Power Electronics and Distributed Generation
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Module - 01
Lecture - 15
Anti-islanding Methods

Welcome to class 15 on topics in power electronics and distributed generation.

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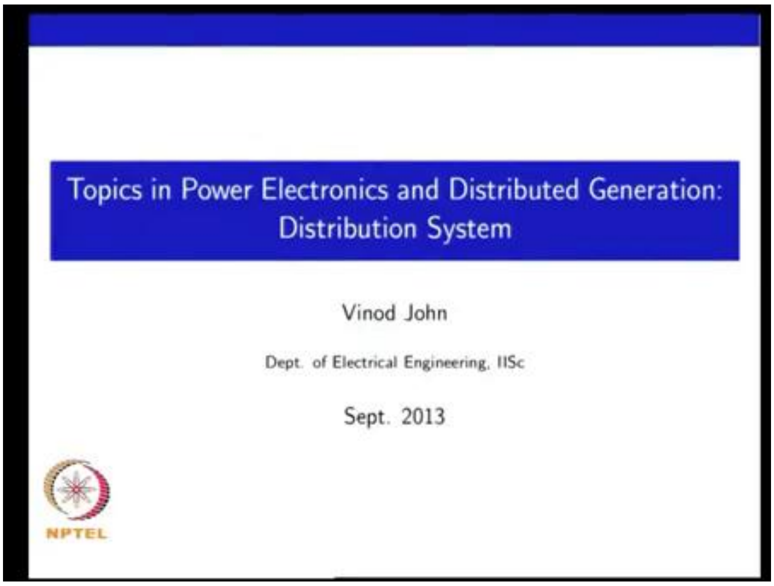

We have been looking at methods of detecting unintentional islands and these are essentially what we call as anti islanding algorithm and we looked at passive anti islanding methods. In the last class we looked at the relationship between power mismatch in between the DG and the load and the voltage level after the disconnection of your upstream switch.

So, it could be upstream breaker, so what would be the voltage and the idea is if the voltage goes beyond some particular bound o voltage level or a under voltage level then you declare that it is an acceptable situation it is the situation of unintentional island. So, today we will look at the relationship between the reactive power mismatch and the frequency deviation that would be seen in the island. So, this is essentially a passive anti islanding method assuming the same or else see load model and the DG model as we have earlier been discussing.

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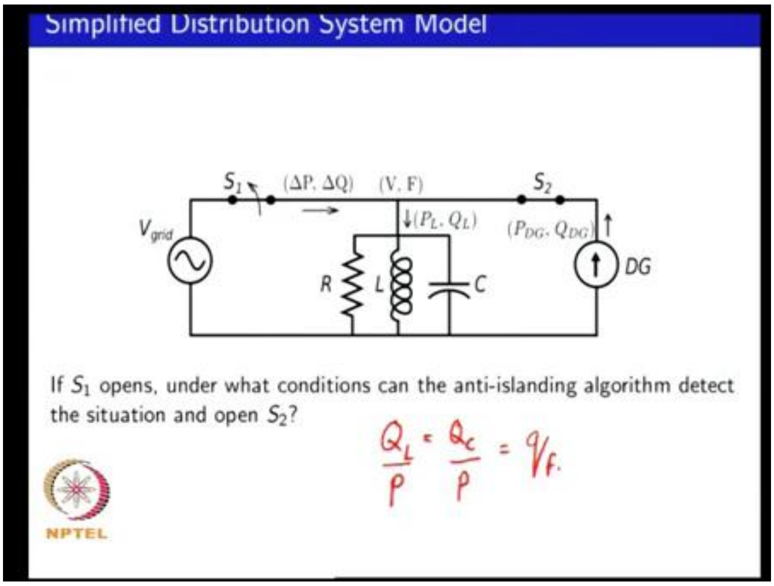

So, again the assumptions are that the L and C draws equal reactive power at 50 Hertz which means that your Q L is equal to Q C and in this condition, essentially your L and C is under resonance at 50 Hertz. You can actually write an expression for the quality factor, you are assuming that the quality factor is large. So, Q L divided by P and Q C divided by P is the quality factor and then assuming that the quality factor is larger than 1 greater than or equal to 1. You are also assuming that your DG given at is operating at unity power factor which means that Q DG is 0 under nominal conditions.

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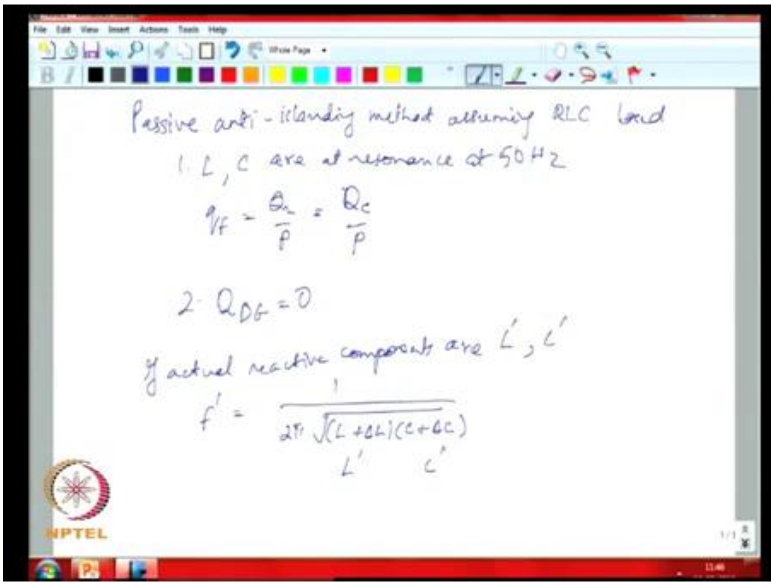

So, the next question is, now if we have a situation where your L and C is different from what was nominal. Then, what would be your new, your reactive power mismatch and the corresponding change in frequency 1 L comma C and Q F is Q L by P and DG is operating at anti power factorial reactive components are L prime comma C prime. Then, your actual resonance frequency is f prime is 1 by 2 pi square root of L plus delta L and C plus delta C, well this is L prime and this is C prime, so you can write an expression now for the deviation in frequency.

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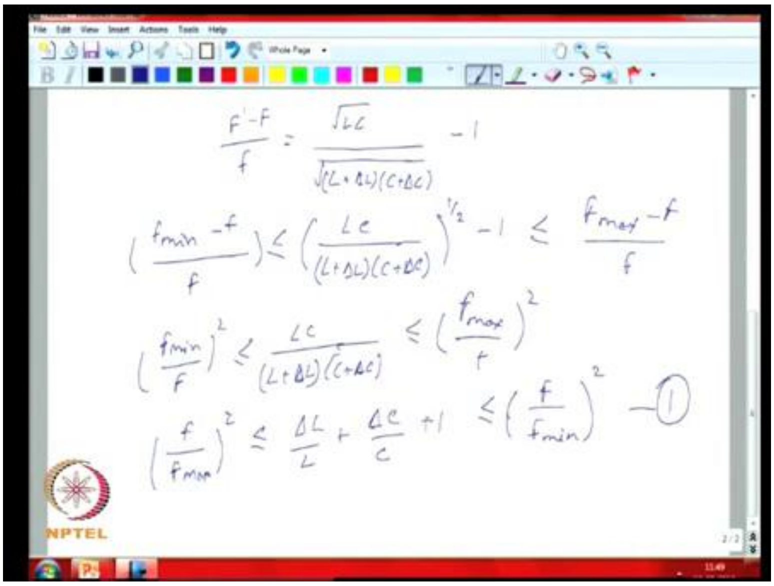

Your f is 1 by S square root of L C, so you can write in the previous expression for f prime and you know what, f is you can simplify it you can get square root of L C. You can then take f prime to be maximum level a or f prime to be a minimum level and then you could consider a threshold f min minus f by f is less than and this could be further simplified. You have minus 1 over here and minus 1 over here and you could simplify it as a f min and then you could take the reciprocal and then you get f by f max square less than or equal. So, here we have neglected the product term delta L delta C, so it is called as expression 1.

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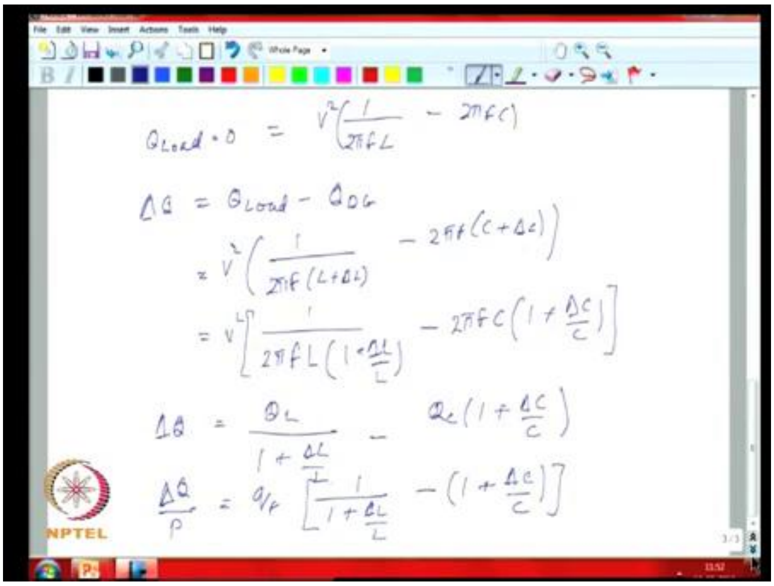

You also know for your ideal load case you have Q equal to Q load is 0 and your delta q is essentially what comes in from your grid side in a in the model that you are having. This is q load minus Q DG and for the case where now you have a deviation from the nominal value; this turns out to be equal to v square 1 by 2 pi f into L plus delta L. So, this can be written as here and we know that Q L is equal to Q C is the quality factor times e. So, this can be written as delta Q will be written as Q L divided by L plus delta L by L.

So, because Q L and Q C is quality factor times P, you can write it as delta Q by pi equal to Q f into 1 by delta l by L and this 1 plus delta L by L can be simplified taking an appropriate summation of 1 plus, 1 plus x 1 by 1 plus x.

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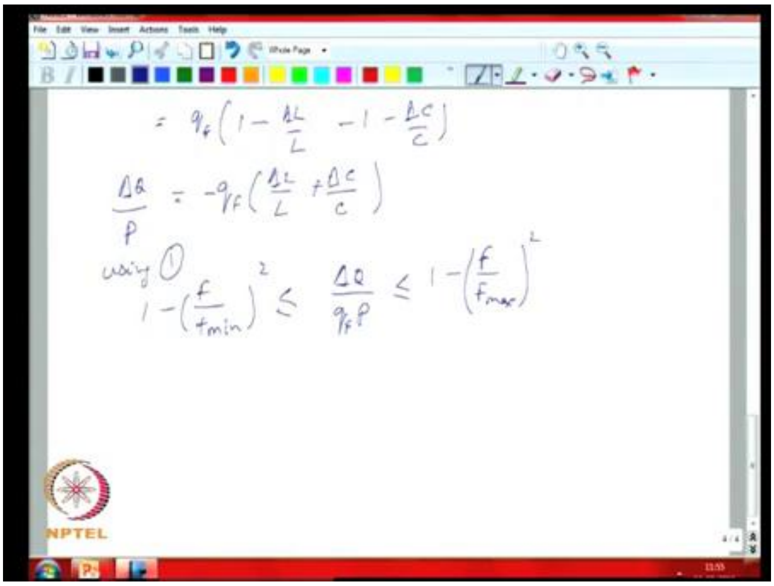

So, this is equal to Q F, so you have now a relationship between delta q p q f and the difference the variation in the load and if you look at what we had, we had an expression for variation in the load and your f min and f max. So, we could substitute this in the in the expression that we just have to write a relationship as 1 minus f by f min, so similar to what we did for the case of voltage, where we had a nominal voltage.

Then, we looked at what would be the power mismatch to determine what would be the resulting voltage amplitude after opening of the upstream breaker. Here, we can look at what is the reactive power mismatch assuming the load is a R L C load to see, then what would be the frequency deviation, when you have a reactive power mismatch or the reactive power that is coming in from the grid. So, again we look at a few examples of what would be the frequency deviation we can expect for some change in reactive, some delta reactive power that is coming in from the substation or any upstream opening breaker.

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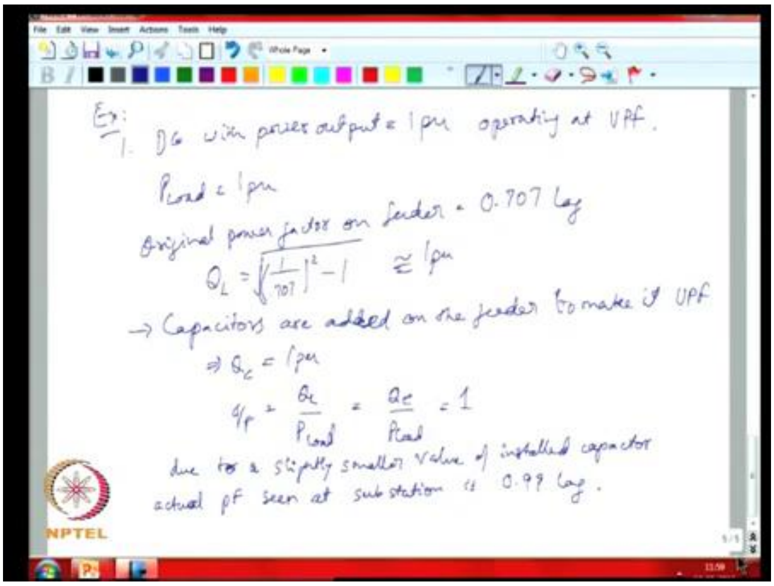

So, we look at an example, so a D G operating with power output equal to 1 per unit and its operating at u p f, unity power factor and the load is also considered 1 per unit. So, power wise, it is perfectly matched and will assume that on the feeder, the original power factor on the feeder was 0.7 on 7 lag point, 7 1 lag. Essentially, what is means is that your reactive power being consumed by the loads on the feeder is 1 by 1 divided by the power factor. So, it is about 1 per unit, then we will assume that this particular feeder because of this large reactive power that is being drawn has power factor correction capacitors that are added on that feeder to try and make it unity power factor.

So, essentially it means you have added capacitor capacitance drawing over of 1 per unit, so that you have essentially a unity power factor coming in from your upstream substation breaker. Then, your quality factor is Q L by P load is 1 and then will assume that say for some variation in the value of the installed capacitance. You see a actual power factor of 0.99 lag rather than unity power factor you are saying 0.99 lag at the upstream breaker. So, essentially this could mean that your having a C prime, which is slightly smaller or essentially a inductive load, which is larger, which means your L prime is again something smaller than the l that you originally thought.

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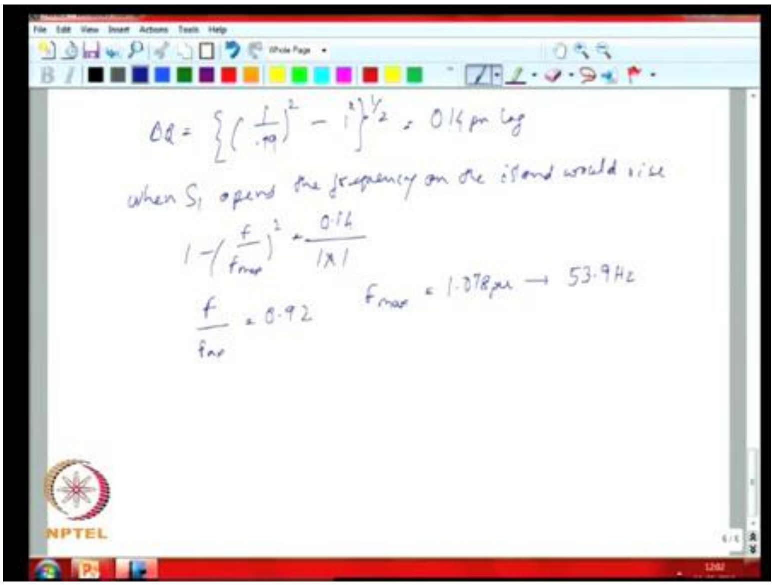

And then you can now calculate your delta Q that is coming from the grid is 1 by 0.99, so in this case you having 0.14 per unit lag essentially is the reactive power coming in from the grid. The question is what would be the resulting frequency change that you would see when a upstream breaker opens. So, you can use the relationship that we have just derived, if you have one minus f by f max P is 1 per unit quality power factor is 1. So, you have f by f max is 0.92 or your f max equal, so you can see that with a 0.99 power factor, essentially you see a frequency deviation of almost 4 hertz 3.99 hertz.

So, you could say if you had set a over frequency relay at 50.5 hertz that would immediately detect that a islanding has occurred and disconnect your DG in response to the feeder frequency rise into a higher value. So, similarly we could look at what would happen, say instead of the power factor being 0.99 lag, what would be the situation if your power factor was 0.99 lead. That would correspond to a situation, where you have slightly lower reactive load or a slightly larger value of capacitance in the power factor correction capacitor bank.

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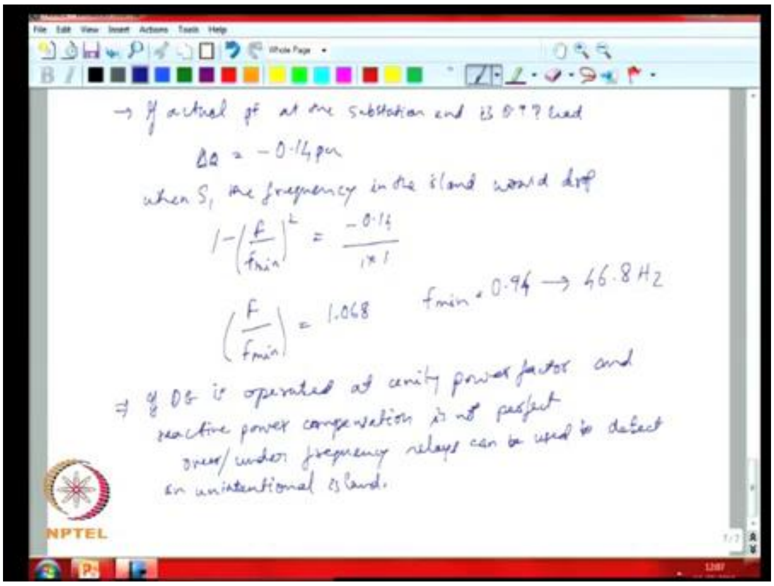

Then, you would get delta q again is minus 0.14 per unit, so when your upstream breaker opens s 1 opens. In this case the frequency would drop and you have 1 minus, so your frequency would drop to about 46.8 Hertz. So, in this case, see if you had a under frequency relays may be its set to open at 48 Hertz, so seeing 46.8 Hertz, it would disconnect the DG and say that there is a situation abnormal situation so that this DG has to be disconnected. So, if the DG is operated at unity power factor and reactive power compensation is not perfect, then over and under frequency relays so, if you again this is assuming that your load model is R L C load model.

You are assuming that your DG is operating at unity power factor in some situation it is might actually be beneficial to operate the DG under non unity power factor because you may have reactive power elements in your facility. You may want to operate it so that you do local compensation rather than always operate it at unity power factor. So, you have to realize that these are under assumptions that these pressures are valid. Again, you might say that assuming that all the loads on the feeder can be approximated as a R L C load is not always valid, but again the reason why people look at R L C load as a model for a situation of unintentional island.

So, you can do a test that is repeatable, in fact more common load might be a induction machine or machine load with or a inductance voltage behind a inductance type of load and if the machine has a large inertia. It can actually sustain in a island for quite a while depending on a how large that inertia is does nothing like a standard induction machine with standard value of core laws or standard value of friction wind age. These are parasitic elements in a induction machine, but you could accurately specify your resistance to be of 2 percent or a your inductance to be of some percent tolerance. You could actually do test in a repeatable manner irrespective of this been done in one location or the other.

So, assuming the simplified R L C model for the feeder allows you to complete test in a repeatable manner again the other assumptions. We are assuming that DG is being controlled in a with constant P constant Q you might have situations where there might be some other methods for controlling the DG, you might control your rather than P and Q. You might control your direct coordinator axis of currents, so depending on how your control is your thresholds can actually also differ, also one needs to keep in mind there. We are assuming a singled g with load and assuming that each of each of this element and where you switching a upstream opening as a upstream breaker and were looking at the power mismatch under reactive power mismatch.

In an actual feeder, the loads are constantly going up and down; your DG's might vary in a power sec point. So, statistically you might have a duration of time where your power generated by the DG might have a small mismatch with the power being considered by the load as the penetration of DG's on the feeder goes up. So, the chances that your delta p and delta q becomes a really small become higher once your DG penetration goes up. So, the there is always a chance of unintentional island for which one needs to be careful as we can as we have seen there are actually equations of continue in a sustained unintentional islands.

So, you can then look at see that these passive methods would work well under penetration of DG on the feeder so initially when there is a just a few photo voltaic panels on the roof and you are having large loads on the feeder, then there would be no problem.

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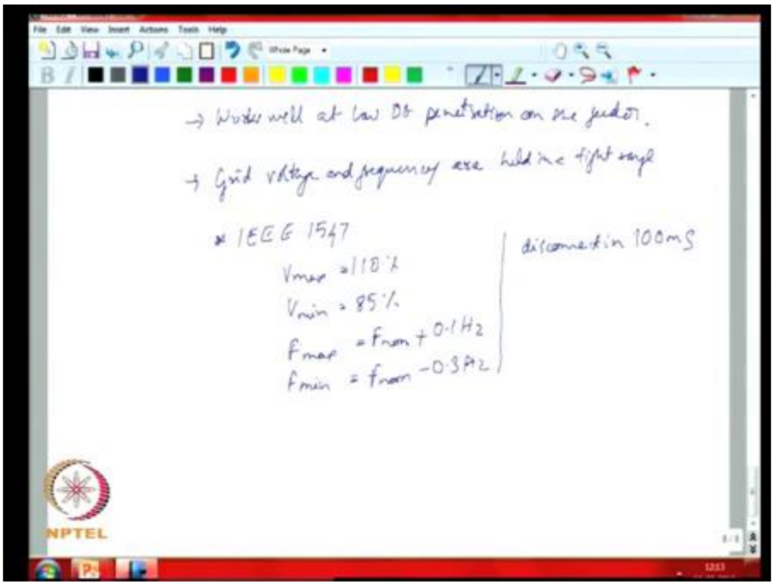

Another situation that we have just seen is that, so it works well, another situation, another result that we saw out from the examples that we did is that it would work well if your good voltage amplitude and a frequency range is maintained in a tight ranges. So, if you look at a standard such as IEEE 1547, which is a standard frontier connecting distributed energy resources with the grid, they would specifies say a v max of 100 and 10 percent V min of 80 percent. Then, you would say f max of f nominal plus 0.1 Hertz f min and what is suggested is that if the voltage amplitude or the frequency goes out of this particular range, you disconnect and in 100 milli seconds.

So, you have a IEEE instantaneous disconnection if your voltage and frequency goes out of this range. If your grid is holding your nominal values in a very tight range then such a tight window for voltage and frequency acceptable, say in the Indian grid, it would this would mean that you may not be able to connect the DG with the grid at all. So, just directly following the standards would not work in all situations, you will have to look at what is realistic in the particular local scenario. Then, see whether that particular method would work or not in for our detection, for example, setting of relays detection of unintentional islands etcetera, we will look at another method of detection of unintentional island.

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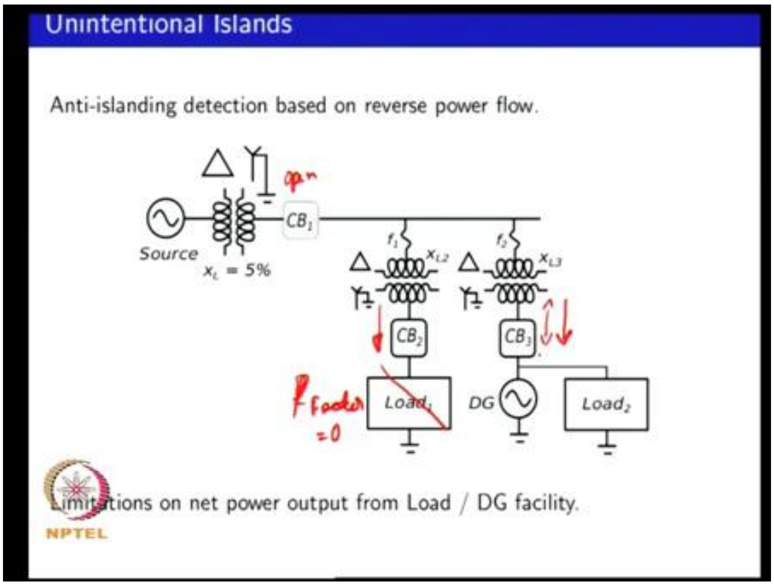

That is based on looking at the direction of power flow. So, if you look at situation where you have normal loads connected to the distribution system, the power that is been drawn by at the a point of common coupling would be from the grid into your load to your facility. When you have a distributed generation sources connected at a load, then now you have the possibility that power might be sent in either, it might be drawn into the facility a DG power is less than the facility loads or it might be sent back out into the grid. If there is a excess power available at the DG, suppose the DG is controlled, so that power is always drawn into the facility and is not. So, you should control the power flow to be only in the direction into the facility.

Then, you could make use of that to detect situation of unintentional island. So, you this is by sizing the DG to be less than your load in your facility or controlling adjusting your DG operating power such that it does not explode power at your point of common coupling. Then, you could actually detect a situation of unintentional island, so the reason why this would be the case is that say if you have a open upstream breaker and assuming that say all other loads on the feeder goes to 0.

Let us say if your L feeder your P feeder goes to 0, then to maintain the unintentional island with the DG, you need to actually send power back out at your point of common coupling even at 0 load. You will have some losses core losses in your interconnection transformer etcetera. So, you could always detect a situation, where your power is flowing out to in a facility to maintain your voltage on the feeder to be some finite positive value. If you detect such a situation, where the power is going out from the facility into the grid that means at some upstream breaker the grid has disconnected and the facility is now supporting the feeder.

That can be used to detect a situation of unintentional island based on the power flow direction that you can see that. You now have restrictions on the sizing of your DG and always ensuring that your power in the DG is less than what is being consumed on the load. So, if you look at this particular case it put restrictions on how you operate your DG which might not be actually be acceptable say suppose your DG is a photo voltaic system or a wind turbine, you may want to operate it.

So, you are harvesting the maximum energy possible and having such restrictions would not be a economically viable. So, methods of anti all methods of anti islanding detection have some drawbacks, you might have some restrictions, you might have non detection zones etcetera, which might lead to how constraints on how you operate the system. Now, we could look at what are considered as active anti islanding methods.

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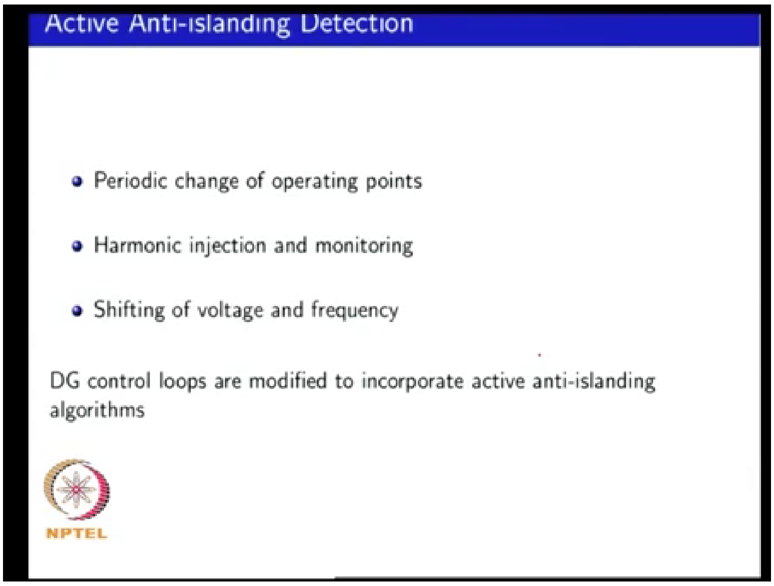

Essentially, active anti islanding methods are interact with DG control and essentially you could have situations, where you might periodically change the operating point of the DG. You are doing that in a periodic manner, you might have power or reactive power mismatch, which causes detection that you have your an intentional island. You might look at injection harmonics and when your grid is connected with your R L C load model, you can you know that the grid maintains the voltage. So, as soon as your disconnected from the grid there is nothing to maintain the voltage.

So, if you are injecting harmonies, you would see a corresponding harmonic distortion at your point of common coupling. Similarly, you can have unbalanced, which is you can detect changes in power factor. Also, you could say try to shift your voltage operating point or your frequency operating point in a active manner, where your DG controls itself is trying to actually shift the operating point of the DG and you can see that these methods are actually modifying the control of the DG in a active manner. You detect an island; some of these methods such as trying to the change the operating point etcetera would be statistical.

To be probabilistic in the sense that you might be able, it might work with a single DG, but when you have a multiple DG's, one might try to take the operating point out. A second DG might take the operating point down and it might cancel out overall. So, some of these things might work on individual bases, but not in a large collective group, so you will have to look at the implications of such situations also. If you look at injection of voltage harmonics and looking at monitoring on balance etcetera, these affect our quality. So, you have power possibilities of per power quality in balance instabilities in the grid etcetera, which can affect the operation.

So, we will look at what is the underlined methods of some of these active and anti islanding skills, especially they wants that try to shift your frequency and voltage operating point. Essentially, what we are trying to do is you saw in the conditions that are required to operate your island as a sustained island. There are two conditions, one is the real and reactive power between the DG and the load should match and the second thing was that the operating point should be stable.

So, if the operating point is not stable, then your potentially your voltage would exponentially drift away from whatever the point it was at, when the upstream breaker disconnected or the frequency might drift away. You can make use of the facts that you can detect this drift and frequency and voltage to detect a situation of unintentional island.

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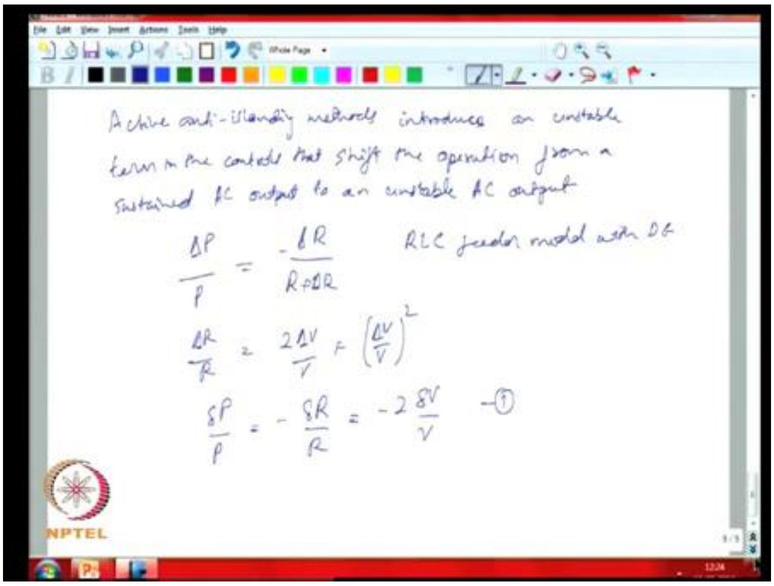

So, essentially the active anti islanding methods, we will first look at how potentially the voltage amplitude can be shifted. So, if you remember based on our r L C model for the feeder and the DG we had an expression for your delta P by P. So, this was the relationship that we had and we also had delta R by R, so if you look at it on a small signal bases you have delta P by P is minus delta R by R, so let us call this one.

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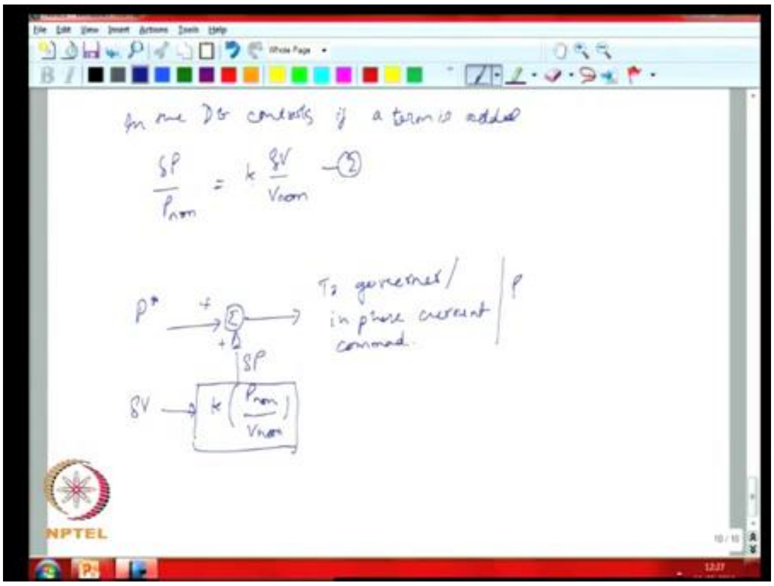

Now, in the DG controls, if we add a term where delta P by P nom, so essentially what you have is your in the DG is from your PPTL algorithm or something which drives your power command. You are adding a additional term to it, where you are looking at deviations from the nominal voltage and adding a term k times P nom by V nom. So, essentially this term corresponds to essentially the expression to and this would go say if you have synchronous machine can go to the exciter of the synchronous machine or it can go to the in phase current AC current command in an inverter.

So, based on that you could actually adjust your actual power that would been put out by the DG to the governor. So, essentially this determines what would be a actual power and if you look at this particular expression, where delta P by P nom is k times delta V by V nom.

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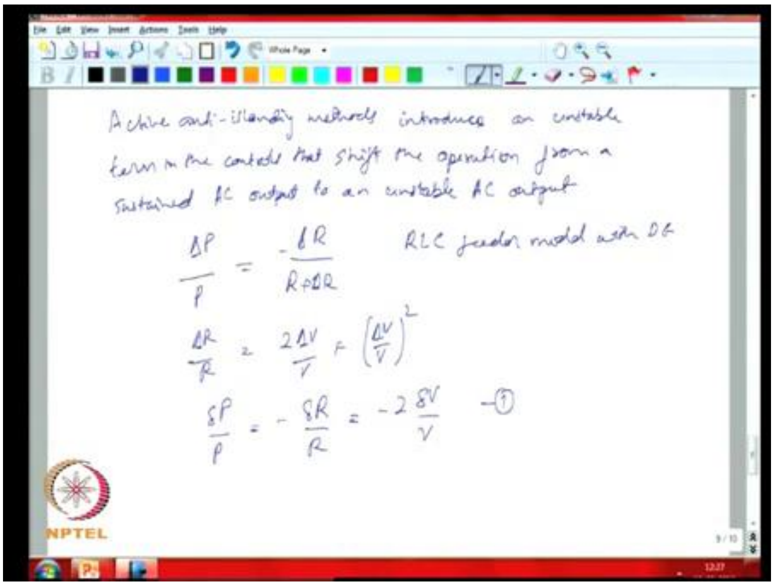

If you look at the expression for the R L C load model physical R L C load model, you can see that the polarity of the sign between delta P and the voltage. The resistance is such that you could essentially base on k have emulated a positive, negative resistance. So, in aim a dynamical system essentially a positive resistance gives you damping, so a negative resistance would give you negative something, which is exponentially divergent. So, you can introduce instability by controlling the term k by tuning the term k to actually cause your voltage to diverge rather than damp down in a dynamical system.

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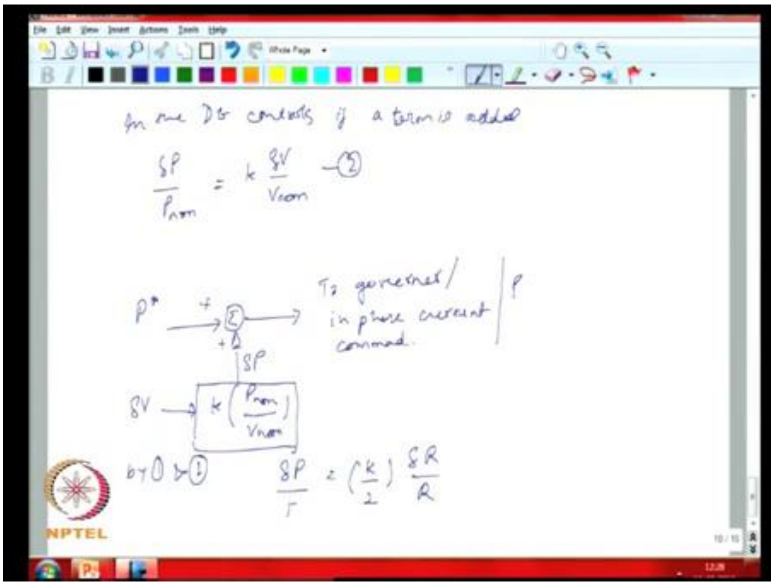

So, essentially what your dynamical resistance that is being emulated can be negative.

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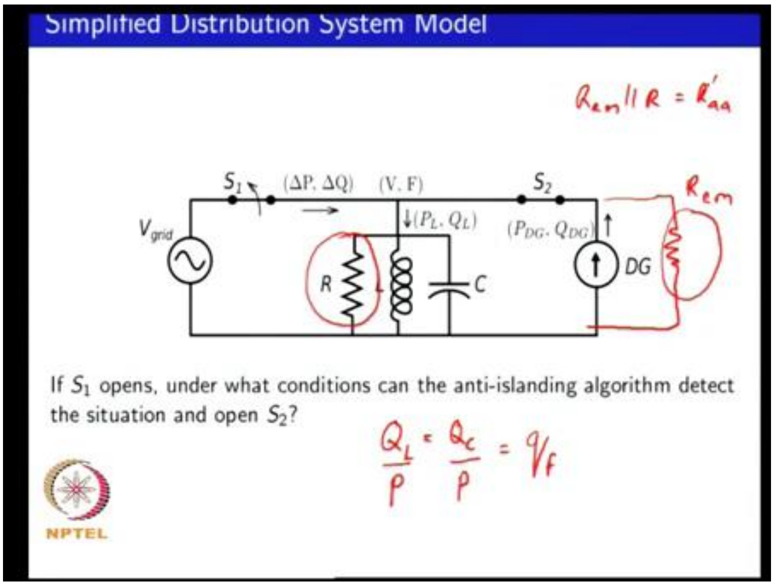

So, if you look at your R L C load model, so essentially what you could have is your dynamically emulating at the systems and this resistance along with your actual load resistance is called is as are emulated. So, R emulated in parallel with R would be your effective resistance in your feeder with after anti after islanding. If that persistence becomes effectively negative you would have a situation, where dynamically you have a system which would, instead of damp down, it would essentially become unstable.

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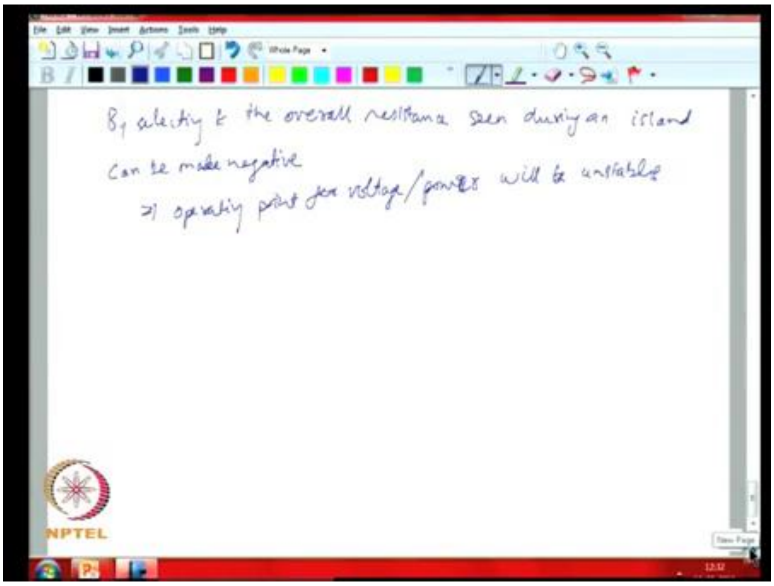

You could also see what this physically means.

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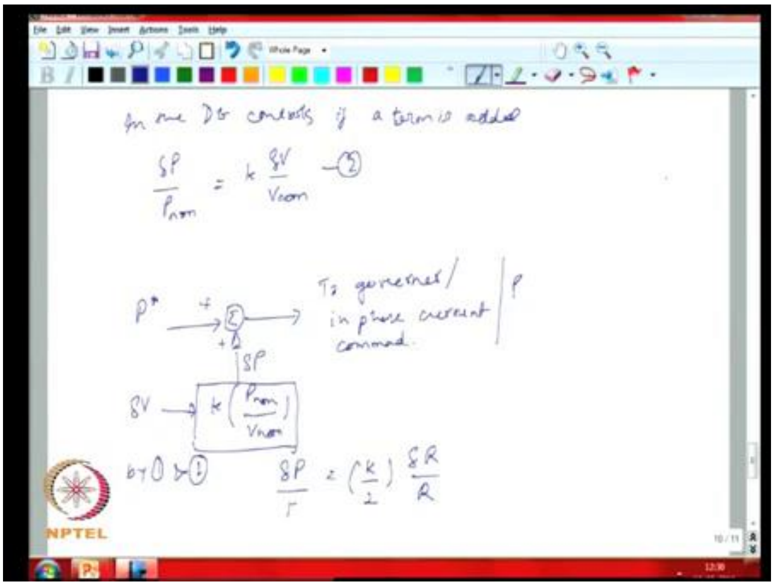

Suppose, you have a situation where the response to the disconnection of the grid, if your voltage falls the possibility of the voltage falling could be because your power that is being injected is lesser than what is required. This particular term would then further reduce the power, which means that in the 17 voltage fault would fall down and this becomes a positive loop. Eventually, the entire feeder voltage collapse if the voltage rises on disconnection, then this term would inject additional power causing a further raise in voltage, essentially causing your final voltage to just go outside your acceptable range.

So, we could in a similar manner where we looked at the voltage and then altered the frequency. We could do a similar thing with by matching the power the react the frequency, you could alter the reactive power and in response to the change in frequency and the reactive power. You could adjust operation of the DG and with an objective of taking the frequency, now outside the nominal range will start looking at the stop could be able to wrap it up in the next class.

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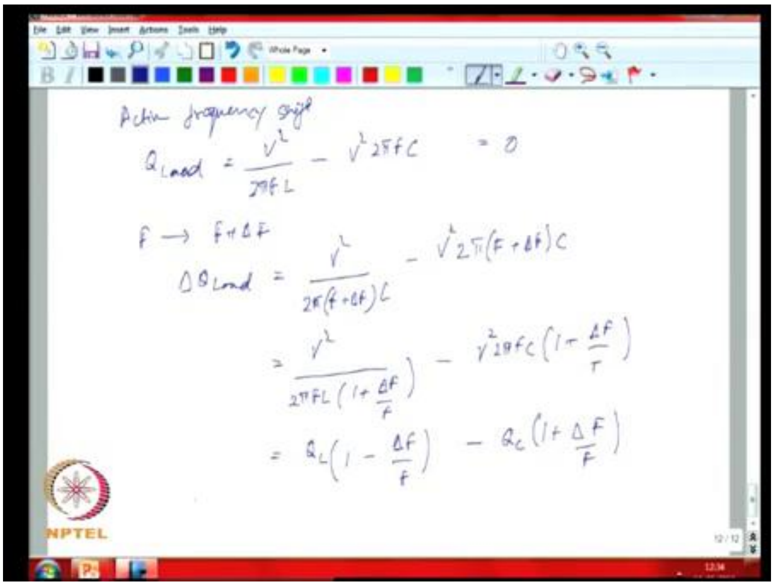

So, this is essentially what you do when you are having a active frequency shift, so we saw in a R L C load model your Q of the load is V square by 2 pi f L and the nominal value was 0. Now, we will look at what would be the situation if your frequency is something which shifted to f plus delta f and what would be the net reactive power that is being drawn by the load. So, you can write your delta Q load, the original value was 0 with the change in frequency. You would have delta Q load equals and taking the 1 plus delta f by f term to the numerical. This is approximately equal to 1 minus delta f by f and we saw again the assumption that we had was that QL and QC are resonant at 50 Hertz.

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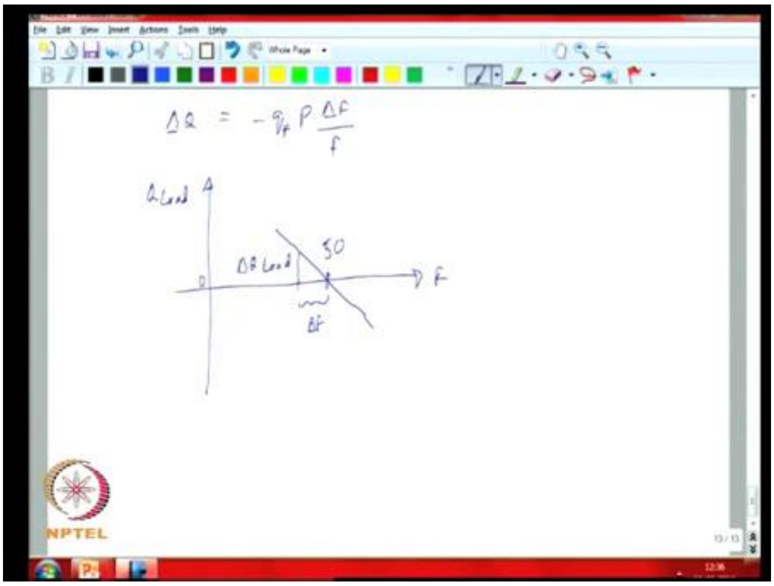

You could write this as your delta Q delta Q that is coming from your grid due to a change in frequency would be. So, if you plot say frequency versus change in your Q load and plot it close to your nominal range. Essentially, you would have a curve with a negative slope and your load is resonant at 50 Hertz. So, at 50 Hertz, your Q is 0 and if your frequency drops by some delta f, then essentially would require some additional delta Q.

If your frequency raises, then essentially the load would act more capacitor because it is a pi parallel R L C model that you are assuming for the load. So, then we could look at what would happen if there is a L and C deviation around a nominal. Essentially, what we will do is will look at the change in the operating reactive power of the DG to be similar to what would happen when there is a nominal L and C variation, that is happening on this particular island.

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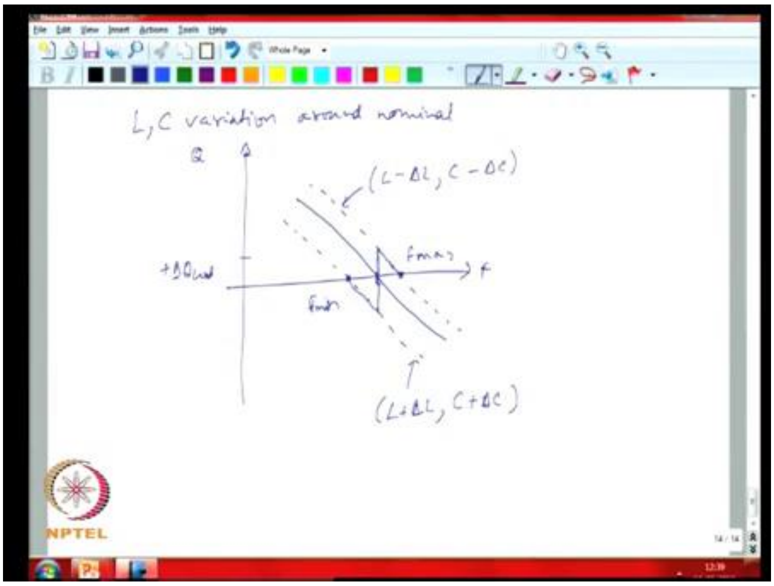

So, this is the nominal curve and suppose you have your L and C to be say l minus delta L and C minus delta C. Essentially, what would happen over there is that your effective power factor current capacitor is less for L minus delta L is that your reactive power that is load is drawn is more. So, you are adding a delta Q load, so you could think of it as corresponding to a new higher frequency at which it would settle. So, this would say let us call it as some f max and say this would be your plus delta Q load. Similarly, you could look at the situation where your L and C parameters, your L plus delta L your C plus delta C.

Then, you could think of it as essentially in the parallel R L C load, your reactive power would drop or it would settle in at a lower frequency f max. So, we look at the change in operating point of the DG to emulate a equivalent change in your L and C are L and C values and use that to see what would be the change required. Actually, your frequency to just be driven out to be driven to a very large value or to a very low small value will do this in the next class.

Thank you.