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METHODOLOGIES IN POWER SYSTEMS OPERATIONS PLANNING

Working Group 03 (Operational Planning Functions)
of
Study Committee 39 (Power System Operation and Control)

1989

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Report by CIGRE SC39-03 Operational planning functions.
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Abstract

This report is the result of an enquiry conducted with some 30 utilities from all over the world, within the activities of the working group "Operational Planning Functions" of Study Committee 39 (Power systems operation and control) of CIGRE.
The aim of the paper is to illustrate the methodologies adopted by power industry to set-up generation strategies or schedules, taking due account of the requirements for economy and security of operation.
The variety of methods used depends on the mix of the generating systems (hydro and thermal), on the importance of the energy exchanges with interconnected utilities, and on the presence of opportunity or "secondary" loads or markets.
An important aspect in the algorithmic approach is the choice of simplifications to adopt, in order to reduce memory and computer time requirements, or in order to render the problem solvable at all.
This paper will deal only with some methods which are more widely used by the respondent utilities, and which have been proved effective over time.
The span of time considered is from 1 to 10 days ahead for short term scheduling and from 1 month to 5 years ahead for medium-long term operations planning.
Particular attention is devoted to the ways adopted to account for randomness, also with reference to the particular time span considered and mix of generating systems.

1.- Introduction

1.1- To manage the operation of their power systems most utilities prepare long and short term plans with iteration between the two, to meet forecast demands according to required economic and security criteria. The long term plans may include many planning activities such as outages of generation and transmission, fuel procurement, coast down of nuclear plants, operation of hydro valleys and pump storage, trading arrangements together with the management of plant capacity and various budgetary provisionings.
To assess the utilisation of the power plants some form of long term scheduling is usually carried out taking account of these plans to determine system operating and marginal costs, water values and merit orders for various system operating strategies. These in turn are used to tune long term plans and provide the basis for short term programming plans.

1.2- As the short term approaches it is necessary to provide system control, power stations and transmission staff with guidance of system requirements to meet expected demands and to implement the long term plans and associated amendments. The problem facing the utilities is how best to manage this and the general approach adopted is to partition the planning timescale, distinct short term scheduling plans being prepared for one day, one week or one month ahead with longer term plans covering the year ahead and beyond. The iteration between the two sets of plans may take place by reviewing the long term plans in the light of actual operating experience as the need arises or at predetermined time intervals.

1.3- There are many methods for preparing short term generation schedules. These range from scheduling plants based on a simple merit order ranking to meet selected demand peaks and troughs or demand duration curves, to sophisticated computing techniques predicting the generation requirements for each hour of the scheduling period based on both forecasted data and actual operating history.

1.4- Some of the features which may need to be considered when developing a new schedule procedure include consideration of:
- the main characteristics of the power system: thermal, hydro or a mixed system; the system control organizational aspects; data input and output for national and a number of regional control centres;
- the problems unique to the system: system size, demand shape, number of power stations and generators, availability of fuel and its transport, hydro inflows, storage ponds and reservoirs, trading arrangements, transmission constraints and cycling of nuclear plants;
- the lenght of the scheduling period and elementary time step; generating plant characteristics, ramp up and down times, start up costs, the need for incremental and decremental cost information; output summaries, the practicality of the results, wether the program will be used to update schedules on the day in control room, management and update of data input;
- the need to cover random events, modelling operating reserves, using a deterministic or stochastic technique, and the skill of personnel to use the program.

Some of the above issues are reviewed further in the attached appendixes.

2.- Short term scheduling

The short term scheduling period is supposed to be one week; often the schedules, which are determined e.g. on friday, cover up to 10 days ahead, to better account for flexibility of thermal units and for particular scheduling needs of week-ends (including occasional maintenance works).
In some cases the short term schedules are updated during the week, both at the day

ahead stage, and a number of times on the day in control room /1/. Hence it is important to have a carefully thought out procedure which may readily be re-run by control room staff at predetermined intervals or when required.
Due to the restricted span of time considered, and to its vicinity, the forecasted values (load, water inflows, generating units availability) are considered deterministic; some allowance for randomness is accounted for by considering the spinning reserve (normally equal to the biggest generating unit in operation).

2.1- Thermal power systems

It may be noted (app. A, sec A.5.1) that the input to short term scheduling is in this case comprised of weekly totals of thermal generation, opportunity import and export, and secondary load; those totals are in some cases previously partitioned in daily totals (or daily totals are directly produced by medium term scheduling procedure, for the next week).
The only integral type condition present in this case is a soft constraint (see the (8) in app. A).
Hence the short term scheduling of thermal power systems turns out to be almost independent of medium-long term operations planning, at least in respect of energy allocation. The tighter connection between short and medium term is constituted by the merit order listing of generation and planned unavailability schedule of generating units (also trading agreements and forecasted changes in prices and availability of fuel are important).
Thermal plant merit orders may be derived by ranking all units in a cost order based on heat cost times heat rate. Two types of ordering are used based on:

(i) full load heat rate times heat cost, to schedule plant on or off("specific cost");
(ii) incremental heat rate times heat cost, to allocate load to plants already operating in the system ("incremental cost").

The merit order cost for scheduling plant to be synchronized to the system may be adjusted to reflect the start up cost of the marginal units being shared over the amount of energy produced by each unit for a given period of time. In a similar way the merit order cost of plants to be shut down over night may be discounted by the cost of starting up again. To ensure that the cost of starting the unit up again in the morning does not exceed the benefit of shutting down overnight, the merit order cost in (i) may be adjusted to reflect the cost of starting up again; e.g. for a 500 MW generating unit costing some £ 5000 to start up after a 5 hours shutdown, a discounting may be calculated as

$5000/(5x500) = 2.0$ £/MWh,

and this is deducted from type (i) costs.
This concept may be extended to reflect other penalty costs associated with plant flexibility parameters which do not meet ideal system requirements, e.g. for peaking plant with long minimum run times of up to some 8 hrs compared with 2 hrs ideal on-times. Penalties for the out of merit period when the plant is not required (i.e. 8 - 2 = 6 hrs) can be assessed and plant costs adjusted as required.
The heat costs are usually derived at the long term scheduling stage taking account of planned generator overhaul programmes, fuel supply agreements and trading arrangements to meet expected demand. A number of methods may be used for assessing heat costs for merit orders. These include using the average cost of all fuels assigned to each station, or the marginal fuel that would be assigned to each station to meet increase in system load forecast. Hence an important link with long term plans is established. In the short term it is necessary to carefully consider the use of any significant amount of cheap spot fuel purchase. This is because penalties may be incurred on longer term fuel contracts, if these are broken or renegotiated.
As far as nuclear generation is concerned, it may be noted as an example that a nuclear PWR (pressurized water reactor) unit is a stock of limited energy. Indeed, unlike fossil fuel powered units, each reactor must be shut down during approximately two months for refueling, between given limits of burn up of nuclear fuel.
As a consequence, from the point of view of operational planning, a PWR unit is similar to a large hydro reservoir without inflows: future values of the energy stored are computed for each unit on a medium term basis. They are then used as a merit order in the short term scheduling to help decide nuclear power modulation.

2.1.1 Unit commitment

The part of the load diagram to be covered by thermal generation is supposed to be known (average MW in each elementary time interval or step, ETI).
For more clarity it is appropriate to distinguish, within the unit commitment algorithm, two different aspects which are, for each ETI :

- the choice of units to be synchronised;
- the share of MW between the running units.

The first aspect involves only the units which may or may not be started up or shut down, and hence does not involve the "shall run" units (see appendix E for the definition of shall run units); the second one involves all the running units (including "shall run").
The most important characteristics to take into account for each unit (excluding "shall run" units) are:
- minimum on and off times;
- start up costs (function of down time duration);

and for all units (including "shall run"):
- ramp duration times;
- input/output curves (MJ/h versus output MW);

- available capacity (MW), min and max.

It is worth noting that normally the number of "shall run" units is high: in addition to the units which must run due to other than economic reasons (if any), the most economic units are likely to be kept on line all through the week (including nights and week end).
This is especially true if the age of the thermal units is staged in a more or less uniform way, as it is natural in almost all power systems (newer units tend to be more economic).
For example, it may well be that out of 100 available thermal units, 70 may be considered as running anyhow ("shall run"). Hence the unit commitment problem involves only a part of the available units.
This is of particular importance, because the unit commitment problem is one which is typically conditioned by dimensionality.
Power flow constraints on transmission system may be represented by dividing the system into zones, the inter-zonal power flows being limited in predetermined levels consistent with operational security standards.
An "exact" algorithm would require a combinatorial approach, which is normally impracticable; approximate methods are normally used instead.
Fig 1 shows an algorithm for unit commitment which uses forward dynamic programming; for simplicity partitioning of transmission network is not considered.

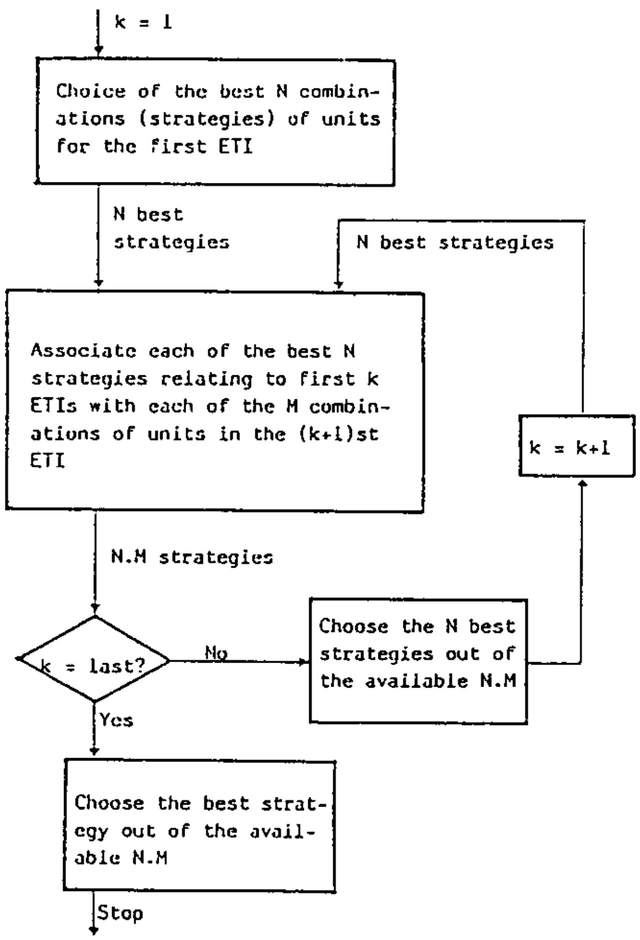

Figure 1 - A unit commitment procedure, based on forward dynamic programming.

The total number of thermal units is n_t; the number of "shall run" is $n_t - m_t$; the "free" units are m_t.
Suppose that for the first k ETI (elementary time intervals) of the period under consideration (e.g. one week) the N lowest cost strategies have been determined. Strategy means here the set of output values (MW) of the thermal units, in each one of the first k ETIs. Some output may of course be zero (unit not committed); the generic strategy is identified by $k*n_t$ output values.
To find out N lowest cost strategies with k = 1 (that is in the first ETI) is a trivial task.
The problem is now to determine a set of N lowest cost strategies for the first k + 1 ETIs.
This will be done by the following steps:

a) consider one generic strategy out of the N determined for the first k ETIs;
b) select for the (k+1)st ETI a number of combinations of the m_t free units, complying with the constraints (besides other, that of covering at least the load plus the requested spinning reserve). Let M be the number of permissible (and selected) combinations;
c) for each one of the M strategies of the (k+1)st ETI determine the optimum sharing of MW between the $n_t - m_t$ "shall run" plus the chosen units (e.g. with the criterion of equal incremental costs, with transmission losses accounted for by means, for example, of B coefficients). Determine also the corresponding cost (this will include the start up cost of those units, if any, which are at standstill in the k-th ETI, and running in the (k+1)st);
d) sum up this cost to the cost of the generic strategy referring to the first k ETIs, selected in step a). M strategies, and corresponding M costs, are so determined for the first k + 1 ETIs;
e) then repeat the steps a), b), c), d) for all the other strategies referring to the first k ETIs; at the end N*M strategies, with corresponding costs, are available for the period composed by the first k + 1 ETIs;
f) choose, out of the above N*M strategies, the N with lowest cost ones. Then go to a), considering next k.

When considering the last ETI only one strategy (that of minimum cost) will be retained, and this will be the schedule of thermal units.
Note that when selecting units for the (k+1)st ETI (step b), one of the constraints to consider is that of ramp duration. If the unit was out of service in the k-th ETI, it may happen that it will be limited, when sharing power between the units (step c), to a certain maximum output in the (k+1)st ETI. This is due to its limited ramping speed. Again, a given unit shall not be selected in the (k+1)st ETI if it was out of service at the k-th, and its minimum down time has not yet elapsed; etcetera.
It is easily understood that the procedure described is good enough, provided that N (the number of strategies retained each

time) is large enough. "Large enough" is a matter of experience with the various mix of thermal units set. For example if there are units with long ramp duration and high start up cost (but with low specific cost in normal operation), with a too low value of N they may be not included in the final schedule, even if their operation would have been economically convenient.
As far as opportunity purchases are concerned, these may be represented, ETI by ETI, as an equivalent thermal unit (or more units, one for each block of specific cost of purchase contracts) with zero start up cost, zero ramp duration, zero minimum up and down times, and appropriate input-output curves and minimum and maximum available capacity (see fig 2c and 2d; fig 2a and 2b correspond to the case of an ordinary unit).

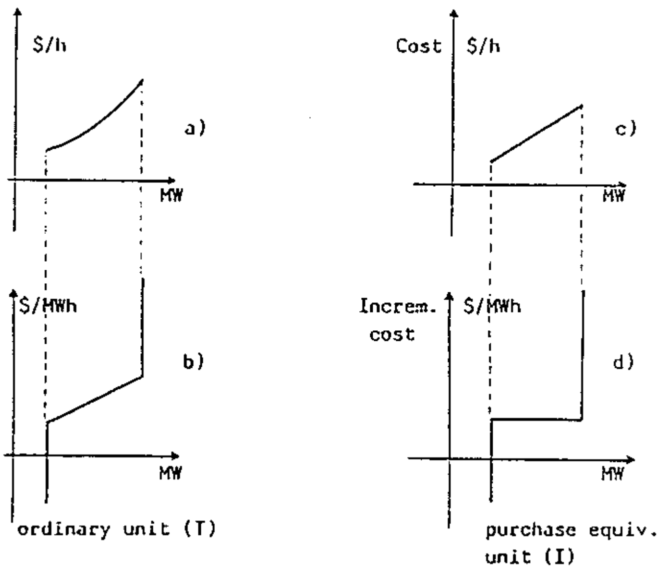

Figure 2 - Cost curves and incremental cost curves of a thermal generating unit (a and b) and of a particular purchase contract (c and d).

As far as opportunity sales and secondary load are concerned, appendix C shows how to represent them and how to consider them in conjunction with ordinary and purchase-equivalent generating units.

2.1.2 System incremental cost grid

Fig 3 represent the forecasted load curve (net from must run generation and must buy/must sell). Fig 3 represent also some other curves (dashed lines) obtained by shifting the load curve up and down.
The unit commitment procedure illustrated in sec 2.1.1 may be performed for each one of the curves shown in fig 3. This enables an incremental cost to be assigned for each ETI and for each load level, as identified by the various load curves. Incremental costs are calculated by the unit commitment procedure for each load level (including opportunity exchanges and secondary load)(fig 4).
If there is not enough power to cover the particular curve considered (as may happen for the curve lying over the load curve), an arbitrary, sufficiently high incremental cost will be set.

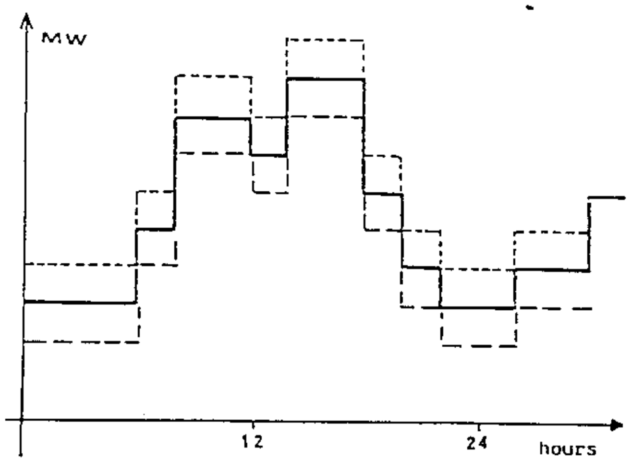

Figure 3 - Load curve (solid line) and shifted load curves.

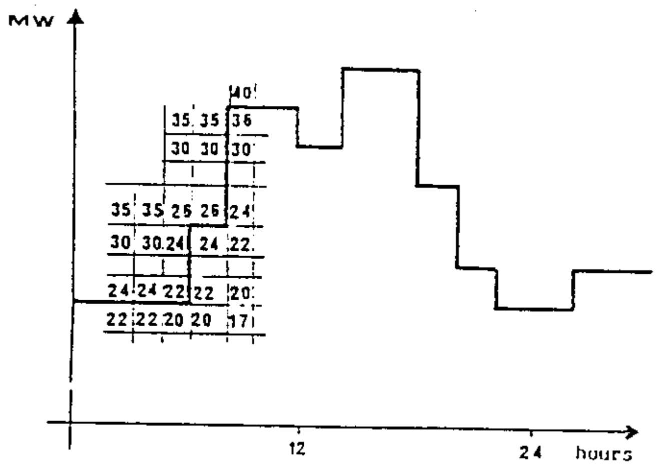

Figure 4 - Incremental cost grid. Solid line is the forecasted load curve. The figures shown represent the incremental costs.

The number of curves of fig 3 shall of course be limited to a minimum, due to the fact that the computation of incremental costs with the procedure 2.1.1 may be time consuming; in some cases it will be possible to consider right the only one corresponding to the forecasted load curve. Nevertheless, it must be stressed that the incremental costs computed in correspondence of one given curve are valid for little variations (up and down, around the curve itself), that is for variations not entailing an economic commitment or decommitment of thermal units.

2.1.3 Determination of hydro pond generation

According to definitions in appendix A, sec A.5.1, there may be some hydro generation from ponds (run of the river plants are similar to "must run" units).
Once a forecast for water inflow is available, the total output (GWh) for the period considered (one week) is known (see the remarks made about this point in app, A, sec A.5.1).

Hydro generation will then be distributed along the week (ETI by ETI) with the criterion of covering the highest incremental cost zones of the system incremental cost grid under the load diagram.
This must be done by complying with the following constraints:

- the total (weekly GWh) ouput must be equal to the forecasted one, corresponding to the forecasted inflow;
- in each ETI the hydro output (MW) will be limited by lower (zero) and upper (maximum available capacity) bounds;
- the storage will be limited, at the end of each ETI, by lower (zero) and upper (maximum storage) bounds.

It may be worth noting that this methodology of allocation ("incremental costs shaving", fig 5 a), which is the optimum, normally gives results not too different from those which could be obtained with the criterion of "peak shaving" (fig 5 b), which is a near optimum solution (it may be demonstrated that it is optimum if there are no start up or shut down of thermal units during the involved period). In both criteria the efficiency of hydro power stations is considered independent from their MW output.

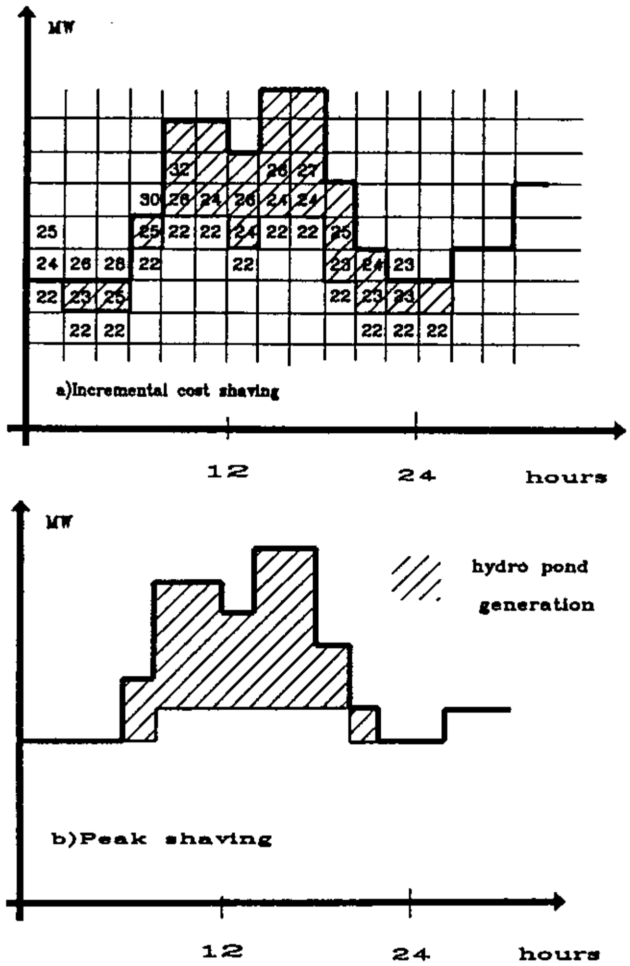

Figure 5 - Allocation of hydro generation on an incremental cost shaving criterion (a), and peak shaving criterion (b). The two shaded areas (from 0 to 24 hours) are equal.

2.1.4 <u>Determination of generation-pumping diagrams of pumped storage power stations</u>

The following discussion is limited to the case of pumped storage plants having no natural inflows. In the case that there are natural inflows a kind of superposition may be considered, splitting the plant into two fictitious power stations (with some care).
A pumped storage plant may be dealt with as a normal hydro pond plant, having a negative lower MW bound; hence the procedure illustrated in sec 2.1.3 applies.

The only additional concern is that the energy balance doesn't check to zero, due to overall efficiency η (generation times pumping) being less than unity (normal values: 0.65 to 0.75), if water balance must check (and it must check).
The difficulty can be overcome in the following way: first determine the generation diagram of the normal hydro plants, with the procedure illustrated in sec 2.1.3. Then, on the residual load curve (that is the load curve minus the generation diagram of normal hydro plants) determine a first tentative generation-pumping diagram of the pumped storage plant again with the same procedure, in which the total (weekly) GWh output is set to zero.
This first tentative diagram would give rise to a negative variation in storage for pumped storage plant. As a matter of fact, P_j (MWh) being the output, positive (generation) or negative (pumping), during the j-th ETI, the sum of all the P_j will be zero and the sum of the positive P_j, V, will equal the sum of the negative P_j, changed in sign; the variation in storage is then easily seen to be equal to (MWh) $\eta V - V$, and this is a negative quantity.
The first addendum corresponds to the water raised to the upper level, the second to the water turbined (which, to comply with zero total MWh ouput, is an amount bigger than that raised).
Then the determination of the generation pumping diagram will be repeated setting the total output at the negative value $(\eta - 1)V$.
This procedure will be repeated until zero storage variation is reached (normally it requires 2 to 3 iterations).
Note that, to take due account of the loss of energy $(\eta -1)V$, when determining the generation-pumping diagram with the incremental cost shaving criterion the incremental cost read on the grid must be increased by dividing it by η, whenever P_j is negative.
Fig 6 a represent the original incremental cost grid, the load curve (net from hydro pond generation) and a possible (dashed line) generation-pumping diagram; fig 6 b shows the modified incremental costs (assuming η = 0.7), and the resulting generation-pumping diagram.
Note that the procedure described here considers only the "short term energy transfer" duty of pumped storage plants.

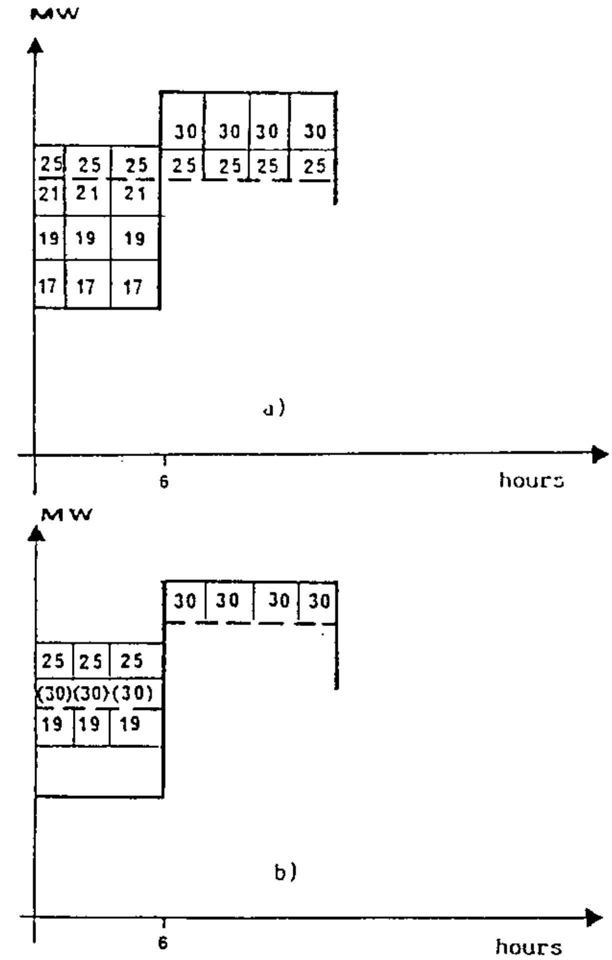

Figure 6 - Allocation of pumping-generation with the incremental cost shaving criterion. In case (a) the pumping-generation cycle efficiency is assumed equal to 1; in case (b) equal to 0.7.

2.1.5 Determination of thermal generation diagrams

If medium-long term operational planning exists, the resulting values of T, I, E and L must be complied with (these are respectively the free thermal generation, the secondary import and export and the secondary load, see app. A).
The full procedure to follow in the more general case is shown in fig 7.
Note that the determination of hydro pond generation schedule and generation-pumping schedule is iterative, as well as the determination of system incremental costs grid, because they are interdependent. The cost grid depends on the diagram to be covered by generation of thermal units (plus the other thermal-equivalent items), and this diagram is the difference between the load (network demand) diagram, which is known, and the hydro pond generation plus generation-pumping diagram of pumped storage plants.
So, at least two iterations are necessary.
The "first tentative" incremental cost grid (which is produced just at the beginning of the scheme of fig 7) is determined with reference to the load curve, as shown in fig 3 and 4, since the hydro generation diagram is not yet known at this point; the "second tentative", on the contrary, is determined, as it must be, with reference to the load curve minus hydro pond and generation-pumping diagrams, that is the "residual curve n°2" of fig 7, which is the right diagram to be covered by thermal units.

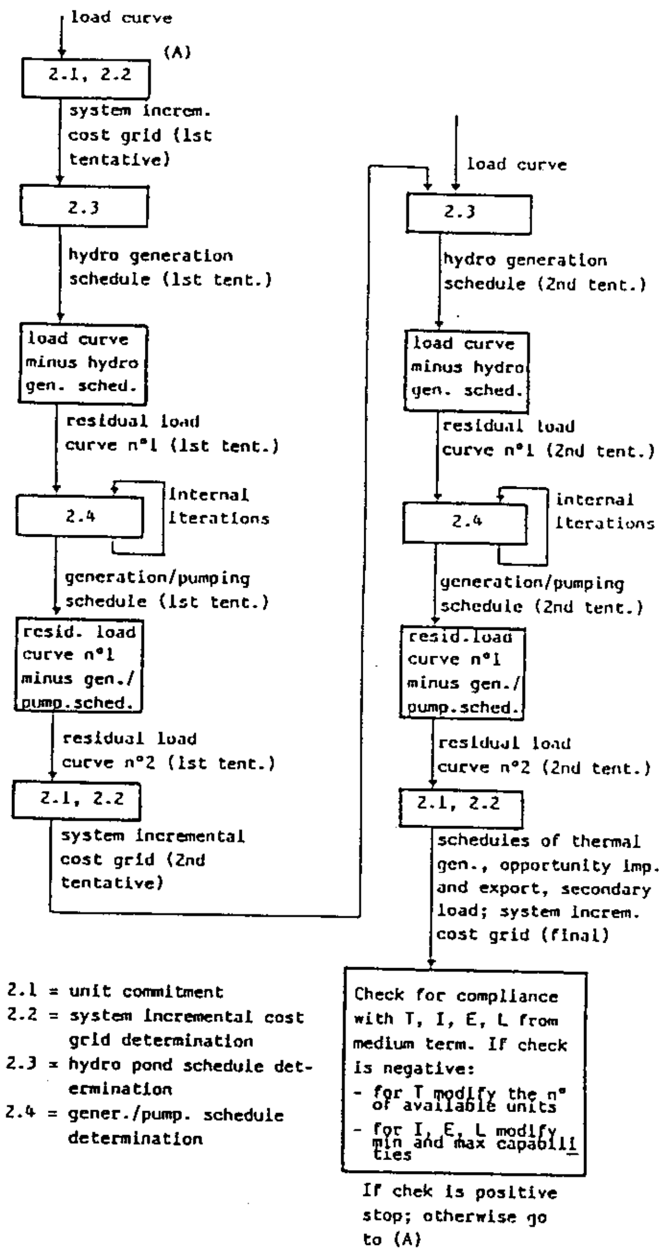

Figure 7 - Overall short term scheduling procedure.

This last diagram may look like that of fig 8.
As an interesting point it may be noted that in the second iteration the pumped storage plants could displace a previously selected (committed) thermal unit.
Often the procedure will not be so complex as it appears in fig 7, due to the absence of some items such as pond hydro, or secondary load etc.
For example the scheme of fig 9 corresponds to the case with no constraints from medium term scheduling and no hydro pond

generation nor pumped storage; fig 10 to no hydro pond nor pumped storage.

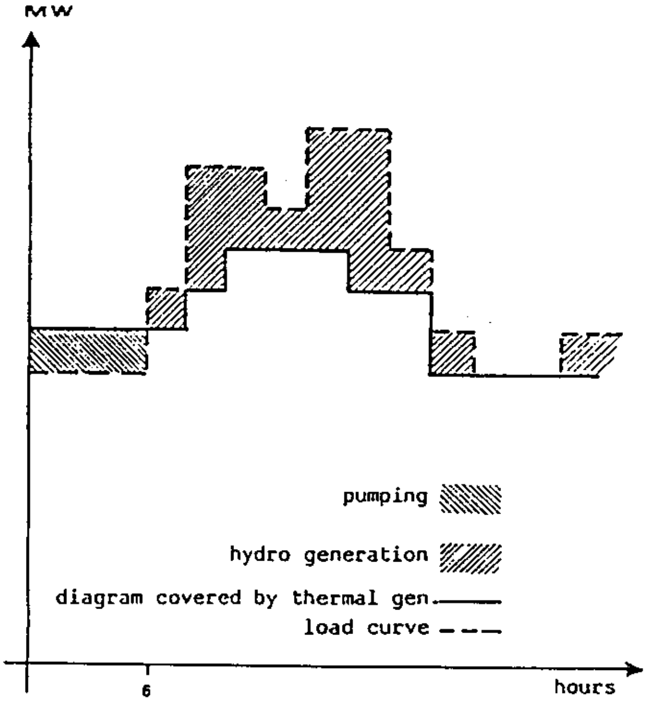

Figure 8 - Coverage of a load curve by hydro plants.

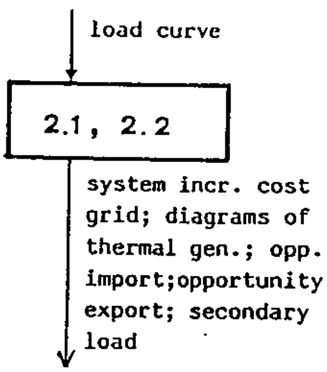

Figure 9 - Short term scheduling procedure in case of neither medium term scheduling constraints, nor hydro generation (compare with fig 7).

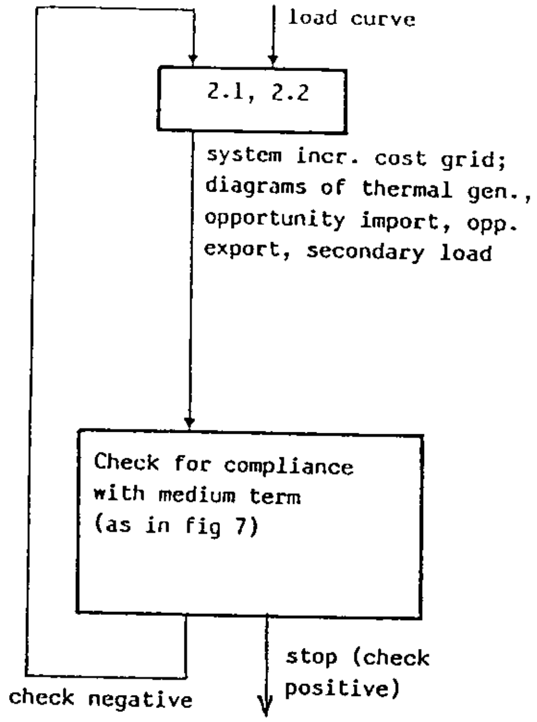

Figure 10 - Short term scheduling procedure in case of no hydro generation (compare with fig 7).

2.1.6 Split saving

It often occurs, especially with thermal utilities of small to medium size, that they cluster in pools in order to take advantage of coordinated operation.
Suppose that a coordinating body performs the procedures described in sec. 2.1.1 to 2.1.5, as appropriate, applying them to the whole of the k interconnected systems.
The optimum schedule will entail operation (weekly) costs C_1, C_2, ..., C_k which must be carried by the participating utilities, and it will be $C = C_1 + C_2 + \ldots + C_k = \min$. Of course, there will be power exchanges between the various utilities, and let P_i be the export (GWh) of utility i towards the rest of the k-1 utilities (P_i may be negative, and $P_1 + P_2 + \ldots + P_k = 0$).
Suppose now that the same procedures 2.1.1 to 2.1.5 are applied separately to each one of the k utilities, these supposedly not being interconnected (or perhaps having separate, firm trading agreements, which should be known).

The optimum costs will now be C_1', C_2', ..., C_k' and $C' = C_1' + C_2' + \ldots + C_k'$ will be bigger than C.
The saving implemented with interconnected and coordinated operation is then $C' - C$.
The split of this saving between the utilities may follow a variety of criteria. In one practical case the split is as follows:

- the coordinating body receives $0.1(C'-C)$
- each utility receives $0.45(C'-C)L_i/(L_1+L_2+\ldots+L_k)$, L_i being the firm load (GWh) of utility i
- each utility receives furthermore
  $1.1*0.45*(C'-C)*P_i/(p_1+p_2+\ldots+p_k)$
if P_i is positive (exporting utility; p is the absolute value of P), or
  $0.9*0.45*(C'-C)*(-P_i)/(p_1+p_2+\ldots+p_k)$
if P_i is negative (importing utility).
All the expressions are positive, and it can easily be seen that their sum equals $C'-C$.

In this case a penalty is given to the importing utilities (to encourage the building up of new plants).
Further penalties, not illustrated here, are in some cases applied to those utilities which are not able to meet their own peak load with their own plants.
Of course, in addition to the above illustrated split saving, the power (energy) exchanges will be sold on the basis of bilateral contracts.

2.2 Hydro power systems

The existing medium term scheduling procedures may be grouped in the following categories, as far as short term hydro scheduling is concerned:
  i - of the type of sec A.5.2, with aggregated reservoir; data transmitted to the short term are H, I, L, E (GWh) for the coming week, that is hydro generation from reservoirs, secondary imports, load and secondary exports;
  ii - of the type of sec A.5.2, with aggregated reservoir; data transmitted to the short term are the water value w of the coming week, this being considered a more stable value than H, I, L and E;
  iii - as in case i, but with disaggregated reservoirs; the data transmitted to the short term are H_1, H_2, ..., H_N, I, L, E (GWh), N being the number of reservoirs;
  iv - as in case ii, but with disaggregated reservoirs: w_1, w_2, ..., w_N.

In cases i and ii a disaggregation is anyway necessary. If the hydrologies of the various watersheds are similar, a simple proportionality of the per unit storage may apply; if this is not the case, the disaggregation should anyway have taken place in a previous phase.
Hence it may be supposed that the input to short term procedure is in any case given in the form iii or iv above.
It should be noted also that in addition to hydro reservoir generation, at least one of the following items is present: opportunity import I, opportunity export E, secondary load L.
In the end of sec. 2.1.1 it was shown that import, export and secondary load may be considered as fictitious or equivalent thermal units (fig 2 and appendix C). This allows to build up, also in the case of hydro power systems, an incremental cost grid like the one commented in sec. 2.1.2 and shown in fig 4.
Nevertheless, in this case it is likely that, unlike fig 4, the zone covered by real incremental costs shall be in the bottom, due to the reduced amount of opportunity items (I, E, L) with respect to reservoir hydro. The upper part, in correspondence of the load curve, will be filled by arbitrary, sufficiently high incremental cost values (see sec. 2.1.2)(fig 11).

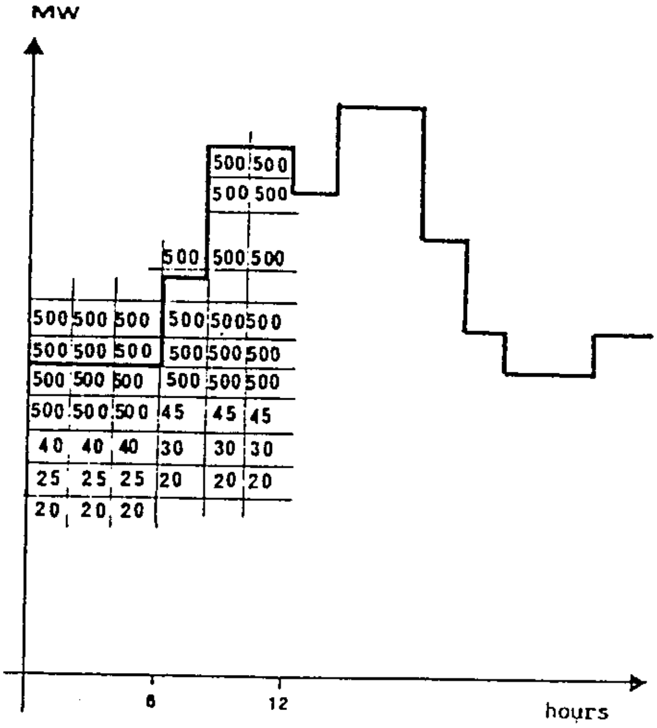

Figure 11 - Incremental cost grid in case of hydro dominant system. The upper part is filled with fictitious, arbitrarily high values.

2.2.1 Assigned reservoir generations

This corresponds to case iii above.
The scheduling of course interests also the ponds.
The allocation of reservoir and pond generation along the week (ETI by ETI) may be done with the criterion of incremental costs shaving (as in case of fig 5a) or, with some approximation, with the criterion of peak shaving (fig 5b).
In both cases various constraints must be taken into account; some of them are like those considered in sec. A.4 (max power of each power station, upper limit of storage of each pond and reservoir); other are more specific to the short term problem, due to

short duration of the ETI and to the detail (plant by plant) with which the schedules must be set up, namely: influencing and water delays between the plants.
All these constraints may be dealt with by means of particular algorithms, like network flow techniques, which shall not be discussed here, being specific to mathematical field.
Some account of the best use of water may be introduced in a simple manner, by inhibiting running at output less than predetermined values (e.g. not less than 10% for Pelton turbines, or 30% for Francis), that is at too low values of efficiency.

2.2.2 Assigned medium term water values

This corresponds to the case iv above.

The water values $w_1, w_2, \ldots, w_N$ will be considered constant all through the week.
Note that the water value is defined in medium term operation planning only for reservoirs (not for ponds).
While in case 2.2.1 the total GWh to be generated from reservoirs and ponds are both assigned, in this case only the GWh from ponds are assigned (on the basis of water inflow forecast).
The short term schedules may be defined in this case by considering the hydro reservoir power stations as equivalent thermal units (having zero start up cost etc.), with an incremental cost equal to w_i (or in some way weighted with efficiency, as in (18) of app. A); hence the two procedures 2.1.1 (unit commitment) and 2.1.2 (incremental cost grid determination) may be performed. Hydro pond generation schedule could then be determined with the incremental cost shaving criterion as illustrated above (sections 2.1.3 and 2.1.4).

2.3 Hydro thermal power systems

In practice the algorithms illustrated in sec. 2.1 and 2.2 apply to this case as well.
Referring for example to fig 7, the only modifications required are:
i - if the input to short term from medium term, as far as hydro reservoirs are concerned, is constituted by the generations $H_1, H_2, \ldots, H_N$ (see sec 2.2, iii), then the reservoir power stations may be regarded as ponds, and fig 7 fully applies;
ii - if the input to short term from medium term, as far as hydro reservoirs are concerned, is constituted by the water values $w_1, w_2, \ldots, w_N$ (see sec 2.2, iv), then the reservoir power stations may be regarded as equivalent thermal units, and fig 7 again fully applies.

2.4 A new frame of scheduling procedure

Fig 7 shows an iterative procedure in which unit commitment, hydro generation, thermal generation and opportunity trading determination, etc., are interleaved.
Some utilities are beginning to test (in some cases to utilize) a different frame, in which there are two hierarchical levels; the upper level is a "coordinator", the lower level is constituted by some "optimizers", one for each source or item of MW balance.
Fig 12 gives an idea of this new structure.
In the initial phase the coordinator gives a series (one value for each ETI) of system incremental values or costs to the optimizers.

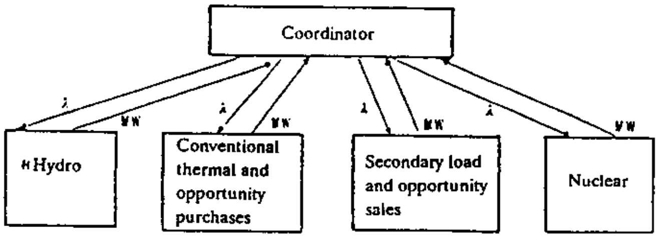

Figure 12 - A new frame of scheduling procedure.

At the first iteration each optimizer, independently of the other, determines an optimal schedule of its own item, taking into account the received incremental values and the local constraints (these are, e.g. for the hydro subsystem, the amounts of water to turbine, the links between the plants, etc.).
The coordinator compares, ETI by ETI, the MW totals, received by the optimizers, with the load; if the balance doesn't check, it modifies in appropriate manner the incremental values (raise if there is a surplus, diminish if there is a deficit), and transmit them back to the optimizers.
Then the second iteration takes place, and so forth.
The results do not differ from those obtainable with the more conventional procedure of fig 7. Which of the two methods is better suited, especially in case of big power systems, is a matter of available mathematical algorithms.
For example, the way the incremental values are modified by the coordinator is important with respect to convergence.

2.5 Conclusions

Each utility develops or adopts a short term scheduling procedure to meet its own requirements. These generally aim to select the generating plants and operation to meet expected demands and trading requirements as economically as possible according to an acceptable standard of security.

Procedures range from using simple merit order listings to sophisticated computer programs. Some simplifications in the representation of the power system (especially hydro subsystem) seem to be anyway necessary. They must be carefully chosen when building up the algorithm.
The conflicting requirements to be met are mainly:

- sufficient accuracy in the determination of optimal and secure schedules (in some cases even feasibility may be difficult to achieve, for some constraints are difficult to represent);
- robustness of the procedure: a long testing time may be required to make sure that all particular cases are taken care of (the simplifications adopted are in general the main cause of failure of convergence to optimal solution, or of yielding unfeasible solutions);
- acceptable execution times and computer memory requirements.

The procedure should also have good man-machine interfaces, to make possible easy modification of input data (e.g. changes in load, water inflows, spot market opportunity), intermediate results control and saving, etc; this is of particular importance in the cases in which the scheduling procedures have to be managed also by the control room staff.

Improvements are needed, in particular in the field of load forecast and plant availability forecast.
Interfaces with longer term scheduling and on line operation should be provided.
Skill of scheduler staff is still of a great importance, even when sound and experienced procedures are available.
Especially in case of complex power systems an easy update and amendment of databases is mandatory; this requires a careful structuring of the various software blocks which constitute the whole procedure.
Some allowance should also be provided for substitution of individual software blocks, when more efficient mathematical solution methods become available.

3. Medium-long term operations planning

In order to make a description of the methodologies adopted to produce medium-long term generation schedules or strategies, it is useful to clarify concepts such as, for example, water value, cost curves, firm-non firm energy, cost or value of unsupplied energy, etcetera; section 3.1 of this paper is devoted to such a description.

Section 3.2 reports on a specific aspect, characteristic of medium-long term operations planning, that is on how one can, in principle, account for randomness affecting the following items: load, energy exchanges with other utilities, generating units availability, energy availability (e.g., water inflows).

Section 3.3 illustrates the methodologies adopted by some utilities; the last have been chosen in such a way so as to cover, as far as possible, a variety of sizes and generation mix; a limit to the choice of examples was nevertheless put by the fact that not all utilities interviewed had a medium-long term operation planning procedure in routine operation.

Some conclusions are finally reported (section 3.4).

It should be stressed that in the field of medium-long term operation planning the research work is still in progress, and that some problems have not yet been satisfactorily solved by all concerned utilities: for example the coordination of two or more interconnected areas with different hydrologies, or a more appropriate modelling of the reliability of thermal units. Reference will be made to such problems during the illustration of the particular procedures.

It should also be considered that medium-long term operation planning has mainly a task of decision support; that is, it is seldom possible to use automatically its results as input to shorter term scheduling. This is due not only to the presence of various uncertainties and of random values, but also to the many simplifications adopted.

3.1.-Definition of some key concepts

3.1.1-Value of reliability

It is well known that in most constitution acts of the State-owned electric utilities (and perhaps also in some private-owned ones) it is stated that the electric service should be economic and reliable (and, more recently, respectful of the environment); this twofold goal may be stated explicitly in two equivalent (but formally different) ways (in the following we only consider the operation aspects, not the expansion planning)/2/:

i- minimize the operation costs, subject to some constraints which guarantee a predetermined level of reliability (e.g.: spinning reserve MW higher than or equal to some preassigned value; expected unserved energy MWh - EUSE - lower than some percent of energy demand; loss of load probability -LOLP -less than a predetermined figure; etcetera);

ii- assign a cost to unserved energy ($/kWh), then minimize the operation costs, including the cost associated to expected unserved energy (the last being considered a generation-like resource, characterised by the above-mentioned cost).

As far as it is known, the first way is the one which is more widely followed, even if it seems, from a theoretical point of view, less sound than the second one; as a matter of fact, the limit amounts of spinning reserve or of EUSE are determined on a heuristic basis, following past experience and perhaps some subjective assumption of the management.

The second way appears more appropriate: should the cost of USE ($/kWh) be known, the limit amounts of spinning reserve (MW) or of EUSE (MWh) would be a result of the optimization (cost minimization) procedure.

Unfortunately, it is difficult to come-up to a definition of the cost of unserved energy; in fact, it is easily understood that it depends on various factors which are well beyond the reach of experience and direct responsability of an electric utility ("external, non monetary costs"); moreover, it is likely to change in time according to unforecasted events, social structure modifications etc...

Nevertheless, some attempts have been made in the past to quantify the cost of unserved energy (only direct, "internal or monetary costs"); one approach that has been employed is the production factor analysis /3/.

It assigns to the unfurnished kWh the value of the goods produced through it, including damage and clean-up expenses of the production facility. In this approach it is necessary, besides other, to account for the duration of the interruption (which can have influence on damages and also on the amount of lost production); the values so determined for the various customers shall then be averaged; as a final result a cost of unserved kWh is found, which shall be in general a function of time of the year (of course, the estimate is done in correspondence of daily peak; the variation in time is likely to depend on the season of the year); it will be also a function of the duration (e.g. few minutes to hours) of the interruption.

Customer surveys are used to help the evaluation of the above-defined costs, including perhaps some other components referring to external or non-monetary costs.

As it appears, the definition of the cost of unsupplied energy is subject to some uncertainty and variability, mainly due to different mix of customers served. The value most frequently recognized is around 1 $/kWh, but the range, from utility to utility, is as wide as 0.5 - 5 $/kWh or more.

As far as the first way (i) above is concerned, a spinning reserve equal to the size of the biggest generating unit synchronized to the system is often assumed as operating rule /1/.

One utility has assumed a limit amount of EUSE equal to 10 system-minutes per year (firm load; that is, this value does not include interruptible customers). The measure unit "system-minute" is defined as the amount of energy obtained by multiplying the peak load of the system, in the year considered, by one minute; e.g., for a system having a peak load of 30,000 MW, 1 system-minute corresponds to 500 MWh, and 10 system-minutes to 5,000 MWh.

With a load factor of 0.6 (that is, yearly load demand equal to .6 times the peak load times 8760 hrs), 10 system minutes correspond to about 0.00003, or 0.003%, of yearly load demand.

Interest in considering EUSE as reference parameter for security is shown mainly by hydro dominant utilities (other utilities often prefer to use LOLP - loss of load probability).

Last, it may be interesting to note that position (ii) above could be adopted, at least from a methodological point of view, assigning to USE a conventional cost, determined on the basis of the experience and depending on higher or lower availability of reserves (that is depending also on the criteria of position (i)). In fact, computation algorithms are in general more straightforward, from a conceptual point of view, in case (ii) (the curtailment of demand may be simply represented by an equivalent generating unit of conventionally high cost)/2/,/6/,/7/.

3.1.2- Firm and non firm energy

This concept refers to system load, energy exchanges with interconnected utilities, and generation. Substantially, a block or parcel is said to be "firm" if it is contracted or committed without possibilities of modifications. A more detailed definition is given in appendix A, sec A.3.

3.1.3- Cost and revenue functions or curves

Cost functions refer to thermal generation and secondary energy imports; revenue functions, to secondary export and secondary load.

A cost or revenue function refers to a given time interval; being known the various amounts of thermal generation, secondary load and secondary imports-exports (GWh) available, an optimization within the considered time interval is performed, so that for each amount of generated or purchased energy the corresponding expenditure is minimum, and for each amount of sold energy the income is maximum. Appendixes A.7 and B illustrate with some detail the definition and possible use of these functions.

3.1.4- Elementary time interval (or time stage) in medium-long term operation planning

The period under study is divided into a number of "sub-periods" or "elementary time intervals" (for example, a 3 years period may be divided into 36 sub-periods, each of one month duration). In each elementary time interval all the variables of the problem (e.g. thermal generation, load, hydro generation etc.) are considered constant with respect to time; in other words, an elementary time interval is a discrete point along the time axis. Appendix A.1 gives a description of possible time partitioning in operation planning problems, and of the assumptions underlying to the choice of it.

3.1.5- Value of water

This concept is especially important for hydro dominant and hydro-thermal utilities.

A "medium term water value" w is defined, as a function of time, in appendix A, sec A.6; this is limited to the case of deterministic approach of medium-long term scheduling.

In section 3.3.1 and appendix D some considerations are developed for the stochastic case.

3.2.- Operations planning in randomness

Three main factors are typically subject to random variations, and namely the load, the generating units availability, the primary energy availability (water inflows to hydro plants).

The "random" character of the above mentioned variables should be opposed to the "uncertainty" of others such as the future prices of fuel or the currency exchange rate with fuel exporting countries. Uncertainty - as opposed to randomness - is often dealt with by performing sensitivity analysis.

When the period of interest is of short duration and near in the future (up to 1 to 10 days ahead), the forecast of those random factors is in general aleatory within a limited degree , so that it is possible, or acceptable, to consider them as deterministic (through the aid of well known procedures, such as load forecast and water inflow forecast techniques); the most probable values may be assumed, and the allocation of appropriate (and easily computed) reserves is sufficient to face expected deviations.

In this context, deterministic optimization procedures may be used (see sec. 2 and ref /1/).

As a result, generation schedules are produced, representing a more or less strict guidance to shift operators (a schedule is a sequence of values, e.g. of thermal generation, one for each elementary time interval of the period under study).

On the contrary, when the period of interest is of longer duration, it is not possible to assume the deterministic forecast; the randomness of the main factors quoted above should be accounted for in a more appropriate fashion.

In order to fix the ideas, let us suppose that the period under consideration is constituted by the next 36 months (starting from the beginning of the next month of the calendar), and that the elementary time interval, or time stage, is one month.

It is supposed that the dates at which new plants are commissioned are known; that a procedure to produce sequences of future, monthly water inflows in a probabilistic way is available (accounting, if it is the case, for correlation between two adjacent elementary time intervals); that reliability parameters of existing and future generating units are known (as well as maintenance schedules of them); that a load (monthly energy) forecasting procedure is available, giving most probable values and expected deviations, or similar parameters; that forecast of market, or secondary load, availabilities has satisfactory accuracy.

3.2.1- One methodology, often referred to as **operation strategy** or **"if-then"** or **closed-loop** methodology, consists in producing, normally through the use of algorithms based on stochastic dynamic programming (SDP), the so called decision tables.

A decision table is a matrix that, for each month, gives the value of the control variable (for example hydro generation, GWh) which minimizes the expected (future) cost; the optimal value of the control variable is given as a function of the present state of the system, that is, typically, of the amount of storage in the aggregated hydro reservoir, and of the amount of water inflow which presented itself in the month just elapsed (this is a state variable if the assumption of correlation between adjacent time intervals was assumed; otherwise, the state is represented by storage only)(fig.13).

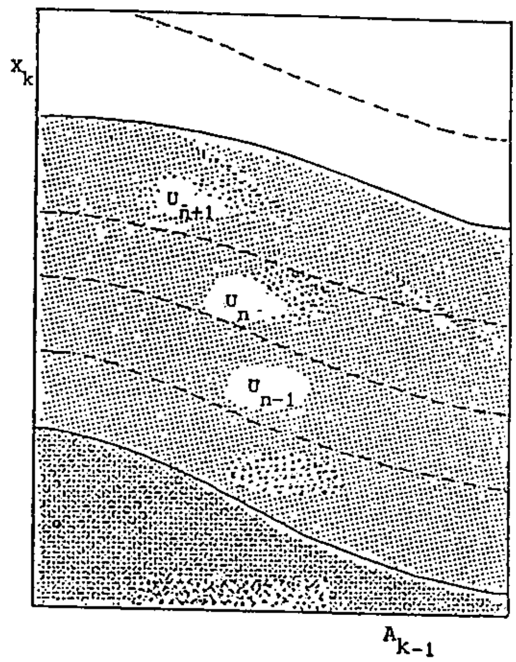

Figure 13 - Decision table for k-th time interval. Ordinate: storage X_k at the beginning of k-th time interval. Abscissa: water inflow $A_{(k-1)}$ during (k-1)th time interval. The lines shown are equi-U curves (U being the control variable). $U_{(n+1)} > U_n$. (Ref /5/).

This methodology, hence, does not produce schedules, because the optimal value of control variable for month k+1 becomes known only when the two state variables (storage and inflow) are known, that is only when month k has elapsed; in other words, it gives operating results only for the next elementary time interval.

On the other hand, it is obvious that when considering random future, schedules may not be produced; the decision of generation can refer only to the next time interval, provided that all the hazards and decisions of the past have led to a given state, assumed to be known.

The tables are produced, when the computation is performed, for each one of the 36 elementary time intervals or months; but each table becomes usable only when "activated" by the calendar.

The need to consider all the future period (36 months, in the example considered) should then be matter of concern, if only one month (the next) is the object of a result or decision, as stated above.

Yet, that need is an obvious requirement for the optimization; theoretically, the period to be considered should be long enough to make it possible to assign a negligible value to the final storage (taking into account an appropriate discount factor, which transforms future values into present ones).

The computation should be repeated, covering again the next 36 months, whenever a major variation occurs in the parameters which were assumed as known (commissioning of new plants, maintenance schedules, reliability parameters of generating units, etcetera); on the contrary, it needs no re-execution in dependence of random variations (within the limits of the historical series) of load, generators availability, water inflows.

This kind of algorithm is quite demanding in terms of computing power and time; hence the hydro system is normally represented by a unique, aggregated or equivalent reservoir; to have n (equivalent) reservoirs represented separately would increase the number of state variables from 2 to 2n. The limitation of a unique reservoir is considered acceptable if the hydrologies of the various watersheds are similar; nevertheless, also in this case, the control of the risk of spillage or of depletion of some particular reservoir can get lost or unsatisfactory.

Some utilities are developing algorithms which could allow the representation of 2 or 3 equivalent reservoirs (allowing also a control of energy flows between the corresponding electrical subnetworks) without a prohibitive increase in computing time and power requirements; in some cases (through the use of "aggregation-disaggregation" methods) the number of equivalent reservoirs could reach 10 or 15 (the computing time, in principle, increases only linearly with the number of reservoirs, when using these techniques); these methodologies are at present at the design or testing phase and shall not be dealt here /2/, /4/, /5/, /6/. Even worst is the case in which electrical subsystems are also hydraulically coupled.

3.2.2- Another methodology, referred to as **operation policy** or **open loop**, is more or less similar to that used in short term, that is deterministic, but devotes more attention to the definition of the constraints; the aim of this more appropriate definition of constraints is to avoid, within reasonable probability limits, curtailments of load or energy waste (water spillages).

The constraints may be, typically, minimum and maximum storages in hydro reservoirs, minimum amount of pumped energy (which may be required to comply with minimum storage requirement), etc...

Those constraints are then used in a deterministic optimization procedure, in which the random parameters (load, water inflows, generating units availability) are set at their most probable, forecasted values; as a result schedules of hydro and thermal generations are produced, in some cases also with confidence limits. This allows to make an estimation, for example, of future needs of fuel and hence to provide purchase schedules (contracts); this is not the case, of course, with methodology illustrated in section 3.2.1.

This is perhaps the reason of the preference given to the methodology 3.2.1 by hydro dominant utilities, and to methodology 3.2.2 by thermal dominant utilities. A purely thermal utility will not make use, of course, of methodology 3.2.1. For a purely hydro utility the methodology 3.2.1 appears to be preferable (the optimization concerns in this case the secondary markets).

The operation policy procedure is in general repeated each month, covering always the next 36 months; this allows to better account for random events, as they become nearer in time and hence easier to forecast (this is also called an open-closed loop procedure).

3.2.3- The presence of random values may be taken into account in a rigorous way through methodologies 3.2.1 or, to some extent, 3.2.2; "rigorous" has here reference only to the aspect of randomness, and does not imply the absence of simplifications in the representation of the power system (these simplifications are on the contrary present in most cases: e.g. aggregated instead of detailed hydro system). To take into account the presence of random values in a "rigorous" way strongly affects the operation planning procedures, making them quite heavy and complex. This is the reason why many utilities (especially thermal dominant) prefer to work with average forecasted values (deterministic computations), and simply consider, to account in some way for randomness, an additional (but limited) number of alternatives for the most important random parameters (global values), such as water inflows and load (sensitivity studies). This choice is supported also by the fact that the results of medium-long term operation planning procedures have in most cases, even when methodologies 3.2.1 or 3.2.2 are adopted, only the task of decision support, and not that of giving precise or mandatory input to shorter term scheduling.

3.2.4- A comparison between the two approaches 3.2.1 and 3.2.2 has been tried by one hydro dominant utility, in order to determine the expected magnitude of saving obtainable with the more appropriate approach 3.2.1.

The comparison was performed as follows.

a) compute, through methodology 3.2.1, the 36 decision tables;

b) sort one sequence of inflows (36 values); by the aid of decision tables determine the schedule corresponding to the sorted inflow sequence (that is, make a "simulation" of the operation), and compute the corresponding total operation cost;

c) repeat the step b) an appropriate number of times (e.g., 50), of course with different inflow sequences;

d) compute the mean value C_r of the 50 computed values of operation costs, and its standard deviation σ_r;

e) with each one of the 50 inflow sequences above sorted, make a deterministic optimization through methodology 3.2.2; the total operation cost is then known for each one of the 50 cases;

f) compute the mean value C_d of the 50 computed values of cost of step e), and its standard deviation σ_d.

In the example considered, assuming as reference value $C_r = 1$ and $\sigma_r = 0.02$ (this being the result of the methodology 3.2.1 plus simulations), it resulted $C_d = 1.03$ and $\sigma_d = 0.07$. The expected saving is hence 3%, in the reported example (the amount of energy or of money to which the 3% applies is in this case that corresponding to the secondary market, which in turn represents a relatively little amount of the total energy balance).

3.2.5- Wathever be the methodology used, hydro subsystem needs a global (only one equivalent reservoir) or partial aggregation. The aggregation, depending especially on mutual influencing between plants, if any, may be not simple to perform. That is, the equivalent reservoir power station in general may not be simply represented by the sum of installed powers, of maximum and minimum storages and of water inflows of the actual reservoir power stations. A method of getting the parameters of the equivalent reservoir power station is illustrated in ref /10/; the method is based on simulations of daily operation of the detailed hydro system, under an appropriate number of power availability and water inflow hypotheses.

3.3-Methodologies in use in some utilities

Of the reporting utilities, about 40% are "purely thermal" (thermal generation higher than 85% of the load), 40% "hydro-thermal" (thermal generation lower than 85% and higher than 15%), 20% "purely hydro" (thermal generation less than 15% of the load).

The major purposes for setting-up a medium-long term operation planning procedure are in the order: to produce generation schedules (also when "strategy" methodologies are used as a first step)(93%); to check generation maintenance schedules (79%); to determine fuel requirements for setting-up purchase contracts (66%, and 83% of non purely hydro utilities); to produce input for shorter term generation scheduling (48%); to check need for new generating plants (aid to expansion planning)(38%).

The main improvement sought for the existing procedures is a better load forecast (59% of utilities).

The generation plans or schedules are updated periodically (59%), upon major outages (45%), upon important variations in power exchange opportunities with other utilities (41%).

The variables considered in the optimization procedure are mainly: conventional thermal generation (83% of the cases, and 96% of non purely hydro); hydro generation from reservoirs (69%; 100% of non purely thermal utilities); pumped storage schedules (48%); peaking units generation (45%); import-export with other utilities (41%).

Key for utilities identification: A = Oslo Electricity Board; B = Hydro Québec; C = Centrais Elétricas Brasileiras; D = ENEL (Italy); E = Ontario Hydro; F = Swedish State Power Board; G = Electricité de France; H = Iberduero S.A.; L = CPTE (Belgium); M = CEGB (Great Britain).

3.3.1-Purely hydro

Three utilities (A, B, C) have been considered. Utility C has some thermal generation, and the other two have secondary market opportunities; nevertheless, either thermal generation and market opportunities represent a minor component of the energy balance.

The methodology used is that outlined in section 3.2.1, with some simplifications consisting mainly in considering deterministic load (monthly energies) forecast and thermal (or opportunity markets) availabilities; water inflows are supposed to be random, with specified stochastic law (derived from historical sequences).

Let be X_k the storage of the equivalent reservoir (GWh) at the beginning of time stage (or month) k; U_k the hydro generation from reservoir during month k; $F_k(U_k)$ the revenue, or monthly profit, function (fig. 14), obtained as shown in A.7. This function includes, due to the preoptimization method used within the elementary time interval k considered, the effects of all the items which are significant in respect of costs and revenues, and namely thermal generation, purchase-sale opportunities and, if necessary, load disconnection; in other words, for each value of U_k, corresponding (optimal) values of thermal generation, opportunity purchase and opportunity sale are predefined (see A.7 and B).

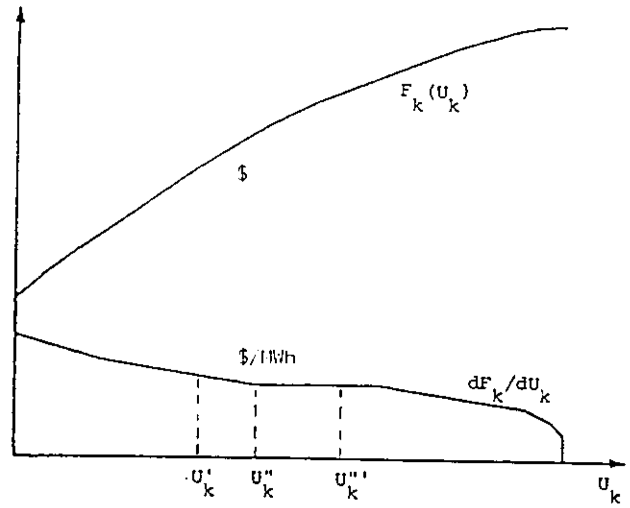

Figure 14 - $F_k(U_k)$ curve and its derivative. U'_k, U''_k, U'''_k correspond respectively to $A'_{(k-1)}$, $A''_{(k-1)}$, $A'''_{(k-1)}$ (from fig. 13), for a given X_k (Ref /7/).

The object function is then

$$\max_{U_k \, A_k} E \left(\sum_{1}^{N} k \, \gamma^{k} F_k(U_k) + \gamma^{N+1} I\right)$$

subject to well known constraints (upper and lower limits for U_k and X_k, etcetera). In the preceeding expression E is a mathematical operator which represents the expected value (that is the mean) of the expression in the brackets, taken with respect to the variables A_k (water inflow during month k), for all values of k from 1 to N (this being the total number of months constituting the period considered, that is 36 in the example of section 3.2.1); γ is the monthly discount factor; I is the terminal value function, which is a function of final storage $X_{(N+1)}$ and may be to some extent of an arbitrary shape, but monotonically increasing with $X_{(N+1)}$ and with decreasing derivative.

Another position of the problem, with recursive formulation, is

$$I_k = \max_{U_k \, A_k} E \quad (F_k(U_k) + \gamma \; I_{(k+1)})$$

with k from N to 1 (backwards).

This optimization problem can be solved by a standard, single variable, stochastic dynamic programming procedure /7/. It gives as a result the decision tables illustrated in section 3.2.1.

It is worth noting that as a by-product, the <u>water value</u> is obtained by this procedure. It is defined as follows.

To any given couple of state variables at month k, X_k and $A_{(k-1)}$, an optimal value U_k is associated as stated before, and hence a profit (or cost) $F_k(U_k)$. The value dF_k/dU_k (computed on the cost-revenue function defined in A.7) may well be assumed as (incremental) water value (\$/kWh), since an increase dU_k in hydro generation will of course entail an equal decrease in thermal generation or opportunity import (or an equal increase in opportunity export). Now, make an average of the various dF_k/dU_k corresponding to the various values of $A_{(k-1)}$, each one weighted according to the probability of the $A_{(k-1)}$ values themselves (fig. 14). This average is, by definition, the incremental water value $V_{(k,X)}$, which is a function of k and of the storage X_k (because U_k is a function of X_k, from decision tables). Since the terminal value function I has been assumed with decreasing derivative with respect to storage, it turns out that, for each k, $V_{(k,X)}$ is a decreasing function of the storage.

This parameter is considered by utilities A and B.

This definition of water value shows again the characteristic of a <u>substitution value</u>.

3.3.2- <u>Hydro-thermal</u>

Utilities D, E, F, G and H have been considered.

<u>Utility D</u> follows a operation policy type methodology (section 3.2.2).

The period considered is 53 weeks, and the elementary time interval is one week.

Three main steps may be considered:

a) definition of **weekly cost curves** $F_k(T_k)$, with k = 1,..., 53. Since utility D has no opportunity markets (load or power exchanges, in the sense in which the opportunity markets were defined in A.3), there is no profit concept, and the cost is associated only to fuel consumption; the control variable is the thermal generation T_k (MWh);

b) definition of **constraints**;

c) **optimization** with constraints.

The definition of **cost curves** is done, according to the general concepts illustrated in A.7, in the following way, for the generic week k.

Assume that a forecast of load (chronological MW values for each hour, or each couple of hours) is available for week k (sequence of 168 or 84 values); the load curve is supposed to be net of power exchanges (utility D does not optimize directly this item of the balance); hence it must be covered by two items only (that is hydro and thermal generation).

Various thermal generation diagrams or curves are then considered (fig. 15), of progressively increasing energy; the shape and number of such curves shall comply with the following requirements:

i- at each hour the difference between load (average forecast minus 1 or 2 times the standard deviation) and thermal power

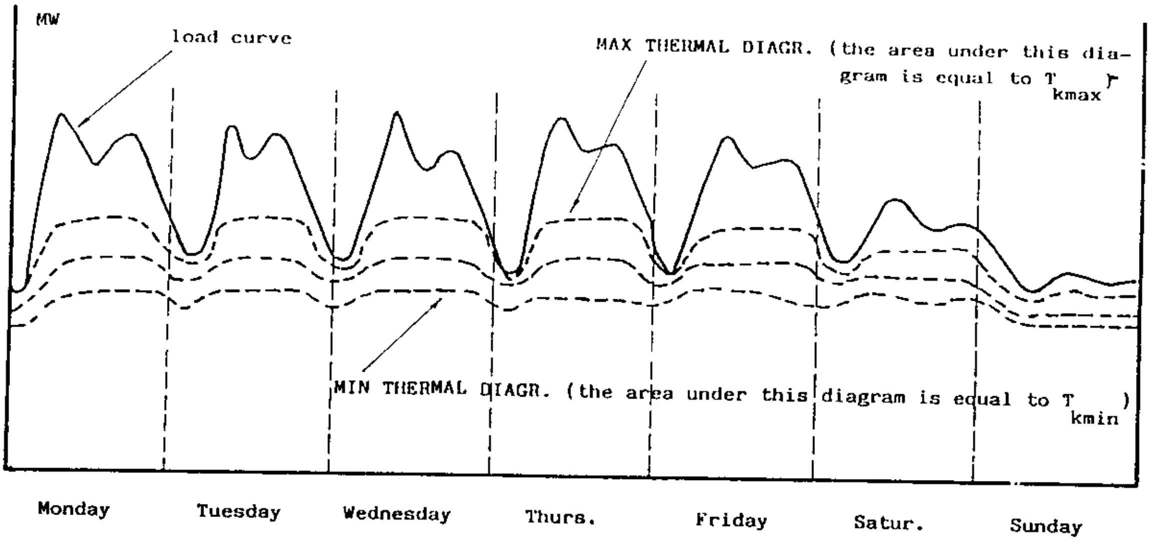

Figure 15 - Various thermal generation diagrams (Ref /10/)

shall not be higher than max hydro power available in case of wet hypothesis for hydraulicity;

ii- at each hour the thermal power shall not be higher than max thermal power available (that is, not on scheduled maintenance);

iii- each curve (to which corresponds a given value of T_k) shall be as flat as possible (hydro generation on peak-shaving duty);

iv- the number of curves considered shall be sufficient to cover, in steps of a not too big value, the range from T_{kmin} (corresponding to low hypothesis for load and high hypothesis for hydraulicity) to T_{kmax} (max thermal availability).

Now perform the following steps:

1- choose one of the chronological thermal load curves defined above and shown in fig. 15;

2- for each one of the thermal units not scheduled for maintenance make a chronological simulation, by Montecarlo methods, of its availability (this simulation produces, on the basis of the transition rates characteristic of the unit, one on-off state sequence, all along the week, of the unit itself);

3- for each hourly interval make a choice (with an economic criterion) of a number of the units which resulted available in step 2, up to cover the total requested power; make a sharing of power between the chosen units, e.g. on the basis of equal incremental costs, and compute the total (weekly optimum) cost;

4- repeat the steps 2 and 3 an appropriate number of times (e.g. 100 or 500). Then for each unit not on scheduled maintenance, as well as for the set of them, the average (over the 100 or 500 sequences sorted) generation, consumption and cost may be computed, together with the corresponding probabilistic parameters (e.g., standard deviations). As far as the set of units is concerned, the average generation is of course T_k, and the corresponding average cost is $F_k(T_k)$;

5- repeat the preceeding steps for all the other chronological thermal load curves (that is, with different values of T_k). As a final result, the (average) cost curve $F_k(T_k)$ is known (by discrete values of T_k), as well as its probability parameters (that is, for each value of T_k, average F_k and the standard deviation of it are known).

The reason for this procedure is to account for randomness in availability of thermal units, which has influence on the operation costs. As a matter of fact, suppose that some units are lower in size, lower in efficiency and of higher reliability, and that some other are of bigger size and higher efficiency, and of lower reliability. Taking into account only the average availability of both little and big units, is likely to produce an underestimation of operation costs /8/. The method above described gives better results /9/ (fig. 16).

Note that duration curves for load may not be used in this case, due to the key role of chronological simulations of step 2 above.

Note also that T_{kmax} will in general be less than that corresponding to full availability of thermal units, due to actual availability values of thermal units themselves taken into account in the Montecarlo simulations.

The definition of $F_k(T_k)$ will of course be performed for each one of the weeks constituting the period under study.

The computing requirements (memory and time) are quite heavy.

The definition of **constraints** for utility D is illustrated in ref /10/ and /11/; the methodology consists in building-up a

Figure 16 - Cumulated probability curve of generation for a thermal unit in the time interval k; the truncation (which may or may not be present) corresponds to maximum output (unit running at rated MW all along the time interval). Similar curves can be built-up for sets of thermal units (e.g., those of the same rating, or those utilizing the same fuel) and for sets of time intervals (covering for example one month, or the whole period under study) (Ref /9/).

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cumulated, hydro plus thermal, probability curve of generation for the 53 weeks period, for the last 52 weeks, for the last 51, etcetera. These cumulated probability curves account for randomness of load, thermal units availability and water inflows (simpler computing methods are used in this phase, with respect to those illustrated for the phase of definition of weekly cost curves). Having established beforehand the accepted EUSE for each one of those time intervals (values given by management), a minimum permissible storage in the equivalent hydro reservoir at the end of each week is accordingly determined; this is a concept similar to that of <u>alarm curve</u>.

The **optimization** is then performed, assuming a hypothesis (a forecast) for water inflows (weekly values) and for load. The optimization procedure utilizes the cost curves above defined, and is performed through a DP algorithm.

Because of the presence of an equivalent hydro reservoir, which can make transfers of energy from week to week (and month to month), the optimization must cover the period of time (53 weeks) as a whole (that is, it cannot be decomposed in 53 separate and independent optimizations); the assumption of final storage equal to initial one is assumed.

Note that due to the deterministic assumptions of water inflows and to the assumptions on given initial and final storages, the total amount of hydro generation (GWh) is known; because of the deterministic forecast of load, also the total thermal generation is known; the optimization then consists in minimizing the cost of that given thermal generation (the presence of pumped hydro makes the problem a little more complex, but doesn't modify the concepts just illustrated).

One of the results is the schedule of thermal generation; it is worth to stress that, as illustrated before, fuel consumption (or associated cost) get determined in average values and probability distribution; of course the average values depend also on the assumed values of hydraulicity. Another result is the weekly drawdown from the equivalent reservoir; etc.

The whole procedure is repeated every four or five weeks, always with a horizon of 53 weeks ahead.

<u>Utility E</u> follows a method quite similar to that illustrated for utility D; some additional simplifying assumptions are made on the representation of hydro generation, which to some extent is dealt with in a predetermined (heuristic) manner, the consideration of randomness being limited to load and thermal units availability /12/,/13/.

The period considered is one year, and the elementary time interval is one month; the optimization is split in 12 decoupled optimizations.

This simplification allows the representation of some power transfer limits between electrical subnetworks. The procedure consists in the use of Montecarlo method to draw a number of possible system "states" (value of load and available thermal units) in each time sub-interval of one hour (there is no sequential simulation, as in case of utility D); for the optimization of each state the algorithm used is linear programming, and the results (thermal generation per fuel type and area) are given in terms of average values and standard deviations.

The methodology followed by <u>utility F</u> is again of the type illustrated for utility D. The period considered is one year and the elementary time interval one week.

The use of network flow techniques allows a more detailed representation of hydro subsystem in the optimization procedure, so making possible a much more accurate accounting of hydro constraints (single reservoir storage limits, influencing etcetera).

Randomness is accounted for thermal units availability; water inflows and load are assumed at their forecasted values.

Weekly cost curves are not used; instead, a first attempt hydro schedule is tried, and correspondingly first attempt weekly thermal schedules and incremental costs are evaluated (with deterministic availability of thermal units). An iterative procedure between two steps (modify the hydro schedule on the basis of thermal incremental costs, to levelize the incremental costs themselves; compute the new thermal schedules and incremental costs) takes place, until the convergence is reached. On this final (optimal) thermal schedule, a more accurate simulation of thermal units availability is performed, to compute the expected energy generation of each thermal unit /14/, /15/.

Utility G is a hydro-thermal system with a dominant share of nuclear generation (pressurized water reactors). Two main steps are considered for medium-long term operation planning:

A - Six years horizon of study: definition of the maintenance and refueling schedule for nuclear PWR units. The procedure used here is of the open-closed loop type with refreshment of the planning each month, taking into account updated information on nuclear cores burn-up and maintenance and refueling constraints. The particular characteristics of PWR must be taken into account here:

- each reactor has to be shut down during six weeks for maintenance and refueling, about once a year. This can be done when the nuclear fuel is between given limits of burn-up (anticipation and stretch-out);

- the average length of a cycle (including maintenance and refueling) is by now about 14 months, and naturally increases when the unit is no longer base-loaded.

Thus, when a PWR is used as a cycling unit, in a load-following mode, or when it is on forced outage, the energy not used may help shift the next refueling window . Special models have been developed to solve this problem on an adequate pluri-annual horizon of study /16/.

B - 18 months to 24 months horizon of study: definition of the operation strategy of the seasonal hydraulic reservoirs and of the PWR units between two refuelings. The procedure used here is of the closed loop type, with two levels of study:

1 - the aggregated, seasonal hydraulic reservoir, weekly pondage and run of the river are first operated with SDP /17/. This first level gives all classical results of annual operation planning and sends the probability law of the marginal costs of operation to the second level;

2 - the strategy for each national watershed is then optimized by operation feedbacks, with its detailed physical description, on the basis of the above mentioned marginal costs. By "feedback" it is meant here an operation rule which disaggregates the global withdraw from the unique, equivalent reservoir into the partial withdraws from the component watersheds. In particular, a "local feedback" is a rule allowing for example the determination of the storage of (or generation from) a particular reservoir: for a reservoir with water inflows coming from snow melting, the more appropriate feedback could be from load trend (that is, generation from that reservoir will be increased or diminished in correspondence with positive or negative deviations of the load, respectively); for a reservoir with water inflows coming from rain, instead, the more appropriate feedback could be from storage itself (generation will be increased if the storage is increasing, and viceversa) /18/.

The water values can thus be obtained for each seasonal reservoir and passed over to daily scheduling.

Utility H follows a methodology which consists in determining the water values according to a procedure similar to that described in section 3.3.1; account is taken of the randomness of the inflows and of the actual reliability of thermal units.

The starting point for the determination of the water values is at the end of the period under study; an arbitrary (to some extent) function $V_{(N+1,X)}$ is assigned ($/kWh as a function of storage X); then an optimization is performed for the Nth time stage, assuming that incremental thermal generation cost is equal to incremental water value $dV_{(N+1,X)}/dX$, so that each trajectory from X_N to $X_{(N+1)}$ is supposed to be at constant incremental water value. Hence the function $V_{(N+1,X)}$ is projected back to give $V_{(N,X)}$ at the beginning of the Nth time stage (and end of the (N-1)th one). Then an optimization is performed for the (N-1)th time stage, and so on, till time zero, that is till determination of function $V_{(1,X)}$. If this last function is different from the starting function $V_{(N+1,X)}$, the assumption $V_{(N+1,X)} = V_{(1,X)}$ is made, and the whole procedure is repeated, until convergence is reached (assuming that $V_{(1,X)}$ must be equal to $V_{(N+1,X)}$ is a likelihood assumption, which is valid if the instants 1 and N+1 are for example distant by an integer number of years. In the case illustrated in sec. 3.3.1, instead, it was requested that the period under study be long enough to make it possible to assume $V_{(N+1,X)} = 0$).

In Appendix D an example of computation of water values according to this methodology is illustrated.

Once that water values have been so computed, the equivalent hydro reservoir plant may be considered as a thermal plant (with some appropriate constraints), and from this point on deterministic schedules may be produced, according to a methodology of the operation policy type (section 3.2.2) /19/.

3.3.3- Purely thermal

The medium-long term operation planning procedures for purely thermal utilities are of course simpler than those for hydro-thermal ones; the key items are unit commitment algorithms, which should take into account the random availability of generating units, and allow for consideration of pumped storage plants if any.

Utilities L and M, which both have pumped storage plants, use deterministic load forecast (chronological, in hourly steps), and consider a horizon of 1 or 5 years ahead. Pumped storage is run on daily or weekly cycles, for reserve or economy duties.

Sensitivity studies are performed, in particular with respect to load increase rate.

A particular attention is devoted to the setting-up of merit order lists, which are used in unit commitment computations, and to the availability of various types of fuel (at costs varying in time); an important outcome of the procedure is the definition of fuel consumption of the various generating units, which is the basis for stipulating medium-long term fuel purchase contracts.

In the following a description of the operational planning procedure of utility M is given.

The medium term plant schedules are computed for each year of the five years ahead period.

a A suite of programs perform the computations corresponding to two main functions. These are to calculate:

(a) the energy production and heat demands for each power station;

(b) a minimum transportation solution to satisfy station heat demands determined in (a) from available fuels.

b The programs perform a number of iterations. The marginal heat costs determined in a(b) are used to determine a merit order which is used at each successive iteration for scheduling plant in a(a). Up to 10 iterations may be necessary to determine the lowest cost solution.

c **Plant scheduling method.** The scheduling method used in a(a) is based on the same program used in the short term day to day control room phase. The only significant difference being that instead of running the program for the next few days ahead it is run to cover a period of one year based on 12 monthly simulations. Some features are as follows:

c1 **Demand.** For each year the power and energy demand for 365 days are modelled in full. Each day is broken into 12 two hours steps. The daily demand curves are obtained from an historical data bank with some allowance for weather sensitivity as required;

c2 **Generation.** Some 80 power stations are modelled; these are predominately coal fired, but also include some nuclear, oil, pumped storage and gas turbines stations. Average forecasts of generating plants availability are used; these reflect the plans for closing old plants, commissioning new plants, seasonal cold plant regimes, maintenance outages, and an allowance for plant breakdown. A deterministic approach is used and random availability changes are not modelled due to complexity of trying to attempt this with the size of the simulation involved;

c3 **Generation plant characteristics.** The full range of parameters for generating plants are modelled as appropriate, i.e. plant output capability, run-up and run-down rates, minimum on and off times, synchronising and maximum generator level, time between sets on and off, starting-up costs, plant flexibility, dual firing, stabilising oil burn and fixed and incremental heat rates;

c4 **Trading.** Long term trading arrangements are modelled and various opportunity options are investigated;

c5 **Transmission system.** The main transmission system is simulated and usually divided into eight key zones to model power constraints associated with maintenance outages. The number of transmission zones may be increased if required. Typical transmission loss factors are modelled for all generating plants;

c6 **System reserves.** A predetermined system reserve policy is modelled which varies with the season of the year. This generally being based on a spinning reserve comprised of pumped storage plant during the day time and steam plant at night. This is backed-up with gas turbine plants in a standby mode;

c7 **Merit order.** For the first iteration of the simulation run a previous merit order is used to start the process off. For the second iteration the heat cost is input to the merit order used by the scheduling program from the fuel allocation program. Two types of merit order are in use, these being based on the system per unit cost multiplied by the incremental or full load heat rate. The full load cost is used in the scheduling algorithm to bring plant on and the incremental cost is used to allocate output to plant brought on. Up to three incremental steps may be modelled for various coal-oil fuel mixes if required;

c8 **Scheduling method.** The scheduling program initially selects plant with the lowest merit order cost based on the full load heat rate to meet peak or trough demands. For a selected amount of marginal plant these costs are then adjusted by various penalties: (a) for starting-up or shutting-down plant; (b) other penalty costs associated with the characteristics of plant with parameters that do not meet ideal system requirements. The program then modifies the selection of plant based on these adjusted costs and allocates output based on incremental costs;

c9 **Pumped storage plant.** The pumped storage plant operation is simulated in the scheduling process as follows: (a) the scheduling procedure described above is carried out; (b) the marginal costs are passed into the pumped storage routine; (c) the procedure described above is repeated with the load curve modified by pumped storage plant operation.

d **Fuel allocation method.** The input to fuel allocation program is as follows:

d1 **Input from the scheduling program.** The annual on-load and off-load heat required at each station is input into the fuel allocation program from the scheduling program;

d2 **Fuel and transport data.** Fuel for each fuel source availability, calorific value and pit head costs are modelled together with the transport routes available from source to power station identifying the mode available and the cost of each mode. Up to 200 fuel sources are modelled together with some 1600 delivery routes. Other parameters modelled include the cost of fuel and ash handling at each station, fuel quality and capability constraints of each transport mode and route together with the fuel stock level requirements. The stock levels may be set to achieve some strategic aim.

e Typically the type of simulation described above is usually carried out for the current and one year ahead. For the years beyond this a simpler process is used based on a fixed merit order adjusted to reflect future fuel agreements. A range of sensitivity studies are carried out to cover uncertainties.

f **Associated operational planning activities.** From the results of the energy planning simulation much useful economic information can be derived using special analysis tools. This includes assessment of monthly weekday-weekend and annual system marginal replacement costs for each generating unit, the associated load factors and plant utilization. This information is then input into other operational planning activities which include generation and transmission maintenance schedules, management of plant capacity for seasonal cold plant, operating regimes and plant refurbishment, trading arrangements, bulk supply tariff work, national spare plant strategies. Another important activity is the assessment of plant margins.

g **Plant margins assessment.** In addition to energy management studies plant margin assessments are carried out to ensure that the amount of plant made available for each week or month of the year meets the operational standards of security. These balances are simple checks and may be performed relatively quickly.

h For the current and one year ahead plant margin balances are carried out every two months for each week of the period. The first six weeks of the current year are reviewed on a weekly basis as part of shorter term work.

3.4.-Conclusions

The methodologies followed in medium-long term operation planning (1 to 5 years ahead) may be grouped in three broad categories: operation strategies, operation policies, deterministic optimizations.

For reasons of practicality, reflecting in some cases the organization of the utility, the methodologies may frequently consist in a mix of the three categories above.

The first one seems to be preferably followed by hydro dominant utilities; it gives operating guides for the next elementary time interval (in most cases, next month) through decision tables. In principle the decision tables (one for each elementary time interval or month) don't need to be updated if the random parameters (water inflows, load, thermal units availability) keep within the hystorical limits (closed loop characteristics). The main theoretical problems are those referring to the representation of the hydro system, which must be more or less aggregated. It is often used to account for randomness of water inflows only (load and thermal units availability are considered deterministic).

The second category leads to the determination of generation schedules covering the whole period under study; randomness is taken into account in a simpler way than in the first category, normally in the phase of definition of appropriate constraints; the last are then introduced in the procedure for determination of schedules (this last procedure is substantially of a deterministic type, hence it is to be expected that optimality is approached with less accuracy than with the first category of methods); the above said constraints have the main aim of ensuring an appropriate degree of security. Hydro-thermal utilities show a preference for this methodology or, in some cases, for a mix of the two. The results must in general be updated (for example, every month), in dependence of major departures of parameters from forecasted values (open-closed loop characteristcs).

The third category is fully deterministic; randomness is in some way accounted for by running the procedure with some alternative values of random parameters, such as load increment rate, that is performing sensitivity studies (open loop characteristics). Purely thermal utilities often use this kind of methodology. It should be stressed that for purely thermal utilities the overall economy of operation is strongly affected by fuel costs and currency exchange rates (if fuel is imported).

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Appendix A

A.1- Partitioning of time in the scheduling problems

Especially for hydro-thermal power systems scheduling is an activity in which the decisions taken today for tomorrow or for the next week can affect future operation requirements. Hence the optimum way to schedule is to consider as long a period as possible (for example up to one or five years ahead). This may be true also for purely thermal power systems, for example in the case in which there are strict constraints in the consumption of contracted fuel within a given period (for example one year).
Nevertheless, the detail needed to plan the operation of tomorrow or of next week is of course higher than that of next month or next year.
Keeping in mind this fact, and the problems related to complexity and length of computations, it appear wise, in addition to other simplifications to be assumed in the representation of the power system itself, to consider at least two levels of time partitioning:

- the first one is of more direct interest in the medium-long term operation planning, in which the period considered (for example one year) is divided into n "medium term time intervals (MTI)"; for example the duration of each MTI might be one week, and n = 52 or 104 or more;
- the second is of more direct interest in the short term scheduling, in which each of the above defined MTI is divided into m "elementary time intervals (ETI)", each of duration, typically, 0.5 or 1 or 2 hours.

In the following it shall be assumed, for the sake of simplicity, that recourse is made to this two-level partitioning of time.

A.2 Simplifications

It shall be assumed that, as far as medium-long term operation planning is concerned, simple power system models or equivalents may be considered (for example, only one equivalent, or aggregated, hydro reservoir will be considered; transmission constraints will be neglected).

Nevertheless, the basic ideas and methodologies remain valid when applied to more complex problems.
Some data are often considered as known (e.g. load and water inflows, available generators) are in practice random and not deterministic. To account for randomness, which is particularly important if the period of study is long, requires further sophistication of the models.
When the short term scheduling period is one week, randomness may still have some importance, especially as far as the last days of the week are concerned. Nevertheless it may be noted that those utilities having a short term scheduling period of one week or more use to repeat the short term scheduling procedure e.g. every day, so considering operational, in practice, only the next (or next two) days schedule /1/.

In the short term scheduling, hence, randomness is normally accounted for by making available an appropriate amount of spinning and stand by reserve (computed perhaps with probabilistic criteria, /1/).

A.3 Categorization of generation, load and power exchanges

For any duration, and in particular for any MTI, the generation must match the load plus exports (average values along the time interval considered, MWh or GWh).
The generation may be made-up of hydro and thermal sources (including nuclear if any and peaking power such as gas turbines).
Hydro may be split into two terms: H, coming from reservoirs, and H', corresponding to the water which may not be stored during the time interval under study.
In a similar manner thermal generation may be thought of as being composed of T, which may be varied, and T' ("must run" at full load or at the maximum available load: for example geothermal and mine-mouth plants; in some utilities also nuclear generation may belong to this category).
The load may be considered as being composed by a firm load L' (that is the load regulated by rigid contracts) plus a secondary load L (load regulated on an interruptible tariff, see appendix E).
In some utilities there may not be any distinction between the two categories of load, in the sense that all load is considered as primary (that is L = 0); the interruptible customers, if any, are in this case considered as firm load which may be curtailed if given prior notice.
Exports may also consist of an amount E' corresponding to firm contracts ("must sell"), plus an amount E, corresponding to opportunity trading. The same may be said for imports I' ("must take") and I.

A.4 Constraints

In the i-th MTI the following energy (GWh) balance will hold:

$$H + H' + T + T' + I + I' = L + L' + E + E'$$

Let now be:

$$F = L'+E'-I'-H'-T' \qquad (1)$$

the amount of firm energy, that is the energy subject to strict commitments, or not subject to optimization.
Also let be

$$M=L+E \qquad (2)$$

the amount of secondary load plus opportunity export, and finally let be

$$U=T+I \qquad (3)$$

the variable thermal generation plus opportunity import. Note that M, U, L, E, T and I are all non negative values.
The first equation may now be rewritten

$$H_i + U_i = F_i + M_i \quad \text{for any } i \qquad (4)$$

Equation (4) shows a balance with one fixed (forecasted) value F, and three values H, U and M which may be varied, to some extent, by the operational planner.
Now define A_i (MWh) as the inflow to the equivalent hydro reservoir, and V_i as the storage (MWh) at the end of the i-th MTI; the following equation will hold:

$$V_i = V_{(i-1)} + A_i - H_i \quad \text{for any } i \qquad (5)$$

which represents the reservoir balance. An additional constraints is

$$0 \leqslant V_i \leqslant V_{max} \quad \text{for any } i \qquad (6)$$

where V_{max} is the maximum storage.
In general there will be also some other constraints of integral type, such as:

$$a_{min} \leqslant \Sigma_i H_i \leqslant a_{max} \qquad (7)$$

$$t_{min} \leqslant \Sigma_i T_i \leqslant t_{max} \qquad (8)$$

Also H_i and T_i have upper bounds H_{imax} and T_{imax}.

In (7), in which a_{min} and a_{max} (GWh) are specified and known amounts of hydro reservoir generation, it may often be $a_{min} = a_{max} = a_{tot}$; in such a case a_{tot} could for example equal the total amount of inflow to the reservoir, (that is the sum of the n values A_i), so that (7) would impose to turbine this total inflow within the whole period considered; as a result, it would be $V_n = V_o$.
Similarly, (8) states that the total thermal generation is constrained within a given range tmin, tmax, due for example to constraints posed by fuel purchase contracts.

A.5 Criteria of optimization

The three variables H, U and M, subject to (4), (5), (6), (7) and (8) must be set at values which minimize the operation cost for the period under study.
It must be taken into account that the presence of eq. (5) (that is the presence of hydro storage), as well as the presence of the inequations (7) and (8), make the problem an integral type one with respect to time; hence the setting in a particular MTI may not be determined independently of the settings in the other intervals.
In other words, the actions taken for interval i affect the economy of the following intervals, and hence the economy of the whole period (which is composed of n MTIs).
Various cases will now be considered, as far as generation mix and market are concerned.

A.5.1 First case: no hydro storage (or "purely thermal")

Note that the meaning of "no hydro storage" is strictly correlated to the duration of the MTI; if this is equal, for example, to 2 hours, "no storage" means the absence of ponds and reservoirs, that is the presence, at most, of run of river hydro plants (or no hydro plants at all).
If the MTI is equal to one week, on the contrary, "no storage" means the absence of monthly or seasonal reservoirs (but there could be daily and weekly ponds).
To clarify this point, it should be noted that the following assumptions have been made: a daily pond shall have the same storage at the beginning and at the end of the day (it can make transfer of generation from hour to hour, within the day); a weekly pond shall have the same storage at

the beginning and at the end of the week (it can make shifts of generation from day to day, within the week). These seem reasonable assumptions and they are normally assumed because they simplify the whole problem of optimal operational planning.
In the case of no hydro storage (4), (5), (6), (7) and (8) reduce to:

$$U_i = F_i + M_i \quad \text{for any } i \quad (9)$$
$$t_{min} \leqslant \Sigma_i T_i \leqslant t_{max} \quad (8) \text{ rep.}$$

To optimize it is necessary to know the cost function $C_i = f_i(U_i)$ and the revenue function $D_i = g_i(M_i)$, with C_i and D_i expressed in monetary units (£ or $).
In sec. A.7 some considerations will be developed about these functions.
The optimality condition in this case will be:

$$C = \Sigma_i(C_i - D_i) = \min \quad (10)$$

A.5.2 Second case: no thermal generation (or "purely hydro")

In this case the (4), (5), (6), (7) and (8) reduce to:

$$I_i + H_i = F_i + M_i \quad \text{for any } i \quad (11)$$
$$V_i = V_{(i-1)} + A_i - H_i \quad \text{for any } i \ (5) \text{ rep.}$$
$$0 \leqslant V_i \leqslant V_{max} \quad \text{for any } i \ (6) \text{ rep.}$$
$$a_{min} \leqslant \Sigma_i H_i \leqslant a_{max} \quad (7) \text{ rep.}$$

The optimization requires the knowledge of the functions $C_i' = f_i(I_i)$ and $D_i = g_i(M_i)$. The condition for optimum is

$$C = \Sigma_i(C_i' - D_i) = \min \quad (12)$$

A.5.3 Third case: hydro-thermal power system

This is the most general case, and the problem has already been formulated by (4), (5), (6), (7) and (8). The condition for the optimum is again

$$C = \Sigma_i(C_i - D_i) = \min \quad (10) \text{ rep.}$$

A.5.4 Fourth case: no market opportunity

In this case there is no secondary load, no opportunity import or export, and hence $M = 0$, $U = T$.
The problem may now be formulated as follows:

$$H_i + T_i = F_i \quad \text{for any } i \quad (13)$$
$$V_i = V_{(i-1)} + A_i - H_i \quad \text{for any } i \ (5) \text{ rep.}$$
$$0 \leqslant V_i \leqslant V_{max} \quad \text{for any } i \ (6) \text{ rep.}$$
$$a_{min} \leqslant \Sigma_i H_i \leqslant a_{max} \quad (7) \text{ rep.}$$
$$t_{min} \leqslant \Sigma_i T_i \leqslant t_{max} \quad (8) \text{ rep.}$$
$$C = \Sigma_i C_i'' = \min \quad (14)$$

with $C_i'' = f_i(T_i)$.

Many utilities may recognize this case as their own problem; as a matter of fact, in many cases the secondary load concept is not used, and opportunity exchanges are considered as parameters and not as true variables.
The reason for this last assumption may be that on the one hand the introduction of a new variable makes it more difficult to solve the problem; and on the other hand, often the purchase or sale opportunities are at prices well below (or above) their own production costs, so that it is not necessary to make sophisticated evaluations to assess the economy of trading.
However, it may happen that the prices are near the production costs; in this case a check may be made by running the optimization problem (13), (5), (6), (7), (8) and (14) twice, that is with and without the new exchange contract, which is considered as a "must take" or a "must sell", and comparing the two operation costs (this is the meaning of "considering the opportunity exchanges as parameters and not as true variables").
To have the exchange opportunities as variables would perhaps require, in addition to a more complicated optimization procedure, stricter coordination between the interested utilities.

A.5.5 Fifth case: purely hydro, no opportunity exchanges, no secondary load

A particular case deserving attention (included in the second and fourth cases above) is that in which $U = M = 0$:

$$H_i = F_i \quad \text{for any } i \quad (15)$$
$$V_i = V_{(i-1)} + A_i - H_i \quad \text{for any } i \ (5) \text{ rep.}$$
$$0 \leqslant V_i \leqslant V_{max} \quad \text{for any } i \ (6) \text{ rep.}$$
$$a_{min} \leqslant \Sigma_i H_i \leqslant a_{max} \quad (7) \text{ rep.}$$

This could be the case of a non interconnected, purely hydro utility, feeding firm load only. Clearly, in this case the degree of freedom is zero and hydro generation must rigidly follow the firm load; depending on the series of values A_i, and on the value V_{max}, there may be in some MTIs unavoidable spillages, or firm load curtailment.
Some kind of optimization could however be carried out at the lower level (short term), taking into account the efficiency curve shapes of the various power plants in order to minimize the water consumption for any global energy output.

A.6 Value of water

It has been assumed that hydro energy has zero operation cost (note: depreciation costs must not be considered in operation problems); a cost has been on the contrary associated to thermal generation and to energy market availabilities, through the functions C_i and D_i.

A.6.1 Medium term water value

With the exception of the fifth case above (sec. A.5.5), in which there is no optimization problem, in the other cases hydro energy H may be given a fictitious operation value in the following way (consider, for the sake of simplicity, the fourth case; the following considerations may be generalized to the more general third case):

* suppose that $H_1, H_2, \ldots, H_k, \ldots, H_n$ and $T_1, T_2, \ldots, T_k, \ldots, T_n$ are the optimum values, that is those satisfying (14) and complying with the constraints (13), (5), (6), (7) and (8) (F_i and A_i are supposed to be known forecasted values);
* consider an elementary energy step e (that is a value sufficiently low with respect to any H, T, F and A);
* suppose that in the time interval k the hydro generation departs from the optimal value H_k to $H_k + e$; correspondingly, T_k will move to $T_k - e$;
* repeat the optimization (equations (13), (5), (6), (7), (8) and (14)), but keeping constant hydro and thermal generations of the k-th MTI at the values $H_k + e$ and $T_k - e$ respectively. The total cost shall now result $C_{min} + d_k$, with $d_k > 0$;
* then the <u>incremental water value</u> in the k-th MTI is $w_k = d_k/e$ ($/MWh) (16)

The incremental value defined above is a <u>substitution value</u>, because the increment d_k is due to the variation of the generation schedules of thermal units (and to variation in the schedules of import/export in the more general case); hence it depends on the costs of the other sources (fuel, opportunity contracts). It depends not only on the costs prevailing in the particular MTI to which it refers, but also on the costs of all other MTIs constituting the period of study.
The value w defined above may be considered as a deterministic "medium term incremental water value". To account for randomness requires more sophisticated mathematical approach, the basic concepts remaining nevertheless unchanged (the "expected water value" instead of the "water value" will be the result; see also appendix D).

A.6.2 <u>Short term water value</u>

Another definition which may be assumed is the "short term incremental water value" v_j ($/MWh).
Its definition may be given for two different contexts: hydrothermal (v_j') and purely hydro (v_j'').
For the first case (hydrothermal) suppose that H_1 (recall sec. A.3 for the definition of H) is the optimum hydro generation in the first MTI, as determined by (4), (5), (6), (7), (8) and (10); the first MTI is the next week. The short term scheduling is done with H_1 as a constraint; that is the total hydro generation in the next week will be equal to H_1 (the hypothesis is assumed that A_1, water inflow, and F_1, firm energy, are forecasted exactly). This hydro generation will be distributed along the m ETIs of the week in the most economic manner, by the short term scheduling procedure.
Let λ_j ($/MWh) be the thermal (plus opportunity import if any) incremental cost in the j-th ETI, as it results from short term optimization.
Suppose also that in the same ETI a hydro power station is running at a flow of Q_o (cubic meters per hour), with a corresponding output P_o (MW).
The criterion followed to define the value of the water is a simple substitution criterion: if an increment ΔP in hydro generation is performed, an equal decrease ΔP will be obtained in thermal generation (or opportunity import), with a saving equal to $\lambda_j * \Delta P$ (in $/h). Hence the incremental water value will be $\lambda_j * \Delta P$; on the other hand, since to produce $P_o + \Delta P$ an increment ΔQ is necessary to the flow Q_o, the incremental water value may also be expressed as $\mu_j * \Delta Q$.
Then $\mu_j * \Delta Q = \lambda_j * \Delta P$ and $\mu_j = \lambda_j * \Delta P / \Delta Q$.
This is expressed in $ per cubic meter. Willing to have it expressed in $/MWh it is sufficient to divide μ_j by a constant reference value (for example the average specific energy content c_{av}, which is expressed in MWh per cubic meter):

$$v_j' = \lambda_j * (\Delta P / \Delta Q) / c_{av} \qquad (17)$$

Fig A1 shows the trends of P versus Q and of $\Delta P/\Delta Q$ versus P for a typical hydro plant.

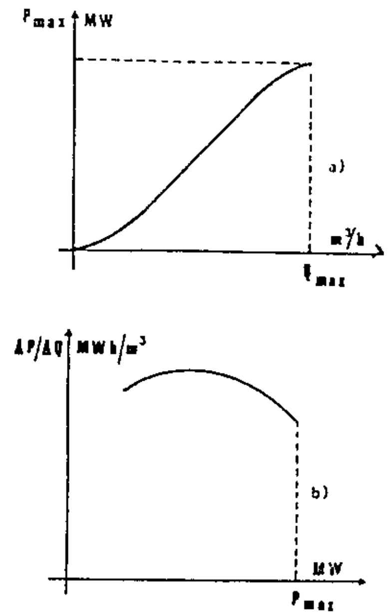

Figure A1 - Trend of output P (MW) versus input flow Q (cubic meters per hour) (a), and of $\Delta P/\Delta Q$ versus P (b), for a typical hydro unit.

For the second case (purely hydro context), the following simple definition may be assumed:

$$v_j'' = w_1 * \eta / \eta_{max} \qquad (18)$$

In eq. (18) w_1 is the medium term incremental water value considered above, prevailing for the first MTI; η is the efficiency of the plant as a function of output, and η max is the maximum value of η (see fig A2).
The introduction of the coefficient η/η_{max}

which is less than or equal to 1, has the aim of discouraging non optimum running of the hydro plants.

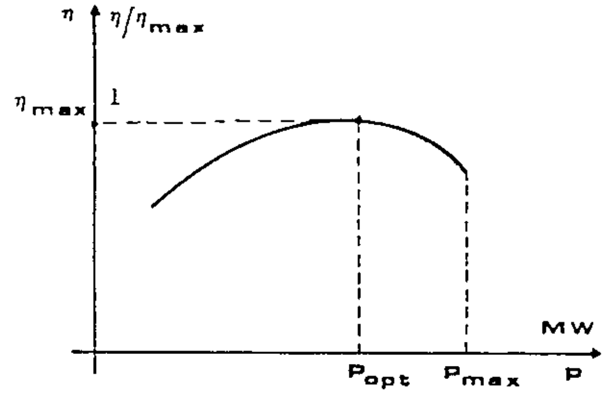

Figure A2 - Efficiency versus output for a typical hydro unit.

Both values, v_j' and v_j'', may be useful when contracting unforecasted market opportunities, to evaluate their convenience, provided that they consist of small amounts of energy with respect to those given by the medium term scheduling; in particular, v_j' and v_j'' would perhaps become meaningless if the unforecasted market opportunities entail the shut-down or start-up of units.
Their use, in the above specified conditions, avoid having recourse to time consuming re-computation of the medium term optimal schedules, to get more (theoretically) exact economic evaluation of the unforecasted market opportunities.

A.7 Cost function and revenue function

A.7.1- Thermal generation plus opportunity import (cost).

To take into account all aspects required to give a complete definition of the cost function for thermal generation and opportunity imports (including start-up and shut-down, and cycling of thermal units), the duration of the MTI to be considered is at least one week. This is due to:
- long start-up and shut-down times (many hours in the case of most thermal units);
- start-up and shut-down costs (for example the penalty factor associated with starting a cold generator may be prohibitive particularly if it is only scheduled to run for a very short duration);
- the adverse effects of cycling thermal plants.

In other words, with the present state of flexibility of thermal units, a MTI of one week (or more) allows complete evaluation of the operation cost with sufficient accuracy, with no need to consider external conditions (that is conditions relating to adjacent MTIs).
Fig A3 refers to a typical MTI and shows, arranged in increasing order, the specific costs of thermal generation (fig A3a) and of imported energy (fig A3b).
With regard to fig A3a the increase in specific costs is due to the fact that as the requested thermal generation increases, less and less economic units shall be started-up. Fig A3a is supposed to take into account, perhaps in a simplified manner, the start-up costs and the fact that thermal units undergo, during the week, cycling according to their technical characteristics and to the shape of the load curve (for example they will follow a flat generation profile as far as possible, based on past experience).
Fig A3b shows in a similar manner the specific costs of imported energy.
In fig A3c the two sources are merged together, again in increasing order of specific cost.
It may be recognized that recourse will be done, in the example shown, first of all to the first block or parcel of imported energy (1I); next to the first block of thermal generation (1T); then to the second block of thermal generation (2T); etc.
Of course, arranging the energy in an increasing order of specific cost is an

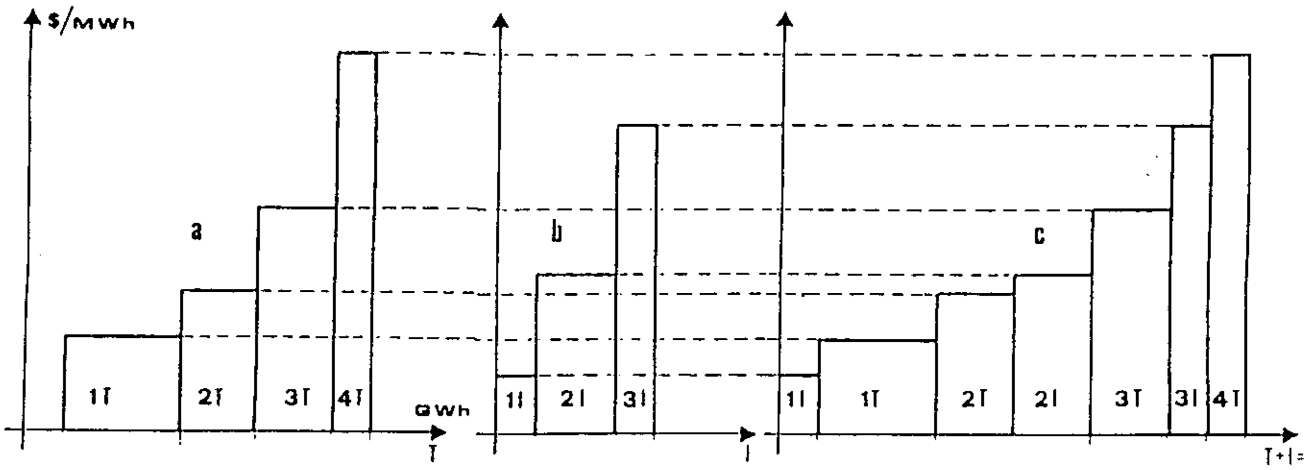

Figure A3 - Specific costs, arranged in increasing order, of various blocks of: thermal generation (a), opportunity purchase or import (b), and the merge of the two.

obvious economic criterion; nevertheless, should some other reason call for a different order, this may well be adopted (but with drawbacks in economy).
Note that load curtailment may be represented by one or more equivalent thermal units, with appropriately high cost (in fig A3 the block 4T could well represent a first block of load curtailment).
The determination of the specific costs of various blocks (perhaps especially those of thermal generation) may appear to be poorly approximated; on the other hand the search of a higher accuracy (for example to take better account of the shape of the thermal generation diagram during the week, or the penalties corresponding to start-up costs) would be meaningless, since the various parameters of the MTI under consideration are subject to uncertainty (higher and higher as the MTI moves into the future).
From fig A3c the function $C_i = f_i(U_i)$ is easily built up (fig A4), this simply being the integral of the curve of fig A3c.

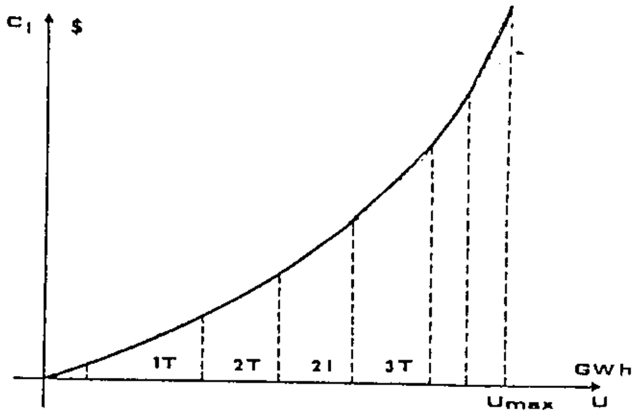

Figure A4 - Cost function of the merge of thermal generation and opportunity purchase.

A.7.2- Secondary load plus opportunity export (revenue).

Fig A5 shows, in a similar manner, the specific sale prices of secondary load L (A5a) and of opportunity export E (A5b), arranged in decreasing order; fig A5c is the merge of the two.

The revenue curve $D_i = g_i(M_i)$ is obtained in the same way as C_i was obtained (fig A6).

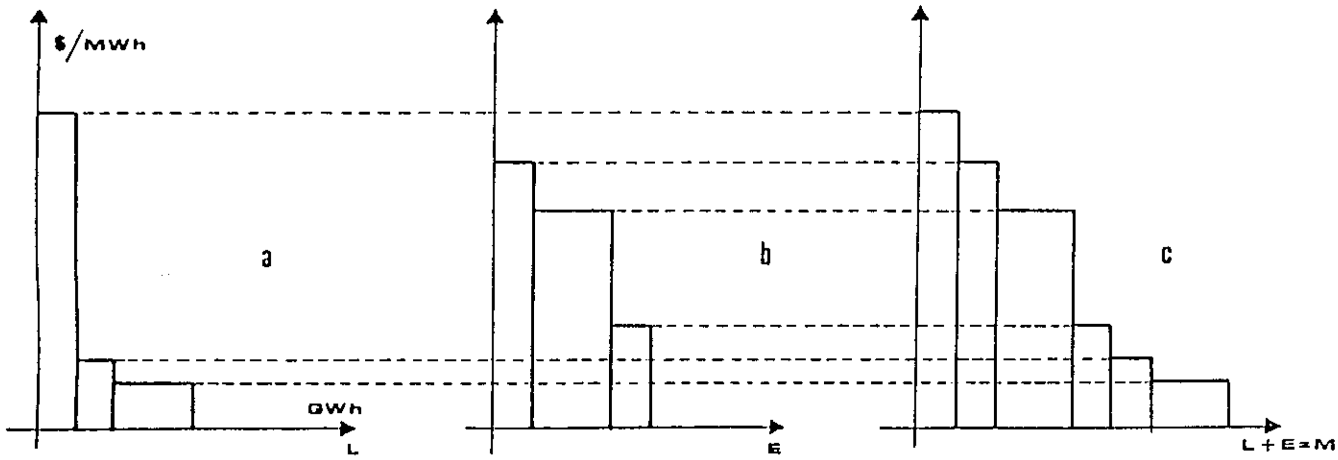

Figure A5 - Specific sale prices, arranged in decreasing order, of various blocks of secondary load (a), opportunity export (b), and the merge of the two.

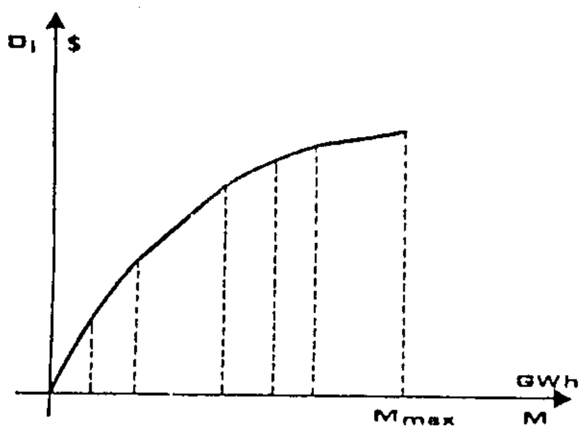

Figure A6 - Revenue function of the merge of secondary load and opportunity export.

A.7.3- Combining the two functions.

The two curves (fig A4 and A6) are defined separately because they represent two different parameters: C_i is a cost, D_i a revenue.
In the optimization procedure care must be taken when dealing with cases in which both are present.
In the appendix B some comments are made about this point.

Appendix B

The problem is formulated, in the case of sec. A.5.1 ("purely thermal") as:

$$U_i = F_i + M_i \qquad \text{for any } i \quad (9) \text{ rep.}$$

$$\sum_i (f_i(U_i) - g_i(M_i)) = \min \qquad (10) \text{ rep.}$$

Inequation (8) is disregarded, as well as the other constraints appearing in the most general case A.5.3, in order to make more straightforward the illustration of the criterion of optimization.
Of course in practical cases some of those constraints shall be active, and their presence introduces some further mathematical concerns.
The solution of (9) and (10) is given by

$$df_i/dU_i - \lambda_i = 0$$

$$-dG_i/dM_i + \lambda_i = 0 \qquad i = 1, \ldots, n$$

$$U_i - M_i - F_i = 0$$

In this case there are n separate problems (one for each MTI). The preceeding equations may be rewritten

$$df_i/dU_i = dg_i/dM_i = \lambda_i$$

$$U_i = F_i + M_i$$

$$i = 1, \ldots, n$$

They state the well known "equal incremental costs" criterion, which in this case is applied to only two sources; the solution is graphically illustrated in fig B1 (the horizontal line is shifted up and down until an intercept equal to F_i is found). The two curves df_i/dU_i and dg_i/dM_i, of course, are nothing but the two curves of fig A3c and A5c, respectively.
It must be, for a solution to exist,

$$U_{imax} - M_{imin} \geqslant F_i.$$

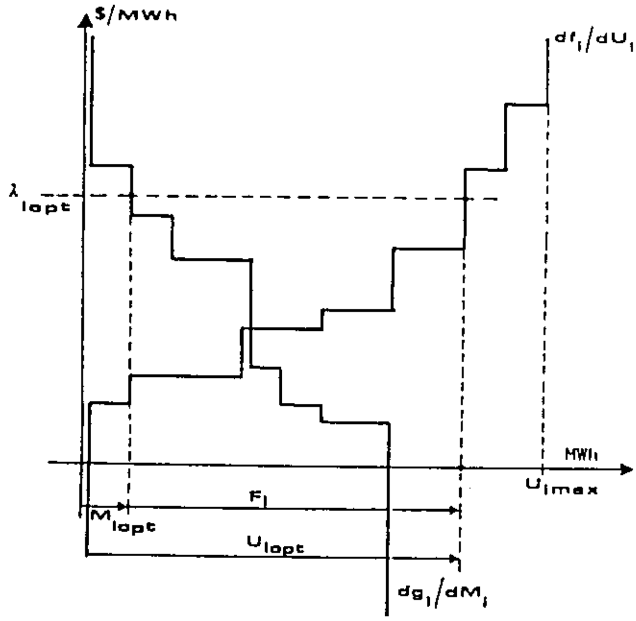

Figure B1 - Finding the optimum values of M and U, with given F, in a typical MTI (M, U and F are defined in sec. A.4)

Appendix C

In each ETI (elementary time interval of the short term scheduling period considered) the optimal choice of P (thermal generation plus opportunity import) and S (opportunity export plus secondary load) must be performed, satisfying the load R.
P, S and R are expressed in MW.

The problem has right the same approach as that dealt with in appendix B. It will be considered with the same limitations with which the last was considered.
Fig C1a shows the incremental cost curves of the running thermal units and of the available blocks of import; with the criterion of equal incremental costs the curve of fig C1b is obtained, which will be

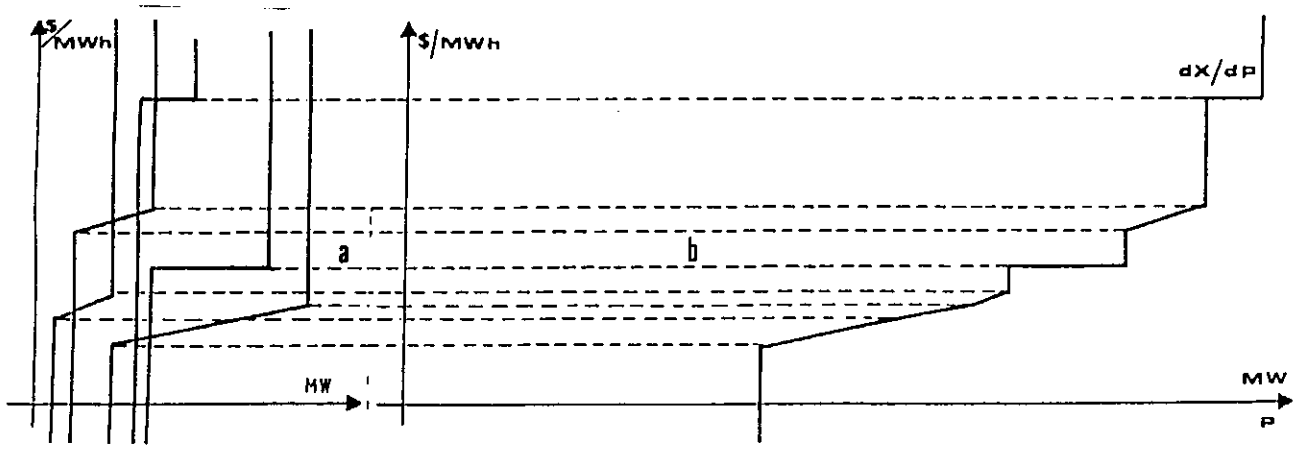

Figure C1 - (a): incremental cost curves of thermal units and of blocks of imported energy; (b): total incremental cost curve, obtained from (a) with the criterion of equal incremental costs. Reference to a typical ETI.

called dX/dP ($/MWh), X being the total (minimum) cost ($/h), which is a function of P.
Fig C2a shows the income curves ($/h) of the various available blocks of opportunity export and secondary load; fig C2b shows the corresponding derivatives (incremental revenues), and fig C2c the overall incremental revenue curve, obtained from that of fig C2b with the criterion of equal incremental revenues.
The curve of fig C2c will be called dY/dS ($/MWh), Y being the total (maximum) revenue ($/h), which is a function of S.
The problem is stated as follows:

$dX/dP = dY/dS = \lambda$

$P = S + R$

The solution is shown in fig C3.

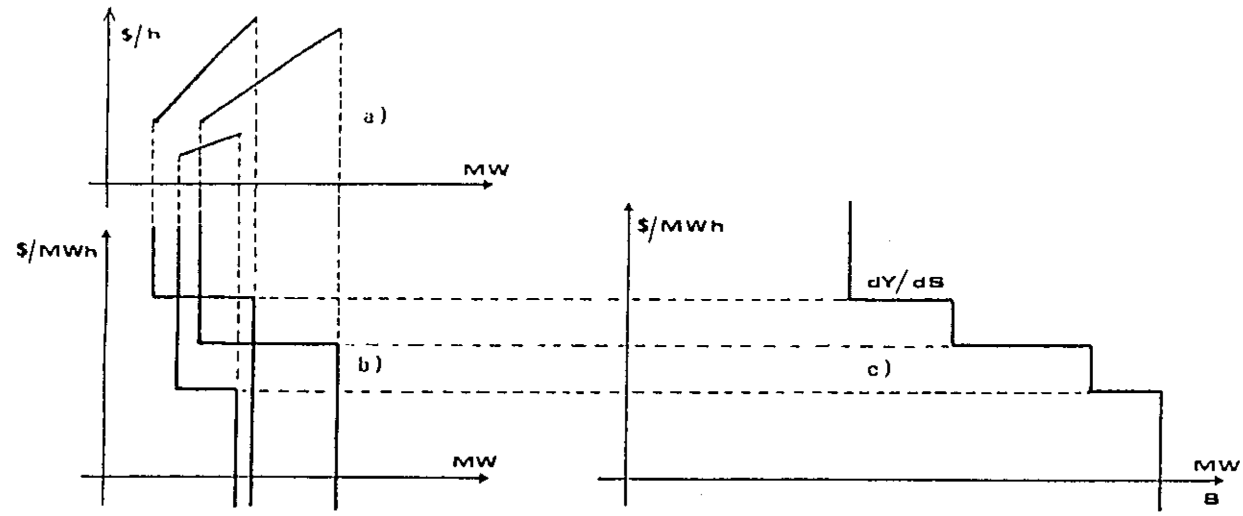

Figure C2 - (a): income curves of various available opportunity exports and secondary loads; (b): incremental revenue curves of those blocks; (c): total incremental revenue curve, obtained from (b) with the criterion of equal incremental revenues. Reference to a typical ETI.

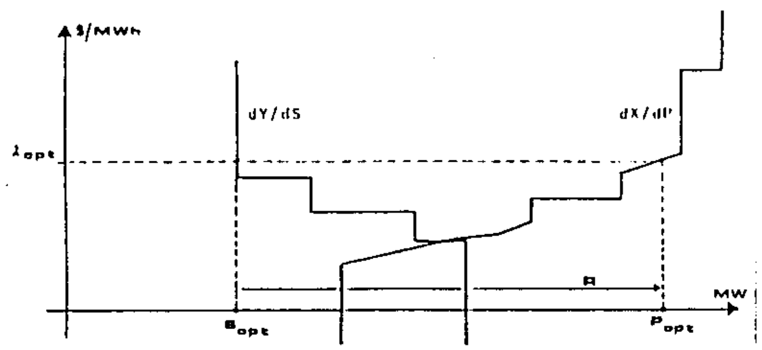

Figure C3 - Finding the optimum values of S and P, with given R, in a typical ETI.

Appendix D

Water value computation (probabilistic case)

The concept of incremental water value relies in the following assumptions (recall that an assumption, or principle, is not proved, but simply accepted due to its likelihood):

i - water has no value in itself, hence a value can be assigned to it on the basis of equivalence or substitution; in particular, the incremental water value is assumed to be equal to the incremental cost of fuel or of any other resource which can replace it;

ii - the incremental water value is a decreasing function of the amount of water stored.

In the example it is assumed a period of study of one year, consisting of 12 elementary time intervals of one month.

The energy quantities are expressed as integers, in a common unit (for example 1 GWh or 1 TWh); the cost or value quantities are expressed as real numbers, in a common arbitrary unit ($/MWh or pounds/kWh or pesetas/GWh).

The power system is supposed to consist in a reservoir of maximum storage equal to 20; an equivalent hydro power station (fed by that reservoir) with maximum energy output varying from month to month; an equivalent thermal power station with maximum energy output varying from month to month and with incremental cost functions also different, in general, from month to month.

The main characteristics of the example power system are summarized in table I and fig D1.

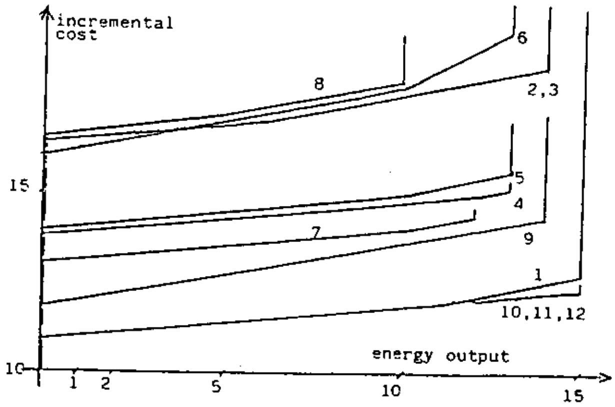

Figure D1 - Incremental costs of thermal generation.

The only parameter considered as stochastic is water inflow: for each month a discrete number of water inflows have been considered, each one with its own probability (for example, in month 3: inflow 4 with probability 10%; 6 with 60%; 8 with 30%); the expected values shown in tab I are the averages (for month 3: 0.1*4+0.6*6 + 0.3*8 = 6.4).

By means of the methodology considered in sec. 3.3.2 (utility H), the "equi-value" (or "equi-price") curves of water storage shown in fig D2 have been determined. The figures near the curves shown represent the incremental water values, expressed in the same units as the incremental thermal costs of fig D1.

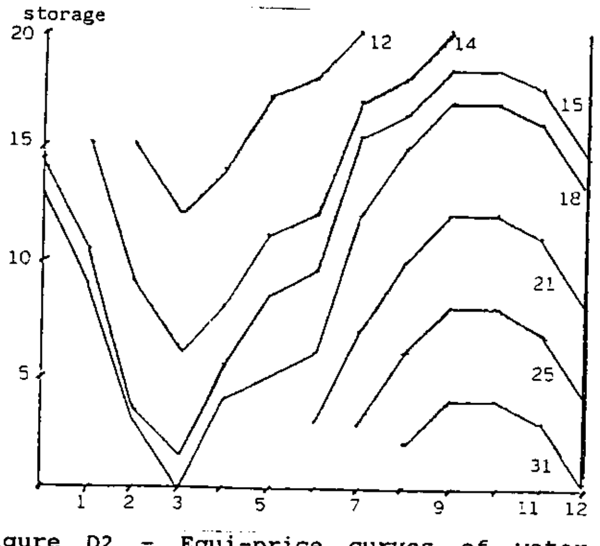

Figure D2 - Equi-price curves of water, obtained for the example system.

The shapes and parameters of the equi-price curves are strongly affected by the upper limits of hydro and thermal generation (max hydro and max thermal output of Table I) and by the distribution of the inflows along the period under study (last column of Table I).

Table I - Generation, load and inflow parameters of the example power system.

time stage	max hydro ouput	max thermal output	load	expected infl ›w
1	10	15	20	1.3
2	9	14	21	3.2
3	9	14	20	6.4
4	8	13	17	10.4
5	9	13	18	12.4
6	9	13	18	10.2
7	8	12	16	10.2
8	5	10	13	6.2
9	8	14	16	4.2
10	9	15	18	3.2
11	10	15	18	2.2
12	10	15	20	2.2

Appendix E

Terminology

* Filling period: the time required for filling the catchment structure from the lowest to the highest level normally allowable in use, with constant supply flow equal to the characteristic mean corrected flow; the downstream hydro power station being supposed at rest (UNIPEDE 1.2.09)
* Run of river installation: catchment structure with filling period less than 2 hrs (UNIPEDE 2.7.01)
* Pond (or pondage) installation: catchment structure with filling period between 2 and 400 hrs (UNIPEDE 2.7.02)
* Reservoir installation: catchment structure with filling period above 400 hours (UNIPEDE 2.7.03)
* Must run unit (hydro or thermal): generating unit which shall run at a predetermined and constant output (positive)
* Shall run unit (hydro or thermal): generating unit which shall run at an output variable between a positive minimum (less than maximum output) and its maximum allowable output
* Scheduling period: the future period of time covered by forecast and scheduling activities of a particular procedure
* MTI (medium term elementary time interval, or medium term time stage): the length of time interval in which the scheduling period is divided, when dealing medium-long term operation planning. For example: a scheduling period of 3 years may be divided into 36 time intervals (MTIs) of 1 month duration each. Within the MTI all the data, parameters and unknowns are considered constant with respect to time, as far as the particular scheduling procedure is concerned
* ETI (short term elementary time interval, or short term time stage): the same as MTI, but when the scheduling procedure is short term

* Integral type constraint (with respect to time): a constraint which involves unknowns belonging to at least two ETIs (or MTIs)

* Secondary load (or non-firm load, or opportunity load):a load which is contracted with the clause of possibility of interruption (with advice), also in normal network conditions. A typical example of secondary load is electric heating, substituting fuel if the contracted electric tariff is economically advantageous (customer are supposed to be equipped with both facilities, so being able to switch from one to the other in short time)

* Secondary (or non-firm, or opportunity) import or export: an import or export which is contracted with the clause of possibility of interruption (with advice)

* Cycle of pumped storage: the period of time during which the balance of water must be closed. For example a daily cycle is that in which the water pumped during night is turbined in the following day hours; a weekly cycle is that in which the water pumped during week-end is turbined in the following five working days. The possibility of performing a longer cycle depends on the relative magnitude of the upper and lower reservoirs or ponds, with respect to the installed pumping and generating capacity.

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