Economic Operation and Control of Power System

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Lecture – 28

Very good morning and welcome you all to the NPTEL course on Economic Operation and Control of Power System and today's lecture 28, Economic Scheduling with Unreserved Load Method. Now with reference to all the lectures that we have gone through as of now, I mean most of the cases the load is considered to be a fixed element and the generations or generating units are considered to be available to me all the time. But in practical scenarios the load is going to be a variable element which is keep on changing. Given the forecasted load that you predict and take your decision not necessarily to be the same load that you have forecasted. So there could be a forecasted error and similarly the unit 1 to N that we have considered to be available to me for catering the load is may not be available to me all the time because of there could be outages, there could be a sudden failure of some of the units. So there are N number of uncertainties is associated with economic dispatch and unit commitment problems.

So considering those uncertainties a probabilistic or stochastic approaches are being used to take care or accommodate those uncertainties associated within the system. Now let us get into probabilistic production cost computation. Now what happens when you talk about production cost as per the characteristic that we have already learned earlier the cost of a unit generating power of P megawatt is given by:

$$\square_{\square}^{2} + \square_{\square} + \square$$

where A and B and C are the constants of parameters. But it may not be true that the cost characteristic which has been developed or created for a particular unit may not be same throughout the year due to certain challenges or uncertainties.

Now production cost programs that recognize unit force outages and compute the statistically expected energy production cost have been developed and used widely. So what we are doing basically the energy cost that we are talking about X rupees per unit may vary because of certain environments. Now different mathematical models or methods based on probability make use of probabilistic models of both the load to be served and the energy and capacity resources. The models of the generation need to represent the unavailability of basic energy resources. For an example if you carry out hydro thermal scheduling we assume that X megawatt of power can be obtained through my hydropower plant but due to certain extreme rain conditions or maybe worst weather conditions the prediction of hydropower plant may not be as expected or as predicted.

That is the random forced outages of units due to certain issues and the effect of contracts for energy sale and or purchases may lead to a solution which may not be a guaranteed solution or may not be as predicted in the past. The computation may also include the expected cost of emergency energy over the tie lines which is sometimes referred to as the cost of unsupplied energy. Now let's say there are two areas are being connected to a tie line and what we do if the load is more than my generation then we extract some of the power from other areas through the tie line and also there are certain uncertainty associated because if someone is committed to give you power but due to some reason if they are not able to you know stick to their commitments then probably your economic dispatch solutions will vary. So those factors need to be considered in day to day analysis. The basic difficulties that were noted when using deterministic approaches to the calculation of system production cost where the base load unit of the system are loaded in the models for nearly 100 percent means we consider that the base load will be provided by certain type of generation and we assume that they are available all the time.

The mid range of cyclic units are loaded for a period that depends on the priority range and the shape of the load duration curve. So as we discussed the load duration curve which is like a valley and there are certain base generations and certain peak generations so those have to generate continuously they are being assigned against a base load and however the peak or the spikes are being managed through some expansive generations which are I mean you know kind of not necessarily to be operated around the day. For example if there is a gas power plant we bring them during the peak hours and then we switch it off as and when required. However a nuclear power plant or a thermal generating unit they are always allowed to generate power. For any system with reasonably adequate reserve level the peaking units of an interval are nearly zero capacity factor.

Now these conditions are in fact all violated to a greater or lesser extent whenever random unit force outages occur on a real system. As I started my today's talk uncertainty become a natural phenomena and generating unit outages cannot be avoided. It can reduce it but certainly in a year few power plants may go back. For example you have n number of units those are supposed to meet your base load but some one of them fails in between then what you do the unavailability of thermal generating units due to unexpected randomly occurred outages is fairly high for large size units. So for example if you have a super thermal power plant having 10 units in a year maybe one or two units suddenly switched off and then you have to see what went wrong you repair and make sure they are in line after few hours.

Now value of 10% are common for full forced outages means we are assuming out of 10 generating units at least one will fail at a given period of time. That is for a full forced outage rate of Q per unit the particular generating unit is completely unavailable that is for

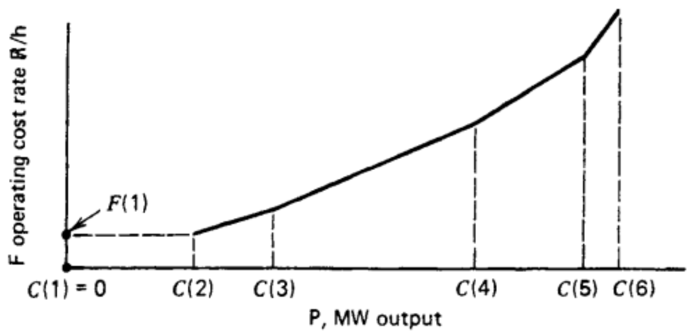
100 Q percentage of the time it is supposed to be available it is supposed to be there for X number of hours but it is available less than X number of hours due to certain practical outages. So generating units also suffer partial outages where the unit must be de-rated that means if it is supposed to produce X megawatt of power due to certain outages we say no it can only produce 0.6 X of megawatts. So that means it is not completely off but the magnitude of generation reduced by 40% so that is also partially outage system we consider in our economic dispatch studies.

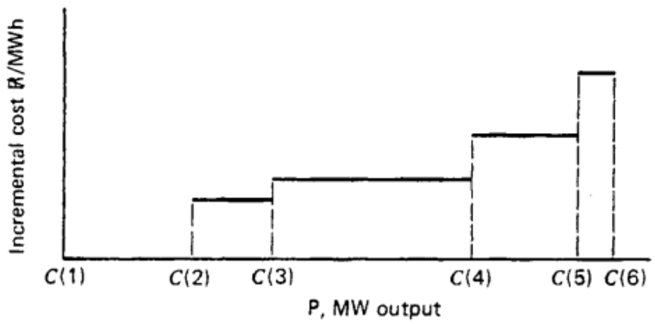
And for some period of time due to the forced outages of some systems or components maybe a boiled boiler feed pump or a fan of a motor there are two techniques that have been used to handle the convolution of the load distributions with the capacity probability density functions of the units. Numerical convolutions where discrete values are used to model all the distributions. The second analytical methods that use continuous functional representations and both techniques may be further divided into approaches that perform the convolution in different orders. In what will be referred to here is the unserved load distribution method. The individual unit probability capacity densities are convolved with the load distribution in a sequence determined by a fixed economic loading criteria to develop a series of unserved load distributions.

Unit energy production is the difference between the unserved load means the amount of load that you could not serve because of certain uncertainties. Energy before the unit is scheduled that is convolved with the previous unserved load distribution and after it has been scheduled and that is known as the load which is not been served. The load forecast is the initial unserved load distribution. In the expected cost method the unit probability capacity densities are first convolved with each other in sequence to develop distributions of available capacity and the expected cost curves as a function of the total power generated. Now this expected cost curves may then be used with the load distribution to produce the expected value of the production cost to serve the given load forecasted distribution.

So here we need to meet the load which is uncertain and the generations which are meeting the uncertainty loads are also partially being unserved under different outages. The analytical methods use orthogonal functions to represent both the load and capacity probability of the units. So there are two major variables units and loads. These are the methods based on use of cumulunts. The merit of this analytical method is that it is usually a much more rapid computation.

The drawback appears to be the concern over accuracy. I mean which can provide you more accurate result as compared with numerical convolution results. The discussions of the numerical convolution technique which follows should provide a sufficient basis for appreciating the approach that is its utility and its difficulties. Now let us all concentrate on the following figure number 28.1.





The data available that describes generating unit in the following format where we can define maximum power output available in megawatt and then the probability unit is available to load to this power. We say that there is a unit of capacity 2200 megawatt and what is the probability that the unit is available to me to meet that load at that particular hour and hence cost of generating maximum available. Now from the diagram as you could see the operating cost that is rupees per hour. I mean you could see there are piecewise linear mechanisms and if you go for the incremental costing that is being differentiated so you could see the characteristic become a step function. So this is megawatt versus incremental cost and this is megawatt versus operating cost.

The probabilistic production cost procedure uses thermal unit heat rate characteristics that is heat input rate versus electric power output that are normally linear segments. It could be nonlinear but in this case we have assumed to be linear segments. Now this type of heat rate characteristic is essential to the development of an efficient probabilistic computational algorithm since it results in stepped incremental cost curves. This implies the economic scheduling algorithm since any segment is fully loaded before the next is required. So what do we do? If the demand is going to be X any generating unit the cheaper unit will be loaded first and we keep on loading till the X megawatt is being achieved.

This unit input output characteristics may have any number of segments so that a unit may be represented with as much detail as it is desired. That is the unit thermal data are converted to cost per hour using fuel cost and other operating costs as is the case with any economic dispatching techniques. The probabilistic production cost model simulate economic loading procedures and its constraints. Fuel budgeting and planning studies utilize suitable approximation in order to permit the probabilistic computation of expected future cost means today if the coal cost is rupees X we create a cost characteristic of a thermal power plant but tomorrow if the coal cost is going to change then my cost characteristic is also going to change. For instance unit commitment will usually be approximated using a priority order.

So what we do in case of unit commitment instead of switching on all the units we only commit those units which are economical and also adding those units the total load is close to my generating unit. So we invite the cheapest unit first operate then call the next cheapest next cheapest till my total load is being met and this is also known as priority listing based unit commitment approach. The priority list might be computed on the basis of average cost per megawatt hour at full load with units grouped in blocks by minimum downtime requirements. Within each block of units with similar downtimes unit could be ordered economically by average cost per megawatt hour at full load. Now if you move towards unit commitment with unit commitment order being established the various available loading segments can be placed in sequence means you have the cost characteristic and the maximum power is P max.

So to generate P max you know the cost that cost upon the P max will give me the unit cost when the generator is operating at its maximum capacity and then based on the lowest cost to highest cost I keep on scheduling my generators to meet the load. In order of increasing incremental cost the loading of units in this fashion is identical to using equal incremental cost scheduling where input output curves are made up of straight line segments means linear even if you differentiate incremental cost they become straight lines means as you have seen in this diagram. Now these are my linear incremental cost, the linear operating cost characteristics and when you plot the incremental cost you could see they are simply straight and linear characteristics. Similarly emergency sources that is tie lines or pseudo tie lines are placed last on the loading order list. The essential difference between the results of the probabilistic procedure and the usual economic dispersed computation is that all the units will be required if generator force outages are considered.

That means if you are assuming that there may exist a force outage mechanism then you have to make all your generator ready because at least the largest generating unit if it fails we must be in a position to take care of those losses. Now must run that is base units are usually designated in these computations by requiring minimum down times equal to or greater than a week that is 168 hours means if a what is down time if the unit is down then it is down for a duration means there are few generating units once they are switched off they take a reasonable time to become backward. So if you say the down time is 7 days that means 168 hours means if the generator is out that it will take 168 hours to come back to action. Now this base load units are committed first which takes longer down time you know so normally we do not allow them to be switched off once they are on we make sure that they are on always after the must turn units are committed they must supply the minimum power the next lowest cost block of capacity may be either a subsequent loading segment on a committed unit or a new unit to be committed. So what is the concept here you have a number of units you know what are those units need to be in operation all the time you cannot afford to switch them off so bring all of them but they are not necessarily to be economic unit because of their physical challenges or physical constraints we have to make them run but they are not necessarily to be a cheaper unit.

So that is why you allow them to operate with its minimum capacity so that they are on and they are always available to me and then when you increase the load or the increase load need to be met there are two way of doing it either you can increase the generation of those units operating at minimum generation capacity or you can take a new unit to be added to meet the loads. Now following this are a similar procedure results in a list of unit loading segments arranged in economic loading order which is then convenient and efficient to use in the probabilistic production cost calculations and to modify for each scheduling interval of a day week month. Now the storage hydro units and the system sales purchase contracts for interconnected system must also be simulated in production cost programs if you are dependent on somebody's energy exchange or if you are dependent on a hydro generating unit which is you know being catching your required load or you have a storage hydro unit means you take the water back to your dam to generate power so that means they are constrained problems now you are dependent on other energy exchange or some of the energy need to be taken back to produce your regular energy. So this kind of problems need to be simulated in a better way the exact treatment of each depends on the constraints and the cost associated with this formulation. For example a monthly load model might be modified to account the storage hydro by peak shaving for example if you take a one day load schedule and you are planning that I will take my water back store it and generate during peak hours which may not be appropriate.

So you need to have a monthly plan or a weekly plan so that you can take the water back and you can discharge as per your planning maybe second day maybe seventh day maybe twentieth day maybe thirtieth day so you can plan it is not a short term planning you need to have a reasonably long term at least one month planning. Now in the peak saving approach the hydro unit production is scheduled to serve the peak load interval ignoring all hydraulic constraints but not the capacity limits and assuming a single incremental cost curve for the thermal system for the entire scheduling interval. This can be done taking into account both hydro unit forced outages and hydro energy availability that is amount of interval energy available versus the probability of it being available. System purchases and sales are often simulated as if they were stored energy systems means when I am expecting my neighbor to give me some energy through a tie line so I am assuming that is being stored for me and that can be taken at any given point of time. It is similar to my hydro energy storage where I know that excess amount of energy water being stored I can generate as and when required.

So energy exchange model is also similar to a storage model. Now sales or purchases from specific units are more difficult to model and the modeling depends on the details of the contract. For instance a pure unit transition is made only when the unit is available. Other less pure what do you mean by less pure contracts might be made where the transaction might still take place using energy produced by other units under specified conditions. So units which are guaranteed we call it is pure and which are less likely depend on other units are called less pure units.

Now in the probabilistic production cost approach the load is modeled in the same way as it was in the previously illustrated load duration curve approach. As a probability distribution expressed in terms of hours that the load is expected to equal or exceed the value on a horizontal axis this is a monotonically decreasing function with increasing load and could be converted to a pure probability distribution by dividing by the number of hours in the load interval being modeled. Now this model is illustrated in the previous slides and figures that you have seen earlier. Therefore each load duration curve is treated either as a cumulative probability distribution function that is Pn x versus x. So that means Pn is nothing but my probability of needing x megawatt.

So if you can draw a characteristic x versus Pn x what is the probability of meeting that x and also there is another term known as Pn x where t is the duration of the particular time interval. The Pn x the probability is equal to 1 or any x less than or equal to 0. The load distribution is usually expressed in a table where t Pn x is available to me which may be fairly short. The table needs to be only as long as the maximum load divided by the uniform megawatt interval size used in constructing the table. In applying this approach a digital computer because now we are slowly making the problem quite complicated the way we started it was quite simple.

Today what we are discussing is a very real time advanced computation technology. In applying this approach a digital computation it is both convenient and computationally efficient to think in term of regular discrete steps and recursive algorithms. Various load duration curves for the entire interval to be studied are arranged in the sequence to be used in the scheduling logic. That means we will have a matrix or a table where based on the different scenarios the different solutions are being stored. So depending upon a given dynamics of today's load curve different outages mechanism we must be in a position to take action which generator to be operated at which capacity.

There is no requirement that a similar distribution that is Pn(x) be used for all time periods. Now in developing the unit commitment schedule it is necessary to verify not only that the maximum load plus spinning reserve. I hope you all understand what is spinning reserve. Spinning reserve means the additional amount of power need to be made available in the system even during the failure of the largest unit in the network available to you. So if there are 10 units the largest generating unit being failed still you are able to manage that means you have taken care of spinning reserve.

Otherwise any outage will lead to loss of load most of the areas will be dark that we do not want. So we always plan my load will be something which is load plus a load which is equivalent to the rating of the larger unit. That means if one unit fails and happen to be the largest unit still I am able to cater or the load that is known as spinning reserve is equal to or less than the sum of the capacities of the committed units. But also that the sum of the minimum loading levels of the committed units is not greater than the minimum load to be served at a given time. A number of different descriptions have been used in the literature to explain this probabilistic procedure of thermal unit schedule.

Conventional thermal unit scheduling we learned and there are many literatures talk about probabilistic way of scheduling the units which is a very very important topic to all of us. The following has been found to be the easiest to grasp by someone unfamiliar with this procedure and is theoretically found. If there is a segment of capacity with a total of C megawatt available for scheduling and if you denote Q the probability that C megawatt are unavailable that is unavailability and P which is 1 minus Q that is the probability of availability of this segment. This segment has been scheduled the probability of the needing X megawatt or more is now P i X. Since the occurrence of the loads and unexpected unit outages are statistically dependent or statistically independent events as the new probability distribution is a combination of mutually exclusive events with the same measure of need for additional capacity.

That means the new P i X which will be Q of P i X plus P of P i X plus C. Now what is Q P i X is the probability that new capacity C is unavailable time the probability of needing X or more megawatt that is P of P i X plus C is the probability C is available times the probability X plus C or more is needed. Now these two terms first segment and second segment represent two different mutually exclusive events. Each representing combined event when X megawatt or more remain to be served by the generating system. This is a recursive computational algorithm similar to one used to develop the capacity outage distribution and will be used in sequence to convolve each unit or loading segment that with the distribution of load not being served. It should be recognized that the argument of the probability distribution can be negative after load has been supplied and then:

$$Pn(x) = 0$$

Now for X greater than the peak load initially when only the load distribution is used to develop TPn(x) that is:

$$Pn(x) = 1 \text{ for } x \leq 0$$

for all the values X less than or equal to zero. So with this let us stop today and when we meet next time we will continue the class again. Thank you. Thank you.