ECE 4354- Power System Protection

Effect of Distributed Generation in Power System Protection

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1. INTRODUCTION

The traditional protection system in power systems is designed and implemented with different assumptions and considerations that become affected by the integration of distributed generation. Mainly the addition of the DGs to the power system on transmission or distribution levels or operation in islanded modes changes the fault level and network topologies. Due to the intermittent nature of the DGs, level of infeed and location of DGs, the protection schemes with pre-defined settings can fail to operate properly. For different conditions, there is a need for modified protection scheme. There are some similarities and some distinct effects in distribution, transmission and microgrid protection with the DGs which is discussed in the report. Some suggested solutions to the issues are also discussed. In addition, the IEEE 1547-2018 standards related to islanding, open and short circuit faults are briefly discussed.

Inverter based DGs have the ability to control fault current contribution from DGs thus they have minimal effect on overcurrent protection and coordination strategies for fuse and circuit breakers. The rule of thumb for fault current level of inverters has been around 1.2- 2 times the rated current, however, there have been studies, for instance, from NREL that shows that the fault current for smaller grid-tied inverters that showed fault currents up to 2-4 times rated current for short duration of time (0.06-0.25 cycles)[1]. It can be understood that the conventional overcurrent based protection schemes designed for synchronous machines and induction machines based systems that have a short circuit fault current levels of ~ 6 times rated current and ~ 2-4 times rated current respectively needs to be revised for inverter based DGs connected to the system.

2. Effects of Distributed Generation in Power System Protection

2.1. Effects on distribution system protection

In conventional distribution system, the operation of the system is based on the assumption of unidirectional power flow. This allows the protection system that assumes the unidirectional power flow such that the current flow is always towards the end of the feeder. However, addition of distributed generation (DGs) at different levels in the network violates this assumption and can cause two significant effects. The first effect is that the overall level of fault currents changes due to addition of DGs and the variation is dependent on the position and the size of DG. The second effect is it can change the direction of fault current and cause improper operation of traditional protection devices designed for operation without DGs.

2.1.1. Blinding of protection

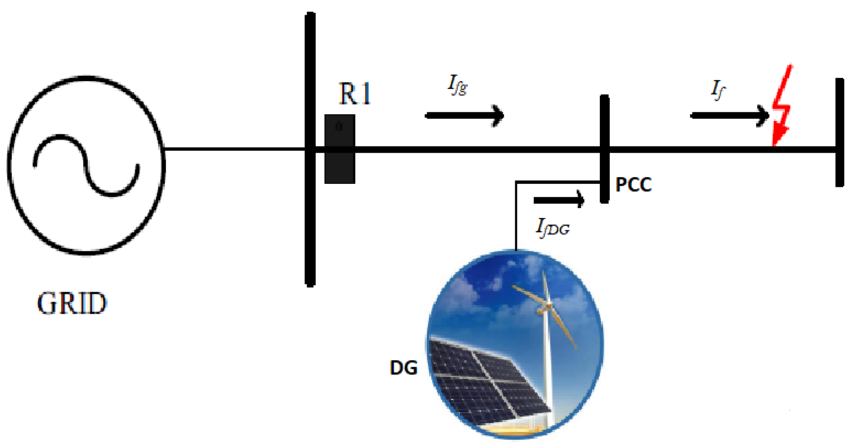

Figure 1: Blinding of protection[2]

As discussed at the beginning of this section, the addition of DGs lead to change in levels of fault current. This variation in current level can affect the protection devices such as overcurrent relays, directional relays and reclosers that operate by detecting the abnormality in the current. Addition of DGs lead to decrease of the fault current contribution from the feeder/ main grid. Thus, the current level seen by the devices is inaccurate and can lead to malfunction due to reduced grid current. This kind of effect on the protection devices is termed as blinding of protection.

Case 1: When R1 is an overcurrent relay

For instance, in figure 1, the addition of DG at the point of common coupling (PCC) leads to decrease of the fault current provided by the grid(I_{fg}), however, the total fault (I_f) current is higher due to the DG current contribution. The reduced grid current might not reach the pickup current of the feeder relay R1 and the relay will not operate, thus R1 is blinded due to the DG current contribution(I_{fDG}).

The reduction in grid current highly depends on the location of the fault with respect to the DG and the feeder. The location of the fault varies the total impedance and can lead to a change in the feeder current that could be drastically different or slightly varying compared to the scenario without the DG. The following explanation summarizes the change in impedance leading to variation in fault current.

For a scenario in figure 1, without the DG connected, the feeder current (I_{fg}) can be calculated as:

$$I_{fg} = \frac{V_{fault}}{\left(Z_{net}+Z_{fault_b}\right)} \qquad (1)$$

Where,

V_{fault} is the pre-fault voltage at the fault point, Z_{net} is the impedance of the feeder up to the PCC, Z_{fault_b} is the total branch impedance from the PCC to the fault including fault impedance.

When the DG is added to the PCC, the thevenin impedance (Z_{th}) for the parallel connection of the grid and the DG is given as:

$$Z_{th} = Z_{fault_b} + \frac{Z_{net}Z_{DG}}{(Z_{net}+Z_{DG})} \qquad (2)$$

Where, Z_{DG} is the impedance of the distributed generator to the PCC.

The modified feeder current, (I_{fgDG}) is given as

$$I_{fgDG} = \left(\frac{V_{fault}}{(Z_{th})}\right)\left(\frac{Z_{DG}}{Z_{DG}+Z_{net}}\right) = \frac{V_{fault}}{\left(Z_{fault_b}+\frac{Z_{net}Z_{fault_b}}{Z_{DG}}+Z_{net}\right)} \qquad (3)$$

When the fault is at the PCC, $Z_{fault_b} \neq 0$, $I_{fgDG}<I_{fg}$

And when $Z_{fault_b} = 0, I_{fgDG} = I_{fg}$

Hence the location of the fault can vary the effect of blinding of protection as the fault current seen by the relay depends on the total impedance.

Case 2: When R1 is a Distance relay:

Distance protection is a zone protection, where protected feeder is divided into three zones. The first zone covers approximately 85% of the line length whereas zone 2 and zone 3 relays cover whole line and provide backup for the subsequent line. Faults in zone 2 and 3 are cleared with a time delay in order to coordinate with the zone 1 relay. For the case with DG infeed, there will be reduced grid contribution. This will raise the apparent impedance seen by the relay R1 and causes protection under reach. Faults normally cleared by zone 1 might have to wait for 0.35s because the apparent impedance increases making it seems like the fault lies in zone 2. This case is the blinding of zone 1 protection.

Without DG, the apparent impedance (Z_{app}) is given as:

$$Z_{app} = \frac{V_1}{I_1} \qquad (4)$$

With DG, the modified apparent impedance(Z_{app}') is given as"

$$Z_{app}' = \frac{V_2}{I_2} \qquad (5)$$

$$I_2 < I_1, \text{ thus } Z'_{app} > Z_{app} \qquad (6)$$

Hence the chances of under reaching of zone protection increases. The severity of under reaching problem is determined by the local short-circuit power, X/R ratio of distribution feeder and size of distributed generator.

2.1.2. False tripping or Sympathetic Tripping

A large scale DG integrated to a distribution system causes bi-directional flow of fault current on some relays. A non-directional over current relay may misoperate by tripping before the tripping of faulty feeder and hence degrading the security of the network. As shown in figure 2, for a fault, the relay R2 may trip in reverse direction because of high reverse current from the DG. This type of tripping is called false tripping or sympathetic tripping. Such trippings in a large interconnected network may result in the isolation of a larger portion of the network.

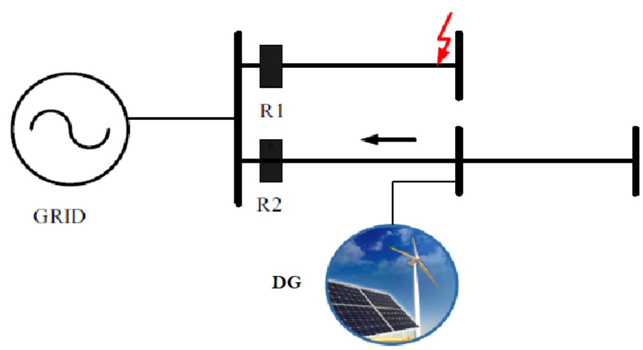

Figure 2: False tripping or sympathetic tripping[2]

The DG has major contribution to the fault current when the generator is large or generator/fault is located near the substation. This kind of tripping is most common in weak grids with long feeder length.

2.1.3. Islanding Problem

From above figure 3, if the infeed from the DG is high enough to issue a tripping signal by relay R2, then it will lead to islanding of DG and its local loads. Generally, DGs are set for constant power generation, there can be power imbalance in the isolated network causing unstable operation.

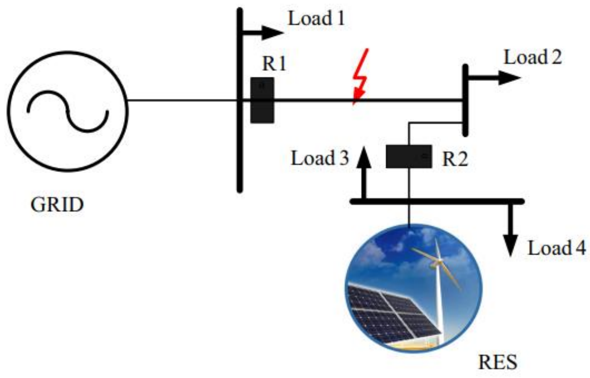

Figure 3:Islanding problem[2]

2.1.4. Recloser problems

Reclosers are commonly used in the protection of the overhead distribution feeders against temporary faults. Also reclosers coordinate with the lateral fuses to provide good selectivity during permanent faults. Integration of DG to the system causes recloser problems such as failure in fault detection and loss of coordination between recloser and fuse.

Fault detection problem

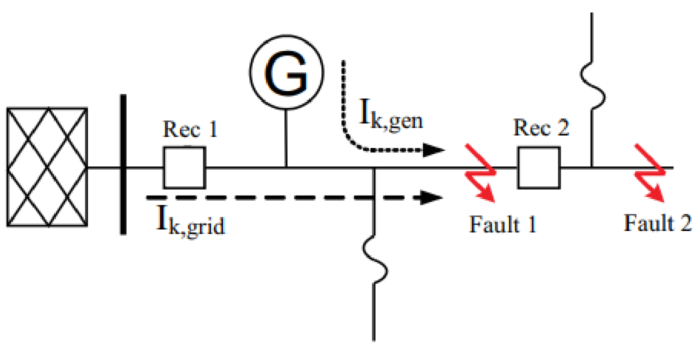

Figure 4: Fault detection problem[3]

For fault 1 in figure 4, the fault current sensed by Rec 1 is $I_{k,grid}$ which is lesser than total short circuit current. This is an example of fault detection problem. For fault 2, the fault current sensed by Rec 2 is $I_{k,total}$ which is larger than the current sensed by Rec 1. Due to this discrepancy, the coordination between reclosers is disordered.

Mis-coordination between recloser and fuse

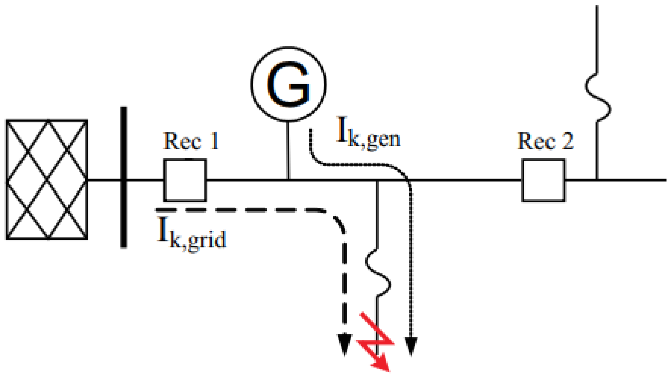

Figure 5: Mis-coordination between recloser and fuse[3]

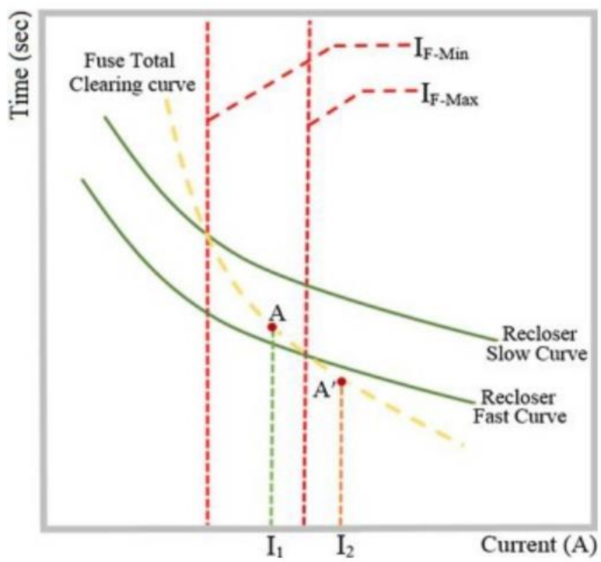

Figure 6: Characteristic curve showing mis-coordination[3]

Figure 6 shows characteristics curves for the fuse and the recloser; $I_{F\text{-}Min}$ and $I_{F\text{-}Max}$ are maximum and minimum feeder fault current. If the fault current lies between min and max limit, recloser and fuse will remain well coordinated. This coordination will be affected according to the level of DG connected. The mis-coordination can occur when the fault current is greater than $I_{F\text{-}Max}$ due to the contribution from DG. This is represented in the figure above by the shift of point A to A'. In this condition, mostly the fuse melts first or both recloser and fuse will operate simultaneously[3].

Autoreclosing problem

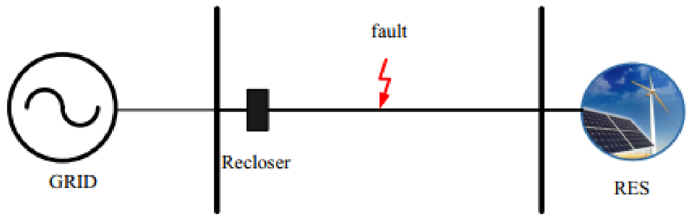

Figure 7: Autorecloser problem[2]

For temporary fault condition, recloser tries to partially clear the fault by disconnecting some part of the network from the main system. This gives time for arc to deionize. However, DG connected systems tends to keep the disconnected feeder part energized and maintains the arc causing temporary fault to be permanent.

2.2. Protection schemes for distribution systems with renewable DGs integration

As discussed till now, the traditional methods of distribution systems protection face problems with the integration of a DGs. In this section, different methods proposed by the literature are discussed.

2.2.1. Point of Common Coupling (PCC) Voltage Based Protection Scheme

$$I_{ref} = \frac{P_{desired}}{V_{pcc}} \quad \text{for } V_{pcc} \geq 0.88 \text{ p.u.} \quad (7)$$

$$I_{ref} = K V_{pcc}^{n} I_{max} \quad \text{for } V_{pcc} < 0.88 \text{ p.u.} \quad (8)$$

Here, voltage is sensed at PCC and utilized via equations 7 & 8 to reduce the fault current contribution of the RES during the fault periods. During fault condition, if the voltage drop at the PCC is less than 0.88 p.u., then the reference converter current is changed using equation 8. This method is simple and works quite well but fails to discriminate between voltage drop due to fault and due to dynamic load changes in the transient periods.

2.2.2. Modifying Protection Scheme

This is a new approach that revises the existing Overcurrent Protection (OCP) scheme of a radial feeder to address the presence of DG. The fuses on the laterals with DGs are removed and replaced with 3 phase reclosers and a relay placed at the interconnection point of the DGs and network feeders. So, during a permanent fault condition, this additional relay will trip and limit contribution from the DGs. However, disconnecting DGs can cause drop in power reliability of the network.

2.2.3. Limiting the DGs capacity

The protection coordination index (PCI) is evaluated from the relation in 9 which is the relationship between changes in the DGs penetration power with respect to change in the coordination time interval (CTI). This can provide information about which location and what DGs capacity can have the less affected coordination margins so that existing protection scheme can be utilized.

$$PCI = \frac{\Delta P}{\Delta CTI} \qquad (9)$$

2.2.4. Using Fault Current Limiters

The main concept here is to block the fault current from the DGs during fault periods so that the original relay settings scheme remains valid even after DGs integration. This can be achieved by placing a series device with DGs called fault current limiter (FCL) as shown in figure 8. FCL must offer low impedance during normal operations and high impedance value during fault.

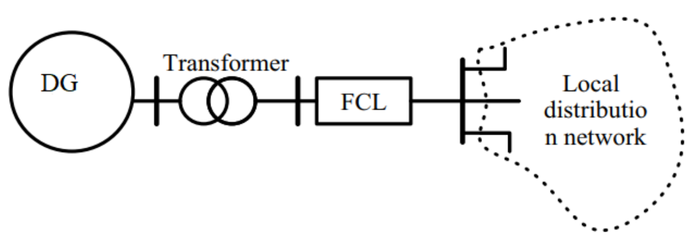

Figure 8: FCL placement[2]

Non-adaptive and adaptive techniques are envisioned for this purpose. In non-adaptive techniques, superconductivity based limiters are intended to improve the switching speed and reduce the loss. However, high cost and big size of DGs are the main drawbacks. Whereas in adaptive protection schemes, the relay settings and characteristics are adapted based on the prevailing condition of the network. Many literatures can be found on adaptive protection schemes based on different algorithms.

2.3. IEEE 1547-2018 standards related to protection with interconnected DGs

2.3.1. Area EPS faults/Short-circuit faults:

When short circuit fault occurs on Area Electric Power System (EPS) the DG should trip unless some other agreement has been done. Since the DGs can desensitize the detection of faults that were detected by area EPS protection systems before adding the DGs so adjustment to the settings of Area EPS protection system or changes to DG's interconnection parameters may be needed that can compensate for DG's fault current contribution for maintaining proper fault detection and coordination.

2.3.2. Open phase conditions:

DGs should disconnect and trip all phases connected during open phase occurring at PCC. It should cease to energize and trip within 2s of the open phase condition.

2.3.3. Islanding

An electric power island is defined as a section of the power system with its own sources and loads so that it can self-power or self-excite. The islands may be intentional or unintentional.

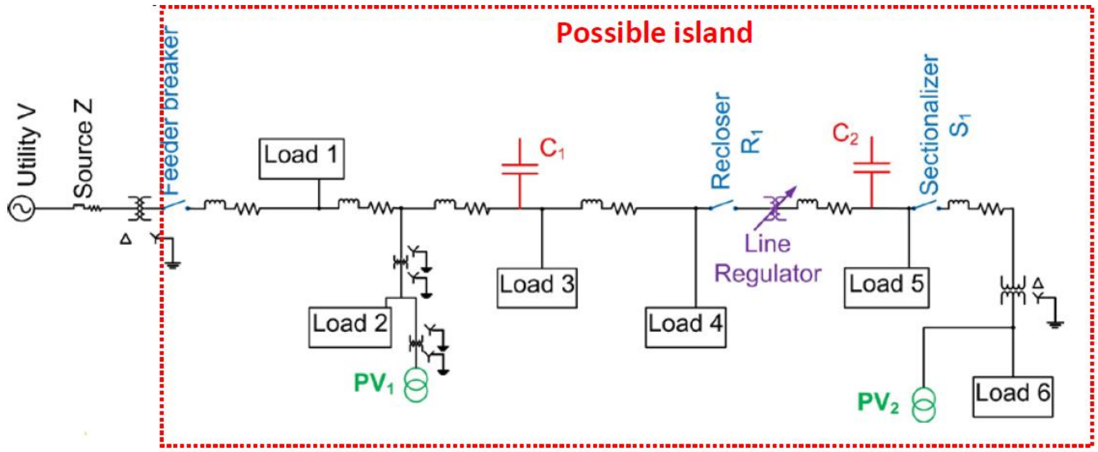

Figure 9: Electric Island

Intentional Island

An electric island that is planned with a defined boundary and voltage and frequency regulation controls. This kind of island can include micro grids, emergency/standby power supply, actual island power supply, remote community grid, military bases and remote resource extraction operations. IEEE 1547-2018 intentional island includes the scope for any intentional island that is a part of the area EPS, its behavior at PCC and impacts on the Area EPS. Anything behind the meter and that doesn't affect the area EPS elements is out-of-scope. The intentional island can leave the grid when conditions that are mutually agreed to by area EPS and DG operators are met; abnormal voltage or frequency trip conditions is met or an unintentional island is detected.

There can be two types of transition to intentional islands:

- Scheduled: initiated by manual action or dispatch
- Unscheduled: automatically initiated due to abnormal Area EPS conditions

Unintentional Island

An electric island that is not planned and doesn't have voltage and frequency regulation control.

The unintentional islands can be formed when there is a close source-sink balance in the island for both real and reactive power and a breaker or recloser has to open without a fault to create an island. The occurrence of both of these events in sequence is very low and unintentional islands are low-likelihood events. However, when they occur they pose numerous risks to the system including damage to the equipment due to unsynchronized reclosing, uncontrolled voltage and frequency. It could also impede service restoration and have potential risk to line worker performing a maintenance.

Distinct changes made in the IEEE 1547-2018 compared to IEEE 1547-2003 with respect to intentional and unintentional islanding is summarized below:

- In Clause 8.1, the default clearing time is 2s but there is a new optional 5s clearing time limit which is allowed provided that there has been a prior mutual agreement between the DG operator and Area EPS operator. Previously, there was a 2s must disconnect clause in IEEE 1547-2003. This additional clearing time allows use of novel islanding detection that may work better in high penetration cases ad require a little more time to achieve sensitivity and selectivity.
- There is an emphasis on the recloser coordination with the Area EPS

2.4. Effects on transmission protection

In the transmission level, bulk integration of wind generation and also increasing large scale integration of solar PV sources affect the existing protection schemes mainly due to intermittent nature of these renewable sources. Different kinds of protection devices including distance protection, overcurrent protection, differential protection and directional pilot protection have been used for transmission line protection. As discussed for the distribution system protection, the distance protection may face overreach and under reach issue during fault when DGs are supplying the fault current in parallel to the feeder. The under each/overreach problem is aggravated as the variation in the generation affects the level of fault current and a setting chosen to accommodate the effect of DG may cause an overreach issue when the DG is not available. Some other factors that affect the distance protection are: type of generators with different short circuit behavior, fault characteristics and nature of faults.

Due to various factors affecting the protection setting dynamic protection schemes are utilized in DG integrated transmission protection such as adaptive distance protection schemes and Artificial Intelligence (AI) based differential protection schemes.

2.5. Protection issues in Microgrids and solutions

Microgrids can operate in off-grid or grid-connected mode depending on the power generation and a couple of other factors including the agreement between the Area EPS and microgrid owners. Some of the main issues for microgrid protection are listed below:

- The fault current level in microgrid is higher when operated in grid connected mode than when it operates in islanded mode which could lead to nuisance tripping of relays.
- The problem of coordination between protection devices and selection of the devices apply to microgrids similarly as for distribution grids. In fact, it may be more complicated owing to the dependence on the topology change during grid connected and islanded modes which will affect the magnitude and directions of the fault currents in the microgrid.

Some of the protection schemes for microgrids can be listed are as shown in the figure below:

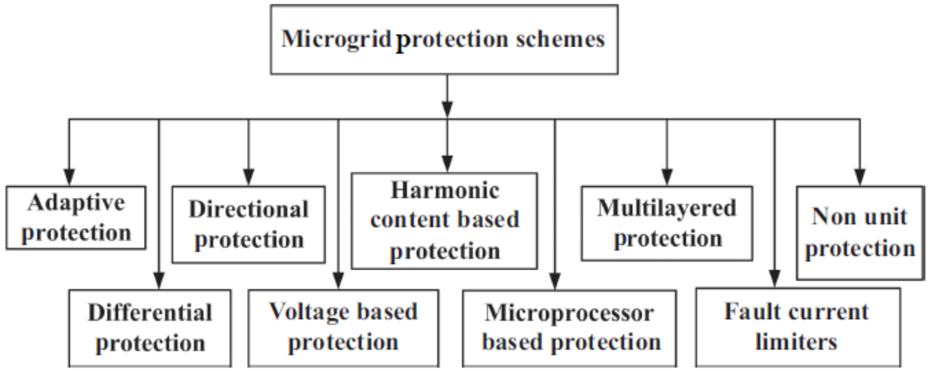

Figure 10:Microgrid protection schemes

In microgrids the fault current limiters are placed at the PCC. The size of fault current limiters depends on the size of DGs and their cost and size can be a constraint for small sized substations. Thus, it may not be applicable for many cases. Time inverse overcurrent relays fails to maintain coordinated operation in microgrid due to limited fault current contribution from weak DGs. Thus voltage controlled protection schemes for over current and over load protection are proposed which is faster than conventional overcurrent relay. Some other techniques such as differential protection schemes using the data to find fault patterns and harmonic content based schemes that detect faults based on total harmonic distortion are also discussed in literature. These schemes work for particular scenario and can fail for others thus, an adaptive protection schemes has a major scope in microgrid protection allowing changing of setting requirement as per the network prevailing conditions[2].

3. CONCLUSION

Protection systems for power system is in need of evolving techniques. The impact of large scale integration of DGs with intermittent nature affect fault current levels, cause bidirectional flow into the system and can result in loss of coordination of the protection devices if integration to the system is increased without addressing the issues that arise leading to malfunction of the system as a whole. Thus, it is becoming increasingly important to study the impact and find suitable schemes that can address this issue and modify existing schemes to keep the power system well-functioning. The solutions for combating the issues that arise in transmission, distribution and microgrids protection with DGs range from modifying the setting of the devices to adaptive protection schemes that update the settings based on the phasor measurements of voltages and current and also artificial intelligence based protection schemes. The most important takeaway is that integration of any distributed generation requires revision of the existing protection to confirm if any modification or upgrade in protection scheme is needed. The necessary modification or addition of protection schemes also needs to be cost justified. Overall, the effect of DGs on power system protection is of diverse nature and may be case specific in some cases, thus requires a comprehensive study to address the impacts it could cause.

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