LECTURE NOTES

ON

ECONOMIC OPERATION OF POWER SYSTEMS

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UNIT – I
ECONOMIC LOAD SCHEDULING

INTRODUCTION:

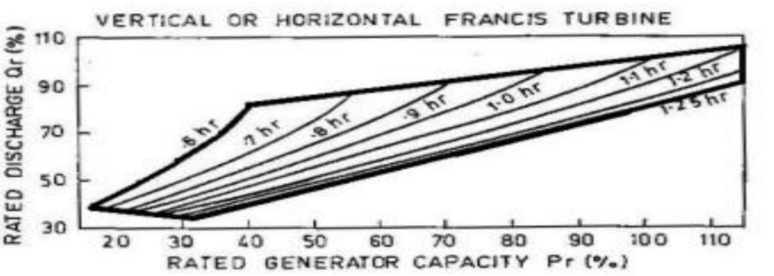
The most important concern in the planning & operation of electric power generation system is the effective scheduling of all generators in a system to meet the required demand. Economic Load Scheduling (ELS) is a phenomenon where an optimal combination of power generating units are selected so as to minimize the total fuel cost while satisfying the load demand & several operational constraints. In a deregulated electricity market, the optimization of economic dispatch is of utmost economic importance to the network operator. The main objective of ELS problem is to minimize the operation cost by satisfying the various operational constraints in order met the load demand. Many traditional algorithms are applied to optimize ELS problems however in these methods it is assumed that the incremental cost curves of the units are monotonically increasing piecewise linear functions, but the practical systems are nonlinear.

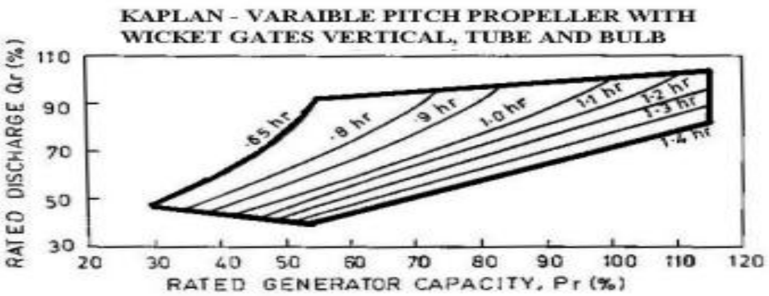
CHARACTERISTICS OF STEAM TURBINE:

Turbine Performance Characteristics of output and efficiency are important parameters. At project feasibility stage these parameters are required to fix number and size of units and determine economic feasibility. For this purpose output and efficiency at part load of the head range for the turbine is required.

In tender documents for procurement these characteristics of turbines are specified to be guaranteed under penalty. In evaluation of bids, equalization on accounts of differences in efficiencies of turbines of various bidders is made. Model tests are required to ensure that the guaranteed parameters offered will be met by the proto type.

Finally field tests for output and efficiency are conducted at different guide vane/needle openings to determine actual output and efficiency parameters. Penalty for shortfall in efficiency and output and rejection limits are specified.





Pr = 9.804, hr , Q r , η t. r η g (kW)

Where:

Pr = Rated capacity at hr (kW)

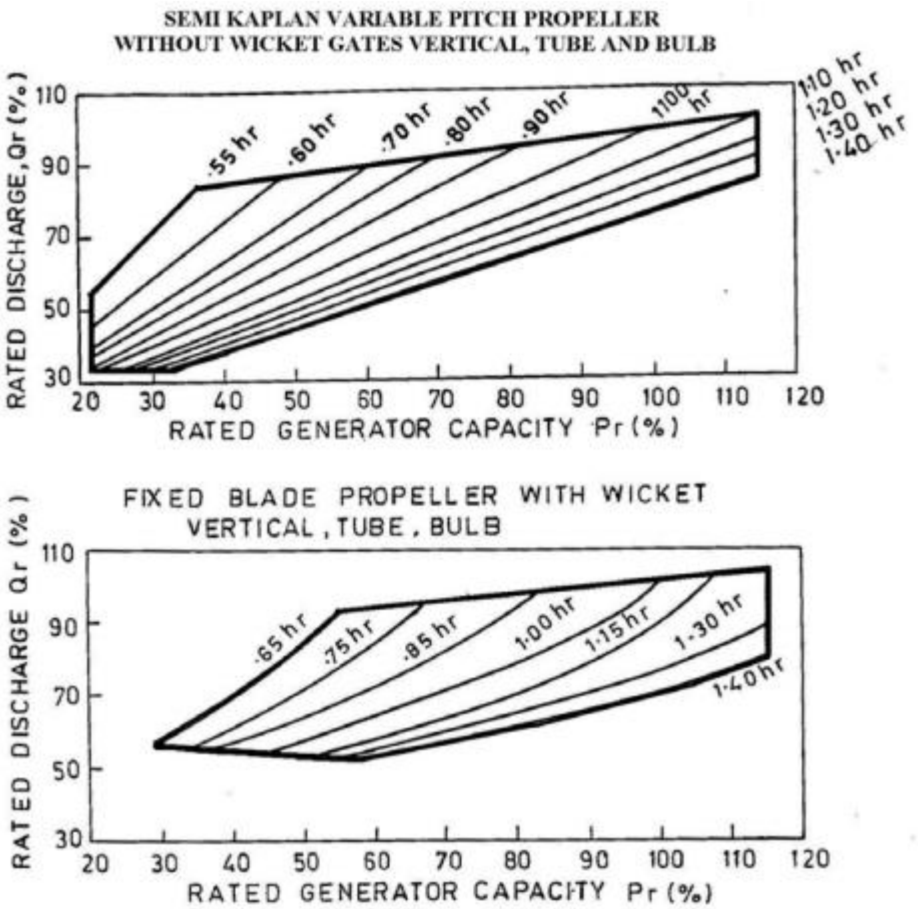
hr = Selected Design Head (meter)

Qr = Turbine Discharge at h r ε Pr (m^3/Second)

η t. r = Turbine efficiency at h r ε Pr (%)

η g = Generator efficiency , (%)

Francis and Kaplan performance curves (Typical)



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Propeller turbine performance curves (Typical)

Turbine Performance Curves for Feasibility Studies

Figure 1 and figure 2 show typical performance characteristics for Francis, and Kaplan (variable pitch blade propeller with wicket gates). Propeller (fixed blades with wicket gates) and semi Kaplan (variable pitch blades without wicket gates) type turbine. These curves are based on the Feasibility Studies for small scale hydro power Additions – Guide manual by US Army Corps of Engineers – 1979. These curves were developed from typical performance curves of the turbines of a special speed that was average for the head range considered in the guidelines. Comparisons of performance curves of various specific speed runners were made and the average performance values were used. The maximum error occurs at the lowest Pr and was approximately three percent. These curves may be used to determine the power output of the turbine and generator when the flow rates and heads are known. The curves show percent turbine discharge, percent Q_r versus percent generator rating, percent Pr throughout the range of operating heads for the turbine.

Following determination of the selected turbine capacity the power output at heads and flows above and

below rated head (hr) and flow (Qr) may be determined from the curves as follows:
Calculate the rated discharge Qr using the efficiency values-

$Qr = Pr / (9.804 \times hr \times \eta t.r \times \eta g)$, ($m^3/s$)

Where,
Pr, Dr = rated capacity and discharge
$\eta t.r$ = Turbine efficiency at rated load (%)
ηg = generator efficiency

Compute the % discharge, % Qr and find the % Pr on the approximate hr line. Calculate the power output.

P = % Pr x Pr (kW)

The thick lines at the boarder of the curves represent limits of satisfactory operation within normal industry guarantee standards. The top boundary line represents maximum recommended capacity at rated capacity.

The turbine can be operated beyond these gate openings; however, cavitation guarantee generally does not apply these points. The bottom boundary line represents the limit of stable operation. The bottom limits vary with manufacturer. Reaction turbines experience a rough operation somewhere between 20 to 40% of rated discharge with the vibration and/or power surge. It is difficult to predict the magnitude and range of the rough operation as the water passageway configuration of the powerhouse affects this condition. Where operation is required at lower output, strengthening vanes can be placed in the draft tube below the discharge of the runner to minimize the magnitude of the disturbance. These modifications reduce the efficiency at higher loads. The right hand boundary is established from generator guarantees of 115% of rated capacity. The head operation boundaries are typical; however, they do vary with manufacturer. It is
seen that these typical performance curves are satisfactory for preliminary feasibility assessments.

When the % Qr for a particular selection is beyond the curve boundaries, generation is limited to the maximum % pr for the hr. The excess water must be bypassed. When the % or is below the boundaries, no power can be generated. When the hr is above or below the boundaries, no power can be generated.

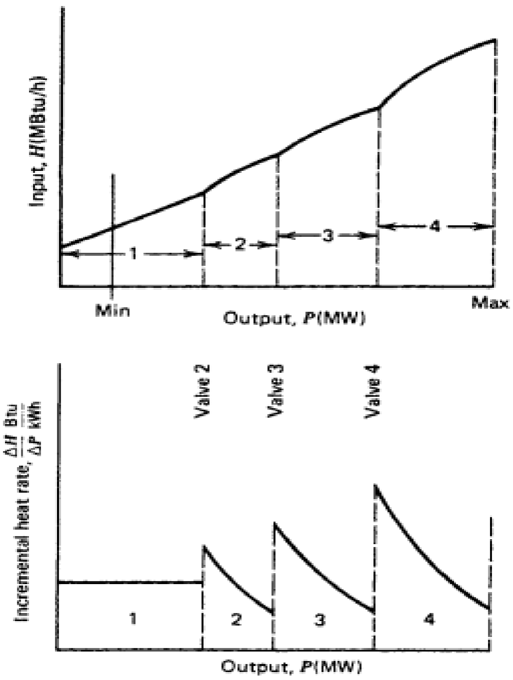
The optimum number of turbines may be determined by use of these curves for annual power generation. If power is being lost because the % or is consistently below the lower boundaries, the annual energy produced by lowering the kW rating of each unit and adding a unit should be computed. If the total construction cost of the powerhouse is assumed to roughly equal the cost of the turbine and generator, the cost per kWh derived above can be doubled and compared with the financial value of the energy. If the selection of more turbines seems favorable from this calculation, it should be pursued in further detail with more accurate studies. Conversely, the first selection of the number of turbines may be compared with a lesser number of units and compared on a cost per kWh basis as described above.

Following the establishment of the numbers of units, the rating point of the turbines can be optimized. This generally is done after an estimate of the total project cost has been made. Annual power production of turbines having a higher rating and a lower rating should be calculated and compared to the annual power production of the turbine selected. With the annual estimate, cost per kWh may be calculated for the selected. With the annual estimate, cost per kWh may be calculated for the selected turbine. Total project cost for the lower and higher capacity ratings may be estimated by adding the turbine/generator costs from the cost chart and correcting the remaining costs on a basis of constant cost per kW capacity. Rates of incremental cost divided by incremental energy generation indicate economic feasibility.

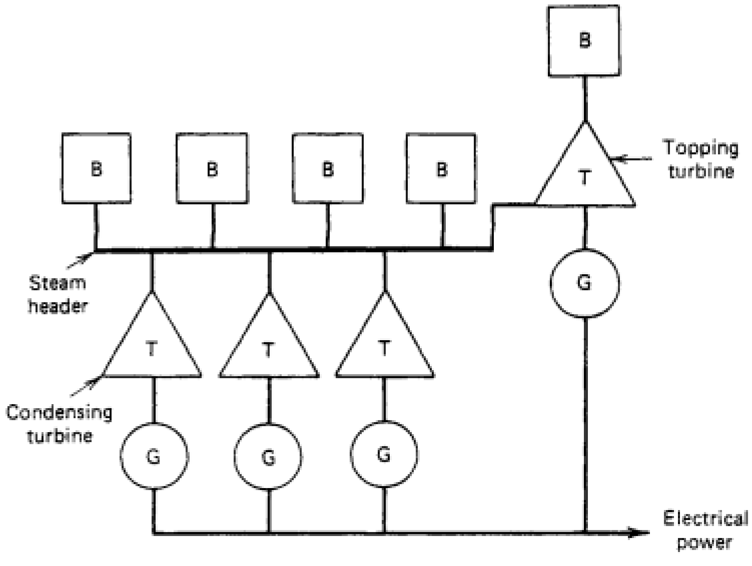
The rated head of the turbine can be further refined by optimization in a similar manner. The annual power production is computed for higher and lower heads with the same capacity rating. The rated head yielding the highest annual output should be used. The boundaries established on these curves are typical. Should energy output of a particular site curtailed, it is suggested that turbine manufacturers be consulted as these boundaries can be expanded under certain conditions.

VARIATIONS IN STEAM UNIT CHARACTERISTICS

A number of different steam unit characteristics exist. Large steam turbine generators will have a number of steam admission valves that are opened in sequence to obtain ever-increasing output of the unit. Figure shows both an input-output and an incremental heat rate characteristic for a unit with four valves. As the unit loading increases, the input to the unit increases and the incremental heat rate decreases between the opening points for any two valves. However, when a valve is first opened, the throttling losses increase rapidly and the incremental heat rate rises suddenly. This gives rise to the discontinuous type of incremental heat rate characteristic shown in Figure. It is possible to use this type of characteristic in order to schedule steam units, although it is usually not done. This type of input-output characteristic is nonconvex; hence, optimization techniques that require convex characteristics may not be used with impunity. Another type of steam unit that may be encountered is the common-header plant, which contains a number of different boilers connected to a common steam line (called a common header). Figure is a sketch of a rather complex



Characteristics of a steam turbine generator with four steam valves.



A common-header steam plant.

common-header plant. In this plant there are not only a number of boilers and turbines, each connected to the common header, but also a “topping turbine” connected to the common header. A topping turbine is one in which steam is exhausted from the turbine and fed not to a condenser but to the common steam header. A common-header plant will have a number of different input-output characteristics that result from different combinations of boilers and turbines connected to the header. Common-header plants were constructed originally not only to provide a large electrical output from a single plant, but also to provide steam send out for the heating and cooling of buildings in dense urban areas. After World War 11, a number of these plants were modernized by the installation of the type of topping turbine shown in Figure . For a period of time during the 1960s, these common-header plants were being dismantled and replaced by modern, efficient plants. However, as urban areas began to reconstruct, a number of metropolitan utilities found that their steam loads were growing and that the common-header plants could not be dismantled but had to be expected to provide steam supplies to new buildings. Combustion turbines (gas turbines) are also used to drive electric generating units. Some types of power generation units have been derived from aircraft gas turbine units and others from industrial gas turbines that have been developed for applications like driving pipeline pumps. In their original applications, these two types of combustion turbines had dramatically different duty cycles. Aircraft engines see relatively short duty cycles where power requirements vary considerably over a flight profile. Gas turbines in pumping duty on pipelines would be expected to operate almost continuously throughout the year. Service in power generation may require both types of duty cycle. Gas turbines are applied in both a simple cycle and in combined cycles. In the simple cycle, inlet air is compressed in a rotating compressor (typically by a factor of 10 to 12 or more) and then mixed and burned with fuel oil or gas in a combustion chamber. The expansion of the high-temperature gaseous products in the turbine drives the compressor, turbine, and generator. Some designs use a single shaft for the turbine and compressor, with the generator being driven through a suitable set of gears. In larger units the generators are driven directly, without any gears. Exhaust gases are discharged to the atmos- phere in the simple cycle units. In combined cycles the exhaust gases are used to make steam in a heat-recovery steam generator before being discharged.

The early utility applications of simple cycle gas turbines for power generation after World War I1 through about the 1970s were generally to supply power for peak load periods. They were fairly low efficiency units that were intended to be available for emergency needs and to insure adequate generation reserves in case of unexpected load peaks or generation outages. Net full-load heat rates were typically 13,600 Btu/kWh (HHV). In the 1980s and 199Os, new, large, simple cycle units with much improved heat rates were used for power generation. Figure shows the approximate, reported range of heat rates

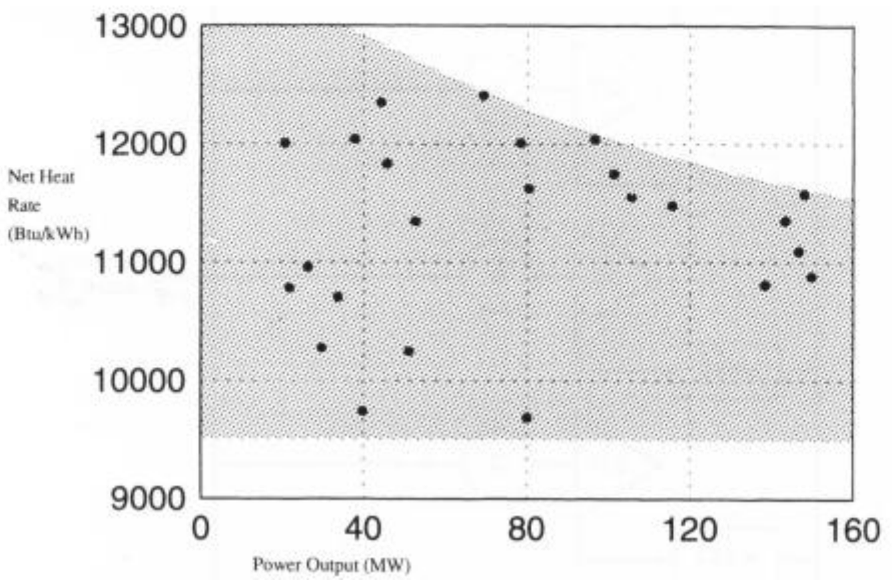
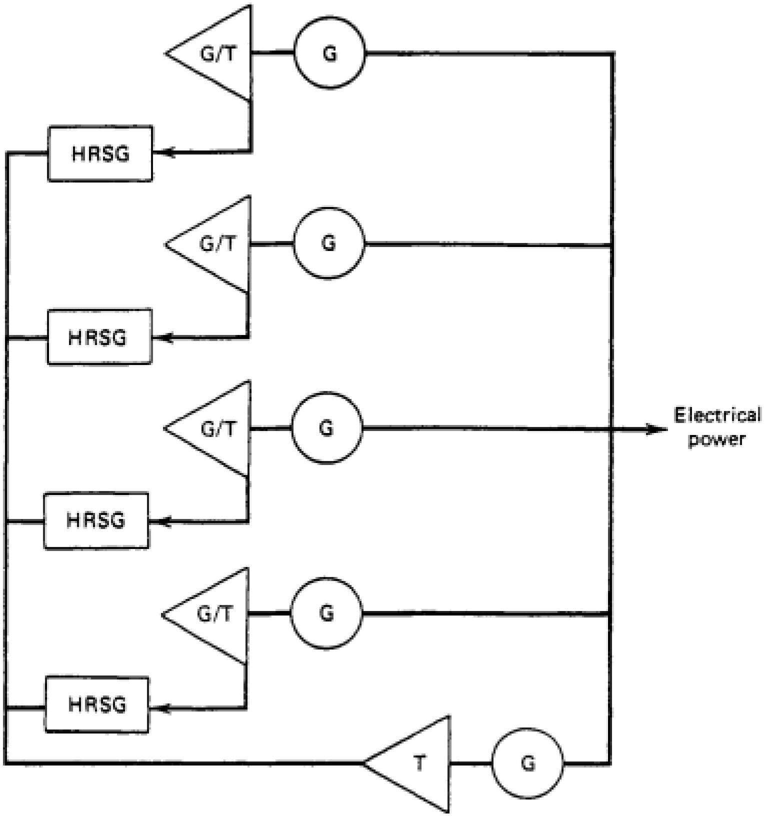


FIG. Approximate net heat rates for a range of simple cycle gas turbine units. Units are fired by natural gas and represent performance at standard conditions of an ambient temperature of 15°C at sea level. (Heat rate data from reference 1 were adjusted by 13% to represent HHVs and auxiliary power needs.)

for simple cycle units. These data were taken from a 1990 publication (reference 1) and were adjusted to allow for the difference between lower and higher heating values for natural gas and the power required by plant auxiliaries. The data illustrate the remarkable improvement in gas turbine efficiencies achieved by the modern designs. Combined cycle plants use the high-temperature exhaust gases from one or more gas turbines to generate steam in heat-recovery steam generators (HRSGs) that are then used to drive a steam turbine generator. There are many different arrangements of combined cycle plants; some may use supplementary boilers that may be fired to provide additional steam. The advantage of a combined

cycle is its higher efficiency. Plant efficiencies have been reported in the range between 6600 and 9000 Btu/kWh for the most efficient plants. Both figures are for HHVs of the fuel (see reference 2). A 50% efficiency would correspond to

a net heat rate of 6825 Btu/kWh. Performance data vary with specific cycle and plant designs. Reference 2 gives an indication of the many configurations that have been proposed. Part-load heat rate data for combined cycle plants are difficult to ascertain from available information.



A combined cycle plant with four gas turbines and a steam turbine generator.

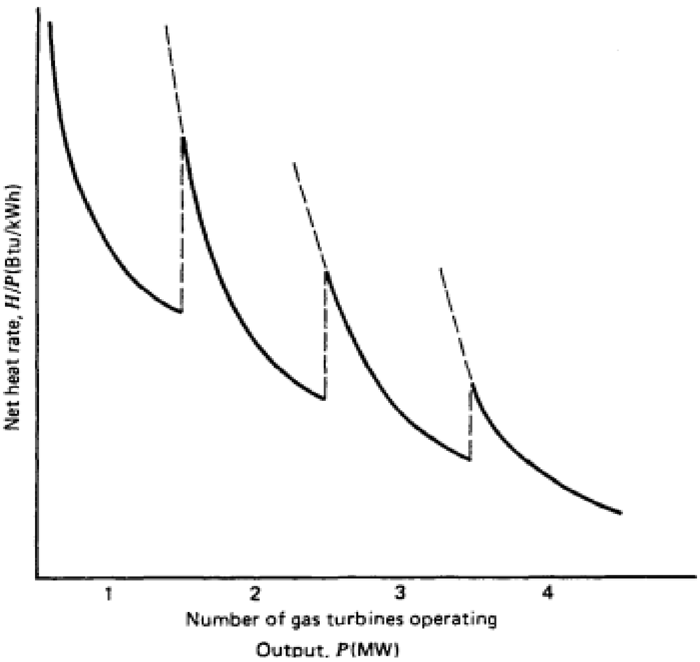


FIG. Combined cycle plant heat rate characteristic

Figure shows the configuration of a combined cycle plant with four gas turbines and HRSGs and a steam turbine generator. The plant efficiency characteristics depend on the number of gas turbines in operation. The shape of the net heat rate curve shown in Figure illustrates this. Incremental heat rate characteristics tend to be flatter than those normally seen for steam turbine units.

ECONOMIC DISPATCH WITH PIECEWISE LINEAR INCREMENTAL FUNCTION AND LINE LOSS:

Mathematically, the economic dispatch problem with piecewise linear incremental cost function and line loss is formed as following equations:

$$\lambda = pf_i(m_{i,j}P_i + b_{i,j}) \quad P_{i\min} < P_i < P_{i\max} \qquad (1)$$

$$\sum P_i = Pl_{oad} + P_{loss}$$

$$pf_i = \frac{1}{1 - \frac{\partial P_{loss}}{\partial P_i}}$$

$$P_{loss} = P^T[B]P + B_0^T P + B_{00}$$

Where,

P_i: the power of ith generator;

$m_{i,j}$ and $b_{i,j}$ are the coefficients of jth segment of ith generator's linear incremental function;

pf_i: penalty factor of ith generator;

P : vector of all generator bus;

P_{loss}: the total power loss in transmission line, which is expressed as the function of generator output;

[B], B_0, B_{00}: loss coefficients;

The equation (1) states that when the system operates at its optimal state, A should be equal for each generator except the one that hits its minimum or maximum. Traditional algorithms are infrequently used to solve economic dispatch because of two factors:

(1) Penalty factor brings nonlinearity to the equation;

(2) Many standard techniques such as in paragraph one fail or end up at suboptimal breakpoints of piecewise curves.

To continue the search and find the optimal solution, a new algorithm bas been developed.

THE ECONOMIC DISPATCH ALGORTHIM

The method developed here to solve economic dispatch problem is called the modified lambda and penalty factor iteration method (MLPFI). The flow chart of the algorithm is shown in Fig. Instead of solving nonlinear equations which are introduced by penalty factor, two iteration loops are used in the algorithm. In the outer loop, an initial value of Poi is set and based on Poi, penalty factor and power loss are calculated. The calculated penalty factor is replaced into (1) to form a linear equation for solving Pi. The calculated Pi will update the penalty factor until the error of the current Pi and last Pi is within the tolerance. At the inner loop, an initial value of lambda is set and generators are scheduled to meet this value. The megawatt output for the units is added together and compared to the desired total. Depending on the difference and whether the resulting total is above or below the desired level, a new value of lambda is tried. This iteration is repeated until the incremental cost is found that gives the correct desired value. MLPFI is different from the standard lambda iteration method, it considers the influence of breakpoint of piecewise linear curve, in this paper, a sorted table method(STM) is used to generate a priority list table shown in Table 1, for setting the initial value of lambda and the searching path of Pi.

Table1: Priority Table

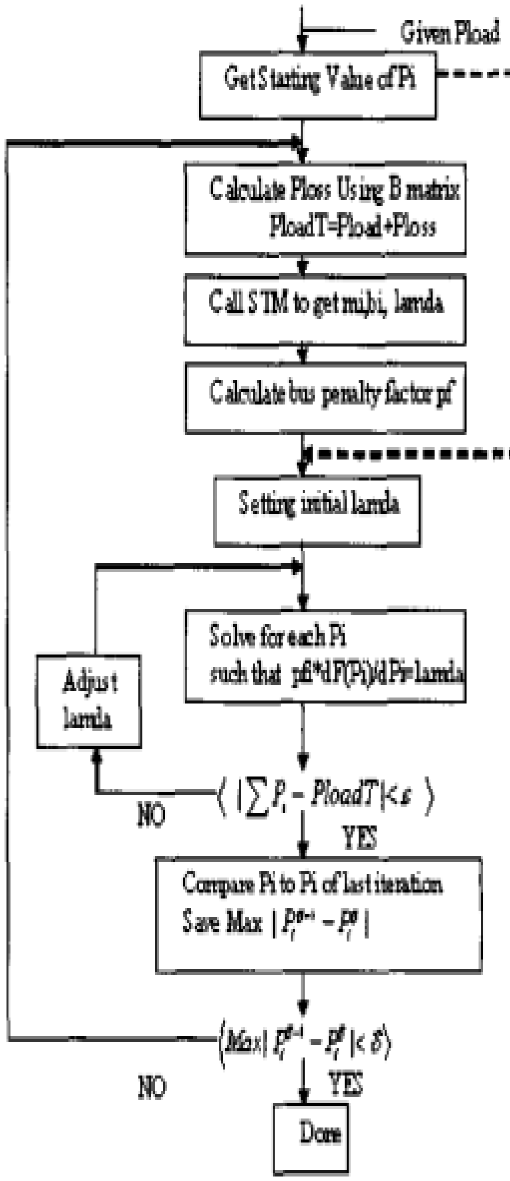
Breakpoint	SIC	Psys	Unit Output and Operating Mode		
			PG1 Mode	PG2 Mode	PG3 Mode
1	1.099	40	min	min	min
2	1.2586	56	Coo	min	min
3	1.2874	63	coor	coor	min
4	1.3950	91	coor	coor	min
5	1.4444	113	coor	coor	Coor
6	1.4819	127	coor	coor	Coor
7	1.5066	137	coor	coor	Coor
8	1.6182	178	coor	coor	Coor
9	1.6740	209	coor	coor	Max
10	1.7255	220	Coor	Coor	Max
*11	1.7270	220	Coor	Coor	Max
12	2.1195	266	Max	Coor	Max
13	2.1721	270	Max	Max	Max

Where: each breakpoint of generators' piecewise function; SIC: System Incremental Cost, which is picked up from Psys: Total power generation level for its according SIC; PGi mode: Min and Max mean that generator is operating at this lower or upper boundary level; Coor means that generation level is on its corresponding searching path;

The actual table is saved as a following matrix:

```
lamda=[1.099    40   -100   -100   -100;
       1.2586   56     1    -100   -100;
       1.2874   63     1      1    -100;
       1.3950   91     2      1    -100;
       1.4444  113     2      1       1;
       1.4819  127     3      1       1;
       1.5066  137     3      2       1;
       1.6182  178     3      2       2;
       1.6740  209     3      2       3;
       1.7255  220     3      2     100;
       2.1195  266     4      3     100;
       2.1721  270   100      3     100; ]
```

During each outer loop iteration, the total desired power is compared with Psys to get the initial lambda from SIC and search path from PG mode. This iteration method can assure that the search is continuing even if it hits the breakpoint of the curve.At the beginning of algorithm, initial operation points are needed to set for Poi. In the algorithm, the initial Poi is set as the no loss optimal operation point. The whole algorithm is developed in Matlab. The program includes three parts: one is for calculating the loss coefficient from transmission system data; one is for calculating the mi, hi and rted table from generator data; the other is to do the lambda and penalty factor iteration.



Flow Chart of the Economic Dispatch Algorithm.

ECONOMIC DISPATCH SOLUTION BY LAMBDA-ITERATION METHOD

- Block diagram of the lambda-iteration method of solution for the all-thermal, dispatching problem-neglecting losses.
- We can approach the solution to this problem by considering a graphical technique for solving the problem and then extending this into the area of computer algorithms.
- Suppose we have a three-machine system and wish to find the optimum economic operating point.
- One approach would be to plot the incremental cost characteristics for each of these three units on the same graph, In order to establish the operating points of each of these three units such that we have minimum cost and at the same time satisfy the specified demand, we could use this sketch and a ruler to find the solution.

- That is, we could assume an incremental cost rate (λ) and find the power outputs of each of the three units for this value of incremental cost. the three units for this value of incremental cost.

- Of course, our first estimate will be incorrect.

- If we have assumed the value of incremental cost such that the total power output is too low, we must increase the 3. value and try another solution.

- With two solutions, we can extrapolate (or interpolate) the two solutions to get closer to the desired value of total received power.

- By keeping track of the total demand versus the incremental cost, we can rapidly find the desired operating point.

- If we wished, we could manufacture a whole series of tables that would show the total power supplied for different incremental cost levels and combinations of units.

- That is, we will now establish a set of logical rules that would enable us to accomplish the same objective as we have just done with ruler and graph paper.

- The actual details of how the power output is established as a function of the incremental cost rate are of very little importance.

- We could, for example, store tables of data within the computer and interpolate between the stored power points to find exact power output for a specified value of incremental cost rate.

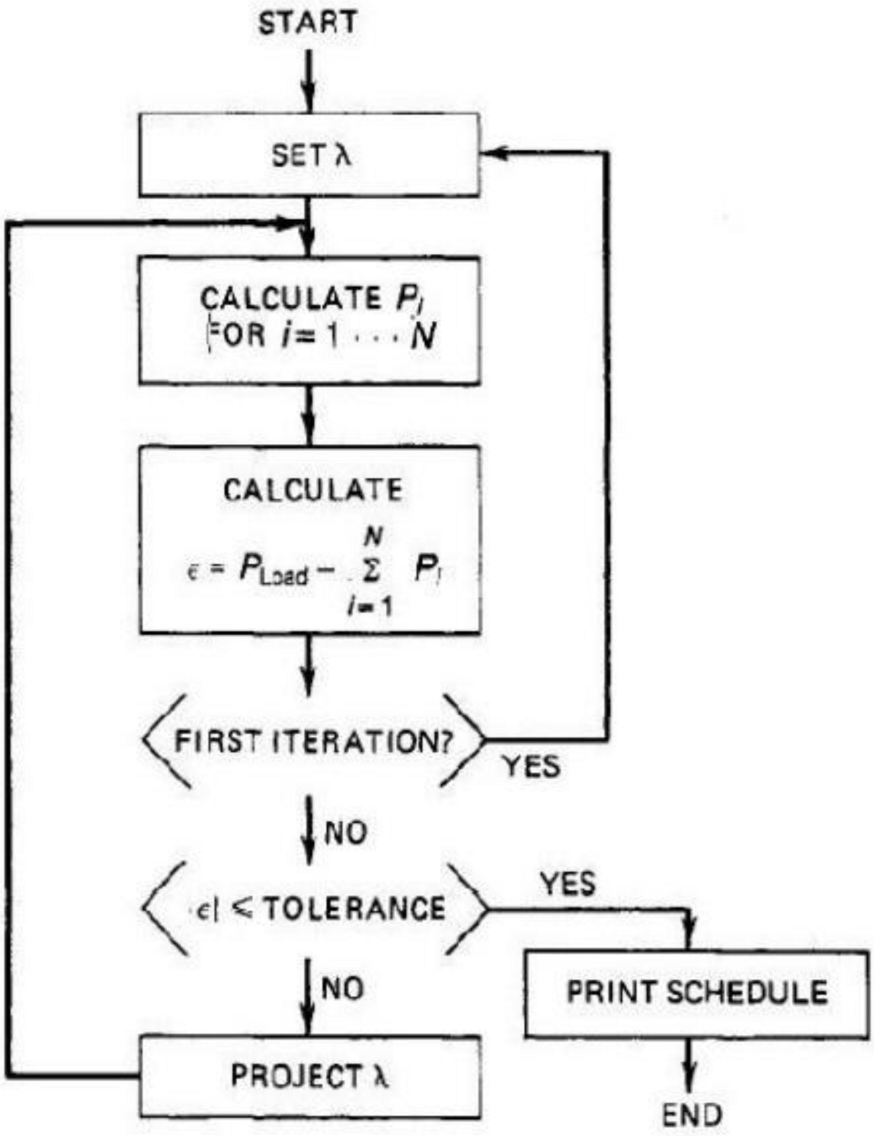
- Another approach would be to develop an analytical function for the power output as a function of the incremental cost rate, store this function (or its coefficients) in the computer, and use this to establish the output of each of the individual units.
- This procedure is an iterative type of computation, and we must establish stopping rules.

- Two general forms of stopping rules seem appropriate for this application.

- The lambda- iteration procedure converges very rapidly for this particular type of optimization problem.

- The actual computational procedure is slightly more complex than that indicated ,since it is necessary to observe the operating limits on each of the units during the course of the computation.

- The well-known Newton-Raphson method may be used to project the incremental cost value to drive the error between the computed and desired generation to zero.



Economic Dispatch by Lambda-iteration method

LINEAR PROGRAMING METHOD:

To make the unit commitment problem amenable to linear programming by casting it in terms of job scheduling. Rather than using an integer programming approach to determine which generators need to run to meet the power bound, we can use and LP to decide when all generators should run (with time as the continuous variable).

The user speci_es a set of generators and consumers and their associated jobs (\generators" will be used to refer to both). Each job ji has an associated scheduled start time js
i , min and max duration j _ d
i ; j ^ d
i , cost jc
i
and production rate (aka watts) jw
i . Consumer jobs di_er from generator

jobs in that their schedules are specified by the user (rather than solved for by the LP) and that the production rate is non-positive (as opposed to non-negative for generators). The user defines the power bound in terms of consumer jobs: the LP constrains total energy between any two job starts to be nonnegative.

All time between t = 0 and t = T must be completely filled with jobs on all generators, but the user is free to specify \idle" jobs with zero production (and possible zero cost). Jobs are well-ordered on a generator, allowing the user to specify \startup" and \shutdown" jobs that accrue some minimum cost and time but do not necessarily contribute to production.

The LP schedules jobs in order to minimize costs between two user-specified job start times. If these times are t
= 0 and t = T then the user must know a priori the optimal number of jobs to schedule. However, the user can force the LP to select the correct number of jobs if the period in question is less than total schedulable time. This requires the user provide enough jobs to be scheduled, which is far easier to determine than the optimal number of jobs.

$\lvert\mathbb{X}\rvert$	Cardinality of set $\mathbb{X}$.
$\mathbb{G}$	Set of all generators and consumers IDs.[a]
$\mathbb{J}_{\mathfrak{g}}$	Set of all job IDs on generator g.
T	Scheduled time for all jobs.[b]
j_i	ID of the ith job.
j_i^s	Scheduled[c] start time of job j_i.
j_i^c	Cost of job j_i per unit time.
j_i^w	Production of job j_i per unit time (i.e. watts).
$j_i^{\hat{d}}$	Maximum duration of job j_i.
$j_i^{\bar{d}}$	Minimum duration of job j_i.

[a] Consumers generate using negative watts.

[b] This should be significantly larger than the time over which we optimize costs.

[c] The scheduled start times of the consumer jobs (with negative watts) are provided as paramters. The scheduled start times of the generating jobs are determined by solving the LP problem.

If there exist job sets outside of the optimized time then by definition there were enough jobs. If on any generator there do not exist job sets outside the optimized time then there may not have been enough jobs schedulable in order to reach the optimal solution. The situation may be complicated by the size of the optimized time compared to the overall time and the number and minimum duration of jobs: if too many jobs with large minima are to be scheduled in too small a margin then the margin may intefer with the solution.

We constrain the system as follows.

Sufficient time For all generators, the sum of the maximum duration of all jobs on that generator must be sufficient to exceed the total schedulable time . Otherwise, there would have to be idle time not accounted for by the system. Likewise, the sum of the minimum durations must not exceed the total available time .

Decision Variables

j_i^s	Scheduled[d] start time of job j_i.
j_i^d	Duration of job j_i.
$d_{i,k}$	Scheduled duration of job j_k occuring at or before j_i^s.
C_i	Total cost accrued up to time j_i^s.
E_i	Total energy accrued up to time j_i^s.

[d] See note b in table 2.

$$\forall g \in \mathbb{G}, \forall j \in g : \sum j^{\hat{d}} \geq T \tag{1}$$

$$\forall g \in \mathbb{G}, \forall j \in g : \sum j^{d} \leq T \tag{2}$$

Complete coverage The first task on each generator starts at time $t = 0$ (eq. 3). The last task on each generator finishes at $t = T$ (eq.4). With the exception of the final job on each generator, the start time of a particular job begins with the end of the previous job (eq. 5).

$$\forall g \in \mathbb{G}, \exists j_0 \in g : j_0^s = 0 \tag{3}$$

$$\forall g \in \mathbb{G}, \exists j_{|\mathbb{J}_g|-1} \in g : j_{|\mathbb{J}_g|-1}^s + j_{|\mathbb{J}_g|-1}^d = T \tag{4}$$

$$\forall g \in \mathbb{G}, \forall j \neq (|\mathbb{J}_g| - 1) \in g : j_i^s + j_i^d = j_{i+1}^s \tag{5}$$

Accrued duration I For two jobs on the same generator, accrued duration can be calculated trivially. For a particular job j_i, constrain the amount of time accrued by job j_k up to j_i^s.

$$\forall g \in \mathbb{G}, \forall i, k \in \mathbb{J}_g, i \leq k : d_{i,k} = 0 \tag{6}$$

$$i > k : d_{i,k} = j_k^d \tag{7}$$

Accrued duration II I really don't have a good way of explaining this.

We want to constrain $d_{i,k}$, which is the amount of time accrued in job j_k by the start of j_i (aka j_i^s). Let's start by making this a little more general.

Let $d_{t,k}$ be the accrued time in job k at point t. There are three cases of interest:

1. j_k begins and ends before time t: $d_{t,k} = j_{k+1}^s - j_k^s$

2. j_k begins and ends after time t: $d_{t,k} = 0$

3. j_k begins before time t and ends after time t: $d_{t,k} = t - j^s_k$

I believe the closest we can get to this is as follows:

$$d'_{t,k} \geq 0 \tag{8}$$
$$d'_{t,k} \geq t - j^s_k \tag{9}$$
$$d_{t,k} \geq 0 \tag{10}$$
$$d_{t,k} \leq j^s_{i+1} - j^s_i \tag{11}$$
$$d_{t,k} \leq d' \tag{12}$$

The tightest bounds are as follows.
For case 1, $0 \leq d_{t,k} \leq j^s_{i+1} - j^s_i$
For case 2, $0 \leq d_{t,k} \leq 0$ (as $t - j^s_k$ is negative)
For case 3, $0 \leq d_{t,k} \leq d'$ (as $d' < j^s_{i+1} - j^s_i$)
Without further bounds the LP could set all values of $d_{t,k}$ to zero. To prevent this, the sum of all durations for all jobs on the same generator as k must equal t for all $d_{t,k}$.

$$\forall g, h \in \mathbb{G}, \forall i \in g : j^s_i = \sum_{k \in h} d_{i,k} \tag{13}$$
$$d_{t,k} \leq d_{t+\epsilon,k} \leq d_{t,k} + \epsilon \tag{14}$$

Cost and Energy Given this it's trivial to add cost (eq. 15) and power (eq. 16) coefficients to the above in order to calculate cumulative values.

$$\forall g \in \mathbb{G}, \forall i \in g : C_i = \sum_{h \in \mathbb{G}} \sum_{k \in h} j^c_k d_{i,k} \tag{15}$$
$$\forall g \in \mathbb{G}, \forall i \in g : E_i = \sum_{h \in \mathbb{G}} \sum_{k \in h} j^w_k d_{i,k} \tag{16}$$

Power Bound To meet the power bound, the difference of the energy between any two points must be nonnegative (eq. 17).

$$\forall g, h \in \mathbb{G}, \forall i \in g, \forall k \in h \text{ s.t. } j^s_k < j^s_i : E_i - E_k \geq 0 \tag{17}$$

Optimization Finally, we optimize for cost between two user-specified points in time (eq. 18).

$$0 \leq t \leq t' \leq T : \min C_{t'} - C_t \tag{18}$$

For an optimal solution where t = 0 and t0 = T the user must know (a priori) the correct number of jobs to schedule. However, if we select a smaller range and choose a sufficiently large number of jobs to schedule, we would expect to find that some jobs were scheduled outside the optimized range. These jobs do no affect the result and their scheduling may be ignored | with three exceptions. If there is not at least one job outside the optimized range on every generator then it is possible that additional jobs may affect the answer: the solver should be rerun with increased jobs. If there are too many jobs with minimum execution times that are large enough and a total time that is small enough, the excess jobs may \crowd in" to the optimized range. And where T is too large relative to the job maximum durations, jobs in the optimized range may be \pulled out." In practice, we do not expect determining the correct number of schedulable jobs per generator will be a signi_cant issue for the power-generation domain.

ECONOMIC LOAD DISPATCH

Definition: The economic load dispatch means the real and reactive power of the generator vary within the certain limits and fulfils the load demand with less fuel cost. The sizes of the electric power system are increasing rapidly to meet the energy requirement. So the number of power plants is connected in parallel to supply the system load by an interconnection of the power system. In the grid system, it becomes necessary to operate the plant units more economically.

The economic scheduling of the generators aims to guarantee at all time the optimum combination of the generator connected to the system to supply the load demand. The economic load dispatch problem involves two separate steps. These are the online load dispatch and the unit commitment.

The unit commitment selects that unit which will anticipate load of the system over the required period at minimum cost. The online load dispatch distributes the load among the generating unit which is parallel to the system in such a manner as to reduce the total cost of supplying. It also fulfils the minute to the minute requirement of the system.

Basic Mathematical Formulation

Consider n generators in the same plant or close enough electrically so that the line losses may be neglected. Let C_1, C_2, …, C_n be the operating costs of individual units for the corresponding power outputs P_1, P_2,…., P_n respectively. If C is the total operating cost of the entire system and P_R is the total power received by the plant bus and transferred to the load, then

$$C = C_1 + C_2 + \dots\dots + C_n = \sum_{i=1}^{n} C_i \dots\dots\dots\dots equ(1)$$

$$P_R = P_1 + P_2 + \dots\dots P_n = \sum_{i=1}^{n} P_i$$

The equation (1) and equation (2) can be minimised as

$$C = \sum_{i=1}^{n} C_i$$

$$P_R - \sum_{i=1}^{n} P_i = 0$$

The above equation shows that if transmission losses are neglected, the total demand P_R at any instant must be met by the total generation. The above equation is the equality constraint.This a constrained minimising problem. This problem can be solved by using Lagrangian multiplier technique.

$$\frac{\partial C}{\partial P_i} = \lambda \ldots \ldots \ldots equ(7)$$

Since C_i is a function of P_i only. The partial derivates become full derivates, that is,

$$\frac{\partial C_i}{\partial P_i} = \frac{dC_i}{dP_i}$$

Therefore, the condition for optimum operation is

$$\frac{dC_1}{dP_1} = \frac{dC_2}{dP_2} = \ldots\ldots = \frac{dC_n}{dP_n} = \lambda$$

$$C^* = C + \lambda f \ldots \ldots \ldots \ldots equ(3)$$

where f is the equality constraint equation given by

$$P_R = \sum_{i=1}^{n} P_i = f(P_1, P_2 \ldots \ldots \ldots . P_n) = 0 \ldots \ldots \ldots equ(4)$$

And λ is the Lagrange multiplier. Combination of equations (3) and (4) gives

$$C^* = C + \lambda\left(P_R - \sum_{i=1}^{n} P_i\right) \ldots \ldots \ldots equ(5)$$

Equation (5) can be solved for minimum by determining the partial derivate of the function C* on variable Pi and equating it equal to zero.

$$\frac{\partial C^*}{\partial P_i} = \frac{\partial C}{\partial P_i} + \lambda \frac{\partial}{\partial P_i}\left(P_R - \sum_{i=1}^{n} P_i\right) = 0 \ldots \ldots \ldots . equ(6)$$

$$\frac{\partial C^*}{\partial P_i} = \frac{\partial C}{\partial P_i} + \lambda(1 - 0) = 0$$

Since the dc_i / dp_i is the increment cost generation for the generator. The above equation shows that the criterion for a most economical division of load between within a plant is that all the unit is must operate at the same incremental fuel cost. This is known as the principle of equal λ criterion or the equal incremental cost-loading principle for economic operation.

COST FUNCTION: CONCEPT AND IMPORTANCE

Concept of Cost Function:

The relationship between output and costs is expressed in terms of cost function. By incorporating prices of inputs into the production function, one obtains the cost function since cost function is derived from production function. However, the nature of cost function depends on the time horizon. In microeconomic theory, we deal with short run and long run time.

A cost function may be written as:

$C_q = f(Q_f P_f)$

Where C_q is the total production cost, Q_f is the quantities of inputs employed by the firm, and P_f is the prices of relevant inputs. This cost equation says that cost of production depends on prices of inputs and quantities of inputs used by the firm.

Importance of Cost Function:

The study of business behavior concentrates on the production process—the conversion of inputs into outputs—and the relationship between output and costs of production.

We have already studied a firm's production technology and how inputs are combined to produce output. The production function is just a starting point for the supply decisions of a firm. For any business decision, cost considerations play a great role.

Cost function is a derived function. It is derived from the production function which captures the technology of a firm. The theory of cost is a concern of managerial economics. Cost analysis helps allocation of resources among various alternatives. In fact, knowledge of cost theory is essential for making decisions relating to price and output.

Whether production of a new product is a wiser one on the part of a firm greatly depends on the evaluation of costs associated with it and the possibility of earning revenue from it. Decisions on capital investment (e.g., new machines) are made by comparing the rate of return from such investment with the opportunity cost of the funds used.

The relevance of cost analysis in decision-making is usually couched in terms of short and long periods of time by economists. In all market structures, short run costs are crucial in the determination of price and output. This is due to the fact that the basis for cost function is production and the prices of inputs that a firm pays.

On the other hand, long run cost analysis is used for planning the optimal scale of plant size. In other words, long run cost functions provide useful information for planning the growth as well as the investment policies of a firm. Growth of a firm largely depends on cost considerations.

The position of the U-shaped long run AC of a firm is suggestive of the direction of the growth of a firm. That is to say, a firm can take a decision whether to build up a new plant or to look for diversification in other markets by studying its existence on the long run AC curve. Further, it is the cost that decides the merger and takeover of a sick firm.

Non-profit sector or the government sector must also have a knowledge of cost function for decision-making. Whether the Narmada Dam is to be built or not, it should evaluate the costs and benefits 'flowing' from the dam.

BASE POINT AND PARTICIPATION FACTORS

- This method assumes that the economic dispatch problem has to be solved repeatedly by moving the generators from one economically optimum schedule to another as the load changes by a reasonably small amount.

- We start from a given schedule-the base point.

Next, the scheduler assumes a load change and investigates how much each generating unit needs to be moved (i.e.,"participate" in the load change) in order that the new load be served at the most economic operating point.

- Assume that both the first and second derivatives in the cost versus power output function are available (Le., both F; and Fy exist). The incremental cost curve of i[th] unit given in the fig.

- As the unit load is changed by an amount, the

$$\Delta\lambda_i = \Delta\lambda \cong F_i''(P_i^0)\Delta P_i$$ -------------(13)

(13) This is true for each of the N units on the system, so that

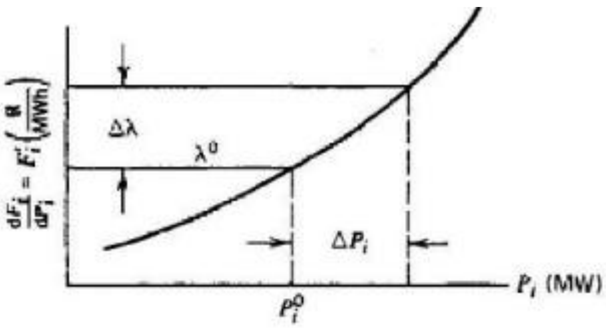
$$\Delta P_1 = \frac{\Delta\lambda}{F_1''}$$

$$\Delta P_2 = \frac{\Delta\lambda}{F_2''}$$

$$\vdots$$

$$\Delta P_N = \frac{\Delta\lambda}{F_N''}$$ ----------------(14)

The total change in generation (=change in total system demand) is, of course, the sum of the individual unit changes. Let P_d be the total demand on the generators (where $P_{load}+P_{loss}$&), then



$$\Delta P_D = \Delta P_1 + \Delta P_2 + \cdots + \Delta P_N$$

$$= \Delta\lambda \sum_i \left(\frac{1}{F_i''}\right)$$ ------------(15)

The earlier equation, 15, can be used to find the participation factor for each unit as follows

$$\left(\frac{\Delta P_i}{\Delta P_D}\right) = \frac{(1/F''_i)}{\sum_i \left(\frac{1}{F''_i}\right)} \qquad \text{------------------------------------}(16)$$

Ø The computer implementation of such a scheme of economic dispatch is straightforward.

Ø It might be done by provision of tables of the values of FY as a function of the load levels and devising a simple scheme to take the existing load plus the projected increase to look up these data and compute the factors.

Ø Somewhat less elegant scheme to provide participation factors would involve a repeat economic dispatch calculation at.

Ø The base-point economic generation values are then subtracted from the new economic generation values and the difference divided to provide the participation factors.

Ø This scheme works well in computer implementations where the execution time for the economic dispatch is short and will always give consistent answers when units reach limits, pass through break points on piecewise linear incremental cost functions, or have non convex cost curves.

THERMAL SYSTEM DISPATCHING WITH NETWORK LOSSES

Ø symbolically an all-thermal power generation system connected to an equivalent load bus through a transmission network.

Ø The economic dispatching problem associated with this particular configuration is slightly more complicated to set up than the previous case.

Ø This is because the constraint equation is now one that must include the network losses.

Ø The objective function, F_T, is the same as that defined for Eq.10

$$P_{load} + P_{loss} - \sum_{i=1}^{N} P_i = \phi = 0 \qquad \text{------------------} (10)$$

Ø The same procedure is followed in the formal sense to establish the necessary conditions for a minimum-cost operating solution, The Lagrange function is shown in Eq.11.

Ø In taking the derivative of the Lagrange function with respect to each of the individual power outputs, P_i, it must be recognized that the loss in the transmission network, P_{loss} is a function of the network impedances and the currents flowing in the network.

Ø For our purposes, the currents will be considered only as a function of the independent variables P_i and the load P_{load} taking the derivative of the Lagrange function with respect to any one of the N values of P_i results in Eq. 11. collectively as the coordination equations

$$\mathscr{L} = F_T + \lambda\phi$$

$$\frac{\partial \mathscr{L}}{\partial P_i} = \frac{dF_i}{dP_i} - \lambda\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right) = 0$$

or

$$\frac{dF_i}{dP_i} + \lambda \frac{\partial P_{loss}}{\partial P_i} = \lambda$$

$$P_{load} + P_{loss} - \sum_{i=1}^{N} P_i = 0$$

Ø It is much more difficult to solve this set of equations than the previous set with no losses since this second set involves the computation of the network loss in order to establish the validity of the solution in satisfying the constraint equation.

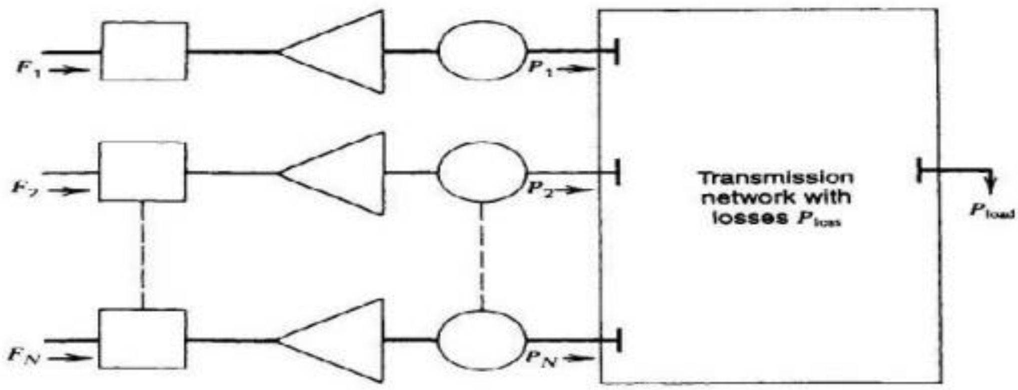
Ø There have been two general approaches to the solution of this problem.

Ø The first is the development of a mathematical expression for the losses in the network solely as afunction of the power output of each of the units.

Ø This is the loss-formula method discussed at some length in Kirchmayer‟s Economic Operation ofPower Systems.

Ø The other basic approach to the solution of this problem is to incorporate the power flow equations as essential constraints in the formal establishment of the optimization problem.

Ø This general approach is known as the optimal power flow.



N thermal units serving load through transmission network

UNIT – II
UNIT COMMITMENT

UNIT COMMITMENT - INTRODUCTION

Ø The life style of a modern man follows regular habits and hence the present society also follows regularly repeated cycles or pattern in daily life.

Ø Therefore, the consumption of electrical energy also follows a predictable daily, weekly and seasonal pattern.

Ø There are periods of high power consumption as well as low power consumption.

Ø It is therefore possible to commit the generating units from the available capacity into service to meet the demand.

Ø The previous discussions all deal with the computational aspects for allocating load to a plant in the most economical manner.

Ø For a given combination of plants the determination of optimal combination of plants for operation at any one time is also desired for carrying out the aforesaid task.
Ø The plant commitment and unit ordering schedules extend the period of optimization from a few minutes to several hours.
Ø From daily schedules weekly patterns can be developed.

Ø Likewise, monthly, seasonal and annual schedules can be prepared taking into consideration the repetitive nature of the load demand and seasonal variations.

Ø Unit commitment schedules are thus required for economically committing the units in plants to service with the time at which individual units should be taken out from or returned to service.

1.Constraints In Unit Commitment

Ø Many constraints can be placed on the unit commitment problem. The list presented here is by no means exhaustive.

Ø Each individual power system, power pool, reliability council, and so forth, may impose different rules on the scheduling of units, depending on the generation makeup, load-curve characteristics, and such.

2. Spinning Reserve

Ø Spinning reserve is the term used to describe the total amount of generation available from all units synchronized (i.e., spinning) on the system, minus the present load and losses being supplied.

Ø Spinning reserve must be carried so that the loss of one or more units does not cause too far a drop in system frequency.

Ø Quite simply, if one unit is lost, there must be ample reserve on the other units to make up for the loss in a specified time period.

Ø Spinning reserve must be allocated to obey certain rules, usually set by regional reliability councils (in the United States) that specify how the reserve is to be allocated to various units.

Ø Typical rules specify that reserve must be a given percentage of forecasted peak demand, or that reserve must be capable of making up the loss of the most heavily loaded unit in a given period of time.

Ø Others calculate reserve requirements as a function of the probability of not having sufficient generation to meet the load.

Ø Not only must the reserve be sufficient to make up for a generation-unit failure, but the reserves must be allocated among fast-responding units and slow-responding units.

Ø This allows the automatic generation control system to restore frequency and interchange quickly in the event of a generating-unit outage.

Ø Beyond spinning reserve, the unit commitment problem may involve various classes of

“scheduled reserves” or “off-line” reserves.

Ø These include quick-start diesel or gas-turbine units as well as most hydro-units and pumped-storage hydro-units that can be brought on-line, synchronized, and brought up to full capacity quickly.

Ø As such, these units can be “counted” in the overall reserve assessment, as long as their time to come up to full capacity is taken into account.

Ø Reserves, finally, must be spread around the power system to avoid transmission system limitations (often called “bottling” of reserves) and to allow various parts of the system to run as “islands,” should they become electrically disconnected.

3. Thermal Unit Constraints

Ø Thermal units usually require a crew to operate them, especially when turned on and turned off.

Ø A thermal unit can undergo only gradual temperature changes, and this translates into a time period of some hours required to bring the unit on-line.

Ø As a result of such restrictions in the operation of a thermal plant, various constraints arise, such as:

1. Minimum up time: once the unit is running, it should not be turned off immediately

2. Minimum down time: once the unit is decommitted, there is a minimum time before it can be recommitted.
Cc = cold-start cost (MBtu)

F = fuel cost
Cf= fixed cost (includes crew expense, maintenance expenses) (in R)

α = thermal time constant for the unit t = time (h) the unit was cooled

Start-up cost when banking = Ct x t x F+Cf

Where

Ct = cost (MBtu/h) of maintaining unit at operating temperature
Up to a certain number of hours, the cost of banking will be less than the cost of cooling, as is illustrated in Figure.

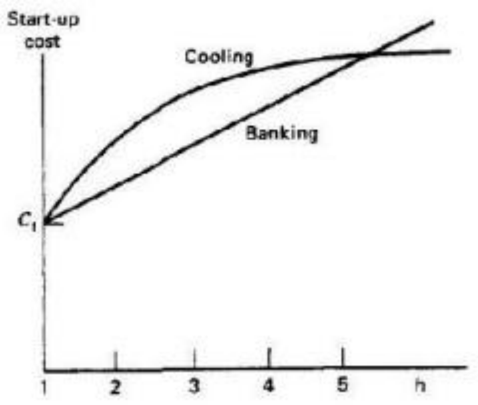
Finally, the capacity limits of thermal units may change frequently, due to maintenance or unscheduled outages of various equipment in the plant; this must also be taken.

4. Other Constraints

1. Hydro-Constraints
Ø Unit commitment cannot be completely separated from the scheduling of hydro-units.

Ø In this text, we will assume that the hydrothermal scheduling (or "coordination") problem can be separated from the unit commitment problem.

Ø We, of course, cannot assert flatly that our treatment in this fashion will always result in an optimal solution.



Hydro Constrains

2. Must Run

Ø Some units are given a must-run status during certain times of the year for reason of voltage support on the transmission network or for such purposes as supply of steam for uses outside the steam plant itself.

3. Fuel Constraints

Ø We will treat the "fuel scheduling" problem system in which some units have limited fuel, or else have constraints that require them to burn a specified amount of fuel in a given time, presents a most challenging unit commitment problem.

UNIT COMMITMENT SOLUTION METHODS

The commitment problem can be very difficult. As a theoretical exercise, let us postulate the following situation.

1. We must establish a loading pattern for M periods.

2. We have N units to commit and dispatch.

3. The M load levels and operating limits on the N units are such that any one unit can supply the individual loads and that any combination of units can also supply the loads.

Next, assume we are going to establish the commitment by enumeration (brute force). The total number of combinations we need to try each hour is,

C (N, 1) + C (N,2) + ... + C(N, N - 1) + C (N , N) = 2N – 1-----------------------------------(18)

Where C (N, j) is the combination of N items taken j at a time. That is,

$$C(N, j) = \left[\frac{N!}{(N-j)!\,j!}\right]$$

$$j! = 1 \times 2 \times 3 \times \ldots \times j$$

For the total period of M intervals, the maximum number of possible combinations is (2N - l)M, which can become a horrid number to think about.

For example, take a 24-h period (e.g., 24 one-hour intervals) and consider systems with 5, 10, 20 and 40 units.

Ø These very large numbers are the upper bounds for the number of enumerations required.

Ø Fortunately, the constraints on the units and the load-capacity relationships of typical utility systems are such that we do not approach these large numbers.

Ø Nevertheless, the real practical barrier in the optimized unit commitment problem is the high dimensionality of the possible solution space.

Ø The most talked-about techniques for the solution of the unit commitment problem are:

1. Priority-list schemes,

2. Dynamic programming (DP),

3. Lagrange relation (LR).

1. Priority-List Method

Ø The simplest unit commitment solution method consists of creating a priority list of units.

Ø A simple shut-down rule or priority-list scheme could be obtained after an exhaustive enumeration of all unit combinations at each load level.

Ø The priority list could be obtained in a much simpler manner by noting the full- load average production cost of each unit, where the full-load average production cost is simply the net heat rate at full load multiplied by the fuel cost.

Priority List Method:

Priority list method is the simplest unit commitment solution which consists of creating a priority list of units.

Full load average production cos t= Net heat rate at full load X Fuel cost

Assumptions:

1. No load cost is zero

2. Unit input-output characteristics are linear between zero output and full load

3. Start up costs are a fixed amount

4. Ignore minimum up time and minimum down time Steps to be followed

1. Determine the full load average production cost for each units

2. Form priority order based on average production cost

3. Commit number of units corresponding to the priority order

4. Alculate PG1, PG2 ………….PGN from economic dispatch problem for the feasible combinations only.

5. For the load curve shown.

Assume load is dropping or decreasing, determine whether dropping the next unit will supply generation & spinning reserve.

If not, continue as it is

If yes, go to the next step

6. Determine the number of hours H, before the unit will be needed again.

7. Check H< minimum shut down time.

If not, go to the last step If yes, go to the next step

8. Calculate two costs

1. Sumof hourly production for the next H hours with the unit up

2. Recalculate the same for the unit down + start up cost for either cooling or banking

9. Repeat the procedure until the priority

list Merits:

1. No need to go for N combinations

2. Take only one constraint

3. Ignore the minimum up time & down time

4. Complication reduced

Demerits:

1. Start up cost are fixed amount

2. No load costs are not considered.

2. Dynamic-Programming Solution

Dynamic programming has many advantages over the enumeration scheme, the chief advantage being a reduction in the dimensionality of the problem. Suppose we have found units in a system and any combination of them could serve the (single) load. There would be a maximum of 24 - 1 = 15 combinations to test. However, if a strict priority order is imposed, there are only four combinations to try:

Priority 1 unit

Priority 1 unit + Priority 2 unit

Priority 1 unit + Priority 2 unit + Priority 3 unit

Priority 1 unit + Priority 2 unit + Priority 3 unit + Priority 4 unit

The imposition of a priority list arranged in order of the full-load averagecost rate would result in a theoretically correct dispatch and commitment only if:

1. No load costs are zero.

2. Unit input-output characteristics are linear between zero output and full load.

3. There are no other restrictions.

4. Start-up costs are a fixed amount.

In the dynamic-programming approach that follows, we assume that:

1. A state consists of an array of units with specified units operating and

2. The start-up cost of a unit is independent of the time it has been off-line

3. There are no costs for shutting down a unit.

4. There is a strict priority order, and in each interval a specified minimum the rest off-line. (i.e., it is a fixed amount).amount of capacity must be operating.

A feasible state is one in which the committed units can supply the required load and that meets the minimum amount of capacity each period.

3. Forward DP Approach

Ø One could set up a dynamic-programming algorithm to run backward in time starting from the final hour to be studied, back to the initial hour.

Ø Conversely, one could set up the algorithm to run forward in time from the initial hour to the final hour.

Ø The forward approach has distinct advantages in solving generator unit commitment. For example, if the start-up cost of a unit is a function of the time it has been off-line (i.e., its temperature), then a forward dynamic-program approach is more suitable since the previous history of the unit can be computed at each stage.

Ø There are other practical reasons for going forward.

Ø The initial conditions are easily specified and the computations can go forward in time as long as required.

Ø A forward dynamic-programming algorithm is shown by the flowchart

The recursive algorithm to compute the minimum cost in hour K with combination

$$F_{cost}(K,I)= \min[P_{cost}(K,I)+S_{cost}(K-1,L:K,I)+F_{cost}(K-1,L)]$$

---------------------------------- (20)

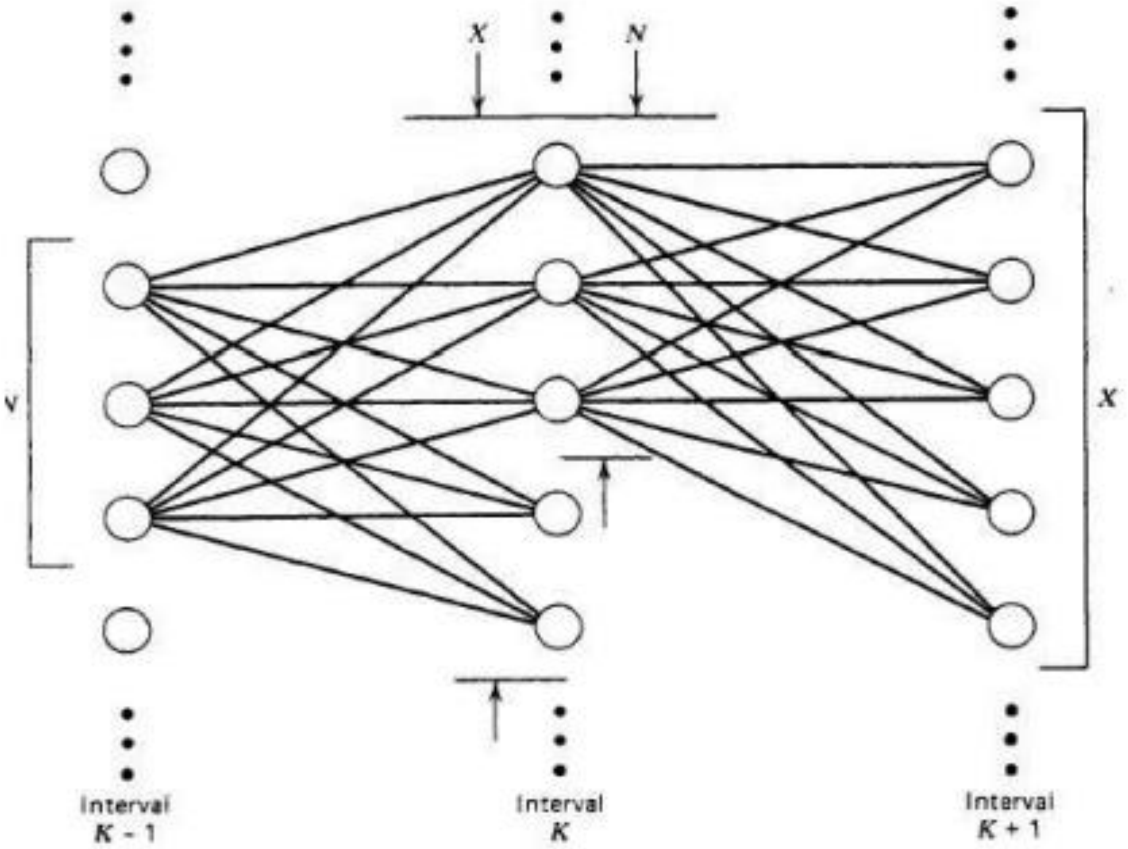
Where
Fcost(K, I) = least total cost to arrive at state (K , I) Pcost(KI,) = production cost for state (K ,I)
Scost(K - 1, L: K , I)= transition cost from state (K - 1, L) to state (K , I)

State (K, 1) is the Zth combination in hour K. For the forward dynamic programming approach, we define a strategy as the transition, or path, from one state at a given hour to a state at the next hour.

Note that two new variables, X and N, have been introduced in Figure. X = number of states to search each period

N = number of strategies, or paths, to save at each step

These variables allow control of the computational effort (see below Figure).For complete enumeration, the maximum number of the value of X or Nis 2n – 1



Compute the minimum cost

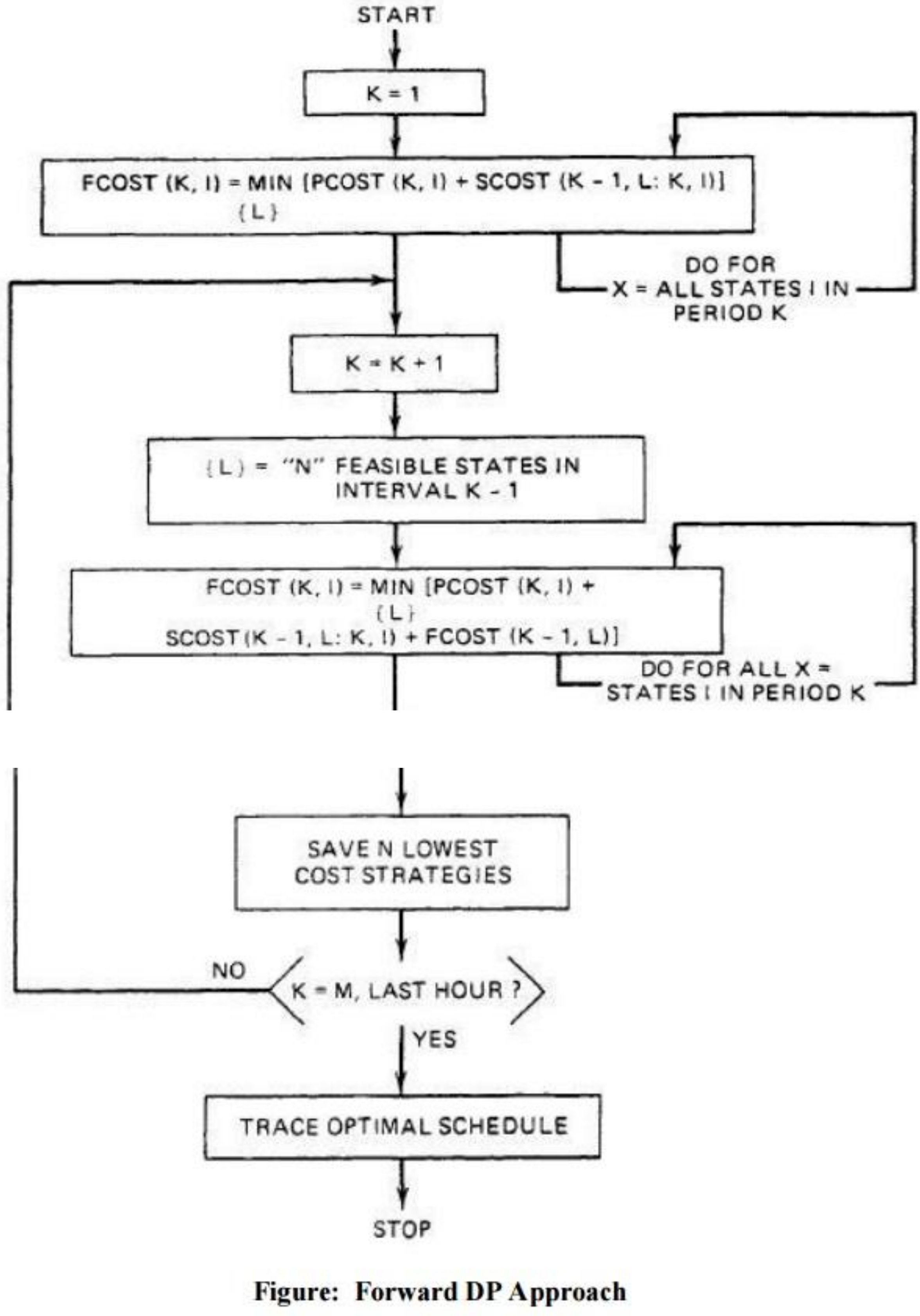


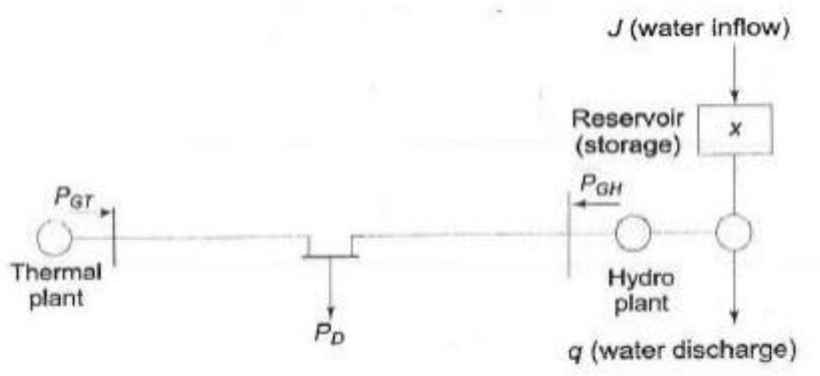
Figure: Forward DP Approach

UNIT – III
HYDRO THERMAL SCHEDULING

OPTIMAL SCHEDULING OF HYDROTHERMAL SYSTEM

- No state or country is endowed with plenty of water sources or abundant coal or nuclear fuel. In states, which have adequate hydro as well as thermal power generation capacities, proper co-ordination to obtain a most economical operating state is essential.
- Maximum advantage is to use hydro power so that the coal reserves can be conserved and environmental pollution can be minimized.
- However in many hydro systems, the generation of power is an adjunct to control of flood water or the regular scheduled release of water for irrigation. Recreations centers may have developed along the shores of large reservoir so that only small surface water elevation changes are possible.
- The whole or a part of the base load can be supplied by the run-off river hydro plants, and the peak orthe remaining load is then met by a proper mix of reservoir type hydro plants and thermal plants. Determination of this by a proper mix is the determination of the most economical operating state of a hydro-thermal system.

The hydro-thermal coordination is classified into long term co-ordination and short term coordination. The previous sections have dealt with the problem of optimal scheduling of a power system with thermal plants only. Optimal operating policy in this case can be completely determined at any instant without reference to operation at other times. This, indeed, is the static optimization problem. Operation of a system having both hydro and thermal plants is, however, far more complex as hydro plants have negligible operating cost, but are required to operate under constraints of water available for hydro generation in a given period of time. The problem thus belongs to the realm of dynamic optimization. The problem of minimizing the operating cost of a hydrothermal system can be viewed as one of minimizing the fuel cost of thermal plants under the constraint of water availability (storage and inflow) for hydro generation over a given period of operation.



For the sake of simplicity and understanding, the problem formulation and solution technique are illustrated through a simplified hydrothermal system of Fig. This system consists of one hydro and one thermal plant supplying power to a centralized load and is referred to as a fundamental system. Optimization will be carried out with real power generation as control variable, with transmission loss accounted for by the loss formula.

Mathematical Formulation

For a certain period of operation T (one year, one month or one day, depending upon the requirement), it is assumed that (i) storage of hydro reservoir at the beginning and the end of the period are specified, and (ii) water inflow to reservoir (after accounting for irrigation use) and load demand on the system are known as functions of time with complete certainty (deterministic case). The problem is to determine q(t), the water discharge (rate) so as to minimize the cost of thermal generation.

$$C_T = \int_0^T C'(P_{GT}(t))dt \tag{3.1}$$

under the following constraints:
(i) Meeting the load demand

$$P_{GT}(t) + P_{GH}(t) - P_L(t) - P_D(t) = 0; \; t \; \varepsilon \; [0,T] \tag{3.2}$$

This is called the power balance equation.
(ii) Water availability

$$X'(T) - X'(0) - \int_0^T J(t)dt + \int_0^T q(t)dt = 0 \tag{3.3}$$

where J(t) is the water inflow (rate), X'(t) water storage, and X'(0) , X' (T) are specified water storages at the beginning and at the end of the optimization interval.
(iii) The hydro generation PGH(t) is a function of hydro discharge and water storage (or head), i.e.

$$P_{GH}(t) = f(X'(t),q(t)) \tag{3.4}$$

The problem can be handled conveniently by discretization. The optimization interval T is subdivided into M subintervals each of time length ΔT. Over each subinterval it is assumed that all the variables remain fixed in value. The problem is now posed as

$$min \; \Delta T \sum_{m=1}^{M} C'(P_{GT}^{m}) = min \sum_{m=1}^{M} C(P_{GT}^{m}) \tag{3.5}$$

under the following constraints:
(i) Power balance equation

$$P_{GT}^m + P_{GH}^m - P_L^m - P_D^m = 0 \tag{3.6}$$

where

P_{GT}^m= thermal generation in the mth interval

P_{GH}^m= hydro generation in the mth interval

P_L^m=transmission loss in the mth interval

$$= B_{TT}(P_{GT}^m)^2 + 2B_{TH}P_{GH}^m + B_{HH}(P_{GH}^m)^2$$

P_D^m = load demand in the mth interval

(ii) Water continuity equation

$$X'^{m} - X'^{(m-1)} - J^{m}\Delta T + q^{m}\Delta T = 0$$

where

X'^{m} = water storage at the end of the mth interval

J^{m} = water inflow (rate) in the mth interval

q^{m} = water discharge (rate) in the mth interval

The above equation can be written as

$$X^{m} - X^{(m-1)} - J^{m} + q^{m} = 0; m = 1,2, \ldots, M \quad (3.7)$$

where $X^{m} = X'^{m}/\Delta T$ = storage in discharge units.

In Eqs. (3.7), X^{o} and X^{M} are the specified storages at the beginning and end of the optimization interval.

(iii) Hydro generation in any subinterval can be expressed as

$$P_{GH}^{m} = h_{o}\{1 + 0.5e(X^{m} + X^{m-1})\}\,(q^{m} - \rho) \quad (3.8)$$

where

$h_{o} = 9.81 \times 10^{-3}\, h'_{o}$

h_{o} = basic water head (head corresponding to dead storage)

e = water head correction factor to account for head variation with storage

ρ = non-effective discharge (water discharge needed to run hydro generator at no load).

In the above problem formulation, it is convenient to choose water discharges in all subintervals except one as independent variables, while hydro generations, thermal generations and water storages in all subintervals are treated as dependent variables. The fact, that water discharge in one of the subintervals is a dependent variable, is shown below:

Adding Eq. (3.7) for m = l, 2, ...,M leads to the following equation, known as water availability equation

$$X^M - X^0 - \sum_m J^m + \sum_m q^m = 0 \tag{3.9}$$

Because of this equation, only (M - l) qs can be specified independently and the remaining one can then be determined from this equation and is, therefore, a dependent variable. For convenience, q^1 is chosen as a dependent variable, for which we can write

$$q^1 = X^0 - X^M + \sum_m J^m - \sum_{m=2}^{M} q^m \tag{3.10}$$

Solution Technique

The problem is solved here using non-linear programming technique in conjunction with the first order gradient method. The Lagrangian $\mathcal{L}$ is formulated by augmenting the cost function of Eq. (3.5) with equality constraints of Eqs. (3.6)-(3.8) through Lagrange multipliers (dual variables) λ_1^m, λ_2^m *and* λ_3^m . Thus,

$$\mathcal{L} = \sum_m \Big[C(P_{GT}^m) - \lambda_1^m \left(P_{GT}^m + P_{GH}^m - P_L^m - P_D^m\right) + \lambda_2^m \left(X^m - X^{(m-1)} - J^m + q^m\right) + \lambda_3^m \{P_{GH}^m - h_o\{1 + 0.5e(X^m + X^{m-1})\}(q^m - \rho)\}\Big] \tag{3.11}$$

The dual variables are obtained by equating to zero the partial derivatives of the Lagrangian with respect to the dependent variables yielding the following equations

$$\frac{\partial \mathcal{L}}{\partial P_{GT}^m} = \frac{dC(P_{GT}^m)}{dP_{GT}^m} - \lambda_1^m \left(1 - \frac{\partial P_L^m}{\partial P_{GT}^m}\right) = 0 \tag{3.12}$$

$$\frac{\partial \mathcal{L}}{\partial P_G^m} = \lambda_3^m - \lambda_1^m \left(1 - \frac{\partial P_L^m}{\partial P_{GH}^m}\right) = 0 \tag{3.13}$$

$$\left(\frac{\partial \mathcal{L}}{\partial X^m}\right)_{\substack{m \neq M \\ \neq 0}} = \lambda_2^m - \lambda_2^{m+1} - \lambda_3^m \left(0.5 h_o e(q^m - \rho)\right) - \lambda_3^{m+1} \left(0.5 h_o e(q^{m+1} - \rho)\right) = 0 \tag{3.14}$$

and using Eq. (3.7) in Eq. (3.11), we get

$$\frac{\partial \mathcal{L}}{\partial q^1} = \lambda_2^1 - \lambda_3^1 \, h_o\left(1 + 0.5 \, e \, (2X^0 + J^1 - 2q^1 + \rho)\right) = 0 \tag{3.15}$$

The dual variables for any subinterval may be obtained as follows:

(i) Obtain λ_1^m from Eq. (3.12).

(ii) Obtain λ_3^m from Eq. (3.13).

(iii) Obtain λ_2^1 from Eq. (3.15) and other values of λ_2^m $(m \neq 1)$ from Eq. (3.14).

The gradient vector is given by the partial derivatives of the Lagrangian with respect to the independent variables. Thus

$$\left(\frac{\partial \mathcal{L}}{\partial q^m}\right)_{m \neq 1} = \lambda_2^m - \lambda_3^m \, h_o\left(1 + 0.5 \, e \, (2X^{m-1} + J^m - 2q^m + \rho)\right) \tag{3.16}$$

For optimality the gradient vector should be zero if there are no inequality constraints on the control variables.

Hydro-Thermal Scheduling (HTS)

1.0 Introduction

From an overall systems view, the single most important attribute of hydroelectric plants is that there is no fuel cost, therefore production costs, relative to that of thermal plants, are very small.

There are three basic types of hydroelectric plants: run-of-river, pumped storage, and reservoir systems. We will just introduce the first two in this section, and then the remainder of these notes will be dedicated to understanding reservoir systems.

Run-of-river

Here a dam is placed across a river to create a height differential between the upstream inlet and the downstream outlet, but without creating an expansive reservoir on the upstream side [1]. The turbine is rotated simply by the normal flow of the river. These plants run at a capacity associated with the natural river current. Figure 1 [2] illustrates a number of different run-of-the-river projects.

Fig. 1 [2]

Pump-storage

This kind of hydro plant is a specialized reservoir-type plant which has capability to act as both a source and a sink of electric energy. In the source or generation mode, it supplies power to the grid using the kinetic energy of the water as it falls from higher-lake to lower-lake as would a typical reservoir plant. In the sink or pumping mode, it consumes power from the grid in order to pump water from the lower lake to the higher lake. Thus, electric energy from the grid is converted into potential energy of the water at the higher elevation.

The original motivation for pumped storage plants was to valley-fill and peak-shave.

- Valleys: During low-load periods, the plant is used in pumping mode, thus increasing overall system load. This is beneficial because a decreased number of thermal plants will need to be shut-down (avoiding shut-down and start-up costs), and for those remaining on-line, they can be used at higher, more efficient generation levels.
- Peaks: During high-load periods, the plant is used in generating mode, thus decreasing the overall system load that must be met by thermal generation. This is beneficial because it avoids the need to start some of the expensive peaking plants. Figure 2 [3] illustrates a typical 24 cycle for a northwestern region of the US.

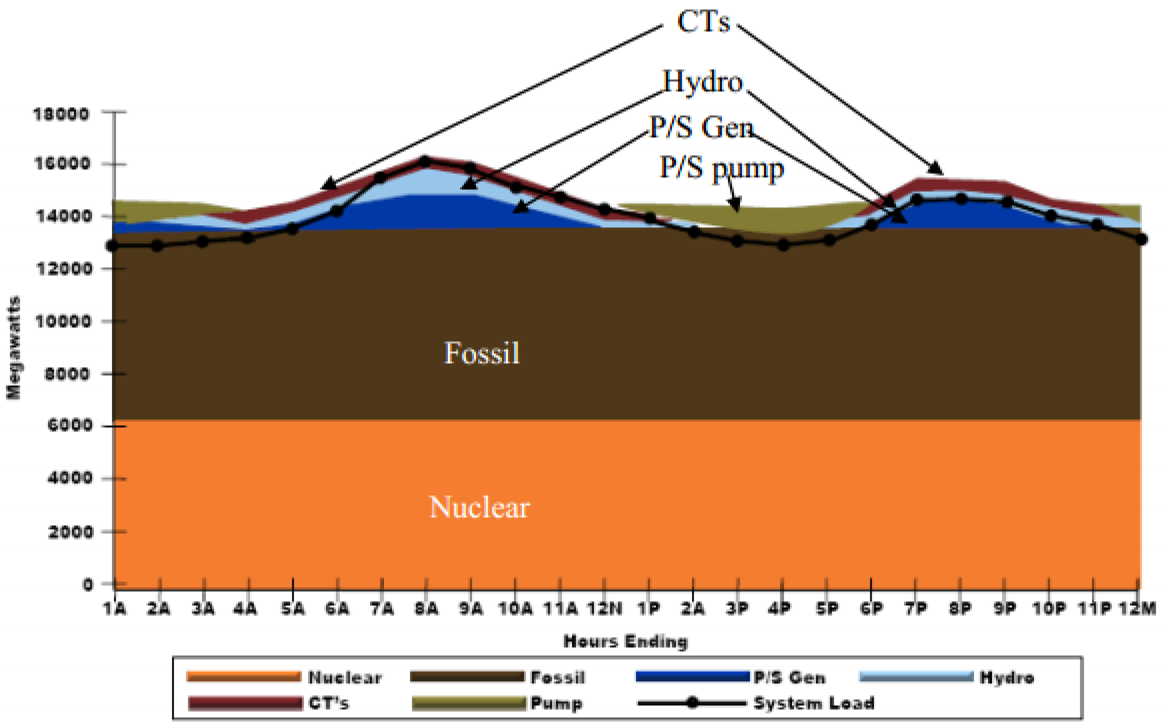


Fig. 2 [3]

Of course, the cycle of pumping and generating incurs a net loss. It is typical for the efficiency of a round-trip pump storage cycle to be about 70%; for every 100 MW used to pump water, only about 70 MW will be recovered by the grid. The cost of this loss is lessened by the fact that the energy is supplied by thermal plants operating at higher (and thus more efficient) loading levels because of the presence of the pumping. This cost is compensated by the savings incurred by avoiding shut-down and start up costs of the thermal plants during the valleys and by avoiding the start-up costs of the peaking plants during the peaks.

Pump storage has become of even greater interest today because it offers a way to store energy that is available from renewable resources (wind and solar) during off-peak times so that they can then be used during on-peak times. Figure 3 [3] illustrates a situation in the BPA region (which is seeing significant wind growth) where

the wind plants are frequently generating when load is low and not generating when load is high.

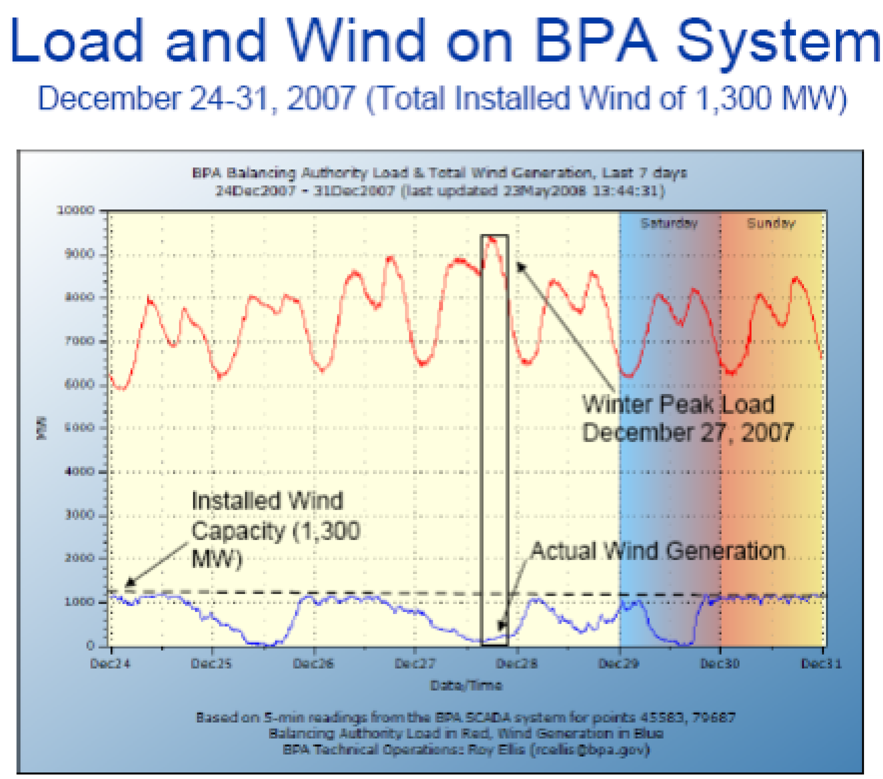


Fig. 3 [3]

Figure 4 indicates the manner in which pumped storage could be used with wind over a 24 hour period.

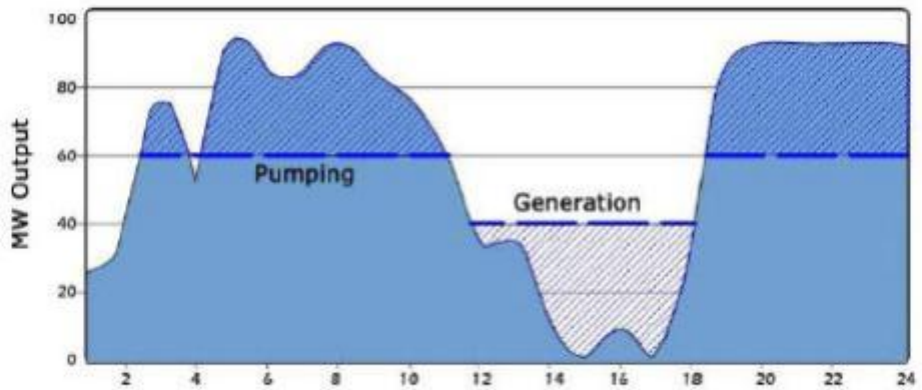


Fig. 4 [3]

Pump storage also supplies regulation and load following to which renewables generally do not contribute.
Figure 5 [4] illustrates a typical pump-storage set-up.

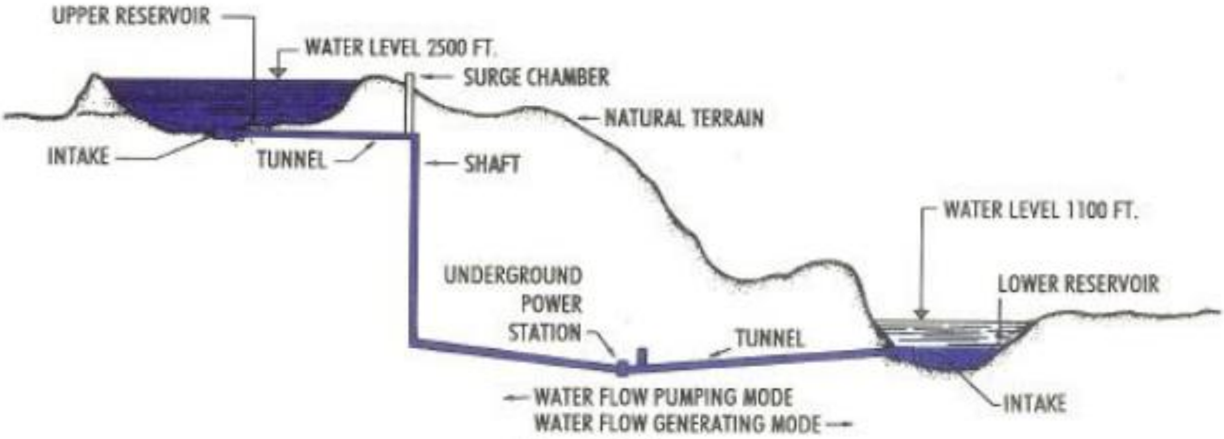
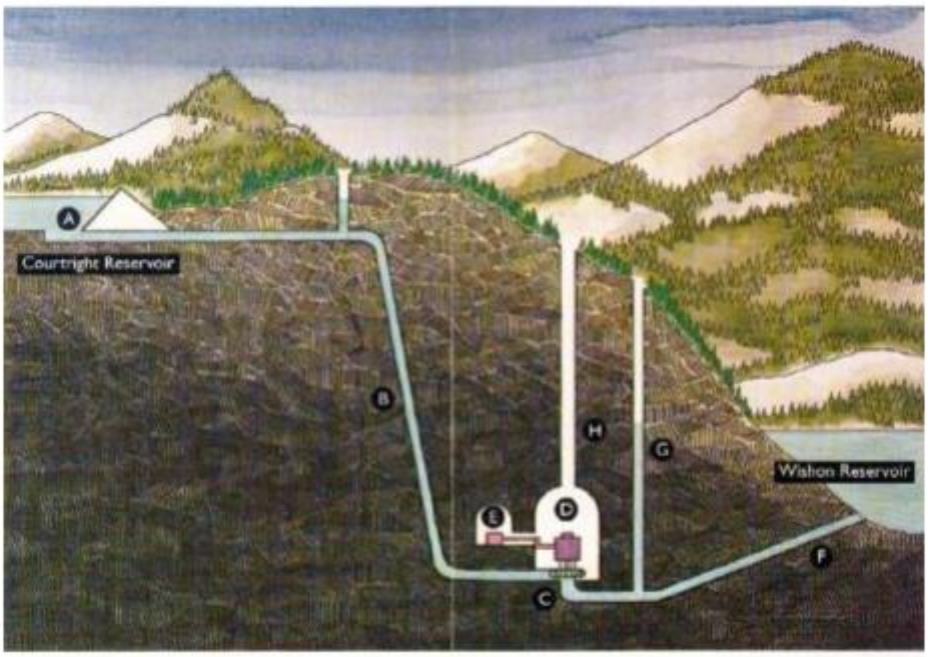


Fig. 5 [4]

One pump-storage plant of which I am familiar is called Helms pumped storage plant, commissioned in 1984. It consists of three units rated at 404 MW (1212 MW total) in the generating mode and 310 MW (930 MW total) in the pumping mode. Figure 6 [5] illustrates the overall setup of Helms which operates between Courtright and Wishon Lakes about 50 miles east of the city of Fresno California.



A-Courtright, B-Supply Tunnel, C-Turbine, D-Generator, E-Transformer, F-Wishon, G-Surge Chamber, H-Elevator

Fig. 6 [5]

Figure 7 [5] shows the powerhouse for Helms, where one can observe that it is underground (at a depth of 1000 ft!).

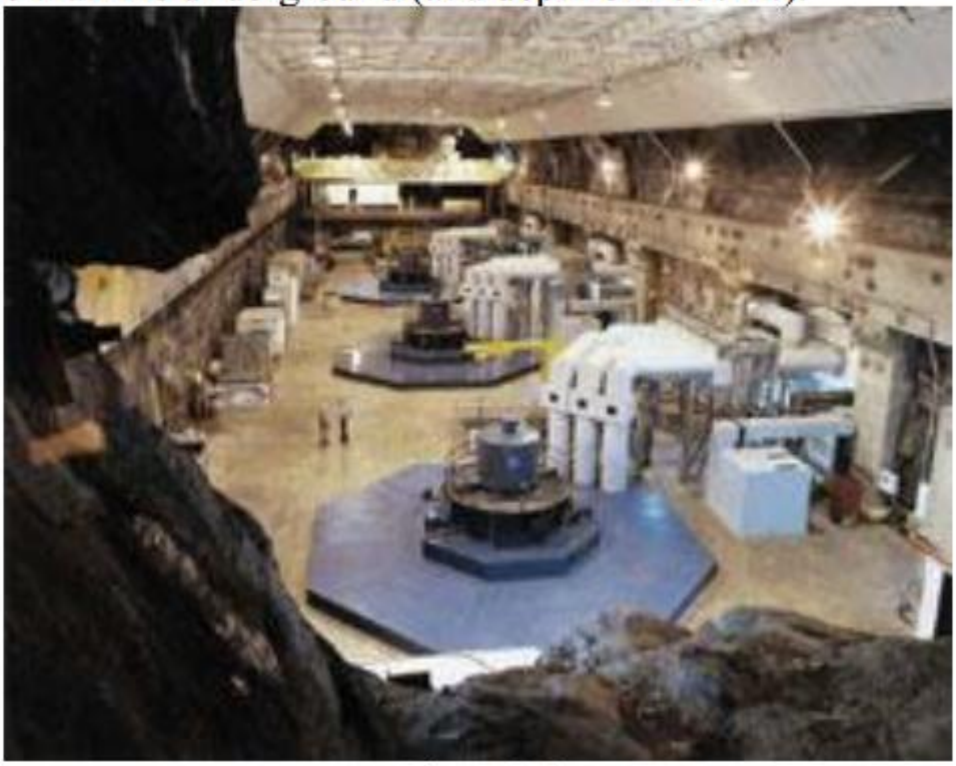


Fig. 7 [5]

Figure 8 [5] below shows the typical week-long cycles of Helms. Note that unit 2 is typically not used as a result of the fact that the region around Fresno has recently become transmission constrained. PG&E had to build new transmission to alleviate this problem.

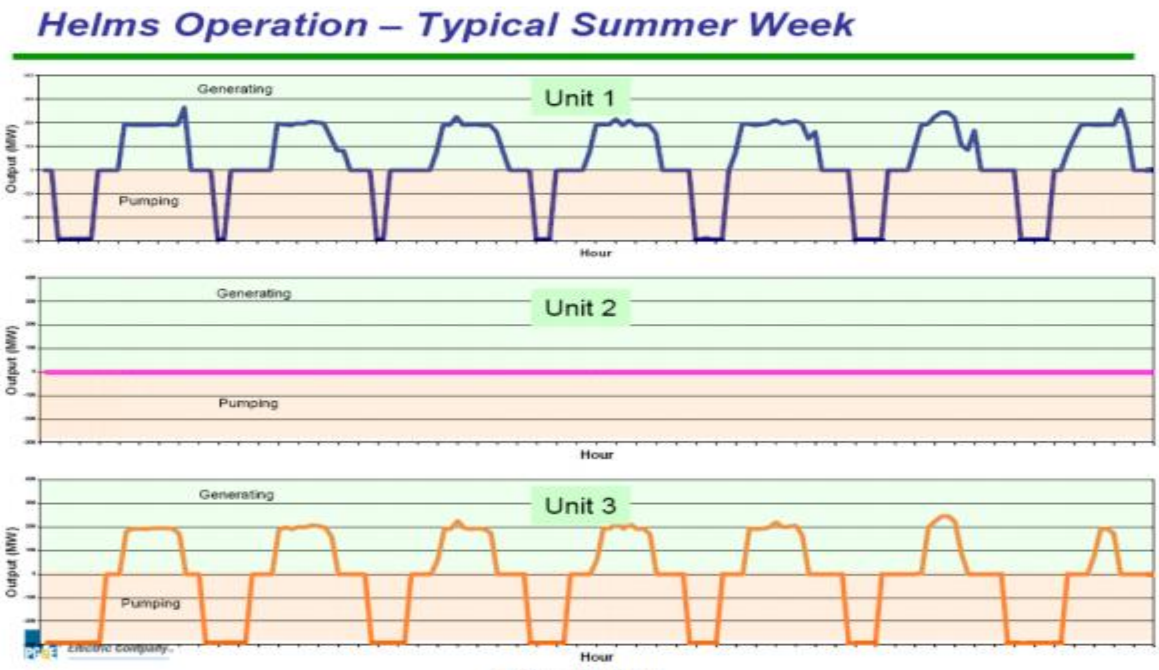


Fig. 8 [5]

In addition to the ability to peak shave and valley fill, Helms is a highly flexible plant with operating flexibility characterized by the following attributes:

- Dead stop to full generation in 8 minutes.
- Dead stop to full pump in 20 minutes.
- Ramp rate of 80 MW/min per unit (about 20% per minute!)

This level of operational flexibility is highly desirable for systems that have high wind penetration levels.

Classification of Hydrothermal Scheduling Problem

1. Long range problem
2. Short range problem

Long Range Problem

Long range problem includes the yearly cyclic nature of reservoir water inflows and seasonal load demand and correspondingly a scheduling period of one year is used. The solution of the long range problem considers the dynamics of head variations through the water flow continuity equation. The co-ordination of the operation of hydroelectric plants involves, of course, the scheduling of water releases. The long-range hydro-scheduling problem involves the long-range forecasting of water availability and the scheduling of reservoir water releases for an interval of time that depends on the reservoir capacities. Typical long-range scheduling goes anywhere from 1 week to 1 year or several years. For hydro schemes with a capacity of impounding water over several seasons, the long-range problem involves meteorological and statistical analysis. The purpose of the long-term scheduling is to provide a good feasible solution that is close to the long-term cost minimization of the whole system. The problem is usually very difficult to solve due to its size, the time span (up to several years) and the randomness of the water inflows over the long term. Long-range scheduling involves optimizing a policy in the context of unknowns such as load, hydraulic inflows and unit availabilities (steam and hydro). These unknowns are treated statistically and long-range scheduling involves optimization of statistical variables.

Short Range Problem

The load demand on the power system exhibits cyclic variation over a day or a week and the scheduling interval is either a day or a week. As the scheduling interval of short range problem is small, the solution of the short-range problem can assume the head to be fairly constant. The amount of water to be utilized for the short-range scheduling problem is known from the solution of the long-range scheduling problem. Short-range hydro-scheduling (1 day to 1 week) involves the hour-by-hour scheduling of all generation on a system to achieve minimum production cost for the given time period.

The short term hydrothermal scheduling problem is classified into two groups

1. Fixed head hydro thermal scheduling
2. Variable head hydro thermal scheduling

Dynamic Programming applied to Medium Term Hydrothermal Scheduling

The medium term hydrothermal scheduling (MTHS) problem is quite complex due to some of its characteristics, specially the randomness of inflows. The MTHS aims to determine, for each stage (month) of the planning period (years), the amount of generation at each hydro and thermal plant which attends the load demand and minimizes the expected operation cost along the planning period.

Stochastic dynamic programming (SDP) has been the most suggested technique to solve the MTHS problem since it can adequately cope with the uncertainty of inflows and the nonlinear relations among variables. Although efficient in the treatment of river inflows as random variables described by probability distributions, the SDP technique is limited by the so-called ”curse of dimensionality” since its computational burden increases exponentially with the number of hydro plants. In order to overcome this difficulty one common solution adopted is to represent the hydro system by an aggregate model, as it is the case in the Brazilian power system. Alternatives to stochastic models for MTHS can be developed through operational policies based on deterministic models. The advantage of such approaches is their ability to handle multiple reservoir systems without the need of any modeling manipulation. Although some work has been done in the comparison between deterministic and stochastic approaches for MTHS, the discussion about the best approach to the problem is far from ending.

The MTHS problem, in systems composed of a single hydro plant, considering the uncertainty of inflows, can be formulated as a nonlinear stochastic programming problem seeking the minimization of the expected operational cost

and is given by:

$$min\ E_y \left\{ \lambda_t \sum_{t=1}^{T-1} \psi_t(d_t - p_t) \right\} + \alpha_T(x_T) \qquad (1)$$

subject to:

$$x_t^{med} = \frac{x_t + x_{t+1}}{2} \qquad (2)$$

$$p_t = k\ [\phi(x_t^{med}) - \theta(u_t) - \delta(q_t)]\ q_t, \quad \forall\ t \qquad (3)$$

$$x_t = x_{t-1} + (y_t - q_t)\beta, \quad \forall\ t \qquad (4)$$

$$u_t = q_t + s_t, \quad \forall\ t \qquad (5)$$

$$x_t \in X_t \qquad (6)$$

$$v_t \in V_t \qquad (7)$$

$$s_t \geq 0 \qquad (8)$$

$$x_0 \text{ given} \qquad (9)$$

In the above equations E_y: represents the expected value of the inflows ; T is the planning period; t is the index of the planning stages; λ_t: is a discount rate to convert cost for present; $\psi_t(.)$ is the thermal cost function at stage t; g_t is the thermal generation at stage t; d_t is the energy demand at stage t; p_t is the hydro generation at stage t, which is the product of a constant k, the water head given by the difference of forebay elevation $\phi(x_t)$ and tailrace elevation $\theta(u_t)$, and the water discharged at stage t; y_t represents the inflow at stage t; x_t is the reservoir storage at the end of stage t; v_t is the water released at stage t; s_t is the water spilled at stage t; β is a constant factor that converts flow into volume; X_t and V_t are feasible sets representing bounds for the variables x_t and v_t.

DYNAMIC PROGRAMMING MODELS FOR MTHS

For solving the problem (1)-(8) by SDP, the optimization problem is divided into stages and at each stage the optimal
control variable is chosen in order to minimize the expected cost for each state of the system. The optimization process is
based on a previous knowledge of the future possibilities and its consequences, satisfying the Bellman optimality principle, [2]. Thus the total operation cost from stage until the end of the planning period is obtained with the sum of the present cost at stage t with the optimal future cost of the following stages, which were previously determined. Since the problem is a stochastic one, the optimal control at each stage is obtained based on the probability distribution of the inflow at that stage, [3], [4], [7]. The dynamic programming recursive equation is given by:

$$F_t(x_t) = \min_{q_t, s_t}\{\psi_t(d_t - p_t) + F_{t+1}(x_{t+1})\} \qquad (10)$$

The recursive equation (10) is solved for each stage t subject to equations (2) -(8).
The four policies based on dynamic programming models considered in this work will be detailed bellow.

Deterministic Dynamic Programming

In the Deterministic Dynamic Programming (DDP) the inflow for each month m is known previously and calculated
based on the historical values of each hydro plant. In this approach the long term average, ym, provides the inflow
arithmetical mean for each month for all N years of the historical.

$$\overline{y}_m = \frac{1}{N}\sum_{r=1}^{N} y_{r,m} \qquad (11)$$

DDP can be considered as a particular case of SDP where the probability is assumed one if the inflow long term average
for a certain month occurs.

The recursive equation for this particular case, where Qt is the decision search space, can be written as:

$$\alpha_{t-1}(x_{t-1}) = min_{q_t \in Q_t}\{\psi_t(d_t - p_t) + \alpha_t(x_t)\} \qquad (12)$$

where:

$$x_t = x_{t-1} + (\overline{y}_t - q_t)\beta \qquad (13)$$

Independent Stochastic Dynamic Programming

If one solves dynamic programming considering the inflows monthly independent, the recursive equation will be similar to DDP and the only difference is the future cost that will be weighted by their probabilities pi considering the inflow discretization divided in Ny parts. Thus, the recursive equation of ISDP is given by:

$$\alpha_{t-1}(x_{t-1}) = min_{q_t \in Q_t} \sum_{i=1} \left\{\psi_t(d_t - p_t^i) + \alpha_t(x_t^i)\right\} .p_i \qquad (14)$$

where:

$$x_t^i = x_{t-1} + (y_t^i - q_t)\beta \qquad (15)$$

and

$$p_t^i = k\ [\phi(\frac{x_t^i + x_{t+1}}{2}) - \theta(q_t) - \delta(q_t)]\ q_t \qquad (16)$$

Stochastic Dual Dynamic Programming

In the Stochastic Dual Dynamic Programming (SDDP) one supposes that in the beginning of each month the inflow that will occur is known. Each final month state is represented by a pair (stored volume at the end of the month; inflow of this month) [7]. The inflow distribution is represented by a inflow set and its probabilities. Each inflow is analysed separetely, resulting in different optimal individual decisions. For each combination of storage level and inflow, according to its discretization, an optimal decision is found. For a given storage level, each optimal decision takes to a total cost of operation. Thus, an expected cost is calculated with these different costs.For this approach one considers the following recursive equation:

$$\alpha_{t-1}(x_{t-1}) = \sum_{j=1}^{Ny} p_j \left\{ min_{q_t \in Q_t} [\psi_t(d_t - p_t^j) + \alpha_{t-1}(x_t^j)] \right\} \tag{17}$$

$$x_t^j = x_{t-1} + (y_t^j - q_t^j)\beta \tag{18}$$

$$p_t^j = k\ [\phi(\frac{x_t^j + x_{t-1}}{2}) - \theta(q_t) - \delta(q_t)]\ q_t \tag{19}$$

Dependent Stochastic Dynamic Programming

When the inflows uncertainty is considered through a Markov chain, leading to the dependent SDP (DSDP),

the state variable changes to include the inflow of the previous stage, the probabilities are now calculated from

the conditional probability density function and the recursive equation is modified to:

$$F_t(x_t) = \min_{q_t, s_t} \{\psi(g_t) + E_{q_t|q_{t-1}}\{F_{t+1}(x_{t+1})\}\} \tag{20}$$

Again, one solves the recursive equation (20) for each stage t according to equations (2)-(8). In this work one represents the inflow uncertainty of the hydro plants by a Normal probability density function with Box-Cox transformation.

UNIT - IV
LOAD FREQUENCY CONTROL

Electric Power Regulation

Power systems consist of control areas representing a coherent group of generators i.e. generators which swing in unison characterized by equal frequency deviations. In addition to their own generations and to eliminate mismatch between generation and demand these control areas are interconnected through tie-lines for providing contractual exchange of power under normal operating conditions. One of the control problems in power system operation is to maintain the frequency and power interchange between the areas at their rated values. Automatic generation control is to provide control signals to regulate the real power output of various electric generators within a prescribed area in response to changes in system frequency and tie-line loading so as to maintain the scheduled system frequency and established interchange with other areas.

Many control strategies for Load Frequency Control in electric power systems have been proposed by researchers over the past decades. This extensive research is due to fact that LFC constitutes an important function of power system operation where the main objective is to regulate the output power of each generator at prescribed levels while keeping the frequency fluctuations within pre-specifies limits.

The mechanical power is produced by a turbine and delivered to a synchronous generator serving different users. The frequency of the current and voltage waveform at the output of the generator is mainly determined by the turbine steam flow. It is also affected by changes in user power demands that appear, therefore, as electric perturbations. If, for example, the electric load on the bus suddenly increases, the generator shaft slow down, and the frequency of the generator decreases. The control system must immediately detect the load variation and command the steam admission valve to open more so that the turbine increases its mechanical power production, counteracts the load increases and brings the shaft speed at the rated value which result generator frequency back to its nominal value.

Load-frequency control (LFC)

For large scale electric power systems with interconnected areas, Load Frequency Control (LFC) is important to keep the system frequency and the inter-area tie power as near to the scheduled values as possible. The input mechanical power to the generators is used to control the frequency of output electrical power and to maintain the power exchange between the areas as scheduled. A well designed and operated power system must cope with changes in the load and with system disturbances, and it should provide acceptable high level of power quality while maintaining both voltage and frequency within tolerable limits. Load frequency control is basic control mechanism in the power system operation. Whenever there is variation in load demand on a generating unit, there is a momentarily an occurrence of unbalance between real-power input and output. This difference is being supplied by the stored energy of the rotating parts of the unit.

Load Frequency Control (LFC) is being used for several years as part of the Automatic Generation Control (AGC) scheme in electric power systems. One of the objectives of AGC is to maintain the system frequency at nominal value (50 Hz).

Automatic generation control (AGC)

Automatic generation control (AGC) is defined as, the regulation of power output of controllable generators within a prescribed area in response to change in system frequency, tie-line loading, or a relation of these to each other, so as to maintain the schedules system frequency and / or the established interchange with other areas within predetermined limits. The two basic inter-area regulating responsibilities are as follows:-

(i) When system frequency is on schedule, each area is expected automatically to adjust its generation to maintain its net transfer with other areas on schedule, thereby absorbing its own load variations. As

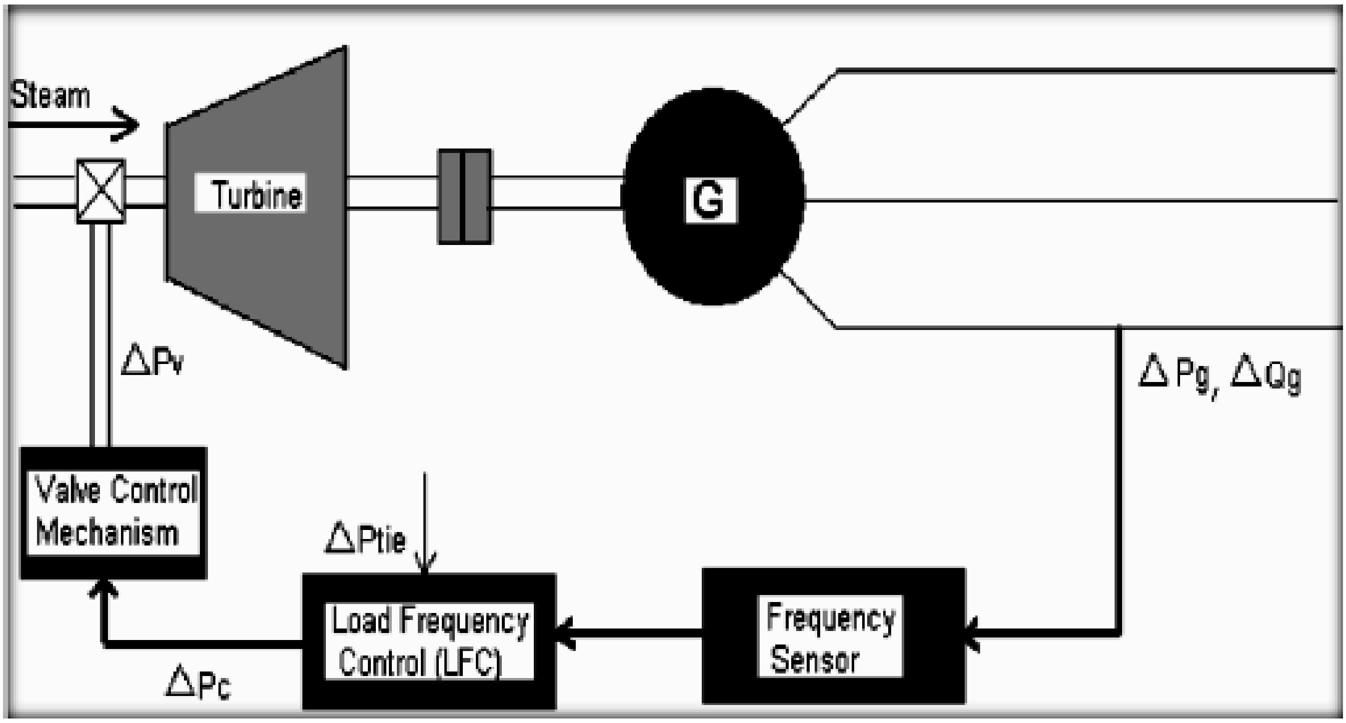
long, all areas do so; scheduled system frequencies as well as net interchange schedules for all area are maintained.
(ii) When system frequency is off-schedule, because one or more areas are not fulfilling their regulating responsibilities, other areas are expected automatically to shift their respective net transfer schedules proportionally to the system frequency deviation and in direction to assist the deficient areas and hence restore system frequency. The extent of each area's shift of net interchange schedule is programmed by its frequency bias setting. Therefore, a control strategy is needed that not only maintains constancy of frequency and desired tie-power flow but also achieves zero steady state error and inadvertent interchange. Numbers of control strategies have been employed in the design of load frequency controllers in order to achieve better dynamic performance.

Control Strategy

The objective of the control strategy in a power system is to generate and deliver power in an interconnected system as economically and reliably as possible while maintaining the frequency and voltage within permissible limits. The power system control has a hierarchical structure. The control system consists of a number of nested control loops that control different quantities in the system. In general, the control loops on lower system levels, e.g. locally in a generator, are characterized by smaller time constants than the control loops active on a higher system level. For example, the automatic voltage regulator (AVR), which regulates the voltage of the generator terminals, responds typically in a time scale of a second or less. While, the secondary voltage control (SVC), which determines the reference values of the voltage controlling devices among which the generators, operates in a time scale of tens of seconds or minutes. That means these two control loops are virtually de-coupled. As another example, AVR (which controls the reactive power and voltage magnitude) and LFC (which controls the real power and frequency) loops can considered. The excitation system time constant is much smaller than the prime mover time constant and its transient decay much faster, which does not affect the LFC dynamic. Thus, the cross-coupling between the LFC loop and the AVR loop is negligible. This is also generally true for the other control loops. As a result, a number of de-coupled control loops operating in power system in different time scales for protection, voltage control, turbine control, tie-line power and frequency control. Although the overall control system is complex, in most cases it is possible to study the different control loops individually due to the de-coupling. Depending on the loop nature, the required model, important variables, uncertainties, objectives, and possibly control strategy will be different.

LFC problem in Single Area Power System

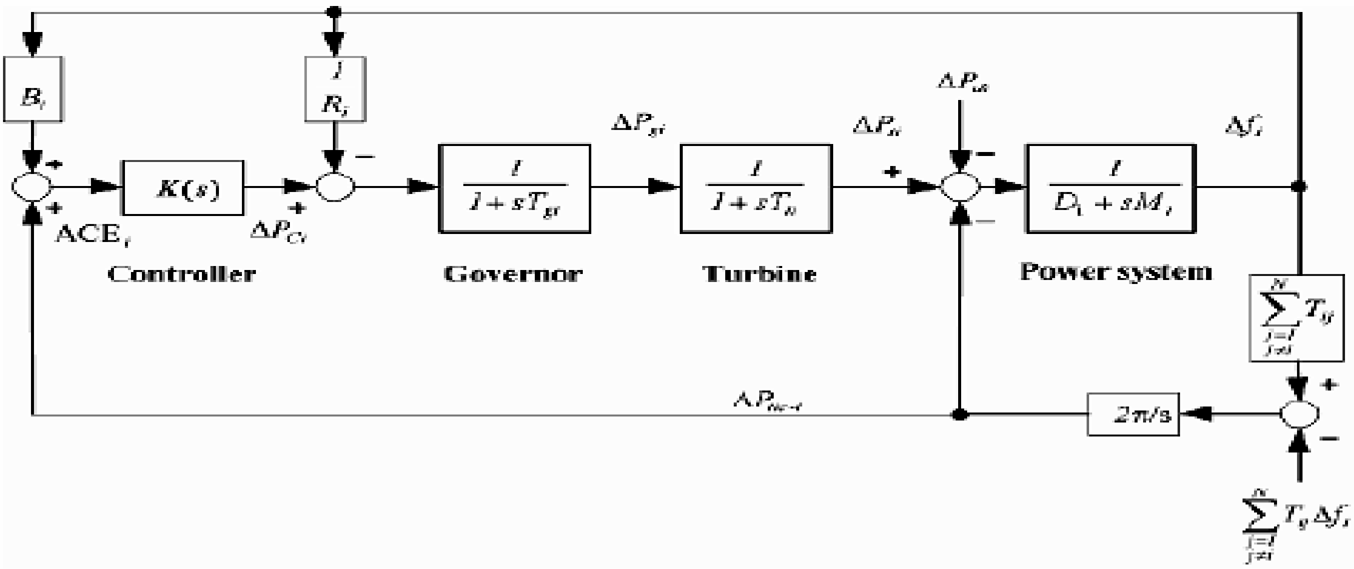
Basically, single area power system consists of a governor, a turbine, and a generator with feedback of regulation constant. System also includes step load change input to the generator. This work mainly, related with the controller unit of a single area power system. The load frequency control strategies have been suggested based on the conventional linear Control theory. These controllers may be unsuitable in some operating conditions due to the complexity of the power systems such as nonlinear load characteristics and variable operating points. To some authors, variable structure control maintains stability of system frequency. However, this method needs some information for system states, which are very difficult to know completely. Also, the growing needs of complex and huge modern power systems require optimal and flexible operation of them. The dynamic and static properties of the system must be well known to design an efficient controller.
Under normal operating condition controller are set for small changes in load demand without voltage and frequency exceeding the pre specified limits. If the operating condition changes by any cause, the controller must be reset either manually or automatically. The objective of load frequency controller is to exert the control off frequency and at the same time real power exchange via outgoing transmission line.



Block diagram Load frequency control in single area power system.

The frequency is sensed by frequency sensor. The change in frequency and tie line real power can be measured by change in rotor angle δ. The load frequency controller amplify and transform error signal, i.e., (Δfi and ΔPtie) in to real power command signal ΔPci which is sent to the prime mover via governor (that control the valve mechanism). To call for an increment or decrement in torque the prime mover balances the output of governor which will compensate the value of error signal that is Δfi and ΔPtie. The process continues till deviation in form of Δfi and ΔPtie as well as the specified tolerance.

The LFC problem in power systems has a long history. In a power system, LFC as an ancillary service acquires an important and fundamental role to maintain the electrical system reliability at an adequate level. It has gained the importance with the change of power system structure and the growth of size and complexity of interconnected systems. The well-known conventional LFC structure for a given control area and a multi area power system (includes N area) is shown in Fig.



A control area equipped with LFC

Concept of Two Area Control

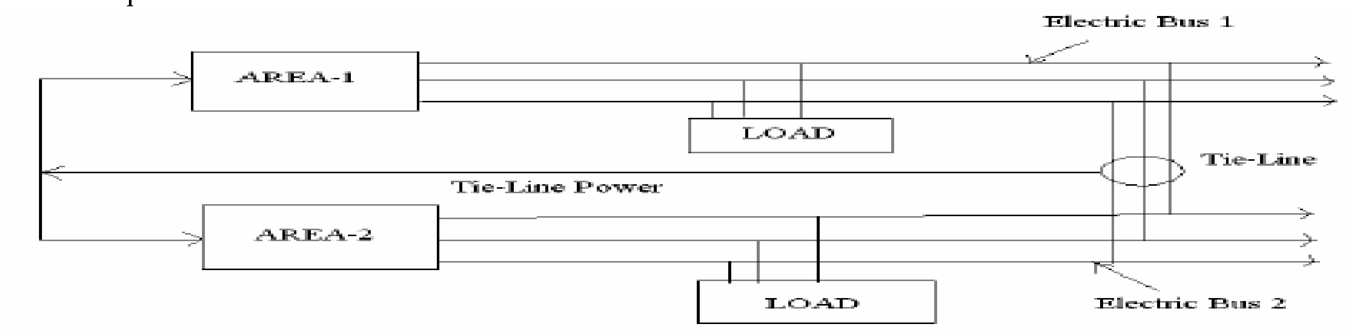
An extended power system can be divided into a number of load frequency control areas interconnected by means of tie lines. Without loss of generality two- area case connected by tie-line is considered. The control objectives are as follows:

(1) Each control area as for as possible should supply its own load demand and power transfer through tie line should be on mutual agreement.

(2) Both control areas should controllable to the frequency control.

A two area system consists of two single area systems connected through a power line called tie-line. Each area feeds its user pool, and the tie line allows electric power to flow between the areas, because both areas as well as the power flow on the tie-line. For the same reason, the control system of each area needs information about the transient situation in both areas to bring the local frequency back to its steady state value. Information about the local area is found in the tie line power fluctuations. Therefore, the tie-line power is sensed, and the resulting tie-line power signal is fed back into both areas. It is conveniently assumed that each control area can be represented by an equivalent turbine, generator and governor system. Symbol used with suffix 1 refer to area 1 and those with suffix 2 refer to area 2. A complete diagram is given in Fig.

In an isolated control area case the incremental power (ΔP_G-ΔP_D)was accounted for by the rate of increase of stored kinetic energy and increase in area load caused by increase in frequency. Since a tie line transports power in or out of an area, this fact must be accounted for in the incremental power balance equation of each area.



Conventional Two Area System: Basic Block Diagram

UNIT – V
OPTIMAL POWER FLOW

The optimal power flow

The Optimal Power Flow (OPF) problem is the most difficult and complicated problem in power system analysis and design, it is a non linear optimization problem. The objective of the OPF is to minimize the total operating cost and total losses, subjected to many constraints such as total generation must equal to total load plus total losses and the voltage profile must be within their limits. The OPF problem is a combination between the economic dispatch and the power flow. In order to solve the OPF problem, they must be solved simultaneously.

POWER FLOW ANALYSIS AND ECONOMIC
LOAD DISPATCH

In power engineering, the power-flow study, or load-flow study, is a numerical analysis of the flow of electric power in an interconnected system. A power system uses simplified notation such as a one-line diagram and per-unit system, and focuses on various aspects of AC power parameters, such as voltages, voltage angles, reactive power and real power. It describes the power systems in normal steady-state operation. Power-flow or load-flow studies are depicted for planning future expansion of power systems as well as in discoursing the best operation of existing systems. The principal information obtained from the power-flow study is the phase angle and magnitude of the voltage at each bus, and the real and reactive power flowing in each line.

NEWTON RAPHSON SOLUTION METHOD

There are various methods of solving the resulting nonlinear system of equations. The most popular is known as the Newton-Raphson method. This method begins with initial guesses of all unknown variables (voltage magnitude and angles at Load Buses and voltage angles at Generator Buses). Next, a Taylor Series is emphasized, with the higher order terms ignored, for each of the power balance equations included in the system of equations. The result is a linear system of equations that can be expressed as:

$$\begin{bmatrix} \Delta\theta \\ |\Delta V| \end{bmatrix} = -J^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \qquad (1)$$

Where ΔP and ΔQ are called the mismatch equations:

$$\Delta P_i = -P_i + \sum_{k=1}^{n} |V_i||V_k|(G_{ik}\cos\theta_{ik} + B_{ik}\sin\theta_{ik}) \qquad (2)$$

$$\Delta Q_i = -Q_i + \sum_{k=1}^{n} |V_i||V_k|(G_{ik}\sin\theta_{ik} + B_{ik}\cos\theta_{ik}) \qquad (3)$$

and J is a matrix of partial derivatives known as

$$J = \text{a Jacobian: } \begin{bmatrix} \frac{\partial \Delta P}{\partial \theta} & \frac{\partial \Delta P}{\partial |V|} \\ \frac{\partial \Delta Q}{\partial \theta} & \frac{\partial \Delta Q}{\partial |V|} \end{bmatrix} \quad (4)$$

The linearized system of equations is solved to determine the next guess (m + 1) of voltage magnitude and
angles based on:

$$\theta^{m+1} = \theta^{m} + \Delta\theta \quad (5)$$

$$|V|^{m+1} = |V|^{m} + \Delta| \quad (6)$$

The process continues until a stopping condition attains. A common stopping condition is to terminate if the norm of the mismatch equations is below a specified tolerance.

Economic Load Dispatch Problem

The economic dispatch problem (EDP) is one of the important problems in operation and control of modern power systems. The objective of the EDP of electric power generation is to schedule the committed generating unit outputs so as to meet the required load demand at minimum operating cost while satisfying all unit and system equality and inequality constraints.

Description of Economic Dispatch Problem

The objective of the EDP is to minimize the total fuel cost at thermal power plants subjected to the operating constraints of a power system. Therefore, it can be formulated mathematically as an optimization problem (minimization) with an objective function and constraints. The equality and inequality constraints are represented by eqns.

Given by:

$$\sum_{i=1}^{n} P_i - P_l - P_d = 0 \quad (7)$$

$$P_i^{min} \leq P_i \leq P_i^{max} \quad (8)$$

In the power balance criterion, an equality constraint must be satisfied, as shown in Eq. (7). The generated power must be the same as the total load demand plus total line losses. The generating power of each generator should lie between maximum and minimum limits represented by Eq. (8), where Pi is the power of generator i(in MW); n is the number of
generators in the system; PD is the system load demand (in MW); PL represents the total line losses (in MW) and Pi
minand Pi max are, respectively, the minimum and maximum power outputs of the i-th generating unit (in MW). The total fuel cost function fc is formulated as follows.

$$\sum_{i=1}^{n} P_i - P_l - P_d = 0 \quad (7)$$

$$P_i^{min} \leq P_i \leq P_i^{max} \quad (8)$$

Where Fi is the total fuel cost for the generator unity i (in \$/h), which is defined by equation:

$$F_i(P_i) = a_i P_i^2 + b_i P_i + c \qquad (10)$$

where ai, bi and ci are cost coefficients of generator i. A cost function is obtained based on the ripple curve for more accurate modeling. This curve contains higher order Non linearity and discontinuity due to the valve point effect, and should be refined by a sinusoidal function. Therefore, Eq. (10) can be modified, as:

$$\tilde{F}_i(P_i) = F(P_i) + |e_i \sin(f_i(P_i^{min} - P_i))| \qquad (11)$$

where ei and fi are constants of the valve point effect of generators. Hence, the total fuel cost that must be minimized, according to Eq. (9), is modified to:

$$\min f_c = \sum_{i=1}^{n} \tilde{F}\, i(Pi) \qquad (12)$$

where

$\tilde{F}$ i is the cost function of generator i(in $/h) defined by Eq. (11). In the case study presented here, we disregarded the transmission losses, PL; thus, PL = 0. The Eq. (12) represents the fitness function. We are minimizing the fitness function.

Integration of DC power flow in unit commitment

Implementation in unit commitment

The objective function of a unit commitment model is to minimize the overall operational system cost. This includes transmission costs. The objective function becomes

$$min \left(\sum_T \sum_I \left(c_{I,T}^{prod} + c_{I,T}^{start} + c_{I,T}^{stop} \right) + \sum_T \sum_L c_{L,T}^{trans} \right) \qquad (7.1)$$

with T the set of time steps, I the set of power plants, L the set of transmission lines (AC and DC), $c_{I,T}^{prod}$ the production cost, $c_{I,T}^{start}$ and $c_{I,T}^{stop}$ respectively the starting and stopping cost and $c_{L,T}^{trans}$ the transmission cost. All cost parameters are expressed in [EUR/timestep].

The transmission cost $c_{L,T}^{trans}$ of a line L at time step T follows from

$$max\,(-P_{L,T} \cdot TC_L\,,\; P_{L,T} \cdot TC_L) = c_{L,T}^{trans} \qquad \forall L, T \qquad (7.2)$$

with the transmission cost per unit TC_L in [timestep · EUR/MWh] and the power flow $P_{L,T}$ in [MW]. A transmission tariff can reflect technical aspects (e.g., losses) or economic aspects (e.g., congestion rents).

The market clearing condition must hold for every node or zone in the grid.

$$G_{N,T} = D_{N,T} + P_{N,T} \qquad \forall N, T \qquad (7.3)$$

with GN;T the total generation in [MW], DN;T the total load in [MW] and PN;T the power injection in the grid in [MW]. The power injection in the grid can be positive (generation exceeds load) or negative (load exceeds generation).

The grid constraints consist of equality constraints linking grid injections with grid flows and inequality constraints limiting the line flows and phase shifter angles. The DC power flow relation between grid injections and line flows, in its most extended form, is

$$\mathbf{p}_{L_{AC},T} = \sum_{Y} \mathbf{PTDF}_Y \cdot \mathbf{p}_{Y,N,T} + \mathbf{PSDF} \cdot \boldsymbol{\alpha}_{L_{AC},T} + \mathbf{DCDF} \cdot \mathbf{p}_{L_{DC},T} + \mathbf{p}_L^0 \quad \forall T \qquad (7.4)$$

In nodal grid models, the zero imbalance flow is zero and the set Y can be dropped as it is not relevant to work with injections per type. In case of injections per type, each injection type is limited to the generation or load of that type and the net injection is the sum of the injections per type . The PSDF-matrix only exists in a grid with phase shifting transformers and the DCDF-matrix is only useful for a grid with DC lines.

The line flows are limited by the line capacities, both for AC lines and DC lines.

$$\mathbf{p}_{L,min} \leq \mathbf{p}_{L,T} \leq \mathbf{p}_{L,max} \qquad (7.5)$$

The phase shifter angle is constrained to the operation range of the phase shifting transformer.

$$\boldsymbol{\alpha}_{L,min} \leq \boldsymbol{\alpha}_{L,T} \leq \boldsymbol{\alpha}_{L,max} \qquad (7.6)$$

In a realistic unit commitment simulation, certain simplifications have to be made about the boundaries of the considered power system. The neglected neighboring power systems can be included in the simulation in diff erent ways. The historical or expected import/export at the boundary of the considered power system can be included in the residual electricity demand of the considered power system. Another approach is to represent the power system outside the considered area by a dummy node with a certain load profile and generation profile.

Algorithm 1: Feasible solution recovery algorithm

Input: solution of SOC-ACOPF p_n^*;
Output: feasible solution of ACOPF p_n^{**};
Initialization;
$i = 1$;
Define $N^* \subseteq N$ such that $\forall n \in N^*, p_n^* > 0$;
$p_n = p_n^*$;
do
    if $c_{n'} = \max\{c_n\}, \forall n, n' \in N^*$ **then**
        Replace $p_{n'} = p_{n'}^*$ by
        $p_{\min,n'} < p_{n'} < p_{\max,n'}$;
        $N^* = N^* \setminus n'$;
    Solve nonconvex ACOPF;
    $i = i + 1$;
while ACOPF is not feasible and $i < i_{\max}$;

Optimal Reactive Power Dispatch Formulation

ORPD problem can be mathematically expressed in terms of objective functions and a set of constraints. Normally, ORPD considers three different targets consisting of minimization of total active power loss, minimization of total voltage deviation of all load buses, and minimization of voltage stability L-index. Besides, all constraints in transmission power network such as voltage bounds of all load buses, upper bound of apparent power flow through transmission branches, reactive power bounds and voltage bounds of generators, and real and reactive power flow balance at each bus. The detail of objectives and constraints is as follows.

Objective Functions

Reduction of total active power loss: total active power loss P_{Loss} in all branches of high voltage transmission power networks is significant, causing ineffectiveness for power system. Thus, reducing total reactive power loss is one of the most important targets when operating power system.

$$\text{Minimize} \quad P_{Loss} = \sum_{i=1}^{N_{bus}} \sum_{\substack{j=1 \\ j \neq i}}^{N_{bus}} G_{linel} \left[V_i^2 + V_j^2 - 2V_i V_j \cos\left(\varphi_i - \varphi_j\right) \right] \tag{1}$$

Reduction of total voltage deviation of all load buses: power quality consists of two most important factors, voltage and frequency, in which frequency can be controlled by tuning reactive power balance while voltage control is dependent on many factors such as transformer, reactive power of generator, and total reactive power loss in branches and capacitors. Voltage control is effective when total voltage deviation is very small, nearby zero.

$$\text{Minimize} \quad TVD = \sum_{i=1}^{N_{load}} \left| V_{loadi} - 1 \right| \tag{2}$$

where V_{loadi} is voltage of load bus and 1 Pu is the expected value of each load bus.

Reduction of L-index: voltage instability is one of the most harmful phenomenon for power system, which can cause voltage collapse gradually even immediately. Thus, the enhancement of voltage stability is one of the most important targets as two objective mentioned above. The enhancement of voltage stability is equivalent to minimization of voltage stability indicator, normally called L-index at each bus in power system. The enhancement of voltage stability is carried out by reducing the highest value of L-index at one bus in the power system. Namely, L-index at each bus i and the voltage stability enhancement are mathematically formulated by

$$L_i = \left| 1 - \frac{\sum_{j=1}^{N_G} Y_{ij} V_j}{V_i} \right|; \quad i = 1, 2, \ldots, N_{bus} \tag{3}$$

$$\text{Minimize} \quad \max\left(L_i\right); \quad i = 1, \ldots, N_{bus} \tag{4}$$

where L_i is the L-index value of bus i and Y_{ij} is the mutual admittance between buses i and j.

Constraints

Active and reactive power flow balance at each bus: at each bus, active power flow is the sum of three terms, generator, load, and lines while reactive power flow at each bus is the sum of four terms, generator, load, lines, and capacitors. The balance of all the terms must be exactly met by the following models

$$P_{Gi} - P_{di} = V_i \sum_{j=1}^{N_{bus}} V_j \left[G_{linel} \cos\left(\varphi_i - \varphi_j\right) + B_{linel} \sin\left(\varphi_i - \varphi_j\right) \right]; \quad i = 1, \ldots, N_{bus} \tag{5}$$

$$Q_{Gi} + Q_{ci} - Q_{di} = V_i \sum_{j=1}^{N_{bus}} V_j \left[G_{linel} \sin\left(\varphi_i - \varphi_j\right) - B_{linel} \cos\left(\varphi_i - \varphi_j\right) \right]; \quad i = 1, \ldots, N_{bus} \tag{6}$$

In addition, all electric components in power systems such as generators, transformers, conductors, capacitor banks, and loads are also constrained by security work capability. Thus, electrical bounds of these components are also considered seriously during operation process. In fact, they are subject to the following rules

$$Q_{Gi,\min} \leq Q_{Gi} \leq Q_{Gi,\max}; \quad i = 1, \ldots, N_G \tag{7}$$

$$V_{G,\min} \leq V_{Gi} \leq V_{G,\max}; \quad i = 1, \ldots, N_G \tag{8}$$

$$T_{\min} \leq T_i \leq T_{\max}; \quad i = 1, \ldots, N_t \tag{9}$$

$$S_l \leq S_{l,\max}; \quad l = 1, \ldots, N_{line} \tag{10}$$

$$Q_{ci,\min} \leq Q_{ci} \leq Q_{ci,\max}; \quad i = 1, \ldots, N_c \tag{11}$$

$$V_{load,\min} \leq V_{loadi} \leq V_{load,\max}; \quad i = 1, \ldots, N_{load} \tag{12}$$