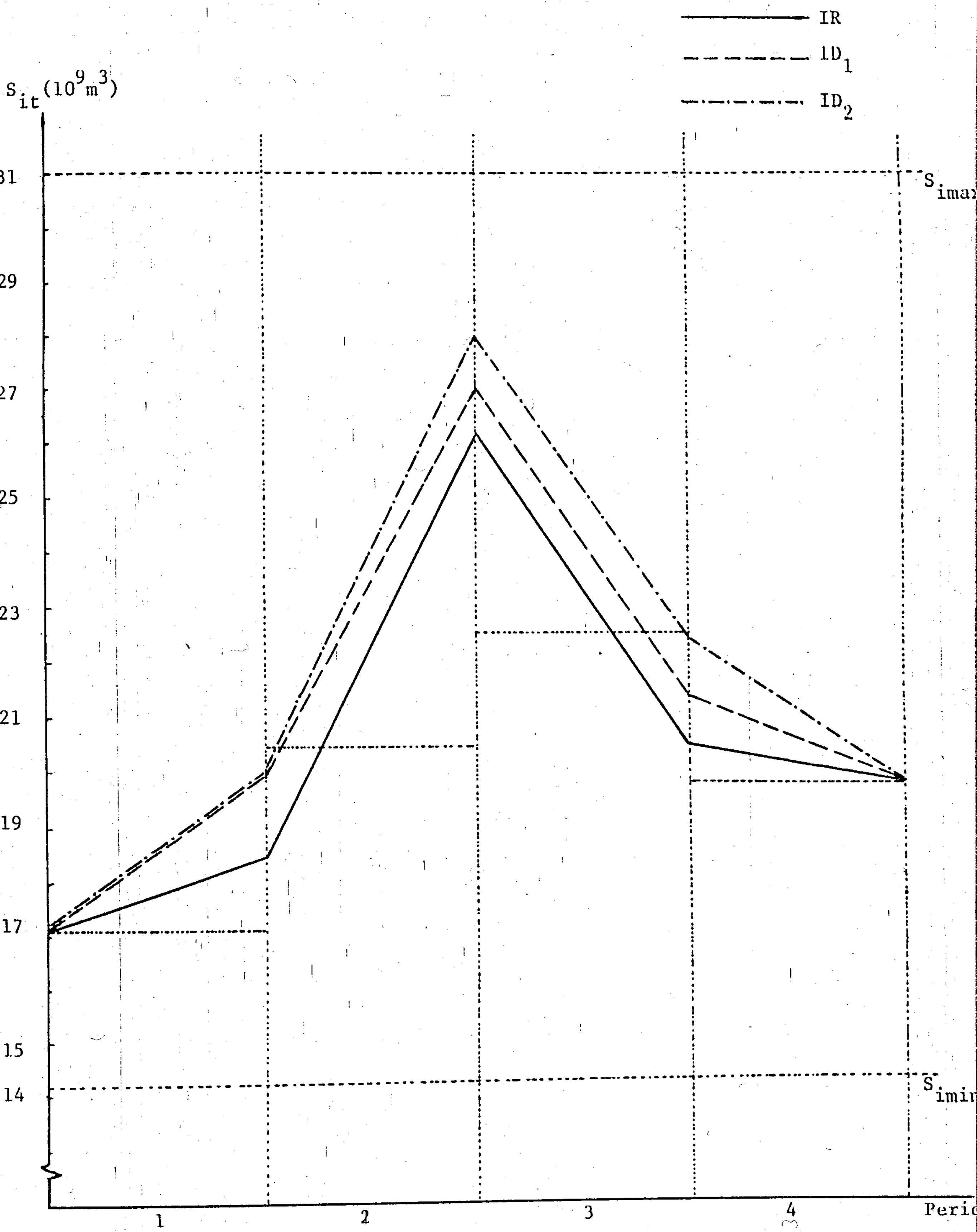

Figure 4. Water usage in Keban reservoir (Forecasted loads)

TABLE 20- Costs of generation for different scenarios (TL/kWh)

Scenario		Average Cost of Generation	Marginal Cost of Generation Period 1	Period 2	Period 3	Period 4
	IR	6.41	20.36	19.0	19.0	19.13
LL	ID_1	7.60	25.0	23.31	23.31	23.47
	ID_2	7.95	26.09	25.0	24.78	24.92
	IR	7.12	23.63	22.03	22.03	22.19
FL	ID_1	8.47	26.98	25.38	25.0	25.29
	ID_2	8.83	27.62	25.89	25.65	25.80
	IR	7.92	26.79	25.0	25.0	25.14
UL	ID_1	10.13	64.02	60.22	60.0	60.0
	ID_2	12.53(10.48)*	200.0	196.84	193.81	193.81

* Excludes unsatisfied demand.

4.2. CASE OF DRY PERIOD WATER INFLOWS

The scenarios considered for the case of average water inflows derived a general framework for the power plant maintenances. In order to examine the variations of this framework against limited availability of hydro resources, a further step has been taken for all scenarios related to commissioning dates and power demands.

To represent the dry period yearly water inflows, the distribution of total annual inflow incorporating all dams is utilized. As can be deduced from Table 9, the average total annual inflow is 1060 m^3/sec. An analysis employing the data of the period 1950-1982 over total annual inflows showed that the standard deviation is $\hat{S}$ = 256.25 m^3/sec. Then, using the t distribution, 95 % confidence limit for the total annual inflow is found as

$$X_{0.95} = \bar{X} - t_{0.95} \cdot \hat{S}$$

$$X_{0.95} = 1060 - (1.645)(256.25) = 638.5 \ m^3/sec.$$

This value is used to reflect the dry period annual water inflows for each dam by simply multiplying their average annual inflow figure by $X_{0.95}/\bar{X}$. The values in Table 10 is used to obtain the corresponding seasonal figures. The dry period annual water inflows are given in Table 21.

TABLE 21- Dry period annual water inflows

Dam	Annual Inflow m^3/sec	Annual Inflow $10^6 m^3$/year
Keban	388.1	12238.59
H.Uğurlu	102.0	3217.78
Sarıyar	55.1	1736.16
Hirfanlı	48.0	1513.91
Demirköprü	17.6	554.66
Kemer	13.9	438.79
Almus	13.8	434.99

In addition, the necessary adjustments related to water efficiencies (reservoir levels) and load factors have been made. The Non-TEK hydro power plants are assigned an overall availability of 45 %, whereas lake and river group is assumed to have a load factor of 35 %.

The optimal maintenance schedules obtained for all dry water year scenarios are given in Table 22.a-b-c. The corresponding operating results in terms of average generations for the generating groups are given in Appendix I-B.

It has been observed that, being similar to the case of average water inflows, the trend seen in the operation of dams with reservoir so as to operate through the aim of maximizing hydro energy utilization appears more definitely because of restricted hydro availabilities. Also, the maintenance schedule alternatives for hydro power plants get enlarged through the lowered operation times.

The percentage distribution of capacities in maintenance in terms of major power plant groups for different scenarios is given in Table 23. Also, the percentage distribution of total maintenance capacity for each scenario is given in Table 24.

Due to the restricted hydro availability, increasing amounts of energy deficit emerge as shown in Table 25. In parallel to the average water inflow scenarios, since the maintenance capacities are being transferred to the first two periods, the first period incorporates a high risk again. But, the decreased hydro availabilities cause the fourth period to have the maximum risk level among other periods.

TABLE 22.a. Capacities in Maintenance, Case of IR (MW)

SCENARIO: DRY WATER YEAR - INVESTMENTS REALIZED

Loads	Decreased by 5 %				Forecasted Loads				Increased by 5 %			
Lignite	-	-	1726	-	-	-	1726	-	-	-	1726	-
Coal	-	-	212	-	-	-	212	-	-	-	212	-
F.Oil	-	-	680	-	-	-	680	-	-	-	680	-
Gas Turbine	-	-	-	386	-	-	386	-	-	-	386	-
Thermal Tot.	-	-	2617	386	-	-	3003	-	-	-	3003	-
Keban	1370	-	-	-	-	1370	-	-	-	1370	-	-
H.Uğurlu S.Uğurlu	546	-	-	-	546	-	-	-	546	-	-	-
Sarıyar Gökçekaya	-	-	-	438	438	-	-	-	-	-	-	438
Hirfanlı Kesikköprü	-	-	13	159	-	-	-	172	-	-	11	161
Demirköprü	-	-	-	69	-	69	-	-	-	-	-	69
Kemer	-	-	-	48	-	-	-	48	48	-	-	-
Almus	27	-	-	-	27	-	-	-	27	-	-	-
Dams Total	1943	-	13	714	1011	1439	-	220	621	1370	11	668
Lake and River P.P.	-	-	-	278	278	-	-	-	278	-	-	-
Hydraulic Total	1943	-	13	992	1290	1439	-	220	899	1370	11	668
General Total	1943	-	2630	1379	1290	1439	3003	220	899	1370	3015	668
PERIOD	I	II	III	IV	I	II	III	IV	I	II	III	IV

TABLE 22.b. Capacities in Maintenance Case of ID_1(MW)
SCENARIO: DRY WATER YEAR - INVESTMENTS DELAYED 6 MONTHS

Loads	Decreased by 5 %				Forecasted Loads				Increased by 5 %			
Lignite	-	-	1711	-	-	160	1550	-	-	875	836	-
Coal	-	-	212	-	-	212	-	-	-	212	-	-
F.Oil	-	-	680	-	-	-	680	-	-	-	680	-
Gas Turbine	-	-	-	326	-	-	-	326	-	-	326	-
Thermal Tot.	-	-	2602	326	-	372	2230	326	-	1087	1842	-
Keban	1370	-	-	-	-	1370	-	-	-	1353	17	-
H.Uğurlu S.Uğurlu	546	-	-	-	546	-	-	-	546	-	-	-
Sarıyar Gökçekaya	-	-	-	438	438	-	-	-	438	-	-	-
Hirfanlı Kesikköprü	-	-	11	161	-	-	-	172	-	-	11	161
Demirköprü	-	69	-	-	-	69	-	-	-	69	-	-
Kemer	-	-	-	48	-	-	-	48	48	-	-	-
Almus	27	-	-	-	27	-	-	-	27	-	-	-
Dams Total	1943	69	11	647	1011	1439	-	220	1059	1422	28	161
Lake and River P.P.	278	-	-	-	278	-	-	-	278	-	-	-
Hydraulic Total	2221	69	11	647	1290	1439	-	220	1338	1422	28	161
General Total	221	69	2613	973	1290	1811	2230	546	1338	2509	1870	161
PERIOD	I	II	III	IV	I	II	III	IV	I	II	III	IV

TABLE 22.c. Capacities in Maintenance.Case of ID_2 (MW)

SCENARIO: DRY WATER YEAR - INVESTMENTS DELAYED 1 YEAR

Loads	Decreased by 5 %				Forecasted Loads				Increased by 5 %			
Lignite	-	-	1711	-	-	367	1344	-	-	1058	652	-
Coal	-	-	212	-	-	212	-	-	-	212	-	-
F.Oil	-	-	680	-	-	-	680	-	-	-	680	-
Gas Turbine	326	-	-	-	326	-	-	-	-	-	326	-
Thermal Tot.	326	-	2602	-	326	578	2024	-	-	1270	1659	-
Keban	-	1370	-	-	1370	-	-	-	1370	-	-	-
H.Uğurlu S.Uğurlu	546	-	-	-	546	-	-	-	546	-	-	-
Sarıyar Gökçekaya	438	-	-	-	438	-	-	-	438	-	-	-
Hirfanlı Kesikköprü	-	-	11	161	-	-	11	161	-	-	-	172
Demirköprü	-	-	-	69	-	-	-	69	-	69	-	-
Kemer	-	-	-	48	48	-	-	-	-	-	-	48
Almus	27	-	-	-	27	-	-	-	27	-	-	-
Dams Total	1011	1370	11	278	2429	-	11	230	2381	69	-	220
Lake and River P.P.	278	-	-	-	278	-	-	-	278	-	-	-
Hydraulic Total	1290	1370	11	278	2708	-	11	230	2660	69	-	220
General Total	1616	1370	2613	278	3034	578	2035	230	2660	1339	1659	220
PERIOD	I	II	III	IV	I	II	III	IV	I	II	III	IV

TABLE 23- Percentage Capacities in Maintenance (Dry Period Water Inflows)

		PERIOD															
		LIGNITE				COAL				FUEL OIL				KEBAN			
SCENARIO	LOADS	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
IR	UL	–	–	100	–	–	–	100	–	–	–	100	–	–	100	–	–
	FL	–	–	100	–	–	–	100	–	–	–	100	–	–	100	–	–
	LL	–	–	100	–	–	–	100	–	–	–	100	–	100	–	–	–
ID_1	UL	–	51.2	48.8	–	–	100	–	–	–	–	100	–	–	100	–	–
	FL	–	9.4	90.6	–	–	100	–	–	–	–	100	–	–	100	–	–
	LL	–	–	100	–	–	–	100	–	–	–	100	–	100	–	–	–
ID_2	UL	–	61.9	38.1	–	–	100	–	–	–	–	100	–	100	–	–	–
	FL	–	21.4	78.6	–	–	100	–	–	–	–	100	–	100	–	–	–
	LL	–	–	100	–	–	–	100	–	–	–	100	–	–	100	–	–

TABLE 24- Distribution of total capacity in maintenance (%)

Loads	Period	Scenario IR	ID_1	ID_2
Upper Loads	1	15.1	22.8	45.3
	2	23.0	42.7	22.8
	3	50.7	31.8	28.2
	4	11.2	2.7	3.7
Forecasted Loads	1	21.7	21.9	51.6
	2	24.2	30.8	9.8
	3	50.4	38.0	34.6
	4	3.7	9.3	3.9
Lower Loads	1	32.6	37.8	27.5
	2	-	1.2	23.3
	3	44.2	44.5	44.5
	4	23.2	16.6	4.7

TABLE 25- Energy Deficits (GWh)

Loads	Scenario	Periods 1	2	3	4	Total
UL	IR	1420.8	377.5	-	1378.6	3176.9
	ID_1	1622.5	1892.2	15.9	1706.5	5237.1
	ID_2	1622.5	1541.9	33.	2529.5	5726.9
FL	IR	1001.5	208.1	-	255.6	1465.2
	ID_1	1208.7	1046.9	99.2	1259.3	3524.1
	ID_2	1547.2	646.8	15.4	1804.6	4014.0
LL	IR	-	-	-	-	-
	ID_1	786.5	87.2	-	925.4	1799.1
	ID_2	920.4	87.2	-	1280.8	2288.4

4.3. DISTRIBUTION OF MAINTENANCE CAPACITIES

Nine different scenarios have been tried assuming that the dams would have average water inflows throughout the periods of the year considered. In addition, the same scenarios have been repeated for a probable dry water year in order to observe the variations in operation and maintenance policies in case of hydro inavailability. Since the problem is modelled in a way such that to obtain the optimal seasonal maintenance schedules while satisfying the operational requirements, the model results enable us to derive a framework for each power plant group in terms of operating characteristics as well as of maintenance. Using the results in Appendices I.A and I.B, it can be observed that there exists a general trend for all dams to operate especially around peak loads, and also in periods where the water accumulation in reservoirs is maximum. So, the operation and maintenance policies for all groups are regulated by this principle in a way so as to perform the thermal capacity maintenances in summer months where hydro resource utilization is preferred due to high reservoir levels. This relation emerges more definitely in case of limited hydro availability such that the "inhibited" periods of maintenance for dams related to the efficiency of system operation can be obtained.

The scenarios, being related to commissioning dates of planned investmens, and yearly power demand patterns, reflect the different states of nature, or environmental conditions. But, it's certain that the chance of occurrence of each environmental condition -i.e. each scenario- is different. In order to emphasize this difference and to realize a more realistic plan against uncertainities in the future, the relative importance of each scenario is derived through probabilities. Utilizing the forecasts made by T.E.K. authorities, the following prior probabilities are assigned to each state considered in the model.

TABLE 26- Prior probabilities of scenario components

Power Demand Pattern	Probability
Upper Loads (UL)	0.30
Forecasted Loads (FL)	0.60
Lower Loads (LL)	0.10
Investment Commission Dates	**Probability**
Planned due dates (IR)	0.80
Delay of six months (ID_1)	0.15
Delay of one year (ID_2)	0.05

Using these prior distributions, the probabilities of environmental conditions as assumed in related scenarios are obtained as in Figure 5.

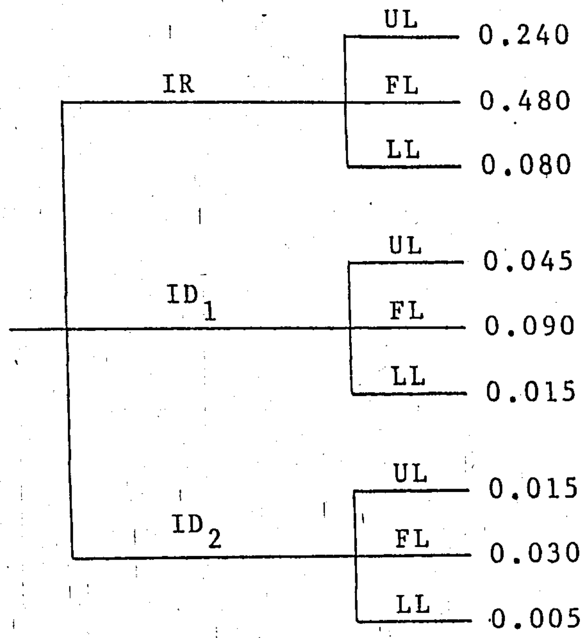

Figure 5. Probability distribution of scenarios.

So, the percentage maintenance capacities obtained for different scenarios can be weighed by the corresponding probabilities in order to obtain the distribution of optimal maintenance schedules with respect to periods and power plant groups. This distribution is shown in Table 27.a for the case of average water inflows and in Table 27.b for dry period water inflows by considering the major generating groups.

Especially for the case of dry period inflows, the maintenance schedules for dams proposed by the model results contain alternative solutions due to the lowered load factor of these groups. So, the "inhibited" periods of maintenance for each dam which result from the differences in water usage efficiencies through periods emerge more definitely. These periods are: Periods 2 and 3 for H.Uğurlu-S.Uğurlu, Sarıyar -

Gökçekaya and Kemer, periods 3 and 4 for Keban, period 3 for Hirfanlı-Kesikköprü and Almus, and period 1 for Demirköprü. As far as the operating system efficiency is concerned, the characteristics of hydraulic units in terms of feasible maintenance periods must be considered in developing an efficient maintenance program for the whole system.

TABLE 27.a. Distribution of maintenance schedules-average inflows (%)

Group	Period 1	Period 2	Period 3	Period 4
Lignite	-	12.9	87.1	-
Fuel Oil	-	35.4	64.6	-
Coal	-	48.	52.	-
Keban	61.8	19.2	-	19.
H.Uğurlu	1.3	-	-	98.7
Sarıyar	2.	-	0.8	97.2
Hirfanlı	0.2	97.9	0.2	1.6
Kemer	27.	-	12.8	60.2

TABLE 27.b. Distribution of maintenance schedules-dry period inflows (%)

Group	Period 1	Period 2	Period 3	Period 4
Lignite	-	5.2	94.8	-
Fuel Oil	-	-	100.	-
Coal	-	18.	82.	-

III. MAINTENANCE SCHEDULING BY CONSIDERING THE RELIABILITY OF SUPPLY

1- MAINTENANCE SCHEDULES AND SUPPLY RELIABILITY

As in most decisions, the two measures of the quality of a maintenance schedule are:

(i) The reliability of operation, and

(ii) Generation and capital costs.

The maintenance is generally scheduled to equalize the net reserves over the course of the year. The outages are scheduled in a sequential, irreversible process and in order of size, i.e. the larger units first(10). The periods for each outage are selected so that the current minimum net reserve over the year is maximized.

An alternative is the levelization of the probability of not meeting daily peak loads (Loss-of-load probability - LOLP) for each period. This approach requires estimated unit forced outage rates and a distribution for daily peak loads. It is reasonable to assume that use of the criterion of equal -or levelized- risk, or reserve, also minimizes the capital cost, since generating reserve requirements are minimized in the long run.

Through the use of monthly LOLP calculations, it's possible to level the reliability over a particular year by proper scheduling of unit maintenances. Leveled reliability maintenance schedules are attractive because the reliability of one month is not improved at the expense of another.

In addition, the fuel costs are minimized over the year by maximizing the total utilization of the most efficient units and minimizing the total utilization of the least efficient units. Consequently, new, larger, more efficient units should be outaged when reserves are highest -i.e. when the loss-of-load probability is smallest-, and not at the same time. This rule has the effect of minimizing the demand on, and the utilization of, less efficient units. It is a reasonable assumption, therefore, that levelizing the risks also corresponds, approximately, to a minimum total fuel cost. Based on these characteristics, it's concluded that the objective will be the risk levelization, i.e. the minimization of the maximum risk over the year, in the procedure of unit maintenance assignments.

The reliability of supply as determined by the generation/demand balance can be assessed in various ways, for example(19):

Index (a): the probable number of times a curtailment of supply will occur in a given period of time-the loss of load probability.

Index (b): the probable ratio of demand energy not supplied to total demand energy-the loss of energy probability.

Index (c): the probable interval between failures to meet the demand, and the duration of such failures.

The loss of load probability is a widely used index of reliability which can be assessed in several forms differing in the frequencies or ways in which the generation/demand comparisons are made, as follows:

(i) the probability of not meeting demand above some specified proportion of the expected peak-may be quoted as, for example, the number of years per 100 years in which insufficient generation is expected;

(ii) the expected number of days per year on which insufficient generation to meet the peaks of the days are expected;

(iii) the expected number of hours per year during which insufficient generation will be available.

In the study, since the monthly maintenance are considered by having prepared the load-duration curves using the daily power demand distributions, the second way of comparing the generation/demand figures in terms of daily peak loads is preferred.

If Δd_L is the number of days in the time period considered in which the peak demands lie between L and L+ΔL, shortage will occur when the cumulative probability of generation is equal to or less than L, that is $F_G(L)$. The expected number of shortage days will be $F_G(L).\Delta d_L$, and over the whole time period, with a maximum demand L_p, the reliability measure will be

$$\int_0^{L_p} F_G(L)\, dd_L$$

The distribution of daily peaks for each month are derived from the results of the load forecasting program developed by T.E.K. as in the optimization model. The distribution of available generation capacity is obtained as a result of the further analysis performed on the forced outage rates (F.O.R.) employing the major power plants in the interconnected system.

While considering the reliability of supply in this part of the study, the results of the seasonal planning model for different scenarios are utilized in order to distribute the planned capacity outages for each generating group and season into months in terms of single generating units. While doing this, the distribution of optimal maintenance capacities derived in Part II.4.3. are considered for thermal and hydro groups in order to have an efficient maintenance program against future uncertainities related to new capacity additions and power demand levels. This reasoning will also satisfy the need to maximize the hydro energy to be generated while observing additional objectives of hydro operation such as irrigation and flood control. In addition, as an important aspect, the interaction maintained between the two parts of the analysis -namely, using the output of the first part as an input for the second- causes the set of feasible monthly unit maintenance schedules to decrease which is almost the main limiting factor faced in scheduling procedures.

2- RISK LEVELIZATION PROCEDURE

2.1. NEW CAPACITY ADDITIONS AND POWER DEMANDS

The risk levelization procedure can be applied to the existing problem by using the results of each scenario independently in order to obtain the corresponding unit maintenance schedule. Instead of this, a more realistic assumption is made employing the consideration of the commissioning dates for the planned investments and power demand patterns as given in Table 26. By attaching the prior probabilities to each planned investment, and assuming the same availability figures as in the optimization model for these power plants, the following figures in terms of installed and available capacities are obtained:

TABLE 28. Distribution of installed and available capacity additions (MW)

		PERIOD			
		1	2	3	4
Capacity Additions	Installed Cap.	168	154	439	175
	Available Cap.	119	108	335	123
Cumulative Additions	Installed Cap.	168	322	761	936
	Available Cap.	119	227	562	685

The generations of the new investments are approximated by simply dropping their cumulative available capacity figures from daily peak loads for each month and period.

On the other hand, the yearly peak is taken as 5656 MW which is the expected value of the distribution in Table 26.

Using the per-unit distribution of hourly loads and assuming the yearly peak as 5656 MW, daily peak load distributions are prepared for each month.

2.2. DISTRIBUTION OF OUTAGE CAPACITIES

The probability of having available various combinations of units is computed from the binomial expansion, where each unit i is characterized by its long-term probability of being available p_i, and not available q_i. For N identical units of type s, the expansion is

$$(p_s+q_s)^N = p_s^N + {}_NC_1\, p_s^{N-1} q_s + {}_NC_2\, p_s^{N-2}\, q_s^2 + \ldots$$

$$\ldots + {}_NC_{N-1}\, p_s\, q_s^{N-1} + q_s^N$$

Each term of the expansion gives the probability of a capacity equivalent to the sum of the included p_i. With 2^N terms, the evaluation of this expansion is impossible unless N is small. If necessary, this can be made so by grouping the units into typical classes and sizes.

As a result of an analysis performed on the durations of breakdown and operation for the major power plants in the interconnected system, the forced outage rates (FOR) are calculated as shown in Table 29. Mainly due to lack of available data for many years, same FOR values are assumed for the generating units of the same power plant. In addition, FOR value of 0.10 is assumed for Yatağan and Soma-B power plants for which no operational data are available.

TABLE 29- Generating Unit Forced Outage Rates of Power Plants Considered in LOLP Analysis

Power Plant	No, of Units	Unit Cap.(MW)	F.O.R.
Anbarlı	3	110	0.06903
"	2	150	
Hopa	2	25	0.03941
Yatağan	2	210	0.10000
Soma B	2	165	0.10000
Seyitömer	3	150	0.13554
Tunçbilek B	2	150	0.0805
Tunçbilek A	1	65	0.08935
"	2	32	
Soma A	2	22	0.02841
İzmir	1	20	0.11423
"	3	5	
"	1	2.5	
Keban	4	185	0.01441
"	4	157.5	
H.Uğurlu	4	125	0.00127
Sarıyar	4	40	0.02833
Gökçekaya	3	92.8	0.08800
Hirfanlı	3	32	0.00896

For each power plant, the binomial expansion values are attached to the corresponding capacity figures in order to obtain the probability distribution of outage-or available-capacity. This procedure is given in Table 30 for Anbarlı power plant.

TABLE 30- Distribution of Available and Outage Capacities-
ANBARLI

$P_i = 3x110 + 2x150 = 630$ MW

$q = 0.06903$

$p = 0.93097$

Capacity Available(MW)	Capacity Outage(MW)		Probability	Cumulative Probability
630	0	p^5	0.69932	1.00000
520	110	$3p^4q$	0.15556	0.30068
480	150	$2p^4q$	0.10371	0.14512
410	220	$3p^3q^2$	0.01153	0.04141
370	260	$6p^3q^2$	0.00384	0.00681
300	330	p^2q^3	0.00029	0.00297
260	370	$6p^2q^3$	0.00171	0.00268
220	410	$3p^2q^3$	0.00086	0.00097
150	480	$2pq^4$	0.00004	0.00011
110	520	$3pq^4$	0.00006	0.00007
0	630	q^5	0.00000	0.00000

The calculated capacity distributions of analyzed power plants are combined together and classified in 50-MW groups in order to form the group distributions. In the analysis, 3 main groups are considered: lignite (1710.5 MW), fuel oil (680 MW) and large dams (2404.4 MW). Through the combination of these distributions, the distribution of total capacity outage is obtained which represents a capacity figure of 4794.9 MW - 70 per cent of the interconnected system installed power capacity , The generating groups that are not considered in LOLP analysis are simply dropped from daily peak loads by their maximum available generations as assumed in the planning model. The distribution of outage capacities for the groups and total capacity are given in Tables 31-35, whereas the distributions of considered power plants are given in Appendix II. The probability and cumulative distributions for the total capacity outage is shown in Figures 6 and 7.

2.3. DISTRIBUTION OF DAILY PEAK LOADS

By taking the yearly expected peak as 5656 MW, the per-unit values for the daily peaks for each month are derived from the hourly load forecasting program results. The distribution of per-unitized daily peak demands are given in Table 36 and Figure 8.

TABLE 31.
LIGNITE GROUP (P_i = 1710.5 MW)

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.266847	1.000000
50	0.084862	0.733153
100	0.006278	0.648291
150	0.228594	0.642013
200	0.123048	0.413419
250	0.033729	0.290371
300	0.085069	0.256642
350	0.071455	0.171573
400	0.030177	0.100118
450	0.020864	0.069941
500	0.022018	0.049077
550	0.012592	0.027059
600	0.004898	0.014467
650	0.004101	0.009569
700	0.003005	0.005468
750	0.001141	0.002463
800	0.000534	0.001322
850	0.000444	0.000788
900	0.000213	0.000344
950	0.000061	0.000131
1000	0.000040	0.000070
1050	0.000023	0.000030
1100	0.000006	0.000007
1150	0.000001	0.000001
1200	0.000000	0.000000

TABLE 32.
FUEL-OIL GROUP (P_i = 680 MW)

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.645284	1.000000
50	0.054037	0.354716
100	0.143540	0.300679
150	0.107620	0.157139
200	0.018653	0.049519
250	0.022178	0.030866
300	0.005326	0.008688
350	0.002165	0.003362
400	0.000926	0.001197
450	0.000166	0.000271
500	0.000095	0.000105
550	0.000010	0.000010
600	0.000000	0.000000

TABLE 33

LIGNITE AND FUEL OIL GROUPS (P_i = 2390.5 MW)

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.172192	1.000000
50	0.069180	0.827808
100	0.046940	0.758628
150	0.188746	0.711688
200	0.106765	0.522942
250	0.069403	0.416177
300	0.102400	0.346774
350	0.074222	0.244374
400	0.047004	0.170152
450	0.039217	0.123148
500	0.030887	0.083931
550	0.019446	0.053044
600	0.012073	0.033598
650	0.008784	0.021525
700	0.005506	0.012741
750	0.002998	0.007235
800	0.001860	0.004237
850	0.001134	0.002377
900	0.000588	0.001243
950	0.000310	0.000655
1000	0.000176	0.000345
1050	0.000087	0.000169
1100	0.000040	0.000082
1150	0.000021	0.000042
1200	0.000013	0.000021
1250	0.000006	0.000008
1300	0.000002	0.000002
1350	0.000000	0.000000

TABLE 34

DAMS (KEBAN, H.UĞURLU, SARIYAR, G.KAYA, HIRFANLI) (P_i = 2404.4 MW)

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.583040	1.000000
50	0.083954	0.416960
100	0.173664	0.333006
150	0.061528	0.159342
200	0.056203	0.097814
250	0.019260	0.041611
300	0.013272	0.022351
350	0.005559	0.009079
400	0.001882	0.003520
450	0.001157	0.001638
500	0.000249	0.000481
550	0.000156	0.000232
600	0.000043	0.000076
650	0.000024	0.000033
700	0.000006	0.000009
750	0.000003	0.000003
800	0.000000	0.000000

TABLE 35

DISTRIBUTION OF TOTAL CAPACITY OUTAGE (LIGNITE GROUP, FUEL OIL GROUP AND DAMS) (P_i = 4794.9 MW)

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.100395	1.000000
50	0.054791	0.899605
100	0.063079	0.844814
150	0.136596	0.781735
200	0.100180	0.645139
250	0.092299	0.544959
300	0.101940	0.452660
350	0.083880	0.350720
400	0.066657	0.266840
450	0.055053	0.200183
500	0.043799	0.14513
550	0.031745	0.101331
600	0.022713	0.069586
650	0.016391	0.046873
700	0.011102	0.030482
750	0.007250	0.019380
800	0.004733	0.012130
850	0.003001	0.007397
900	0.001826	0.004396
950	0.001095	0.002570
1000	0.000648	0.001475
1050	0.000369	0.000827
1100	0.000205	0.000458
1150	0.000113	0.000253
1200	0.000062	0.000140
1250	0.000032	0.000078
1300	0.000023	0.000046
1350	0.000012	0.000023
1400	0.000006	0.000011
1450	0.000003	0.000005
1500	0.000002	0.000002
1550	0.000000	0.000000

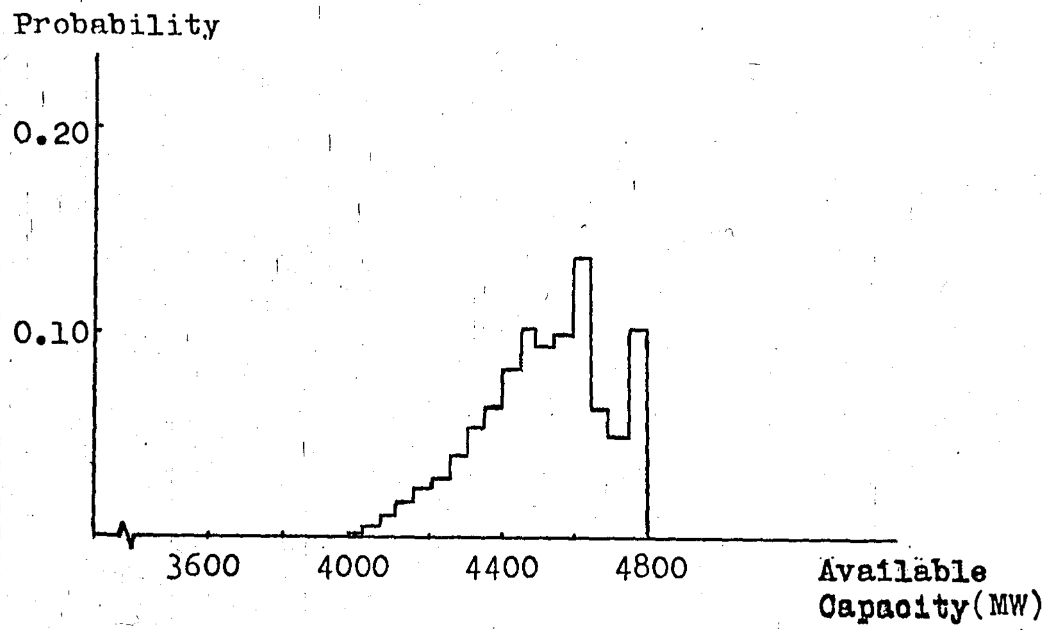

Figure 6. Probability distribution of total available capacity.

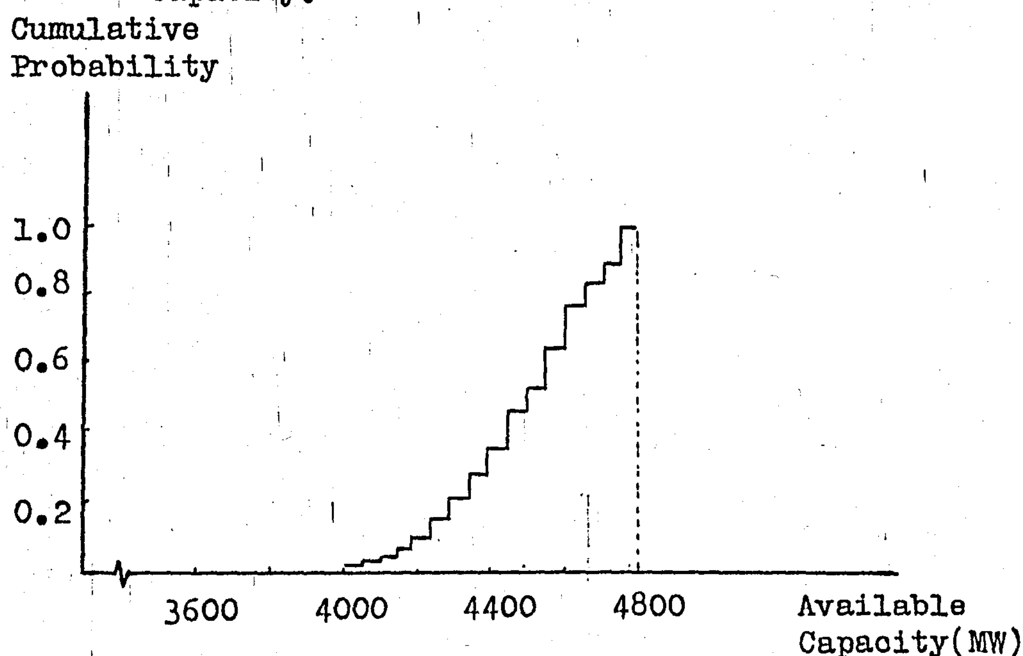

Figure 7. Cumulative probability distribution of total available capacity.

TABLE 36- Daily peak loads through months.

MONTH	LOAD(PER-UNIT)	No.Of DAYS	MONTH	LOAD(PER-UNIT)	No.Of DAYS
JANUARY	0.9215	4	JULY	0.9471	13
	0.9200	4		0.9359	9
	0.9164	13		0.9336	5
	0.9003	5		0.9214	4
	0.8893	5			
FEBRUARY	0.8826	5	AUGUST	0.9159	5
	0.8781	4		0.9134	4
	0.8667	12		0.9129	14
	0.8616	4		0.9070	4
	0.8491	4		0.9037	4
MARCH	0.9687	14	SEPTEMBER	0.9204	4
	0.9637	5		0.9039	12
	0.9412	4		0.9003	5
	0.9374	4		0.8892	4
	0.9345	4		0.8670	5
APRIL	0.9434	4	OCTOBER	0.9275	5
	0.9412	12		0.9259	13
	0.9355	4		0.8979	4
	0.9191	5		0.8971	5
	0.8968	5		0.8578	4
MAY	0.9408	4	NOVEMBER	0.9648	4
	0.9221	5		0.9576	14
	0.9130	14		0.9196	4
	0.8965	4		0.8192	4
	0.8661	4		0.8909	4
JUNE	0.8954	5	DECEMBER	1.000	5
	0.8884	4		0.9951	4
	0.8823	13		0.9725	12
	0.8606	4		0.9706	5
	0.8606	4		0.9618	5

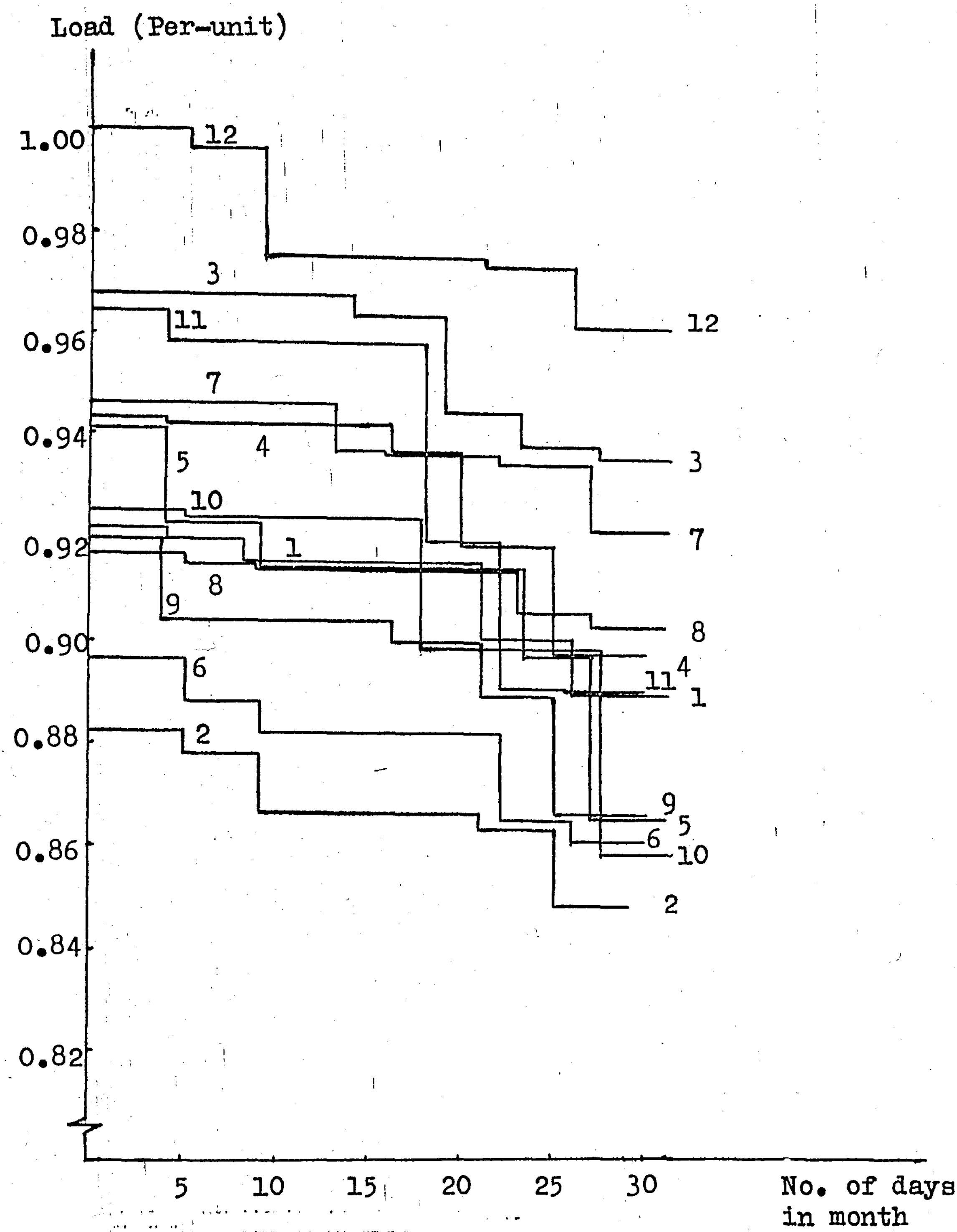

Figure 8. Distribution of daily peak loads in months.

2.4. CHARACTERISTICS OF THE PROCEDURE

In the risk levelization procedure, the comparison of generation and demand is performed through the distribution of total available generation capacity and the distribution of daily peak loads for each month as shown in Figure 9.

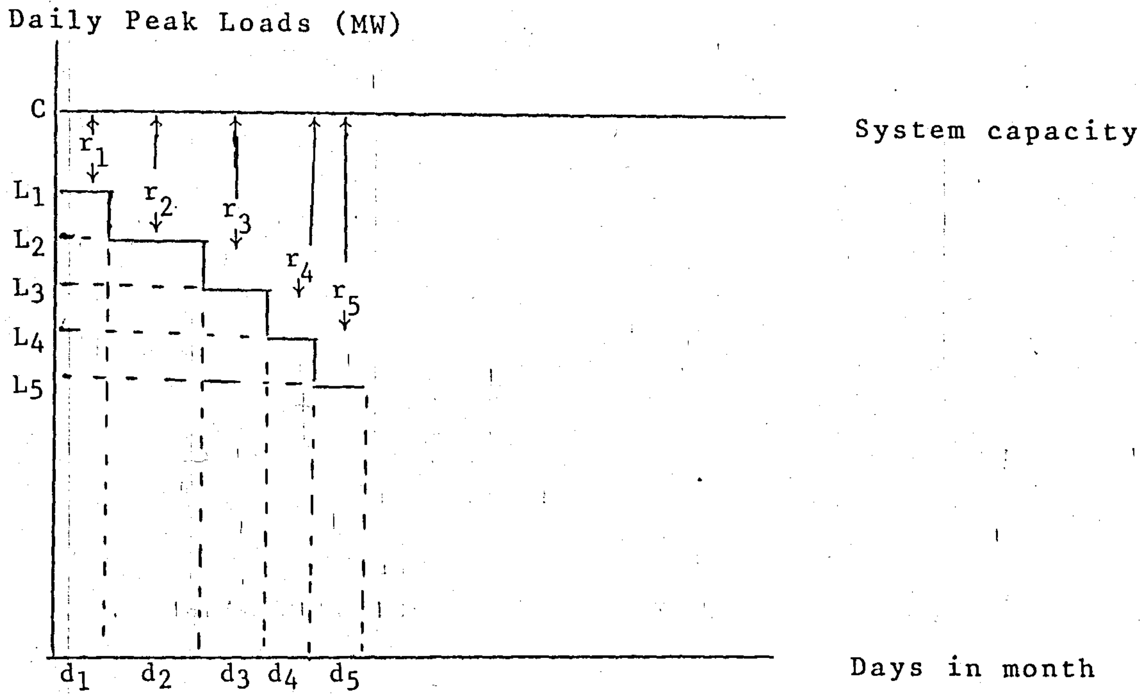

Figure 9. Outline of monthly LOLP calculations.

The risk level in terms of "expected number of shortage days" for a month is calculated with LOLP method from the relation

$$R_i = \sum_{j=1}^{n} d_j . F_o(r_j)$$

where,

R_i: Risk level of month i in terms of expected number of shortage days during the month.

d_j: Number of days for which the system is subjected to peak load L_j.

$F_o(r_j)$: The cumulative probability of outage capacity being greater than or equal to r_j.

Since the total system capacity C is defined as

$$C = L_j + r_j \text{ and since } F_o(r_j) = F_G(C - r_j)$$

for each peak load L_j and reserve capacity r_j, it is concluded that $F_o(r_j)$ is equivalent to $F_G(L_j)$, i.e. the cumulative probability of generation being less than or equal to peak load L_j as defined previously. So, the cumulative probabilities of available and outage capacities can be used alternatively.

As an application, the risk level for March 1984 by assuming no new capacity additions and no maintenances at all during that month is calculated in Table 37.

Table 37. Calculation of the risk level for March 1984

Per-Unit	MW	DAYS	ADJUSTED LOAD(MW)	DEMAND LEVEL	No.Of DAYS	GENERATION LEVEL	CUM. PROB. OF GENERATION	EXPECTED No.Of SHORTAGE DAYS
0.9687	5479	14	3831	3800-3850	19	3800	0.001475	0.028025
0.9637	5451	5	3803					
0.9412	5323	4	3675	3650-3700	8	3650	0.000253	0.002024
0.9374	5302	4	3654					
0.9345	5286	4	3638	3600-3650	4	3600	0.000140	0.000560
								0.030609

In Table 37, the yearly peak is taken as 5656 MW, and a load of 1648 MW is dropped from all daily peak loads in order to obtain the adjusted load figures. This load drop corresponds to the total of maximum available generations of existing power plants (non-TEK, coal, gas turbine, lake and river groups and small dams) and imported power which are not considered in the analysis. It should be noted that the dropped generations still keep their related uncertainties with them and the analysis is current only for the considered part of the system.

In the levelization procedure, the expected new capacity additions in cumulative terms are again dropped from the daily peak loads for the months of each period by their maximum available generations as were shown in Table 28. Through the process of maintenance scheduling, the effect of planned outage (i.e. the maintenance) is approximated by increasing the daily peak demands by the capacity of plant under planned outage.

The flow chart of the risk levelization procedure is given in Figure 10. The procedure is composed of following steps:

i. Initialization: By assuming the expected figures for the yearly peak load and the new capacity additions, the initial monthly risk levels are calculated using the per-unit values in Table 36. In addition, the maintenance priority lists reflecting the framework of optimal maintenance capacities proposed by the optimization model are prepared for the months. Within a priority list, the units are to be ordered for maintenance in decreasing installed capacities.

ii. Maintenance scheduling by considering monthly risks: The month with the minimum risk level is selected and the generating unit maintenances are scheduled for that month until a new minimum-risk month emerges and/or no units are left in the list.

iii. Termination: The procedure terminates when there remains no unscheduled units.

While scheduling unit maintenances, the following conditions are considered:

a) It is possible to schedule at most one generating unit of a power plant for maintenance in the same month. This is a technical restriction adopted by T.E.K. resulting from the limitations in maintenance crew and material availabilities.

b) The maintenance schedule must be performed in the framework proposed by the optimization model from the viewpoint of operational economics.

c) In any month, the unit with the largest capacity must be considered first among the candidates satisfying the conditions a and b. The units with higher availability are scheduled first in case of equal capacities.

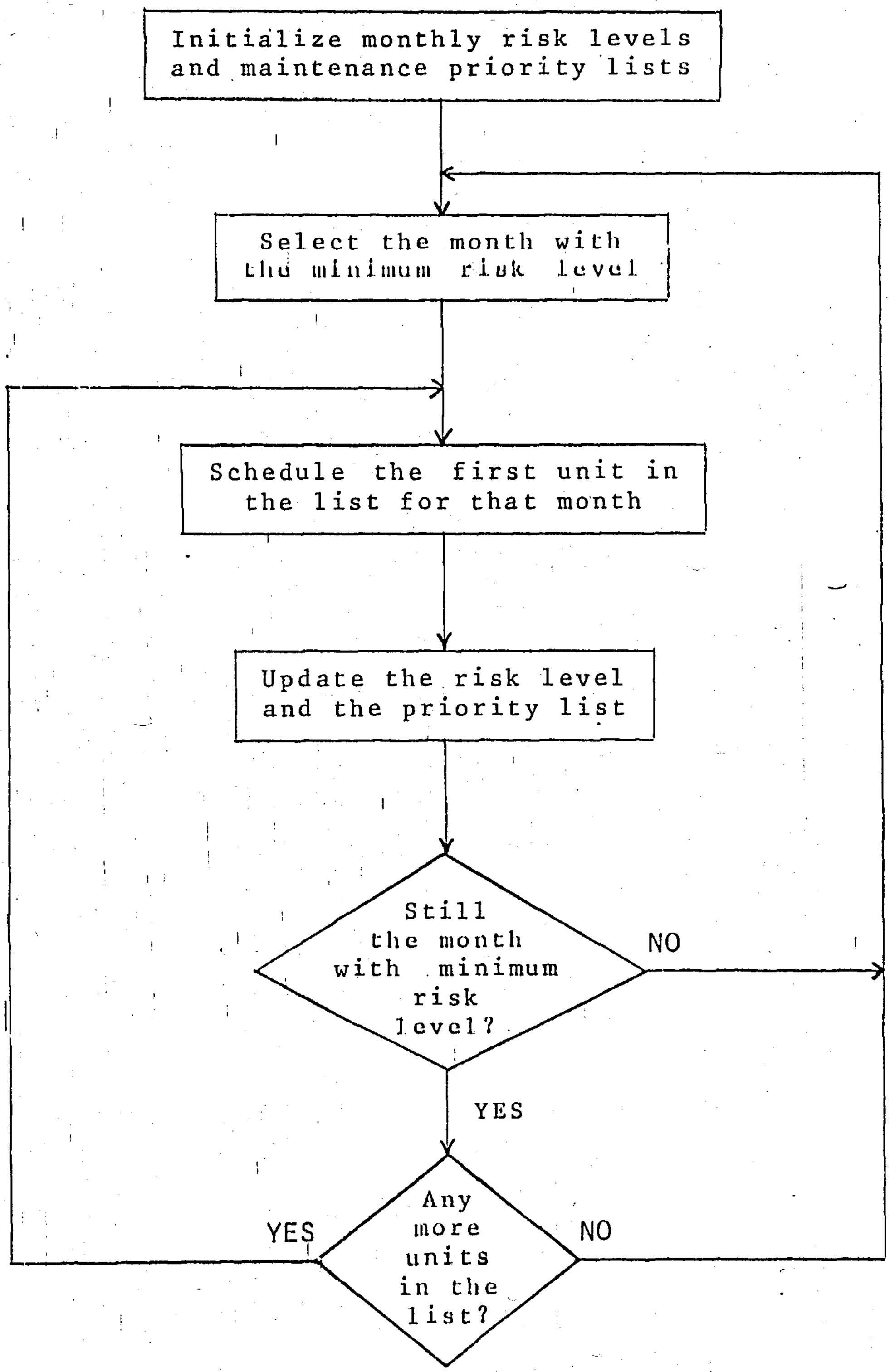

Figure 10. Flow-Chart of the Risk Levelization Procedure.

The maintenance of TEK power plant groups not considered in the analysis are scheduled in the beginning of the procedure accordingly with respect to the distributions obtained as a result of the planning model.

3- RESULTS AND EVALUATIONS

The defined procedure is applied to a major part of the interconnected TEK power plants containing all lignite and fuel oil generating units and large dams with reservoir (Keban, H.Uğurlu, Sarıyar, Gökçekaya and Hirfanlı) which totally amount to 82 % of TEK installed capacity.

As a first step, without considering maintenances, two cases are handled for the calculation of monthly risks such as:

a) The case of no new capacity additions in 1984.

b) The realization of the expected amount of new capacity additions as in Table 28, which constitutes the initial frame for the risk levelization procedure. The associated risk patterns are shown as "a" and "b" in Figure 11, respectively.

The annual risk levels are 0.201225 days/year and 0.008940 days/year for cases a and b. By assuming the yearly standard risk level as 0.08 days/year(32), it can be said that the system will incur an annual risk which is 2.5 times larger than the standard level in case of no new capacity additions, even though no maintenances are concerned.

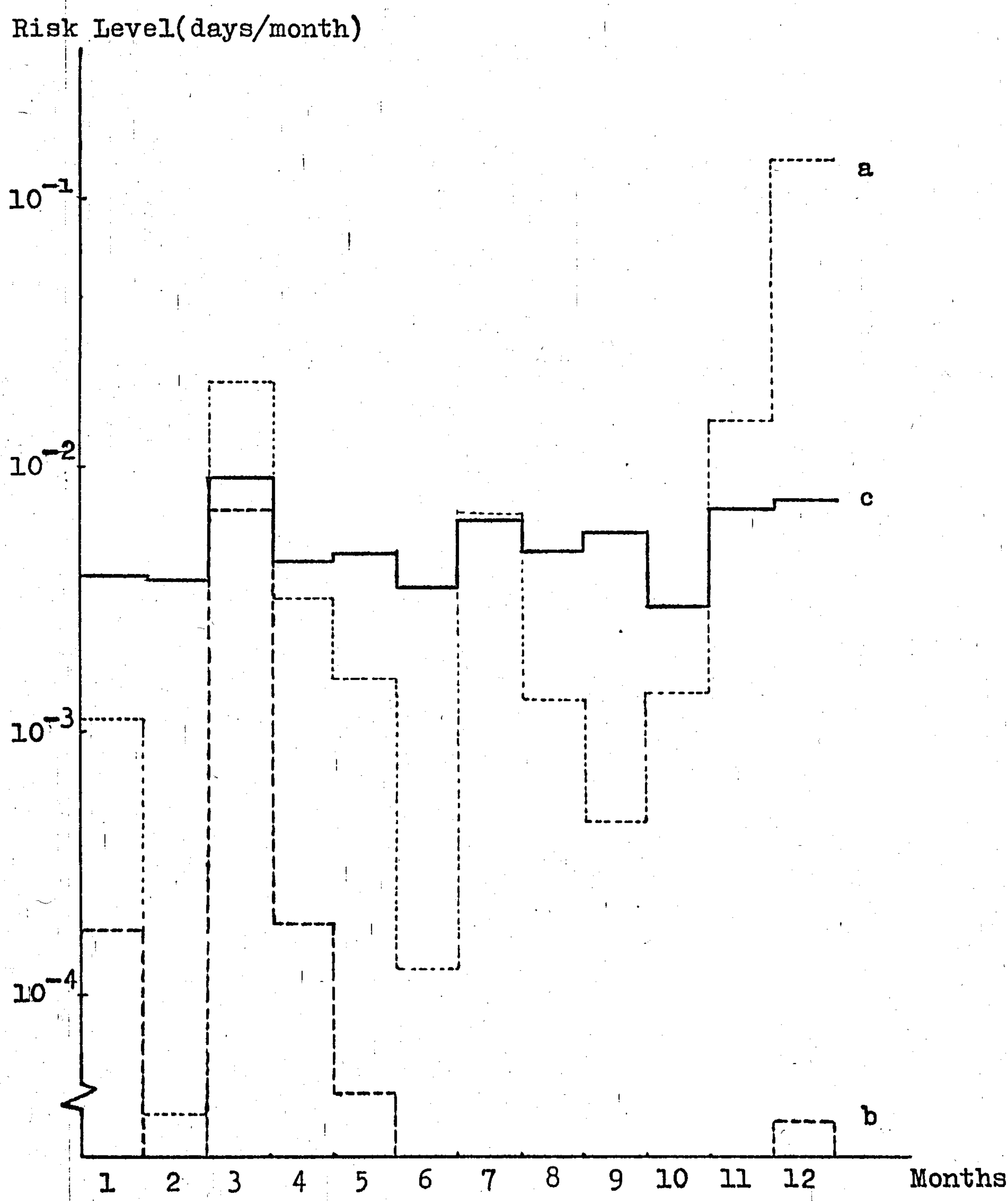

Figure 11. Monthly risk levels (Shortage days/month)

Beginning with the risk pattern b, the risk levelization procedure is applied as explained previously. The levelized risk pattern obtained is shown in Figure 11 as "c". The monthly risk levels for different cases are given in Table 38.

TABLE 38- Monthly risk levels for different cases

MONTH	No Investment Realization	Expected Investment Realization	Levelized Risks Through Maintenance Schedules
1	0.001302	0.000241	0.005933
2	0.000018	0.000000	0.005726
3	0.030609	0.008357	0.009638
4	0.005053	0.000278	0.006325
5	0.002090	0.000054	0.006725
6	0.000101	0.000000	0.005490
7	0.008226	0.000000	0.008006
8	0.001242	0.000000	0.006939
9	0.000663	0.000000	0.007471
10	0.001503	0.000000	0.004976
11	0.017830	0.000000	0.008352
12	0.132588	0.000010	0.008737
TOTAL	0.201225	0.008940	0.084318

As a result of maintenance scheduling through the risk levelization procedure, the unit maintenance schedules obtained are given in Table 39. Since the generating units of a certain power plant are assumed to have equal forced outage rates through operation, the distinction between the specific units are not emphasized. This situation results mainly from the lack of breakdown data for many years in terms of single generating units for each power plant. By having available the unit-by-unit analysis of breakdown and operation times, a more detailed and improved schedule can be obtained.

On the other hand, the generating groups of coal, gas turbine, lake and river groups and some small dams are not included in the analysis due to the related breakdown data covering short periods of time. Dropping these units by their maximum available generation from daily peak loads can cause the monthly risks to be underestimated. But, the fact which should be noted is that the analysis performed covers only the considered portion of the system capacity while the unconsidered units still keep the uncertainity of generation with themselves. The power import and non-TEK unit generations are also included in this group.

The analysis employed requires the comparison of generation capacity with the daily peak loads through months. A more detailed analysis employing the comparison of generation capacity with all load levels-i.e. the load-duration curve as a whole-through each month will reveal the precise relationship between the supply and demand sides of the existing system.

TABLE 39- Unit maintenance schedules derived from the risk levelization procedure (MW)

	MONTH											
	1	2	3	4	5	6	7	8	9	10	11	12
Keban	157.5	185	-	157.5	157.5	-	-	-	185	185	185	157.5
H.Uğurlu	-	125	-	-	-	-	-	-	-	125	125	125
S.Uğurlu	-	23	-	-	-	-	-	-	-	23	-	-
Sarıyar	-	40	-	-	-	-	-	-	-	40	40	40
G.Kaya	-	-	-	-	-	-	-	-	-	92.8	92.8	92.8
Hirfanlı	-	32	-	32	-	-	-	-	-	-	-	32
K.Köprü	-	38	-	38	-	-	-	-	-	-	-	-
Ambarlı	-	-	-	-	110	110	150	150	-	-	110	-
Hopa	-	-	-	-	25	-	-	-	-	25	-	-
Yatağan	-	-	-	-	-	210	-	210	-	-	-	-
Soma B	-	-	-	-	-	-	165	-	165	-	-	-
T.Bilek B	-	-	-	-	-	150	-	-	150	-	-	-
Seyit Ömer	-	-	-	-	-	-	150	150	-	150	-	-
T.Bilek A	-	-	-	-	-	-	-	32	65	32	-	-
Soma A	22	-	-	-	-	-	-	22	-	-	-	-
İzmir	-	-	-	-	-	-	-	20	-	17.5	-	-
Dams Total	157.5	443	-	227.5	157.5	-	-	-	185	465.8	442.8	447.3
F.Oil Total	-	-	-	-	135	110	150	150	-	25	110	-
Lignite Tot.	22	-	-	-	-	360	315	434	380	199.5	-	-
GENERAL TOT.	179.5	443	-	227.5	292.5	470	465	584	565	690.3	552.8	447.3

IV. CONCLUSIONS

A common characteristic of energy models is that they are subjected to some specific assumptions while being unable to answer all questions related to the real system. For instance, in mathematical programming optimization models, the variables which must be determined through mutual interactions are to be considered as parameters. So, it's not possible to define a model as the "best" or the one yielding the "most precise" solutions(16).

In this study, an attempt is made to combine the two objectives in power system operation and maintenance planning, namely the costs through operation and the reliability of supply. An approach is developed in which the problem of maintenance planning is handled in two parts. In the first part, a linear programming model is constructed that investigates the optimal seasonal maintenance policies subject to various operational constraints such as power demand satisfaction, capacity, water usage, energy generation, importation and maintenance requirement, while the objective is the minimization of total system costs.

By using the results obtained for different scenarios related to yearly peak power demand and the commissioning dates of planned investments in the optimization model, a further attempt is made to distribute the planned capacity outages for each generating group and season into months in terms of single generating units. While doing this, the "Inhibited" periods of maintenance implied by the optimization model which reflect the economics of operation are utilized when determining the feasible periods for generating unit maintenances. The objective here is considered as the levelization of monthly risks.

In the study, it is aimed to emphasize the various effects on operating policies and maintenance schedules for the system caused by different demand patterns, new capacity additions and annual water inflows. It is possible to obtain more detailed results in terms of system operation and maintenance policies by analyzing the distribution of new capacity additions and power demands to a deeper extent. Also, by employing additional different cases for annual water inflows that represent the corresponding probability distribution, the relative weights of different scenarios can be obtained more precisely.

Through the analysis of operating results, it is concluded that the leading factor in planning the operation and maintenance of the power system is the usage of hydro facilities in regulating the system supply against different power demand levels while performing the required plant maintenances. So, the planning models which will employ the interaction between water inflow, usage and reservoir levels rather than assuming average overall figures will represent a better framework for the description of hydro system operation.

When scheduling generating unit maintenance, the main aim is to satisfy all the constraints imposed on the system while keeping it as reliable as possible, i.e. still satisfying the load demand with a reasonable assurance of continuity. The constraints on the system can be very diverse and often unpredictable: they include crew and material availability, seasonal limitations, sudden forced-outages, deviations from forecasted peak loads, possible delays to be incurred in commissioning dates of new investments, future expectations related to water inflows, etc. So, a decision making process performed for such a complex system must consider the above characteristics as detailed as possible in order to resolve the uncertainties related to the future.

Such a process, which is of introductory nature, is searched for by decomposing the problem into two parts in which the economics of operation and the reliability of supply are handled consequtively by aiming to achieve feasible maintenance schedule patterns for generating units. Finally, it can be concluded that the main benefit obtained through the modelling of power system operation is the derivation of system structure and functioning in detail through data collection and model implementation.

APPENDIX I. OPERATION RESULTS IN TERMS OF AVERAGE GENERATIONS (UNIT:MW)

A. CASE OF AVERAGE WATER INFLOWS

SCENARIO: NORMAL WATER YEAR-INVESTMENTS REALIZED (LOADS DECREASED BY 5%)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
LIGNITE	1415	1415	1415	1415	1415	1415	1193	1193	1193	1653	1653	1653
COAL	-	-	-	-	-	-	-	-	-	-	-	-
F.OIL	592	592	592	443	592	592	35	395	395	592	592	592
GAS TUR.	-	-	-	-	-	-	-	-	-	-	-	-
TEK TH.TOT.	2007	2007	2007	1858	2007	2007	1227	1588	1588	2245	2245	2245
KEBAN	192	968	968	812	643	1257	1315	1315	1315	227	1281	1281
H.UĞURLU	-	409	518	296	518	518	30	518	518	141	-	-
SARIYAR	345	28	412	-	151	160	235	160	263	28	119	278
HİRFANLI	84	158	158	-	-	-	158	158	158	-	-	126
DEMİR KÖP.	64	66	66	-	-	-	-	-	-	31	-	66
KEMER	19	-	45	45	45	45	4	-	-	-	17	45
ALMUS	-	-	-	14	26	-	26	26	26	-	-	-
TEK DAMS TO.	706	1631	2168	1167	1384	1980	1769	2177	2280	428	1418	1797
TEK LAKE RI.	186	289	289	273	416	416	427	131	539	466	493	607
NON-TEK TH.	-	-	-	-	-	-	-	-	-	-	-	-
NON-TEK HY.	162	162	162	162	162	162	162	162	162	162	162	162
TOT.GENERAT.	3062	4089	4626	3461	3969	4565	3586	4058	4570	3301	4318	4811
IMPORT	350	350	350	-	350	350	-	311	350	350	350	350
TOTAL SUPPLY	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
UNS.POWER DE.	-	-	-	-	-	-	-	-	-	-	-	-

SCENARIO: NORMAL WATER YEAR-INVESTMENTS REALIZED (FORECASTED LOADS)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3591	4673	5289	3644	4547	5151	3775	4599	5171	3843	4914	5460
LIGNITE	1415	1415	1415	1415	1415	1415	1193	1193	1193	1653	1653	1653
COAL	165	165	165	-	165	165	-	74	110	165	165	165
F.OIL	592	592	592	509	509	509	478	478	478	592	592	592
GAS TUR.	-	-	-	-	-	-	-	-	-	-	-	-
TEK TH.TOT.	2172	2172	2172	1924	2089	2089	1671	1744	1781	2410	2410	2410
KEBAN	201	1066	1116	748	529	1159	1315	1315	1315	290	1231	1231
H.UĞURLU	-	409	518	296	518	518	30	518	518	125	-	292
SARIYAR	351	-	412	118	412	412	59	132	412	28	121	275
HİRFANLI	84	158	158	-	-	-	158	158	158	-	-	126
DEMİR KÖP.	64	66	66	-	-	-	-	-	-	30	11	66
KEMER	19	-	45	45	45	45	2	-	45	-	24	30
ALMUS	-	-	-	14	26	-	26	26	26	-	-	-
TEK DAMS TO.	720	1700	2315	1221	1530	2134	1592	2149	2474	473	1388	1934
TEK LAKE RI.	187	289	289	273	416	416	351	543	543	447	604	604
NON-TEK TH.	-	-	-	-	-	-	-	-	-	-	-	-
NON-TEK HY.	162	162	162	162	162	162	162	162	162	162	162	162
TOT.GENERAT.	3241	4323	4939	3581	4197	4801	3775	4599	4960	3493	4564	5110
IMPORT	350	350	350	63	350	350	-	-	211	350	350	350
TOTAL SUPPLY	3591	4673	5289	3644	4547	5151	3775	4599	5171	3843	4914	5460
UNS.POWER DE.	-	-	-	-	-	-	-	-	-	-	-	-

SCENARIO: NORMAL WATER YEAR-INVESTMENTS REALIZED (LOADS INCREASED BY 5%)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3771	4907	5501	3826	4774	5432	3964	4829	5438	4035	5160	5705
LIGNITE	1415	1415	1415	1415	1415	1415	1193	1193	1193	1653	1653	1653
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	467	467	467	520	520	520	592	592	592
GAS TUR.	-	-	-	-	-	-	-	-	-	-	-	-
TEK TH.TOT.	2172	2172	2172	1992	1992	1992	1878	1878	1878	2410	2410	2410
KEBAN	77	996	1025	869	853	1315	1315	1315	1315	275	1167	1167
H.UĞURLU	-	409	518	296	518	518	30	518	518	125	-	210
SARIYAR	350	-	412	118	412	412	42	229	412	28	121	275
HİRFANLI	84	158	158	-	-	-	158	158	158	-	-	126
DEMİR KÖP.	64	66	66	-	-	-	-	-	-	28	17	66
KEMER	20	-	45	45	45	45	2	-	45	-	24	30
ALMUS	-	-	-	14	26	-	26	26	26	-	-	-
TEK DAMS TO.	596	1630	2224	1342	1854	2290	1574	2246	2474	457	1330	1875
TEK LAKE RI.	187	289	289	273	416	416	351	543	543	447	604	604
NON-TEK TH.	304	304	304	-	-	222	-	-	31	208	304	304
NON-TEK HY.	162	162	162	162	162	162	162	162	162	162	162	162
TOT.GENERAT.	3421	4557	5151	3770	4424	5082	3964	4829	5088	3685	4810	5355
IMPORT	350	350	350	56	350	350	-	-	350	350	350	350
TOTAL SUPPLY	3771	4907	5501	3826	4774	5432	3964	4829	5438	4035	5160	5705
UNS.POWER DE.	-	-	-	-	-	-	-	-	-	-	-	-

SCENARIO: NORMAL WATER YEAR-INVESTMENT DELAYED 6 MONTHS (LOADS DECR. BY 5%)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
LIGNITE	1403	1403	1403	1246	1246	1246	1105	1105	1105	1415	1415	1415
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	-	-	-	-	-	-	-	-	-	-	-	-
TEK TH.TOT.	2160	2160	2160	1948	1948	1948	1665	1665	1665	2172	2172	
KEBAN	60	690	897	691	672	1294	1315	1315	1315	535	1315	1315
H.UĞURLU	-	409	518	296	518	518	31	518	518	127	-	185
SARIYAR	363	-	191	118	412	412	40	236	412	17	169	323
HİRFANLI	84	158	158	-	-	-	158	158	158	-	-	126
DEMİR KÖP.	64	66	66	-	-	-	-	-	-	20	66	66
KEMER	21	-	30	45	45	45	2	-	45	-	18	45
ALMUS	-	-	-	15	26	-	26	26	26	-	-	-
TEK DAMS TO.	593	1324	1861	1164	1673	2269	1572	2253	2474	699	1568	2061
TEK LAKE RI.	139	139	139	130	186	186	187	289	289	268	416	416
NON-TEK TH.	8	304	304	-	-	-	-	-	-	-	-	-
NON-TEK HY.	162	162	162	162	162	162	162	162	162	162	162	162
TOT.GENERAT.	3062	4089	4626	3404	3969	4565	3586	4369	4590	3301	4318	4811
IMPORT	350	350	350	57	350	350	-	-	330	350	350	350
TOTAL SUPPLY	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
UNS.POWER DE.	-	-	-	-	-	-	-	-	-	-	-	-

SCENARIO: NORMAL WATER YEAR-INVESTMENTS DELAYED 6 MONTHS (FORECASTED LOADS)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3591	4673	5289	3644	4547	5151	3775	4599	5171	3843	4914	5460
LIGNITE	1403	1403	1403	1049	1049	1049	1297	1297	1297	1415	1415	1415
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	-	-	-	-	-	-	-	-	-	-	-	-
TEK TH.TOT.	2160	2160	2160	1751	1751	1751	1857	1857	1857	2172	2172	2172
KEBAN	-	708	919	846	784	1315	1315	1315	1315	428	1273	1273
H.UĞURLU	-	409	518	296	518	518	31	518	518	115	-	345
SARIYAR	321	160	412	118	412	412	21	339	412	24	150	275
HİRFANLI	84	158	158	-	-	99	158	158	158	-	-	64
DEMİR KÖP.	64	66	66	-	-	-	-	-	-	204	66	66
KEMER	20	-	45	45	45	45	2	-	42	-	23	33
ALMUS	-	-	-	15	26	-	26	26	26	-	-	-
TEK DAMS TO.	490	1502	2118	1320	1785	2389	1554	2356	2471	587	1510	2056
TEK LAKE RI.	126	195	195	128	195	195	202	224	224	268	416	416
NON-TEK TH.	304	304	304	217	304	304	-	-	304	304	304	304
NON-TEK HY.	162	162	162	162	162	162	162	162	162	162	162	162
TOT.GENERAT.	3241	4323	4939	3578	4197	4801	3775	4599	5019	3493	4564	5110
IMPORT	350	350	350	66	350	350	-	-	153	350	350	350
TOTAL SUPPLY	3591	4683	5289	3644	4547	5151	3775	4599	5171	3843	4914	5460
UNS.POWER DE.	-	-	-	-	-	-	-	-	-	-	-	-

SCENARIO: NORMAL WATER YEAR-INVESTMENTS DELAYED 6 MONTHS (LOADS INCREASED BY 5 %)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3771	4907	5501	3826	4774	5432	3964	4829	5438	4035	5160	5705
LIGNITE	1403	1403	1403	1125	1125	1125	1221	1221	1221	1415	1415	1415
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	229	229	229	-	-	270	-	-	78	149	270	270
TEK TH.TOT.	2389	2389	2389	1827	1827	2097	1781	1781	1859	2321	2442	2442
KEBAN	-	447	902	841	935	1315	1315	1315	1315	457	1290	1290
H.UĞURLU	-	409	518	296	518	518	31	518	518	115	-	330
SARIYAR	275	412	412	152	412	412	-	265	412	20	170	275
HİRFANLI	84	158	158	-	-	34	158	158	158	-	-	105
DEMİR KÖP.	64	66	66	-	-	-	-	-	-	20	66	66
KEMER	17	14	45	45	45	45	-	11	45	-	24	30
ALMUS	-	-	-	15	26	-	26	26	26	-	-	-
TEK DAMS TO.	440	1507	2101	1349	1936	2324	1530	2293	2474	619	1551	2096
TEK LAKE RI.	126	195	195	128	195	195	187	289	289	284	351	351
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	162	162	162	162	162	162	162	162	162	162	162	162
TOT.GENERAT.	3421	4557	5151	3770	4424	5082	3964	4829	5088	3685	4810	5355
IMPORT	350	350	350	56	350	350	-	-	350	350	350	350
TOTAL SUPPLY	3771	4907	5501	3826	4774	5432	3964	4829	5438	4035	5160	5705
UNS.POWER DE.	-	-	-	-	-	-	-	-	-	-	-	-

SCENARIO: NORMAL WATER YEAR-INVESTMENTS DELAYED 1 YEAR (LOAD DECREASED BY 5%

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
LIGNITE	1403	1403	1403	1160	1160	1160	1178	1178	1178	1403	1403	1403
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	-	-	-	-	-	-	-	-	-	-	-	-
TEK TH.TOT.	2160	2160	2160	1862	1862	1862	1738	1738	1738	2160	2160	2160
KEBAN	-	152	689	637	833	1315	1315	1315	1315	745	1315	1315
H.UĞURLU	-	435	435	299	501	501	31	518	518	88	118	445
SARIYAR	151	412	412	245	401	401	36	257	412	-	286	286
HİRFANLI	84	158	158	-	-	117	150	158	158	-	-	158
DEMİR KÖP.	64	66	66	-	-	22	-	-	1	19	66	66
KEMER	11	45	45	45	45	45	2	-	45	-	24	30
ALMUS	-	-	-	14	26	-	26	26	26	-	-	-
TEK DAMS TO.	310	1268	1805	1241	1806	2400	1560	2274	2475	851	1810	2303
TEK LAKE RI.	126	195	195	139	139	139	126	195	195	128	186	186
NON-TEK TH.	304	304	304	-	-	2	-	-	-	-	-	-
NON-TEK HY.	162	162	162	162	162	162	162	162	162	162	162	162
TOT.GENERAT.	3062	4089	4626	3405	3969	4565	3586	4369	4570	3301	4318	4811
IMPORT	350	350	350	56	350	350	-	-	350	350	350	350
TOTAL SUPPLY	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
UNS.POWER DE.	[illegible]	[illegible]	[illegible]	-	-	-	-	-	-	-	-	-

SCENARIO: NORMAL WATER YEAR-INVESTMENTS DELAYED 1 YEAR (FORECASTED LOADS)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3591	4673	5289	3644	4547	5151	3775	4599	5171	3843	4914	5460
LIGNITE	1403	1403	1403	1151	1151	1151	1187	1187	1187	1403	1403	1403
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	-	-	-	-	-	-	-	-	-	-	-	-
TEK TH.TOT.	2160	2160	2160	1853	1853	1853	1747	1747	1747	2160	2160	2160
KEBAN	-	677	1020	667	682	1172	1315	1315	1315	623	1315	1351
H.UĞURLU	-	423	473	296	518	518	31	518	518	100	70	391
SARIYAR	308	233	412	118	412	412	52	183	375	-	274	312
HİRFANLI	84	158	158	-	-	117	150	158	158	-	-	158
DEMİR KÖP.	64	66	66	-	-	23	-	-	-	19	66	66
KEMER	19	-	45	45	45	45	3	-	30	-	18	45
ALMUS	-	-	-	15	26	-	26	26	26	-	-	-
TEK DAMS TO.	476	1558	2174	1140	1683	2287	1576	2200	2422	742	1743	2289
TEK LAKE RI.	139	139	139	128	195	195	128	186	186	125	195	195
NON-TEK TH.	304	304	304	304	304	304	162	304	304	304	304	304
NON-TEK HY.	162	162	162	162	162	162	162	162	162	162	162	162
TOT.GENERAT.	3241	4323	4939	3588	4197	4801	3775	4599	4821	3493	4564	5110
IMPORT	350	350	350	56	350	350	-	-	350	350	350	350
TOTAL SUPPLY	3591	4673	5289	3644	4547	5151	3775	4599	5171	3843	4914	5460
UNS.POWER DE.	-	-	-	-	-	-	-	-	-	-	-	-

SCENARIO: NORMAL WATER YEAR - INVESTMENTS DELAYED 1 YEAR (LOADS INCREASED BY 5%)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3771	4907	5501	3826	4774	5432	3964	4829	5438	4035	5160	5705
LIGNITE	1403	1403	1403	1054	1054	1054	1284	1284	1284	1403	1403	1403
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	229	229	229	-	-	229	-	-	109	213	270	270
TEK TH.TOT.	2389	2389	2389	1756	1756	1985	1844	1844	1953	2373	2430	2430
KEBAN	-	-	-	820	1006	1315	1315	1315	1315	603	1315	1315
H.UĞURLU	-	488	264	296	518	518	31	518	518	96	102	376
SARIYAR	256	64	160	244	412	412	-	296	412	-	228	412
HİRFANLI	84	158	158	-	-	146	156	158	158	-	-	59
DEMİR KÖP.	64	66	66	-	-	-	-	-	-	20	66	66
KEMER	22	-	-	45	45	45	-	10	45	-	17	45
ALMUS	-	-	-	14	26	-	26	26	26	-	-	-
TEK DAMS TO.	427	776	649	1420	2007	2436	1528	2324	2474	719	1728	2273
TEK LAKE RI.	139	139	193	128	195	195	126	195	195	128	186	186
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	162	162	162	162	162	162	162	162	162	162	162	162
TOT.GENERAT.	3421	3770	3643	3770	4424	5082	3964	4829	5088	3685	4810	5355
IMPORT	350	350	350	56	350	350	-	-	350	350	350	350
TOTAL SUPPLY	3771	4120	3993	3826	4774	5432	3964	4829	5438	4035	5160	5705
UNS.POWER DE.	-	787	1508	-	-	-	-	-	-	-	-	-

APPENDIX I.B. CASE OF DRY PERIOD WATER INFLOWS

SCENARIO: DRY WATER YEAR-INVESTMENTS REALIZED (LOADS DECREASED BY 5 %)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
LIGNITE	1415	1415	1415	1415	1415	1415	1193	1193	1193	1653	1653	1653
COAL	165	165	165	165	165	165	110	110	110	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	270	270	270	121	270	270	-	-	-	-	-	66
TEK TH.TOT.	2442	2442	2442	2293	2442	2442	1698	1698	1698	2410	2410	2476
KEBAN	-	176	843	-	-	316	1015	1310	1310	170	1315	1315
H.UĞURLU	-	130	-	207	518	518	-	88	474	-	-	-
SARIYAR	57	412	412	154	412	412	71	289	412	22	0	0
HİRFANLI	-	158	158	-	-	-	158	-	-	-	-	-
DEMİR KÖP.	37	66	66	-	-	-	-	-	-	14	-	-
KEMER	-	-	-	39	45	45	-	1	43	-	1	-
ALMUS	-	-	-	-	-	-	21	25	25	-	-	-
TEK DAMS TO.	94	942	1479	399	975	1291	1266	1712	2263	206	1316	1315
TEK LAKE RI.	110	289	289	209	136	416	207	543	543	340	176	604
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	112	112	112	112	112	112	112	112	112	112	112	112
TOT.GENERAT.	3062	4089	4626	3317	3969	4565	3586	4369	4920	3372	4318	4811
IMPORT	350	350	350	144	350	350	0	0	0	279	350	350
TOTAL SUPPLY	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
UNS.POWER DE.	-	-	-	-	-	-	-	-	-	-	-	-

SCENARIO: DRY WATER YEAR - INVESTMENTS REALIZED (FORECASTED LOADS)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3591	4673	5289	3644	4547	5151	3775	4599	5171	3843	4914	5460
LIGNITE	1415	1415	1415	1415	1415	1415	1193	1193	1193	1653	1653	1653
COAL	165	165	165	165	165	165	110	110	110	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	270	75	-	58	270	-	-	-	-	270	-	-
TEK TH.TOT.	2442	2247	2172	2230	2442	2172	1698	1698	1698	2680	2410	2410
KEBAN	-	-	-	-	-	-	1068	1310	1310	219	1315	1315
H.UĞURLU	24	-	-	207	518	518	-	76	518	-	-	-
SARIYAR	-	38	-	154	412	412	207	373	412	22	-	-
HİRFANLI	-	-	-	-	-	-	158	158	158	-	-	15
DEMİR KÖP.	54	-	-	-	-	-	-	-	-	14	-	-
KEMER	-	-	-	39	45	45	-	1	43	-	1	-
ALMUS	-	-	-	-	-	-	21	25	25	-	-	-
TEK DAMS TO.	77	38	-	399	975	975	1454	1942	2466	255	1316	1330
TEK LAKE RI.	179	-	-	250	-	-	207	543	543	416	-	-
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	112	112	112	112	112	112	112	112	112	112	112	112
TOT.GENERAT.	3115	2702	2588	3294	3833	3563	3775	4599	5122	3768	4142	4156
IMPORT	350	292	350	350	350	350	-	49	76	350	350	350
TOTAL SUPPLY	3465	2993	2938	3644	4183	3913	3775	4599	5171	3843	4492	4506
UNS.POWER DE.	126	1680	2351	-	364	1238	-	-	-	-	422	954

SCENARIO: DRY WATER YEAR - INVESTMENTS REALIZED (LOADS INCREASED BY 5 %)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3771	4907	5501	3826	4774	5432	3964	4829	5438	4035	5160	5705
LIGNITE	1415	1415	1415	1415	1415	1415	1193	1193	1193	1653	1653	1653
COAL	165	165	165	165	165	165	110	110	110	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	270	-	-	270	-	-	-	-	-	109	-	-
TEK TH.TOT.	2442	2172	2172	2442	2172	2172	1698	1698	1698	2519	2410	2410
KEBAN	-	-	-	-	-	-	1264	1310	1310	25	1315	1315
H.UĞURLU	24	-	-	172	518	518	-	267	518	-	-	-
SARIYAR	-	38	-	154	412	412	200	412	412	22	-	-
HİRFANLI	-	-	-	-	-	-	158	158	158	-	-	15
DEMİR KÖP.	54	-	-	-	-	-	-	-	-	14	-	-
KEMER	-	-	-	39	45	45	-	1	43	-	1	-
ALMUS	-	-	-	-	-	-	21	25	25	-	-	-
TEK DAMS TO.	77	38	-	365	975	975	1643	2172	2466	61	1316	1330
TEK LAKE RI.	179	-	-	250	-	-	207	543	543	416	-	-
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	112	112	112	112	112	112	112	112	112	112	112	112
TOT.GENERAT.	3115	2626	2588	3472	3563	3563	3964	4829	5122	3411	4142	4156
IMPORT	350	350	350	350	350	350	-	-	316	51	350	350
TOTAL SUPPLY	3465	2976	2938	3822	3913	3913	3964	4829	5438	3462	4492	4506
UNS.POWER DE.	306	1931	2563	4	861	1519	-	-	-	573	668	1199

SCENARIO: DRY WATER YEAR-INVESTMENTS DELAYED 6 MONTHS (LOADS DECREASED BY 5 %

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
LIGNITE	1403	1403	1403	1403	1403	1403	948	948	948	1415	1415	1415
COAL	165	165	165	165	165	165	110	110	110	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	229	-	-	270	270	-	-	-	-	81	-	-
TEK TH.TOT.	2389	2160	2160	2430	2430	2160	1452	1452	1452	2253	2172	2172
KEBAN	-	-	-	-	-	-	1228	1310	1310	61	1315	1315
H.UĞURLU	24	-	-	165	518	518	-	306	518	-	-	-
SARIYAR	-	38	-	154	412	412	200	412	412	22	-	-
HİRFANLI	-	-	-	-	-	-	158	158	158	-	-	15
DEMİR KÖP.	54	-	-	-	-	-	-	-	-	14	-	-
KEMER	-	-	-	39	45	45	-	1	43	-	1	-
ALMUS	-	-	-	-	-	-	21	25	25	-	-	-
TEK DAMS TO.	77	38	-	358	975	975	1607	2212	2466	97	1316	1330
TEK LAKE RI.	121	-	-	94	148	-	110	289	289	259	-	-
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	112	112	112	112	112	112	112	112	112	112	112	112
TOT.GENERAT.	3003	2614	2576	3298	3969	3551	3586	4369	4623	3025	3904	3918
IMPORT	350	350	350	163	350	350	-	-	297	243	350	350
TOTAL SUPPLY	3353	2964	2926	3461	4319	3901	3586	4369	4920	3268	4254	4268
UNS.POWER DE.	59	1475	2050	-	-	1014	-	-	-	383	414	893

SCENARIO: DRY WATER YEAR-INVESTMENTS DELAYED 6 MONTHS (FORECASTED LOADS)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3591	4673	5289	3644	4547	5151	3775	4599	5171	3843	4914	5460
LIGNITE	1403	1403	1403	1359	1359	1359	991	991	991	1415	1415	1415
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	229	-	-	270	-	-	-	-	-	124	-	-
TEK TH.TOT.	2389	2160	2160	2331	2061	2061	1551	1551	1551	2296	2172	2172
KEBAN	-	-	-	-	-	-	1310	1310	1310	-	1191	1315
H.UĞURLU	24	-	-	134	518	518	-	482	518	-	-	-
SARIYAR	-	38	-	154	412	412	208	367	412	22	-	-
HİRFANLI	-	-	-	-	-	-	158	158	158	-	-	15
DEMİR KÖP.	54	-	-	-	-	-	-	-	-	14	-	-
KEMER	-	-	-	39	45	45	-	1	43	-	1	-
ALMUS	-	-	-	-	-	-	21	25	25	-	-	-
TEK DAMS TO.	77	38	-	326	975	975	1698	2343	2466	36	1192	1330
TEK LAKE RI.	121	-	-	117	-	-	110	289	289	259	-	-
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	112	112	112	112	112	112	112	112	112	112	112	112
TOT.GENERAT.	3003	2614	2576	3190	3452	3452	3775	4599	4722	3006	3780	3918
IMPORT	350	350	350	56	350	350	-	-	350	350	350	350
TOTAL SUPPLY	3353	2964	2926	3247	3802	3802	3775	4599	5072	3356	4130	4268
UNS.POWER DE.	238	1709	2363	398	745	1349	-	-	99	487	784	1192

SCENARIO: DRY WATER YEAR-INVESTMENTS DELAYED 6 MONTHS (LOADS INCREASED BY 5 %)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3771	4907	5501	3826	4774	5432	3964	4829	5438	4035	5160	5705
LIGNITE	1403	1403	1403	1164	1164	1164	1187	1187	1187	1415	1415	1415
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	229	-	-	270	-	-	-	-	-	124	-	-
TEK TH.TOT.	2389	2160	2160	2136	1866	1866	1746	1746	1746	2296	2172	2172
KEBAN	-	-	-	-	-	-	1310	1310	1310	-	1191	1315
H.UĞURLU	24	-	-	134	518	518	-	482	518	-	-	-
SARIYAR	-	38	-	154	412	412	202	402	412	22	-	-
HİRFANLI	-	-	-	-	-	-	158	158	158	-	-	15
DEMİR KÖP.	54	-	-	-	-	-	-	-	-	14	-	-
KEMER	-	-	-	39	45	45	-	1	43	-	1	-
ALMUS	-	-	-	-	-	-	21	25	25	-	-	-
TEK DAMS TO.	77	38	-	326	975	975	1691	2378	2466	36	1192	1330
TEK LAKE RI.	121	-	-	117	-	-	110	289	289	259	-	-
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	112	112	112	112	112	112	112	112	112	112	112	112
TOT.GENERAT.	3003	2614	2576	2995	3257	3257	3964	4829	4917	3006	3780	3918
IMPORT	350	350	350	56	350	350	-	-	350	350	350	350
TOTAL SUPPLY	3353	2964	2926	3051	3607	3607	3964	4829	5267	3356	4130	4268
UNS.POWER DE.	418	1943	2575	775	1167	1825	-	-	171	679	1030	1437

SCENARIO: DRY WATER YEAR-INVESTMENTS DELAYED 1 YEAR (LOADS DECREASED BY 5 %)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3412	4439	4976	3461	4319	4915	3586	4369	4920	3651	4668	5161
LIGNITE	1403	1403	1403	1403	1403	1403	936	936	936	1403	1403	1403
COAL	165	165	165	165	165	165	110	110	110	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	153	-	-	229	223	-	-	-	53	153	-	-
TEK TH.TOT.	2320	2160	2160	2389	2383	2160	1440	1440	1493	2313	2160	2160
KEBAN	-	-	-	-	-	-	1280	1310	1310	13	1315	1315
H.UĞURLU	24	-	-	146	518	518	-	412	518	-	-	-
SARIYAR	-	38	-	154	412	412	200	412	412	22	-	-
HİRFANLI	-	-	-	-	-	-	158	158	158	-	-	15
DEMİR KÖP.	54	-	-	-	-	-	-	-	-	14	-	-
KEMER	-	-	-	39	45	45	-	1	43	-	1	-
ALMUS	-	-	-	-	-	-	21	25	25	-	-	-
TEK DAMS TO.	77	38	-	339	975	975	1656	2318	2466	49	1320	1330
TEK LAKE RI.	121	-	-	87	195	-	74	195	195	121	-	-
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	112	112	112	112	112	112	112	112	112	112	112	112
TOT.GENERAT.	2927	2614	2576	3231	3969	3551	3586	4369	4570	2899	3892	3901
IMPORT	350	350	350	231	350	350	-	-	350	172	350	350
TOTAL SUPPLY	3277	2964	2926	3461	4319	3901	3586	4369	4920	3070	4242	4256
UNS.POWER DE.	135	1475	2050	-	-	1014	-	-	-	581	427	905

SCENARIO: DRY WATER YEAR-INVESTMENTS DELAYED 1 YEAR (FORECASTED LOADS)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3591	4673	5289	3644	4547	5151	3775	4599	5171	3843	4914	5460
LIGNITE	1403	1403	1403	1303	1303	1303	1036	1036	1036	1403	1403	1403
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	37	-	-	229	229	-	-	-	-	270	-	-
TEK TH.TOT.	2197	2160	2160	2234	2234	2005	1596	1596	1596	2430	2160	2160
KEBAN	-	-	-	-	-	-	1310	1310	1310	-	1191	1315
H.UĞURLU	24	-	-	134	518	518	-	487	501	-	-	-
SARIYAR	-	38	-	154	412	412	200	412	412	22	-	-
HİRFANLI	-	-	-	-	-	-	158	158	158	-	-	15
DEMİR KÖP.	54	-	-	-	-	-	-	-	-	14	-	-
KEMER	-	-	-	39	45	45	-	1	43	-	1	-
ALMUS	-	-	-	-	-	-	21	25	25	-	-	-
TEK DAMS TO.	77	38	-	326	975	975	1689	2393	2448	36	1192	1330
TEK LAKE RI.	121	-	-	117	-	-	74	195	195	121	-	-
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	112	112	112	112	112	112	112	112	112	112	112	112
TOT.GENERAT.	2811	2614	2576	3093	3625	3396	3775	4599	4655	3003	3768	3906
IMPORT	350	350	350	350	350	350	-	-	350	49	350	350
TOTAL SUPPLY	3161	2964	2926	3443	3975	3746	3775	4599	5005	3052	4118	4256
UNS.POWER DE.	430	1709	2363	201	572	1405	-	-	166	791	796	1204

SCENARIO: DRY WATER YEAR-INVESTMENTS DELAYED 1 YEAR (LOADS INCREASED BY 5%)

PERIOD	I			II			III			IV		
LOAD LEVEL	1	2	3	1	2	3	1	2	3	1	2	3
POWER DEMAND	3771	4907	5501	3826	4774	5432	3964	4829	5438	4035	5160	5705
LIGNITE	1403	1403	1403	1114	1114	1114	1225	1225	1225	1403	1403	1403
COAL	165	165	165	110	110	110	165	165	165	165	165	165
F.OIL	592	592	592	592	592	592	395	395	395	592	592	592
GAS TUR.	229	–	–	229	–	–	–	–	–	115	–	–
TEK TH.TOT.	2389	2160	2160	2045	1816	1816	1785	1785	1785	2275	2160	2160
KEBAN	–	–	–	–	–	–	1310	1310	1310	–	1191	1315
H.UĞURLU	24	–	–	134	518	518	–	518	390	–	–	–
SARIYAR	–	38	–	154	412	412	200	412	412	22	–	–
HİRFANLI	–	–	–	–	–	–	158	158	158	–	–	15
DEMİR KÖP.	54	–	–	–	–	–	–	–	–	14	–	–
KEMER	–	–	–	39	45	45	–	1	43	–	1	–
ALMUS	–	–	–	–	–	–	21	25	25	–	–	–
TEK DAMS TO.	77	38	–	326	975	975	1689	2424	2338	36	1192	1330
TEK LAKE RI.	121	–	–	117	–	–	74	195	195	121	–	–
NON-TEK TH.	304	304	304	304	304	304	304	304	304	304	304	304
NON-TEK HY.	112	112	112	112	112	112	112	112	112	112	112	112
TOT.GENERAT.	3003	2614	2576	2904	3207	3207	3964	4819	4733	2848	3768	3906
IMPORT	350	350	350	350	350	350	–	10	350	47	350	350
TOTAL SUPPLY	3353	2964	2926	3254	3557	3557	3964	4829	5083	2896	4118	4256
UNS.POWER DE.	420	1943	2575	572	1217	1875	–	–	355	1140	1042	1449

APPENDIX II. DISTRIBUTION OF OUTAGE CAPACITIES

SEYİTÖMER (3x150 = 450 MW) q = 0.13554
p = 0.86446

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.64600	1.00000
150	0.30386	0.35400
300	0.04760	0.05014
450	0.00254	0.00254

YATAĞAN (2x210 = 420 MW) q = 0.10000
p = 0.90000

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.81000	1.00000
210	0.18000	0.19000
420	0.01000	0.01000

SOMA-B (2x165 = 330 MW) q = 0.10000
p = 0.90000

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.81000	1.00000
165	0.18000	0.19000
330	0.01000	0.01000

TUNÇBİLEK-B (2x150 = 300 MW) q = 0.0805
p = 0.9195

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.84548	1.00000
150	0.14804	0.15452
300	0.00648	0.00648

TUNÇBİLEK-A (2x32,1 x 65 = 129 MW) q = 0.08935
p = 0.91065

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.75519	1.00000
32	0.14819	0.24481
64	0.00727	0.09662
65	0.07410	0.08935
97	0.01454	0.01525
129	0.00071	0.00071

SOMA-A (2x22 = 44 MW) q = 0.97159
p = 0.02841

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.94399	1.00000
22	0.05521	0.05601
44	0.00081	0.00081

İZMİR (3x5+1x2.5+1x20 = 37,5 MW) q = 0.11423
p = 0.88577

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.78459	1.00000
17.5	0.10118	0.21541
20	0.10118	0.11423
37.5	0.01305	0.01305

ANBARLI (3x110+2x150 = 630 MW) q = 0.06903
p = 0.93097

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.69932	1.00000
110	0.15556	0.30068
150	0.10371	0.14512
220	0.01153	0.04141
260	0.02307	0.02988
300	0.00384	0.00681
330	0.00029	0.00297
370	0.00171	0.00268
410	0.00086	0.00097
480	0.00004	0.00011
520	0.00006	0.00007
630	0.00000	0.00000

HOPA (2x25 = 50 MW) q = 0.03941
p = 0.96059

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.92273	1.00000
25	0.07572	0.07727
50	0.00155	0.00155

KEBAN (4x157,5+4x185 = 1370 MW) q = 0.01441
p = 0.98559

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.89037	1.00000
157.5	0.05207	0.10963
185	0.05207	0.05756
315	0.00114	0.00549
342.5	0.003043	0.00435
370	0.00114	0.00131
472.5	0.00001	0.00017
500	0.00007	0.00016
527.5	0.00007	0.00009
555	0.00001	0.00002
630	0.00000	0.00001
657.5	0.00000	0.00000

H.UČURLU (4x125 = 500 MW) q = 0.00127
p = 0.99873

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.99493	1.00000
125	0.00506	0.00507
250	0.00001	0.00001
375	0.00000	0.00000
500	0.00000	0.00000

SARIYAR (4x40 = 160 MW) q = 0.02833
p = 0.97167

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.89141	1.0000
40	0.10396	0.10859
80	0.00455	0.00463
120	0.00008	0.00008
160	0.00000	0.00000

GÖKÇEKAYA (3x92.8 = 278,4 MW) q = 0.08800
p = 0.91200

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.75855	1.00000
92.8	0.21958	0.24145
185.6	0.02119	0.02187
278.4	0.00068	0.00068

HİRFANLI (3x32 = 96 MW) q = 0.00896
p = 0.99104

Capacity Outage(MW)	Probability	Cumulative Probability
0	0.97336	1.00000
32	0.02640	0.02664
64	0.00024	0.00024
96	0.00000	0.00000

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