A Communication-less Protection Strategy to Ensure Protection Coordination of Distribution Networks with Embedded DG

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Abstract—Distributed Generation (DG) has emerged as best alternative to conventional energy sources in recent times. Decentralization of power generation, improvement in voltage profile and reduction of system losses are some of key benefits of DG integration into the grid. However, introduction of DG changes the radial nature of a distribution network (DN) and may affect both magnitude and direction of fault currents. This phenomenon may have severe repercussions for the reliability and safety of a DN including protection coordination failure. This paper investigates the impact of DG on protection coordination of a typical DN and proposes a scheme to restore the protection coordination in presence of DG. Moreover, impact of different DG sizes and locations on DN’s voltage profile and losses has also been analyzed. The sample DN with embedded DG is modelled in ETAP environment and the simulation results presented show the effectiveness of the proposed protection strategy in restoring relay coordination of the network in both isolated and DG connected modes of operation.

Index Terms—Distributed Generation, Size and Location, Protection Coordination

I. INTRODUCTION

The rapid increase in electrical energy demand combined with scarcity of fossil fuels and their high prices has made Distributed Generation (DG) based on renewable energy resources (RER) installed near to load centers as an attractive alternative. Recent advancement in renewable energy technologies is also one of the reasons for wide spread use of DG for electricity replacing generation from large centralized plants. Many studies focus on the selection of proper size and location of DG units as it may affect the voltage profile, total power loss and protective relay coordination, etc., of a distribution network (DN) [1], [2].

The objective of power system protection is to isolate the faulty part of the network from healthy part in case of fault. A good protection scheme should selective, fast, reliable, and sensitive [3]. Directional overcurrent relays (DOCRs) are widely described in literature for protection of distribution networks (DNs) with integrated DG due to their effectiveness and low price. There is an extensive literature that describes impact of DG on protection coordination of a DN and suggests various solutions based on both conventional as well as optimal techniques [4], [5], [6]. A protection coordination scheme is proposed in this paper that utilizes different time current characteristics (TCC) of microprocessor based relays to ensure protection coordination of a DN with embedded DG. TCCs that are selected for different relays hold good no matter whether DN is working with or without DG connection.

The remaining paper is arranged as under. Section II describes system modelling whereas section III contains protection design scheme for the original system without DG. The criteria for selection of size and location of DG is presented in Section IV. Section V contains impact of DG on protection coordination of the test system whereas section VI describes the proposed protection scheme for restoration of protection coordination in presence of DG. Section VII concludes the paper.

II. SYSTEM MODELLING

Fig. 1 represents the Single Line Diagram(SLD) of Distribution Network modelled in ETAP which is modified version of Eastern Libyan Distribution Network [7]. The network comprises of three transformers and eleven buses. The grid is shown as an equivalent source with a short circuit capacity of 200 MVA connected at Bus 1. Table I enlists all system components along with their specifications. All the relays are directional except those connected with the grid and loads. The grid parameters are as shown in Fig 2.

Over-current protection scheme for the sample network is designed and tested in ETAP software with DG connected at bus 8. The DG size and location are selected on the basis of power loss reduction and improvement in voltage profile of the network. After DG integration, short circuit currents in the network increase and the existing protection scheme maloperates. To minimize the effect of DG on protection coordination, two potential solutions are investigated and simulated here. First solution is to redesign the protection scheme in the presence of DG by adaptively changing the relay settings [7], [8], [9]. In this case, relays will have two sets of settings; one setting for DG connected mode of operation and other for
III. PROTECTION SCHEME DESIGN AND COORDINATION WITHOUT DG IN DN

A three phase bolted fault is simulated at different buses to determine the maximum fault currents for setting of DOCRs. Pick-up settings of the relays are calculated by allowing 25% overloading. The settings of DOCRs are based on standard inverse time characteristics [10].

\[
Pickup = Normal\ Load\ Current \times 1.25 \tag{1}
\]

\[
PS = \frac{Pickup \times CTR}{CTR + PS} \tag{2}
\]

Characteristic Equation For Standard Inverse Relay is:

\[
T_0 = \frac{0.14 \times TMS}{\left(\frac{CTR \times PS}{L_I}\right)^{0.02} - 1} \tag{3}
\]

where:
- \(T_0\) = Operating Time of Relay
- CTR = Current Transformer Ratio
- \(I_f\) = Three Phase Fault Current through that Relay
- PS = Plug Setting of Relay
- TMS = Time Multiplier Setting
- CTI = 200ms = Coordination Time Interval

**A. Calculation for Relay Setting At Bus 23**

Upon careful observation of the simulated network, it can be noticed that for fault at Bus 23 Relay35 is the primary relay and Relay32 is its backup. TMS of Relay35 is 0.05. From Equation [3]:

\[
T_{35} = \frac{0.14 \times 0.05}{\left(\frac{0.110}{1200 \times 0.598}\right)^{0.02} - 1} = 0.16sec \tag{4}
\]

\[
T_{35} = 0.16sec
\]

Also,

\[
T_{32} = T_{35} + CTI = 0.36sec
\]
Time Multiplier Setting of Relay32 is determined from Equation 3 as under:

\[
TMS = \frac{T_0 \times (\frac{I_f}{CTR \times PS})^{0.02} - 1)}{0.14}
\]

\[
TMS_{32} = \frac{0.36 \times (\frac{6110}{1200 \times 0.275})^{0.02} - 1)}{0.14}
\]

\[
TMS_{32} = 0.15\text{sec}
\]

B. Protection Coordination Settings

The method described above has been used to determine the settings of DOCRs installed in the DN. Table II shows the setting of protection devices without DG. All the current transformers has a ratio of 1200:1.

| Bus | If (A) | Rp | Rb | Relay No | Type | PS | TMS |
|-----|--------|----|----|----------|------|----|-----|
| 23  | 6110   | 35 | 32 | 35       | Dir  | 0.598 | 0.05 |
| 27  | 2210   | 32 | 29 | 32       | Dir  | 0.275 | 0.14 |
| 26  | 2330   | 29 | 10 | 29       | Dir  | 0.848 | 0.126 |
| 25  | 2660   | 10 | 12 | 10       | Dir  | 0.466 | 0.17 |
| 8   | 2910   | 12 | 14 | 12       | Dir  | 0.831 | 0.18 |
| 6   | 3140   | 14 | 1  | 14       | Dir  | 1.21  | 0.115 |
| 2   | 501    | 1  | Nil| 1        | ND   | 0.324 | 0.19 |
| 28  | 3430   | 36 | 16 | 36       | Dir  | 0.583 | 0.05 |
| 5   | 1720   | 16.18 | 21.22 | 16.18 | Dir  | 0.291 | 0.135 |
| 4   | 1760   | 21.22 | 25.26 | 21.22 | Dir  | 0.584 | 0.102 |
| 3   | 1790   | 25.26 | 1   | 25.26 | Dir  | 0.585 | 0.128 |

C. Relay Curves

Relay curves can be seen for faults at Bus 26 and Bus 27 in Fig. 4 and Fig. 5 respectively. For fault at Bus 26 Relay29 is primary relay and Relay10 is secondary relay. Similarly for Bus 27 Relay32 is primary and Relay29 is secondary relay. It can be seen that in both the cases, protection coordination is ensured as the value of CTI is close to required value of 200 ms as given in Equation 6 and Equation 7. Table III shows timing of various primary and backup relays of the network without DG connection. Abbreviations used in the Table are:

\[T_{relay10} - T_{relay29} = CTI = 879ms - 689ms = 190ms\]

\[T_{relay29} - T_{relay32} = CTI = 719ms - 506ms = 213ms\]

\[R_p= Primary \ Relay\ number\ \ R_b=Backup\ Relay\ number\ \ T_p=Primary\ Relay\ time\ \ T_b=Backup\ Relay\ time\ \ CTI=Coordination\ time\ interval\ MC=Misscoordination\]

IV. SELECTION OF DG SIZE AND LOCATION

From Table IV it can be seen that losses are reduced to 1109.7 KW from original 3849 KW after DG connection which shows an improvement of 68%. However, due to certain constraints, Bus 27 is not a feasible location for DG connection. So, Bus 8 which is next to Bus 27 in terms of loss reduction is selected for DG connection.

| Fault at Bus | Rp | Rb | Tp | Tb | CTI(ms) | MC |
|--------------|----|----|----|----|---------|----|
| 23           | 35 | 32 | 161 | 506 | 345     | Nil |
| 27           | 32 | 29 | 506 | 719 | 213     | Nil |
| 26           | 29 | 10 | 689 | 889 | 200     | Nil |
| 25           | 10 | 12 | 751 | 951 | 200     | Nil |
| 8            | 12 | 14 | 889 | 1099 | 210    | Nil |
| 6            | 14 | 1  | 991 | 1500 | 509    | Nil |
| 2            | 1  | 36 | 1026 | nil | Nil     | Nil |
| 28           | 36 | 16.18 | 21.22 | 21.22 | 0.584 | 0.102 |
| 5            | 16.18 | 21.22 | 25.26 | 25.26 | 0.585 | 0.128 |
| 4            | 21.22 | 25.26 | 904  | 1100 | 196    | Nil |
| 3            | 25.26 | 1  | 1165 | 1376 | 211    | Nil |

V. PROTECTION COORDINATION AFTER CONNECTION OF DG

Major protection issues associated with integration of DG into a DN are change in direction and magnitude of fault current, blinding of protection and false tripping of relays etc. It can be seen in Fig. 6 and Fig. 7 that after DG integration, CTI is not ensured for faults at Bus 26 and Bus 27.

For Bus 26:

\[T_{10} - T_{29} = CTI = 685ms - 528ms = 157ms\]

As 157 ms is considerably smaller than 200 ms, so in this case CTI is not ensured.
TABLE IV

Network Losses of the DN with DG at Different Locations

| Bus No | DG Size (KW) | Losses (KW) | Bus No | DG Size (KW) | Losses (KW) |
|--------|--------------|-------------|--------|--------------|-------------|
| 2      | 25           | 3560.1      | 5      | 25           | 3558.97     |
| 2      | 50           | 3560.1      | 5      | 50           | 3584.97     |
| 3      | 25           | 3477        | 25     | 25           | 1851.93     |
| 3      | 50           | 3477        | 25     | 50           | 1851.93     |
| 8      | 25           | 1683        | 26     | 25           | 1741.41     |
| 8      | 50           | 1683        | 26     | 50           | 1741        |
| 23     | 25           | 2037        | 27     | 25           | 1506        |
| 23     | 50           | 2037        | 27     | 50           | 1109.7      |
| 1      | 25           | 3849        | 28     | 25           | 2887        |
| 1      | 50           | 3849        | 28     | 50           | 2887        |
| 4      | 25           | 3366        | 4      | 50           | 3366        |

Fig. 6. Relay TCC curves for fault at bus 26 with DG

Similarly, for Bus 27:

\[ T_{29} - T_{32} = CTI = 564 ms - 439 ms = 125 ms \]

As 125 ms is considerably smaller than 200 ms, so CTI is not ensured in this case, too.

From Table [V], it can be seen that miscoordination of relays occur when fault is introduced at Bus 26 and Bus 27 which needs to be corrected.

VI. METHODS TO SOLVE PROTECTION COORDINATION PROBLEMS AFTER DG INTEGRATION

A. PROTECTION REDESIGN IN THE PRESENCE OF DG

In order to regain protection coordination between primary and backup relays, we redesigned the protection settings in the presence of DG. DG integration into the system have increased the short circuit current levels that is the source of miscoordination between primary and backup relays. New TMS and PS of the relays are calculated in exactly the same manner as was used for the protection settings of DN without DG. Redesigned protection settings works fine in the presence of DG but at the time when DG is removed, some relays maloperate. So the coordination problem remains still unresolved. New protection settings are shown in Table [VI].
TABLE VII
RELAY CHARACTERISTIC CURVES FORMULAS

| Degree of inverstion of the Relay | a   | b   |
|-----------------------------------|-----|-----|
| Normal Inverse                    | 0.02| 0.14|
| Very Inverse                      | 1   | 13.5|
| Extremely Inverse                 | 2   | 80  |

TABLE VIII
EXTREMELY INVERSE CASE

| Fault at Bus No | Tp  | Ts  | CTI | MS |
|-----------------|-----|-----|-----|----|
| 23              | 60  | 112 | 62  | Yes|
| 27              | 112 | 386 | 274 | nil |
| 26              | 310 | 443 | 133 | Yes|
| 25              | 300 | 1300| 1000| nil |
| 8               | 2126| 1000| 1126| nil |
| 6               | 473 | 4000| 3527| nil |
| 2               | 6000| nil |    |    |
| 28              | 97.2| 405 | 307.2| nil |
| 5               | 405 | 818 | 413 | nil |
| 4               | 743 | 1467| 724 | T13=313|
| 3               | 1384| 6400| 5016| T13=296,T11=729|

B. Changing Characteristic Curves of Relays

The second solution that is, changing characteristic curve of the relays that malfunction, is adopted here to restore protection irrespective of DG connection status. Available Curves for relay REF542plus are:

1) Normal Inverse:
2) Extremely Inverse:
3) Very inverse:
4) Long inverse:

\[
T_0 = \frac{a \times TMS}{(CTIMS)^b - 1} \tag{6}
\]

Table VII shows parameters 'a' and 'b' for different types of curves. There are also some special type of curves like RI type and RXIDG type which are used where high selectivity is required. Relays time are calculated using extremely inverse and very inverse in Table VII and IX respectively.

It can be seen from Table VIII and IX that when the characteristic curves of all relays are changed from normal inverse to extremely and very inverse even then miscoordination occurs. Not a single characteristic curve could fix the mis-coordination problem. So, a strategy to change curves of only those relays that maloperate, from normal inverse to extreme and very inverse has been used to ensure coordination.

In Table X and XI, it is shown that by changing the characteristic curve of some relays have solved the problem of mis-coordination between primary and backup relays for both cases, without and with DG connection, as CTI is now higher than 200ms. Table XI shows Characteristic curve of different relays, which ensures coordination with DG and without DG case.

In Fig 8 and 9 relay TCC curves are shown in case of without DG for bus fault 27 and 26 respectively. Similarly Fig 10 and 11 shows TCC curves in with DG case. In both cases CTI is insured between primary and backup relays.

TABLE IX
VERY INVERSE CASE

| Fault at Bus No | Tp  | Ts  | CTI | MS |
|-----------------|-----|-----|-----|----|
| 23              | 63.4| 179 | 115.6| Yes|
| 27              | 179 | 379 | 200 | Nil |
| 26              | 323 | 380 | 207 | Nil |
| 25              | 404 | 184 | 1470| Nil |
| 8               | 1406| 1343| -63 | Yes|
| 6               | 1162| 2700| 1538| Nil |
| 2               | 300 | 2700| 2400| Nil |
| 28              | 123 | 503 | 380 | Nil |
| 5               | 504 | 600 | 96  | Yes|
| 4               | 550 | 1102| 552 | T13=325|
| 3               | 1072| 2700| 1628| T13=315,T11=437|

TABLE X
CHANGING CHARACTERISTIC CURVE IN WITHOUT DG CASE

| Bus | Rp | Rb | Tp | Tb | CTI | MC |
|-----|----|----|----|----|-----|----|
| 23  | 35 | 32 | 29.7| 229| 199.3| Nil|
| 27  | 32 | 29 | 408 | 723| 315 | Nil |
| 26  | 30 | 10 | 639 | 1100| 461 | Nil |
| 25  | 12 | 14 | 988 | 1199| 211 | Nil |
| 8   | 16 | 14 | 1081| 1600| 519 | Nil |
| 6   | 1  | 36 | 1350| Nil | Nil |    |
| 28  | 36 | 16 | 184 | 493 | 399 | Nil |
| 5   | 16 | 18 | 493 | 704 | 211 | Nil |
| 4   | 21 | 22 | 493 | 704 | 211 | Nil |
| 3   | 25 | 26 | 858 | 1357| 1079| Nil |

TABLE XI
CHANGING CHARACTERISTIC CURVE IN WITH DG CASE

| Bus | Rp | Rb | Tp | Tb | CTI | MC |
|-----|----|----|----|----|-----|----|
| 23  | 35 | 32 | 29.7| 229| 199.3| Nil|
| 27  | 32 | 29 | 408 | 723| 315 | Nil |
| 26  | 30 | 10 | 639 | 1100| 461 | Nil |
| 25  | 12 | 14 | 988 | 1199| 211 | Nil |
| 8   | 16 | 14 | 1081| 1600| 519 | Nil |
| 6   | 1  | 36 | 1350| Nil | Nil |    |
| 28  | 36 | 16 | 184 | 493 | 399 | Nil |
| 5   | 16 | 18 | 493 | 704 | 211 | Nil |
| 4   | 21 | 22 | 493 | 704 | 211 | Nil |
| 3   | 25 | 26 | 858 | 1357| 1079| Nil |

TABLE XII
CHARACTERISTIC CURVES OF RELAYS

| Relay No | Characteristic Curve | Relay No | Characteristic Curve |
|----------|----------------------|----------|----------------------|
| 35       | Extremely Inverse    | 36       | Normal inverse       |
| 32       | Very Inverse         | 16,18    | Normal inverse       |
| 29       | Very Inverse         | 21,22    | Normal inverse       |
| 10       | Normal inverse       | 25,26    | Normal inverse       |
| 12       | Normal inverse       | 14       | Normal inverse       |
| 14       | Normal inverse       | 1         | Normal inverse       |
| 1        | Normal inverse       | 37,27    | Normal inverse       |
VII. Conclusion

The study shows that in some circumstances, it may not be possible to keep and restore coordination of DOCRs in presence of DG. A solution is proposed based on selection of different time current characteristics curves for the DOCRs installed in the network. A sample network is modeled in ETAP environment and through simulation results it is shown that it is possible to retain the original protection coordination through intelligent selection of characteristics curves for the system relays.

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