Electricity Generation and Costing Simulation Model

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First Draft: Comments are solicited!

Content

Introduction

For estimating electricity generation and costs of power production systems, various models were developed. For planning purposes, two classes of models are particularly popular: ad-hoc optimisation models incorporating load duration curves, and linear programming cost minimization models. Either because of structural characteristics or because of dimensionality problems, both models are not well suited to represent accurately specific production techniques, such as non-dispatchable or partly dispatchable plants, pumped storage, capacities with operational constraints on modulation flexibility, etc... However, the models are generally simple and fast, and therefore well adapted for planning generation systems over longer time periods.

The first goal of the model discussed here is to complement existing power generation planning models, by a detail simulation of the working of future power systems projected by the planning models. We aim at a simulation period of somewhat 10 years in the future. On the one hand, uncertainty averages out some particularities (e.g. maintenance schedules); on the other hand, simulating a 10 year period within acceptable computing budgets requires trading-off some of the detail one can imagine theoretically.

Our model simulates generation and costing of any diverse power system on an hourly load basis and on an individual units basis, i.e. one can estimate the output and cost of any plant of the system during any hour considered. Hourly loads are arranged together chronologically to daily subperiods (night and day) and afterwards to one 24-hour day. Three typical days are selected to make up one typical week. Finally, seven typical weeks represent a year. Outputs and costs of the thermal production plants during a typical day, are simulated by a unit commitment procedure, based on a dynamic programming algorithm. Afterwards, pumped storage activity is built up incrementally up to the minimum of the total cost function, being a boundary solution when capacity constraints prevail.

The submodels and routines are assembled in the above way because simulation of planned power systems was the primary goal. However, by adapting the main program, one can model some other interesting topics, e.g. marginal cost information for tariff-making, short-run (a few months; one year) operation planning and maintenance scheduling, etc...

In addition, raising the accuracy of the simulation processes is feasible, by arranging seven typical days in one week, by extending the number of typical weeks handled, etc...

Trading-off accuracy versus complexity, depends on the destination of the results and the extent of the computing budgets.

I. ELECTRIC LOAD MODELING

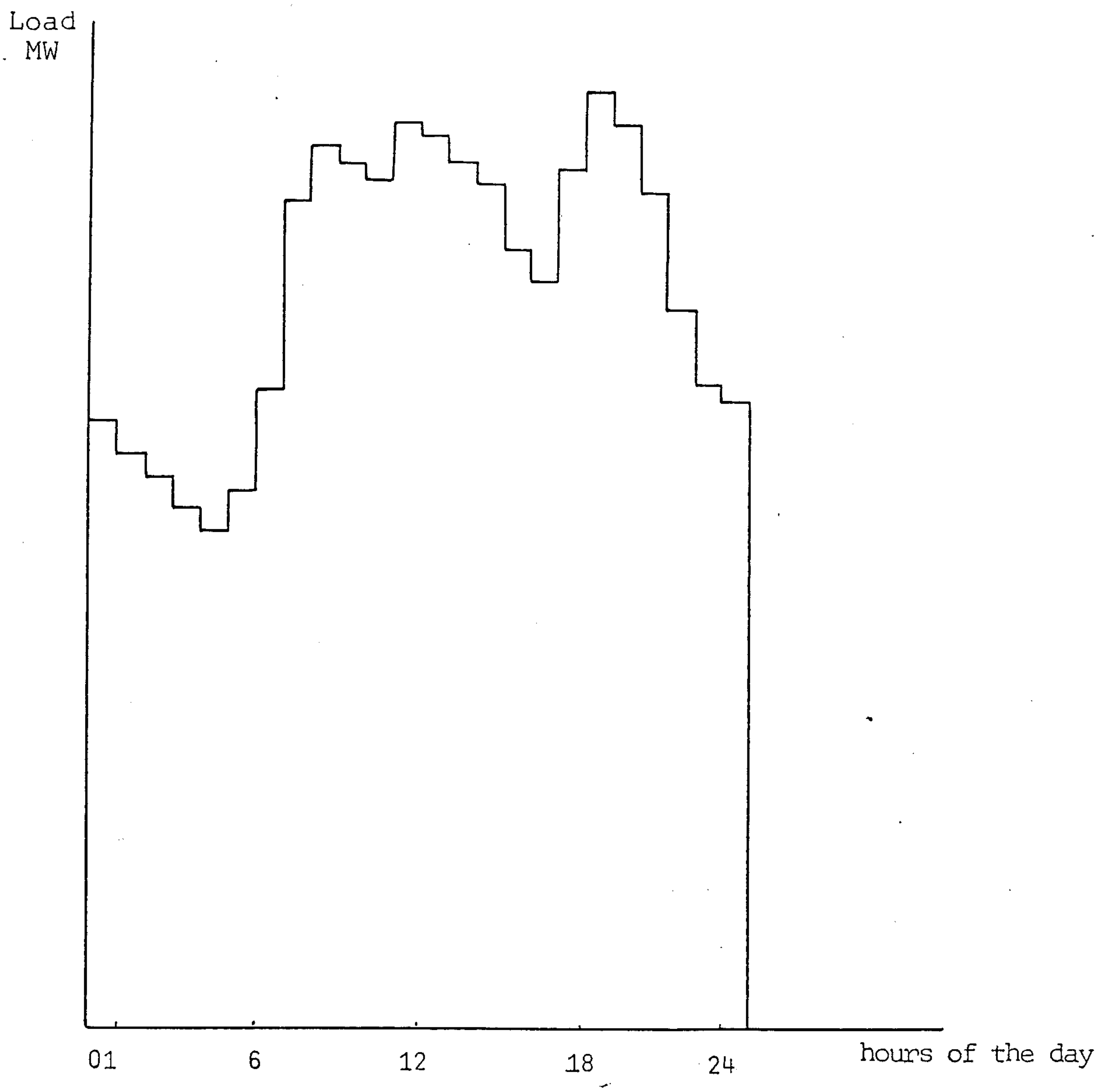
The aim of the model is a detail simulation of the performance of a power generation system under various assumptions with respect to composition of the system, maintenance scheduling, etc... Therefore, a chronological electric load representation was retained, viz. a discrete hourly load pattern. If a finer approximation is required, the model can be extended by modeling the load per quarter of an hour. The model is not adapted to process continuous load curves.

Fig. 1.1.

In its present version, the basic time interval has a length of 1 hour. A common hourly load structure is shown in figure 1.1 for a 24-hour day. At 01 a.m. the load is down and this during most hours of the night. At 07 and 08 a.m. the load builds up rather fast and remains at high levels until late in the afternoon (about 03 at 04 p.m.). A local minimum is observed around 04 or 05 p.m., succeeded by a peak demand period. Depending on the season and on the type of day, the highest load of the day is observed either in the first or in the second peak demand period. Following the evening peak, the load decreases to its night level. During some days around 11 p.m., a small peak arises as a result of higher demand due to night tariff-making.

For implementation in the model, the daily load patterns are translated over an interval of 2 hours: a 24-hours period starts at 10 p.m. and runs over 11 p.m., 01 a.m. until 9 p.m. This translation aims at an easy separation of the night period from the day-time. The night period starts at 10 p.m. and runs until 6 a.m., or 7 a.m. or any other hour, indicating the last low-load hour of the night. For the various daily load patterns, one can impose an independent length of the night subperiods. The remaining hours make up the daytime subperiods. The separation of the 24-hour day into two subperiods - night and day - was required in order to model the cogeneration units in an accurate way. It involves also some advantages for the simulation of the pumped storage activities.

Figure 1.1. Electric load pattern during 24 hours



With respect to pumped storage, it should be noted that the discussed load patterns have to be free of the load on the system due to pumping

Although a load pattern similar to the one shown in figure 1.1 results for nearly all days of the year, one knows that the amplitude of the load fluctuations is very different for week-end and working days. On top of these differences, seasonal variations are observed.

In order to model the former distinction - between week-end and working days - three days are used to represent a typical week: Saturday, Sunday and one working day. Because of data availability (*) the working day used is Wednesday. It was impossible for us to verify whether Wednesday is a representative day for all working days of the week.

In order to model seasonal variations, several typical weeks are required to cover one year. After a rough study of the available information for the year 1982, we decided to retain 7 typical weeks, each one representative for a particular subperiod of the year of unequal duration.

An overview of the construction of the yearly load pattern is shown in figure 1.2. It requires no structural adaptations to the model either to refine the basic time interval from 1 hour to 1/4 hour, or to extend the considered number of typical days that make up one week or of typical weeks that make up one year.

Fig. 1.2.

In the present formulation, 7 typical weeks are modeled, i.e. 21 typical days. In table 1.1 a short description of these weeks is given.

(*) The detailed load information at our disposition consists of the typical day chronological load patterns available for the Saturday, Sunday and Wednesday of one particular week for every month of the year 1982 (CPTE, unpublished).

Figure 1.2. Construction of the yearly load structure

Basic time interval	1 hour	
Aggregated to 24 hour-days	24 hours	
Divided into two subperiods of flexible length	NIGHT 10 p.m. up to 6,7,... a.m.	DAY-TIME from 6,7,... a.m. to 9 p.m.

3 typical days make up a typical week	Saturday	night / day-time
	Sunday	night
	Weekday	night / day-time

Several typical weeks represent one year	Week 1	Saturday	number (1,1)
		Sunday	(1,2)
		Weekday	(1,3)
	⋮		
	Week n	Saturday	number (n,1)
		Sunday	(n,2)
		Weekday	(n,3)
	1 year		365 days

Table 1.1. Overview of the subyearly periods (based on typical weeks)

Subyearly period	Approximate reference months	Number of days Sat.	Sun.	Week	Total	Share of annual load %
1	Jan.	3	4	14	21	7.02
2	Jan.-Fe.-Mar.	8	8	40	56	17.40
3	Mar.-Apr.-May	8	10	38	56	15.47
4	May-Jun.-Sep.	12	14	58	84	21.69
5	Jul.-Aug.	11	13	53	77	17.22
6	Okt.-Nov.	6	8	28	42	11.81
7	Dec.-Jan.	4	5	20	29	9.28
	YEAR	52	62	251	365	100.00

Every typical day is defined by 30 real numbers:

1,...,24 = hourly load in MW

25 = number of days of the year similar to this typical day (see table 1.1)

26,27 = directory numbers to model the production of non-dispatchable units (see chapter II)

28 = directory number to the maintenance scheduling of the production system (see chapter II)

29 = last hour of the night period (see figure 1.2)

30 = optional constraint on the pumped storage energy (MWh) processed during the typical day (see chapter III).

As shown in table 1.1, the number of days assigned to a particular typical day (i.e. its implicit weight) can be chosen freely within the constraint that the numbers add to 365 over the year. We have selected 52 Saturdays and 62 Sundays, because there are 10 official holidays in Belgium. The choice of the particular weights assigned to the various typical days and typical weeks was directed by several considerations. First we tried, on the basis of a rough comparison, to approximate the monthly provided chronological load patterns. Secondly, we aimed at a division of the year in subperiods that are suitable for incorporating cogeneration units in the production system (see chapter II). Thirdly, we required that the total load over the year 1982 imbedded in the programmed typical days and their weights, should be nearly equal to the observed load in 1982.

It is difficult to check whether our performance on the first point is sufficient in modeling the real representative load of the Belgian system. This check would require a lot more data than we have at our disposition, besides a considerable theoretical effort which is out of scope of this work. The performance on the second point will be illustrated in chapter II. With respect to the third issue, the load and weights structure imbedded in the program gives rise to an accumulated demand of 47 486.5 GWh for the year 1982, while the observed number amounts to 47 492.6 GWh.

Having defined the load structure for a typical year, we have to discuss two more issues: the scaling of this load structure at the aggregated load during any future year, and the modeling of shifting load profiles. Scaling the load structure to the demand in any future year is simply done by multiplying the hourly loads (MW) by a scale factor being the ratio of the future year's demand to the demand in the year analysed previously. Modeling shifting load profiles is not provided in the present program. It could be added in short time by using functions defining for the typical days 24 correction factors, one for every hour of the day. One expects these factors to cluster around 1. It would be waste of time to spend more time at this issue at this stage of the model development because we lack a reliable empirical and theoretical basis for electric load modeling.

II. THE PRODUCTION SYSTEM

The model is developed in order to simulate the working of the Belgiar power generation system. The composition of the Belgian system is shown in table 1.2. 2.1

Table 2.1. Estimated power generation capacity of the Belgian utilities in 1986

Type	Capacity (MW)		%
Water: pumped storage	1 238		9.6
river hydro	67		0.5
Nuclear (excl. Tricastin)	5 136		39.7
Fossil: recovery gas burning	1 016		7.8
coal fired,	2 631		20.4
composed as < 100 MW		458	
100-150 MW		1344	
> 150 MW (retrofits)		829	
oil/gas fired,	2 847		22.0
composed as < 100 MW		1018	
100-150 MW		714	
> 150 MW		1115	
TOTAL	12 935		100.0

Although the system consists primarily of thermal units, it owns some of the particularities of most modern interconnected power grids, e.g. a large pumped storage capacity, the presence of non-dispatchable units (which could be extended significantly when cogeneration plants would be built), a significant proportion of nuclear capacity, ... Therefore, after some minor adaptations, the model may be useful for other interconnected systems.

This chapter contains three sections. In the first the modeling of the thermal generation plants is discussed. In section two, we show how non-dispatchable capacities are incorporated. The solution to the maintenance scheduling problem is described in section three.

II.1. Thermal generation plants

All plants of the Belgian system are stored in a matrix GO[13,99].

Each generation unit is described by 13 characteristics of which the most relevant for our discussion at this moment are:

GO[1,k] = code number identifying unit k. In addition to individual identification, the code number is used to assign the units to a particular class

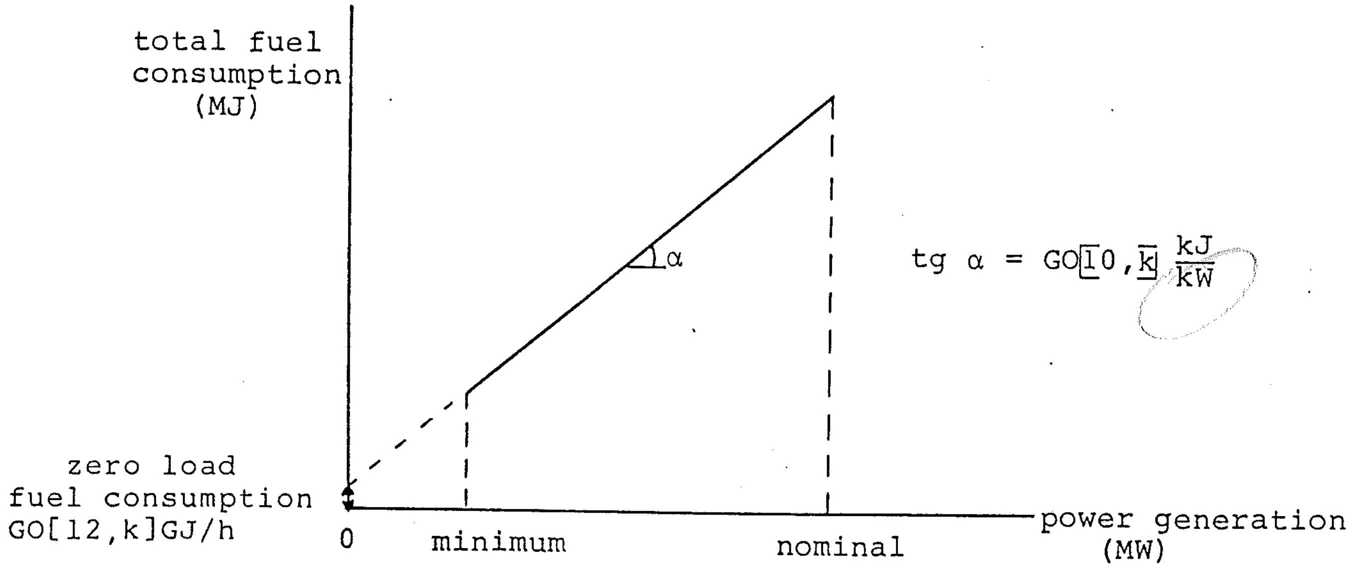
100._ _ 199. non-dispatchable or partly dispatchable units (see § II.2)
200._ _ 299. nuclear plants
300._ _ 399. coal fired plants
500._ _ 599. oil and/or gas fired plants involving start-up costs
700._ _ 799. rapid start units (gasturbines; turbojets)
800._ _ 899. pumped storage plants (see § II.4).

GO[2,k] = minimum capacity to be delivered by the unit when it is running (MW)
GO[3,k] = nominal generation capacity of the unit (MW)
GO[10,k] = specific fuel consumption (kJ/kWh)
GO[12,k] = zero load fuel consumption (GJ/h)
GO[13,k] = short-run costs apart from fuel to keep the unit operational (FB/h)

Because the specific fuel consumption of a unit is expressed by one (average) number, it will turn out that the production costing methodology is based on a merit-order loading of the plants. We discuss this option here briefly.

The fuel consumption of a thermal generation plant is modeled as shown in figure 2.1. The slope of the line segment in figure 2.1 equals the specific consumption GO[10,k] (kJ/kWh). The constant term of the linear curve equals the zero load fuel consumption GO[12,k] (GJ/h) of the unit. By modeling the minimum load bound explicitly, one includes the modulation constraints that are imposed on the units.

Figure 2.1. One-stage (merit-order loading)



Merit-order loading is often criticized in the literature as being too rough. Two alternatives to merit-order loading are proposed: representing the generation plants as multi-stage capacities or extending the number of stages infinitely to continuous capacities (incremental loading). Multi-stage loading (figure 2.2) is applied in Belgium by the central dispatching board CPTE (Centre for Production and Transportation of Electricity) in dispatching the plants on an hourly and quarter hourly basis. At the cost of some minor model adaptations and of a significant extension of the dimensions of the model, we could incorporate a multi-stage representation of the generation plants. Contrarily, incremental loading (figure 2.3) is not feasible because the algorithms are developed for discrete capacity additions.

Figure 2.2. Multi-stage

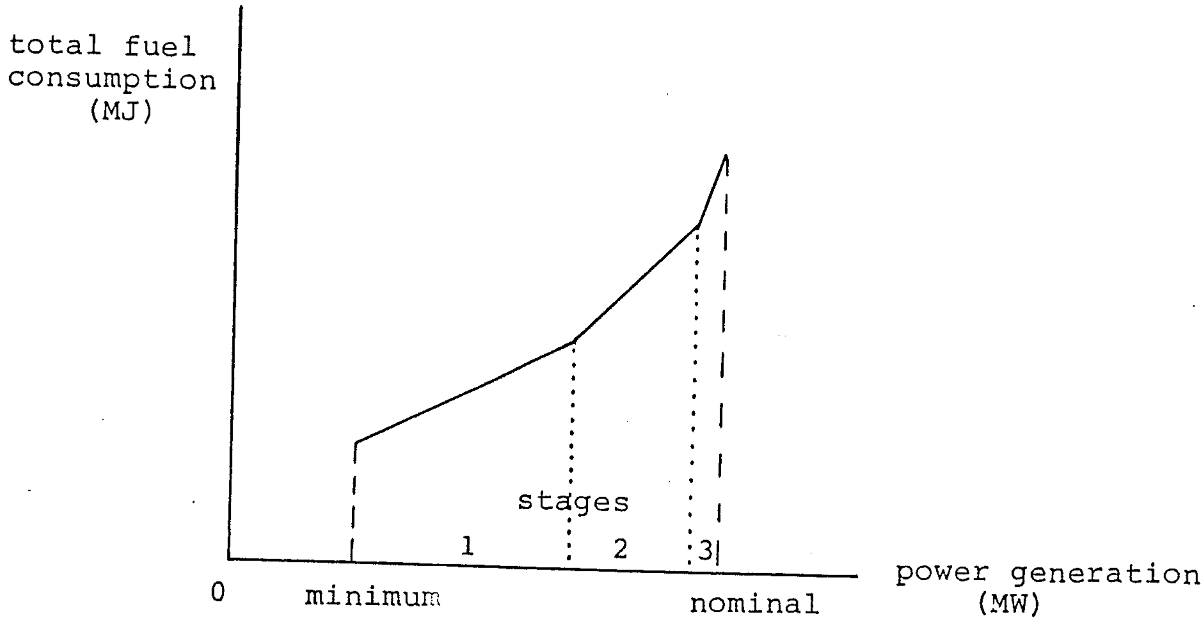
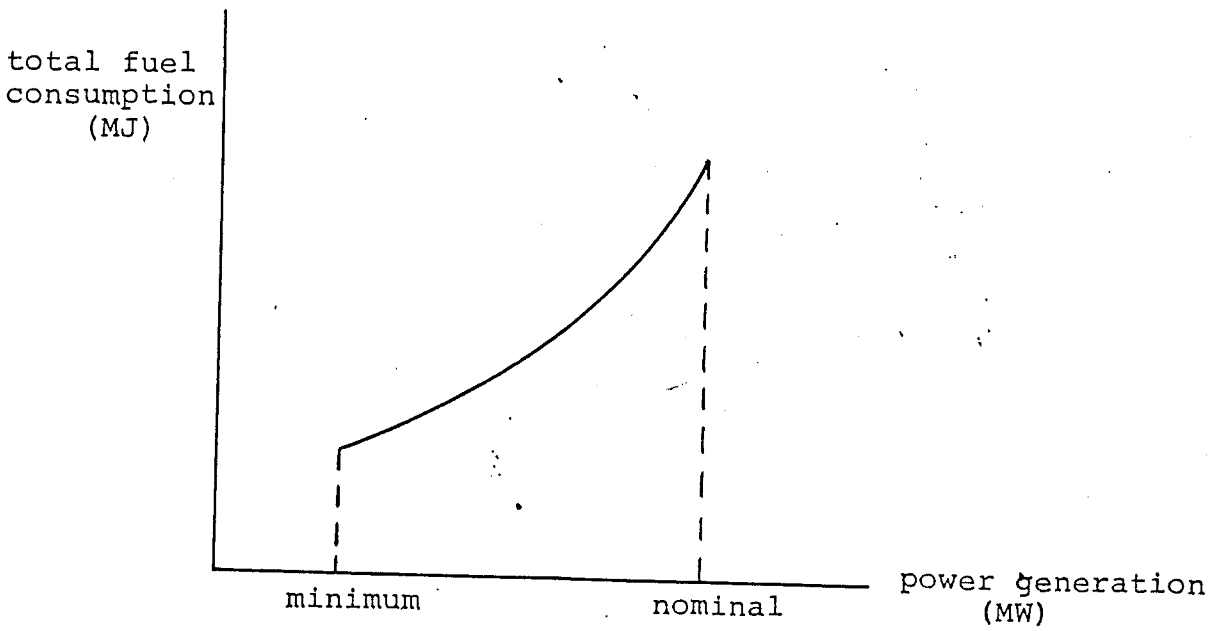
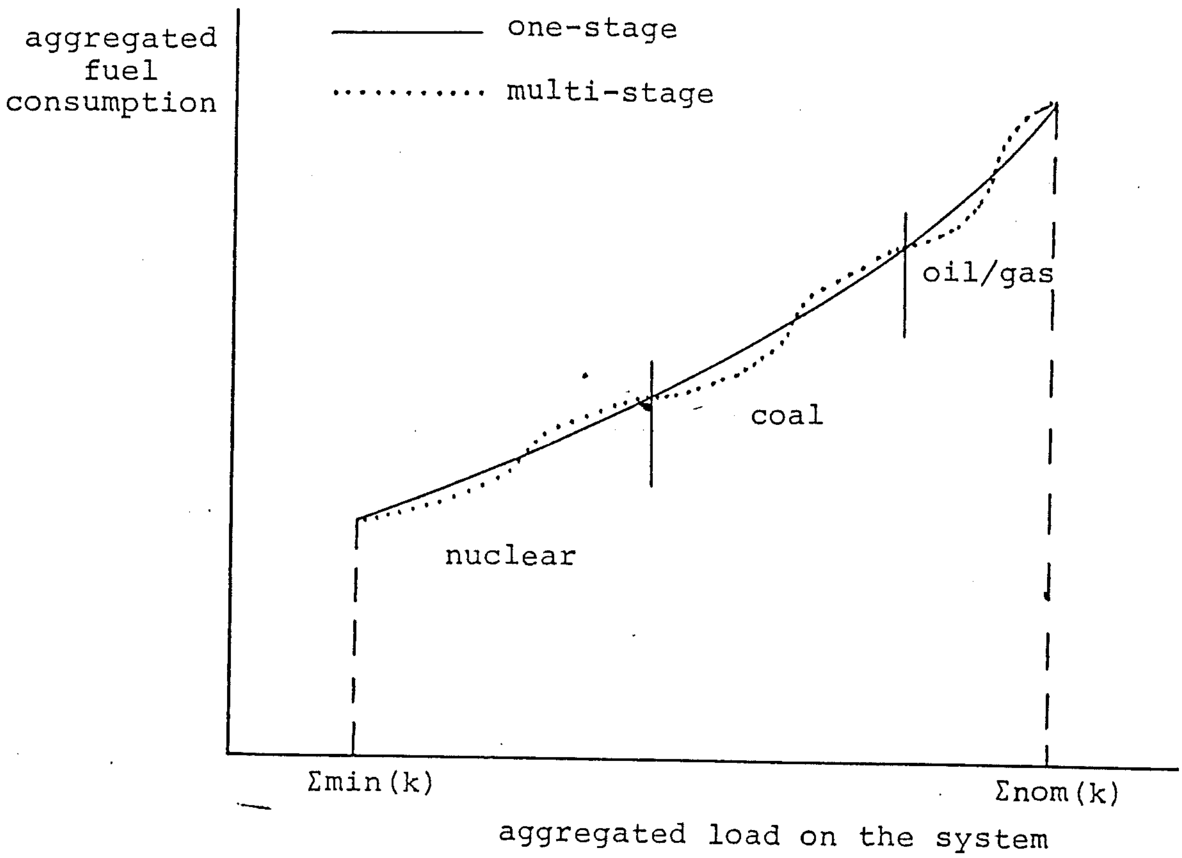


Figure 2.3. Continuous (incremental loading)



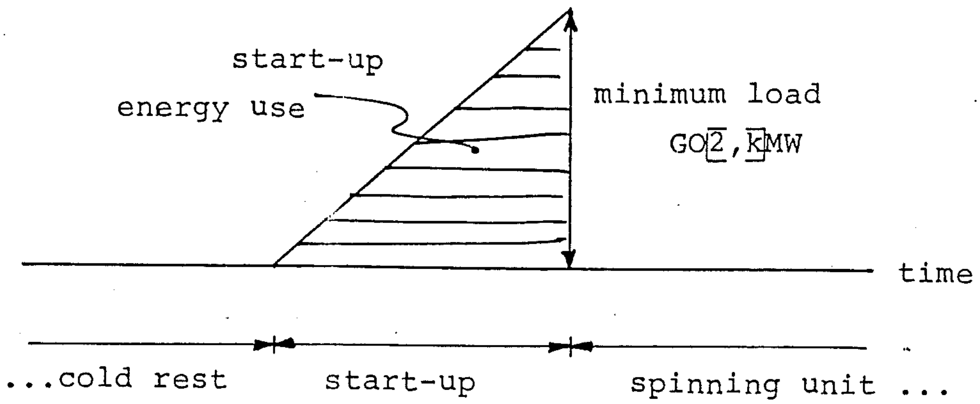
In trading off the higher accuracy of a multi-stage modeling of each unit and the significant reduction in dimension of the one-stage representation we decided in favour of the latter. One argument was the lack of reliable data on the multi-stage representation. The other argument stems from the planning perspective we have chosen. After all, the difference between a multi-stage and a one-stage approach can be expected to be rather small. As shown in figure 2.4, the multi-stage fuel consumption patterns of a diversified production system will fluctuate around the one-stage solution. The distance between both patterns is rather small and this is partly due to the separability of the diversified system in capacity blocks of nuclear, coal fired and gas/oil fired units because of the large difference in short-run marginal costs (fuel costs) of these various technologies. These capacity blocks appear as separable from one another in a merit-order operation schedule, as well as in a multi-stage or incremental loading arrangement.

Figure 2.4. Comparison between one-stage and multi-stage modeling of the units in estimating total fuel consumption of the system



In GO[11,k] the start-up fuel consumption of unit k is noted, i.e. the fuel required to heat the thermal unit from cold rest to minimum-load capacity. When no reliable number for this fuel amount is available, a proxy is estimated by multiplying the minimum load (GO[2,k]MW) with the length in hours a cold start takes and dividing this outcome by two (see figure 2.5). Fortunately, we dispose of the exact start-up costs for most units of the Belgian system.

Figure 2.5. Start-up fuel consumption



Start costs of large-scale plants are significant. Because these plants are in general base-load units, their start-costs are not incurred during periods of normal performance of the plants and of normal loads. Peak units such as gas-turbines, turbojets, diesel engines,... carry lower start costs.

Avoiding start costs in going from hours of lower demand to hours of higher demand on the system is important in order to minimize total generation costs. The number of start/stop operations is limited by modulating the load on several units simultaneously when loads are decreasing. During hours of very low demand, pumped storage plants can be used as buffer capacity in order to take-up the excess supply of power of nuclear stations and to avoid or lessen their down scaling. Simultaneous modulation of several intermediate and peak units can be modeled by a multi-stage or incremental loading scheduling of the units. In our model simultaneous modulation results from the dynamic programming algorithm used to solve the unit commitment problem.

Converting fuel consumption for generating power or for starting plants into costs requires the multiplication by the price of the fuel used (FB/GJ). Therefore in GO [9,k] the type of fuel used by the unit is represented by a dummy variable, i.e.:

GO[9,k] = 1. nuclear fuel
= 2. coal
= 3. natural gas
= 4. heavy fuel oil
= 5. light fuel oil
= 6. recovery gas from blast furnaces, refineries or coke manufacturing
= 7. oil and gas
= 8. hydro

Because of the large gap between oil/gas prices on the one hand and coal prices on the other hand, it makes little sense to consider multi-fuel units if one of the fuels is coal: burning coal will always dominate burning oil or gas, at least when no environmental restrictions or flexibility constraints are imposed.

II.2. Non-dispatchable capacities

The role of non-dispatchable generation in the Belgian power system is presently limited but is expected to be ever-increasing in the future. Non-dispatchable generation includes such sources as wind, solar, or run of the river hydro whose output cannot be controlled by the utility dispatch center, as well as electricity purchases from a non-utility owned generator. This type of generation is very limited in Belgium, and there is no indication a significant development will be observed in the next decades. We discuss these sources in section II.2.a.

More common is another type of non-dispatchable capacity, i.e. units burning recovery gas, and cogeneration plants owned by the utilities. Our model was developed inter alia to simulate the impact of capacity expansion in cogeneration facilities. Although these plants are scheduled in the list of plants of the utilities their dispatching is limited because one has either to burn the supplied recovery gas or to supply the required amount of heat. We discuss these capacities in II.2.b and II.2.c.

a. Capacities that are non-dispatchable because they are weather dependent or because they are not controlled by the utility (e.g. run of the river hydro; cogenerators selling excess power to the utility).

The problem of integrating these capacities in an expansion planning model has been solved by the EGEAS model of EPRI. The solution exists in the reduction of the customers load by the amount of power generated by the non-dispatchable capacities. It is obvious that we can incorporate this solution rather easily in our model because of the detailed representation of the load structure we have chosen (basic time unit = 1 hour) (see chapter I). At this moment we found this issue of minor importance because this type of power supply is non-existent in Belgium, except some small run of the river hydro stations. For the latter plants only the seasonal variation should be considered.

The EGEAS methodology of reducing or enhancing the load on the Belgian system because of non-dispatchable loads could be very valuable when treating power exchanges between Belgium and neighbouring countries. Unfortunately, we have no systematic detail information on power exchanges at our disposition. Therefore, we assume that the Belgian system has to meet the Belgian load in isolation. This assumption is rather common in dealing with generation planning.

A few non-dispatchable capacities are integrated in our model at the top of the merit-order, e.g. 67 MW run-of-the-river hydro (derated to ~40 MW), a fixed supply of 170 MW (from the Belgian participation in Eurodif-Tricastin (France), etc...

b. Capacities burning the supplies of recovery gas from refineries, blast furnaces and coke manufacturing.

It is common practice in Belgium that the utilities buy this gas and burn it in their nearby power plants. When recovery gas is supplied the plants are entirely or partly non-dispatchable. When no recovery gas is available the plants can be dispatched as any other fossil fired station. In the model these plants are divided into a non-dispatchable part (proportional to the amount of recovery gas supplied) and a dispatchable part on top of the previous one. This is illustrated in figure 2.6.

Figure 2.6.

For the dispatching problem it makes no difference whether the recovery gas has to be mixed with a fuel rich in heat content or whether it can be burned unmixed. In figure 2.6 two situations are shown: in the first figure, the unit is full loaded when the maximum amount of recovery gas is supplied; in the bottom figure the recovery gas entails always part loading of the unit.

In practice it is common that recovery gas deliveries fall short in energy to run the units at or above their minimum load levels (see figure 2.1). In this case, one has to add coal, oil or natural gas from the fossil fuel pool to keep the units operating at their minimum output. In addition, the utilities used to keep two turbo-sets on line permanently in the plants supplied with recovery gas in order to guarantee the take-up of the gas at all times. However, because of the significant built-up of nuclear capacity in the system, it is planned to change this procedure and to designate a single unit for permanent availability.

Figure 2.6. Plants burning recovery gas

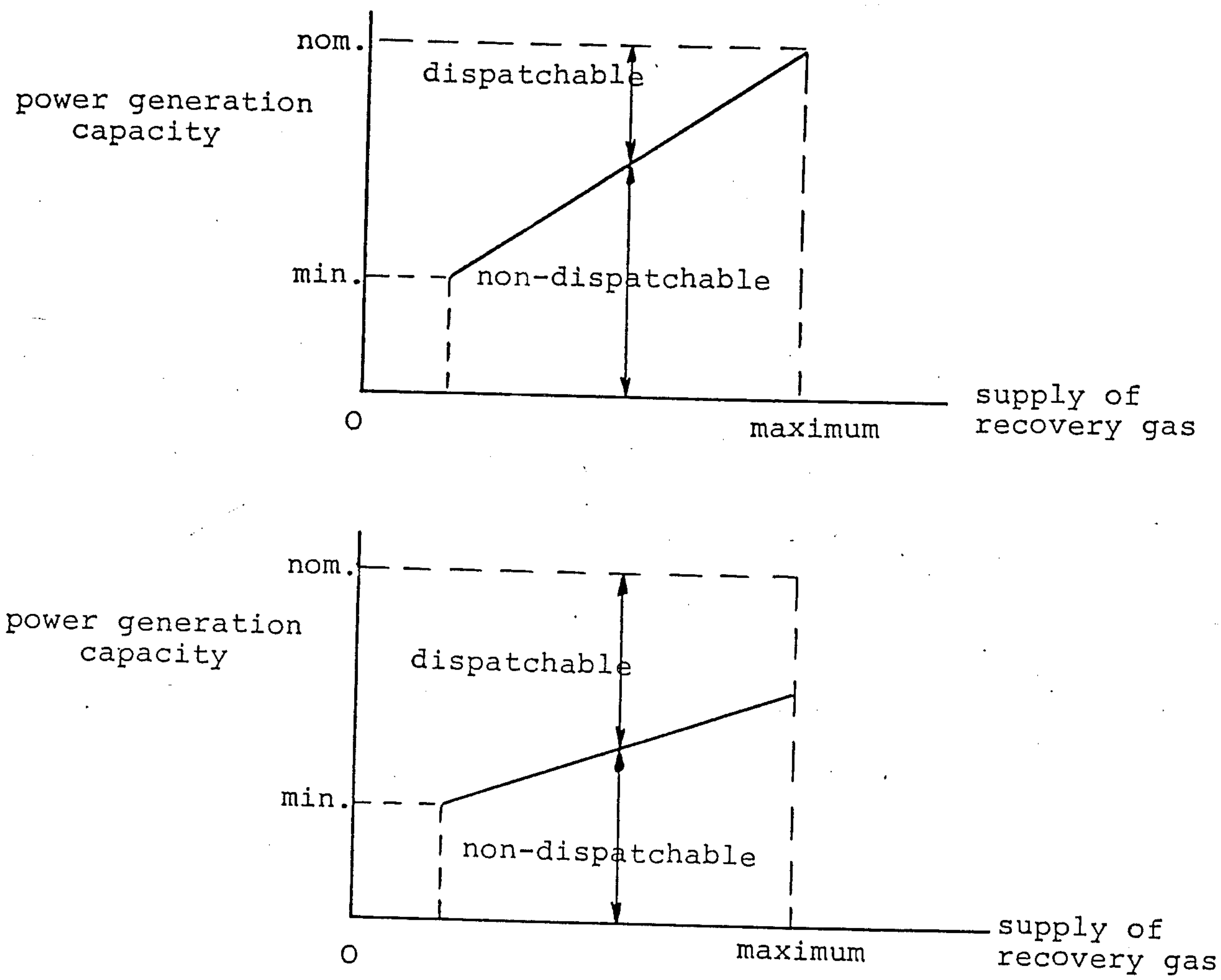


Table 2.2. Recovery gas burning units

Name of plant	Capacity (MW) minimum	nominal	Complementary fuel
Monceau	60.	117.	coal
Baudour	60.	114.	coal
Schelle	45.	123.	coal
Amercoeur	60.	126.	coal
Verbrande brug	90.	113.	coal
Péronnes	60.	114.	coal
Rodenhuyze	120.	260.	oil & gas
Farciennes	20.	49.	oil & gas

The recovery gas burning units incorporated in our model are shown in table 2.2. We retain one turboset per plant. When the supply of recovery gas falls short in attaining the minimum capacity level of the unit, complementary fuel is burned.

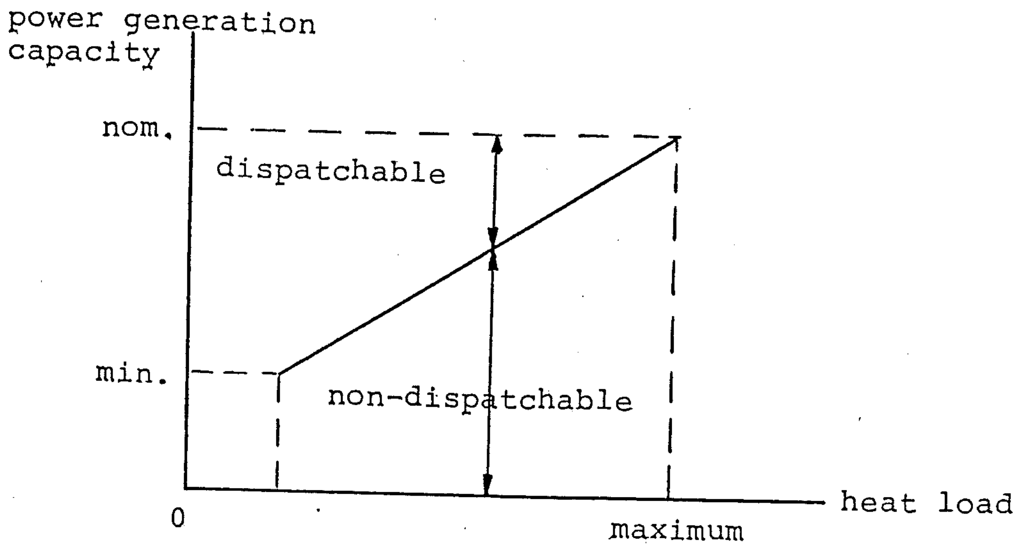
c. Cogeneration or Combined Heat and Power (CHP) plants owned and controlled by the utilities.

Although presently the Belgian utilities own only a few CHP plants of limited capacity, coal fired cogeneration stations are often discussed as a viable alternative for large-scale centralized power stations. The CHP plants would supply steam to industries or low-temperature heat to district heating networks. Steam supplying cogeneration can be developed by the industries themselves. In this case, their power output has to be modeled as discussed in § II.2.a. Given the particular institutional structure of the energy sector in Belgium, it seems very unlikely that district heating, and especially CHP-generation for district heating can be developed without the partnership of the power utilities.

In our model, three types of CHP-plants are considered:

i) diesel engines and gas turbines with heat recovery from the cooling water and from exhaust gases. Because the heat recuperation process interferes only slightly with the power generation capabilities of the plant, the dispatching of the unit is modeled as shown in figure 2.7. This arrangement is similar to the one of the plants burning recovery gas (see II.2.b and figure 2.6).

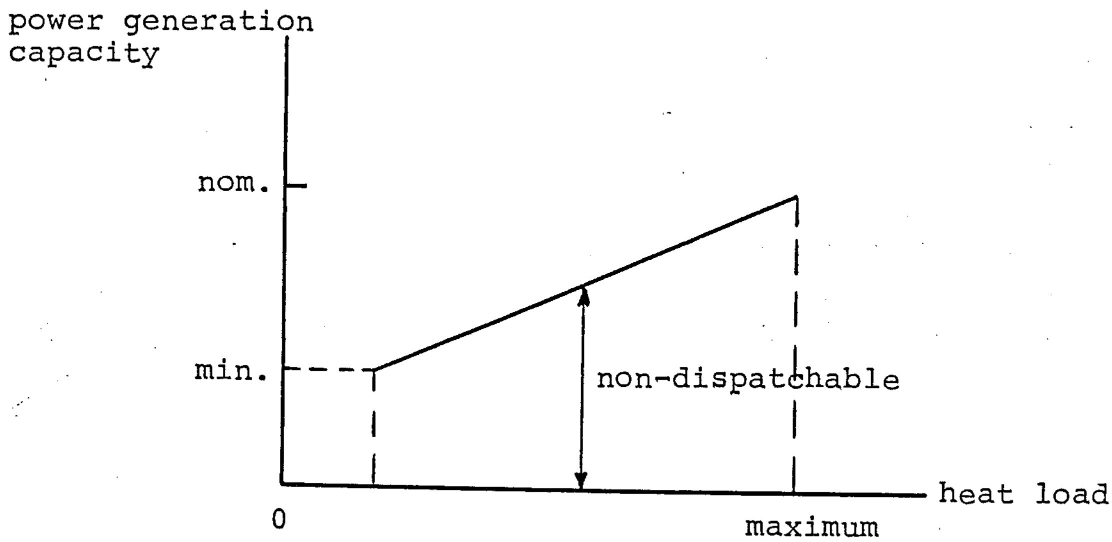
Figure 2.7. Cogeneration plants: i) dispatching of diesel engines, gasturbines, ... with heat recovery



ii) back-pressure steam turbines.

The relationship between heat load and power generated is perfectly complementary for a given pressure-temperature level of the exhausted steam. In other words: all power from a back-pressure plant is to be considered as non-dispatchable when the heat load is imposed exogeneously (figure 2.8).

Figure 2.8. Cogeneration plants : ii) back-pressure steam turbines

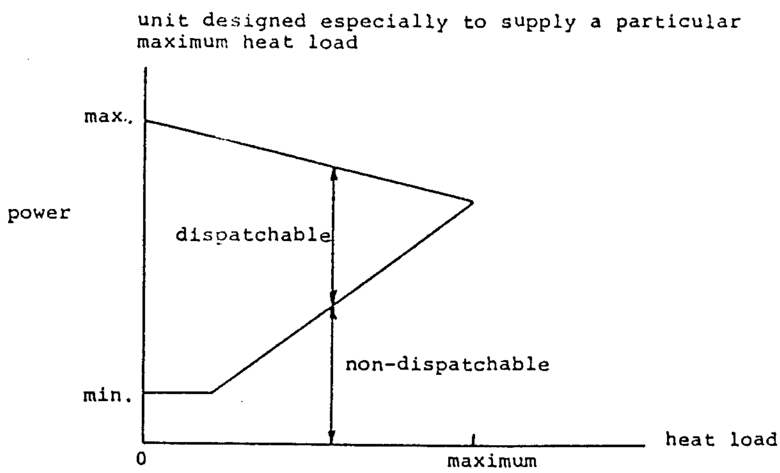


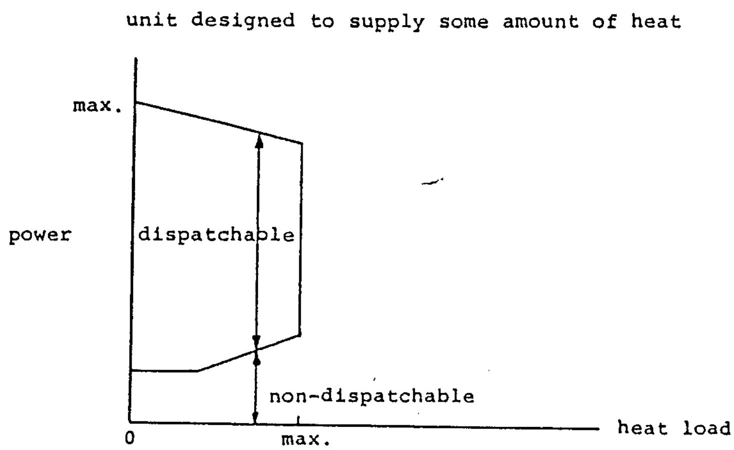
iii) extraction-condensing steam turbines.

In an extraction-condensing plant, steam is extracted at several stages from the turbines, discharging the remaining steam in a cold water condenser. Depending on the lay-out of the unit and the dimensioning of the condensing tail of the turboset, more or less heat can be delivered by the unit.

In countries with a long experience in district heating and related cogeneration (e.g. Sweden, Germany), CHP-plants are installed to 250 MW electric condensing capacity, and designed to supply 350 MW low-temperature heat at a power output of 220 MW. The heat-electricity possibility set of such a specially designed turboset is shown in the top figure of figure 2.9. Because of the availability of a cold water condenser, the non-dispatchable back-pressure operation mode of such a unit can be supplemented by dispatchable condensing generation.

Figure 2.9. Cogeneration plants: iii) extraction-condensing steam turbines





A strong argument against the investment in CHP-plants is based on the limited scale of special designed cogeneration units. It may be true that the minimum efficient scale of fossil power generation amounts to at least 300 MW electric, or even 600 MW electric. The mass of heat offered by plants in this power range may be in excess of the needs of local heat markets. In this case, the plant has to be designed as a condensing unit with provision for heat extraction at particular rates. The heat-electricity production possibility of this type of unit is shown at the bottom of figure 2.9.

* * *

In our model, units that are entirely non-dispatchable are assigned to block 1 of the units (code-number between 100. and 199.). This power output is modeled as a one-to-one correspondence to the fuel supply rate or to the imposed heat load. This output is fixed and is brought into the model by putting GO[2,k] = GO[3,k], (i.e. minimum capacity = nominal production capacity).

Plants that are only partly non-dispatchable are modeled as two units the non-dispatchable share is allocated to group 1 of the units, while their dispatchable share is assigned to block 3 (code number between 300. and 399.) when coal-fired, or to group 5 (code number between 500. and 599.) when oil/gas fired.

Modeling the non-dispatchable capacities requires knowledge of the load factors on the units (i.e. recovery gas supply rates for the type of plants described in II.2.b and heat loads on CHP plants). These load factors are provided exogeneously and for each type of non-dispatchable capacity separately. The model provides some flexibility in representing these load factors which may be altered from plant to plant and which are to be specified for each typical day allowing for a distinction between night and day-time subperiods.

The load options that are used presently in our model are shown in table 2.3. There is no limitation either in extending or changing the options shown in the list. The pre-assigned load factor on a particular non-dispatchable unit is multiplied by the load factors selected from the list. For each type of non-dispatchable plants the load factor is allocated independently from the other types.

Table 2.3. Loading options for non-dispatchable or partly dispatchable plants owned by the utilities

	Loading option	Load factors Night	Day-time
equal	1	1.	1.
subperiod	2	.75	.75
loads	3	.50	.50
	4	.25	.25
	5	0.	0.
unequal	6	.75	1.
subperiod	7	.50	1.
loads	8	.50	.75
	9	.25	.75
	10	.25	.50
	11	0.	.50
	12	0.	.25

In table 2.4 we have shown the load factors used during the test runs of the program. They were selected in a way to generate results that are conform to observed reality in Belgium. Because of lack of detail information on the variation in the supply of recovery gas we used a non-informative distribution of the load factors (everywhere 25 %). The latter number was choosen to make the total amount of recovery gas about equal to the forecasted amount by the utilities, i.e. 17 000 TJ/year.

Table 2.4. Applied load factors on non-dispatchable plants used in the test runs

Subyearly period (see ch.I)	Recovery gas plants: Recovery gas supply as % of max. charge on the plants		Cogeneration plants: Heat load as % of maximum heat load	
	at night	at daytime	at night	at daytime
1	25	25	100	100
2	25	25	75	100
3	25	25	50	75
4	25	25	25	50
5	25	25	0	0
6	25	25	50	75
7	25	25	100	100
	The above structure implies a recovery gas supply of approx. 17130 TJ/year		The above load structure implies a utilisation rate of 4630 hours/year	

The load factors on the CHP plants providing low-temperature heat are varied along the seasons of the year and along the night and daytime subperiods. The aggregated weighted load factor over the year for the non-dispatchable share of the CHP-plants amounts to 52.85 %, i.e. a utilization rate of 4630 hours/year. The latter number is very plausible for cogeneration providing low-temperature heat to district heating networks.

II.3. Maintenance scheduling

Maintenance planning is of primary importance when generation capacities have to be scheduled in the short to medium term (from a few months to a few years). In long-range planning models it is nearly impossible to organize a reliable maintenance plan because unforeseen accidents require a continuous reoptimisation of the maintenance scheduling (e.g. forced outages on nuclear stations may delay the refuelment period; forced outages on classical units may advance their overhaul).

The procedure inbedded in our model is rather coarse. The results of it are biased because they are based on an optimisation algorithm that in real life will be constrained by such stochastic events as mentioned above. Therefore, we have included the possibility of sensitivity analysis. The program user can formulate any maintenance plan he assumes to be in order in the future and simulate the results of the system under his plan. In the remainder of this section we discuss only the automatic procedure provided in the model.

The purpose of the procedure is to indicate which generation capacities will be unavailable during which periods of the year because of shutdown for maintenance. The first problem one faces in solving this problem is due to the disparity between the length of the periods of the year considered and the length of the maintenance cycles of the various units. If accuracy in maintenance planning should be of high priority one should have to take care that maintenance cycles are an integer multiple or the sum of subperiods of the year analysed. We will comment this problem later on.

Our procedure works as follows. First, we estimate the required maintenance for the various blocks of generation capacities considered and listed in table 2.5 (see also § II.1). Required maintenance is expressed as a number of MW days that units of a particular class are in planned outage, i.e. for units i_k in class k:

$$\sum_{i_k} (\text{planned outage factor})_{i_k} * (\text{capacity})_{i_k} * 365$$

The results of these calculations per class are shown in tabel 2.5 for the year 1990.

Table 2.5. Required maintenance for the Belgian generation system (estimation anno 1990)

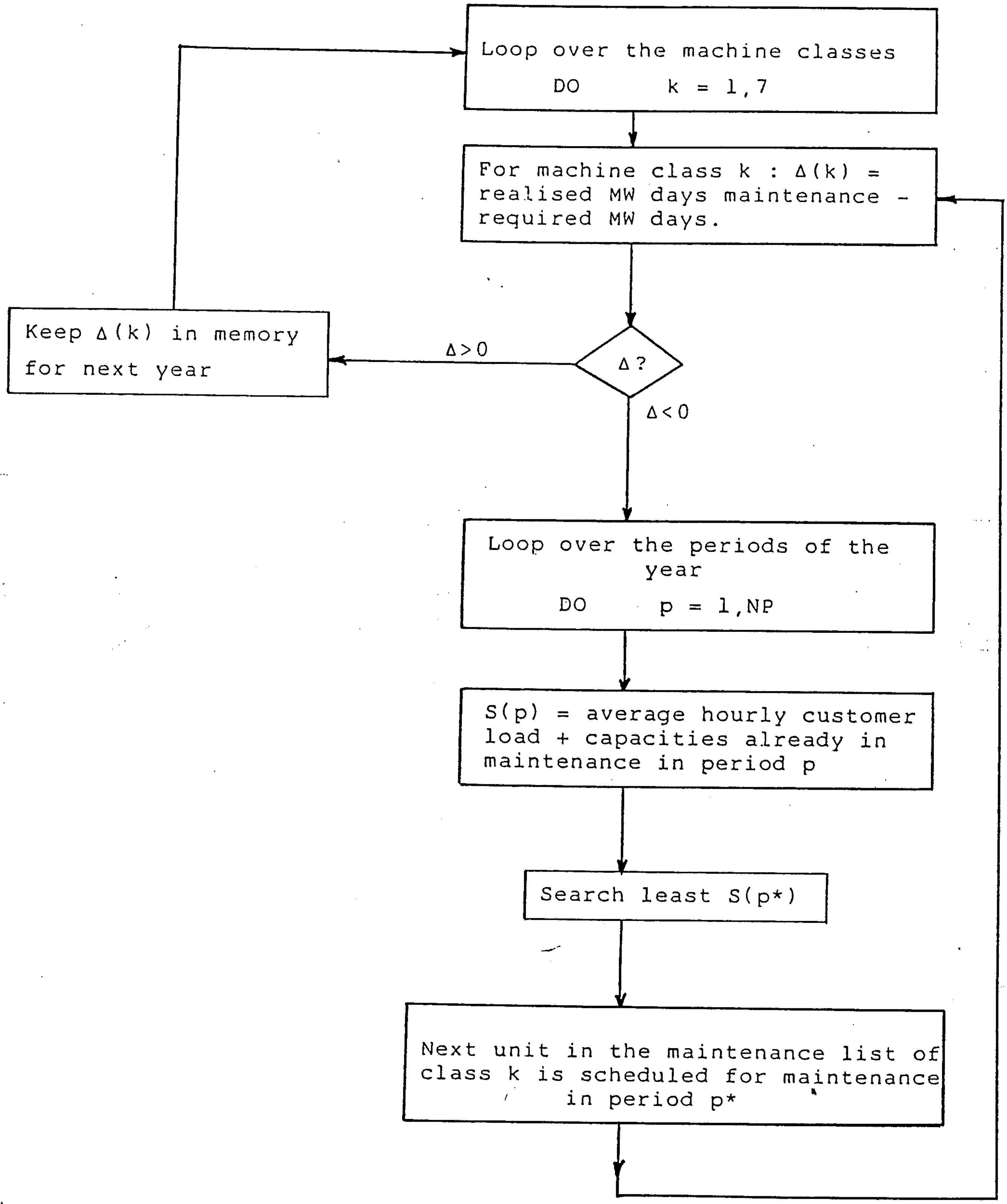
Capacity class	Required maintenance in MW days/year
1. recovery gas	27 740
2. cogeneration	p.m.
3. nuclear	187 245
4. coal fired	62 050
5. oil/gas fired	56 575
6. rapid start	29 200
7. pumped storage	18 250
TOTAL	381.060

Secondly, within each class of units, a tabulation is made of the sequence in which the units will be committed to a shutdown overhaul.

Thirdly, for each class a counter is initialised in order to store the spillover of maintenance days from the previous year, i.e. the difference between the realised and required maintenance days in a particular year is transferred to the next year. This transfer is necessary to improve the results of our approximate procedure.

The commitment of generation units to maintenance and their redrawal from the plants' list is shown in the flowchart of figure 2.10. The units classes are handled one by one in the sequence shown in table 2.5. When the stock of realised maintenance days is lower than the required amount of days, the next unit from the tabulation in this class is selected. Next a search procedure is set up to find out in which period of the year its maintenance will take place. Therefore, we have computed the average hourly customer loads during all periods of the year, and we have added to these numbers the capacities already scheduled for maintenance in the various periods. When we have found the period p* showing the lowest combined load, the particular unit is added to the list of units in planned outage during period p*. The combined load of this period is raised by the production capacity of the unit, and the counter of realised maintenance days is increased by the production

Figure 2.10. Flowchart of maintenance scheduling procedure



capacity times the length of period p* expressed in number of days. The further evolvement of the procedure may be clear from figure 2.10. An additional control is added and consists in the constraint that the total amount of capacity in maintenance during any period of the year should not exceed some prespecified value(we use 2000 MW).

When the disparity between the length of the load periods of the year and the length of the maintenance cycles of the units is rather important (as it is in the present formulation of our model) the generated maintenance schedule is rather approximative. To improve the results we have introduced a buffer counter that transfers the surplus of realised maintenance days with respect to required maintenance days to the next year. In the latter year, the counter of realised days starts from this surplus on. The transferred surplus may be significant when we deal with large unit capacities (nuclear stations) Another point concerns the length of subyearly periods considered, which may be a multiple of the maintenance time of the units. The impact of this distortion is limited by a suitable tabulation of the plants in maintenance sequence. Because many plants belong to a serie of capacities (e.g. 125 MW coal fired units or 1000 MW nuclear plants) it makes little difference to schedule either two times the same capacity of a twin plant or to schedule both one after the other. E.g. the maintenance time of a nuclear station amounts to about 6 weeks/year. When we consider the two 900 MW-nuclear units in Belgium (Doel 3, Tihange 2) and a period of the year encompassing 12 weeks, our procedure will result in a 12-week maintenance time of e.g. Doel 3 and a zero maintenance for Tihange 2.

Given the long-range planning perspective of our model, we judged the present maintenance planning procedure sufficiently accurate.

III. PRODUCTION SIMULATION AND COSTING

When a capacity generation planning model is based on a detailed representation of the load structure, the procedures for production simulation and costing have to be efficient. If not, computing time constraints become too binding. Each model therefore entails a trade-off between accuracy and speed, correlated with the complexity of the model.

It is generally acknowledged in the literature that the most simple approach to generation simulation and costing is based on the effective capacity procedure also called 'derated' capacity procedure. One multiplies the generation capacity of the units by their probability of being available for generation (given they are not on planned outage) and the result is called the effective or derated capacity of the units. For production simulation and costing the units are loaded by their effective capacity. Critics on this procedure argue that the results are rather approximative. An improved algorithm was developed by Baleriaux for production simulation and costing when the load on the system is modeled by load duration curves. More detailed analysis is sometimes proposed by a random sampling of various states of the production system and for each state evaluating power generated and fuel consumed. In section III.1 we discuss the value of the three methods -effective capacity, Baleriaux probabilistic simulation and random sampling - in the framework of our model. It will be shown that for a thermal generation park and given an hourly modeling of the loads on the system, the effective capacity approach provides results that are as reliable as the other more complex procedures do.

In section III.2 we discuss the basic algorithm for production simulation and costing imbedded in the model. The unit commitment problem is solved by a forward dynamic programming routine, taking into account the start costs of the various units and the modulation constraints that may be imposed (e.g. non-dispatchable capacities).

By their very nature, pumped storage capacities have to be treated specifically. —In section III.3 we show how pumped storage capacity is incorporated in the daily load and generation cycle and how in the weekly cycle.

III.1. Cost analysis of thermal power generation

In this section we compare three methods for estimating the fuel costs of thermal power generation: effective capacity approach, Baleriaux probabilistic costing and random sampling. In accordance with our load modeling, loads are represented by hourly values. The loading procedure consists of a merit-order loading of the units.

a. Baleriaux probabilistic costing versus effective capacity costing

The value of the Baleriaux framework is well-proven when the electric load on the system is modeled by load duration curves (e.g. Vardi, Avi-Itzhak or EPRI's EGEAS model).

It can be shown that as long as minimum loads are not attained, Baleriaux probabilistic costing generates exactly the same outcomes as an effective capacity loading procedure. When loads are represented by hourly magnitudes as in our model (see figure 1.1), it follows that the difference between the Baleriaux and the effective capacity approach concerns only the marginally producing unit. The output of the unit loaded as last one in an effective capacity schedule, will be distributed geometrically over this last and all remaining units in the Baleriaux framework.

In our opinion one should prefer in this case the simpler effective capacity procedure above the Baleriaux framework, for two reasons. First, the difference between the outcomes of both methods is rather small. A simple illustration may be helpfull:

let C_m = nominal generation capacity of the marginal capacity (e.g. C_m = 100 MW)

$1 - p_m$ = forced outage rate of this capacity (e.g. $p_m = 0.9$)

l_m = remaining load faced by the marginal unit (e.g. l_m = 50 MW).

The situation considered at this point is identical whether one models an effective capacity procedure or Baleriaux probabilistic procedure for all preceding capacities i (i=1,...,m-1). For the marginal unit, the procedures differ:

Effective capacity approach:

Effective capacity of unit m = $C_m * p_m$ = 90 MW
Because $l_m \leq C_m * p_m$, it follows that the load on unit $m = l_m$=50MW
All remaining units i(i>m) carry no load at all.

Baleriaux probabilistic costing:

Of the marginal load l_m, capacity m will meet $l_m * p_m$ (= 45 MW). The rest of the load, i.c. 5 MW is transferred to the next plant, providing 5 * p_{m+1}MW. The rest 5*(1-p_{m+1}) is transferred to unit m+2, generating 5*(1-p_{m+1})*p_{m+2}, etc...

Consequently, the difference between both methods concerns the generation of $l_m*(1-p_m)$MW, in the effective capacity approach assigned to unit m and in the Baleriaux framework distributed geometrically over the remaining capacities m+1, m+2, ... When, as in the numerical example, we assume a marginal load of $C_m/2$, the difference has an impact of $\frac{(C_m/2*(1-p_m)}{C_m}$ %, i.e. $\frac{1-p_m}{2}$ of the capacity of the marginal unit. This percentage amounts to values that are statistically not higher than 5 to 10 % of a (generally small) marginal capacity. Moreover, in a Baleriaux framework, the largest share of this rest load is assigned to the nearby capacities belonging in many cases to the same capacity class.

It is obvious that for our model the Baleriaux probabilistic procedure would not improve our results significantly.

A second reason why the Baleriaux procedure is omitted, deals with the dynamic programming algorithm set up for unit commitment (see III.2) and with the incorporation of pumped storage (see III.3). A contribution of the DP algorithm is the modeling of start costs of the units. Because in a Baleriaux loading, all available units are virtually loaded, the start (and modulation) problem would pass unsolved. On the other hand, the output of pumped storage plants will iron out the generation of marginal thermal capacities at peak load periods, burrying in this way most of the improvement brought in by the Baleriaux probabilistic procedure.

b. Random sampling versus effective capacity approach

In this section we will show why an effective capacity procedure may generate results as good as a very extensive random sampling of various states of a thermal generation system. We illustrate our findings by an analysis of a representative thermal generation system, consisting of 78 units and amounting to a total production capacity of 11320 MW (45 % nuclear, 20 % coal steam plants, 27 % oil/gas steam plants, 8 % rapid start peak load plants). The fuel prices used equal 50 FB/GJ for nuclear fuel, 130 FB/GJ for coal, 300 FB/GJ for oil/gas and 320 FB/GJ for light fuel oil. We use a merit-order loading of the plants.

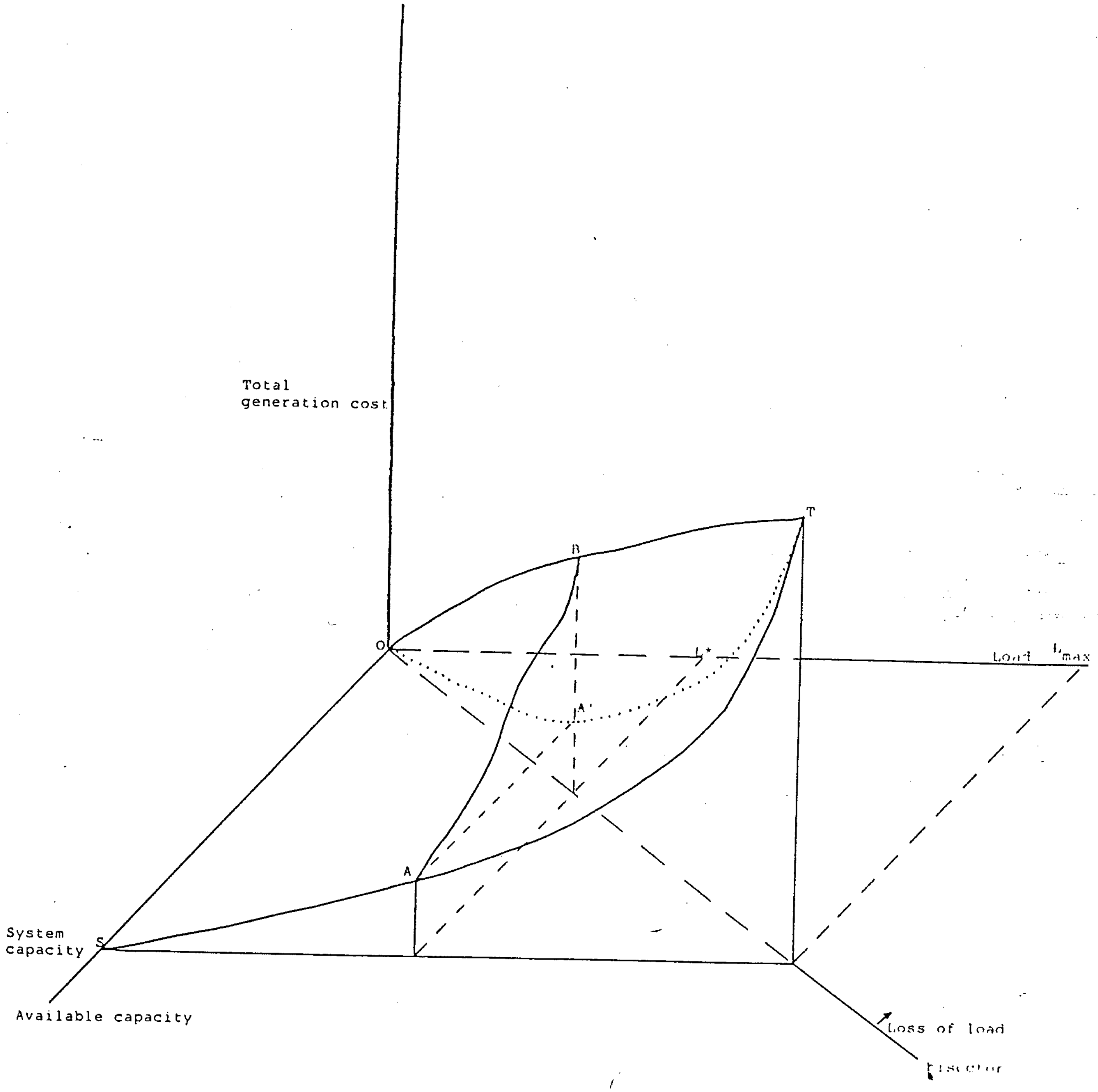
In figure 3.1 the relationship between available capacity, load and total fuel costs is shown in a 3-dimentional picture, requiring some explanation.

figure 3.1.

The positive quadrant of the horizontal plane is made up by the possible combinations of available capacity and load. The bisector of the quadrant divides this possibility set into a half where loss of load occurs (load exceeds available capacity) and a half where available capacity is equal to or larger than the load on the system. We will focus our attention on the latter situation. On the vertical axis total fuel costs are shown. These costs are a function of the load on the system and the state of availability of the system. Given any particular state, the fuel costs are the minimum costs one can obtain to meet the load.

The space included in the irregular enveloppe O,S,A,T,B,O,A',T contains all feasible cost states of the production system. Consider first the curve SAT, lying in the perpendicular plane through point S. On this curve the fuel costs are shown to generate loads from 0 to

Figure 3.1.


Total
generation cost
O
B
T
L*
Load
A'
A
S
System
capacity
Available capacity
Loss of load

L_{max} when all units are available. This curve is shown in detail in figure 3.2 for the example production system. The different slopes of this curve show the diverse production technologies (nuclear - coal - oil/gas).

Figure 3.2.

Next, we consider the vertical plane with as bottom line the bisector of the capacity-load plane. The boundary of the feasible costs set is made up here by the convex curvature OA'TBO. The curve OA'T is identical to curve SAT and is redrawn in figure 3.3. The feasible cost plane OA'TBO contains all possible solutions to generate the load on the system (from 0 to L_{max}) when the available capacity of the production system is exactly equal to the load (points on the bisector in figure 3.1). The lower curve OA'T in figure 3.3 shows the fuel costs of the generation system in its best state, i.e. for any particular load, the available generation capacity is exactly equal to this load but is composed of the top units up to the required capacity of the merit-order ranking. With respect to cost simulation we obtain the same results as if the entire system would be available. The upper boundary OBT of the feasible cost set in figure 3.3 shows the fuel costs of the generation system in its worst state. Again available capacity equals load on the system but now the capacity is composed of the bottom units of the merit-order ranking.

When the available production capacity amounts to a particular magnitude (e.g. 4000 MW), this total capacity can be supplied by numerous combinations of the various units in the system. Each combination will result in another fuel cost for generating the load. All feasible cost outcomes will however lie in the interval between OA'T and OBT, i.e. for a load of 4000 MW (= available capacity) on the segment A'B (see figure 3.3).

Figure 3.3.

Figure 3.2. Total fuel costs of generating the load given all units are up

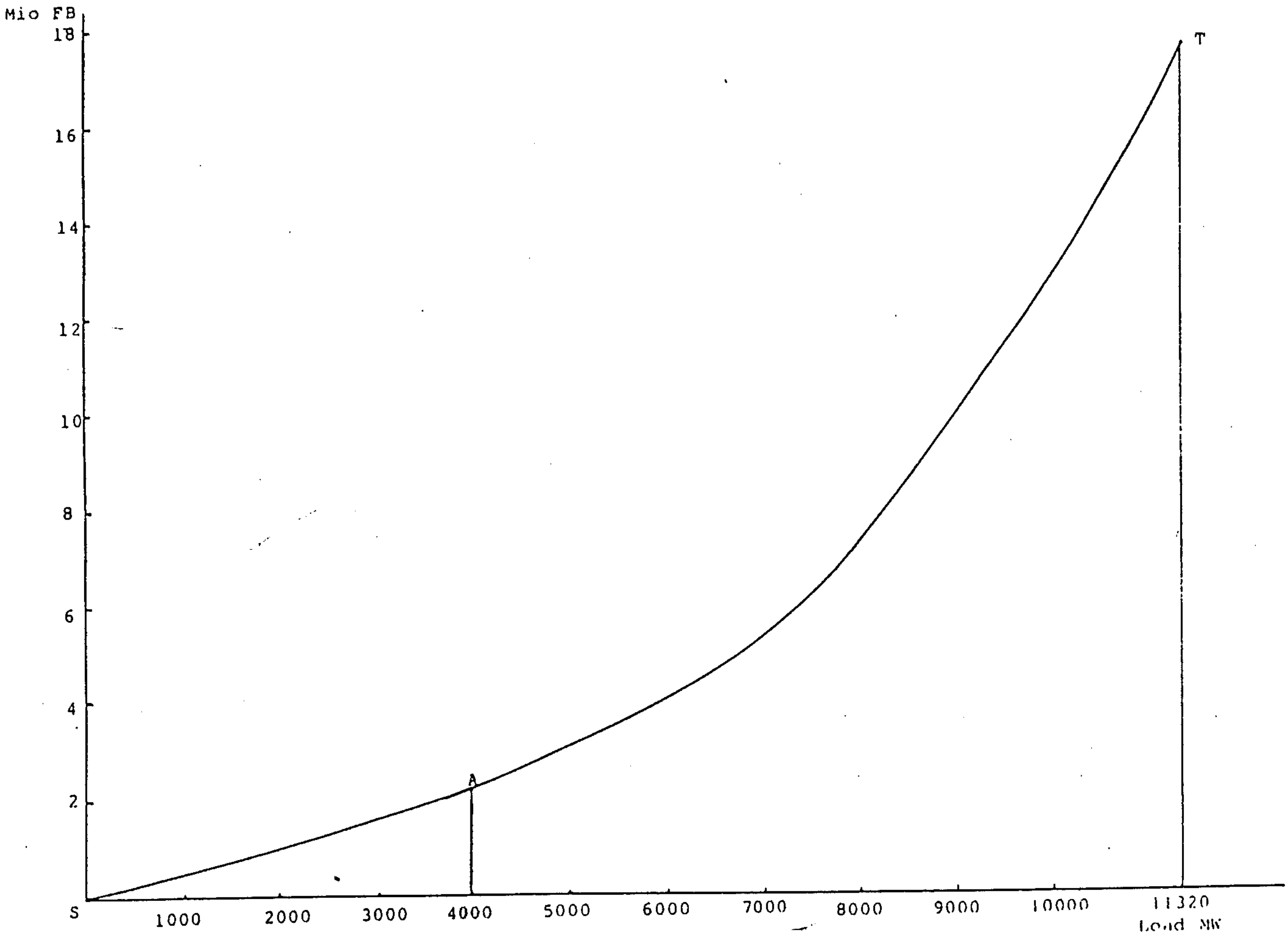
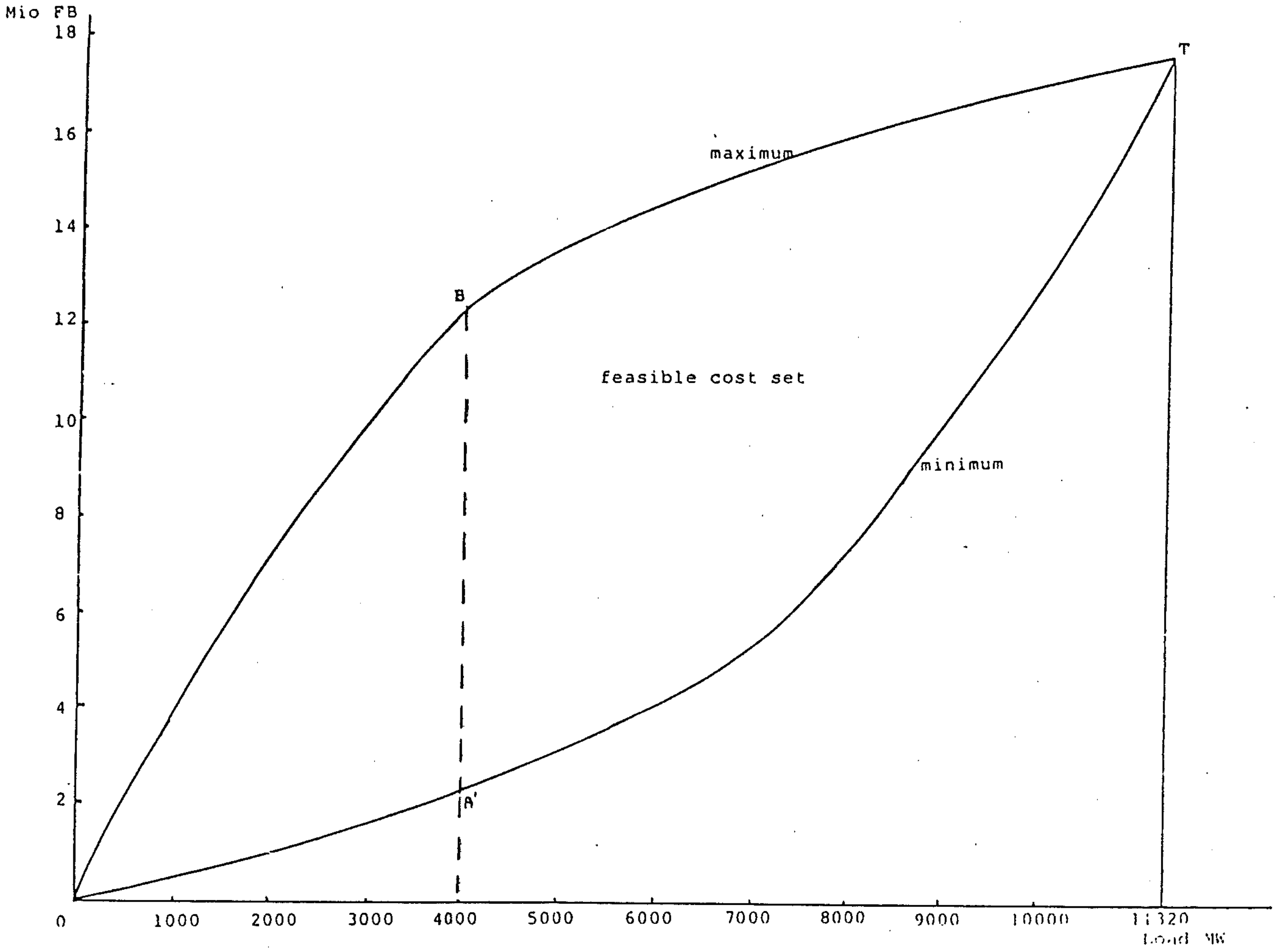


Figure 3.3. Generation costs when available capacity equals load



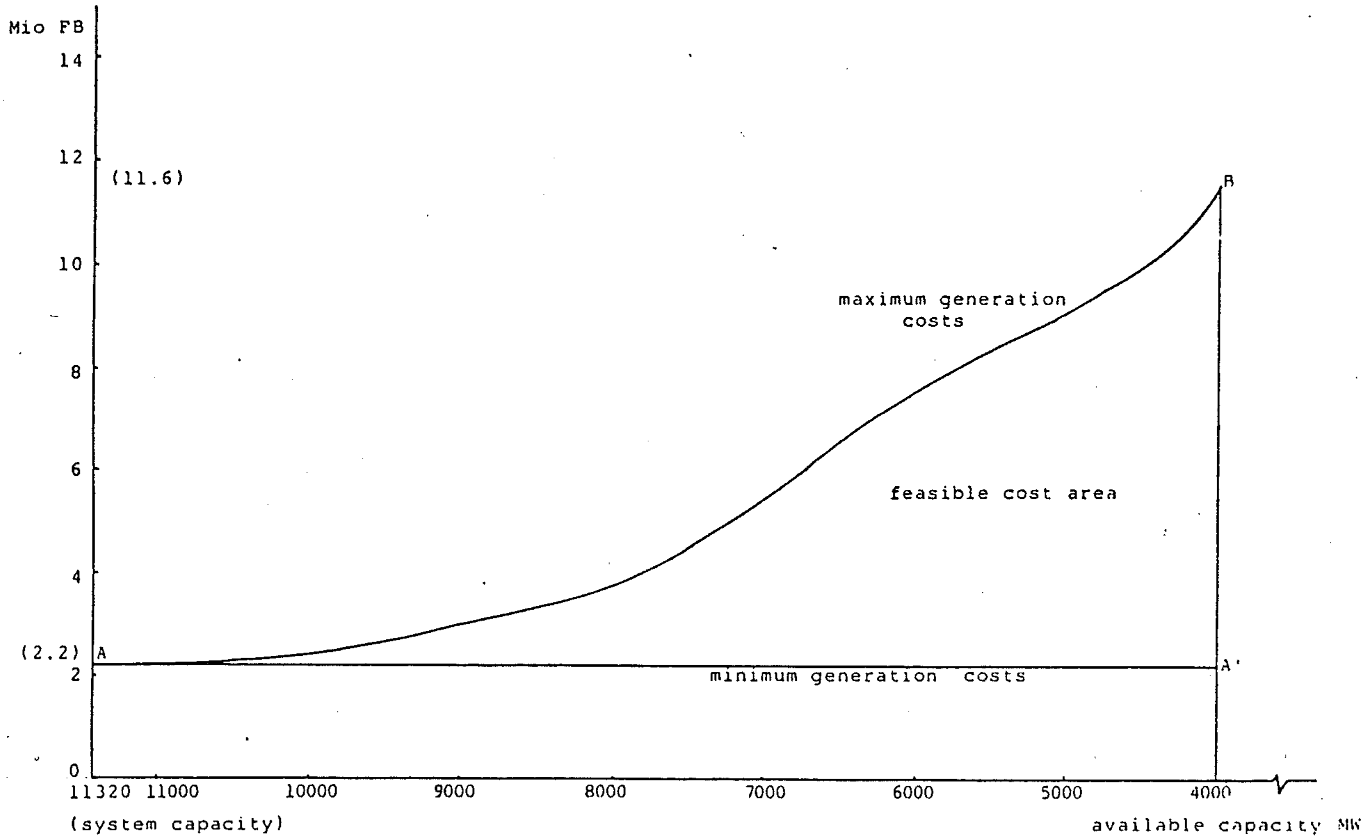
We return to figure 3.1, and focus our attention on the plane perpendicular to the load axis, at point L* cutting out the feasible cost set the area AA'B. We already know from figure 3.3 the meaning of segment A'B. To explain the area AA'B we have redrawn this for L* = 4000 MW in figure 3.4. On the horizontal axis of graph 3.4 is shown the available capacity (excluding loss of load), ranging from 11 320 MW to 4000 MW. The line AA' parallel to the horizontal axis indicates the minimum generation costs for a load of 4000 MW. It assumes that the top units up to 4000 MW of the merit-order are always included in the available capacity, whatever magnitude this capacity scores between 4000 and 11.320 MW. It is obvious that in this case the fuel costs are everywhere minimal and equal to one another.

<u>Figure 3.4.</u>

The upper curve AB in figure 3.1 and 3.4 represents the worst case for generating 4000 MW at any availability level of the system. One should keep in mind that the very significance of cost curve in economics always refers to the least cost one can obtain given the degrees of freedom at his disposition. The worst case in this situation therefore refers to the best solution one can get in the words environment. Consider e.g. a state of availability of the system of 7000 MW. The words environment means that this 7000 MW available is composed of the bottom units up to 7000 MW of the merit order. Given a load of 4000 MW the dispatching center will of course call for a loading of the best 4000 MW from this 7000 MW available, arriving at generation costs that are significantly lower than the fuel costs one would incur if the bottom units up to 4000 MW of the merit-order were loaded (i.e. point B in figure 3.4).

The upper surface of the 3-dimentional cost space in figure 3.1 is made up by a continuous succession of curves similar to the one shown in figure 3.4. We have added as an appendix to this section the curves resulting for load levels at 5000, 6000, 7000, 8000, 9000 and 10,000 MW on our example generation system. The entire cost-load-capacity possibility set may be now be visualized sufficiently.

Figure 3.4. Total generation costs (Mio FB) to generate 4000 MWh



Thus far, we only described the possibility set. For a comparison between the effective capacity loading procedure and random sampling simulations we have to introduce both approaches in our framework. Effective capacity loading is shown in figure 3.5, being an extended copy of figure 3.1. Effective capacity loading selects in the feasible cost set points that are on a homothetic transformation of the curve SAT, called C_eXY in figure 3.5. For a particular load L* below L_e (= C_e in MW) the curve C_eXY crosses through a point (X) the inner area of the feasible plane (AA'B) at that load. The crossing points X shift in the feasible load planes when load increases to arrive at a point Y at load level L_e, which is not far away from the maximum cost point. The marginal loads above L_e are considered as loss of load.

Figure 3.5.

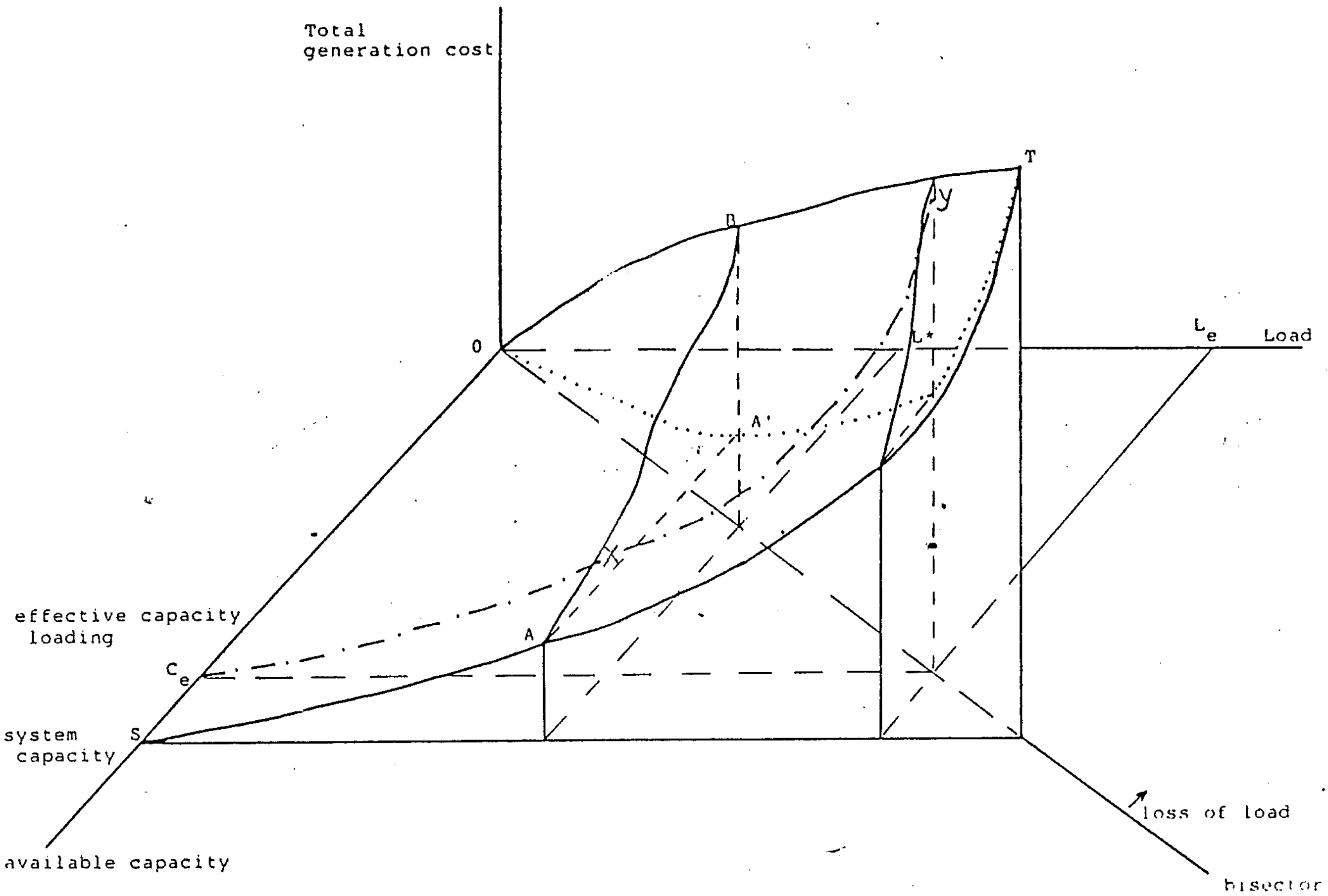
In our example system of total generating capacity of 11320 MW, the maximum effective capacity amounts to 10100 MW. In tabel 3.1. is shown how minimum, maximum and effective capacity loading fuel costs are related at various load levels.

Table 3.1. Minimum fuel cost, maximum fuel cost and fuel cost from an effective capacity loading for various load levels

	Fuel costs in 1000 FB		
Load (MW)	Minimum	Maximum	Effective
4000	2240	11586	2244
5000	2807	12865	3186
6000	3953	14111	4442
7000	5214	14798	6162
8000	7082	15361	8905
9000	9825	15924	11683
10000	12596	16483	15038

Forecasting the results of random sampling is of course impossible. However one can try to predict the mean values, an extensive random sampling may generate at various load levels. For any particular load L* we know that the cost result of one experiment will be found in the feasible plane AA'B (figure 3.1), ignoring for the time being

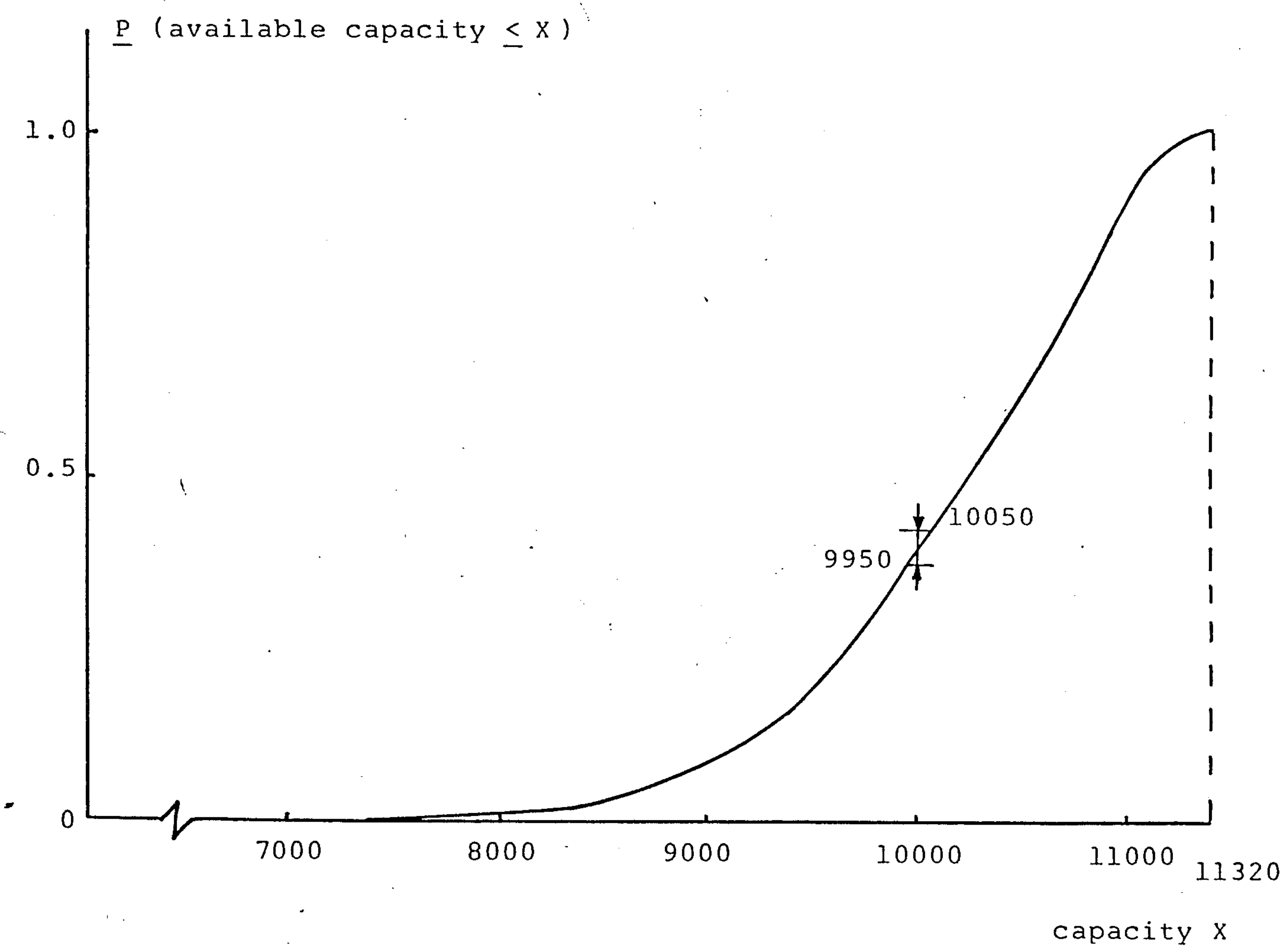
Figure 3.5.


Total
generation cost
T
B
y
O
L*
L_e
Load
A'
effective capacity
loading
A
C_e
system
capacity
S
loss of load
available capacity
bisector

the impact of loss of load on the system costs. Actually, we are not interested in the exact outcome of one experiment, but in the overall average of all experiments. To find the latter one has to incorporate his prior knowledge on the probability distributions of the system. The first relevant distribution is the probability density function over the available production capacity. For our example generation system, this function was estimated by a procedure for generating benchmark LOLP values for systems with rounded-off unit capacities (EPRI EL-2874). This procedure provides perfect results in our case because our example system consists of only rounded-off capacities. A smooth approximation of the cumulative probability distribution over the available capacity of the system is shown in figure 3.6. For loads under 7000 MW loss of load is extremely ulikely. From 7000 MW on loss of load becomes more and more likely with increasing loads.

One has to combine the information of figure 3.1 and particularly figure 3.4, with the probability distribution shown in figure 3.6. Consider figure 3.4. One can assign to any interval on the available capacity axis a probability that the generation system will be in this capacity state, using the distribution shown in figure 3.6. When one takes an interval length of 100 MW (as we have done in our calculations) the probability that the system is in a capacity state between 9950 MW and 10050 MW is shown in figure 3.6 as the difference between two points on the cumulative function. This probability was adhered to the available capacity level 10000 MW. Focusing our attention on this particular state, we know from figure 3.4 that the fuel costs for generating the load of 4000 MW on the system can lie anywhere between the minimum and maximum curve on the vertical line at the capacity point 10000 MW. To find the exact cost position one has to know the exact composition of the system for an accumulated capacity of 10000 MW. It is at this point of the discussion that the curse of dimensionality appears because even for a small system of 78 units the number of possible combinations is excessively large ($3 * 10^{23}$). Some of all these combinations will involve a total production capacity of 10000 MW, giving rise to the cost possibilities indicated in our figures. We have assumed, without further control, that the expected value of the latter costs will be the midpoint of the segment between the minimum and maximum cost curves at any particular available capacity. Consequently, we allow for any probability distribution over the

Figure 3.6. Cumulative probability distribution of the capacity available



particular cost segments given the mean value of the distribution is at the midpoint.

Another point to be considered here are the costs of loss of load. It is clear that at load levels approaching system capacity, loss of load becomes significant. We have weighted the loss of load, occurring at any particular load on the system, by the maximum cost possible at that load (point B in figures 3.1 for load L*). Trying to visualize this procedure one could prolonge the ridge OBT horizontally towards the cost-load quadrant in figure 3.1.

Summarizing the computations of the expected cost at any particular load L* we do the following steps:

1) for each increment of 100 MW, starting at the capacity level equal to L* we compute the midpoint between the maximum and minimum fuel cost;
2) we weigh these cost values with the probability that the system will be available in a 100 MW range, around the capacity levels;
3) the remaining weight, i.e. the loss of load on the system, is attributed to the highest fuel cost that may occur at that load L*.

The results for the example power system are shown in tabel 3.2 for various load levels from 4000 MW to 10100 MW (the maximum effective capacity of the system), and compared with the cost estimations of an effective capacity loading. The most remarkable result of this comparison is the fact that the difference between the cost results of both simulation procedures is oscillating around zero. Related to the arithmetic mean of both cost results, the difference between the results ranges from -7.4 % at 4400 MW load to + 6.2 % at 7700 MW load, the negative sign indicating that the cost estimate of an effective capacity loading is lower than the estimate of the average of probabilistic costing evaluation (and vice versa for the positive sign).

Table 3.2.

Table 3.2. Comparison effective capacity vs. expected results of random sampling

Load	Effective capacity	Random sampling	Difference
MW	1000 FB	1000 FB	1000 FB
4000	2243.555	2354.868	-111.313
4100	2300.305	2428.650	-128.345
4200	2357.055	2504.103	-147.047
4300	2413.805	2581.382	-167.577
4400	2470.555	2660.416	-189.861
4500	2567.755	2741.483	-173.729
4600	2691.255	2824.828	-133.573
4700	2814.755	2910.588	-95.833
4800	2938.255	2998.802	-60.547
4900	3061.780	3089.383	-27.603
5000	3186.388	3182.137	4.251
5100	3311.356	3276.746	34.610
5200	3436.376	3392.840	43.536
5300	3561.437	3523.492	37.944
5400	3686.519	3655.427	31.092
5500	3811.878	3788.803	23.075
5600	3937.452	3923.790	13.662
5700	4063.154	4060.798	2.356
5800	4189.231	4200.353	-11.121
5900	4315.553	4342.274	-26.722
6000	4442.082	4486.825	-44.743
6100	4569.709	4634.301	-64.592
6200	4698.118	4784.977	-86.858
6300	4827.622	4939.141	-111.519
6400	4960.259	5096.887	-136.628
6500	5095.229	5258.176	-162.947
6600	5261.761	5423.076	-161.315
6700	5449.488	5591.721	-142.232
6800	5645.568	5764.057	-118.488
6900	5894.228	5940.664	-46.437
7000	6162.402	6121.529	40.873
7100	6435.983	6307.392	128.592
7200	6709.583	6498.154	211.429
7300	6983.461	6694.677	288.784
7400	7257.721	6896.500	361.221
7500	7531.980	7120.903	411.077
7600	7806.372	7355.265	451.107
7700	8080.837	7596.207	484.630
7800	8355.637	7862.615	493.021
7900	8630.438	8142.829	487.608
8000	8905.486	8428.590	476.896
8100	9180.887	8716.600	464.287
8200	9456.287	9007.615	448.672
8300	9732.096	9302.889	429.207
8400	10008.096	9601.602	406.494
8500	10284.441	9905.527	378.914
8600	10561.342	10215.238	346.104
8700	10838.242	10531.492	306.750
8800	11116.908	10852.869	264.039
8900	11399.238	11178.377	220.861
9000	11683.342	11504.936	178.406
9100	11970.945	11832.830	138.115
9200	12260.049	12169.094	90.955
9300	12552.123	12504.930	47.193
9400	12846.830	12844.662	2.168
9500	13145.154	13193.627	-48.473
9600	13448.102	13563.248	-115.146
9700	13778.102	13937.576	-159.475
9800	14112.705	14307.609	-194.904
9900	14525.639	14660.771	-135.133
10000	15037.637	14982.373	55.264
10100	15549.635	15292.031	257.604

We conclude from the above cost analysis that the effective capacity loading procedure can be retained as a valid procedure for cost simulation. It may be that the probalistic approach provides more reliable cost estimations providing one can solve the problem of estimating the probability density functions over the cost segments at any available capacity level for a given load on the system. We do not expect that (even extensive) random sampling experiments will generate more reliable results than the ones we have estimated.

III.2. Unit commitment, production simulation and costing

To meet the goals put forward for our model, we have represented the load on the system by chronological hourly values (chapter I). In this section we describe how power generation is simulated and how fuel costs are estimated.

As discussed in the preceding section, we use an effective capacity loading of the units during each hour considered. In this section, we ignore the existence of pumped storage plants, except at one particular occasion. The pumped storage plants are discussed in the next section.

The hourly loads are arranged in typical days, subdivided in a night and daytime subperiod, because the generation system may be composed differently during these respective periods (primarily because of the non-dispatchable capacities). The operational production system is divided in various blocks, i.e.

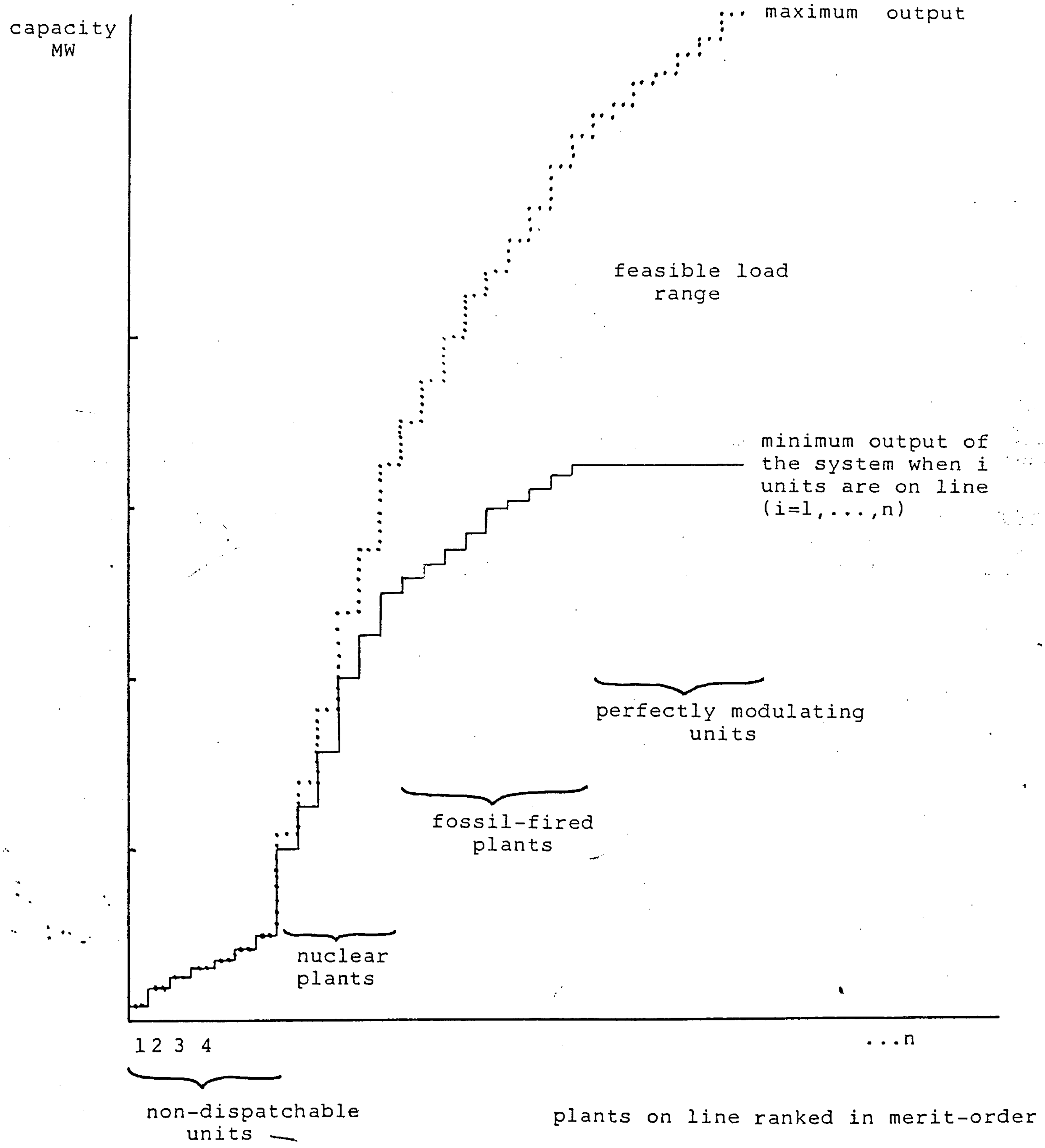
1) non-dispatchable capacities, i.e. non-dispatchable units or the non-dispatchable shares of partly dispatchable plants;
2) nuclear capacity, modeled as one power slice equal to the accumulated effective production capacity of the nuclear plants;
3) coal fired plants: dispatchable shares of partly dispatchable plants and dispatchable plants;
4) oil/gas plants: dispatchable shares of partly dispatchable plants and dispatchable plants;
5) rapid start plants;
6) pumped storage (and limited energy) capacities.

The units within each block are arranged in merit-order and the merit-order of the entire system consists of the succession of the merit-orders of the various blocks. Therefore,it may occur that a unit with lower specific fuel cost is ranked after one or more units carrying higher fuel costs. Where this may happen readily is between units of block 4) and 5), disregarding the obvious and programmed sequence of block 1) versus the other blocks.

The block division of the production system is in our opinion better than a straightforward merit-order of all capacities because of the difference in start costs of the various units, and because our main problem deals with a reliable unit commitment rather than with the instanteneous dispatching of spinning capacities.

We consider now a particular subperiod of the 24-hour day, e.g. the daytime. First the production system is adjusted for plants in maintenance and for the loads imposed on partly dispatchable and non-dispatchable units. The system is divided in blocks, and the merit-orders are constructed within each block and thereafter over all available plants. For this adjusted and ranked system, excluding pumped storage and limited energy units, the unit commitment problem is solved by using a dynamic programming (DP) algorithm, based on the idea of composite cost functions. The feasible load range on the system is searched by adding in one vector the minimum generation capacity of the units and in another vector the nominal generation capacity (see section II.1, figure 2.1). The result of such calculation is shown schematically in figure 3.7. The full stepline shows the added minimum capacity to be delivered in function of the number of plants incorporated in the system. Similarly, the pointed step line shows the maximum capacity that can be delivered. As shown in the figure, both lines coincide when we start from non-dispatchable units on. The distance between both lines grows only slowly by adding nuclear stations because of their weak modulation capabilities. Fossil fired plants are more flexible, and rapid start units carry no minimum deliveries.
The load feasibility set, as shown in figure 3.7, remains valid during a particular daily subperiod, but is reconstructed for each subperiod because the performance of non-dispatchable units changes.

Figure 3.7. Feasible load range as a function of the number of plants on line



The load fasibility set of the generation system is adjusted by imposing flexibility limiting constraints on the operation of the system. One can incorporate also some computing time saving tunnel restrictions for the dynamic programming research.

Operation flexibility covers a lot of aspects. E.g. we disregard the minute gradient increasing or decreasing load problem. In our model it is assumed, each plant can be brought from its minimum load to its nominal load, and vice versa, within one hour. Accurate load following routines should use a continuous modeling of the load on the system and of the loading order of the plants, both continuities being absent from our model.

A first flexibility check of our model deals with the incompressible capacities, i.e. non-dispatchable capacities and nuclear capacities when no hourly modulation is permitted for the latter type of plants. When during a particular 24-hour day, the minimum hourly load on the system (always occuring during the nighttime subperiod) is lower than the sum of non-dispatchable + nuclear generation effective capacities, an adjustment procedure is started. In a first round, the minimum hourly loads are increased by buffer pumping loads, i.e. nuclear generated electricity is converted into potential energy of stored water. If the pumped storage plants are large enough for taking up all excess power, no further adjustments are required. This situation is illustrated in figure 3.8(a).

Figure 3.8(a)

Figure 3.8(b)

Figure 3.8(a) Buffer pumping can absorb all excess power from incompressible capacities

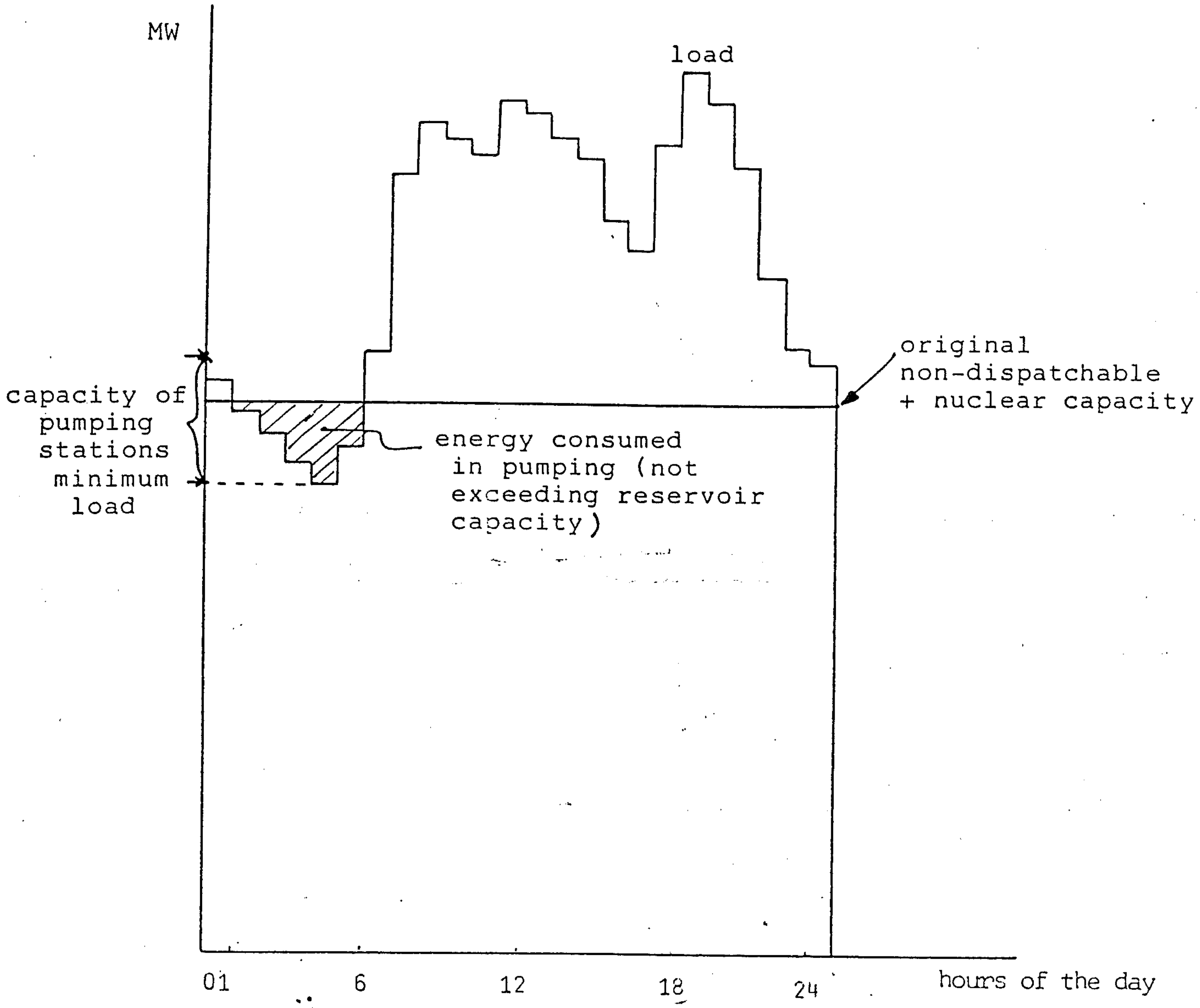
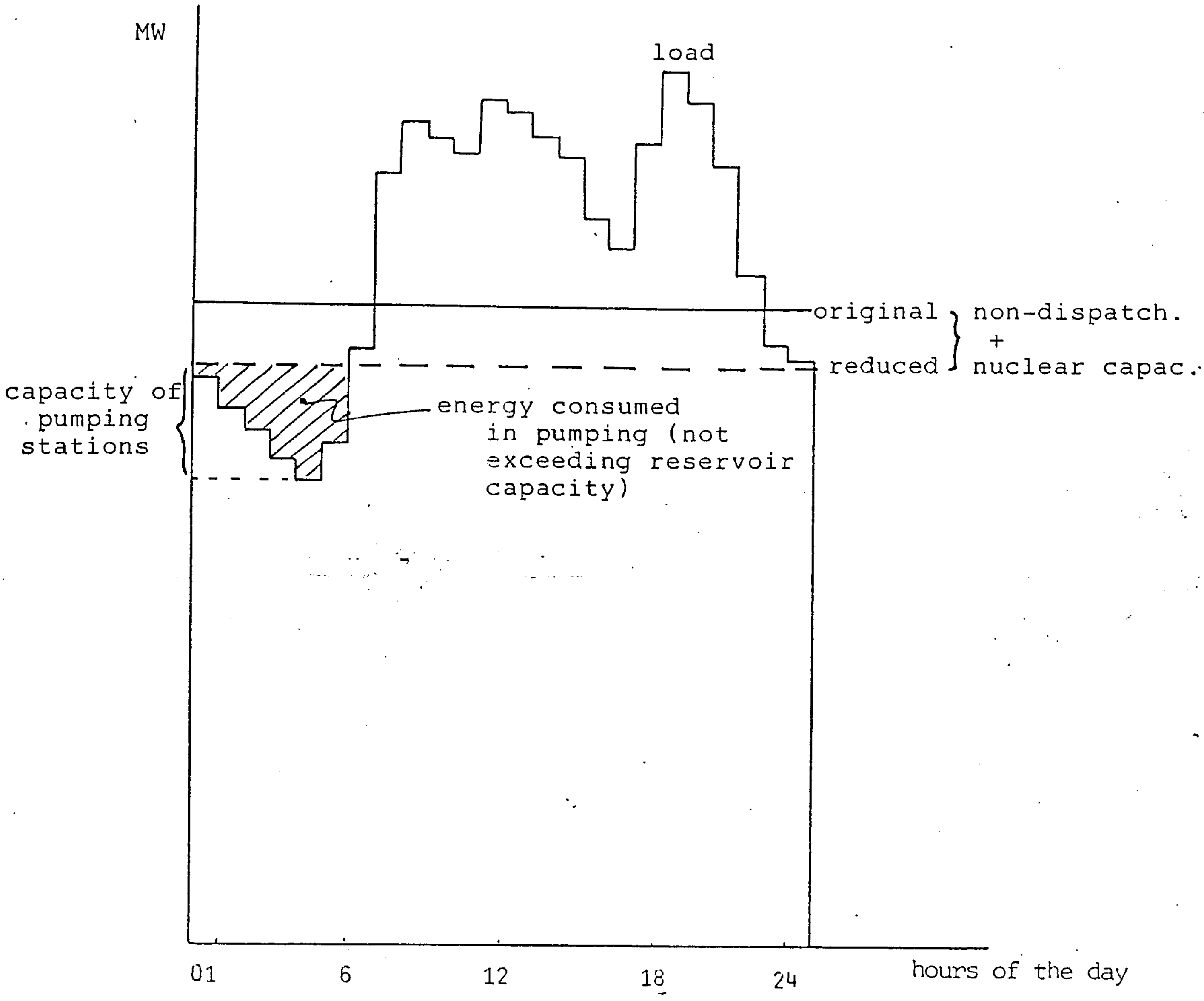


Figure 3.8(b) incompressible capacities have to be reduced because buffer pumping cannot absorb all excess power



If, on the other hand, excess power exceeds pumping capacity or storage capability, the program reduces the incompressible capacity from its original level to the maximum feasible level. In figure 3.8(b), this reduction is shown for the pumping capacity being the bottle-neck restriction. The reduction is always imposed on the nuclear facilities, substituting a reduced nuclear "palier" for the original nuclear effective capacity slice.

The check on buffer pumping and incompressible capacities is carried out for each typical day separately, and nuclear capacity is reduced independently for all typical days within one week. In other words, we assume nuclear capacity can be modulated on a daily basis. It would be no problem changing our program by requiring a single nuclear "palier" for an entire typical week. This however would increase the generation costs of the system because the capacity factor of available nuclear capacity will generally decrease. It is obvious, the latter lowers also the competitiveness of nuclear power versus other generation technologies.

Following the control on the incompressible capacities, a check is carried out on the operation flexibility of the remainder of the production system. For this purpose the units are divided in two classes: units that have to be kept on line during the entire 24-hour day (eventually as hot spinning capacities when no other dispatching opportunities are available) and units that can be started and shut down during the various hours of the day. For some units, start costs are significant, inter alia because we assume each start to take place from cold rest on; for other units start costs are zero (e.g. the dispatchable shares of operating partly dispatchable plants). Depending on the hourly load structure and on the present generation system, it may be necessary to exclude plants that cannot be started and shut down within a day, from the available plants' list. The withdrawal of inflexible units is carried out one by one and following the merit-order of the system. The decision to remove plants from the system is based on a test similar to the one carried out for controlling incompressible capacities. Now we verify whether minimum hourly loads (increased by buffer pumping loads when storage pumping is feasible) exceed the minimum system output in function of the number of units on line. In figure 3.9 a detail of the feasible load range of the production system is shown (see figure 3.7).

Figure 3.9.

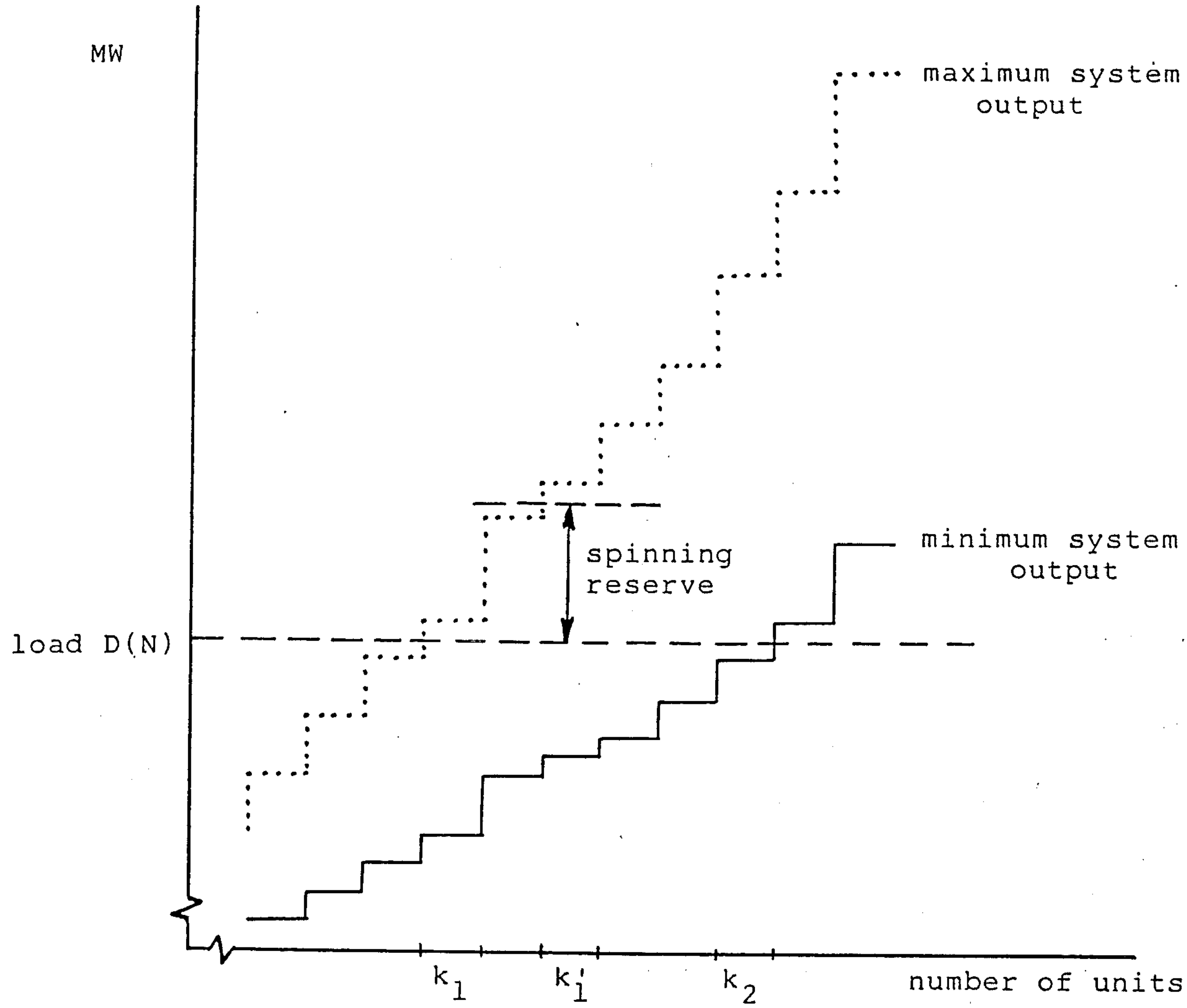
Let e.g. D(N) be the load on the system during any hour N of a typical day. It is clear that the minimum number units on line required to meet load D(N) should carry an added maximum generation capacity at least as large as the load imposed, i.e. at least k_1 units should be on line. The latter number may be adjusted to k_1' by a provision of spinning reserve (e.g. the largest unit on line must be replacable by spinning capacities).
On the other hand, the maximum number of units that can be scheduled to meet the load D(N) should result in an accumulated minimum system capacity less than or equal to the load D(N), i.e. a number of k_2 units as shown in figure 3.9.

Considering 24 loads D(N), N=1,...,24, for the 24 hours of the day, one has to look for consistency in the 24 pairs $[k_1(N),k_2(N)]$. E.g. one has to avoid that the programmed machine system during high load hours involves a large inflexible minimum system output during low load hours. This is modeled by removing inflexible plants from the plants' list.

It is evident that the $k_2(N)$ constraints on the number of active units are only binding when several plants carry a significant minimum output requirement. Otherwise one will find for all N $k_2(N)$ = total number of units in the system.

By adjusting the available production system to the particular load structure of the typical day, one has reduced the number of feasible solutions for the unit commitment problem. Two further reductions are programmed. As shown in figure 3.9, the pairs $[k_1(N), k_2(N)]$ are derived for each hour N and load D(N). This provides a neat lower boundary (i.e. $k_1(N)$) on the number of units on line during each hour N of the day. Because, in general, the upper boundary $k_2(N)$ is too wide, an additional time saving restriction is imposed: one finds the peak load hour during the period or, being in fact the same, the largest $k_1(N)$ (eventually $k_1'(N)$). In the optimal solution, the minimum number of units required to meet the peak load will be the optimum number because capacities are loaded in merit-order. Also this number of active

Figure 3.9.



k_1 = minimum number units on line required to meet load D(N)

k_2 = maximum number units on line feasible for meeting load D(N)

k_1' = minimum number required when a spinning reserve is imposed units will not be exceeded at other hours (loads), and is used as a constraint on the maximum number of units active during all hours of the period.

Thus far, attention was focused on the model solutions for low loads pressing on the flexibility constraints of the production system.

At the upper side of the range of numbers of active units, loss of load occurs when the accumulated maximum effective capacity of the generation system is lower than the load on the system. In a first step the model verifies the impact of interruptible loads. These loads are interrupted up to the point where system capacity equals remaining load, or up to the interruption constraint. If the latter prevails, the remainder of the load not covered by the system is reported as real loss of load. Loads that were interrupted are noted separately. The extent of both kinds of loss of load gives a rough indication of the reliability of the system in meeting the load.

After these preparatory computations, the dynamic programming algorithm is started by estimating the operating costs for all feasible states (= number of units on line) at all hours of the day. The operating costs are the sum of the short-run exploitation costs and of the least fuel costs for generating the load given the number of active units, disregarding the start costs of the units.
At any hour of the period one will have as many cost results as there are feasible states of the generation system.

A forward dynamic programming procedure is now started. At any stage (= hour of the period), the least accumulated operating costs are estimated for all feasible states at the particular stage. If we consider the feasible state j at hour or stage N, i.e. $k_1(N) \leq j \leq k_2(N)$ the least cost is found formally as:

$C_{j,N}$ = generation costs to meet the load at hour N with j units on line;

$A_{i,N-1}\{i=k_1(N-1),\ldots,k_2(N-1)\}$ = accumulated generation costs of meeting the loads up to hour N-1 when i units are on line at hour N-1;

$S_{i,j}$ = start costs of units. These costs are zero when $i \geq j$, and are equal to the sum of the start costs of the units from i+1 to j when i<j.

The subproblem to be solved is:

$$A^*_{j,N} = C_{j,N} + \{\underset{i}{\text{Min}}\ A_{i,N-1} + S_{i,j}\}$$

When this problem is solved, one stores the outcome $A^*_{j,N}$ as the relevant cost figure of state j at stage N, and one keeps also in memory the value of i solving the problem in order to recover the overall optimal solution.

After these computations, one finds the minimum accumulated costs at the last stage (hour) of the period and recovers the optimum path over the period. One problem, that cannot be given a real satisfactory solution in our model, is that of the initial and terminal constraint, being the number of units on line entering and leaving the subperiod considered. By an adequate definition of the daily subperiods (see chapter I) we have tried to minimize the impact of these constraints. The load at the beginning of our reordered day is nearly equal to the load at the end of that day. It is imposed that the number of active units leaving the period is at least equal to the number of active units entering the system being equal to the minimum number of units on line to meet the initial load.

After the recovery of the optimum path over the period, indicating for each hour the optimum number of units on line, the program estimates the power generated by every unit during each hour. This information is inter alia required for modeling the impact of the pumped storage plants on the performance of the system. Simultaneously with the production assignment, we detect for each hour of the period the marginally producing unit, i.e. the unit carrying the marginal load on the system at the particular hour. In general the latter unit will be different from the last active unit. Because of start costs and flexibility constraints one will prefer a rather stable number of units on line, meeting load fluctuations by modulating several plants simultaneously. These results are in agreement with the chronological production diagrams published by the national dispatching center.

We have defined the hourly short-run marginal costs of the system as the fuel costs related to the marginally producing capacity. It is evident that this simple definition of marginal costs is not without problems. E.g. a load increase at the peak hour may involve that over the entire period, one more production capacity is kept on line, reducing the marginal costs at the other hours. The same effect occurs when a particular spinning reserve capacity is imposed. Generally, these cost effects are small because the shifts occur between neighbouring units in the merit-order. Only when the border between capacity blocks is crossed, significant differences are noted.
The distinction between the last active unit and the marginally loaded unit at any hour of the period is important for the incorporation of pumped storage and limited energy plants.

For any typical day the dynamic programming algorithm is runned for the 24 hours at once, although the available production system can differ along the subperiods of the day.

III.3. Pumped storage

In this section we discuss the incorporation of pumped storage capacity in the generation system. As shown in EPRI-EL2561, one can consider limited energy plants as an analogous problem.

In a modern power system, pumped storage plants have several functions. They are operated as buffer capacity in order to avoid modulation or shut-down of incompressible and inflexible capacities (see III.2). They are called upon as reserve capacity to meet load shocks instantaneously. They are dispatched as economic capacity to transfer cheap power from low-load hours to high-load hours substituting for expensive energy from peak plants. In Belgium, being rich in nuclear but poor in hydro capacity, the function of net frequency adjustment may in the future also be assigned to the storage plants.

The buffer function of storage capacity was discussed in the previous section III.2. In modeling this function we have ignored a physical property of the pumping activity as we will do in the remainder of our analysis. Although technically, pumping requires full loading of the set we assumed pumping can be carried out incrementally. This assumption is somewhat attenuated by the diverse composition of the Belgian pumping plants (see table 3.3). In our model all pumping units are added to one plant except for the maintenance scheduling (section II.3). We handle therefore with one pumping capacity of 1238 MW, one storage reservoir of 5800 MWh net deliverable power, etc...

Table 3.3. Pumped storage capacity in Belgium

COO 1	3 x 165 MW	=	495
COO 2	3 x 200 MW	=	600
Plate-Taille	3 x 37.75 MW	=	143
	Total capacity	=	1238 MW

The overall efficiency of the pumping & generating cycle is equal to 0.7125 (= 0.75 * 0.95), i.e. the efficiency from the busbar of the thermal plant supplying power for pumping, to the delivery at the network nodes where the load arises that is met by the stored energy.

Modeling the reserve and the economic functions of pumped storage is complex because both functions are competitive to one another. Given a particular storage capacity, one has to withold a share of this capacity as reserve power, providing the remainder for economic transfers. The latter capacity can be taken up entirely or partly, depending on the state of the system. Additionally, one has to manage the storage capacity on the basis of short-run load and system forecasts, involving uncertainty. Moreover, the pumped storage time cycle encompasses two time periods: the daily cycle with pumping at low-load (night) hours and generating at peak-load (daytime) hours; the weekly cycle with pumping during low-load days (Sundays, holidays) and generating during peak-load days (working days).

The reserve function of pumped storage plants is important. They provide the system instantaneous, zero start cost capacity. Therefore, spinning reserve capacity from thermal units can be minimized in supplying active power. A remaining problem is the generation of reactive power, pumped storage plants being concentrated on two sites. This problem cannot be solved by models as ours assuming all system capacity concentrated at one point.

In agreement with sector practice, we modeled the provision of 500 MW pumped storage capacity as permanent reserve, the leftover 1238-500 = 738 MW setting free for the other functions. Analogously, 1000 MWh energy is kept in stock permanently as reserve energy, reducing the free reservoir capacity to 4800 MWh net deliverable electricity.

In figure 3.10, it is shown how the reservoir capacity is assigned during the three typical days.

Figure 3.10

Next to the 1000 MWh permanent reserve (A), some part of the reservoir (B) may be filled because of buffer pumping activities during low load hours. For all three days, B is derived from the unit commitment routines discussed in section III.2. During sundays/ holidays part B is stretched out with B' to built up reservoir capacity that will be used during the coming week. Stored energy is transferred from sundays/holidays to weekdays (part C in figure 3.10). Because our model works with a single typical working day per typical week, we have to use an average transfer, resulting in a rather mechanistic representation of the weekly cycle.

Finally, part of the reservoir (D) can be used for economic transfers, i.e. pumping occurs at low-load hours and water is released during peak-load hours. The amount of economic transfer within each typical day is estimated by the model. In principle, one will transfer energy through the pumped storage stations as long as the cost of pumping, storing and releasing water is smaller than

Figure 3.10. Destination of pumped storage reservoir capacity

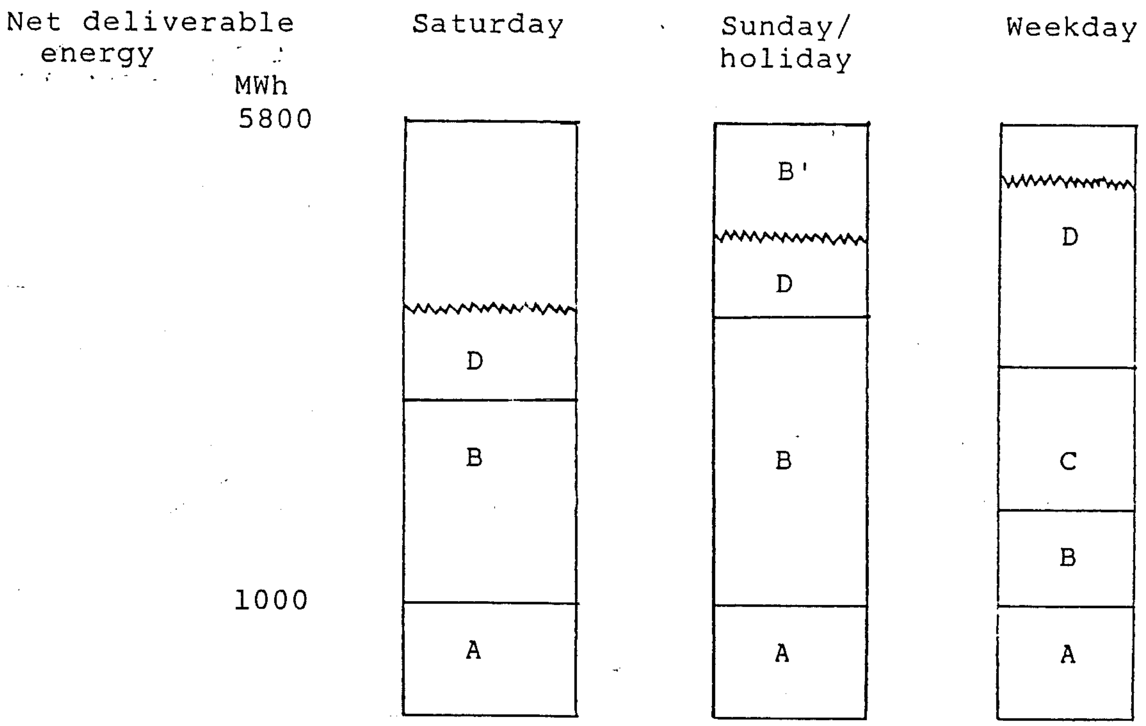
A = permanent reserve

B = stock built up by buffer pumping during the same day

C = energy transferred from other days

D = economic use

B'= week-end storage



the cost of direct generation. For a particular day, after unit commitment and production costing is carried out, one looks for the marginally active unit, i.e. the active unit with the highest unit generation costs. The model recovers the output of this unit and all operation costs related to this output, including start-up costs. In other words, all costs that can be saved by withdrawing the marginal active unit from the active plants'list are added. In a second step, the costs for pumping and storing the amount of energy to compensate for the output of the withdrawn unit, is estimated. With an overall cycle efficiency of 0.7125, one has to generate 1.4 kWh for each kWh nett delivered from the storage plants. The cost for generating the compensating energy is found by loading low-cost plants producing below their nominal capacity, up to their nominal capacity.

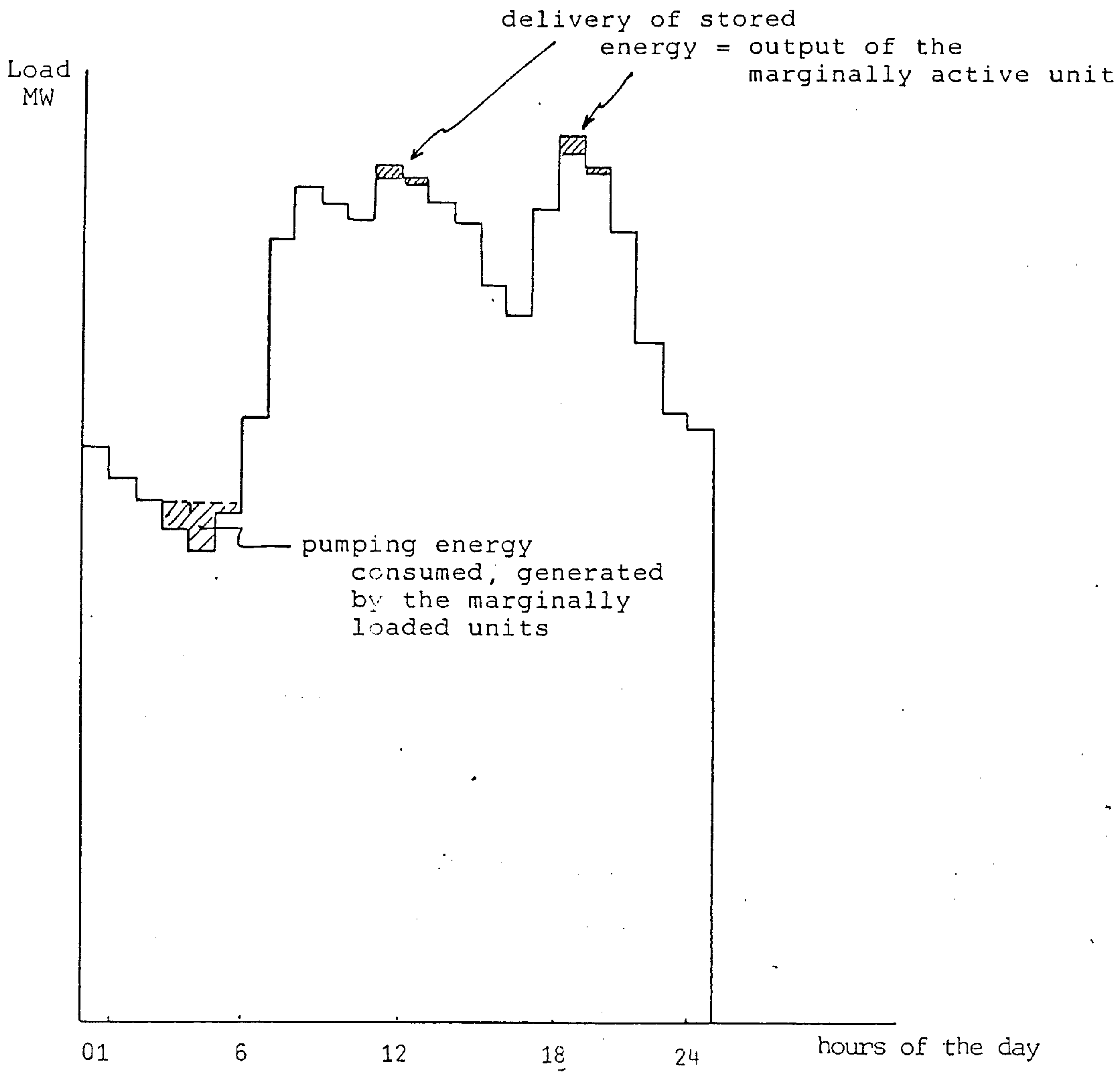
Figure 3.11

E.g. let X equal the output of the most expensive unit in the system. Replacing X by power from the storage plants allows for withdrawing the particular unit and for saving all costs related to its use. When X kWh is taken from the storage plants a previous thermal production of X/0.7125 or 1.4 X kWh is required. The generation of 1.4 X is scheduled at the hours of lowest load (see figure 3.11).

A special case arises in considering days with loads exceeding available thermal production capacity. In order to avoid or to minimize loss-of-load, pumped storage plants will be called upon. The savings realised in this way are evaluated by weighing this generation from storage plants by the generation cost of the marginal unit of the system. Costing of the compensating pump drive energy is accounted for by loading the plants carrying the lowest loads during the day.

In the next section, some examples of results will be shown.

Figuur 3.11. Economic transfer by pumped storage energy



IV. SOME RESULTS

The model we developed can be used in several studies, e.g. detail analysis of the unit commitment problem within a short time period (one day, one week), output and cost forecasting for the various units of a generation system during a particular future year, evaluating investment proposals over a period of some years, assisting in tariff-making for electricity, etc... It is obvious that these different goals require different emphasis on the various parts of the model. In addition, one expects a different outprint of results for each topic under study.

In this chapter, we show by way of illustration some results that can be selected by the program user in a standard interactive run of the model.

We runned our program over a10 year period 1986-1995. Electric load is assumed to grow at a constant 2.5 %/year rate, starting from 48 507.GWh in 1983. The production system consists of all Belgian power plants owned by the utilities, including foreseen scrappings and new capacity additions decided upon today (i.e. the 25 % participations in Chooz B1 and B2). Fuel prices were kept constant over the entire period and amount to:

nuclear	0,575 FB/kWh
coal	120.FB/GJ
natural gas	255.FB/GJ
heavy oil	235.FB/GJ
light fuel	340.FB/GJ
recovery gas	200.FB/GJ

The typical year consists of 7 typical weeks, each encompassing 3 typical days of 24 hour loads. This yearly load structure remains invariant over the period analysed, but is scaled each year at the total yearly load.

In table 4.1, results of the maintenance scheduling routine for six years of the period are shown. As discussed in chapter I (table 1.1), seven typical weeks are incorporated. In tabel 4.1, the code-numbers of units in maintenance during the various weeks are given. According to our routine, developed in section II.3, one observes the largest capacity on planned outage during July-August (week 5), followed by week 4 (May-June-September) etc... By our procedure some type of optimal maintenance planning is imbedded in the results: the largest amount of capacity, and by priority base-load capacity, is scheduled for maintenance during low-load periods. During high-load periods, no capacity or but a minor amount, is on planned outage. As stated in II.3, the possibility of sensitivity analysis on this issue is built into the model.

Table 4.1.

After withdrawal of units in maintenance, the generation system on line during a particular subperiod is filed and ranked. In tabel 4.2 some results are shown. Column 1 gives the merit-order of the system. In column 2, the code-numbers of the plants are printed. In columns 3 and 4, the minimum output and nominal output of the plant are shown (see chapter II, figure 2.1). In column 5 we mention the variable cost in FB/MWh used in the construction of the merit-order ranking. For the first 21 units of the system of tabel 4.2, no ranking has taken place, and one may observe that minimum output equals nominal output. We are dealing here with non-dispatchable and incompressible capacities. E.g. if we look at positions 10 and 11 of the merit-order (code-number 113., respectively 163.), we are dealing with a fossil plant burning recovery gas. During the subperiod considered, recovery gas is supplied at a rate loading the unit at 28. MW (position 10). Apparently 28 MW is lower than the minimum output of the particular plant, involving an additional non-dispatchable 13.MW (position 11) burning the normal fuel of the plant. In addition there is a dispatchable share (position 29, code 363.) of the unit that can be loaded freely from 0. to 71. MW. The variable costs (FB/MWh) in column 4 are respectively:

Table 4.1. Maintenance scheduling results

Maintenance Scheduling in year 1986

Typ.week 1	Units Nr:	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 2	Units Nr:	316.	513.	715.	812.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 3	Units Nr:	212.	215.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 4	Units Nr:	211.	311.	511.	512.	514.	516.	714.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 5	Units Nr:	111.	112.	113.	210.	214.	314.	315.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 6	Units Nr:	213.	310.	312.	510.	710.	713.	810.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 7	Units Nr:	515.	711.	712.	811.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

Maintenance Scheduling in year 1987

Typ.week 1	Units Nr:	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 2	Units Nr:	322.	518.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 3	Units Nr:	211.	520.	717.	710.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 4	Units Nr:	217.	218.	210.	321.	517.	815.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 5	Units Nr:	114.	115.	116.	216.	213.	318.	320.	323.	0.	0.	0.	0.	0.	0.	0.
Typ.week 6	Units Nr:	212.	317.	319.	519.	718.	813.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 7	Units Nr:	716.	719.	814.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

Maintenance Scheduling in year 1988

Typ.week 1	Units Nr:	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 2	Units Nr:	535.	510.	715.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 3	Units Nr:	217.	324.	325.	326.	327.	328.	310.	313.	513.	0.	0.	0.	0.	0.	0.
Typ.week 4	Units Nr:	215.	311.	532.	534.	511.	512.	514.	712.	816.	0.	0.	0.	0.	0.	0.
Typ.week 5	Units Nr:	117.	111.	214.	216.	312.	528.	529.	530.	531.	533.	0.	0.	0.	0.	0.
Typ.week 6	Units Nr:	218.	210.	716.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 7	Units Nr:	711.	713.	714.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

Maintenance Scheduling in year 1989

Typ.week 1	Units Nr:	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 2	Units Nr:	516.	518.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 3	Units Nr:	215.	717.	718.	710.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 4	Units Nr:	212.	213.	314.	316.	318.	515.	517.	810.	0.	0.	0.	0.	0.	0.	0.
Typ.week 5	Units Nr:	112.	113.	114.	211.	214.	315.	317.	319.	0.	0.	0.	0.	0.	0.	0.
Typ.week 6	Units Nr:	216.	817.	819.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 7	Units Nr:	719.	711.	818.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

Maintenance Scheduling in year 1990

Typ.week 1	Units Nr:	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 2	Units Nr:	510.	717.	813.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 3	Units Nr:	212.	215.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 4	Units Nr:	211.	320.	323.	327.	528.	529.	530.	532.	534.	511.	513.	0.	0.	0.	0.
Typ.week 5	Units Nr:	115.	116.	217.	218.	210.	213.	321.	324.	325.	519.	0.	0.	0.	0.	0.
Typ.week 6	Units Nr:	214.	322.	326.	520.	531.	533.	535.	512.	712.	713.	714.	716.	812.	0.	0.
Typ.week 7	Units Nr:	715.	811.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

Maintenance Scheduling in year 1991

Typ.week 1	Units Nr:	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 2	Units Nr:	517.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 3	Units Nr:	211.	718.	712.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 4	Units Nr:	217.	218.	210.	315.	515.	719.	711.	814.	0.	0.	0.	0.	0.	0.	0.
Typ.week 5	Units Nr:	117.	111.	216.	212.	312.	313.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 6	Units Nr:	328.	310.	311.	314.	514.	516.	710.	0.	0.	0.	0.	0.	0.	0.	0.
Typ.week 7	Units Nr:	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

Table 4.2.

position 10	→	1946	FB/MWh
position 11	→	1448	FB/MWh
position 29	→	1060.	FB/MWh

These figures would suggest the opposite ranking than the one in table 4.2. However, because of the non-dispatchable nature of the capacities at position 10 and 11, they have to be ranked prior to the dispatchable units. The position of 10 versus 11 is of no relevance, because these capacities fill in the real base of the load diagram.

In position 22 we find under code 205. the nuclear capacity slice (4613.MW in table 4.2). Next we have coal fired capacities (position 23 to 46), oil/gas fired units (positions 47 to 67) and rapid-start units (positions 68 to 77). The plants'list as shown in table 4.2 is a corrected one for flexibility constraints. We already treated the case of a recovery gas burning plant, fallen apart in three capacities (positions 10, 11 and 29 in table 4.2). Depending on the load diagram of the subperiod under study, the nuclear capacity slice may have been derated because of modulation inflexibility. Additionally, inflexible plants (high-temperature; high-pressure fossil plants) are withdrawn when it is impossible to guarantee their minimum loading in order to avoid short-time shut downs (see section III.2).

In the last three columns of table 4.2 one has the composite power ranges and composite costs in FB to meet the lower range. In section III.2 (figure 3.7), the meaning of these series is explained. In column 6 of table 4.2 we have the accumulated minimum output that will be delivered when the ranked capacities are brought on line. In column 7, the maximum output deliverable by the ordered system is shown. In column 8, the variable costs in FB in generating power equal to the amount shown in column 6 is given. E.g. at position 21, there is an accumulated (non-dispatchable) output of 809.MW (columns 6 equals column 7) in-

Table 4.2. Ordered machine system during a particular daily subperiod

Merit Order	Code Nr	MW	MW	FB/MWh	Composite cost function MW	MW	FB
1	100.	40.	40.	0.	40.	40.	0.
2	101.	170.	170.	575.	210.	210.	97750.
3	102.	68.	68.	1146.	278.	278.	181030.
4	103.	50.	50.	1158.	328.	328.	244830.
5	104.	12.	12.	1186.	340.	340.	259065.
6	111.	27.	27.	1905.	367.	367.	321938.
7	161.	28.	28.	1210.	395.	395.	355786.
8	112.	26.	26.	1870.	421.	421.	421214.
9	162.	29.	29.	1181.	449.	449.	455067.
10	113.	28.	28.	1946.	477.	477.	525032.
11	163.	13.	13.	1448.	490.	490.	543812.
12	114.	29.	29.	2028.	519.	519.	614940.
13	164.	26.	26.	1307.	545.	545.	648846.
14	115.	26.	26.	1946.	570.	570.	725696.
15	165.	56.	56.	1140.	627.	627.	789742.
16	116.	26.	26.	2112.	653.	653.	861319.
17	166.	29.	29.	1328.	681.	681.	899378.
18	117.	60.	60.	1770.	741.	741.	1063584.
19	167.	51.	51.	2081.	792.	792.	1168859.
20	118.	11.	11.	2966.	802.	802.	1209427.
21	168.	7.	7.	3807.	809.	809.	1235093.
22	205.	4613.	4613.	728.	5422.	5422.	4701077.
23	316.	55.	109.	993.	5477.	5531.	4779751.
24	362.	0.	49.	1005.	5477.	5581.	4779751.
25	315.	55.	115.	1015.	5531.	5695.	4857647.
26	361.	0.	52.	1030.	5531.	5747.	4857647.
27	311.	46.	261.	1042.	5577.	6008.	4938293.
28	365.	0.	21.	1050.	5577.	6029.	4938293.
29	363.	0.	71.	1060.	5577.	6100.	4938293.
30	310.	40.	112.	1081.	5617.	6212.	4994110.
31	317.	55.	113.	1090.	5672.	6325.	5068667.
32	318.	55.	113.	1090.	5726.	6438.	5143344.
33	312.	55.	123.	1091.	5781.	6561.	5221810.
34	314.	55.	113.	1097.	5835.	6673.	5293608.
35	364.	0.	60.	1109.	5835.	6733.	5293608.
36	319.	82.	247.	1114.	5917.	6980.	5412014.
37	323.	55.	106.	1116.	5972.	7086.	5490757.
38	321.	55.	106.	1130.	6026.	7191.	5565160.
39	366.	0.	49.	1148.	6026.	7240.	5565160.
40	325.	0.	56.	1158.	6026.	7296.	5573669.
41	322.	22.	110.	1159.	6048.	7406.	5613174.
42	320.	68.	105.	1173.	6116.	7511.	5699183.
43	324.	0.	48.	1174.	6116.	7559.	5712171.
44	326.	22.	58.	1229.	6139.	7616.	5747083.
45	327.	0.	51.	1257.	6139.	7668.	5757959.

Table 4.2. (cont.)

Merit Order	Code Nr	MW	MW	FB/MWh	Composite cost function MW	MW	FB
46	328.	0.	51.	1274.	6139.	7719.	5768331.
47	511.	0.	46.	1575.	6139.	7764.	5809295.
48	512.	0.	46.	1575.	6139.	7810.	5850259.
49	531.	0.	9.	1763.	6139.	7819.	5850259.
50	532.	0.	7.	1763.	6139.	7825.	5850259.
51	533.	0.	19.	1851.	6139.	7844.	5855494.
52	528.	0.	26.	1868.	6139.	7870.	5862100.
53	530.	0.	15.	1875.	6139.	7885.	5867335.
54	567.	0.	129.	1881.	6139.	8014.	5867335.
55	513.	46.	264.	1995.	6185.	8278.	6013812.
56	535.	0.	19.	2021.	6185.	8297.	6019733.
57	529.	0.	4.	2036.	6185.	8301.	6023131.
58	517.	83.	253.	2048.	6268.	8554.	6252134.
59	534.	0.	26.	2053.	6268.	8580.	6258740.
60	516.	46.	116.	2082.	6314.	8696.	6376190.
61	514.	46.	116.	2089.	6360.	8811.	6490874.
62	518.	83.	253.	2091.	6442.	9064.	6723399.
63	510.	55.	256.	2099.	6498.	9320.	6878289.
64	515.	59.	121.	2105.	6556.	9442.	7020139.
65	519.	52.	104.	2205.	6608.	9546.	7171025.
66	520.	24.	55.	2471.	6632.	9600.	7251636.
67	568.	0.	25.	2553.	6632.	9625.	7251636.
68	710.	0.	99.	1773.	6632.	9724.	7337502.
69	714.	0.	68.	2407.	6632.	9791.	7374327.
70	711.	0.	42.	2416.	6632.	9834.	7408204.
71	713.	0.	24.	2444.	6632.	9858.	7444682.
72	712.	0.	65.	2553.	6632.	9923.	7494159.
73	715.	0.	57.	5452.	6632.	9980.	7494159.
74	716.	0.	57.	5452.	6632.	10037.	7494159.
75	717.	0.	57.	5452.	6632.	10094.	7494159.
76	718.	0.	57.	5452.	6632.	10151.	7494159.
77	719.	0.	38.	5452.	6632.	10189.	7494159.

volving generation costs of 1 235 093 FB (on average 1527 F/MWh). Next the nuclear slice is added: 5422 MW implies a cost of 4701077 FB (on average 867 FB/MWh). From there on the magnitudes in columns 6 and 7 diverge, column 6 being the accumulation of column 3, and column 7 being the accumulation of column 4. The costs in column 8 correspond to the generation of the amount of power shown in column 6.

Because the plants'list as shown in table 4.2 may be different for the various subperiods considered (two in each typical day), the print of this information has to be asked for explicitly, by the program user.

On request, the program user receives a listing of the performance of the generation system in meeting the load during a particular day. For each capacity in the system its generation during each hour of the day is revealed. In table 4.3(a) such an overview is given for the state of the system after the dynamic programming routine (including buffer pumping) but before pumping activities on economic grounds have taken place. One observes a rather stable pattern of number of units on line, while load variations are met by modulating several production units near the end of the merit order list. This is particularly clear during the first 9 hours of the day: 42 capacities are kept on line (see table 4.2 for the corresponding characteristics of the plants). The capacities 39 to 42 are kept at their minimum output level during all 9 hours and capacity 38 is only partly loaded. At the minimum load (hour 7), plants 26 to 42 are not full loaded. This type of results, observable over the entire day, is due to the dynamic optimization algorithm applied to production systems involving modulation constraints and modulation costs.

<u>Table 4.3(a)</u>

The fluctuations in the loading pattern over a 24-hour period are dampened by pumped storage activities. Storing water during low-load hours increases the output of the partly loaded capacities; releasing water at high-load hours decreases the output of the marginal active units and allows the withdrawal (or non start-up

Table 4.3(a).

matrix of individual outputs BEFORE pumping , year 1986 day= 3

Nr.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.
2	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.
3	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.
4	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.
5	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.
6	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.
7	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.
8	26.	26.	25.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.
9	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.
10	28.	29.	28.	28.	29.	29.	28.	28.	28.	29.	28.	28.	29.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.
11	13.	13.	13.	13.	12.	13.	13.	13.	12.	13.	13.	13.	13.	13.	13.	12.	13.	13.	13.	13.	13.	13.	13.	13.
12	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.
13	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.
14	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.
15	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.
16	26.	26.	25.	26.	25.	26.	25.	26.	25.	26.	26.	26.	25.	26.	25.	26.	26.	26.	26.	26.	26.	26.	26.	26.
17	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.
18	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.
19	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.
20	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.
21	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.
22	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.
23	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.
24	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.
25	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.
26	52.	52.	52.	52.	52.	52.	45.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.
27	261.	261.	261.	261.	149.	94.	46.	149.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.
28	21.	21.	21.	21.	0.	0.	0.	0.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.
29	71.	71.	71.	71.	0.	0.	0.	0.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.
30	112.	112.	112.	112.	40.	40.	40.	40.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.
31	113.	113.	113.	113.	55.	55.	55.	55.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.
32	113.	113.	113.	105.	55.	55.	55.	55.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.
33	123.	123.	123.	55.	55.	55.	55.	55.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.
34	113.	113.	113.	55.	55.	55.	55.	55.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.
35	60.	60.	21.	0.	0.	0.	0.	0.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.
36	247.	247.	82.	82.	92.	92.	82.	82.	217.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.
37	106.	86.	55.	55.	55.	55.	55	55.	55.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.
38	94.	55	55.	55.	55.	55.	55.	55.	55.	106.	106.	106.	105.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.
39	0.	0.	0.	0.	0.	0.	0.	0.	0	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.
40	0.	0	0.	0.	0.	0.	0.	0.	0	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.
41	22.	22.	22.	22.	22.	22.	22.	22.	22.	110.	110.	110.	110.	110	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.
42	58.	58.	58	58	58.	58.	58	58	58.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.
43	0	0	0.	0.	0.	0.	0	0.	0.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.
44	0	0	0.	0	0.	0.	0.	0.	0	58.	58.	58.	58.	56.	58.	58.	58.	59.	58.	58.	58.	56.	58.	58.
45	0.	.	0.	0.	0.	0.	0.	0.	0.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.
46	0.	0	0.	0.	0.	0	0	0.	0.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.
47	0.	0.	0.	0.	0.	0	0	0.	0	46.	46	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	37.
48	0.	0.	0	0.	0.	0.	0.	0.	0.	46.	45.	46.	46.	46.	45.	46.	46.	46.	46.	46.	45.	46.	46.	0.
49	0.	0.	0.	0	0.	0.	0.	0.	0.	9.	9.	9.	9.	9	9.	9.	9.	9.	9.	9.	9.	9.	9.	0.
50	0.	0.	0.	0	0.	0.	0	0.	0.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	0.
51	0.	0.	0.	0	0	0.	0	0.	0.	19.	19.	19.	19.	19.	19.	19.	19.	19.	19.	19.	19.	19.	19.	0.
52	0.	0.	0.	0.	0	0	0	0.	0.	26.	26.	26.	25.	26.	26.	25.	26.	26.	2.	25.	26.	26.	26.	0.
53	0.	0.	0.	0.	0.	0	0	0.	0	15.	15.	15.	13.	15.	15.	15.	15.	15.	0.	15.	15.	15.	15.	0.
54	0.	0.	0.	0.	0.	0.	0.	0.	0.	129	129.	129.	129.	129.	129	129.	129.	126.	0.	129.	129.	129.	129.	0.
55	0.	0.	0.	0.	0.	0	0.	0.	0.	126.	264.	264.	264.	264	264.	264.	264.	46.	46.	151.	264.	264.	236.	0.
56	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	19.	19.	19.	19.	19.	19	0.	0.	0.	0.	19.	19.	0.	0.
57	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	4.	4.	4.	4.	4.	4.	0.	0.	0.	0.	4.	4.	0.	0.
58	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	233.	233.	233.	233.	224.	224.	83.	83.	83.	83.	253.	253.	0.	0.
59	0.	0.	0.	0	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	5.	0.	0.	0.	0.	26.	26.	0.	0.
60	0.	0.	0.	0	0.	0.	0.	0	0.	0.	46	46.	46.	46.	0	0.	0.	0.	0.	0.	116.	56.	0.	0.
61	0.	0.	0	0	0	0	0.	0.	0.	0.	0.	0	0	0.	0.	0.	0.	0.	0.	0.	72.	0.	0.	0.
62	0.	0.	0.	0	0.	0	0.	0	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
63	0	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
64	0.	0.	0	0.	0	0.	0	0	0.	0.	0	0	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.
65	0.	0	0.	0.	0.	0	0.	0	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.
66	0	0	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
67	0.	0.	0.	0.	0.	0.	0.	0.	0	0	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
68	0.	0.	0	0.	0.	0.	0.	0	0	0	0	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
69	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.
70	0.	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.
71	0.	0.	0.	0	0.	0.	0.	0	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
72	0.	0.	0.	0.	0.	0.	0	0	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.
73	0.	0	0.	0.	0.	0.	0.	0.	0	0	0	0.	0.	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.
74	0.	0.	0	0.	0.	0	0	0.	0	0	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.
75	0.	0.	0	0.	0	0	0.	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
76	0.	0.	0	0.	0.	0	0	0	0.	0.	0.	0.	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
77	0	0	0	0.	0.	0	0	0	0	0	0.	0.	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

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of several of them. In the example shown here, use of the pumped storage plants has taken place at its maximum level: 4800 MWh is generated during the day. So doing, the output pattern shown in table 4.3(a) is transformed into the one of table 4.3(b).

Table 4.3(b)

In comparing table 4.3(a) with 4.3(b) one should incorporate the information of table 4.4. In the latter table an overview of some hourly magnitudes is given. In column 1 the hours are numbered. Column 2 contains the load in MW. In columns 3 to 6 the activity status of the generation system is summarized: column 3 contains the position of the unit that would carry an incremental load during the hour, referred to as the marginally loaded unit; in column 4 the position of the last active or running capacity is shown. Columns 5 and 6 indicate the feasibility range of the number of units on line, corrected eventually for computing time cut-backs (see section III.2). In column 7, the capacity of the pumping station taken up for either pumping or turbo-generating is shown. Because 500 MW pumped storage capacity is kept in reserve, only 700.86 MW is available for normal use. Because of the latter constraint we observe (when maximum use of the pumped storage plants occurs) that the pumping and releasing activities are spread out over nearly all hours of the day (see column 7 in table 4.4). In addition, storing during low-load hours is limited to a capacity use of 700.86 MW, involving that e.g. during hour 7 capacity 36 is the marginal loaded one, while during e.g. hour 1, unit 42 is loaded marginally to increase the water level in the reservoirs. Consequently, the 500 MW reserve constraint spreads out the pumped storage activities over more hours and limits the savings made feasible.

Table 4.4

In the last column of table 4.4, the fuel cost of the marginally loaded capacity is shown. Because the fluctuations in the output pattern are dampened significantly, the marginal fuel costs vary

Table 4.3(b)

Matrix of individual outputs AFTER PUMPING , year 1986 day= 3

nr.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	hours of the day																							
1	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.	40.
2	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.	170.
3	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.	68.
4	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.	50.
5	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.	12.
6	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.	27.
7	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.
8	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.
9	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.
10	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.	28.
11	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.	13.
12	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.
13	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.
14	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.
15	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.
16	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.	26.
17	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.	29.
18	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.
19	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.
20	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.	11.
21	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.
22	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.	4613.
23	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.	109.
24	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.
25	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.	115.
26	52.	52.	52.	52	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.	52.
27	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.	261.
28	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.	21.
29	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.	71.
30	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.	112.
31	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.
32	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.
33	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.	123.
34	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.	113.
35	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.	60.
36	247.	247.	247.	247.	203.	148.	93.	203.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.	247.
37	106.	106.	106.	106.	55.	55.	55.	55.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.
38	106.	106.	106.	106.	55.	55.	55.	55.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.	106.
39	49.	49.	49.	49.	0.	0.	0.	0.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.	49.
40	56.	56.	56.	56.	0.	0.	0.	0	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.	56.
41	110.	110	110.	110.	22.	22.	22.	22.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.	110.
42	58.	58.	58.	90	68.	68.	58.	63.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.	105.
43	0.	0.	0.	0.	0.	0.	0.	0	0	48	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.	48.
44	0	0.	0.	0.	0.	0.	0.	0.	0.	53.	58.	58.	58.	58.	58.	58.	58.	58.	58.	58.	58.	58.	58.	58.
45	0	0.	0.	0.	0.	0.	0.	0.	0.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.
46	0.	0.	0.	0.	0.	0.	0.	0.	0.	51.	51.	51	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.	51.
47	0.	0.	0.	0.	0.	0.	0.	0.	0	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	37.
48	0	0.	0.	0.	0.	0.	0.	0.	0.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	46.	0.
49	0.	0.	0.	0.	0.	0.	0.	0.	0	9.	9.	9.	9.	9.	9.	9.	9.	9.	9.	9.	9.	9.	9.	0.
50	0.	0.	0.	0.	0.	0.	0.	0.	0.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	7.	0.
51	0.	0.	0.	0.	0.	0.	0	0.	0.	19.	19.	19.	19.	19.	19	19.	19.	19.	19.	19.	19.	19.	19.	0.
52	0.	0.	0.	0	0.	0	0.	0.	0.	26.	26.	26	26.	26	26.	26.	26.	26.	2.	26.	26.	26.	26.	0.
53	0.	0.	0	0	0.	0	0.	0.	0.	15.	15.	15.	15.	15.	15.	15.	15.	15.	0.	15.	15.	15.	15.	0.
54	0.	0.	0.	0.	0.	0.	0.	0.	0.	129.	129.	129.	129.	129.	129.	129.	129.	126.	0.	129.	129.	129.	129.	0.
55	0.	0.	0.	0.	0.	0.	0.	0.	0.	126.	264.	264.	249.	0.	0.	0.	0.	0.	0.	0.	53.	0.	0.	0.
56	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
57	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
58	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
59	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
60	0.	0.	0	0.	0	0.	0	0.	0.	0.	0.	0	0	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0
61	0.	0	0.	0.	0	0	0.	0.	0.	0.	0	0.	0.	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.
62	0.	0	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
63	0	0.	0.	0	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
64	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	0	0.	0.	0.	0.	0	0.	0.	0.	0.
65	0	0	0	0.	0.	0.	0	0.	0	0	0.	0	0	0	0.	0.	0.	0.	0	0.	0.	0.	0.	0.
66	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.
67	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
68	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
69	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
70	0.	0	0.	0.	0.	0	0	0.	0	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
71	0.	0.	0	0.	0	0	0.	0.	0.	0.	0.	0	0	0	0.	0.	0	0	0.	0.	0.	0.	0.	0.
72	0.	0.	0	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
73	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
74	0.	0	0.	0.	0.	0	0.	0.	0.	0.	0.	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
75	0	0	0	0.	0.	0	0.	0.	0.	0.	0.	0	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
76	0	0.	0.	0.	0.	0	0	0.	0	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0.	0.
77	0	0	0	0	0.	0.	0	0	0	0.	0	0	0.	0.	0.	0.	0.	0.	0	0	0.	0.	0.	0.

Table 4.4. Some hourly statistics on the performance of the generation system

HOUR-DAY 3	LOAD MW	NUMBER UNITS MARG.	NR.ACT	ACTIVITY RANGE		PUMP CONS. OR PROD.	MARG. COST FR. /MWH
1	7260.23	42	42	40	61	213.990	1124.520
2	7205.22	42	42	39	61	268.993	1124.520
3	6985.22	42	42	37	61	488.999	1124.520
4	6820.21	42	42	36	61	676.213	1124.520
5	6435.20	36	42	32	61	700.860	1073.640
6	6380.20	36	42	32	61	700.860	1073.640
7	6325.20	36	42	32	61	700.860	1073.640
8	6435.20	36	42	32	61	700.860	1073.640
9	7150.22	43	42	38	61	360.394	1064.760
10	8140.25	55	55	55	61	0.000	1957.315
11	8580.27	56	55	60	61	302.320	1927.235
12	8580.27	56	55	60	61	302.320	1927.235
13	8470.26	55	55	58	61	207.405	1957.315
14	8580.27	55	54	60	61	566.360	1957.315
15	8525.27	55	54	58	61	511.359	1957.315
16	8525.27	55	54	58	61	511.359	1957.315
17	8360.26	55	54	58	61	346.353	1957.315
18	8140.25	54	54	55	61	128.800	1881.410
19	7975.25	52	52	54	61	128.800	1771.430
20	8250.26	55	54	55	61	236.351	1957.315
21	8767.27	55	55	61	61	700.860	1957.315
22	8635.27	55	54	60	61	621.362	1957.315
23	8250.26	55	54	55	61	236.351	1957.315
24	7755.24	47	47	47	61	0.000	1528.215

little and within a rather narrow range during a day. The significance of the marginal cost concept is not as straightforward as in economic textbooks. E.g. one may lower the marginal cost i.e. the fuel cost of the marginally loaded unit at a particular hour by increasing the number of units on line, involving a higher cost of the marginal active capacity. This phenomenon occurs constantly in a dynamic optimization process, trying to minimize the overall generation costs. In addition, the incorporation of pumped storage plants changes the marginal cost picture profoundly.

Except for the maintenance schedules, the information shown above is referring to a particular typical day, to daily sub-periods or to hourly magnitudes. It is clear one should request a print of these results only when special attention on a particular day is focused. The next two tables summarize some information for all typical days of the year analysed. In table 4.5 the marginal fuel costs during all hours of the 21 typical days considered is shown. Each of the 21 columns contains the 24 hourly values.

Table 4.5

In table 4.6 a few other results per typical day are shown. The load is aggregated over the 24 hours of the day to indicate the amount of electricity that has to be delivered. In the next column, the variable costs to generate that power are shown. The following column contains the revenues the power company would raise if short-run marginal cost pricing on an hourly basis was applied. The (positive) difference with the previous column (the running costs) may be seen as payment for fixed liabilities.

Table 4.6

In the next column, "Nucl.pal %" shows the load rate on the nuclear stations. A percentage lower than 100. means that nuclear capacity works at the lower output rate during all

Table 4.5.

MARGINAL COSTS (FR./KWH) PER HOUR IN YEAR 1986

****

HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
1	1.06	1.04	1.12	1.03	1.11	1.15	1.11	1.05	1.16	1.04	1.76	1.07	1.00	1.05	1.07	1.03	1.15	1.11	1.00	1.17	1.11
2	1.11	1.05	1.12	1.03	1.15	1.11	1.05	1.05	1.16	1.06	1.15	1.05	1.00	1.05	1.11	1.03	1.15	1.07	1.00	1.15	1.11
3	1.07	1.05	1.12	1.06	1.11	1.11	1.07	1.05	1.15	1.05	1.06	1.05	1.05	1.04	1.05	1.05	1.11	1.07	1.05	1.53	1.08
4	1.05	1.05	1.12	1.03	1.01	1.07	1.05	1.05	1.08	1.06	1.11	1.06	1.04	1.04	1.00	1.03	1.06	1.05	1.00	1.17	1.07
5	1.04	1.05	1.07	.97	1.01	1.05	1.00	1.05	1.07	1.01	1.11	1.04	.95	1.04	1.00	.95	1.06	1.06	1.01	1.15	1.05
6	1.00	1.05	1.07	1.03	1.01	1.05	1.00	1.05	1.07	1.01	1.11	1.04	1.00	1.04	1.00	.95	1.06	1.00	1.01	1.06	1.05
7	.97	1.04	1.07	1.03	1.01	1.05	1.00	1.05	1.07	1.01	1.11	1.04	1.00	1.04	1.00	.95	1.03	1.00	1.01	1.03	1.05
8	1.01	1.06	1.07	1.03	1.01	1.11	1.03	1.05	1.15	1.01	1.11	1.04	1.00	1.00	1.00	.95	1.03	1.05	1.01	1.01	1.07
9	1.01	1.00	1.06	1.03	1.01	1.11	1.03	1.05	1.15	1.01	1.01	1.05	1.00	1.00	1.04	.95	1.05	1.07	1.01	1.01	1.11
10	.97	1.00	1.96	1.03	1.03	1.17	1.00	1.04	1.76	1.01	1.15	1.11	1.00	1.04	1.07	1.01	1.01	1.11	.97	1.06	1.53
11	1.06	1.06	1.93	1.03	1.03	1.76	1.06	1.05	1.76	1.05	1.06	1.76	1.05	1.04	1.15	1.01	1.06	1.53	1.00	1.06	1.96
12	1.05	1.05	1.93	1.00	1.03	1.76	1.07	1.05	1.76	1.05	1.06	1.76	1.05	1.04	1.06	1.06	1.11	1.53	1.04	1.17	1.96
13	1.11	1.05	1.96	1.06	1.03	1.76	1.07	1.05	1.76	1.05	1.06	1.76	1.05	1.05	1.06	1.05	1.15	1.53	1.05	1.17	1.96
14	1.07	1.05	1.96	1.04	1.11	1.76	1.11	1.07	1.96	1.05	1.76	1.76	1.07	1.05	1.06	1.11	1.15	1.53	1.05	1.53	1.96
15	1.07	1.07	1.96	1.04	1.53	1.76	1.07	1.07	1.77	1.05	1.76	1.76	1.07	1.11	1.06	1.11	1.53	1.53	1.05	1.53	1.96
16	1.07	1.05	1.96	1.00	1.06	1.76	1.07	1.05	1.77	1.04	1.06	1.76	1.05	1.04	1.06	1.00	1.11	1.53	1.04	1.53	1.96
17	1.05	1.05	1.96	1.03	1.03	1.76	1.05	1.05	1.77	1.06	1.06	1.76	1.05	1.04	1.06	1.01	1.11	1.53	1.00	1.17	1.88
18	1.06	1.05	1.88	1.03	1.03	1.53	1.06	1.05	1.77	.97	1.06	1.76	1.04	1.04	1.06	1.01	1.11	1.53	1.03	1.17	1.88
19	1.04	1.05	1.77	1.03	1.03	1.53	1.00	1.05	1.77	1.01	1.06	1.16	1.04	1.05	1.12	1.01	1.11	1.06	1.06	1.17	1.88
20	1.07	1.05	1.96	1.03	1.03	1.15	1.05	1.05	1.53	.97	1.06	1.12	1.04	1.05	1.11	1.00	1.11	1.17	1.07	1.53	1.88
21	1.11	1.11	1.96	1.04	1.11	1.53	1.06	1.05	1.53	.97	1.06	1.11	1.05	1.05	1.15	1.07	1.53	1.53	1.07	1.53	1.88
22	1.11	1.07	1.96	1.04	1.53	1.53	1.06	1.05	1.15	1.03	1.06	1.11	1.05	1.05	1.07	1.07	1.53	1.76	1.07	1.53	1.88
23	1.07	1.11	1.96	1.04	1.53	1.53	1.04	1.05	1.15	.97	1.06	1.11	1.04	1.05	1.07	1.11	1.53	1.53	1.05	1.53	1.77
24	1.05	1.05	1.53	1.00	1.15	1.12	1.07	1.05	1.77	.97	1.06	1.07	1.00	1.05	1.05	1.06	1.53	1.11	1.04	1.17	1.11

Table 4.6.

Summary statistics in year 1986
****

Day	Load MWh	Tot.cost Mio FB	MCpr.rev Mio FB	Nucl.pal %	Pumping activities (deliveries in MWh) buffer	ec.marge	econ.use	transfer	total use
1	156843.	146.084	165.542	100.000	5.	4795.	64.	0.	68.
2	146415.	141.209	153.976	100.000	334.	4466.	0.	0.	0.
3	186533.	186.677	306.633	100.000	0.	3429.	3429.	1371.	4800.
4	137152.	122.288	140.991	100.000	1025.	3775.	780.	0.	1805.
5	124117.	115.483	139.297	96.615	4509.	291.	498.	0.	498.
6	174982.	178.268	248.044	100.000	9.	3931.	3931.	860.	4800.
7	129749.	125.280	136.449	100.000	0.	4800.	0.	0.	0.
8	118144.	118.937	123.780	100.000	47.	4753.	0.	0.	0.
9	155677.	158.129	232.813	100.000	0.	3537.	3537.	1263.	4800.
10	118881.	109.310	121.252	100.000	614.	4186.	459.	0.	1073.
11	106241.	104.108	125.114	92.606	2005.	2795.	586.	0.	586.
12	145139.	140.747	194.347	100.000	45.	3738.	859.	1017.	1920.
13	107847.	98.768	111.019	100.000	296.	4504.	180.	0.	476.
14	96737.	96.085	100.739	94.521	1143.	3657.	0.	0.	0.
15	123578.	117.230	131.836	100.000	10.	3613.	186.	1177.	1373.
16	133753.	121.919	137.305	100.000	674.	4126.	145.	0.	819.
17	118936.	111.502	142.373	96.671	3529.	1271.	1061.	0.	1061.
18	157712.	151.271	208.345	100.000	182.	3549.	2860.	1068.	4111.
19	146877.	134.284	151.243	100.000	271.	4529.	297.	0.	568.
20	134732.	124.273	171.437	99.715	2717.	2083.	2231.	0.	2231.
21	179394.	177.902	287.152	100.000	4.	4153.	4153.	642.	4800.

hours of the day. In the example of table 4.6 this occurs only at Sundays.

The last five columns of table 4.6 give an overview of the pumped storage activities. All magnitudes are given as net deliverable energy to the customer. Under the heading "buffer" we show the energy that is stored in the reservoirs because of buffer pumping in order to avoid/minimize shut-down/modulation of base-load plants. The next column contains a constraint variable, i.e. the amount of storage space available for economical transfer of thermal power from low-load to high-load hours of the day. Next is indicated the amount of the available space effectively used. In the following column, the energy disposable in the reservoirs transferred from previous days is mentioned. Finally, the last column shows the total use of pumped storage made during the day. As obvious from the numbers, total use is limited to reservoir capacity of 4800 MWh.

The information supplied by the program is round-up by two tables summarizing yearly statistics. One table deals with physical (energy) flows, the other contains monetary magnitudes (see tables 4.7 and 4.8). In table 4.7, the calender year and the yearly power demand (GWh) is printed first. The next eight columns contain the percentages of total demand generated by the various types of fuel used.

Table 4.7

LOAD DEMAND + POWER GENERATED
****

YEAR	LOAD GWh	%NUCL.	%COAL	%N.GAS	%H.OIL	%L.OIL	%R.GAS	%LO	%HYDRO	PUMPS GWh	CHP GWh	GROSS LOSS MWh	NETT LOSS MWh
		% computed on generation incl. pump consump.											
1986	52237.	68.545	26.260	.441	1.193	0.000	3.594	0.000	.671	910.	0.	0.	0.
1987	53543.	71.034	24.374	.336	.989	0.000	3.333	0.000	.654	955.	0.	0.	0.
1988	54881.	71.245	24.102	.418	1.039	0.000	3.320	0.000	.638	1038.	0.	0.	0.
1989	56253.	64.492	30.139	.519	1.832	0.000	3.165	0.000	.623	1073.	0.	0.	0.
1990	57660.	65.367	28.316	.674	2.715	0.000	3.187	0.000	.608	1237.	0.	0.	0.
1991	59101.	67.800	26.088	.580	2.576	0.000	3.083	0.000	.593	1055.	0.	0.	0.
1992	60579.	65.153	28.416	.571	3.101	0.000	2.939	0.000	.578	1138.	0.	0.	0.
1993	62093.	62.825	29.480	.841	4.268	0.000	2.781	0.000	.564	1168.	0.	0.	0.
1994	63645.	66.955	25.062	.903	4.596	0.000	2.603	0.000	.551	1056.	0.	0.	0.
1995	65237.	67.476	23.642	1.304	5.618	.023	2.112	0.000	.537	1155.	0.	0.	0.

Due to losses in pumped storage activities, more electricity has to be produced than the amount delivered to the network. The percentages shown in table 4.7 contain those losses. Therefore they add to a little bit more then 100 %, the difference to 100 % representing the amount of GWh lost in pumped storage. If we consider e.g. the first line in table 4.7 we see:

fuel type	gross generation as a % of load
nuclear	68.545
coal	26.260
nat.gas	0.441
heavy oil	1.193
light oil	0.
recovery gas	3.594
loss-of-load	0.
hydro	0.671
Sum	100.704

With a load of 52 237 GWh, this means 52 237. * 1.00704 = 52 605 GWh was generated, implying losses of 368. GWh. Net power delivered by the pumped storage plants amounts to 910 GWh (see next column in table 4.7). With a constant, overall efficiency of 0.7125 for the pumping/storing/generating cycle we can verify the losses to be $910(\frac{1}{0.7125} - 1) = 367.$ GWh. Small differences between the two loss-numbers are due to rounding off errors.

The additional information in table 4.7 gives the amount of power provided by cogeneration plants operated by the electric utilities. This energy is already included in the frequency-distribution of the power generated over the various fuel types and is repeated here. Next the expected loss-of-load is shown: gross loss means that we have included loss-of-load due to interruptible customers, and nett loss excludes the interruptible loads. Only the latter magnitude has to be considered as real black-out energy.

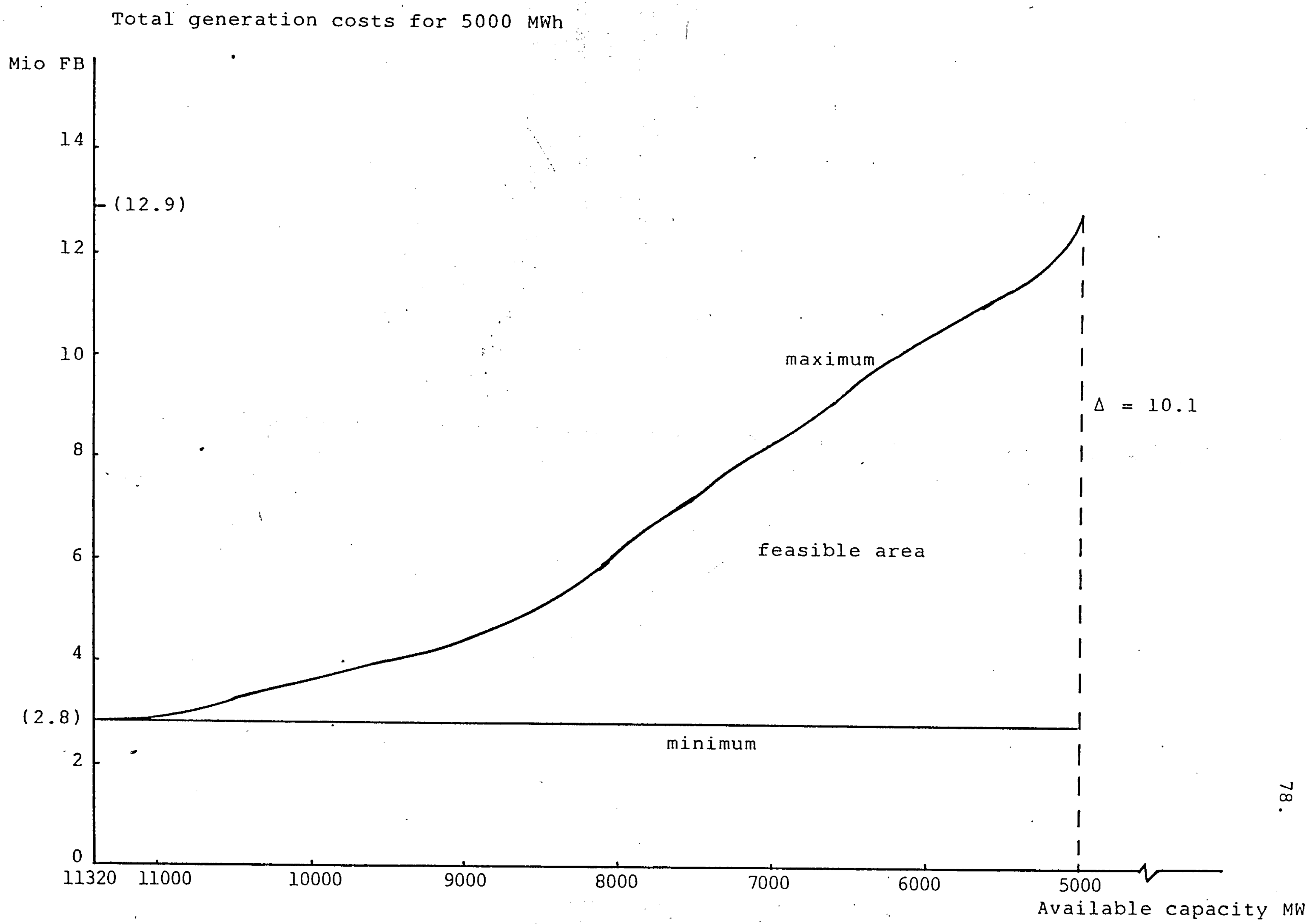
Table 4.8. Cost analysis

Year	Tot.Cost Mio.fr.	MC-pr.rev Mio.fr.	Sav.pumps Mio.fr.	AV.M.Cost FB/kWyear
1986	50587.	67744.	908.	10925.
1987	50630.	66249.	955.	10464.
1988	52095.	71512.	1339.	11010.
1989	55223.	77479.	963.	11524.
1990	57085.	85023.	1264.	12283.
1991	57632.	83739.	1272.	11881.
1992	59823.	87862.	1037.	12117.
1993	62586.	97173.	1020.	13032.
1994	63014.	98067.	1062.	12823.
1995	64732.	113842.	1516.	14267

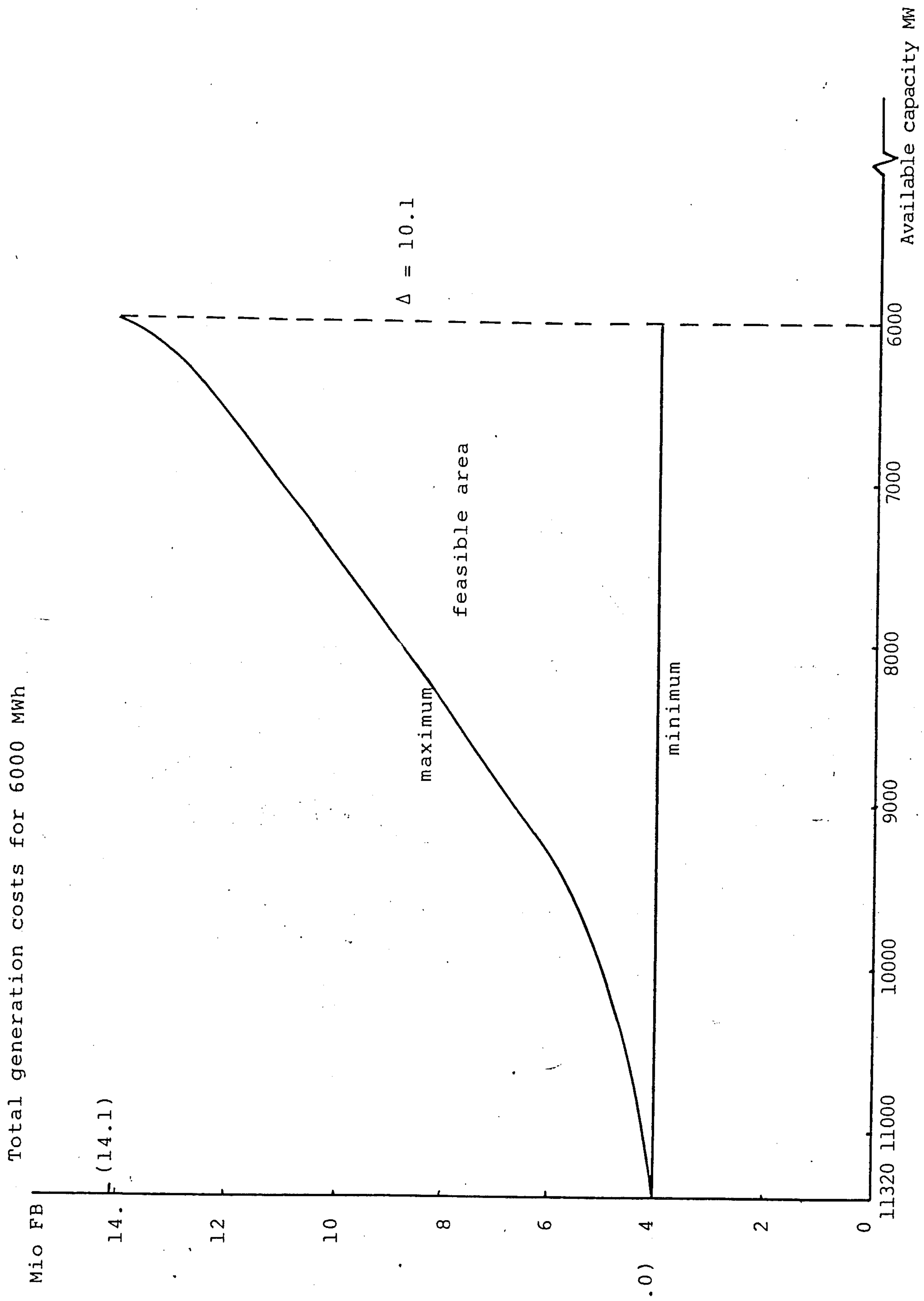
Finally, in table 4.8, some economic numbers are summarized. "Tot.Cost" gives the total variable costs of running the production system to meet the load of the year. In this cost figure is included: fuel, personnel and maintenance. The next column shows the revenues raised by the utilities if a pricing schedule based on hourly short-run marginal costs were applied. As mentioned above, the gap between both preceding figures is an estimation of the money that economically should be allocated to capital investment. In the following column the monetary savings due to pumped storage activities are shown. In the last column we print the expected variable cost of generating a marginal kW more during all 8760 hours of the year. Therefore the dimension of the number FB/kW-year. When this cost is high, new investment is urgent.

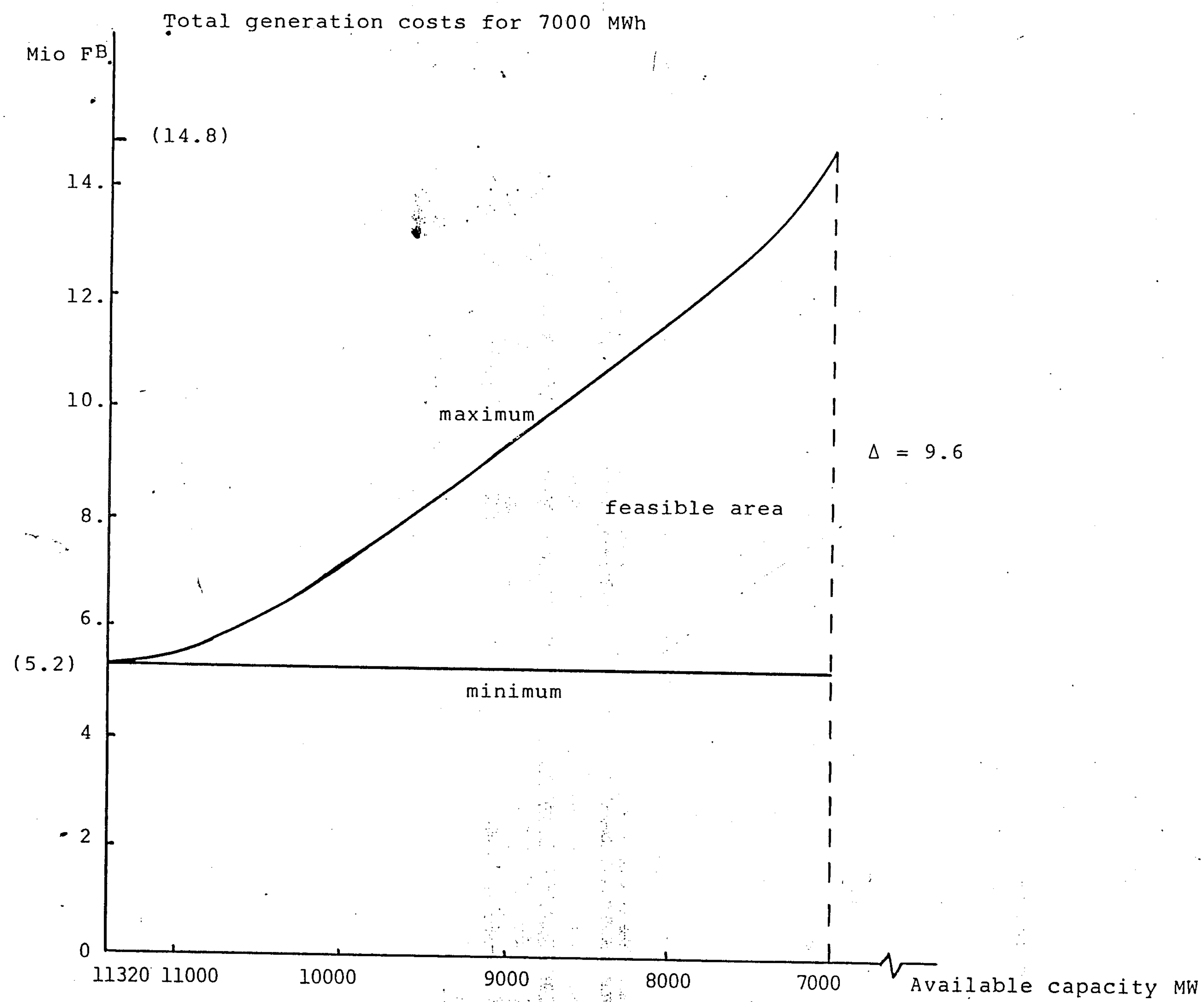
It is obvious, many more intermediate results can be shown. E.g. we included a print option variable to ask for "trace information", providing the program user with detail data on the steps taken by the program. Also, depending on the use of the program, suitable result reporting routines can be added at low cost.

APPENDIX. FEASIBLE COST SETS FOR GENERATING VARIOUS LOADS CONDITIONAL ON THE AVAILABLE CAPACITY

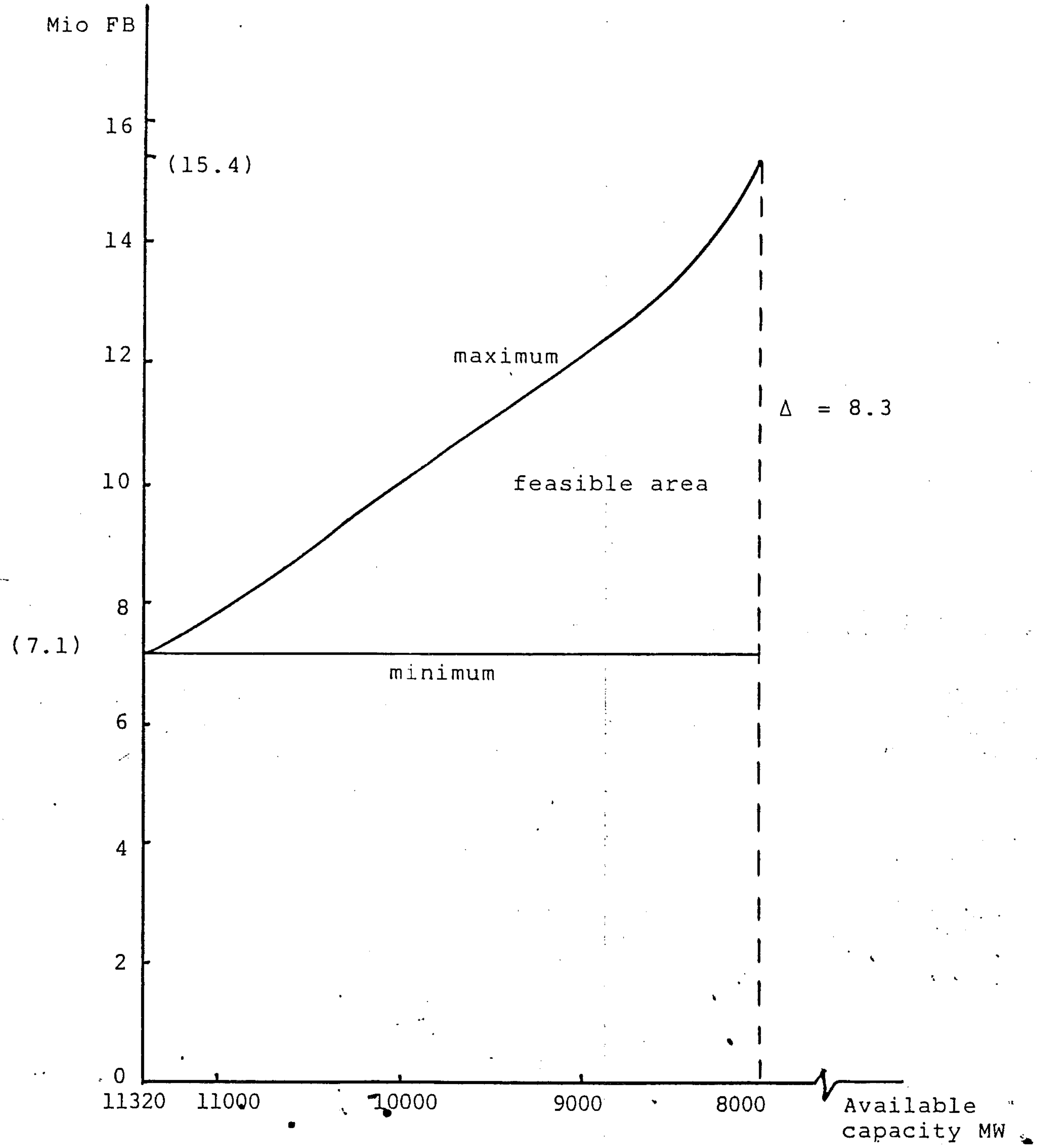


Total generation costs for 5000 MWh
Mio FB
14
(12.9)
12
10
8
6
4
(2.8)
2
0
11320
11000
10000
9000
8000
7000
6000
5000
Available capacity MW
maximum
feasible area
minimum
Δ = 10.1

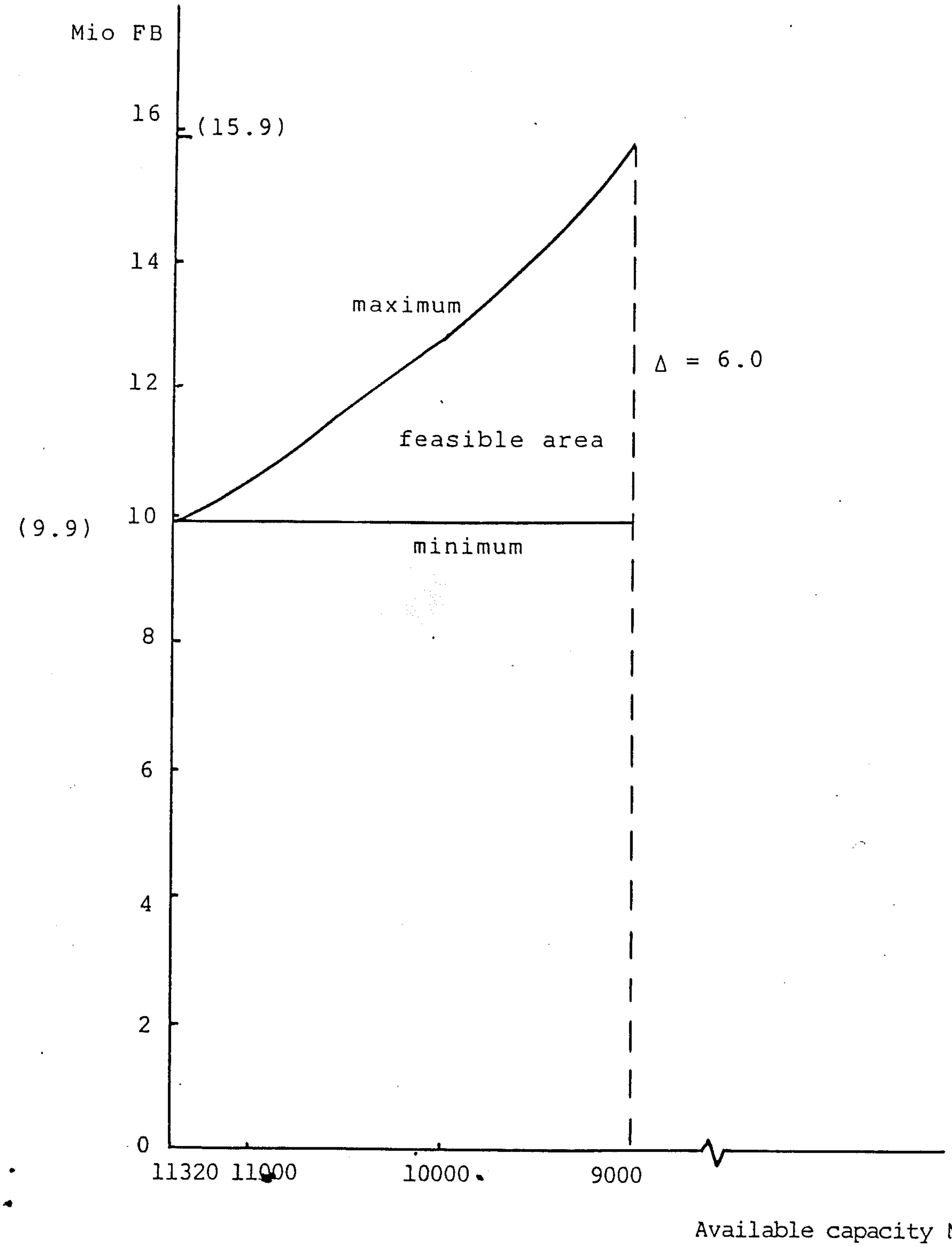

Total generation costs for 6000 MWh
Mio FB
14.
12
10
8
6
4
2
0
(14.1)
(4.0)
11320
11000
10000
9000
8000
7000
6000
Available capacity MW
Δ = 10.1
feasible area
maximum
minimum

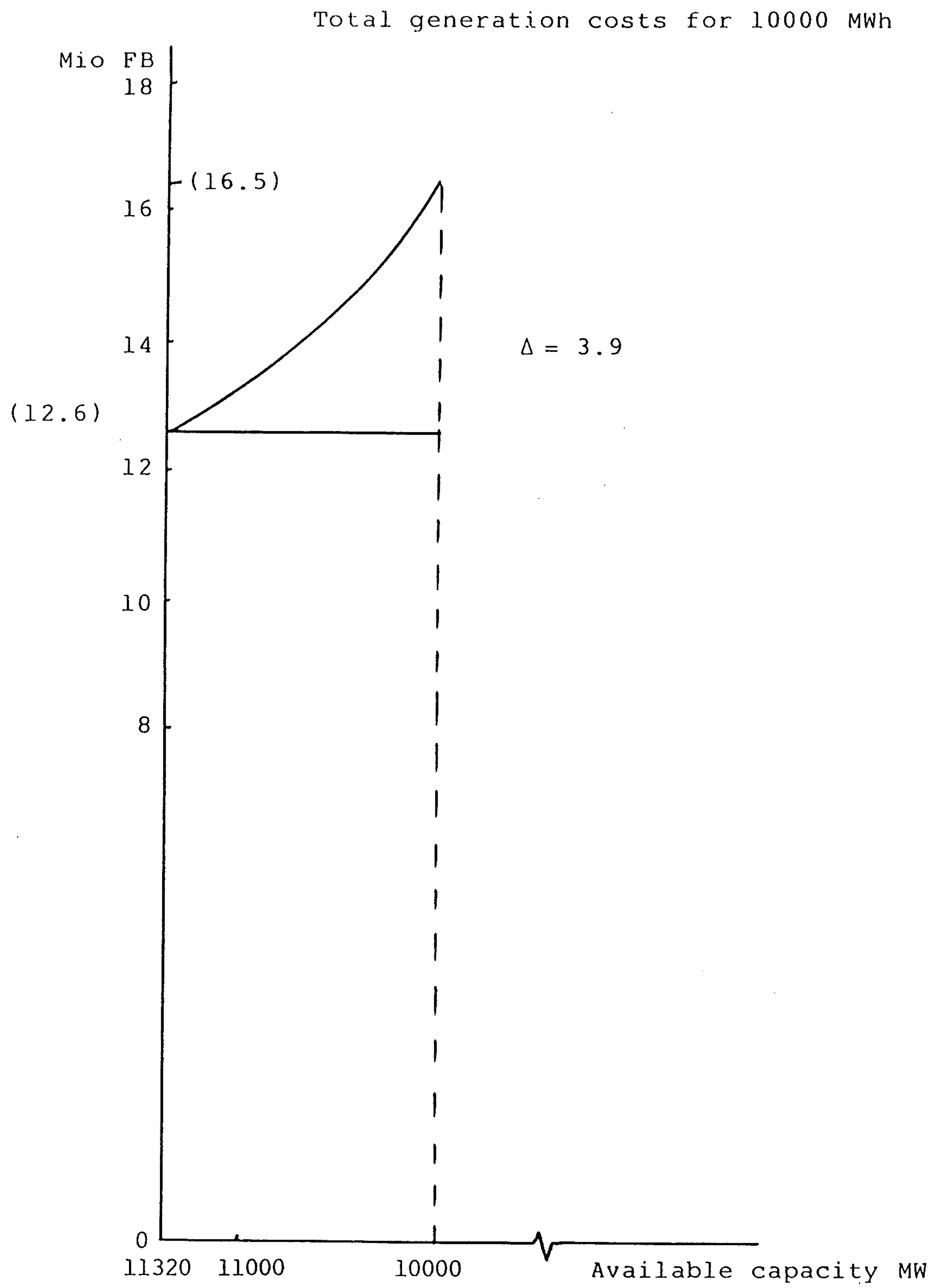

Total generation costs for 7000 MWh
Mio FB
(14.8)
14.
12.
10.
8.
6.
(5.2)
4
2
0
maximum
feasible area
minimum
Δ = 9.6
11320 11000
10000
9000
8000
7000
Available capacity MW

Total generation costs for 8000 MWh



Total generation costs for 9000 MWh




Total generation costs for 10000 MWh
Mio FB
18
(16.5)
16
14
Δ = 3.9
(12.6)
12
10
8
0
11320
11000
10000
Available capacity MW

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