Power System Dynamics and Control
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Module No. # 01
Lecture No. # 43
Stability Improvement

We will embark on the last part of this course that is the various methods for stability improvement. Before we do that, let us just have a quick look at where we ended last time; we had basically discussed the phenomena of sub-synchronous resonance. There is one case study which I ran, so I will just quickly relook at that and then we will move on to the next part of this course that is on Stability Improvement.

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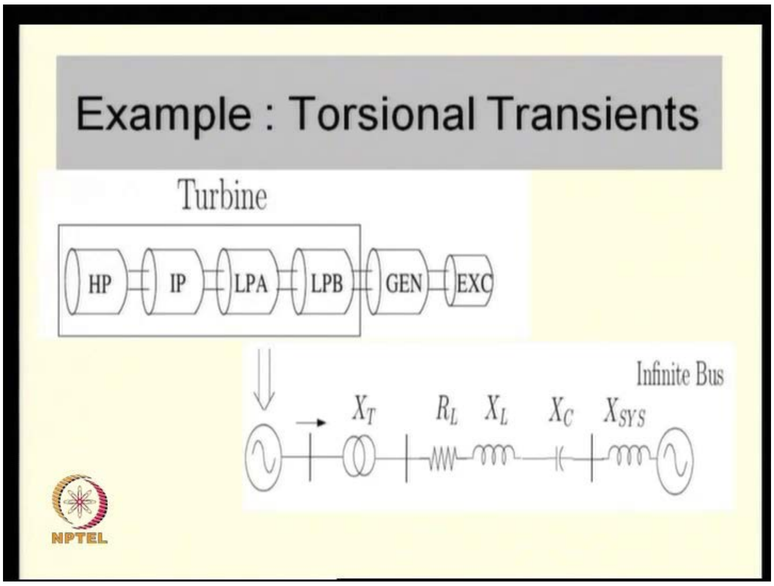

So today's lecture primarily on stability improvement, in the previous example, where we studied sub-synchronous resonance, we considered the adverse interaction of a series compensated transmission network on the shaft of a generator turbine system, so we had done a case study of a steam turbine generator and where the rotor was represented by a 6 mass system connected by shafts.

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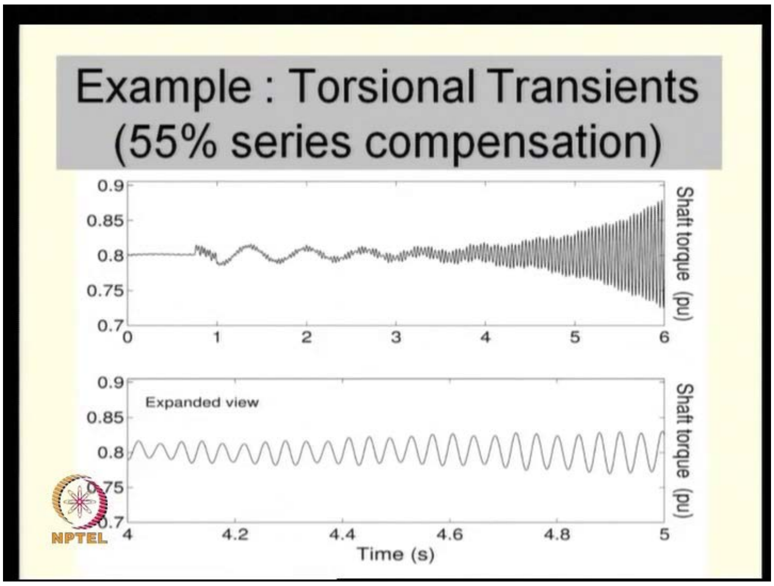

So, we had seen that for a certain level of series compensation there was adverse interaction, and you had growing oscillations for one particular torsional mode.

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Example : Torsional Transients (55% series Compensation)

Common mode	$-0.489 \pm 9.78i$
Torsional mode 1	$0.011 \pm 99.45i$
Torsional mode 2	$0.005 \pm 127.03i$
Torsional mode 3	$\mathbf{0.954 \pm 161.27i}$
Torsional mode 4	$0.009 \pm 202.74i$
Torsional mode 5	$0.0 \pm 298.18i$
Network mode 1	$\mathbf{-4.18 \pm 163.7i}$

Note : 60 Hz system

So, if you look at in fact, the eigen values which we got for this particular system, we see the torsional mode 3 is very badly affected, in fact that is what you see in the simulation study is well, you see that particular mode growing with time. Now, in this particular study of course, I should mention that we did no damping was considered no mechanical viscous damping was considered.

So, the the only damping which was possible was due to the interaction with the electrical network, and you see that in fact all the torsional modes seem to have positive real parts. In actual practice there will be some viscous damping, and some of these modes actually torsional mode 1, 2, 4 and 5 would be stable, if one considered that viscous damping typically, but torsional mode 3 has got a very large positive real part, and you see that it could cause a real problem in the system.

So, if you have got this kind of situation it under that is you have got a sub-synchronous network mode due to series compensation, and typically if you have a situation where the network mode frequency coincides with the torsional mode frequency this problem could occur. Now, of course, there are a few more qualifications to this statement it is assumed that the electrical torque can can affect the torsional modes, all torsional mode, this need not be true, in fact the electrical torque is actually applied at the generator mass, that may not actually you know you know kind of control or affect all torsional modes.

In fact, in this system torsional mode 5 it turns out is hardly affected by the presence of the network mode, sub-synchronous network mode, so in fact although this is not really, we have not proved this or I am not really proved this to you, but it actually turns out at in this particular case this is true. So, it is not certainly true that if I, you have got a series compensated network it should affect all torsional modes equally, and you know it depends on how much and the electrical torque affects a particular mode; so if that actually a kind of analysis can be done using our eigen vector eigen vector and eigen value analysis.

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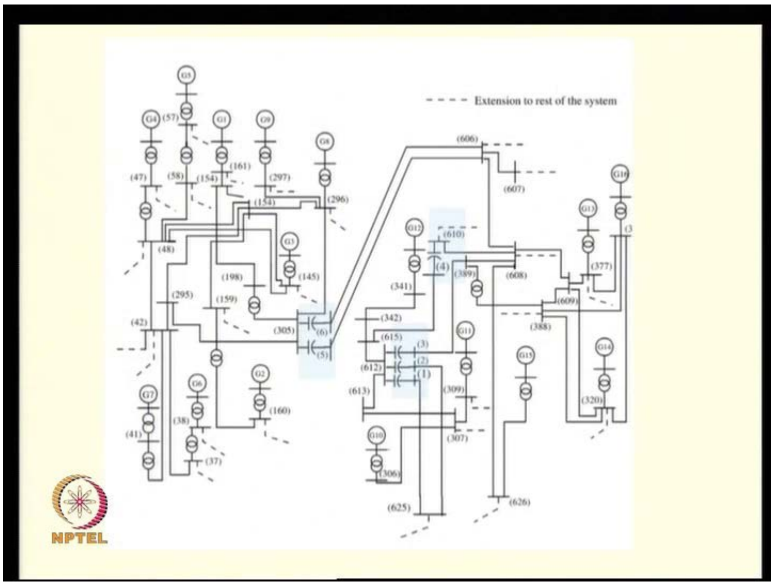

Now, there are some other situations which we need to the last word has not been said on this for example, in a practical situation you can have several series compensated lines. This is one possibility you know you have got 1, 2, 3, 4, 5, 6 series compensated lines in this network and several generators and each generate, what I shown here is generators these round things are generators themselves may be actually several units of a power plant may may not, need not be one generator here.

So, in fact you can have many sub-synchronous network modes and you can have many many torsional modes, and you actually have to do hear a kind of a linear a linearis analysis to check out the actual effect of all these network modes on individual turbine generator shafts. Normally, as I mentioned sometime back, hydro turbines have a relatively large generator, a very large generator mass compared to the turbine mass, this is not true in fact for steam turbine generators. So, in such a situation one one can the what really happens is that, the electrical torque does not have that much controllability over the torsional modes.

These are all statements which of course, I am making without much proof, in this course it is out of the scope of this course to discuss these things in too much detail, it will take a very long time. So, I request you to go through the literature on this subject especially the kind of discussions which are given in Padiyar and Padiyars book and Kundurs book.

In fact, for this particular system where I have shown 6 series compensated line, just to give you an idea.

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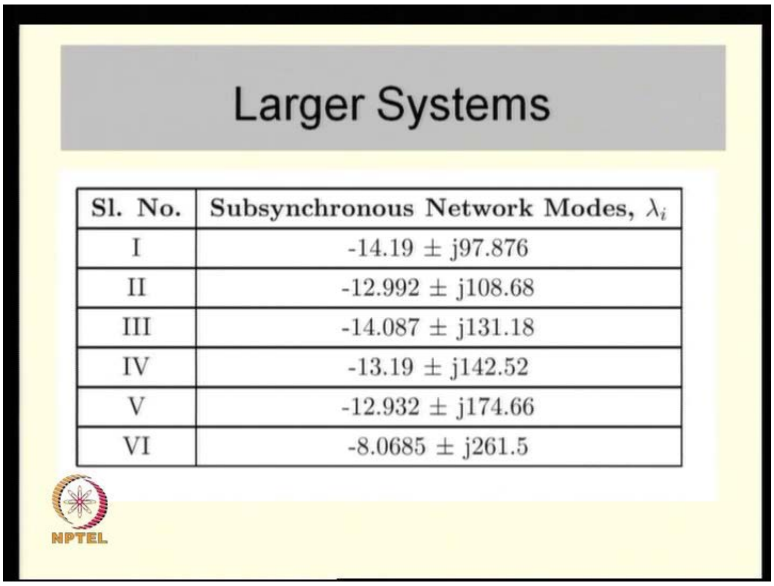

You have got 6 series sub-synchronous network modes of course, there are other network modes, there are other modes is well, but I have just written down the sub-synchronous network modes. Now, this kind of analysis can be done with the tools which I have already you know discussed in this course, so in principle you should be able to formulate the equations of this multi machine system, each generator having you know several rotor masses.

And it should be possible to do a kind of linearis analysis, no remember it is a non-linear system, so you can simulate the non-linear system, but if you want to do a linear analysis you have to linearis the system around an equilibrium point. So, this is one one of the things which I would like, I I wanted to discuss before we go on which before we take on the new topic.

So, with this a kind of end my discussion of sub-synchronous resonance, the phenomena of sub-synchronous resonance; remember one thing of course, how can you avoid sub-synchronous resonance. One of the ways it appears you can do that is to prevent the coincidence of network mode with the torsional mode, remember that is there is no coincidence the effect on the other torsional modes is quite low.

See, torsional mode 1, 2 and 4 the adverse interaction is quite low and one would expect that, if mechanical viscous damping is present this these modes would actually be, would be stable, problem comes in torsional mode 3 whether the good coincidence. So, it would make sense to a limit where the series compensation in a transmission line, such that it avoids coincidence of, you know coincidence with the torsional mode.

Then this usually can be done, if you try to design your series compensation, so that the network mode frequency is higher sub such significantly higher than the highest torsional mode frequency, which is controllable by the electrical torque. So, in this case you should you should limit fix series compensation in the form of fix capacitors, such that the network mode frequency is higher than this 202 radian per second.

So, you need to, you cannot have a very large x c, you can easily prove that this sub-synchronous network mode frequency reduces this is of course, the equations are formulated in d q reference frame remember, the sub-synchronous frequency reduces, if the equations are formulated in the d q frame, if x c that is the series compensation the reactance corresponding to the series compensation increases. So, one way actually have to limit the amount of series of compensation, so that there is no torsional mode and network mode coincidence.

In fact, this actually tells you one important thing, that stability issues in certain conditions can restrict, what you can do with this system, in fact if you recall I had mentioned that series compensation is something you do to reduce the reactance, the series reactance of the transmission network. This in turn you know improves the power transmission capability of a transmission line, because it reduces x of the transmission line, if it reduces x you can improve, you know you can have a better large disturbances stability characteristics.

So, by because of this SSR problem under certain situations you may have to limit the amount of series compensation you can have, so stability problems sometimes can be a limiting factor in the design of your system, so now let us end discussion on this topic.

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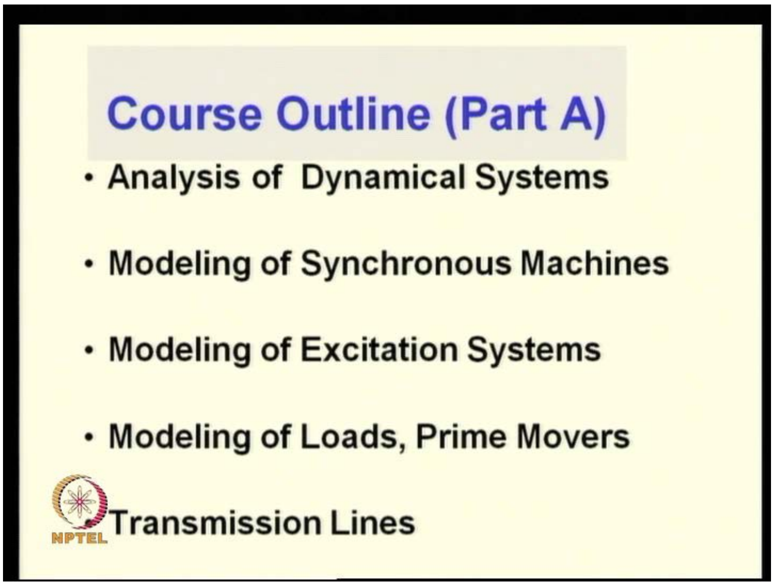

And move on to what our next and last topic is, that is improvement of this stability of a system, so the whole idea of doing this analysis was, to see how it affects of real power system. So, just to keep things in perspective the first part of our course is dealt with analysis, so generalized analysis of dynamical systems, then we spend a quite a bit of time on modeling of synchronous machines, excitation systems, loads, prime movers. We would like probably to go back and have a look at these some of the simulations and all which I carried out, when I was discussing these topics then we also discussed, how you can model transmission line.

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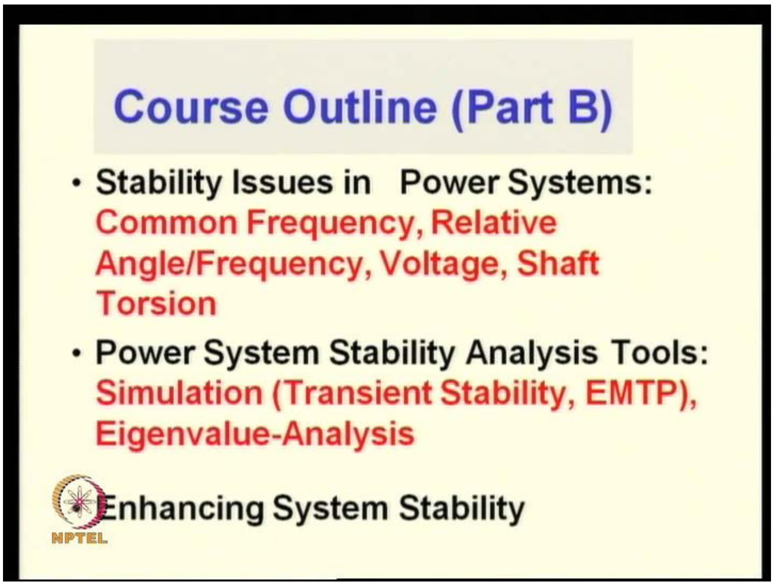

The part B of this course, we discussed several stability issues, one was the motion of common frequency that is the center of inertia frequency of the system, which is in fact affected by the load generation balance in the system. Then we also discussed the most probably, the most important problem in a synchronously connected system, say that is when you have got synchronous machines connected by AC transmission lines. The most important problems, stability problem is in fact, the relative angle or the relative frequency motion; and we we discussed things a loss of synchronism etcetera, under the topic of relative angle movement and frequency movement.

Then we also discussed voltage stability, we took an example of voltage stability, we in fact studied slow voltage in stability caused by the action of torque changing transformers, and reactive power limits in a synchronous generator. The last topic which we just kind of ended the discussion sometime back was on shaft torsion, the stability of shaft torsional oscillations.

We also actually merged, we did not considered this is actually although I listed it as a separate topic, we have in fact discussed or actually done a few simulations, and the two kind of simulations, we did one in which we considered network transients and stator flux transients and the other in which we did not consider it.

The studies in which we consider, do not consider network transients the stators, flux transients are called stub transient stability program, because these are really low frequency phenomena’s, the rather suited for the study of low frequency phenomena and EMTP type had a programs, in fact have to model fast transients in detail. We also did a side by side an eigen value analysis in many cases, but eigen value analysis remember require linearization of the system, in case your system is non-linear.

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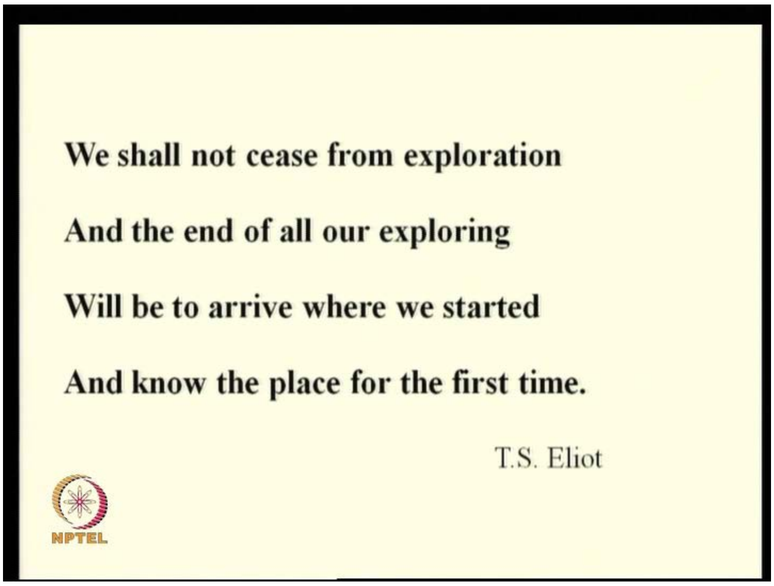

We now, move on to enhancing system stability and in this context will be, I think appropriate to consider this from T.S written by kind of (()), written by T.S. Eliot, we shall not cease from exploration and the end of all our exploring will be to arrive where we started, and to know the place for the first time, so in fact when I am talking about the topic of stability improvement, when I will be discussing this topic.

We have done all these phenomena before, the first phenomena in fact, I will be consider considering is under frequency relaying, stability improvement measures. We have actually discussed this issue of under frequency or over frequency which results, because of load generation imbalance. So, we have done all these things before, now we shall focus on trying to see how we can actually improve stability of the systems.

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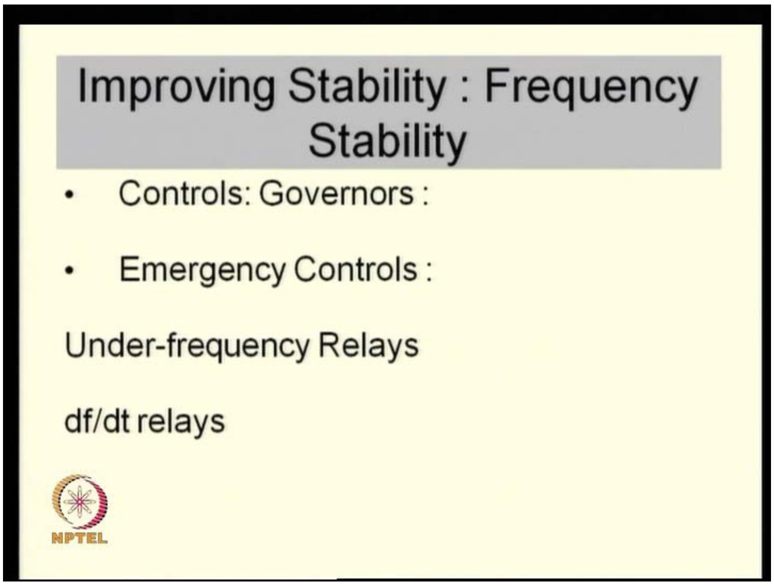

So, let us take the simplest phenomena that is a frequency stability, frequency stability is easy to understand, we saw that the movement of the centre of inertia of a multi machine system is dependent on the load generation balance, and the controls which affect this are effectively the speed governors which may be present on the turbine of a synchronous generator. So, this the main control by which we can actually affect the frequency of a system or ensure that the frequency remains within limits, is essentially a governing action of steam or hydro turbines or gas turbines.

Now, in addition to governors remember that, the loads themselves a frequency dependent, but that frequency dependence is not very strong, so if you do not have governors and is a load generation imbalance the frequency changes and it settles down, because the loads themselves are the function of frequency.

But, say in our system which is around 150 gigawatt, it is a 150 gigawatt system of installed capacity, a 100 megawatt change may cause say 0.1 hertz change in the frequency. In case, there is there is no governors, if there is no governors, just because of the load genera, load frequency dependence you can come to an equilibrium which is reasonably (()) which is acceptable, if the load generation imbalance is low. But, if there is a say a sudden generation trip of 100 megawatts, then just depending on load frequency dependence to get you to an equilibrium is not appropriate. Because the frequency deviation can be very large, and remember we have discussed this before that if frequency deviation is large, many turbines will have to be tripped out.

Because typically under off off nominal frequency there is a danger of exciting shaft torsional vibration, not shaft torsion vibration sorry, blade vibrations in the turbine. So, if there is a frequency deviation of more than one and half hertz or so, you may have to quickly trip out your turbine, so actually a black out can ensure, in case your frequency of your grid falls below say 47.5 in a 50 hertz system.

So, this is in fact an important consideration, so in fact along with governors and effect of load, you know load frequency, you know flow frequency dependence another way of ensuring that frequency does not you know go to you know perils kind of levels is having some kind of under frequency or you know these are emergency controls. If the primary control in the form of governor’s etcetera, is not able to arrest frequency drop in that case, you may consider using under frequency relays or in fact rate of change of frequency relays in trying to arrest this stick line.

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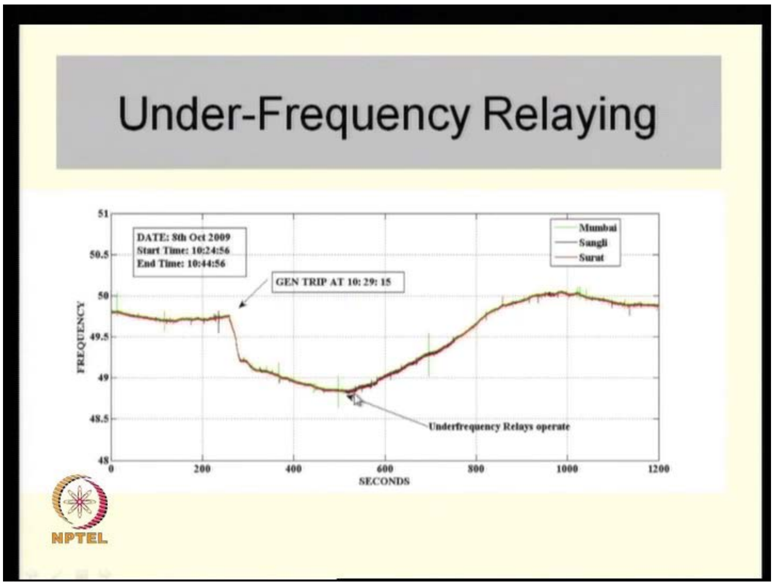

So, let me just show you an actual event which occurred in our Indian grid several years about a year ago, this 8th august 2009 there was a generation trip at a generator at Anpara that is in Uttar Pradesh and the effects of it is surprisingly were immediately felt, not surprisingly we know that frequency everywhere in the grid is practically the same its not really surprising.

But, something to wonder about it it really evokes quite a bit of wonder that immediately you see a frequency decline in the Mumbai, Sangli and Surat, because these parts of the grid are synchronously connected to the grid in Utter Pradesh, which is more than 1000 kilometers away. So, there was a generation trip in the synchronous grid and the frequency drops everywhere in the grid including the western region, and you see this quite a precipitous drop in frequency, very high rate of change of drop frequency.

And if you just allow this to go on, then the frequency can go down, right down and cause a tripping of all turbines, all the steam turbines in this in this system and they could be a black out. So, what you have is some kind of control action here seems to have you know reduce the rate of drop, and at around 48.8 there seems to have been some load relief in the form of under frequency relays, so at this point the frequency is dropped down.

And in the system you have got certain loads which are designed to trip or rather there are you know protect relays, which are designed to trip out these loads in case the frequency falls; and this is exactly what is occurred at this point here and of course, after the frequ the load is tripped the frequency rises again.

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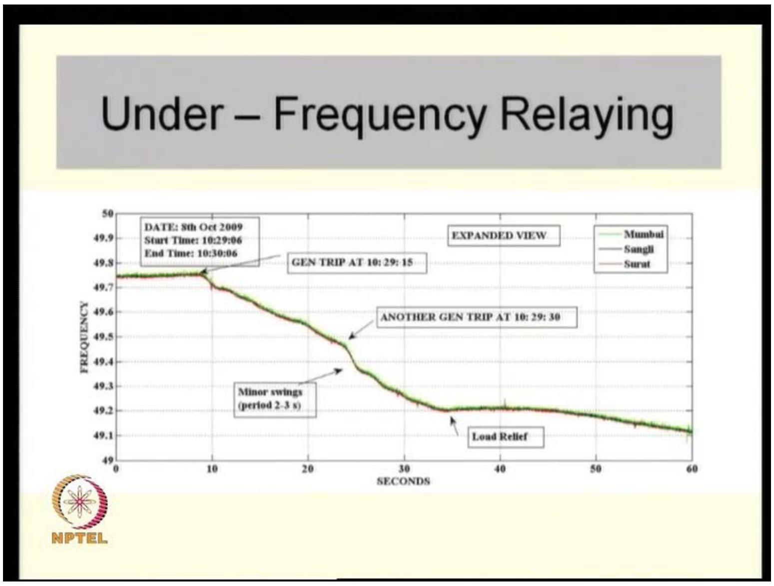

So, in fact if you look at this bit carefully, there is a generation trip of occurring here there appears to be another generator tripped out here, this is an event which occurred about a year back; and it seems that there has been, if you look at the there is the sudden slope change at this point, so there was some load relief even at this point. So, there are actually two, you have got a load relief somewhere here and you have got under frequency load relief even at this point, so this is what is probably been designed in the grid to it is a kind of an emergency control in the grid.

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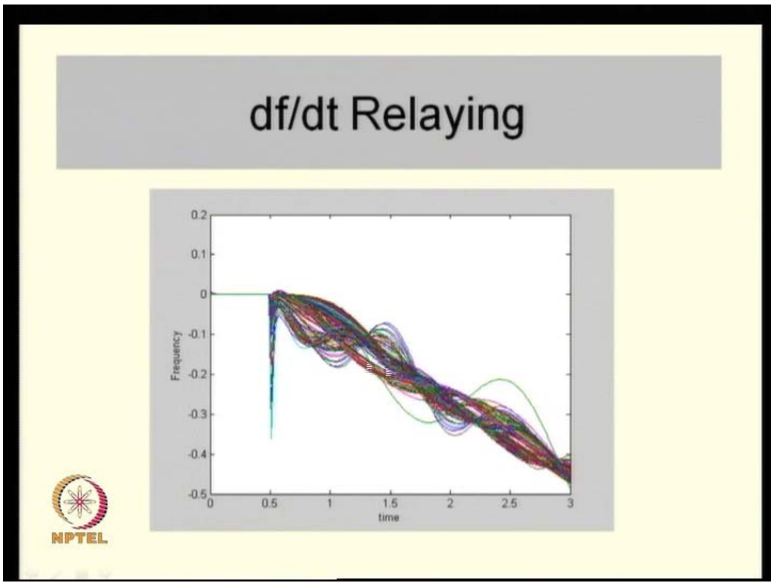

Now, you can instead of having under plain, under frequency relaying in case there is a drop trip in generation you will find that the frequency drops, you can kind of you know measure the rate of change of frequency at various buses. In fact, this is the rate of change of frequency at various buses after a generator trips this is simulated response of a multi machine system, and you see that there is a, this ra the centre of inertia frequency goes on dipping.

Now, you can use this rate of change information also to do some quick control action, now if you even look at plain under frequency relaying, what is plain under frequency relaying? If the frequency falls below a certain value you trip out certain loads, that is basically what happens here, frequency falls you trip out load.

Now, if you look at the issues behind which have to be considered, when designing an under frequency scheme they are as follows, first thing how much load do you trip, at what frequency do you trip, remember loads comes in chunks; so you have to trip out a certain amount of load if the frequency falls below certain value, which value should you choose. Another point is how much do you trip, if you trip too much, you know you trip too many loads say you trip out the loads at several small towns or cities, small cities in the country say to get a road kind of load relief of say 600 or 700 megawatt.

Then the point is how much, you know how much load you actually trip, if you trip too much you will find that they may you may have an over frequency situation, so the point really is that this kind of design of an emergency control system is often carried out based on off lines studies. So, you kind of do an off line study based on the parameters of the system and see you know if I trip this much load how much you know frequency rise will be there, but this is obviously since, its an off line study it it is based on some you know our or knowledge of the parameters of the system, but if you do not have adequate knowledge of the parameters of the system design of this may be quite tricky.

In fact, under normal operation you will find that the operating condition which you have under normal say today right now, may be difficult to anticipate during planning, but roughly you have got you can get a operating point close to what the situation is, when I say what is the operating point today, basically the the generation schedule the load at various points actually changes from day to day from hour to hour and depends on the season as well.

So, during planning you have to kind of anticipate the kind of load pattern and the generation pattern in the grid and you know design how much load would need to be tripped in case the frequency fell below a certain value. So, this is how you design your under frequency relaying, see obviously it is not a perfectly a perfect science. So, as I was saying instead of plain under frequency relaying, you can even think of d f by d t relaying, d f by d t relaying is basically checking out the derivative or the rate of frequency dropped at a bus and then take a decision of whether to trip or not to trip.

So, these schemes also have to be designed at the planning stage, but remember d f by d t is a kind of a anticipatory scheme, in the sense that if if the rate of change of frequency exceeds a certain value, then you trip out certain predetermined loads, so it is a kind of a anticipatory, but its again designed off line. And the things you need to really consider in your design is, what exactly affects the rate of change of frequency, in fact if you note if you remember the centre of inertia frequency of the system, the rate of change of the centre of the inertia of frequency of the system is inversely proportional to the some of the machine inertias.

The other thing which determines d f by d t is the amount of load generation imbalance, so if the load generation imbalance is large we will have a larger rate of change of course, so by looking at d f by d t at a particular bus, the bus frequency as it falls you can roughly make out whether the disturbance is large or small. Now, there are of course, again design issues of how much load to trip, why do you trip, and so design of this aspect is usually done off line, but if you if you really look at some import, let us just look at some important aspects, when you which you need to consider when you design a d f by d t relaying scheme.

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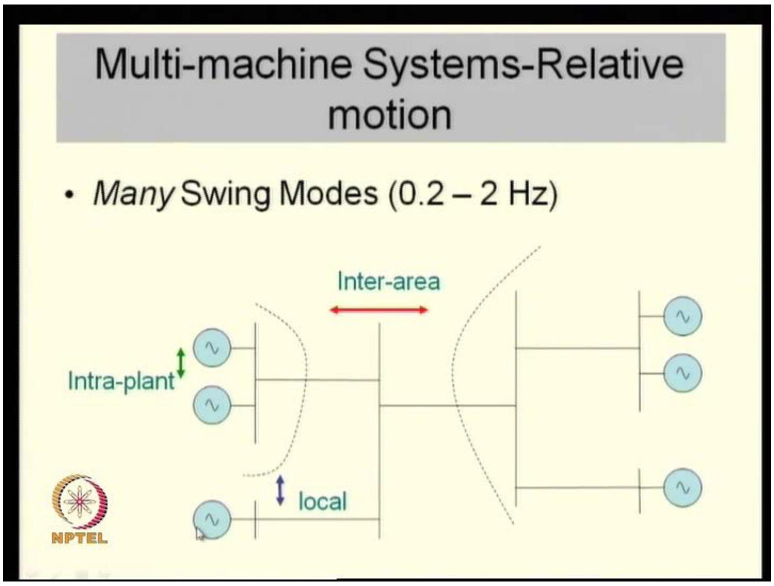

Remember that although I have said that the centre of inertia frequency depends on the load generation imbalance, remember that local frequency or frequency of an individual generator is often contaminated or it contains swings as well. So, what you see for example is the frequency of all generators or the frequency at various buses in the system you will see, that not only is there a centre kind of a common motion, there is also these swings.

And and interestingly they have many many swings, you see that there is one relatively low frequency swing here, then there is a higher frequency swing here, so there seems to a mixture of swings along with super imposed with the centre of inertia or the common motion of this system. So, these of course, the swings are something we have discussed before they arise due to the power oscillation or the motion of or the relative motion between generators.

So, in fact we have done simulation of a single machine connected to an infinite bus, then we had also done simulation of a two machine system and what you notice there was, in addition to the common motion which depends on the load generation balance, there is also the motion, relative motion of speeds and angles, rotor angles of individual machines.

If you have got a large multi machine system this is not a large multi machine system, but this is just to illustrate in a large multi machine system you can have oscillations between the machines within a plant or the machines. The oscillations between a machine in the same area or a machine nearby against the machines in a plant all moving together, so you have got in an inter plant intra plant mode only the machines within a plant participate and a swing against each other, the swing against each other.

Then you can have this local mode in which these two machines swing together with respect to this machine in the same area or you can have all these machines in an area swinging together against the machines in another area. So, in fact if you look at this simulated response, you will find in fact, if you look in the closely enough, you have got some machines which have swinging together against machines in another area.

If you look at this real real life picture of how the frequency changes, you see that the frequency is measured at Mumbai, Sangli, Surat which are all in one area, seem to swing together here, you see this small oscillation here, the minor oscillations here swings which you see, these are actually (()) for these this particular mode which is visible, oscillatory mode which is visible all these machines swing together. This is not actually surprise, this disturbance occurred very far away from these locations which are in the western system and therefore, all the machines in this area swing together, so this is intuitively makes sense.

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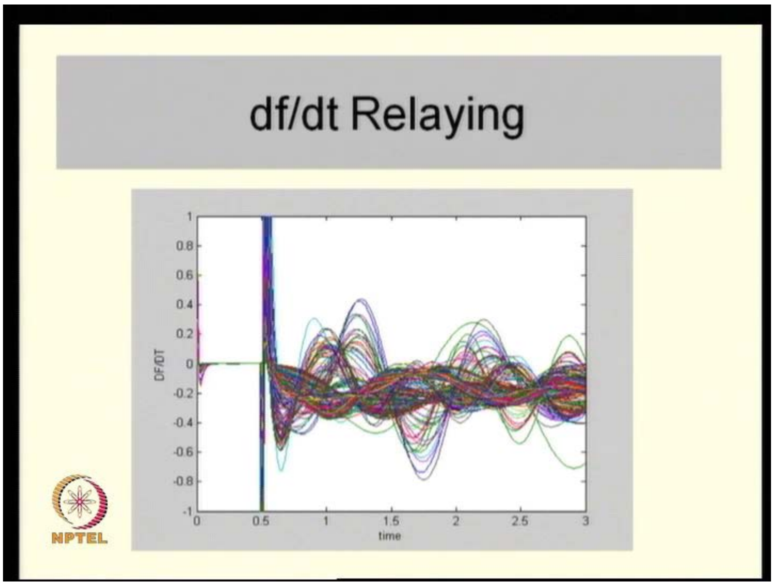

So, whenever you are going for d f by d t relaying you have to face one problem that is, in addition to the common motion they also these swings, so that may actually give a completely complicated picture of, so if I take the derivative of the frequency this is what I see. So, if I see, this I may actually have spurious tripping, because you know because the slope at some points may be large, because of the swings and not because of the you know common motion.

So, this is one problem which you may face, if you are going to have local frequency measurements, so if I take a frequency at one particular point and try to taka a local decision whether to trip a load or not; I may actually have a problem, because the local frequency actually has got these swings. And because of that I may get wrong information spurious information about load generation imbalance in this system, so this is one of the problematic issues when you try to apply a stability improvement method like under frequency or d f by d t relaying.

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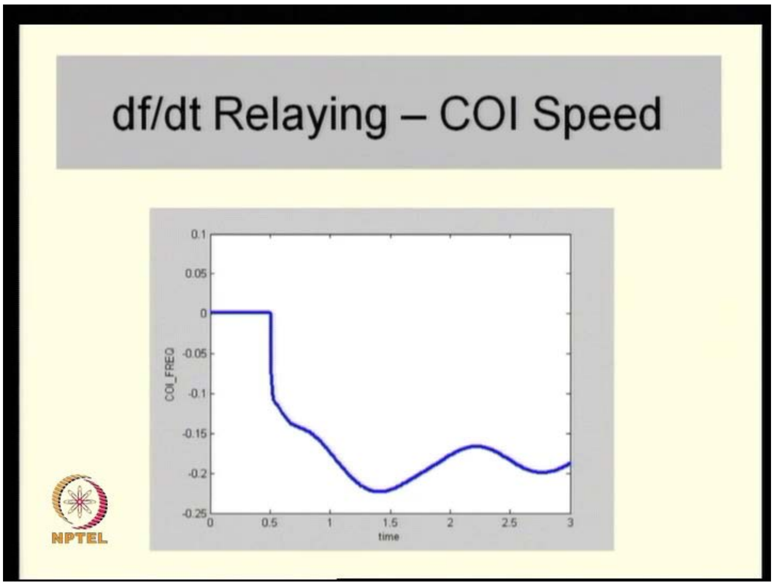

But, one may suggest at this point that why do not we actually compute the centre of inertia speed, remember we had we had got this formula (No audio from 29:53 to 30:28).

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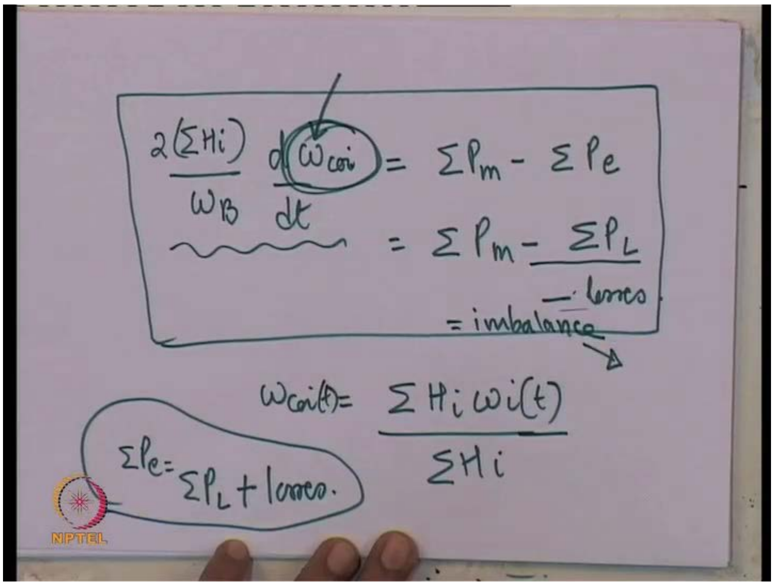

So, we had actually derived this formula sometime back in our course, that the centre of inertia motion depends on is proportional to the sum of the mechanical, total mechanical input to all generators minus the total load minus the losses, that is because sigma P e is equal to sigma P L plus losses. So, this is of course, with network transients neglected, this is true if network transients are neglected electrical power out put of a generator is equal to under sinusoidal steady state conditions sigma P L plus losses, we are considering a slow phenomena, so we do not have to consider network transients in our analysis, so this is certainly true.

So, the point is that suppose there is some disturbance and now you want to trip load to control the drop in the centre of inertia frequency or the common motion, you want to prevent a precipitous drops, so you want to do some load shedding. Now, what one can do is try to compute omega c o i and then, because you know omega c o i you can compute this rate of this particular term and because of this you can estimate what this imbalance is, so that I will call this imbalance.

So, depending on this imbalance you can then decide to trip certain loads to bring back balance, in case there is a drop in frequency, but what is the catch in all these the good thing of course, in doing this in doing this particular comp this kind of computation is unlike frequency, local frequency measured at every bus or at every generator which is contaminated by these oscillations, which may kind of blur the common motion.

A minor error here, the y axis is the rate of change of the centre of inertia frequency. It is wrongly indicated in this figure in the centre of inertia frequency itself; so, remember the y axis stable should read rate of change of centre of inertial frequency.

So, what you are seeing in this graph is in fact rate of change of centre of inertial frequency, the centre of inertia speed you know is somewhat in component, you see here is relatively lesser than what you will see here, so you can use the rate of change of the centre of inertia speed. But, what is the catch, the catch is that this omega c o i is not a local signal first of all, you will have to take out the speeds of all the generators, then use the speeds of all the generators to compute this, remember that speed of generator is time varying, so you have to get the speed of the generators at you know kind of to a common point and then compute this particular thing.

So, this requires some communication of signals similarly, if there is imbalance, so if you estimate the imbalance you will have to send the trip signal to a remote location and trip out the thing. So, this seems nice I mean as engineers it sound like a nice challenge, to really make a wide area measurement scheme of frequency a speeds of all generators compute this and then do this kind of thing.

So, this is just of course, is not implemented anywhere in the world, but this is an interesting thing you can do and students also you can easily conceptualize this kind of thing, but remember things are not as easy as they look, remember that the gen power system is spread over 10’s of 1000’s of sca 10 10’s of 1000’s of square kilometers.

And you need to communicate quickly you know you do not want to any delays in all these, you have to quickly communicate this signal to a common place where this computation is done and this computation has to be done. And then you have to estimate the load generation imbalance, and then you have to choose a suitable chunk of load, remember load comes in chunks, so you have to choose a suitable chunk of load which you can trip to get the frequency back to normal.

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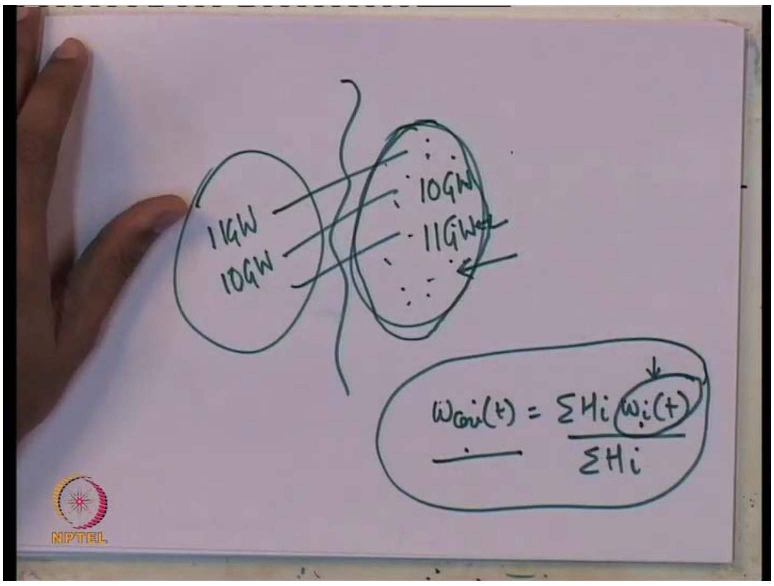

Now of course, there are several important points which have to be considered at this point is that, when you have got a synchronous grid typically this very precipitous kind of drop in frequency occurs, when you have got an inter connected grid, suppose you have got an inter connected grid which has got connections with the AC line the two areas suppose.

One has one area has got say, 10 gigawatt generation and 11 gigawatt load and the other generation is region has got 11 gigawatt generation and 10 gigawatt load we will assume losses are negligible, in that case if this, because of say some disturbance there is a loss of synchronism and you separate out these two systems.

Then this system will be an under generated island there is a load generation imbalance and you will have to trip out this load, some load to get this load generation balance, so one of the way is you can really do it is compute the center of inertia of the, now once you separate out you just have, you have to compute the centre of inertia speed of this particular system. So, something which your central computer which is computing the centre of inertia needs to know is the, which are the generators in this island, so you need to know that, so this is one issue.

The other thing is the speed of all the generators in this island need to be computed in a synchronous way in the sense that they should be time tagged and sent to a common centre at which they are all you know after all omega c o i t is sigma H i omega i t by sigma H i. You need to know, the generators speeds of all generators in that island at the same instant of time in order to get the centre of inertia at that point of time, so you need to time tag all the frequency measurement send them to a common location and compute this for every time time instant and then take out the derivative and then do d f by d t relay.

So, this is one particular scheme you can do this which you can use you know proper technology, and actually compute this and have derived a good scheme for under frequency relay. So, this particular scheme is not implemented, but it turns out that today it is feasible to do this although there is issue as I mentioned sometime back you should know whether you are there is an island, which generates the part of the synchronous grid which are not and so on.

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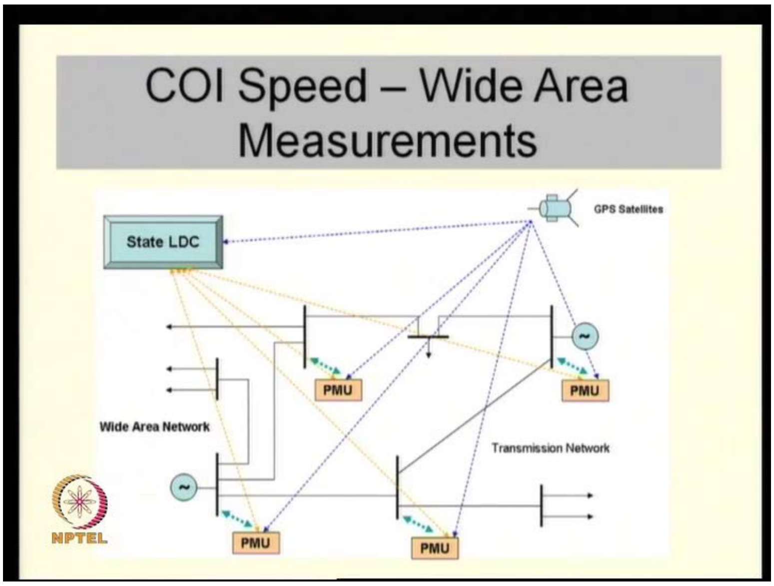

So, there are still some issues which you need to be you know considered before such a scheme can be actually put into action, but today it turns out that it is feasible to have time synchronized, very well time synchronized measurements using GPS satellite; so you can actually measure the frequency or generator speeds at various locations, time tag them.

All measurement units here these are called phaser measurement units are all synchronized having the same you know kind of synchronized clocks by using GPS, you know GPS signals you make all these have synchronized clocks, so that times stamp the frequency or generator speeds are time stamped and sent to a common load dispatch centre, wherein the centre of inertia speed in principal can be calculated and then you can use these signals to trip out certain loads.

So, in principal this kind of scheme is feasible, the reason why I have discussed this kind of scheme is not, because I mean I am not done a kind of rigorous analysis of the feasibility of such a scheme or anything of that kind just to spur you to think, that you can actually use technology and actually implement these kind of things in principle it is possible. But, of course, as I have cautioned and I will caution you again there are many many engineering issues which you need to be dealt with before you kind of kind of make this kind of scheme, is called as emergency control scheme.

So, I have kind of introduce you to a way by which you can have method for improving stability, in this particular case we are talking of improving the frequency stability of a system. So, we have talked about under frequency relaying to prevent sudden drops, you know which may occur when there is a sudden load generation imbalance, because of generator trip or sudden islanding, because of loss of synchronism which is another stability phenomena will just discuss a bit later.

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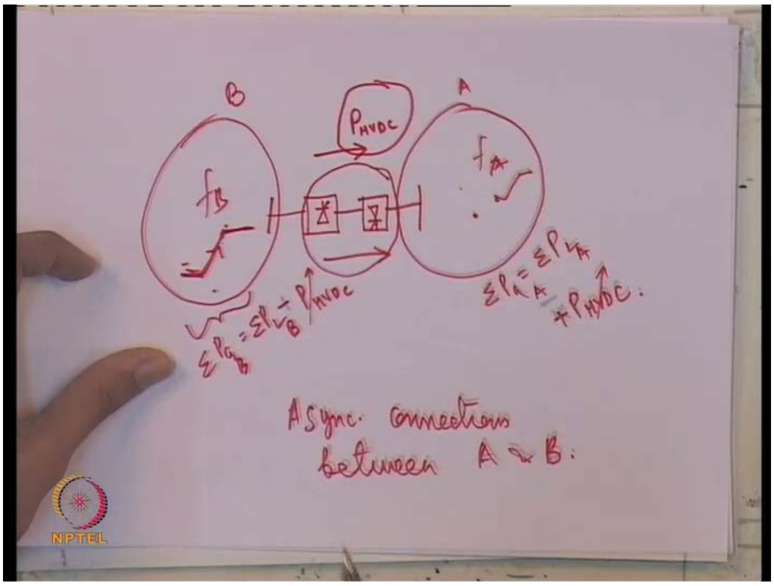

Now, if you have got two systems which are not con you know connected synchronously with each other that is they are connected via HVDC links, so the frequency and phase angles of system A and B are need not be the same, the frequency here f A and here f B need not be the same, a power through this link is regulated strictly.

In this situation in case, there is a precipitous fall of frequency here or in fact even a rise of frequency sudden rise of frequency, because of a major load trip in that case, you could ramp up the power suppose there is for example, a sudden, very large load trip in this system, because of this the frequency tense to rise and the governor here are unable to prevent a sudden you know the rate of change of frequency of the frequency rise is very fast and the governors are not able to control it.

Because, say the limits of the turbines etcetera, they are not able to control it in that case, you can use for example, in HDVC links to temporarily pump some power out of this, pump some power out of this and push it into this. But the frequency here will rise remember because of that, but rather than have a very large rise in one system you can use this particular HVDC links to ram the power and push that power here; and kind of distribute this frequency change.

This kind of also scheme can be kind of developed remember that in a synchronous link in each area, the generation is equal to some of loads plus losses and similarly, P G here will be equal to some of load plus losses plus minus P HVDC and this will be plus P HVDC, remember P HVDC is completely controlled in a local fashion by these rectifier inverter here.

So, you can actually at the the link itself can regulate power flow, because you have got firing angle controls, so by in some cases you can change HVDC power and control the frequency, but you cannot do independent frequency control in both region. If you change the HVDC power this will affected and this will get affected, so this is just to a kind of tell you that, kind of encouraging to think of all these things yeah.

So, this is when you have got a synchronous link, a synchronous connection between two regions, so you can use HVDC power to equalize a slightly help one region, by changing the HVDC power. Please note that there is a minor error in the sign here, so this should be positive here and negative here, if the direction of HVDC flow is as shown in the figure here. We now, move on to more worry some problem or (()) not even frequency change is the varies sudden frequency changes are worry some problem, but the more commonly felt problem for which it understanding what needs to be done is not very obvious.

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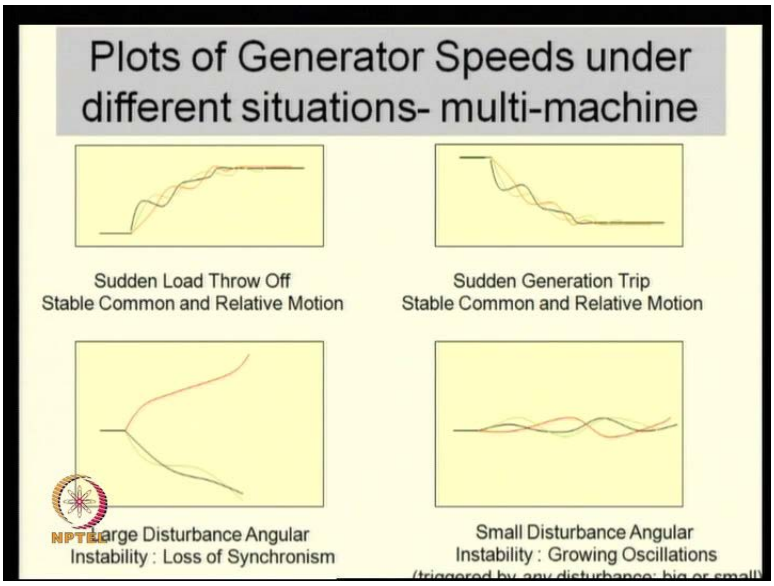

Now, let us to you know kind of get a very clear picture of what we are talking about, remember that just a few moments ago I was talking of this problem, if there is a sudden load throw off or a sudden generator trip and governor action load frequency dependences, in adequate you can have may be stable common motion. But, the frequency change may be too high or too low or rather the frequency change may be too large in magnitude and therefore, you may think of emergency schemes like load tripping schemes or the converse of that is a generated tripping scheme.

Of course, generator trip is something which you have to be careful while doing, because the fully loaded generator, if you suddenly trip to prevent an over frequency it is, it gives a big shock to the mechanical elements of your system that is the turbine generator system sorry the turbines may be. So, generation trip is is not often talked in the same breath as load tripping, load tripping is somewhat more benign compared to generate tripping of fully loaded generator.

So, these are the things which you need to do in case there is a large magnitude of frequency change, the common frequency change, but you may have unstable relative motion as well for example, the figure which I am pointing out here, shows the generator speeds for relative angle in stability in which, there is a loss of synchronism, that is the machines are connected, but couple of machines here run at a different frequency compared to the other.

So, you will this happens whenever you give a large disturbance like a fault, this can happen for large disturbance like a fault wherein synchronous machine which normally run at the same speed, because of the fault suddenly loose synchronism, this is the large disturbance phenomena. Another problem which you may which may arise with relative motion is that the power swings or the low frequency oscillations which we see, following even a small disturbance sometimes may be poorly damped or even grow with time.

This is a more complicated problem in the sense that even so small disturbance is sometimes ,you see that the oscillations which we are triggered take a very long to damp, time to damp out or in some situations they may even be unstable, so this kind of situation can occur under certain situations.

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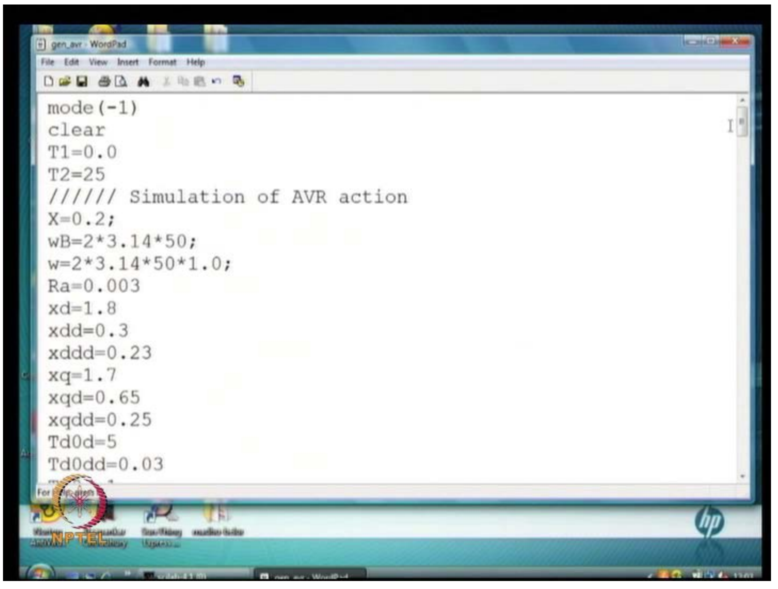

So, let us I will just show you the phenomena and then we will end this particular lecture, we have done this simulations sometime back, we have done a scilab simulations in which if you recall this is the scilab simulation, I have actually changed the program, so let me save this. This is the program which simulates a synchronous machine connected to an infinite bus, the field voltage of the synchronous generator is actually being controlled by the automatic voltage regulator and what I am going to simulate is, the response of the system for small disturbance is around an equilibrium point.

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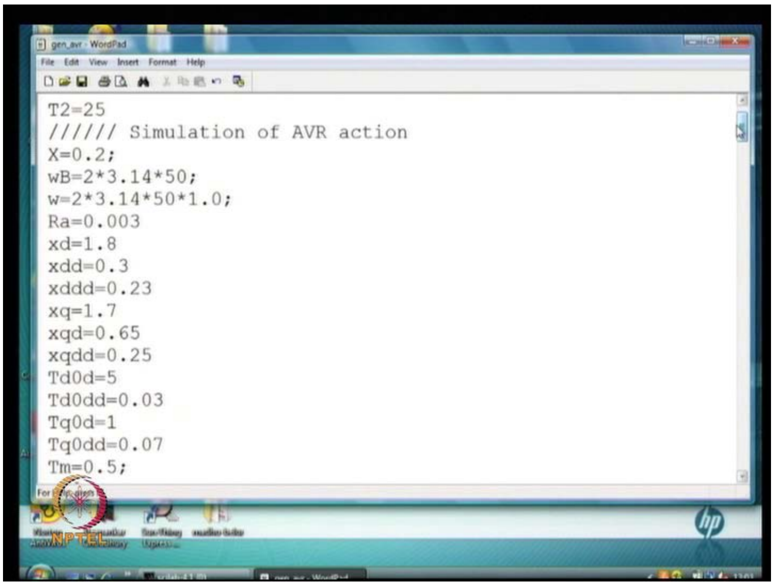

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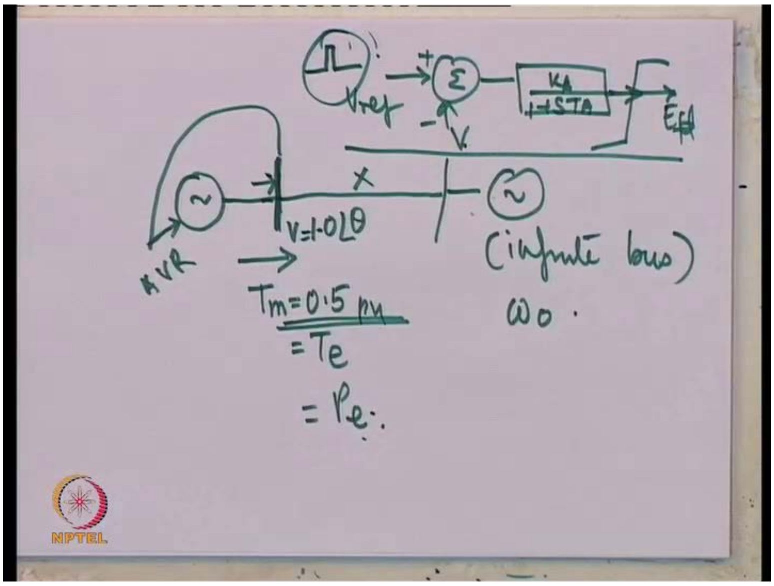

So, what we have got, so the simulation which I will just show you before we end today's lecture is you have got a synchronous machine, it is connected via transmission line to a fixed voltage source, you call this in infinite bus of frequency omega naught, the machine is assumed to be operating at a mechanical power output of 0.5 which is equal to the electrical power output in per unit.

This generator is equipped then AVR which maintains the terminal voltage of the generator a cons, means almost at a constant value, the AVR basically has a structure V ref V a proportional controller and this is the voltage which effectively is through as static excitation system applied to the field which creates the which really creates the field flux. So, you by having this kind of control system you are controlling the field voltage and therefore, you are kind of almost maint, if this k is large you practically are regulating this voltage V to constant value which is almost equal to V ref.

So, we have done this simulation before what I will do is assume that the system is operating at this operating point, so when I am simulating what I need to do is specify the terminal conditions, specify the power output. From that you can back calculate the current, if I know the reactance of the line, resistance of the line you can back calculate the current output of the generator and back calculate all the initial states of the generator.

Now, if the initial states of the generator are those corresponding to this kind of scenario, equilibrium scenario the system will simply remain where it is; now thereafter what I will do is give a small disturbance here, what I will do is, I will increase V ref at 5 seconds for a short while and (()) back, I will do that and then we will see what happens. Now, just to keep things in perspective what you need to do is of course, simulate we have what what we are going to do is simulate the system.

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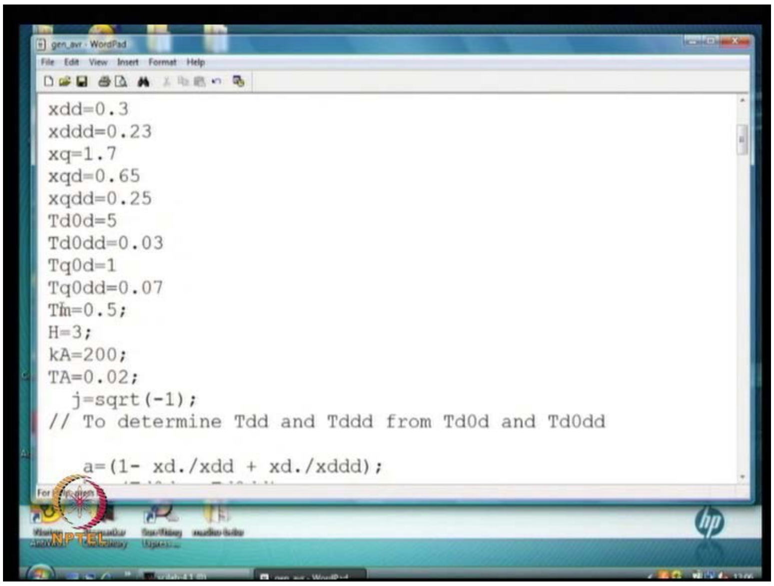

So, you have to feed in the data will give T m is equal to 0.5 per unit is the gain and time constant of the AVR.

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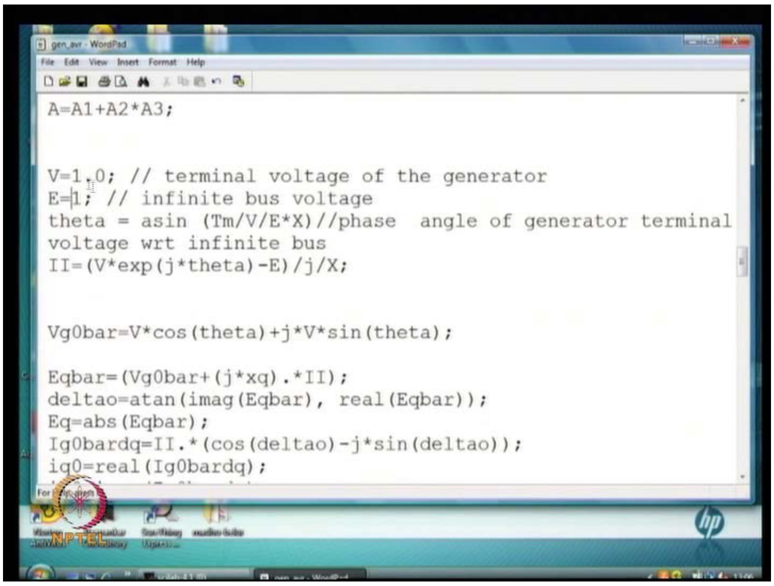

Thereafter is specify the infinite bus voltage magnitude, we assume that the infinite bus voltage angle is 0, thereafter we calculate theta which is the phase angle of the terminal voltage of the synchronous machine, this is obtained by we will also specify, we have already specified what T m is. In equilibrium conditions p m is equal to T m is equal to p e is equal to T e there is the torque and the powers are the same, with the assumption that infinite bus voltage frequency is the same as the base frequency.

After that we calculate the initial conditions the steady state values and then we do a simulation, the simulation of course, will remain if you have calculated the values of the state to be equal to those corresponded to equilibrium values, we will just stay where we are. So, we will just stay where we are, and at T is equal to 5 seconds we will give a step change to V ref, after 0.5 seconds we will get it back to its old value.

So, if I simulate this system, so I will just run this simulation (No audio from 51:40 to 51:52), if I run this simulation and plot time verses p e the electrical power output of the generator, we will just see what it is called its p sorry, this this taking some time to simulate, because we are using Euler method. We can afford to use Euler method, because we have in this particular simulation, we have kind of removed the stiffness from the equations using by neglecting the stator flux d by d ts, that is psi d by d psi d by d t is set equal to 0 and d psi q by d t is set equal to 0.

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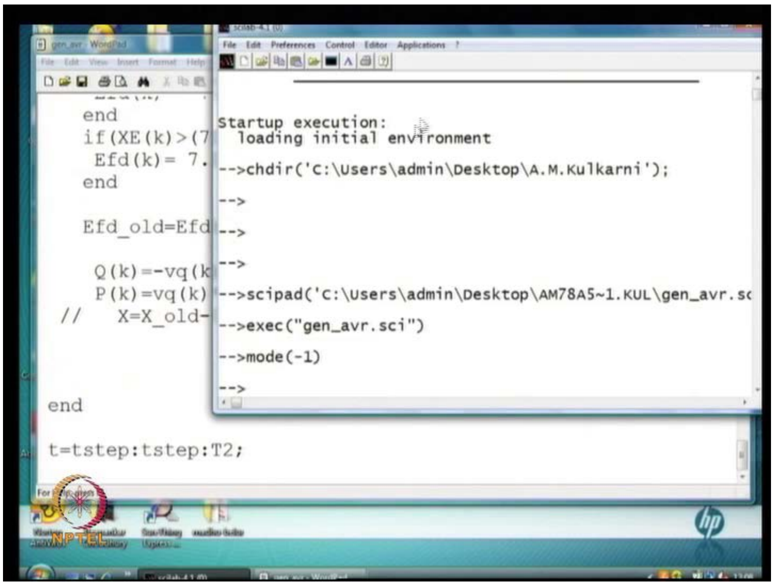

And remember another thing is that we ought to use of course, more more accurate method like even though we are using explicit method, it would have been better if you would have used Runge Kutta method which is the higher order method, but instead we have using Euler method with a smaller time step. So, do not use do this for for real life problem, it is better to use a better method like RK fourth-order, I have just used the Euler method for illustration, because it is easy to program for the first time its not a bad idea.

Now, what I have done is electrical power is 0.5 and at 5 seconds, I give a step change in V ref, if you give a change in V ref, the the actually its a pulse change in V ref which starts at 5 and ends at 5.5, but it excites, because there is a disturbance like a pulse it excites the swing mode and you see that the swing mode eventually of course, does die out it time.

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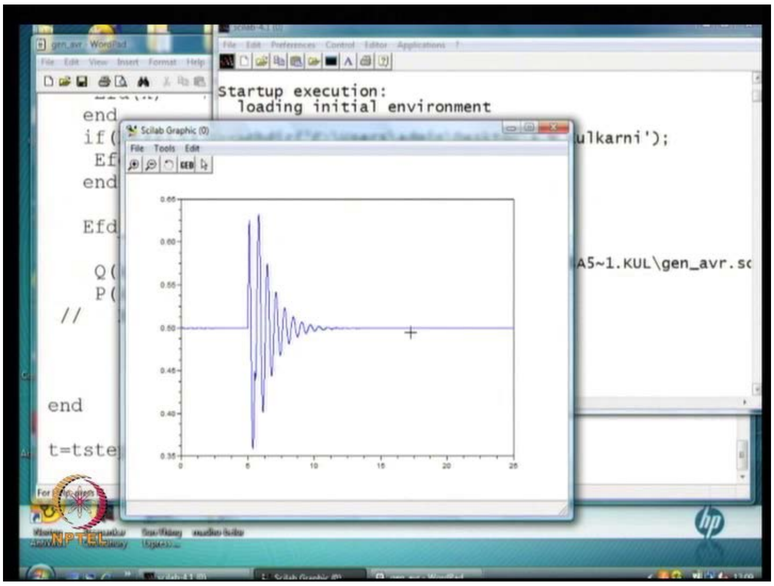

So, this is the this how the swing mode would like to behave, now the thing is that if I change the operating condition a very interesting thing occurs, so I change this operating condition from 0.5 to 0.8, so we will assume that the operating scenario is such that, your output of the generator is 0.8 per unit.

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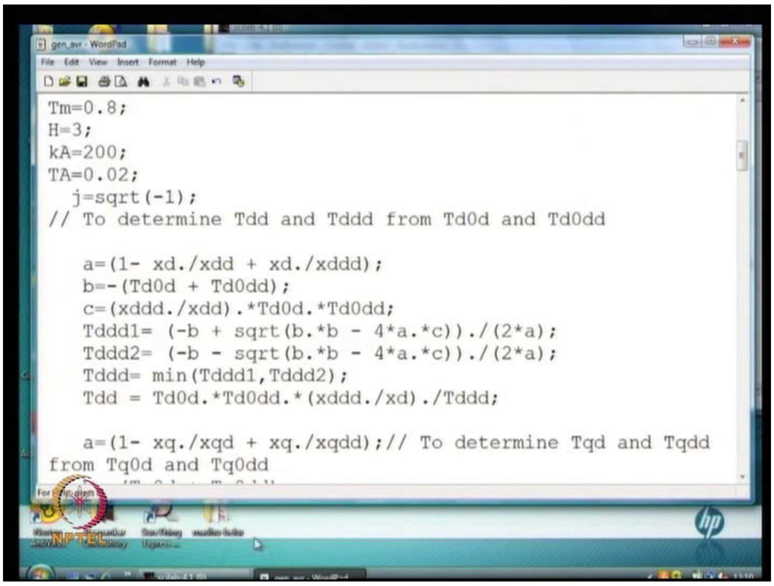

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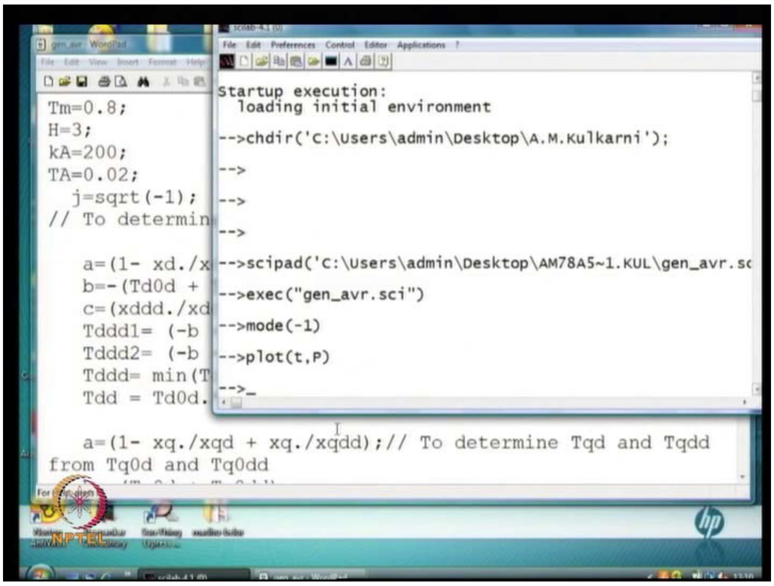

So, we are at a different operating point, we do the simulation from that point onwards, so I execute this program again and few plot while this is executing, let me just (()) that we are assuming a different operating point calculating the equilibrium conditions of the state corresponding to that equilibrium point, then giving a pulse change in V ref, so the system gets pushed out from its equilibrium, but it is a pulse change, we get the V ref back to its old value.

So, what we are doing is, because of this pulse change the system get shaken out of its equilibrium conditions, the states move away from the equilibrium conditions, and once the disturbance disappears the system attempts to well, we have see whether the system comes back to the equilibrium again or not. In the previous exam previous case where T m is 0.5 this actually happened.

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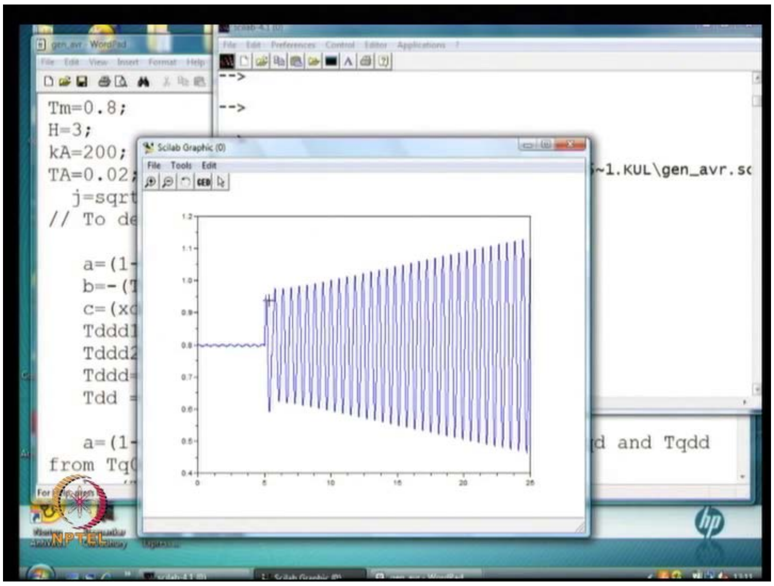

But, now let us see whether it will happen, when T m is 0.8 what you notice here of course, is not this what you notice is that, when you give a disturbance, the shake the system get shaken out of its equilibrium, but it does not come back to its original equilibrium point, it just goes on oscillating and is oscillation grows with time. In fact, this occurs under certain operating conditions only and for certain AVR parameters, but this is a distinct possibility and this in fact, has been observed in real power systems.

So, in the next class we will try to see how this poorly damped oscillation or in fact growing oscillations can be damped by appropriate control system, so this is another aspect of improving stability which we will discuss in the next class.