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Adaptive Protection Scheme in Distribution Networks Considering Intermittency of DG Using Fuzzy Logic Controller

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ABSTRACT

Integration of renewable energy-based distributed generations (DGs) in power systems has become an active research area for the last few decades due to various economic, environmental, and political factors. The integration of DGs brings several challenges even if it offers many advantages. The loss of coordination between primary and backup relays is one of the disadvantages of integrating DGs, since traditional relay settings may fail or work incorrectly under new conditions. Thus, new protection schemes able to maintain protection coordination are strongly needed in distribution networks with a significant integration of DGs. The adaptive protection schemes are likely to have widespread and being used in the current and future complex structure of distribution systems in the presence of renewable energy-based DG penetration. In these networks, the fault levels are intermittent and continuously changing as per connection of DG in the network. In this paper, Adaptive protection scheme in distribution networks considering intermittency of DG using a Fuzzy Logic Controller was proposed. The controller chooses the best Time Multiplier Setting (TMS) of the relay depending on the size of the DG connected.

Keywords Adaptive Protection, Distribution Networks, Distributed Generation, Fuzzy Logic

I. INTRODUCTION

Currently, distribution systems are in a significant transition phase where the system is shifting from a passive distribution system with unidirectional power flow to an active distribution network with bidirectional flow and small-scale generators called Distributed Generators (DGs). Future power systems are encouraged by the necessity to diminish the impact of global climate change and lower the concentration of greenhouse gases in the atmosphere. [1].

Distributed Generation (DG) can be defined as “small-scale generating units located close to the loads that are being served” [2]. It is possible to classify DG technologies into two broad categories: non-renewable and renewable energy sources. The former comprises reciprocating engines, combustion gas turbines, micro-turbines, fuel cells, and micro Combined Heat and Power (CHP) plants. The latter includes biomass, wind, solar PV, geothermal and tide power plants [2]. Many terminologies are used to refer this new type of generation such as embedded generation, distributed generation, and distributed energy resources [3].

Augmentation of distributed energy resources (DER) are motivated by economical, environmental, technical and political factors. There is an increasing interest in the penetration levels of DGs specifically of renewable energy based technologies like wind turbines and photovoltaics. Given the suitability of business, regulatory and policy landscape, decreasing technology prices, It is expected that penetration levels of DGs will continue to increase [4].

When DGs are integrated into existing systems, they can offer numerous advantages. These include: increasing network reliability, reduction of line congestion, transmission loss reduction, generation cost reduction, postponement of investments in network expansion, and lowering capital investment costs [5],[6],[7]. Apart from these advantages, integrating DGs in the network can result in different problems such as: increase in short circuit level, bidirectional power flow, need for new protection techniques, and voltage fluctuation [7]. Increase in short circuit level and bidirectional power flow affect the protective relays because they are not designed to operate under these new conditions. Some of the consequences are like false tripping, under or over reach of relays, and loss of coordination between primary and backup relays [8],[9],[10].

Various researchers have proposed different solutions to mitigate the negative impact of penetrating DGs on sub transmission and distribution networks protection. These solutions include the following:

- ❖ Disconnecting the DGs immediately after fault detection [11]
- ❖ Limiting the capacity of installed DGs [12][13]
- ❖ Modifying the protection system by installing more protective devices [14]
- ❖ Installing the fault current limiters (FCLs) to preserve or restore the original relay settings [15][16][17][18]
- ❖ Employing fault ride through control strategy of inverter based DGs [19][20]

- ❖ Controlling the fault current by solid-state-switch-based field discharge circuit for synchronous DGs [21]
- ❖ Adaptive protection schemes (APS) [22][23][24]

Even though these approaches can sufficiently mitigate the negative impacts of penetrating DGs on the way protective relays perform, they can have various limitations as well. Disconnecting large DGs immediately after fault detection may lead to severe voltage sags as the contribution of reactive power from DGs will be cut off. Moreover, most faults are temporary, thus disconnecting the DGs is not economically beneficial since the DGs will need to be reconnected to the network after the clearance of temporal fault in order to profit from the renewable energy. Also, stability problem may occur if there were high penetrations of DGs in the network.

Limiting the DGs capacity is a provisional solution, since renewable energy is cheap, it should be fully exploited to gain more profit and also to avoid excess CO_2 emission mostly generated from conventional power plants. Modifying the protection scheme by installing extra protective devices like circuit breakers for sectionalization, reconfiguration of networks or change of protection principles is costly, and also the use of numerous protection principles in a certain area of the power system may lead to more complicated protection coordination scenario and difficult post-event analysis.

Both the fault ride-through control strategy of inverter based DGs and control of fault current by solid-state-switch-based field discharge circuit for synchronous DGs are low-cost solution compared to the previous ones. The first consists of a commutation control strategy of the inverter switches in order to limit the fault current contribution. The second consists of installing a solid-state-switch-based field discharge circuit for synchronous DGs in order to drain the excess fault currents. However, both are only partial solutions to the problem since the first solution is only applicable to inverter-based DGs and the second only to synchronous DGs. These shortcomings lead to another alternative called Adaptive Protection Scheme. The exceptionally good aspect of this protection scheme is that it can monitor the network and immediately update the relay settings according to the variations that occur in the network.

Introduction of microprocessor-based protective devices, Intelligent Electronic Devices (IEDs) and communication systems stimulated this very important aspect of adaptive relaying. The adaptive protection schemes are likely to have widespread and being used in the current and future complex structure of distribution systems in the presence of renewable energy-based DG penetration. In these networks, the fault levels are intermittent and continuously changing as per connection of Distributed Energy Resources (DER) in the network. Considering this intermittency of DGs, fuzzy logic systems are advantageous because they allow a larger solution space and find applications in areas that derive inferences from uncertain, undefined data. In this paper, Adaptive protection scheme in distribution networks considering variability of DG using a Fuzzy Logic Controller was proposed. The controller chooses the best Time Multiplier Setting (TMS) of the relay depending on the size of the DG connected. This scheme keeps the network well protected and well coordinated even after connecting the DG.

II. METHODOLOGY

II.I. Modelling of traditional protection coordination in radial distribution network

The electrical power system may be subjected to many types of faults during its operation that can damage the equipment connected to this system. Hence, there is a great need for designing a reliable protective system. In order to obtain such reliability, there should be a backup protection in case of any failure in the primary protection. The backup protection should operate if the primary fails to take the appropriate action. This means it should operate after a certain time delay known as coordination time interval (CTI), giving the chance for the primary protection to operate first. The above mentioned scenario leads to the formulation of the protective relay coordination. It consists of selecting a suitable setting of each relay so that their fundamental protective functions are met under the required attributes of protective relaying, which are sensitivity, selectivity, reliability, and speed [25].

Commonly, distribution networks are designed in a radial configuration with only one source and single power flow. Their protection is simple and it is usually implemented using fuses, reclosers and overcurrent relays. When the fault occurs in a system, it is sensed by both primary and backup protection. If the relays are coordinated, the primary relay will be the first to operate when fault occurs, as its operating time is less than that of the backup relay. In order to verify the system protection is well coordinated, the performance of all protection devices in the fault current path between the sources and the fault point should be verified. These sources are the substation or feeder and the DGs. The main aspect of the protection coordination of a system is that the primary protecting device, closer to the fault point, should operate before the backup device [26].

To model the traditional protection coordination, 3-phase fault was created in the network and the fault current was found. Then, the operating time for the primary and the backup relays were obtained based on the inverse characteristic of the relay. The IEC standard inverse characteristic equation of overcurrent relay (1) was used.

$$t_i = \frac{0.14 * TMS}{\left[\frac{I_f}{i_{pickup}}\right]^{0.02} - 1} \qquad (1)$$

Where:

TMS is the time multiplier setting of the relay

I_f is the fault current seen by the relay

I_{pickup} is the pickup current of the relay

Figure 1 shows the 13-bus radial distribution network used in this study. It is a modified IEEE 13 bus radial distribution feeder adopted from [27]. This network was modelled using ETAP software. It is an 11 KV Distribution network connected to the utility of 110 KV, through a 110/11 KV transformer. Table 1 indicates the load data on the buses of the network used. These data are the active and reactive powers, while Table 2 shows the impedance data of the lines connecting buses, which are the resistance and reactance for each line.

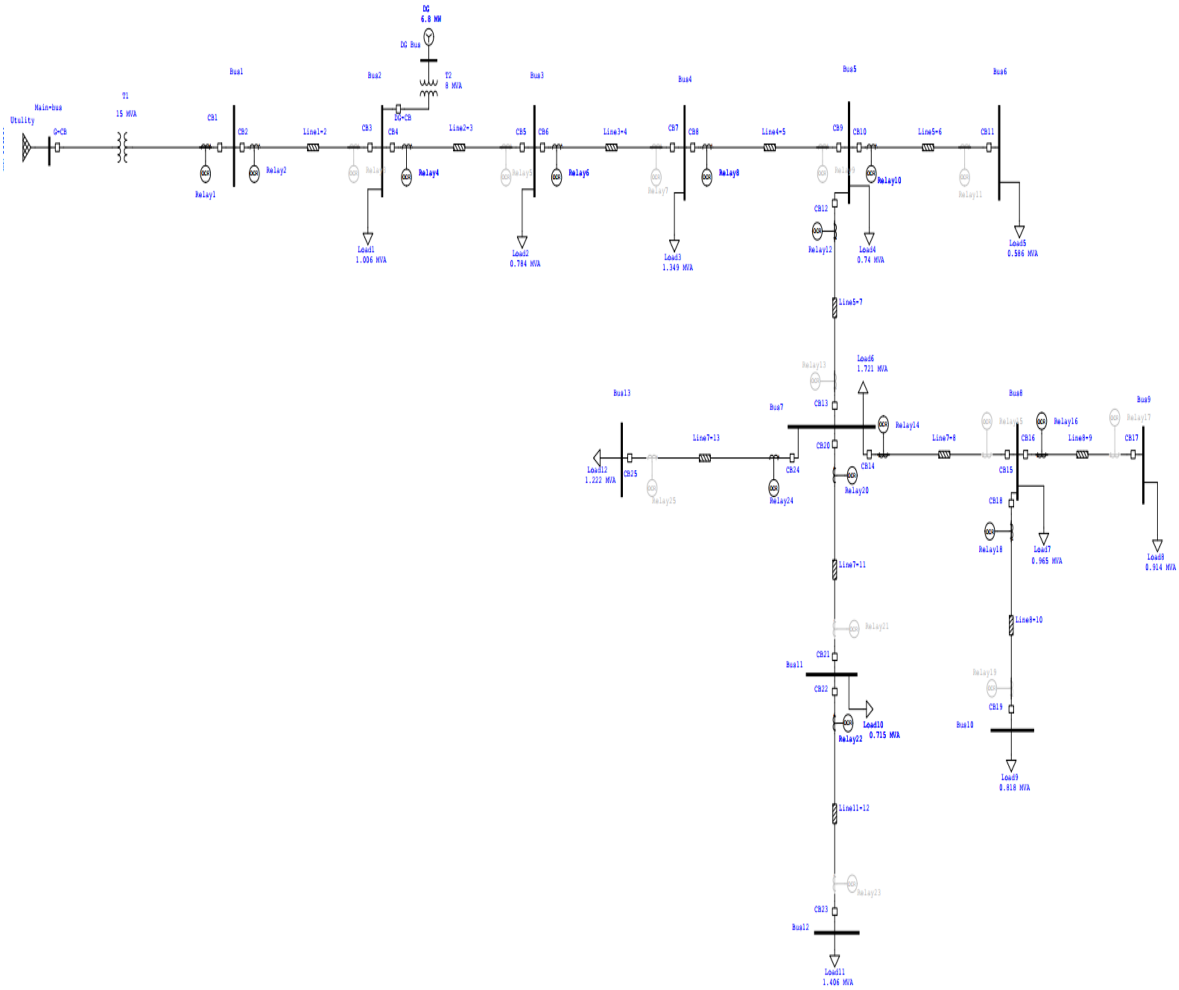

Figure 1: 13 Bus distribution networks used

II.II. Investigating the impact of integrating DGs on Protection Coordination

To investigate the impact of integrating DG in distribution network, Three-phase fault was generated on different bus-bars in the distribution system, with and without DG. For the distribution network without DG, the fault currents and operating time of the relay were recorded. The DG was then connected on the distribution network at a given bus, and the fault current were recorded by specifying the contributed current from the main feeder, and from the DG. These values were used to analyze the impact of penetrating DG has on the fault current magnitude and direction, and on protection coordination that was already set.

Table 1*:* Load data on the buses

No.bus	P(Kw)	Q(Kwr)
1	0	0
2	890	468
3	628	470
4	1112	764
5	636	378
6	474	344
7	1342	1078
8	920	292
9	766	498
10	662	480
11	690	186
12	1292	554
13	1124	480

Table 2: Impedence Data on the lines

From bus	To bus	R(ohm)	X(ohm)
1	2	0.176	0.138
2	3	0.176	0.138
3	4	0.045	0.035
4	5	0.089	0.069
5	6	0.045	0.035
5	7	0.116	0.091
7	8	0.073	0.073
8	9	0.074	0.058
8	10	0.093	0.093
7	11	0.063	0.05
11	12	0.068	0.053
7	13	0.062	0.053

II.III. Application of Adaptive protection scheme

The approach proposed in this paper based on the adaptive setting method is an on-line activity that changes the Time Multiplier Setting (TMS) of the protective relays in a case of any change in system configuration by means of control action. The proposed adaptive feature in numerical relays modifies automatically the protective device settings based on the system topology and DG capacity to maintain the coordinated overcurrent relays with the optimum selectivity and sensitivity. Figure 2 shows the flow chart of the proposed adaptive protection scheme.

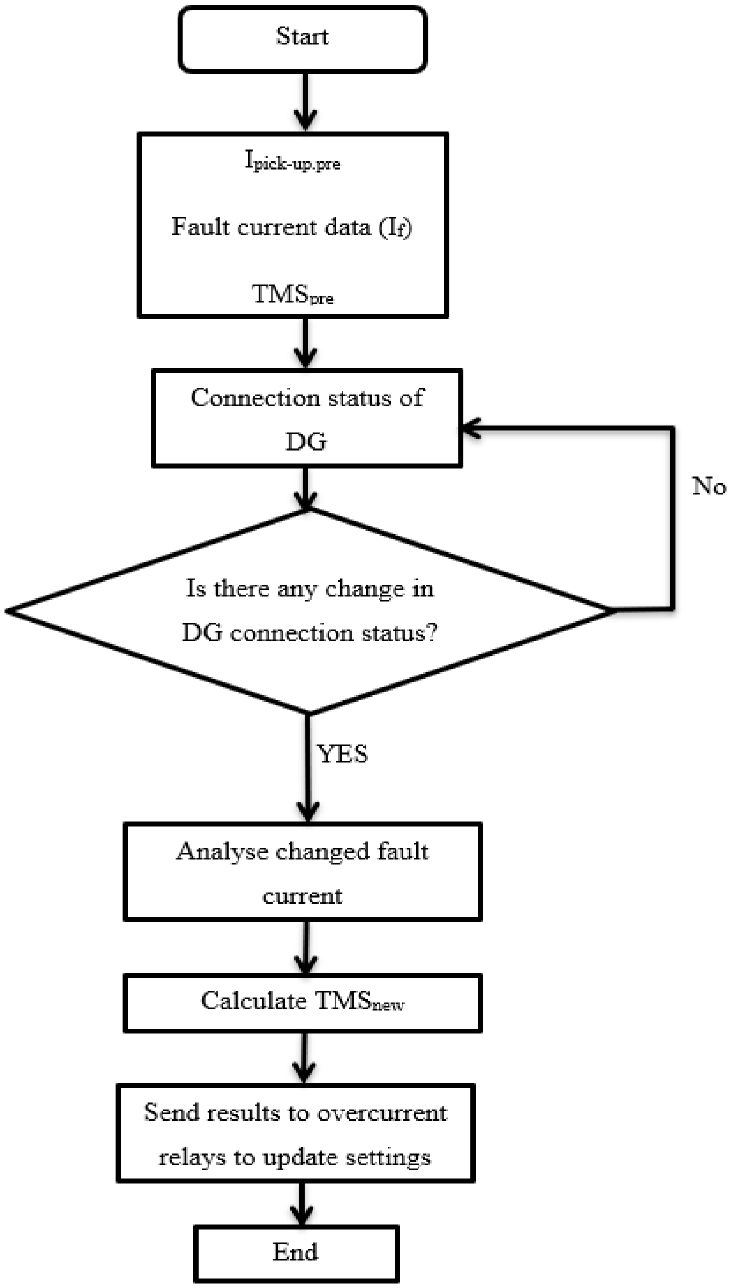

Figure 2: Flow chart of the proposed adaptive protection scheme

II.IV. Designing a Fuzzy Logic Controller (FLC)

Due to the variability nature of DGs, variation of the DG size has been taken into consideration and the characteristics of fuzzy systems are suited for this kind of applications.

The following parameters for membership functions were considered

i. Controller inputs: size of the DG

ii. Controller Output: Time multiplier Setting (TMS) of the relay

The fuzzy based approach was used for identifying the operational network topology. This was achieved by fuzzification of the rule base corresponding to given topology which come in existence due to connection of DG. The output of a zero-order model of a Sugeno-type fuzzy inference system (FIS) was used in this study. The input variable "size of the DG" is ranged between 0 and 8 MVA and its membership function is represented in Figure 3. To take the range for the output variable "TMS", the lower limit was considered to be the TMS value for the network before connecting the DG. The upper limit is the value of TMS got after connecting the maximum size of DG. Figure 4 represents the membership function for the output variable "TMS" for a sample relay R4

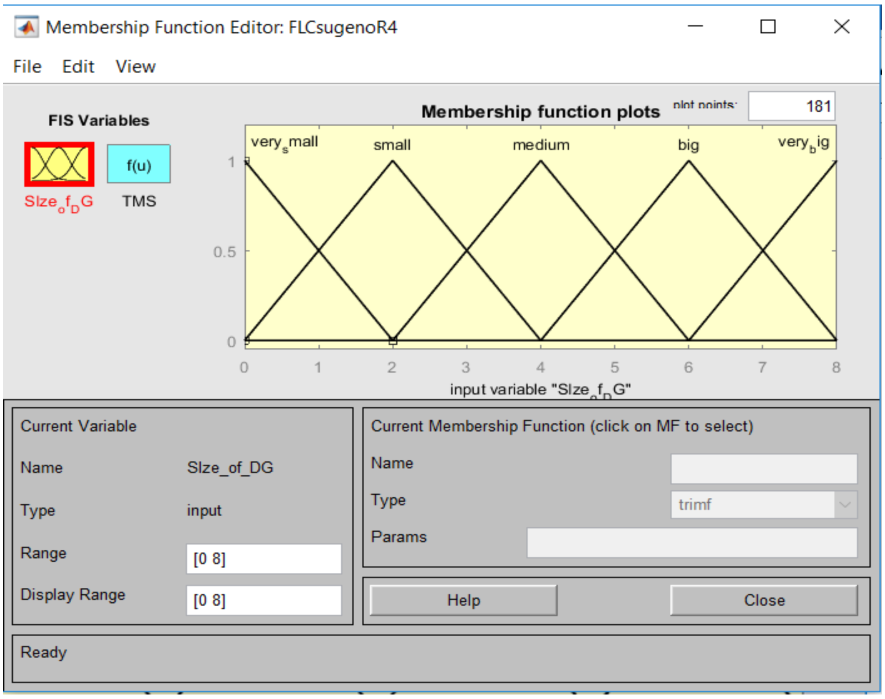

Figure 3. Membership function for the size of DG

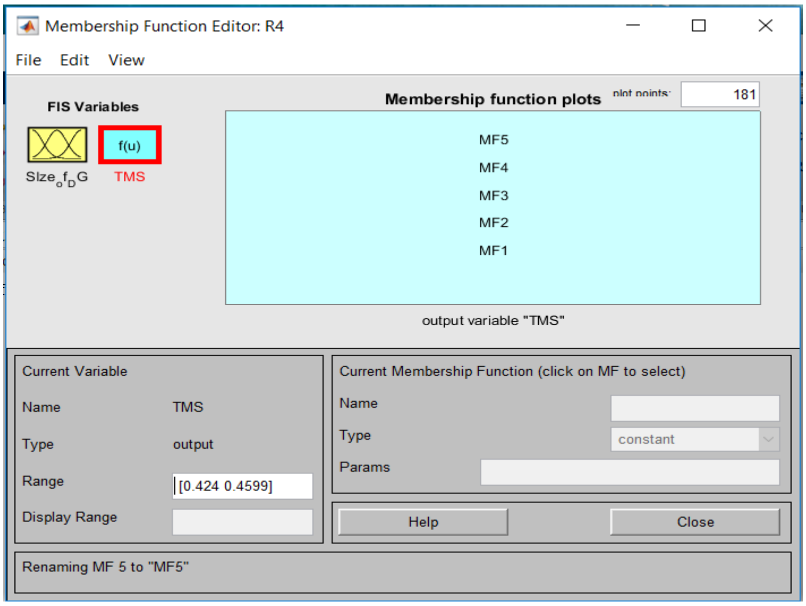

Figure 4: Membership function for TMS

III. RESULTS AND DISCUSSION

III.I. Overcurrent relays coordination in the distribution network without DG

ETAP software was used to get power flow and short circuits data which are necessary for setting and coordinating overcurrent relays. The operating time t_i for the primary and the backup relays were obtained based on the inverse characteristic of overcurrent relays. The IEC standard inverse characteristic equation of overcurrent relay (1) was used.

Pick up current settings for the relays should be above the feeder load currents and not the bus load currents. In fact, one should consider the maximum possible loading conditions, to decide conservatively pick-up current settings. A rule of thumb is to set the pick-up current at 1.25 times maximum load current. Another 'rule of thumb' is to limit pick-up current to 2/3rd of the minimum fault current. This decides the range available for setting relay pick-up [28]. Table 3 shows the pickup currents for different relays.

Table 3: Pickup currents for different relays

Relay number	R1,R2	R4	R6	R8	R10	R12	R14	R16	R18	R20	R22	R24
Pickup Current(A)	900	800	800	800	50	600	200	75	75	200	100	100

When doing a protection coordination for a radial distribution network, we start with the relays which do not have co-ordination responsibility (relays at the far end nodes) and TMS for these relays can be set to the minimum. With the knowledge of I_f, Ipickup and TMS, the desired relay operating time can be calculated. To start the coordination, the far end relay R22 was given a TMS of 0.05 and the CTI of 0.3 s was used during coordination. Table 4 shows the faults currents for different faults location obtained before connecting the DG and after connecting the DG. It also shows the contribution in fault currents from the grid and from the DG.

Table 4: Fault currents for different fault locations

Fault location (Bus)	Fault current without DG	Fault current with DG (kA)	Fault current contribution	
			From grid	From DG
1	9.75	11.75	9.75	2
2	7.71	9.73	7.71	2.1
3	6.24	7.55	5.98	1.63
4	5.94	7.12	5.64	1.54
5	5.42	6.39	5.06	1.38
6	5.19	6.07	4.81	1.31
7	4.86	5.62	4.45	1.21
8	4.51	5.16	4.09	1.11
9	4.24	4.81	3.81	1.04
10	4.13	4.67	3.7	1.01
11	4.59	5.27	4.17	1.14
12	4.33	4.93	3.19	1.06
13	4.58	5.26	4.17	1.13

Considering a fault at bus 3, the fault current is 6240 A. For this fault, relay R4 is the primary relay while relay R2 is the backup relay.

Using the TMS of 0.4240 which is found during coordination process, the operating time of R4 will be

$$t_{R4} = \frac{0.14 * 0.4240}{\left(\frac{6240}{800}\right)^{0.02} - 1} = 1.4154\ s$$

So, for this fault, R4 will operate at 1.4154 s, R2 will be the backup and it has to operate after a coordination time interval (CTI) of 0.3 s, if the R4 fails to operate.

Expected $t_{R2} = 1.4154 + 0.3 = 1.7154\ s$

The relay R2 has to be set with a different TMS compared to the one of relay R4

$$TMS_{R2} = \frac{1.7154 * \left\{\left(\frac{6240}{900}\right)^{0.02} - 1\right\}}{0.14} = 0.4838$$

Now, for a fault at bus 2, where the relay R2 has to operate as the primary, its operating time is

$$t_{R2} = \frac{0.14 * 0.4838}{\left(\frac{7710}{800}\right)^{0.02} - 1} = 1.5431\ s$$

Table 5 shows the TMS values for the relays involved in coordination. Table 6 gives the operating time for all the relays considering the coordination pairs depending on the faulted bus. It also shows the CTI between the primary and the backup relays.

III.II. Investigating the Impact of integrating DG on overcurrent Protection relays

A 8 MVA Distributed Generator (DG) was connected at bus 2. The output voltage of DG is 6.6 kV, and it is connected to the system through a 6.6/11 kV transformer.

To investigate the impact of integrating DG in distribution network, a 3-phase fault was created on different locations in the distribution network, with and without DG. The fault currents before connecting DG and the fault currents after connecting DG were compared. Figure 5 illustrates the change in fault currents after connecting the DG on the network

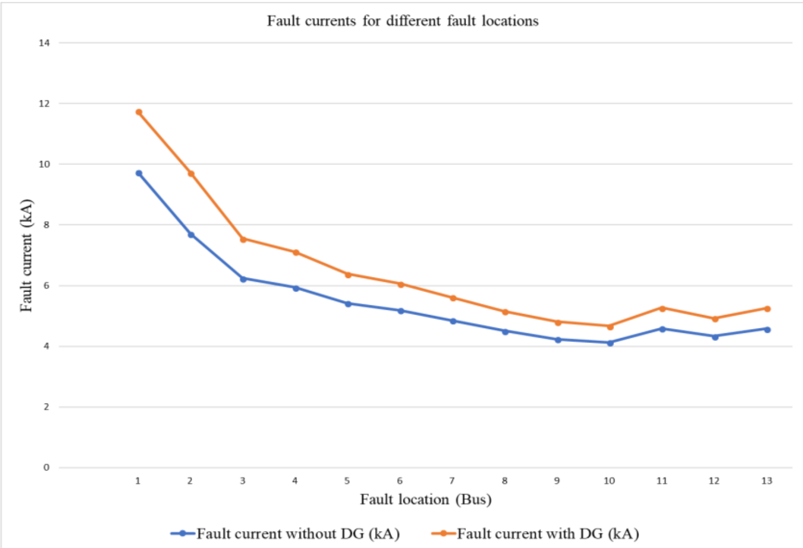

Figure 5: Fault currents with and without DG

When the DG is connected, the fault current (for a fault at bus 3) becomes 7550 A. The fault current has increased from 6240 A to 7550 A. By using the old settings for the relays, The new Operating time for the relay R4 which is the primary becomes

$$t_{R4} = \frac{0.14 * 0.4240}{\left(\frac{7550}{800}\right)^{0.02} - 1} = 1.2928\ s$$

This time is lower compared to the way it was before connecting the DG. The difference is 0.1226 s. Table 6 shows the operating time for the relays and the CTI values for the coordination pairs when old settings of the relays are used for the network protection after connecting the DG to the network. Figure 6 shows graphically the change in operating time for the relays after connecting DG.

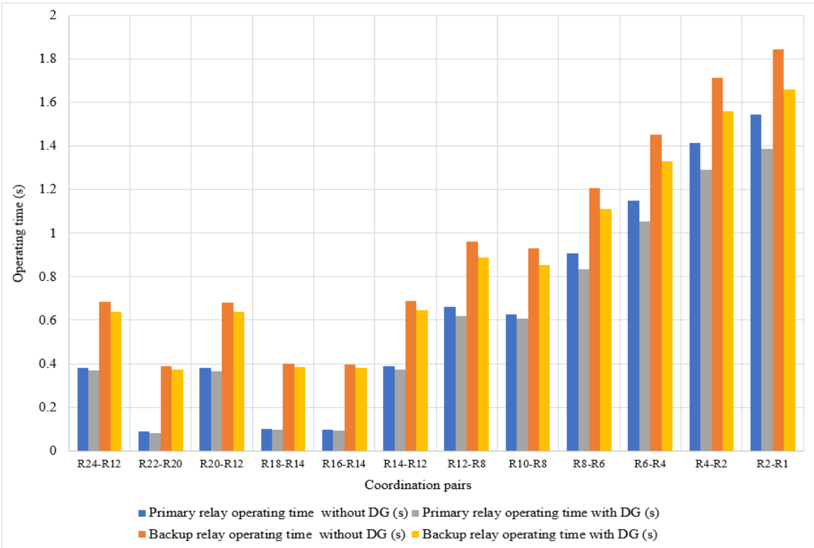

Figure 6: Change in operating time of relays after connecting DG

Generally, it was seen that after connecting the DG, there is an increase in fault current value, due to the contributed current from the DG. Also, it was observed that in most cases, the fault current contribution from the utility has been decreased, and this is due to the presence and the participation from the DG, which fed the fault.

The increase in the fault current will decrease the operating time for the relays located downstream from the faulted bus and increase the operating time for the relays between the substation and DG. Those conditions can cause nuisance trip in the protective devices operation and disturb the protection coordination. The decrease in fault current contribution from the substation may lead to blinding of the relays located upstream to faulted bus, when the fault current goes below the pickup current.

III.III. Application of Adaptive protection scheme

In order to mitigate the impact of integrating DG in the distribution network, Adaptive protection scheme is the effective way. This is applied by changing the settings of the protective relays in order to maintain the same operating time and coordination as it was before connecting the DG.

In order to maintain the operating time of the relay R22 as it was before connecting the DG, we can change the TMS of the relay.

$$TMS_{new} = \frac{0.0894 * \left\{ \left(\frac{4950}{100} \right)^{0.02} - 1 \right\}}{0.14} = 0.0518$$

Table 5 indicates the new TMS values for all the relays involved in coordination in order to maintain the network well coordinated.

Table 5: TMS values before and after connecting DG

Relay	TMS before connecting DG	TMS After connecting DG
R1	0.5779	0.6329
R2	0.4838	0.5284
R4	0.424	0.4599
R6	0.3363	0.3641
R8	0.2527	0.2731
R10	0.4367	0.4493
R12	0.2023	0.2163
R14	0.1782	0.1864
R16	0.0577	0.0604
R18	0.0594	0.0623
R20	0.1764	0.1844
R22	0.05	0.0518
R24	0.2173	0.2253

Table 6: Operating time of relays and CTI values for 3 different scenarios

		Before connecting DG			After connecting DG and using traditional settings			After connecting DG and using Adaptive protection		
Faulted bus	Coordination pair	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)
13	R24-R12	0.3827	0.6827	0.3	0.3688	0.6382	0.2694	0.3824	0.6824	0.3
12	R22-R20	0.0894	0.3893	0.2999	0.0811	0.3731	0.292	0.0894	0.39	0.3006
11	R20-R12	0.3819	0.6819	0.3	0.3652	0.6377	0.2725	0.3818	0.6818	0.3
10	R18-R14	0.0996	0.3996	0.3	0.0965	0.3836	0.2871	0.1013	0.4012	0.2999
9	R16-R14	0.0961	0.3961	0.3	0.0931	0.3799	0.2868	0.0974	0.3974	0.3
8	R14-R12	0.388	0.688	0.3	0.3714	0.6441	0.2727	0.3885	0.6886	0.3001
7	R12-R8	0.6629	0.9629	0.3	0.6189	0.8898	0.2709	0.6618	0.9616	0.2998
6	R10-R8	0.6284	0.9284	0.3	0.6069	0.855	0.2481	0.6244	0.9244	0.3
5	R8-R6	0.907	1.207	0.3	0.8337	1.1096	0.2759	0.901	1.2013	0.3003
4	R6-R4	1.1508	1.4509	0.3001	1.0535	1.3282	0.2747	1.1406	1.4407	0.3001
3	R4-R2	1.4154	1.7153	0.2999	1.2928	1.5586	0.2658	1.4022	1.7023	0.3001
2	R2-R1	1.5431	1.8432	0.3001	1.389	1.6592	0.2702	1.517	1.8171	0.3001

Table 6 gives the operating time for the relays and the CTI values for different coordination pairs , after connecting the DG to the network and using adaptive protection.

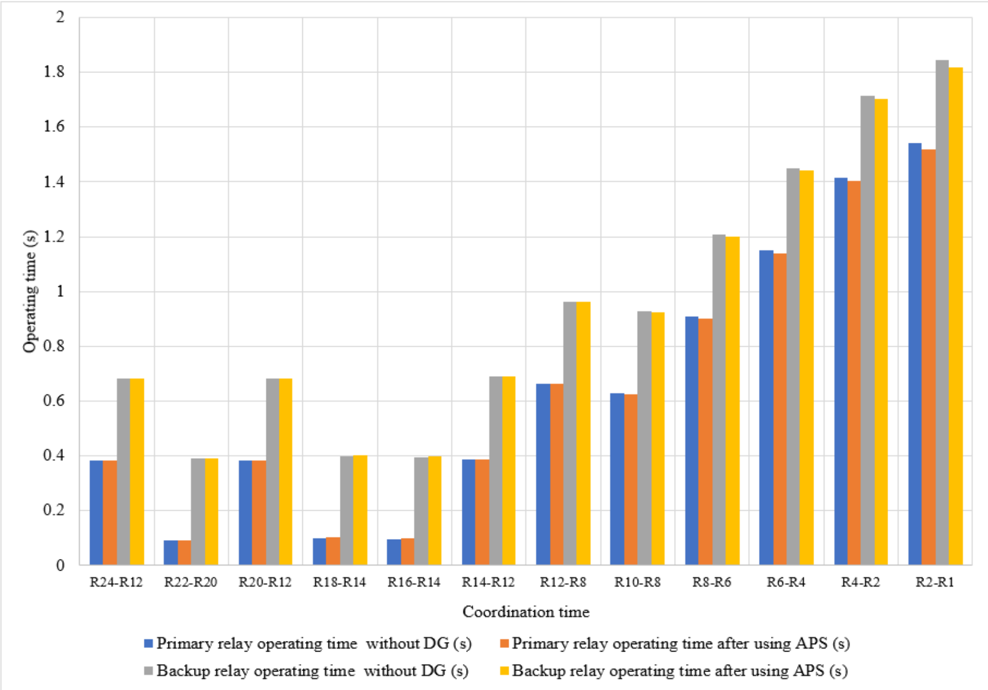

Figure 7: Operating time of the relays after using adaptive protection scheme

From Figure 7, it can be seen that the operating time of relays after using adaptive protection scheme was kept almost as it was before connecting the DG. This is done by changing the TMS value for each relay.

Figure 8 shows the comparison of the CTI values for different coordination pairs in 3 different scenarios. The first scenario is the distribution network without DG and employing a traditional protection coordination. The second one is the distribution network with DG connected and employing traditional protection coordination. The third one is the distribution network with DG connected and employing the adaptive protection scheme.

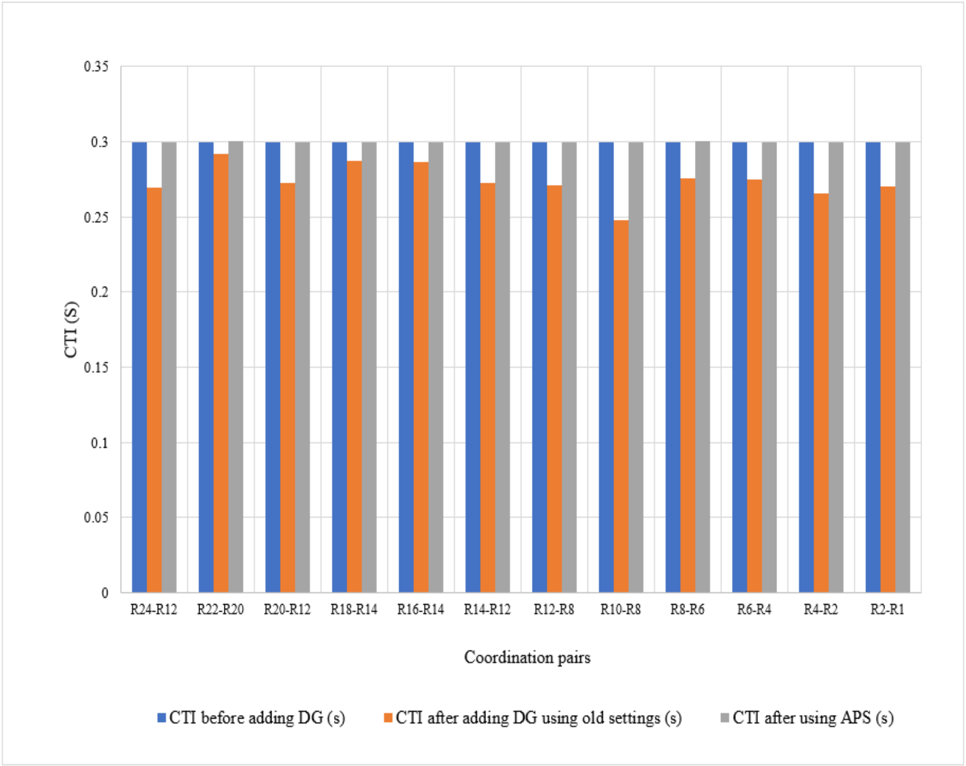

Figure 8: Comparison of the CTI values for different coordination pairs in 3 scenarios

From Figure 8, the CTI values for different coordination pairs were reduced after connecting DG to the network. This causes the loss of coordination between the primary and the backup relays. After using the adaptive protection scheme, the CTI values were brought back almost to the value of CTI used for coordination in the network before connecting the DG which was 0.3 s.

III.III. Using the designed Fuzzy logic controller in Adaptive Protection Scheme

After designing a fuzzy logic controller, it was used to find the TMS values of relays for different sizes of the DG between the 0 and 8 MVA which is the maximum size of the DG. In order to evaluate the performance of the designed fuzzy logic controller, the TMS values for the relays involved in coordination were found using the designed controller. These values were used in coordination to see if the operating time and the coordination time interval for different coordination pairs will remain the way they were before connecting the DG. Table 7 shows the TMS values obtained using the designed fuzzy logic controller for a DG of 3 MVA and 5 MVA.

Table 7: TMS values got using the designed controller

Relay	TMS for 5MVA DG	TMS for 3MVA DG
R1	0.612	0.599
R2	0.512	0.501
R4	0.446	0.437
R6	0.354	0.347
R8	0.266	0.261
R10	0.445	0.441
R12	0.211	0.208
R14	0.183	0.181
R16	0.0594	0.0587
R18	0.0612	0.0605
R20	0.181	0.179
R22	0.0511	0.0507
R24	0.222	0.22

Table 8. indicates the operating time for the primary and the backup relays, as well as the coordination time interval for different coordination pairs, got during coordination using the TMS values obtained using a fuzzy logic controller for both 5 MVA DG and 3 MVA DG.

Table 8: Operating time of relays for a 5 MVA DG and 3 MVA DG using TMS got from the controller

		5 MVA DG			3 MVA DG		
Faulted bus	Coordination pair	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)
13	R24-R12	0.3797	0.6749	0.2952	0.3791	0.6742	0.2951
12	R22-R20	0.0889	0.3861	0.2972	0.0888	0.385	0.2962
11	R20-R12	0.3782	0.6742	0.296	0.3776	0.6742	0.2966
10	R18-R14	0.1001	0.397	0.2969	0.0996	0.3962	0.2966
9	R16-R14	0.0964	0.3934	0.297	0.0959	0.3924	0.2965
8	R14-R12	0.3848	0.6806	0.2958	0.3841	0.6802	0.2961
7	R12-R8	0.6547	0.9483	0.2936	0.6545	0.9454	0.2909
6	R10-R8	0.6228	0.915	0.2922	0.6216	0.9131	0.2915
5	R8-R6	0.8889	1.1874	0.2985	0.8874	1.1844	0.297
4	R6-R4	1.1286	1.4219	0.2933	1.1269	1.4192	0.2923
3	R4-R2	1.3845	1.6811	0.2966	1.3827	1.6784	0.2957
2	R2-R1	1.4977	1.7902	0.2925	1.4987	1.7919	0.2932

Figure 9 compares the operating time of the primary and the backup relays for 3 cases. The case where the network had no DG connected, the network with 5 MVA DG connected using a fuzzy based APS and the case for the network with a 3 MVA DG connected using fuzzy based Adaptive Protection Scheme.

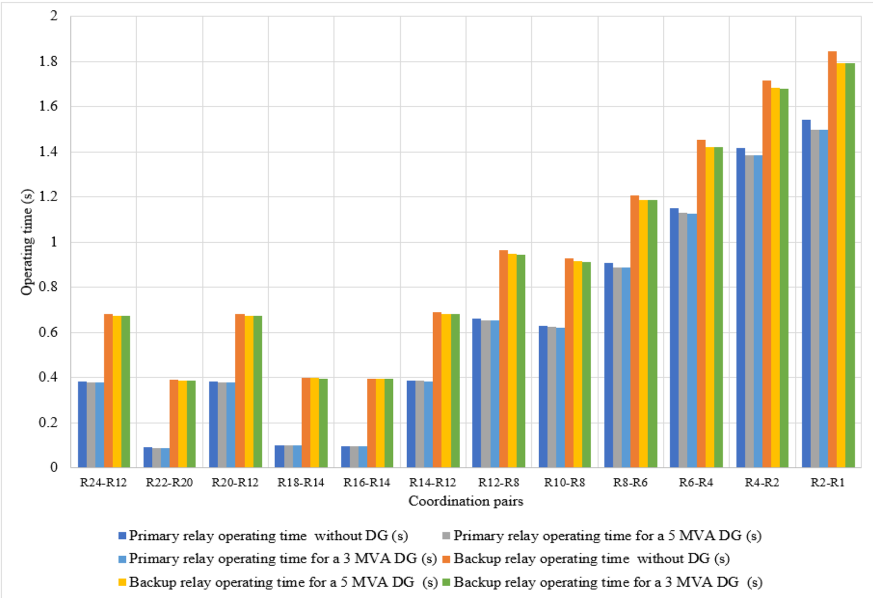

Figure 9: Comparison of operating time for different coordination pairs after using a fuzzy based Adaptive Protection Scheme

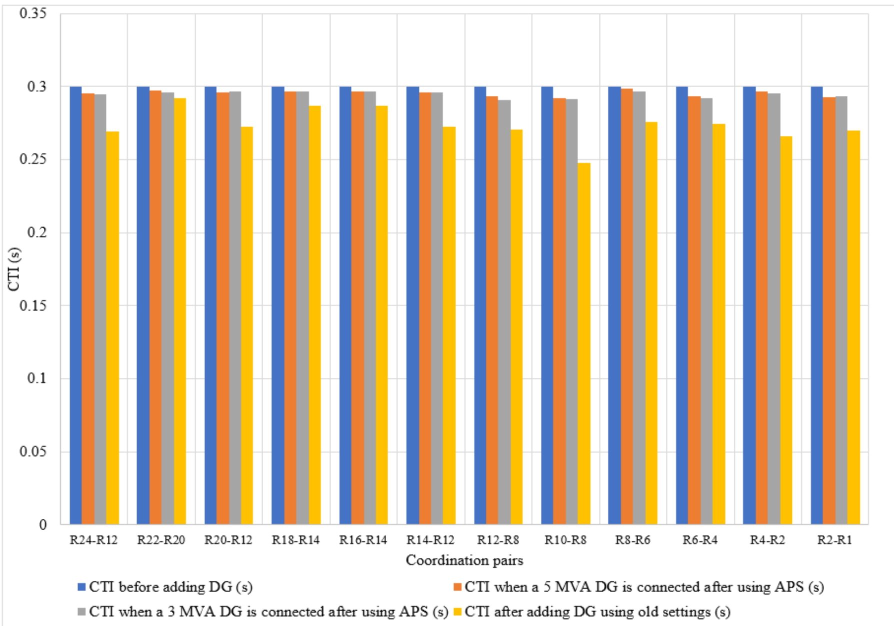

Figure 10: Comparison of coordination time intervals for different coordination pairs after using a fuzzy based Adaptive Protective Scheme

Referring to Figure 9, it was seen that the operating time for primary and backup relays for different coordination pairs are almost the same for the case of the network with a 5 MVA DG connected and the one for the network with a 3 MVA DG connected. In addition, the operating time for those above two cases are close to the way it was before connecting the DG. Figure 10 compares the coordination time intervals for different coordination pairs for 4 cases. The case where the network had no DG connected, the network with DG connected using old settings, the network with 5 MVA DG connected using a fuzzy based adaptive protection scheme and the case for the network with a 3 MVA DG connected using fuzzy based adaptive protection scheme.

Referring to Figure 10, the coordination time interval for the coordination pairs in the network before connecting the DG was 0.3 s. After connecting the DG in the network and using the old settings for the relays, the coordination time interval was reduced for all the coordination pairs. When the fuzzy based Adaptive Protection Scheme is used, the coordination time interval for the coordination pairs was increased again to nearly the way they were before connecting the DG and become around 0.3 s.

The fact of keeping the operating time of the relays and the coordination time interval for different coordination pairs to the way they were before connecting DG, made the network to remain well protected and well coordinated after connecting the DG to the network by using a fuzzy logic based adaptive protection scheme.

IV. CONCLUSION

This paper focused on overcurrent relays related concerns of integrating DG to the distribution systems. From this study, it was observed that connecting the DG to the distribution network changes the operating time of the relays both the primary and the backups. It also causes the loss of coordination between the primary and the backup relays by violating the coordination time interval, and this influence negatively the performance of the protection system. This is due to the fact that conventional relay settings for traditional systems may fail or may work incorrectly under new conditions. Thus, protection schemes able to maintain protection coordination are strongly needed in distribution networks with a significant integration of DGs. In these networks, the fault levels are intermittent and continuously changing as per connection of DG in the network. The trend is to use the Adaptive protection scheme which changes the settings of protection relays depending on the prevailing network configuration.

In this paper, Adaptive protection scheme in distribution networks considering intermittency of DG using a fuzzy logic controller was proposed. The controller chooses the best Time Multiplier Setting (TMS) of the relay depending on the size or the capacity of the DG connected. It was found that the adaptive protection scheme keeps the network well protected and coordinated with the required selectivity and security.

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