Effects of Distributed Generation on Overcurrent Relay Coordination and an Adaptive Protection Scheme

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Abstract. Integration of distributed generation (DG) such as renewable energy sources to electrical network becomes more prevalent in recent years. Grid connection of DG has effects on load flow directions, voltage profile, short circuit power and especially protection selectivity. Applying traditional overcurrent protection scheme is inconvenient when system reliability and sustainability are considered. If a fault happens in DG connected network, short circuit contribution of DG, creates additional branch element feeding the fault current; compels to consider directional overcurrent (OC) protection scheme. Protection coordination might get lost for changing working conditions when DG sources are connected. Directional overcurrent relay parameters are determined for downstream and upstream relays when different combinations of DG connected singular or plural, on radial test system. With the help of proposed flow chart, relay parameters are updated and coordination between relays kept sustained for different working conditions in DigSILENT PowerFactory program.

1. Introduction

Distributed generation includes the power plants connected to low or medium voltage network and their output power varies between a few watts to 100 MW. Per module production ranges of commonly used DG sources rates are given as for micro turbines 35 kW-1 MW, wind turbines 200 W-3 MW, photovoltaic panels 20 W-100 kW, biomass 100 kW-20 MW and geothermal 5MW-100 MW [1]. According to power capacity, generator type and connection shape, DG has influences on electrical network. Some advantages appear due to the influences followed as; decrease in transmission and distribution line losses, lowering the pick power demands, and better voltage profile. However some disadvantages arise as; changing power flows directions, voltage rises in condition of low power demand, harmonic-flicker issues and protection problems such as selectivity loss [2]. Grid connected DG sources creates an impact which increases the short circuit level of network depend on its output power, power converter interface and generator electrical parameters. If a fault happens in network, short circuit contribution of DG creates a new branch element feeding the fault current. Radially constructed medium voltage network protection scheme is able to isolate the effect of one source feeding the fault which is actually the network itself. In another words, radial protection scheme cannot isolate the impact of multiple sources fault contribution when fault currents are bidirectional. Therefore existing protection scheme has to be made convenient for directional over current protection. Main and backup protection device settings may require revise for each fault current directions with considering the short circuit contribution of DG sources, in order to reachieve protection selectivity with coordination time interval between the protection devices.

IEEE Standard 1547 is pointed out; if a fault happen in DG connected network, DG sources should be disconnected. In addition to prevent unintentional islanding, DG sources have to disconnect within 2 seconds. For abnormal voltage drop situations, it is defined for the voltage amplitude of 0.5 p.u. (per unit), DG sources have to disconnect within 160 milliseconds [3].

Literature review shows that the main topic is utilization of adaptive relay. Typical relay protection will response due to predetermined protection curve characteristic but adaptive relaying is capable of determining relay response character for changing working conditions prevailing on network. This approach consist of a software determines the relay functions, communication featured relays and a control centre which commands remotely [4]. Adaptive relay concept is used in [5], [6] and [7]. In some studies; adaptive relay protection focus on grid connected DG or islanded working conditions scenarios which are generally uses communication between relays or breakers. Utilization of communication systems causes the high costs so in some studies authors interested in communication less or partially communication used solutions that are generally uses local measurement devices or switching positions of breakers [8]. Considering the working conditions prevailing on system, optimal adaptive relay settings are determined by using the algorithms as fuzzy inference module, neural network learning module [9] or symbiotic organism search optimization technique [10].

In addition to adaptive relaying, short circuit limiter is applied to limit growing fault currents due to presence of DG sources [11-12]. It consists of superconductive element and resistive shunt element which are installed at beginning or end of the line. When the measured current amplitude is over the determined critical value, it changes the operation mode to high resistive shunt element with the help of growing magnetic field or an external source and let the fault current flow over the resistance. In this study, negative effects of DG connections on OC protection is mentioned in Section 2, multiple source radial network protection scheme is given in Section 3, analysis and simulation studies are carried out in Section 4, conclusions and further work are given in Section 5 and Section 6. In a DG connected radial test system directional overcurrent relay parameters are determined for downstream and upstream relays when different combinations of DG connected as singular or plural, proper relay parameters may require update by means of adaptive relay protection.

2. Effects of distributed generation on overcurrent protection

2.1. Changing short circuit power and fault level

Generally large amount of the DG sources comprise rotating machines. With the impact of DG connections, thevenin impedance of the network decreases [13]. Thus, short circuit level and fault current magnitude will increase with presence of the DG machines in parallel. Fault currents are much higher than load currents so it is the basic tripping circumstance for the OC relays to discriminate the measured current magnitude easily. In condition of asymmetrical faults, fault contribution of DG sources is slightly different because of the transformer vector group and the generator grounding connection [14-15]. Growing short circuit currents due to DG connections have negative impacts on OC relays as listed below:

- Bidirectional fault currents require more than one switching operation to isolate the faulted part.
- Directional OC relay utilization requires new protection and switching devices.

- Some DG sources may have restricted short circuit contribution to protect their power electronic parts [16]. The restricted fault contribution flowing over the high impedance line makes relay level detection harder when fault contributions are measured near load currents.
- Changing fault currents may cause blinding of protection or false tripping [17].

2.2. Short circuit behavior and fault contribution of various DG generators

Generally, synchronous and asynchronous machines are modelled with voltage source and reactance, in short circuit calculations and fault behaviour depends on subtransient and transient reactance with its time constants. However, DG sources are generally connected via power converters so the fault behaviour depends on converter controller and its temperature endurance or design parameters [16]. In some short circuit cases, fault currents might be evaluated as normal operating conditions when restricted fault contribution and high impedance lines considered. Table 1 shows the short circuit contribution of DG sources as percentage of its nominal current [1]. The values given in the table is calculated for the faults at the output terminals of the sources. The more the faulted point moves away from generator terminals, fault contribution of DG decreases immediately.

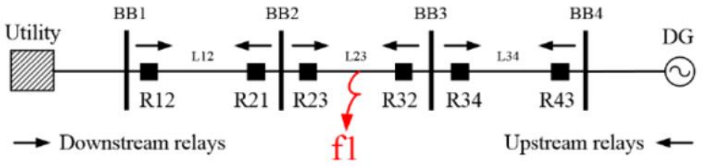
Table 1. Fault current contribution for various generator types [1].

Generator Type	Fault current at generator terminals, percentage of rated output current
Inverter interface	100-400
Seperately excited Synchronous generator	First few cycles: 100-500 Permanent: 200-400
Induction generator or self excited Synchronous generator	First few cycles: 500-1000 Permanent: approximately 0

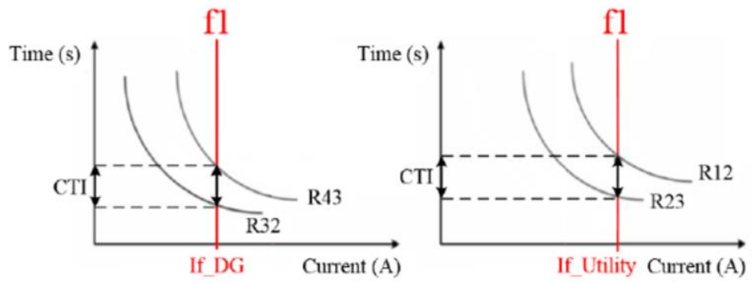
3. Overcurrent relay parameters in radial network with multiple sources

OC relay trip settings are determined with “pickup current (Ip)” and “time delay” parameters. Pickup current is the threshold current value and it is sensed with current level detection principle which has to be exceeded for relay trip. There are two approaches applied in common to determine the pickup current. First approach specifies pick up value as two times of maximum load current or it should be equal 1/3 times of minimum fault current at the nearest busbar [4]. Second approach suggests that it should be chosen between 1.25 times of maximum load current and 2/3 times of minimum fault current [18]. Time delay settings are defined depend on definite time and inverse time characteristics. Definite time characteristic has a smooth time delay for changing fault currents which are measured over the pickup value. On the other hand, inverse time characteristic has different time delays value for changing fault currents over the pickup value. Time delay setting is specified by “time multiplier settings (TMS) for inverse time relays.

Multiple sources radial network OC protection scheme is generally provided with directional OC relay (67) function [4]. Relays with the directional element can produce trip signal only for one direction of fault current. Figure 1, illustrates working scheme of directional OC relay on the simple test system. Figure 1(a) represents the downstream relays as R12, R23 and R34 and upstream relays as R21, R32 and R43. Downstream relays have coordination between each other and they can only trip for the fault contribution comes from utility side. Likewise, upstream relays have coordination between each other and they can only trip for the fault contribution comes from DG side. As seen in Figure 1, if a 3-phase f1 fault happens at the middle of L23 line, R12, R23, R32 and R43 relays will sense the fault currents. R21 and R34 relays cannot see the fault because they are looking different directions which are contrary to fault currents. Figure 1(b) shows the main and backup relays for the fault at L23 line. R23 is assigned as main protection relay and should trip first. If R23 do not isolate downstream fault current, backup relay R12 has to trip with a sufficient time delay which is called coordination time interval (CTI). This value is usually between 0.2-0.5s [19]. Similarly, R32 relay is assigned as main protection relay and its backup relay is R43 for the upstream fault current. If there are DG connections at BB2 and BB3 as shown in Figure 2, traditional radial protection scheme will result in curve intersections which are undesirable. Thus, it is common using instantaneous elements of OC relays to prevent such situations.



(a) Multiple sources radial network



(b) Upstream and donwstream relay selectivity for f1 fault

Figure 1. Multiple sources radial network OC protection scheme

4. Analysis and simulation studies

Analysis and simulation studies are carried out in 4 busbars radial test system given in Figure 2 [20]. Electrical parameters of the system given in Table 2. DG sources are connected to busbars named BB2, BB3, BB4 and short circuit contributions of the sources are modelled considering generator type as inverter interface similarly given in Table 1. Each source has minimum short circuit contribution as twice of its nominal current and maximum fault contribution as three times of nominal current of a DG source. Directional OC relays are used for the protection coordination therefore downstream relays are R12, R23, R34 and upstream relays are R21, R32, R43. Relay R12 and R21 have 300/5 A and the other relays have 200/5 current transformer ratio.

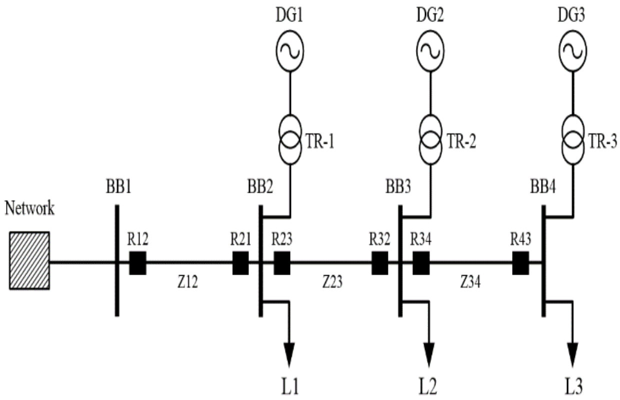


Figure 2. Radial test system with DG sources [20]

Table 2. Electrical parameters of test system [20].

Network	U	11 kV (phase to phase)
	S_k''	30.4841 MVA
	I_k''	1.6 kA
	x_o/x_1	1.2
Lines $Z_{12}=Z_{23}=Z_{34}$	Z_1	0.585+j2.9217 Ω
	Z_0	0.877+j4.382 Ω
	Z_0/Z_1	1.50
Transformers $Uk_1=Uk_2=Uk_3$	S	1 MVA
	U_1/U_2	11/0.4 kV
	U_k%	3.00
	U_{k0}%	3.30
Loads L1=L2=L3	S	1 MVA 0.8 (end.)
DG Sources DG1=DG2=DG3	S	1.111 MVA
	S_{kk}*	2.2 MVA

4.1. Scenario I

In this study case, all DG sources are connected. Before determining the relay parameters, it is necessary to look at minimum and maximum short circuit currents besides load currents at busbars. Minimum fault currents are calculated with 2-phase faults and maximum fault currents are calculated with 3-phase faults at the busbars. With the help of the calculated fault and load currents, downstream and upstream relay parameters are specified in Table 3 using the second approach mentioned in section 2.

Table 3. Relay parameters for scenario I.

Relay Parameters	Downstream Relays			Upstream Relays		
	R12	R23	R34	R43	R32	R21
Pickup current Ip (A)	4	4.25	2.5	1.55	2.75	2.92
Time multiplier settings	0.083	0.062	0.025	0.063	0.042	0.015

In order to make it clear how the relay parameters are set, downstream relay R34 settings will be explained. Each of the loads are given 1 MVA so it corresponds 52 A of current. Minimum fault current for R34 is calculated via 2-phase fault at BB4 without DG connections on test system as 427 A. Likewise, maximum fault current is calculated with 3-phase fault at BB4 as 582 A. Lower limit of the pickup current is calculated as 1.5 times of load current and higher limit of pickup current is calculated 2/3 times of minimum fault current respectively. Between the upper and lower values, pickup current of relay R34 is 100 A selected which corresponds 2.5 A when CT conversion considered. TMS value should be set as low as possible for the relay at far end so in this case TMS value is set 0.025 for R34 relay. Using the formula of IEC standard inverse curves, given in (1), (I_f represents maximum fault current and I_p is pickup current) with the parameters explained above, R34 pickup time is calculated 98 ms for the 3-phase fault at BB4.

$$t(s) = TMS \cdot \frac{0.14}{\left(\frac{I_f}{I_p}\right)^{0.02} - 1} \tag{1}$$

In case of R34 relay malfunction for fault at busbar BB4, R23 relay provide backup with a sufficient time delay of 300 ms. R23 will experience 503 A when fault occurs at BB4 so using (2) given below,

$$TMS_{R23} = \frac{(0.098+0.3)s}{\left(\frac{0.14}{\left(\frac{503}{170}\right)^{0.02}-1}\right)} \tag{2}$$

TMS value of R23 relay calculated as 0.062. By using the calculated TMS, pick up current and maximum fault current values of R23 relay from (1), tripping time for the fault at BB3 is obtained as 0.306 s. Same procedure is followed for the relay R12. This approach is applied for the upstream relays with some adaptations. It will be explained with the R21 relay parameters. When all DG sources online, R21 will measure the load current as the difference between the DG generation and load consumption of the whole system so it is hard to say exact value due to the changes of load and generation. Therefore it would be better look at the past load profile which illustrates the generation and consumption variation more precise. In our case, pickup currents of upstream relays will be selected near its higher limit value which corresponds 2/3 times of minimum fault current. Minimum fault current seen by R21 relay is the lowest fault contributions of three DG sources and it is calculated with 2-phase fault at BB1 as 263 A. Upper limit of the R12 pickup current should be 2/3 times minimum fault current which is calculated as 175 A. When considering the pickup current of R21, it would be better choosing it near the maximum fault current as 170 A due to the uncertainty of upstream load currents. TMS values are selected starting from 0.015 for the upstream relays. Using (1), R21 trip time for the 3-phase fault at BB1 calculated as 152 ms. If R21 relay has malfunction to clear the fault at BB1, R32 relay trip at 452 ms with the addition of CTI as 300 ms. When fault happens in BB1, R21 and R32 relays see different fault currents because of the presence of DG1 source so R32 pickup current should be set considering the DG1 fault contribution. However R21 measures 263 A for the 2-phase fault at BB1, R32 relay measures 165 A. Therefore R32 pickup current is calculated as 2/3 times of 165 A which is equal 110 A. When R32 provides backup for R21 relay, it measures 210 A for the 3-phase fault at BB1 so TMS value of R32 relay is calculated using (2) as 0.042. R32 relay measures its maximum current as 260 A and minimum current as 194 A for the 3-phase and 2-phase faults at BB2 respectively. Using the equation (1) with R32 relay trip time calculated as 339 ms. Same procedure is followed for R43 to calculate tripping times or TMS value. In order to prevent curve intersection to a certain degree, R21 R32 and R43 relays will use instantaneous elements with the pickup currents given; 415 A 300 A and 150 A respectively for the primary side of CT with 100 ms time delay. These values are determined as simulating the 3-phase fault near the upstream relays.

4.2. Scenario II

This scenario focuses on making a different approach for upstream relays so downstream relay parameters will stay same. Alternately, for the upstream relays, definite time curve characteristic can be used. Maximum load current can be measured flowing to utility side only if the loads are neglected. Upstream relays will experience the minimum fault currents in condition of 2-phase fault at BB1. In this case, coordination time interval is 200 ms specified. By using the information mentioned above, Table 4 shows the parameters for R21, R32 and R34 relays when all DG sources are connected to network. Pick up currents are selected as 1.2 times of load currents.

Table 4. Relay parameters for scenario II.

Relay Parameters	Upstream Relays		
	R43	R32	R21
Pickup current Ip(A)	1.56	3.12	3.12
Pickup time t(s)	0.6	0.4	0.2

Both scenarios prove that inverse or definite time curves can be used for the protection schemes when all DG sources connected radial network. On the other hand analyses indicate that coordination between the upstream relays might get lost according to connection combination of DG sources such as singular, dual groups, so relay coordination is kept sustained with updating upstream relay parameters.

4.3. Proposed algorithm for updating upstream relay parameters

A flow chart diagram is proposed in Figure 3. This diagram allows updating upstream relay parameters based on monitoring the network at upstream relay locations and common coupling points of DG sources. When there is a change in prevailing system condition such as connection or disconnection of DG sources or local loads, flow chart will update the upstream relay parameters. In the beginning, it is necessary to calculate load flow and short circuit analysis for the prevailing system conditions. At the upstream relay points; power flow direction may vary depend on consumption and DG productions in the system so each of the upstream relay should sense the magnitude and power flow directions wherever its location. If power flows to utility side (upstream), relay measures positive current magnitude. If upstream relay measures negative currents, it means that power flows to downstream or the local loads. “i” is an identifier for the 3 upstream relays. When “i” value is equal to 1, algorithm is calculating the parameter of R21 relay which is the far end upstream relay. If the measured current through the R21 relay is higher than zero for the certain working condition, pickup currents will be updated based on load flow analysis, as 1.2 times of maximum load current towards to utility side. If the measured current is negative, pickup current will be set to 2/3 times of minimum fault current, which is calculated in fault analysis for the R21 relay. For this case, it is essential to know which DG sources are grid connected and ready to contribute any fault events might happen so algorithm needs to monitor injected DG source currents to detect active current sources for both load flow and fault analyses. After choosing the pickup current (Ip) of R21 relay, tripping time can be calculated with the determined TMS value and stored fault currents calculated at BB1. Lowest TMS value for the upstream relay is given 0.015 for the far end relay R21. B(i,i) busbar fault current includes maximum and minimum short circuit currents calculated at busbar named BB1 for the relay R21 when “i” equals to 1. Then using the known values of CTI and R21 relay trip time, TMS value of relay R32 is calculated and stored for the next iteration of “i” value. Relay identifier is set its new value with an increment. Same procedure is followed for the R32 relay for choosing its pickup current. When calculating the trip time of R32, stored TMS value is used from the previous iteration. R43 relay will backup R32 relay so its TMS value is calculated and stored for the next iteration with a sufficient time delay. By using the proposed flow chart above in Digsilent Programing Language (DPL) script, relay coordination is tested in some different working conditions of the test system. Results are given in Table 5. Scenarios includes the working conditions which relays are able to sense both negative and positive currents. Load flow directions is varied depend on changing load scales and connecting different combinations of DG sources. Three phase fault events are simulated at the busbars for testing relay coordination. Each row shows the tripping time of relays for a 3-phase faulted busbar. For example, in scenario 1, for the case of faulted busbar is BB2, R12 and R32 relays will trip in 431 ms and 342 ms respectively. If R32 relay malfunctions, R43 backup relay will trip in 642 ms. In scenario 3, upstream R43 relay senses load flows to utility side so its pickup current is set based on upstream maximum load current. On the other hand, R32 and R21 relays sense downstream load flow directions so their pickup currents selected based on minimum fault current of DG source. However, there is a difference in way of selecting pickup currents, time grading margin is still satisfactory. Scenario 4 and 5 also diversify the load flow directions for each upstream relay. Coordination time interval is nearly 300 ms for the upstream relays so the algorithm determines the optimal parameters.

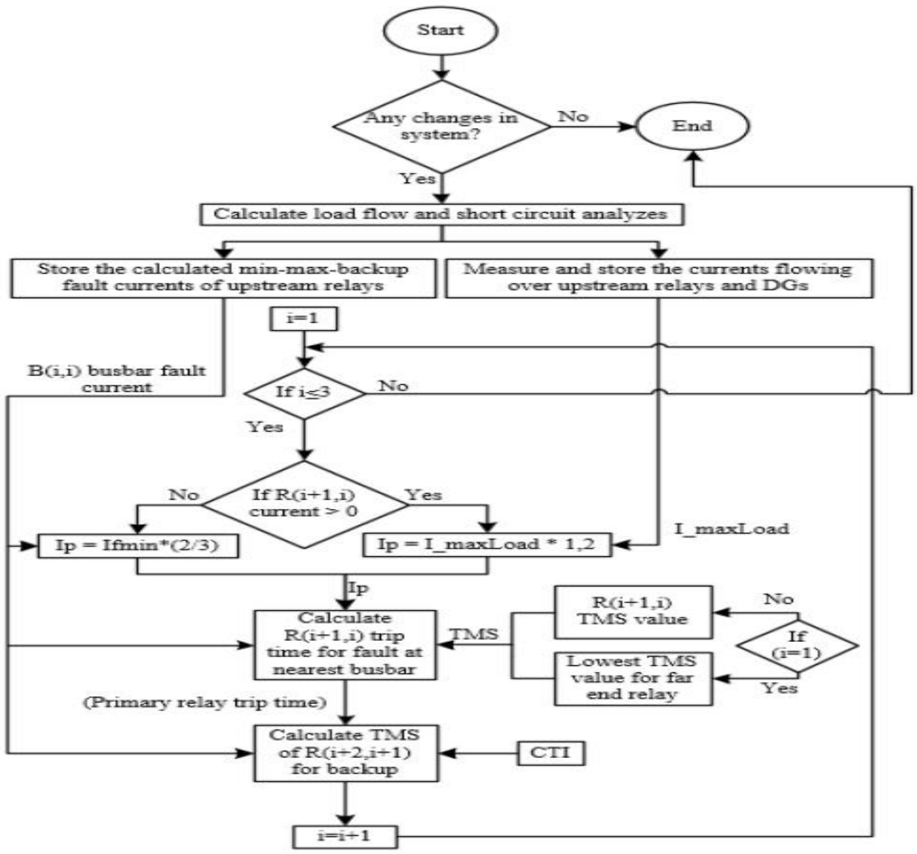


Figure 3. Proposed flow chart updating upstream relay parameters

Downstream relay trip times are slightly changed between the prevailing working conditions but time grading is in the acceptable range for the relay pairs although their relay parameters are constant. This algorithm could also be applied for the downstream relays but relay operating times are in the acceptable range as seen in Table 5.

Table 5. Relay trip times with proposed algorithm.

Scenarios	3-phase fault location	Relay Trip Time (s)					
		Downstream Relays			Upstream Relays		
		R12	R23	R34	R21	R32	R43
Scenario 1 (Inverse time Upstream Relays) Load scale 100%	BB1	-	-	-	0.160	0.460	0.944
	BB2	0.431	-	-	-	0.342	0.642
	BB3	0.625	0.308	-	-	-	0.517
	BB4	0.971	0.410	0.096	-	-	-

Scenarios	3-phase fault location	Relay Trip Time (s)					
		Downstream Relays			Upstream Relays		
		R12	R23	R34	R21	R32	R43
Scenario 2 (Definite time Upstream Relays) Load scale 100%	BB1	-	-	-	0.2	0.4	0.6
	BB2	0.431	-	-	-	0.4	0.6
	BB3	0.625	0.308	-	-	-	0.6
	BB4	0.971	0.410	0.096	-	-	-
Scenario 3 Only DG3 connected Load scale 90%	BB1	-	-	-	0.291	0.591	0.897
	BB2	0.431	-	-	-	0.508	0.808
	BB3	0.591	0.334	-	-	-	0.727
	BB4	0.797	0.421	0.111	-	-	-
Scenario 4 Only DG2 connected Load scale 40%	BB1	-	-	-	0.240	0.540	-
	BB2	0.431	-	-	-	0.477	-
	BB3	0.592	0.333	-	-	-	-
	BB4	0.878	0.443	0.99	-	-	-
Scenario 5 DG1 and DG3 connected Load scale 70%	BB1	-	-	-	0.170	0.470	0.815
	BB2	0.431	-	-	-	0.349	0.649
	BB3	0.625	0.307	-	-	-	0.587
	BB4	0.901	0.388	0.105	-	-	-

5. Conclusion

In this study, such issues are investigated as; negative effects of DG sources on OC protection, DG fault contributions, regaining the lost relay coordination due to changing working conditions. Directional OC relay protection is applied to a radial test system with DG sources. Analysis show that upstream relay coordination might get lost due to connection variants of DG sources, because upstream relay coordination is suffered from changing fault contribution of DG sources. Therefore, a flow chart diagram is proposed to update upstream relay parameters, monitoring the system at upstream relay points and common coupling point of DG sources whether they are grid connected or not. Consequently, directional OC relay coordination is achieved for changing working conditions.

6. Further work

It seems that directional OC relays will continue to be used due to their simplicity and reliability. Future developments such as remote control capability, communication featured relays and network monitoring or scada systems will also favour the use of adaptive relay protection. This study focuses on protecting the DG connected system with adaptive relay parameters only for the upstream relays due to the prevailing working condition. Downstream relays may also require parameter update depending on DG fault contribution for the different test systems. Further studies will repeat the analysis process for earth fault protection and meshed distribution network.

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