Power Network Analysis

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Week-11

Lecture-51

Lecture 51: Fault analysis- Protection challenges due to Renewable Energy (RE) resource integration

Hello everyone, welcome to the first lecture of Week 11 of the course Power Network Analysis. In this discussion, we will be discussing certain protection-related challenges that arise due to the integration of renewable energy resources, specifically inverter-based renewable energy resources like solar PV. wind generation, battery energy storage systems, etc. What challenges do these renewable-based resources face, specifically with inverters or converters between the device and the AC power network? What challenges arise that we will discuss in today's session, which is going to be the last discussion on the module on fault analysis? Although, given the time that we have, if one wants to discuss these protection challenges, one could discuss for hours, but given the limited period of time that we have and the importance of understanding what issues these renewable energy resources bring while integrating them with the power network. Obviously, the reason for their integration is that these are green energy resources; they are non-conventional energy resources not based on fossil fuels, which create their own economic and environmental impacts. So, to limit the discussion, I will be expanding on three bullet points to give the importance of the discussion that we have.

I will be emphasizing the impact of renewable energy resource integration on short circuit capacity evaluation, also sometimes known as short circuit ratio. The impact that this integration will have on the SCC or SCR of the overall network will create difficulty in finding the relay or circuit breaker settings. Remember when we started the fault analysis discussion, we sort of understood that there SCC or SCR dictates the ratings of the protective devices, specifically breakers and isolators, and that if these renewable energy resources are integrated, the short circuit ratio and capacity do not remain fixed because these are renewable energy resources. So, their generation would depend on the availability of solar and wind.

So, basically, these have variable injections. If these are variable injections, it is likely that the SCC and SCR will vary according to the available injection. And then the question that arises is what the specific setting should be for the circuit breaker or relay that is designed to protect the system against these disastrous faults that we have discussed. That would be one point of discussion. The other point of discussion would be.

Understanding the importance of issues related to renewable energy integration in HV networks, what typical relay philosophies are used for protecting high voltage transmission networks, and what certain issues arise while protecting low voltage distribution networks, as well as what could be the typical resolutions for them? These issues, in terms of the protection challenges, are what we will discuss in today's discussion. The last discussion we had at length on a few solved examples emphasized the importance of using Fortescue's theorem and Thevenin's theorem for analyzing balanced high voltage transmission faults and the different types of faults that could occur. And what could be the corresponding current contribution evaluations using the bus impedance matrix? So I hope the examples are clear enough for the sake of understanding. So coming to our main topic of today's discussion, we will compare the typical conventional generating devices, which are mostly synchronous generator-based devices, with the renewable-based devices. So there is a clear segregation between the quantum of current that these generators can generate.

So typical conventional thermal plants or hydro plants, which basically have a synchronous generator or several synchronous generators operating in parallel. During a fault, the typical current contribution is almost 5 to 10 times the normal rated load current or fault current. The reason for this significant increase in current is due to the internal dynamics, or rather the variation in the transient reactance, sub-transient reactance, and synchronous reactance of the synchronous generator during a fault event. So basically, what I am trying to say is that the fault current contribution by conventional synchronous-based generators is significantly higher compared to normal load current. And if we talk about similar current contributions from renewable-based resources that have an inverter or converter present in between.

The diagram here shows essentially a typical arrangement of how the renewable energy resources, often called distributed energy resources, are integrated. So if we have, let's say, a wind turbine, which is mostly an induction generator-based device, or if we have solar PV, a fuel cell, and a battery energy storage system, which are usually DC-based devices. So typically, wind generation is inherently AC, not at synchronous frequency, whereas the other resources inherently generate DC supply or DC power. These devices, when being integrated because of their good environmental impacts, cannot be directly integrated into the utility grid or the high-voltage transmission network. There is a need for this polytronic-based interface, which consists of rectifiers, inverters, converters, boosting of voltage, etc etc. These rectifiers and inverters inherently have certain protective functions. Specifically, if we talk about an inverter or rectifier, the switches that are used in these devices to regulate the voltage level or the generation frequency inherently have a certain overcurrent rating capacity philosophy that entails that if the If some fault occurs on the generation side or on the grid side, then these inverters and rectifiers will stop operating. They will stop responding to such changes because of their own inherent protective functions inbuilt in the switches, the sensors that exist. And that is one aspect. That means there is an inherent protective function involved in inverter-based resources.

The other aspect is that because of these converters and inverters, the fault current level is not significantly high compared to synchronous generator or conventional generator resources. It is capped at 1.2 to 2 times the typical normal rated load current from the renewable-based resources that have inverters in between, due to their inherent control philosophy and partly because of the inherent protection scheme that they have. So the question is, why do we need to have these pyratonic interfaces when we are integrating renewable resources? The typical answer to that lies in the fact that from the DC sources, which are solar PV or battery and energy storage systems, it's a DC-based device, so if we have to integrate it into an AC network, we would definitely need an inverter, specifically a DC to AC inverter. Probably this may also have certain other boost or buck-boost converters that sort of enhance the voltage level.

So typically, let's say solar PV, if it is generating at a few tens, twenties, or hundreds of volts, and the same voltage level needs to be scaled up to seven hundred kilovolts or seven hundred sixty-five kilovolts, typically direct integration doesn't happen; it all happens at different levels of voltage, so there is definitely a need for that. Suppose the DC source is being generated at 400 volts, and if we want to integrate it to, let's say, sub-transmission levels of 33 kV or 66 kV, then there is definitely a need for an inverter with some boost capacity for the voltage. So that is where the necessity of an interface or inverter comes in. That's about DC sources. The question then still remains: why do we need an interface for a wind generator that is inherently AC in nature? The issue with wind turbines or wind generation is that it is not usually generated at 50 hertz.

So in order to match the frequency on the AC side of the wind turbine as well as the AC side of the utility grid, we need to have a conversion mechanism that enables synchronizing or connecting two non-synchronous devices, where the frequency is not 50 Hz while the other frequency is 50 Hz. That's where we need an AC-DC converter or a DC-AC converter, again with voltage boost-up or boost-down capacities present if required. So that's the essence of having this palatronic interface, which sort of limits the fault current. And then there is an aspect known as FRT, which is fully called fault ride-through capability. Also, in literature, it is analogously termed LVRT, which also stands for low voltage ride-through capability.

So what do LVRT or FRT mean? Because of the inherent protection scheme enabled in the inverters or converters, if the inverter doesn't have this fault ride-through capability, what would it do? The red line here shows that particular fault characteristic or current characteristic that would be observed. After a fault has occurred, the current tends to go up, typically 1 to 2 times the normal load current, and then, without write-through capability, the inverter does not respond; it does not contribute anything to the fault. Now, why is it necessary to have FRT or LVRT? So basically, what are FRT and LVRT given the limited time that we have? FRT or LVRT refers to the mechanism of a generator still being connected to the power network while it is experiencing a fault, and this ride-through capability is important to support the system without going into an unstable state or a blackout condition. Eventually, if the faults persist, the system will experience a blackout condition. But at least only the non-healthy part of the network remains isolated; the healthy part should still continue supplying the load, still continue operating even during voltage sag or swell conditions, and that is the essence behind FRT or LVRT.

So basically, it is all about sustaining the fault during the fault while it has occurred by a typical synchronous generator or renewable-based resources. The blue line phenomenon of synchronous generators has been very well understood in the previous few lectures, and the red line of the response of the inverter is an undesirable response because if all inverters do not respond to the fault conditions and stop reciprocating, then unnecessarily some healthy loads in part of the network will get isolated, which may create trouble. So the green characteristic inverter with FRT is a desired attribute of the particular inverter so that the system can still continue operating even during a fault condition while the relays and circuit breakers do their job of isolating or removing the unhealthy part from the healthy part. So, this being the premise of our discussion, let us move into the short circuit capacity assessment. We have clearly understood the aspect of SCR assessment or SCC assessment in the previous few lectures, where SCC is basically the ratio of short circuit MVA, the worst-case MVA that can occur during a bolted three-phase fault, divided by the rated MVA of the power network.

$$Short\ circuit\ ratio\ (SCR) = \frac{Short\ circuit\ MVA\ at\ the\ bus}{Rated\ MVA\ of\ The\ source}$$

Now, and more importantly, the power circuit ratio dictates or entails what can be the fault ride-through capability of these inverter-based resources. These inverter-based resources, although green, have variable injections due to their dependency on the weather for how much power can be generated. So typically, the SCR value would depend on how many such sources are present under the network and where we are trying to estimate the SCR value. Typically, when the SCR location is done near the generating devices, the short circuit capacity is higher because more current can flow from these generators, being electrically closer to the fault location.

The farther the SCR location is from generating sources, the lower the typical fault current contribution is likely to be. SCR typically depends on the number or type of resources that are present at the point of interconnection. There are different ways to find the SCRs for different types of resources present. One such common estimation is through weighted short circuit ratio evaluation, which is basically a power-dependent capacity evaluation of the short circuit capacity.

$$\text{Weighted Short Circuit Ratio (WSCR)} = \frac{\sigma_i^N SC_{MVAi} \times PR_{MWi}}{\left(\sigma_i^N PR_{MWi}\right)^2}$$

So PR megawatt I is the rated output of the non-synchronous generator generated at bus i. So basically, it's a weighted average of the short circuit ratio from individual points of contribution at the point of estimation. The other possibility is through the composite short circuit ratio, where based on the overall SCR evaluation, instead of taking an average rated evaluation, we try to evaluate SCR at the point of location, considering all generators as partially or equally contributing to the short circuit capacity, and then take the ratio with respect to the nominal rating of all inverter-based resources. The other well-known popular mechanism or index that has recently emerged in the last few years is the short circuit ratio with interaction factors,

$$\text{(SCRIF)} = \frac{S_i}{P_i + (IF_{ij} \times P_j)} \quad \text{where } IF_{ij} = \frac{\Delta V_i}{\Delta V_j}$$

where the short circuit ratio is essentially the rated short circuit capacity divided by the participation or interaction of how the inverter-based device can sustain itself during voltage swell or sag conditions, provided it has low LVRT. Capability in it basically, this ratio is in a way an estimate of whether the source at node j, the inverter at node j, is trying to contribute or sort of respond with FRT characteristics to the fault occurrence. Then at node i, with some other inverter placed, how much is the voltage magnitude change? That's one way of finding this interaction factor.

So basically, it is like trying to link the voltage through capability, or it is basically an assessment of how much the voltage relates to the capability that can exist for different inverter-based resources. All that having been said, it all looks good theoretically, but the actual problem is that since our inverter-based resources are weather-dependent, their injection is uncertain and variable. Therefore, during variable conditions where the weather is changing and injection is changing, the SCR assessment is still a challenge. It might also happen that a particular device that is interconnected right now may not be available at a different point in time. So the issue with this is that SCR assessment is a challenge, and then the question arises: is SCR assessment a variable quantity? If it's a challenging factor, how do we decide or dictate finding reliable relay and protection equipment settings so that our system can still operate to the extent possible? Moving on to the next aspect of protection schemes or issues in high voltage transmission systems.

Typical high voltage transmission systems are protected by certain philosophies known as distance protection, differential protection, and directional overcurrent protection, usually for medium voltage lines. A detailed discussion on these different protection philosophies in itself could be an elaborated course. So I will not go into the details of what these schemes are. I will just browse cursorily through what these techniques are. In addition to these protection philosophies for protecting high voltage transmission lines, these schemes have certain elements specified with them.

The number codes here indicate those elements. It's again as per some ANSI standard, IEEE standard, which we don't have to bother about as of now. To enable these schemes, we need the help of certain elements. Those elements are mentioned here: distance element, directional protection element, negative sequence protection element, and fault phase identification logic. Basically, FID helps in identifying whether a fault has actually occurred in the area of interest and whether, based on this identification, these elements should reciprocate or act; basically, these are relays that reciprocate or act to clear the fault.

So, in terms of the distance element, the distance briefly explains what the distance element is; it basically tries to evaluate the ratio of voltage sensed by the relay with respect to the current sensed by the relay and evaluates the impedance. So basically, in case there is a system that does not have a fault, the typical impedance measured by the distance element would be the healthy impedance of the line.

$$\text{fault impedance } Z_{calc} = \frac{\bar{V}}{\bar{I}}$$

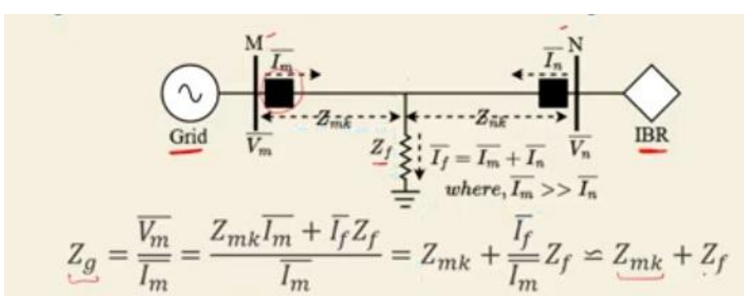
In case a fault occurs, the voltage would tend to go down, and the current would tend to go up; that is a typical signature of the fault distance element. What would happen is that during a fault, the distance element may experience a dip in the fault impedance, and that is the overall basis or reasoning of okay that. A fault has occurred on a particular section of a transmission line; because of the fault, the fault impedance has also come into the picture.

So, the overall impedance measured during a fault is less than the actual threshold or suitable value, and hence the corresponding distance element detects that a fault has occurred. So this diagram here essentially indicates what I was trying to say. We have a distance element or a delay present or shown by this square black box, and under healthy conditions, it would be monitoring the ratio of voltage and current sensed by the delay, and it would typically try to protect the entire length of the line, which is defined by its Z set value. The Z set is usually the positive sequence impedance of the transmission line between buses M and N. In case there is an internal fault, the overall impedance sensed by this relay would be less than the Z set, and the distance element would trigger that a fault has occurred.

In case there is an external fault, the fault sensed by the impedance of this particular element will be greater than z set, and since it is not designed to operate under such conditions, it will try to inhibit operation during the external fault. The typical locus of a simple impedance relay is also referred to as SIR, which is short for simple impedance relay. If we try to plot the locus of operation of a simple impedance relay, it is what is shown by this black box. Then Z set is the typical positive sequence impedance of the line that it should monitor; in case there is no fault, it would still be sensing that same value. In case a fault has occurred, F1 is the internal fault, so it should operate internally, and for F3, it should restrain.

So basically, this is the locus of the simple impedance relay on the RX plane, where the inside portion refers to the trip region for the relay to operate, and restrain refers to external faults. Now, in case we have inverter-based resources present in the transmission network, let's take a very simple example. I've considered two buses. On one bus, I have a synchronous generator for the typical AC grid, and on the other end of the line, I have an inverter-based resource, IBR. If a fault occurs on the line between bus M and N and I want to see what the impedance sensed by the relay on the grid side, which is ZG, is, then since the synchronous generator is contributing current ZF, which is marked by the blue line.

So if I tend to see this fault impedance ZZ, it would more or less be the same as ZMK, which is the impedance of the line between bus M and fault point K, and it would also be encountering or measuring ZF because IF by IM, this ratio would be more or less equal to 1. Remember, we are talking about a synchronous generator-based grid. So, the fault current contribution would be significantly higher from the synchronous generator side. And hence, this ratio would be more or less equal to 1. So basically, the grid-side relay will act normally the way it is supposed to operate.



The same thing applies if we try to see from the inverter-based resource side, where the current being fed to this fault is much smaller compared to the current contributed by the grid side because of the protection or internal control philosophy of the inverter. In that case, Zc would be a value Znk, where Znk is the impedance of the line between node N and the fault point K with apparent impedance Zup. Now, if we talk about this Zup, which is dependent on this ratio, the fault current IF is significantly higher than IN.

$$Z_c = \frac{\overline{V}_n}{\overline{I}_n} = \frac{Z_{nk}\overline{I}_n + \overline{I}_f Z_f}{\overline{I}_n} = Z_{nk} + \frac{\overline{I}_f}{\overline{I}_n} Z_f \simeq Z_{nk} + Z_{app}$$

In fact, it is almost comparable to I.M. The contribution is much, much smaller. So this value would be much larger than 1. And for the inverter-based side, what we see is that there is an additional factor that is much larger than the actual fault impedance, and hence a large impedance of Z-app appears. The issue with this operation is that the distance element present near the inverter-based resource will basically be seeing a fault that has occurred far beyond the actual location because Z app is going to be much larger than ZF. And as a result, the impedance seen by the fault distance element would vary in terms of the current contribution from the inverter-based resources.

So fault distance is difficult to identify, and the relay may even maloperate with the correct settings provided because the relay would be sensing a fault location beyond the actual value. Coming to our other elements, negative sequence direction elements 67Q and 32Q typically indicate the level of unbalance present in the system during faults; ground faults or line-to-line faults tend to have this negative thickness element present in them. So 67Q and 32Q in a way help sense how much unbalance is present in the network during a fault operation. 67Q sort of also helps in detecting the direction of the fault, whether it is an internal fault, a forward fault, an external fault, or a backward fault. Going by the distance element philosophy, 67Q again tends to compare or assess the negative sequence current by comparing the negative sequence voltage and current phasors.

So, typically in a synchronous generator-based setup, 67Q would be able to compare the ratio of voltages and clearly segregate the reverse faults from the forward faults. Typically, the relay that is present on the transmission line should be protecting or operating for forward faults rather than operating for reverse faults because, for reverse faults, there may be another element present dedicated to it. So, basically, that is what we call the reach or set of the relay. So, so far with no inverters present, all looks good; all looks fine from a synchronous generator perspective because we are able to clearly get an assessment of what the negative sequence component present in the network is. In the presence of inverter-based resources, the issue is that inverter-based resources not only limit the current quantum contribution, but they also inhibit or provide a limited number of zero-sequence current or negative-sequence current in the network.

So the level of negative sequence current becomes drastically lower with inverter-based resources; as a result, the sensing of this ratio becomes a tricky affair for the directional element or negative sequence current element, and hence the issue of the negative sequence relay or directional relay not being able to identify the directionality of the fault because of the low quantum of negative sequence injection from the inverter during the fault becomes a difficult aspect. So the overall story is that traditional negative sequence-based directional elements may maloperate during inverter-based resources.

So what are the... Challenges arise from the brief discussion we had about inverter-based resources; the current quantum contribution is very limited, and the fault current angle is also very controlled with respect to the voltage sensed by the relay, indicating a lack of negative and zero sequence components in the inverter-based resources. As a result, our conventional distance directional-based elements may find it difficult to correctly decide whether they should operate or not, and that is where the issue of maloperation comes in. So a possible solution for mitigating these issues with inverter-based resources is to not just depend on conventional Fourier transform-based relay setting evaluation, which we have not discussed, but those of you who are interested may explore topics or courses on power system protection where conventional voltage ratio and current ratio are based on conventional Fourier transform or discrete Fourier transform-based devices. which does not involve certain sequences that are present. So the possibility that researchers across the globe are exploring to mitigate these issues between inverter-based resources is not just to depend on conventional methods but also to expand or look forward to certain signal processing-based methods that can help identify certain good features from the current corresponding voltage and current signals.

Certain machine learning-based methods and, obviously, other methods that are being well researched or talked about. Unfortunately, I cannot discuss these methods at length, but those of you who are interested may please explore them accordingly. The last bit is about protection systems for medium-voltage or low-voltage sub-transmission or distribution systems. where the protection philosophy is mostly based on overcurrent protection. The distance element and directional element are there, but they're not very popular, given that the distance element is an expensive device compared to overcurrent protection.

So, what does overcurrent protection do? It essentially compares the magnitude of the current with respect to a particular threshold. If the current level is not at a particular value, the overcurrent doesn't operate, since during a fault, the current tends to go up. It's expected that during a fault, current would go up, so overcurrent protection tends to operate accordingly. The overcurrent philosophy may also have directional features in it. Typical overcurrent relays, from a design perspective, are inherently non-directional.

So basically, they don't sense what type of current magnitude increase has occurred, whether it's for a reverse fault or a normal fault. In order to make it directional, we have to sense or get an estimate of the ratio of the phase angle between the forward current and the voltage sensed by the relay, which helps in indicating whether the fault is a forward fault or a backward fault. Let's say I have a transmission or distribution line where the overcurrent relay is placed just near the bus, and if I am trying to build the directionality feature into this overcurrent relay, then for a forward fault, if I draw the phasor diagram typically for the Vr, which is the voltage sensed by the relay for a forward fault, assuming it is an inductive system, the current would typically lag by a few degrees of displacement. So, this is for a forward fault; on the other hand, if I have a backward fault which the relay is not supposed to sense, then compared to forward current and backward current, the backward current would definitely be a very reverse current in a negative sense of IF. So the phase angle differences during forward faults and backward faults are significantly different.

By comparing this ratio, which was also discussed in the negative sequence direction element, the overcurrent relay can determine whether it should operate for a forward fault or not. So it basically helps increase the selectivity of the relay. Now, with inverter-based devices or resources present, the fault current contribution from the inverter-based resources does create its own issues. So one such example of relay blinding is shown here. What is shown is that a fault has occurred in this particular section of the fault.

And since inverter-based resources do not contribute much current to the fault, the majority of the fault current contribution is happening from the grid side. So, what would happen is that, pardon me, it might occur that a fault has happened in this particular section because of the electrical distance and the closeness of the fault location to the inverter-based resource. The current contribution of IBR may be higher compared to the physical distance of the grid side from the fault location. So basically, it might happen that IIBR may be less than or may be more than the grid current, and as a result, the relay that is supposed to operate, since it is not sensing much of a change in the fault current contribution from the grid side, is essentially blinded to the fault location, and this is typically going to happen when. The IBR, or the fault point, is much closer to the IBR point; maybe it is a non-serious fault like a single line-to-ground fault where the current difference is not highly different from the normal load current and the grid location is far from the actual fault location.

The other aspect that may occur is the case of false tripping, where a fault has occurred in this particular section of the network; the grid is also contributing to the fault, and the inverter is also contributing to the fault. So, ideally speaking, the relay that should clear out the unhealthy part is the relay marked by this mark enclosed here. The relay present near the inverter-based resource should not operate because the fault has not occurred in its own section. But because of the current contribution to the inverter, this relay may also operate.

And the last part is coordination issues. There are dedicated primary and backup pairs assigned to relays. So if the primary relay doesn't fail to operate, the backup relay should take the opportunity to operate. And this sort of issue also arises because of poor direction in the flow of power or current from the inverter-based resources. So, in a way to sort of summarize, similar to high voltage line protection, low voltage line protection also has similar aspects because of the current contribution from the DGs.

Intermittent power generation may lead to relay coordination issues. So the suggestion still remains the same: in order to cater to these challenges, one has to look for non-conventional methods like machine learning methods, data-driven methods, or feature extraction methods, which can help easily identify. The signatures that come in because of inverter-based resources or distributed generators. So that's all for the fault analysis part. In the next lecture, we will start with our last module, which is stability analysis. To be precise, stability analysis, again in itself, is a very vast and voluminous subject.

We would specifically be talking about one specific stability analysis problem, which we call transient rotor angle stability analysis. The other stability analysis problems we will not discuss. We will understand at length, but in the next lecture, we will just go through the basics and understand the different stability problems that might come up.

Thank you.