**Economic Operation and Control of Power System**

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**Week - 11**

**Lecture – 52**

Hello and good morning everyone. Welcome you all for the Intel online course on Economic Operations and Control of Power Systems. Today we will continue our discussion with respect to control of generation. So as we have discussed, the automatic generation control will help to restore frequency when it deviates from 50 hertz or 60 hertz. And it reallocates generation to keep it at economic dispatch. Keep interchange with other control areas at the scheduled megawatt and monitor and control generators as they ramp up a ramp down.

The overall control action with respect to generator is being monitored. Now we will discuss the tie line model. The power flow across a tie line can be modeled using a linear load flow approach. Let us say there is a two network, this network one, there is another network and these are the bus to which the tie line is connected.

Now this is tie line. This is tie line. So you can see a steady state or nominal flow quantity. The power flow which is happening in this tie line can be obtained by:

- steady-state or nominal flow quantity: $P_{tie\ flow} = \frac{1}{X_{tie}}(\delta_1 - \delta_2)$
- deviation from the nominal tie-line flow

$$P_{tie\ flow} + \Delta P_{tie\ flow} = \frac{1}{X_{tie}}[(\delta_1 + \Delta\delta_1) - (\delta_2 + \Delta\delta_2)]$$

$$= \frac{1}{X_{tie}}\left(\delta_1 - \delta_2 + (\Delta\delta_1 - \Delta\delta_2)\right)$$

$$\Delta P_{tie\ flow} = \frac{1}{X_{tie}}(\Delta\delta_1 - \Delta\delta_2)$$

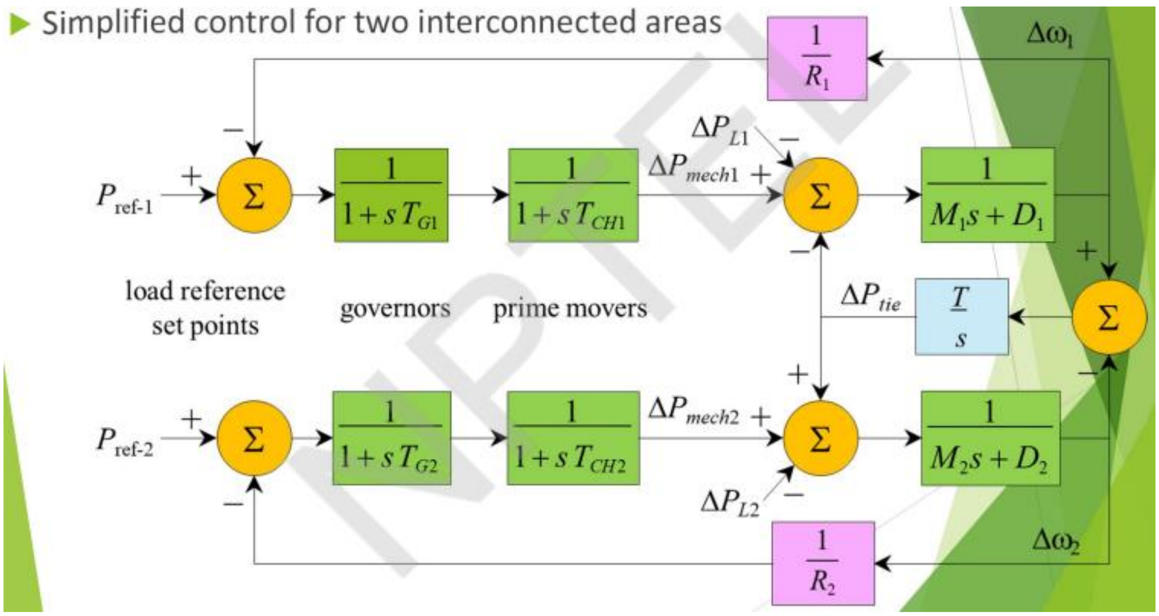
Where, $\Delta\delta$ must be in radians for $\Delta P_{tie}$ to be in per unit

Using the relationship for speed and $\Delta\delta$: $\Delta\delta = \frac{\omega_0}{s}\Delta\omega$

then $\Delta P_{tie\ flow} = \frac{\omega_0}{s}\frac{(\Delta\omega_1 - \Delta\omega_2)}{X_{tie}} = \frac{T}{s}(\Delta\omega_1 - \Delta\omega_2)$

where $T = 377/X_{tie}$ for a 60 Hz system.

So now the simplified control for two interconnected areas.




This is the overall control loop looks like. So this is the load reference set points, p reference 1, p reference 2 for the individual networks. And we have got this control system model from the previous class.

This is governor transfer function. This is prime mover transfer function. Governor output is given to prime mover. Prime mover will generate mechanical, after the prime mover you will get the mechanical torque is converted into electrical energy. This is delta p mechanical one and then there is a load which is connected, change in load which is happening at network 1 and there is this extra term which is coming into play because of the tie line, it is an interconnected network.

So due to load disturbance if at all if there is any load disturbance because of which that is reflected as a change in power flow. So and then this again is applied to the model where this is expressed as moment of inertia and the change in frequency component of load and that is expressed as d1. So this is with respect to network 1. So ultimately we will get change in frequency, overall change in frequency and there is a droop coefficient and that is applied back to this control loop. Whereas this delta omega 1, delta omega 1 minus delta omega 2.

Similarly there is also a delta omega 2 factor which is coming from the second network. Delta omega 1 minus delta omega 2 is delta omega, this is delta omega. Delta omega, this is interrelated to delta p tie. From the previous expression we got this. So d by s into delta p tie, d by s into delta omega will give you delta p tie.

This is positive for one network and negative for another network. That means if there is a change in power flow which is happening due to load disturbance, there could be power flow from one positive from one network. That means power is flowing from one bus towards another bus to meet out because of this disturbance. That means there is a positive power change and there is a negative change at another bus. So both should be opposite.

So this is a typical tie line model. So tie line model considered two areas, each with a generator. The two areas are connected with a single transmission line. The line flow appears as a load in one area and an equal but negative load in the other area or generation at one side, excess generation and consumption at the another side. The flow is dictated by the relative phase angle across the line which is determined by the relative speed deviations basically.

Let there be a load change delta p L1 in area 1 for example. To analyze the steady state frequency deviation, the tie flow deviation and generator outputs must be examined. Now what is happening? After the transients have decayed, the frequency will be constant and equal to the same value in both areas. Ultimately because it is an interconnected network, during transients there could be deviation in frequency at individual network. But after some point of time, they will come to a common agreement and the frequency will be settling at one point.

It is a common frequency ultimately. So delta omega 1 change in speed that is at network 1 which is delta omega 1 minus delta omega 2 which is equal to delta omega and if change in over a period of time, d by dt of delta omega 1 is equal to d by dt of delta omega 2 and that is equal to 0. Rate of change of this frequency deviation will be 0. That means delta p mechanical 1, that means this is with respect to the power output, change in power output from network 1. If there is a frequency change, there is also an increase in generation at the network 1 minus delta p Ti.

This represents the net power flow which is happening in the tie line minus this is change in load at network 1 basically. So that is equal to delta omega into d1. How we are getting this value from the previous network? You can see here previous tie line model delta p mechanical 1 minus delta p L1, delta p mechanical 1 minus delta p L1 minus delta p Ti into 1 by mns plus d1 is equal to delta omega 1. Let me write it down for easiness. Delta p1 minus delta p1 plus delta p mechanical 1 minus delta p Ti into 1 by m 1 s plus d1 is equal to delta omega 1.

But we are speaking in steady state. At steady state s is 0. So that means delta p1, delta p mechanical 1 minus delta p1 minus delta p Ti is equal to d1 into delta omega 1, d1 into delta omega 1. Similarly here what is happening? In the second network, this is delta p mechanical 2 plus delta p Ti, delta p mechanical 2 plus delta p Ti minus delta p L2. But this term will be 0 because there is no load change that we are assuming at the network 2.

So this change in load is 0. So only it is delta p mechanical 2 plus delta p Ti is equal to d2 into delta omega 2, d2 into delta omega 2 in steady state. So that is what we are getting here. Delta p mechanical 1 minus delta p Ti minus delta p1 is equal to delta omega into d1 and delta mechanical 2 plus delta p Ti is equal to delta omega into d2. And delta p mechanical 1 is equal to, that can be also further reduced.

You see here, what is delta p mechanical 1? If you try to analyze this, what is delta p mechanical 1? This is nothing but this transfer function into this transfer function into the input which is coming which is delta omega 1 into minus 1 by R1. This is minus signal. At steady state this component will be 0. This is also 0.

The overall gain is just 1. So what you are getting?

$$\Delta\omega = \frac{-\Delta P_{L1}}{\frac{1}{R_1}+\frac{1}{R_2}+D_1+D_2}$$

$$\Delta P_{tie} = \frac{-\Delta P_{L1}\left(D_2+\frac{1}{R_2}\right)}{\frac{1}{R_1}+\frac{1}{R_2}+D_1+D_2}$$

Here delta p Ti is there. You replace that with this delta p Ti. Now you will get what is delta omega. Delta omega is expressed in terms of minus delta p L1 divided by this. And delta p Ti is nothing but minus delta p L1 into, this is delta omega, this is delta omega into d2 plus 1 by R2. So that can be also expressed as delta omega is nothing but minus delta p L1 by this.

So you will get this expression. So finally you got an expression for delta omega which is change in frequency. And what is the change in tie line power flow. That is expressed in terms of, you see the parameters here. One is you should know how much is the change in load deviation, delta p L1.

Delta p L2 is 0. Change in load deviation is happening only at network 1. And we have these constants which are already known to us. The droop coefficients R1 and R2 and d1 and d2 which are frequency dependent load components. So this is already known to you. So the new tie line flow is determined by the net change in load and generation in each area but not influenced by the tie stiffness.

Do you understand? A tie stiffness is what which defines the, whether the line it is electrically very tightly coupled or it is loosely coupled. In the sense it depends upon its own parameters X by R. Here there is no term of line reactance or line resistance. It is totally independent of line stiffness basically. So this is happening by the net change in load and generation in each area.

That is it. The generation in each area is dependent upon the droop coefficients. Because of droop coefficients only the power flow is happening. So the tie stiffness determines the phase angle across the tie line only. Now example, let us take an example to understand. Consider two areas:

- consider two areas, each with a generator, motor loads, and a single tie-line connecting the two areas.
  - Area 1: $R_1 = 0.01\, pu,\ D_1 = 0.8\, pu,\ \ Base\ MVA = 500$
  - Area 2: $R_2 = 0.02\, pu,\ D_2 = 1.0\, pu,\ \ Base\ MVA = 500$
- a load change of 100 MW (0.2 pu) occurs in area 1
- find the new steady-state frequency and net tie flow change

$$\Delta\omega = \frac{-\Delta P_{L1}}{\frac{1}{R_1}+\frac{1}{R_2}+D_1+D_2} = \frac{-0.2}{\frac{1}{0.01}+\frac{1}{0.02}+0.8+1.0} = -0.001318$$

$$f_{new} = 60 + (-0.001318)(60) = 59.92\ Hz$$

$$\Delta P_{tie} = \Delta\omega\left(D_2 + \frac{1}{R_2}\right) = (-0.001318)\left(\frac{1}{0.02} + 1\right) = 0.06719\ pu = 33.6\ MW$$

You will get this is the change in frequency. That means if there is an increase in load at network 1, what naturally happens? There will be decrease in frequency. That means from earlier frequency, the frequency has decreased by this hertz, this per unit actually. So in terms of frequency, you get the latest frequency which is settled down at steady state is 59.92 hertz. And what is the power flow which is happening corresponding to this? The delta PTI is delta omega into d2 plus 1 by r2.

That means 33.6 megahertz, megawatt in terms of actual value. This is the power flow which is happening from network 2 to network 1. Let us suppose just for an assumption, let us say there is no network 2 at all. Network 2 at all is, let us ignore that.

- change in the prime movers.
  - $\Delta P_{mech1} = {}^{-\Delta\omega}/_{R_1} = {}^{0.001318}/_{0.01} = 0.1318 \ (65.88\ MW)$
  - $\Delta P_{mec} \ = {}^{-\Delta\omega}/_{R_2} = {}^{0.001318}/_{0.02} = 0.0659 \ (32.94\ MW)$
- change in the motor loads

$\Delta P_{L1\,(motor)} = \Delta\omega D_1 = -0.001318 * 0.8 = -0.001054 \ \ (-0.527\ MW)$

$\Delta P_{L2\,(motor)} = \Delta\omega D_2 = -0.001318 * 1.0 = -0.001318 \ \ (-0.659\ MW)$

- change in tie flow

  $\Delta P_{tie} = \Delta P_{mech2} - \Delta P_{L2\,(motor)} = 0.0672 \ \ (33.6\ MW)$
- change in apparent loading

  $\Delta P_{L1} = \Delta P_{mech1} - \Delta P_{L1\,(motor)} + \Delta P_{tie} = 0.200 \ \ (100\ MW)$

Now frequency has decreased that means they are directly depending upon this frequency, directly proportional. So the power output from this motor loads will also decrease. A power consumption from this motor loads, its motor means it is a load, the power consumption from this motor loads will decrease. That means delta omega into d1, this delta omega is negative that means the power consumed by these loads have reduced from their original value to by a value of 0.527 megawatt in network 1 and 0.6 by 9 megawatt in network 2. So change in time flow, delta Pti is equal to delta P mechanical 2 minus delta PL2, the overall output. This is a change in generation at network 2. The change in tie line power flow is there is a reduction in load consumption plus increase in generation. So there will be net increase in power output. So that is 32.94, this is 32.94 minus of minus which is plus 0.659 that is coming out to be 33.6 megawatt. This is what the exact power which is flowing into the network of network 1, 33.6 megawatt. So you see here, so if 33.6 is being catered by the second network and remaining is being managed so total power will be 100 megawatt. That is what is the change in load. So automatic generation control is a control system that has three major objectives. Hold the system frequency at or very close to a specified nominal value that is 50 Hz or 60 Hz.

Maintain the correct value of interchange power between control areas. Enforce contracts for shipping or receiving power along the tie lines to neighboring utilities. And maintain each generating unit's operating point at the most economical value. You need to operate at the most economical value, ensure that power happens, power flow happens as per their schedule, dispatch and ensure that the frequency is restored at nominal value which is 50 or 60 Hz. Now you see here, there is a, this is a frequency response to load change. So there is a frequency change because of which here there is no governor action.

There is no governor action that, henceforth we do not see 1 by R1 plus 1 by R2 terms.

This is not there here. Thus, just there is a change in load because of which there is already frequency dependence loads, because of which finally there is some overall frequency error. This is a nominal value.

This is the actual value where it is settled on ultimately. Now if there is a governor action which is present, it will try to adjust because of presence of 1 by R1 and 1 by R2. But this is not coming to steady state. The steady state error is not 0 here. This is not coming to a value of 60 Hz or 50 Hz. The reason being, even though there is governor action which is taking place, this is a primary control loop.

Henceforth they are adjusting their power based on the droop coefficients which is primary response but nobody is guiding them to make the steady state error as 0 in the entire control loop. So we need to make it. How do you make it? By using supplementary control action. Assume for the moment that a single generating unit supplies load to an isolated power system.

For example, isochronous generator we discussed in the initial class. A load change will produce a frequency change. Magnitude depends on the droop characteristics of the governor and the frequency characteristics of the system load. Now a momentary control must act to restore the frequency to the nominal value 60 Hz. This is through an integral control loop to the governor.

Ultimately you need to have integral controller to make it as a 0 steady state error. The control action forces the frequency error to 0 by adjusting the speed reference set point. The governor set points need to be adjusted. See what is happening here? Now this loop was already there. Now you need to adjust the frequency error.

This is a frequency restoration control error. There is an integral controller and this is being added here. This will ensure that ultimately due to primary response they will adjust themselves and reach to some frequency which may be lesser or higher than the original frequency. Maybe some reasons. And due to an additional frequency restoration control now will bring back the frequency to the 60 Hz or 50 Hz.

That is your desired objective. Two utilities will interconnect their systems for several reasons. Why they will have to interconnect if you try to understand this point? One is to buy and sell power with neighbouring systems whose operating costs make the transactions profitable. So let us say even not only between two networks within the country there will be power exchange between two countries also. So Bangladesh and India and so many other countries in Europe also.

So why they do that? The reason being I want power and you have excess power. If I generate my own, build a new thermal power plant, try to augment the power, it will be more costlier for me. Rather I will take power from the neighbouring country. He will also be benefited, I will also be benefited. Such sort of agreement.

So improvement to overall reliability for events like the sudden loss of generating unit. Even though there is no regular power exchange but still you get interconnected, in case of emergency scenarios can we have a rerouting of power if there is a fault or due to any reasons. If there is an emergency scenario to improve the reliability we can have this interconnection. Provide a common frequency reference for frequency restoration. So define time flows and time flow changes.

Total actual net interchange, this is termed as Pnet interchange. This is plus for power leaving the system, this is a convention. And negative for power entering the system. So scheduled or desired value of interchange is Pnet interchange scheduled. So change in time flow delta Pnet interchange is, this is happening because of there is a disturbance. There is a sudden disturbance and before that there is already a scheduled exchange, agreement which is happening.

Apart from that if there is sudden change in load which is not as part of the agreement, then the total power increase or decrease in the tie-line power flow because of this sudden disturbance in power, load power consumption either in the networks, either of the networks and that is expressed as delta Pnet interchange. So interconnections present a challenging control problem now. There is already a tariff, there is economics behind this tie-line power flow happening. Now due to load changes which is not part of the agreement, then a generation may have to cater to this additional load change because it is connected to the physical network.

The physics is working. Then by electrical control parameters, the change in phase angle, power flow is happening, but that is not under the umbrella of the economics. Now how to ensure that we will not allow sudden change, any, we will not cater to the requirement of change in load which is not part of the schedule. So that need, that is a very critical control problem.

This need to be adjusted as a control problem. Now consider a two area system. Both areas have equal load and generator characteristics. For example, that is R1 group coefficients are same, frequency dependence loads are also same. Assume that area 1 sends 100 MW to area 2 under an interchange agreement between the system operators of the two areas. Let area 2 experience a sudden load increase of 30 MW. Then both areas see a 15 MW increase in generation because R1 and R2 are same and the tie-line flow increases from 100 to 115 MW. This is what we are saying. The 30 MW load increase is satisfied by 15 MW increase in generation 2 plus a 15 MW increase in tie-line flow into area 2. This is fine except that area 1 contracted to sell only 100 MW. There is already agreement. I will give only money for 100 MW.

So what will happen for the rest 15 MW? So generation costs have increased without anyone to bill. So a control scheme is needed to hold the system to the contract. So such a control system must use two pieces of information. One is the overall system frequency and net power flow across the tie-line. A few possible network conditions include if the frequency decreases, a net interchange power leaving the system increases.

A load increase has occurred outside the area. Try to understand this point. If the frequency decreases, a net interchange power leaving the system, this increases. Now what is happening? The overall frequency is decreasing and from this network perspective the power which is leaving the system, that means the load has increased has occurred outside the area. Somebody is consuming the power.

That is why for me the positive convention is happening. Power is leaving this network. Let us say if the frequency is decreasing, the second case, and net interchange power leaving the system decreases, then what is happening? Instead of power is going outside, it is consumed here itself but still frequency is decreasing means there is a load which is changed or increased inside the area itself. So define a control area. By this we will come to know which generation need to be adjusted basically. Design a control area, part of an interconnected system within which the load and generation will be controlled.

You make some boundaries for control action. All tie lines that cross a control area boundary must be metered. I will explain you with this table. Now you see there are two networks, network 1 and network 2 here. They are interconnected and as per convention, delta P net interchange is the power which is flowing from network 1 to network 2. If this is positive that means power flow is happening from network 1 to network 2 and delta P L1 is load change in area 1, delta P L2 is load change in area 2.

Now let us try and figure out all permutation and combination. So delta omega that means change in speed which is happening, we say net change in speed which is nothing but delta omega 1 minus delta omega 2 which is equal to delta omega, the overall change in speed or overall change in frequency basically. That is negative. That means frequency has decreased. That means somewhere the load might have increased, frequency has decreased and from telemetry data we are getting the measurement that delta P net interchange is negative.

That means what is happening? Power flow in this case is happening this side, this way from 2 to 1. That means if frequency is decreasing, power flow is happening from 2 to 1. What is the easy understanding? There is a net load increase at network 1. That means what you need to do? Increase P generation in area 1.

That is what we have said delta P L1 is positive, delta P L2 is 0. There is no load change in network 2. Let us say frequency change is positive and delta P net interchange is also positive. That means frequency has increased and power flow is also happening from 1 to 2. Then what is happening? If frequency has increased and power flow is also happening from 1 to 2 that means there is a curtailment in the load. Frequency is increasing means earlier there was some X load, now that load has decreased, switched off or whatever may be the reason. That means what is the control action that you need to do? Increase P generation in area 1 to restore the frequency to the nominal value.

Why do you want to unnecessarily send the power to the network 2? And next case the frequency is negative that means there is decrease in increase in load basically and here delta P net interchange is positive. Then what is happening? Third case, there is increase in load. Where it is happening that we do not know yet. There is overall increase in load somewhere and there is frequency because of this there is a frequency decreasing, frequency decreasing, delta P L is increasing.

That is why frequency is decreasing. Now we need to identify and we have understood that delta P net is positive. That means power flow is happening in this direction. That means what is happening? There is an increase in load at network 2 because frequency is decreasing with respect to network 1 perspective and that indicates the power there is a increase in load somewhere, but power flow is happening from network 1 to 2 that means there is increase in load at generated at the network 2. That is what we have mentioned delta P L2 is positive and delta P L1 is 0.

What is the control action that you need to do? Increase generation, it is your problem. This is not under the agreement. You increase the generation and you do not put burden on my shoulders basically from network 1 perspective. And the last case is frequency is again increasing. That means obviously there is decrease in load somewhere, frequency is increasing and delta P net interchanges negative. That means power flow is happening from network 2 to network 1 here.

That means what is happening here? There is decrease in load at network 2. That is why the frequency overall is increasing and power flow is positive into the network 1. Henceforth you ask the generation 2 to decrease their generation. This is how the control action is brought in. Just take one row for example, how do you implement it in control row? For the first row of the control response table, it is required that delta P generation 1 is equal to delta P L1.

There is a net increase in load, increase in generation. That was the task. Delta P generation 2 is equal to 0. Now the required change is known as the area control error. A new term is being brought in, defined which is area control error. The equations for the area control error for each area is A c e 1 is equal to minus delta P net interchange.

Because of this only there is a change in flow because of which you need to take an appropriate action.

Minus P 1 into delta omega. That is depending upon frequency again. Now P 1 is defined as 1 by R 1 plus D 1. Basically because of your frequency dependent loads and the generation, how do you adjust the generation? Because of 1 by R 1. The control action is happening because of 1 by R 1 plus D 1. Somehow or the other this change has to be brought in to the picture of the steam valve. You need to bring in steam valve, increase the change in steam valve output such that the mechanical power output to the turbine is changed and electrical power output will be adjusted.

So this block need to be reflected in the overall control room. Similarly, for area control error 2, this is also this expression which is depending upon its own droop coefficient and D 2. Now this is your overall expression. A C 1 is equal to, this is due to original tie line, this is as per the schedule.

So and this you are getting, I will just define this. You just have to use this formula. Minus delta P net interchange minus P 1 into delta omega. What is B 1? 1 by R 1 plus D 1 and delta omega we have already defined, delta P L 1 by this. So ultimately this is delta P L 1 and A C E 2 is equal to 0

We are not considering this. In this specific row, first row, we are not changing any generation. The error is because of the network 1. So error, there is no error because of network 2. We are not giving any command to area network 2.

So how do you reflect this here? So this was the overall control loop earlier. This was the overall control loop. And now there is a delta omega 1 and you have brought this new term B 1 which is 1 by R 1 plus D 1. And error means, see this delta P tie, this is the power change in power flow. This delta P ti could be positive for 1 and negative for 1. Because power flow is happening from one network, output is positive and negative at another side, it is consuming.

So this is given to the area control error block and you just adjust this because of the presence of B 1 and then integrator is brought. This will ensure that the error will be 0 ultimately, area control error is 0. So a typical control area contains many generators. The individual outputs must be set according to economics. The solution of the economic dispatch must be coupled to the generation control system. The input consists of the total generation required for the area in order to satisfy the load demand and maintain contractual power flows across the tie lines basically.

The output is the power distribution across the outputs of all the generators within the control area. The continuously varying system load demand, a particular total generation value will not exist for a very long time. Of course this continuously by varying system load demand, generation value will not exist for a very long time. This sort of disturbance will not be present for a very long time. And it is impossible to simply specify total generation. How do you really, in real sense how do you manage these disturbances? So calculate in general purpose, it is impossible to simply specify total generation, calculate the economic dispatch schedule and give the control system the output schedule for each generator.

Imagining exactly this is the disturbance that is going to happen, you cannot pre-plan everything because disturbance happens all of a sudden. Now how do you manage this disturbance in real sense? So unless such a calculations can be made very quickly, if you can do this calculation exactly and do the economic dispatch also and then assign, if you do it very quickly it is well and fine but in practical sense that does not happen. For digital control system it is desirable to perform the economic dispatch calculation at intervals of 1 to 50 minutes. This is where you can carry out ED, 50 minutes once. So independent of the calculation schedule apart from this calculation of ED there should be some other means where you manage this sort of disturbance.

So how do you do it? The allocation of generation must be made instantly whenever the required area total generation changes. So the allocation control of generation must run continuously. This allocation should run continuously but economic dispatch command will happen 15 minutes once. A rule must be provided to indicate the generation allocation for values of total generation other than that used in economic dispatch. That means there is a base generation which is coming from economic dispatch apart from that you should have that flexibility with each generator to suddenly adjust their power output such that you will meet out the perturbation in the system.

So the allocation of individual generators over a range of total generation values accomplished using base points and participation factors. If you remember we have discussed in the beginning classes about participation factors. Change in load, how much is the participation from the individual generator to meet out to the change in load. So for period K the economic dispatch sets the base point generation values for the total generation value measured at the start of the period. The base point generation for the ith unit P i base is the most economic output for the particular total generation value. So the participation factor P fi sets the rate of change in the ith unit's power output with respect to a change in total generation of the base points and the participation factors are used as follows.

That means this is coming from ED and because of P fi, this is participation factors, this will meet out the change in total load. So the total delta P t total is equal to P nu total minus summation of the total base generations. So with this we will conclude today's session and we will continue in the next class. Thank you very much.