EFFECTS OF DISTRIBUTED GENERATION ON UTILITY PROTECTION SCHEMES

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Synopsis: The effects of the addition of Distributed Generation to a distribution feeder can be minimized by having digital multifunction overcurrent with voltage protection schemes previously installed as standard feeder protection.

I. Introduction

What effects will Distributed Generation – DG – have on relay protection schemes when a request is made to install DG on your feeders? Distributed Generation may come to your distribution system for a variety of reasons ranging from a "get rich quick" possibility appealing to financial investors to the reliability of onsite backup or stand-by generation power sources for very critical industrial or commercial processes that could require a lengthy and costly clean up after loss of power for even a few minutes. Peak shaving applications to reduce energy costs are another reason to install onsite DG. There are many issues to consider when a DG owner requests a connection to your distribution system. Some of these are:

- Transient and Stability studies
- Voltage drop analysis
- Power Quality
- System configuration and grounding of interface transformer
- Possible Ferro-resonance conditions
- Short Circuit studies
- Impact on interrupt capabilities of equipment

Other texts and papers address the preceding topics in greater detail. *[1-6]*

While several types of generators are used in DG applications, the one with the greatest affect on system fault protection is the synchronous generator. This paper presents some of the protection issues associated with connection of a three phase synchronous DG ranging from 500kW to 10 MW in single or group installations. Multiple small single DGs at scattered locations along the feeder may have the same effects as a single large DG on feeder protection. Also, this paper addresses some of the benefits of having digital or numeric multifunction protective relaying in place when distributed generation is added to a distribution circuit, as opposed to the continued use of discrete single function legacy relays for feeder protection.

II. Protection Issues

Issue 1: Will the location of the DG have an affect on the phase and ground overcurrent protection of the utility feeder?

Location! Location! Location! How important is the location of a Distributed Generation Source when it comes to your distribution circuit?

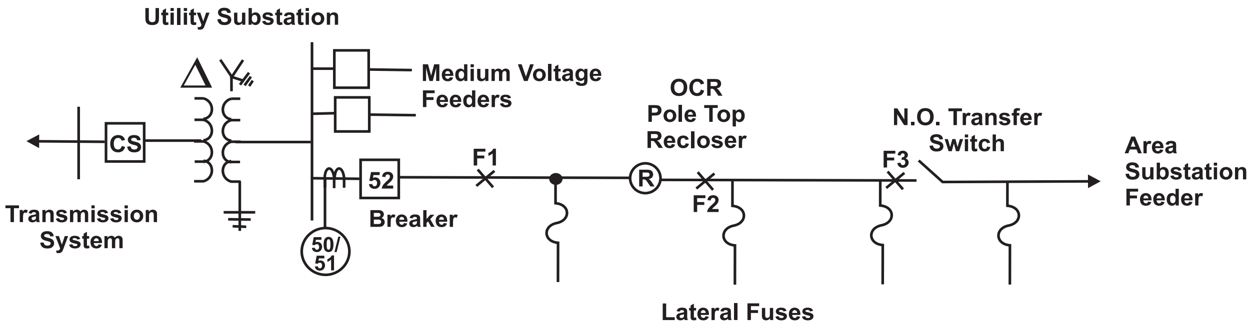

Fig. 1: Typical Distribution Feeder Overcurrent Protection

Figure 1 is a one-line diagram of a typical four wire, radial distribution feeder circuit and the overcurrent devices used for protection of various parts of the feeder. “Radial” means that there are no other sources of power or fault current on the feeder other than the source substation. The ultimate loading capability of these circuits may range from 10 to 25 MVA for voltages of 12.5 to 34.5 kV. The circuit leaves the substation through a power circuit breaker or recloser, device 52, with instantaneous and time overcurrent protection, devices 50/51, applied for phase and ground fault detection. Along the circuit are fused lateral taps to various size customers or main line pole top reclosers where fault current detection or coordination is beyond the limits of the substation protection. All overcurrent devices on the distribution feeder are time coordinated so that the one closest to the fault will trip the fastest, except for systems using “fuse saving” philosophy. In “fuse saving”, a low instantaneous overcurrent element, device 50L, will be set to detect or see faults on much of the feeder length without regard to time coordination. After one or two reclosures of the circuit breaker, the 50L element will be removed from service by the reclosing relay, device 79, which controls the time sequence of the reclosing cycle. When the 50L is disabled, normal time overcurrent coordination will take place.

Zone coverage of the 50L, 50H and 51 phase elements is shown in Figure 2. The 50H instantaneous element is set to not operate for fault F2 on the load side of the OCR. The 51 phase time overcurrent element must be able to see to the end of the longest section of the circuit in the event that all protection fails to operate. As shown in Figure 2, that point will be F3 at the normally open transfer switch. When this switch is closed, adding additional length to the substation overcurrent relay zone of protection, it may be necessary to lower the pickup current setting of the 51 element, provided there is enough current setting range, to see faults on the added length of line.

Table 1 Three phase fault current division between Utility and DG		
DG & Fault Location	Current Split	
C1, at or on Utility bus for Fault F1	Iutil = 80% IDG = 20%	
C2, near middle of feeder for fault at F2	Iutil = 50% IDG =50%	
C2, near middle of feeder for fault at F3	Iutil =40% IDG = 60%	

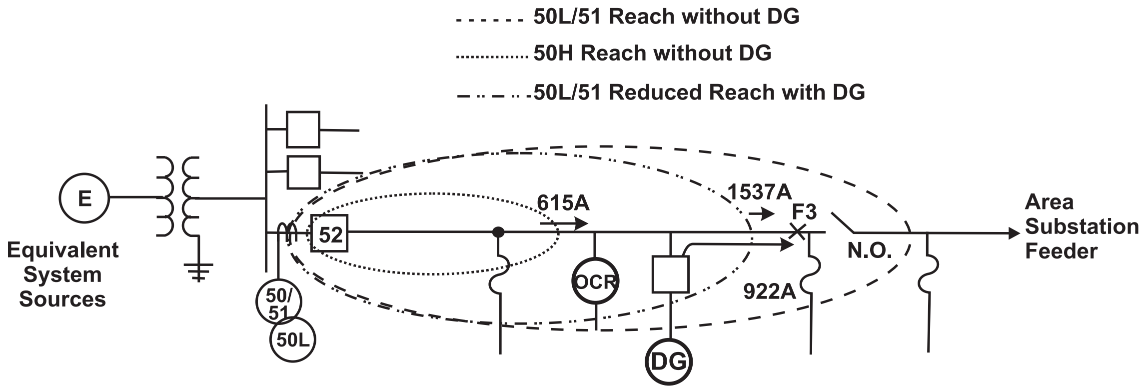

Fig. 2: DG Affect on Feeder Overcurrent Reach

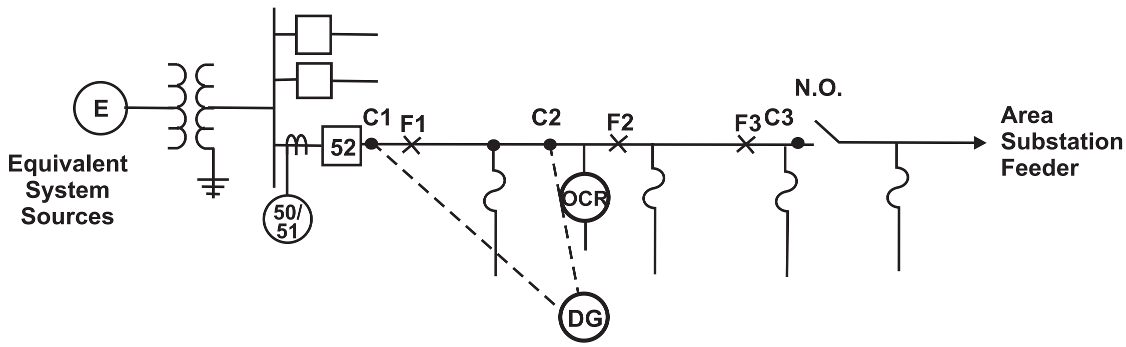

Fig. 3: DG Connection Locations for Case Study

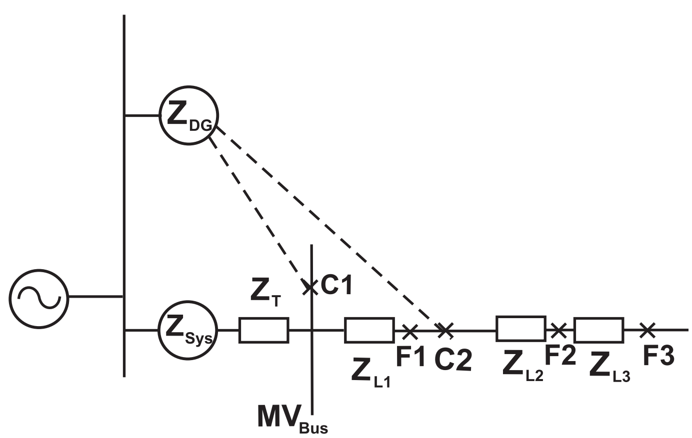

Fig. 4: Positive Sequence Network Diagram

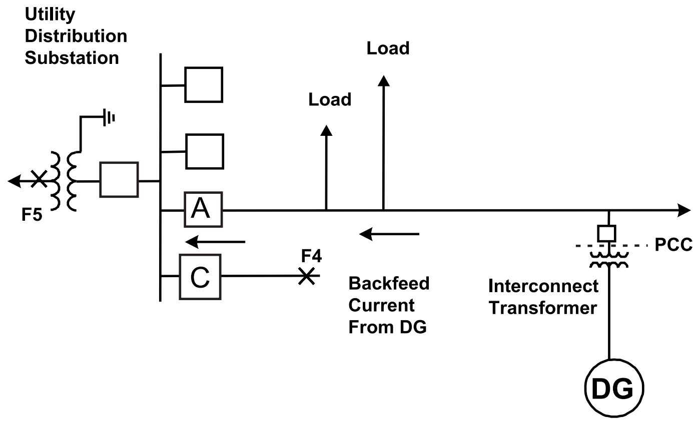

Fig. 5: DG Fault Backfeed Through Breaker A

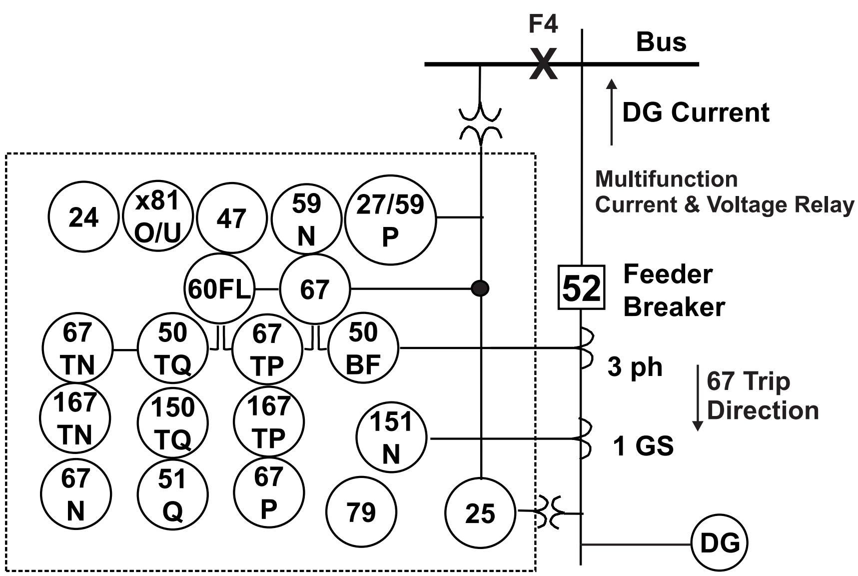

Fig. 6: Directional Feeder Protection Blocks for DG Backfeed

Table 1 represents the fault current distribution between the substation source and a 12.5 kV, 3.0 MW synchronous DG direct connected at various locations on the feeder circuit. Figure 4 represents the positive sequence network impedance diagram for three phase faults at the three locations shown in Figure 3. If the feeder time overcurrent relay pickup is set for 10 MVA circuit capacity plus thirty percent for load transfers, its pickup would be set for 600 primary amperes. At DG location C1, the relative impedance for three phase fault F1 is such that it gives an 80% system and 20% DG division of fault current. The substation protection has twenty percent less fault current through it when the DG is on line and running but still has ample current to operate its overcurrent protection. For a DG location at C2 and a three phase fault at F2, the ratio of fault current split is 50/50. This could approach the minimum pickup level of the overcurrent elements, so a change in pickup current should be considered on the overcurrent protection at the substation. If a multifunction protective relay is already on the feeder in the substation, it usually has a multiple setting groups feature such that its overcurrent settings can be changed from a remote location or through a local panel switch or the relay HMI, Human Machine Interface. With the DG located at C2 and the fault at F3, the DG is now the majority source with sixty percent of the fault current and the substation feeder is supplying only forty percent. Electromechanical discrete utility feeder overcurrent protection no longer may be able to be set low enough to see the fault without affecting its load current carrying capability. Figure 2 also shows the DG affect on the reach of the feeder overcurrent 50L/51 elements. These two elements no longer will have the necessary reach to the end of the circuit with the DG running at location C2. Installation of another overcurrent device such as a pole top recloser would be required in the main line in the vicinity of location C2 to provide adequate overcurrent protection by the utility to the end of the circuit. If a multifunction relay with multiple setting groups is protecting the feeder, the recloser may not be necessary.

The above explanation of how the DG affects the phase overcurrent protection by desensitizing it, depending on the location of the DG, also applies to ground fault current protection. If the DG is connected to the utility circuit through a grounded primary step-up transformer, there will be desensitization of the ground protection even if the DG is not on line but the transformer remains energized. *[5,6]* Table 2 shows the affect of the DG on the utility system for a direct connected DG and for various interconnect transformer configurations.

Advantages of having only numeric multifunction overcurrent protection at the substation for Issue 1 are, first, that it will have multiple time overcurrent curve shapes for coordination plus wider current pickup ranges than discrete relays from which to select. Also, its multiple setting group selection capabilities can be used to change operate current settings either manually or remotely depending on if the DG is or is not running.

However, when applying numeric multifunction protection systems to distribution feeders, protection engineers must guard against single contingency failures. That is, the application tendency is to use the multiple protection elements in one box to provide primary and backup protection. In the event of a single contingency failure, the feeder would be left unprotected. Electromechanical relays have the advantage of phase redundancy; that is, one of the phase relays could fail and the other two phases still would be able to operate. Application of numeric multifunction protection systems requires the protection engineer to overlap multiple protection elements of upstream protection systems (bus, bank breaker, transformer, etc.) with the associated feeder protection systems to guard against single contingency failure. In rare cases (critical feeder) a redundant feeder protection system also could be installed. Also, the self-testing and remote communications capabilities of numeric multifunction systems can immediately alert the user of a problem with the system, allowing for resolution of the condition before it becomes a reliability issue. Problems with non-communicating electromechanical and solid state protection schemes will not be found until an unexpected incorrect operation occurs or during routine maintenance.

Issue 2: How will DG backfeed for faults on adjacent feeders or the transmission system affect feeder protection?

Figure 5 shows two situations for fault current going backwards through breaker A at the substation. If the DG is located close enough to the substation, it could provide enough current to operate the non-directional overcurrent protection at the substation for fault F4 on an adjacent feeder or even fault F5 on the high voltage system supply to your utility transformer. To prevent false operation on adjacent faults like F4, directional overcurrent protection devices 67 and 67N are needed on the feeder in place of the non-directional 50/51 phase and neutral protection to prevent incorrect operation. Figure 6 shows the various elements available in a typical multifunction overcurrent relay system with voltage inputs, including the 67 elements that will prevent incorrect operation for faults on adjacent feeders. The additional voltage inputs are used to polarize the phase and ground overcurrent elements so that they will operate for current flow in only one direction. Uses of other elements in the multifunction relay in Figure 6 will be addressed in other issues. The upstream Bus Zone of protection will clear Fault F4 shown in Figure 6.

Table 2 DG Interconnection Contribution to Utility System Faults

DG Connection Type	Operating Condition	Phase Fault Contribution	Ground Fault Contribution
Solid or Low Resistance Grounded DG, Grid connected, no Interconnect Transformer	Generator On Line Generator Off Line	YES NO	YES NO
Through Interconnect Transformer Configurations:			
High voltage side Wye grounded, Low voltage side Delta	Generator On Line Generator Off, Transformer On	YES NO	YES YES
High voltage Wye ungrounded, Low voltage side Delta	Generator On Line Generator Off, Transformer Off	YES NO	NO NO
High voltage side Delta, Low voltage side Delta	Generator On line Generator Off , Transformer On	YES NO	NO NO

Issue 3: Protection for DG backfeed to faults on the transmission system

Most utility power transformers use a delta high voltage winding, solid or low resistance grounded wye low voltage winding configuration. When a DG is added to a feeder, it can backfeed to faults on the high voltage system F5 in Figure 5. After high voltage circuit breakers have operated for a single line to ground fault, the DG can keep the line energized without current flow to the fault, because the delta winding blocks the flow of zero sequence fault current to the fault. The high voltage system can remain energized as an ungrounded system if proper protection is not installed to detect this condition. Figure 7 shows an additional multifunction relay system that can detect these faults on the high voltage system. The 67 directional overcurrent or 21 impedance elements will detect phase faults. A power directional element, device 32, is sometimes incorrectly applied for phase backfeed protection. *[4]* The 32 element normally operates for a current and voltage in phase, while the 67 element is typically polarized from a current and the other two phases to ensure strong polarizing will be available for phase-to-phase faults. Additional voltage transformers are needed for a zero sequence voltage detector, device 59N, to detect the single phase to ground condition when fed from the DG through the feeder breaker. If only a single phase voltage transformer is available, a combination 27/59N under/overvoltage element can detect most single line to ground faults. However, it can be fooled if a single line to ground fault occurs during heavy loading conditions.

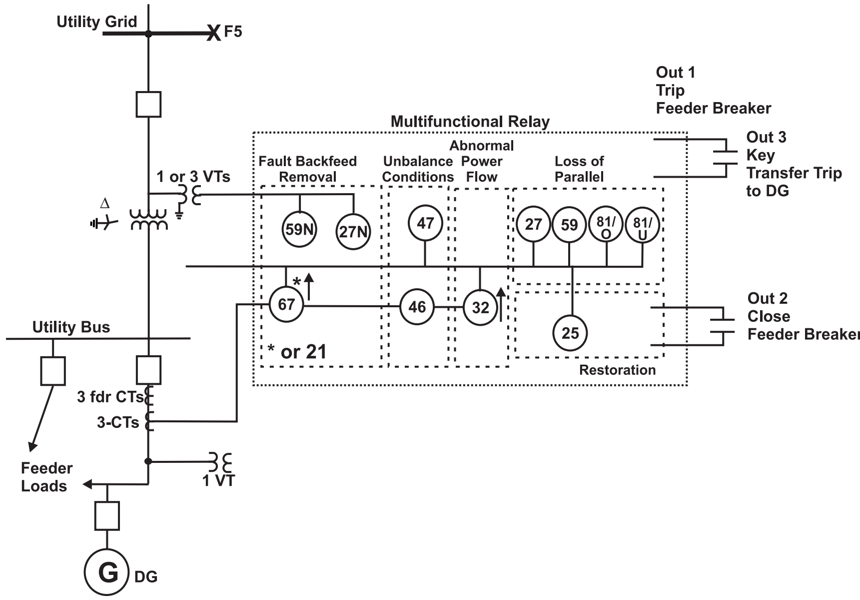

Fig. 7: Typical Protection for DG Backfeed to High Voltage System Faults

A Transfer Trip, TT, system is sometimes used, depending on the size of the DG, to provide primary isolation of the DG from the utility. Transfer Trip is a communication system with a transmitter at the utility end keyed by any opening of the feeder breaker, whether manually, remotely by SCADA or automatically by protective relays. The signal is then sent by a communication link such as microwave radio, fiber optics or telephone pairs to a receiver at the DG location. The receiver then will trip the interconnect breaker at the DG site. Protective relays at the DG intertie point also are needed as backup protection for the transfer trip scheme to detect all faults on the utility system. [5]

Issue 4: Protection for DG Backfeed to an isolated or islanded utility distribution circuit

A situation can occur when a DG is connected to a distribution circuit where the substation feeder breaker A in Figure 5 trips for a fault condition and, due to a malfunction or incorrect setting of the protective relays at the DG intertie point or “Point of Common Coupling, PCC”, the DG continues to supply utility loads. This is an “islanding” condition. Islanding is not a good situation for several reasons such as possible hazards to the utility workers when power lines continue to be energized even with the substation feeder breaker open. The DG could be providing utility load with operating voltages or frequency outside the State Regulatory Commission Standards. While protection for this condition is at the DG intertie location and not provided as part of the utility feeder package, this issue is mentioned because it supports the feasibility of using Transfer Trip to provide opening of the DG intertie breaker for any operation of the feeder breaker. Under/overvoltage elements, devices 27/59, under/over frequency elements, devices 81 O/U, and rate of change of frequency, device 81R are available in multifunction protection systems at the DG intertie for islanding protection. Careful consideration must be given to the generation-to-load ratio to establish the voltage and frequency trip thresholds.

Issue 5: Blocking out of synchronism reclosures by the utility feeder breaker

Most utility feeders have automatic reclosing control available on a feeder breaker to initiate one high speed reclose (20 to 30 cycles) after clearing a fault. The DG must be separated from the circuit by either substation initiated transferred trip or on site backup protection within the twenty to thirty cycles before the feeder breaker reclose to prevent damage to the generator from being closed in out of phase with the utility. This will require undervoltage elements, device 27P in Figure 6, or 25VM (conditional voltage reclosing), which are not normally available as part of the basic feeder protection scheme, to block closing of the feeder breaker until the DG has been separated from the feeder.

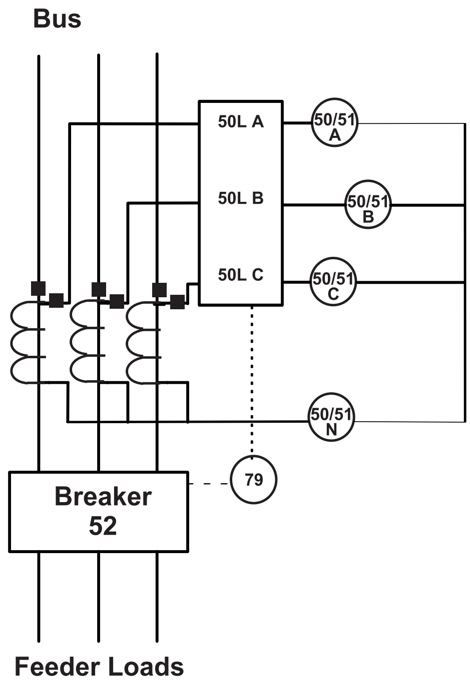

Fig. 8: Feeder Protection and Control with Discrete Relays in Six Individual Relay Cases

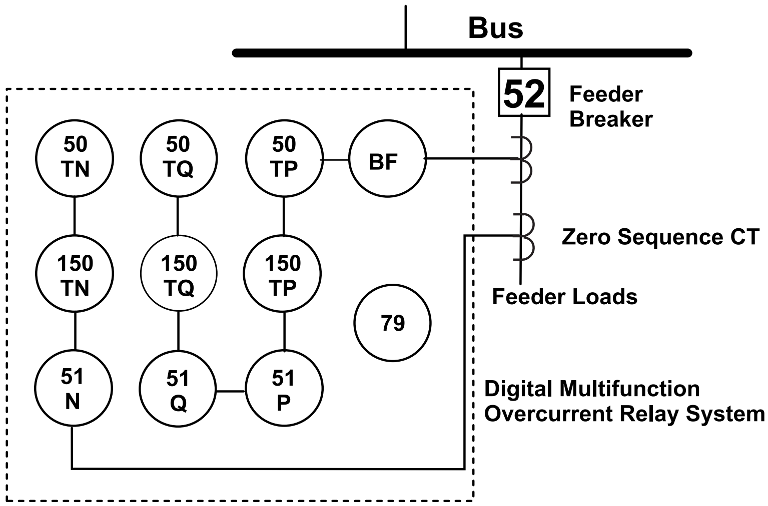

Fig. 9: Digital Multifunction Feeder Protection and Control Functions in One Case

Summary of Issues: Protective elements for providing solutions to Issues 1, 2 and 5 are available in most numeric or digital multifunction overcurrent with voltage protection packages as shown in Figure 6. Issue 3 requires the cost of additional relays not associated with feeder protection that would be considered for addition only when a DG applies for a connection to your utility circuit. Protection for Issue 4 could be a multifunction relay as part of the DG owner's responsibility at the DG intertie point.

III. Benefits of Digital or Numeric Multifunction Protection Systems

A normal basic overcurrent protection scheme consists of six individual relay cases as indicated in the three-line diagram of Figure 8. All of the elements in a multifunction system without voltage inputs, as shown in Figure 9, can be purchased in a case that is the same physical size as only one of the phase overcurrent relays. Cost of this overcurrent only multifunction package is less than half that of the basic discrete relays in six cases. To achieve the same functionality of the multifunction high voltage backfeed package would require physically larger directional overcurrent relays and would take up more than double the mounting space. Also, the addition of a three phase voltage monitoring element to control breaker closing would be required. For less than seventy-five percent of the cost of the basic four discrete 50/51 instantaneous/time overcurrent relays, a three phase instantaneous overcurrent relay for fuse saving and a 79 reclosing relay, a communicating multifunctional overcurrent with voltage protective relay manufactured to ANSI Standards can be purchased. The cost of individual discrete relays to provide the protection shown in Figure 7 can be as much as five times the cost of the multifunction system. People with foresight will be wise to begin their savings by applying multifunction protection at the initial design and installation of feeder protection in order to be prepared for the addition of Distributed Generation in the future.

Now that we have shown a cost saving advantage in the initial purchase of a multifunction protection system package over individual discrete relays for the previous issues, this section of the paper looks at other benefits of multifunction protection systems.

III.1. Digital Multifunction Relay Elements

Multifunction relay systems have the advantages of additional protection, control and metering elements. Elements shown in Figures 6 and 7 include negative sequence overcurrent detectors, (device 46 or 51Q,) that can be set to operate for system unbalance conditions from a blown high side fuse of a power transformer or unbalance due to operation of single phase switches or protective devices. Also, a breaker failure element, device 50BF, for operating backup devices for stuck breaker conditions is usually included. For relay systems with voltage inputs, other elements included are frequency elements, device 81, and under/over voltage, devices 27/59, for loss of parallel or operation of the DG outside of State Regulatory Commission requirements. The 81 elements also can be used for load shedding applications. Power or watt detecting elements, device 32, can be used for load import export supervision and control. Instantaneous and demand metering of the phase, negative sequence and ground current quantities and voltage and watt var quantities are also a part of these systems.

III.2. Engineering time for each type of protection

Engineering time to provide one-line and control schematic diagrams will be about the same for both discrete and multifunction relays. Time savings can be realized in production of wiring diagrams, because most of the logic is designed or “wired” inside the box of the multifunction relay rather than the hard-wired connections required between the discrete relays and their controls. Any time saved in the engineering is likely to be absorbed in the learning curve for programming and documenting the logic in multifunction relays.

III.3. Time required to set each type of relay

Discrete relays can take as much as three times longer to set than multifunction relays, because the current pickup points involve setting up a current source, running current through the element, and adjusting a plunger or spring or tweaking a potentiometer to calibrate it to the proper current level. Pickup points of multifunction relays can be entered through the HMI or uploaded from a computer and do not have any mechanical adjustments. Testing time of multifunction relays also can be less because the testing of each individual current input for the phase functions is not necessary. After a phase current being input is converted into binary coding, the relay usually uses common internal circuitry to produce an output. However, it is a good practice to use a current source to verify that proper operate current has been set on multifunction relays at the initial commissioning of the protection.

III.4. Installation time of each, including advantage of retrofit packaged digital relay

Panel space required for installing discrete relays is four to five times more than required by a multifunction relay package. Typical panel area for six discrete relays may be twenty-six by thirty inches. A multifunction relay in a full draw-out case with the same functionality as the six discrete relays can be installed in a panel area about seven by 10 inches or the equivalent of one phase of a discrete relay package. If the multifunction relay is a half rack type design, it can be installed along with a current and trip circuit isolating switch in a nineteen by three and one half inch space. Wiring connections to six discrete relays may require as many as 68 connections to terminals, whereas the multifunction package may require a maximum of twenty-four. Thus, the multifunction relay results in savings in mounting and wiring labor costs.

III.5. Periodic Maintenance intervals of each type

Depending on how critical the loads connected to the feeder circuit, discrete electromechanical relays may have test current run through them and calibrated at intervals ranging from annually to several years. They also may have tripping and reclosing tests performed at different intervals than current operate and calibration tests.

Some users choose not to maintenance test multifunction relays at regularly scheduled intervals, depending on critical loads, because they have the ability to communicate to a remote location their internal failures at the instant they occur. Some users perform only an occasional test of the trip output circuit or note fault operations as an indication that the relay is functioning properly. Another advantage of the multifunction relay is its ability to display or communicate to a remote location the instantaneous value of currents, voltages and watts and vars. These quantities also provide an indication of the relay health.

III.6. Programming methods of multifunction relays, ASCII commands, Excel spreadsheet and Software packages

Designing the logic structure inside the multifunction relay is the most time-consuming aspect of applying this type of device for system protection and circuit breaker control. If a person begins "cold", without much prior knowledge of multifunctional relay programming or how it works, a learning curve for studying the instruction manual to learn command structure of the elements and their interconnection logic may be between eight and sixteen hours. Another eight hours could be taken up with actual programming in ASCII language and troubleshooting the program if the relay will not accept it because of incorrect characters or extra spaces between characters. This is very tedious work. Excel spreadsheets have been developed to aid in this programming method, but each command line must be acceptable to the relay or it will not accept the program. This leads to troubleshooting time to find and correct the error. The Excel Spreadsheet method may be done in about half the time of the ASCII individual command method or in the range of eight to twelve hours.

Some multifunction relay manufacturers have developed Windows based "point and click" software programming methods that do not require knowledge of the ASCII commands. With this type programming software, preprogrammed schemes have been developed by the relay manufacturer. They can be used as they were designed or easily can be modified through this point and click logic, then uploaded to the relay. Persons commissioning the relay with minimal knowledge of programming but armed with the manufacturer's logic building software have been led by an application engineer via phone to develop a basic overcurrent logic scheme and install it in the relay in less than two hours. The learning curve for this type of programming can range from four to twelve hours depending on the complexity of the protection and control logic program.

III.7. Data available from multifunction relays

Most discrete relays do not have any memory or data storage capabilities so they cannot retain a history of what they see during operate conditions. Multifunction relays have the ability to retain a time tagged sequence of events such as when an input, output or element changes state and when it times to provide a trip output. Oscillography can be downloaded from the relay to provide a picture of the individual currents, voltages when provided, and digital element changes of state over time.

III.8. Benefits of having digital multifunction protection in place when Distributed Generation is added to a distribution circuit

III.8.1 Larger span of element operate ranges and time curve shapes available if the influence of DG results in lower operate point for overcurrent elements.

III.8.2 Multiple setting groups to select different operate parameters depending on whether the DG is on line or off.

III.8.3 Sequence of Events, Fault Records and Oscillography for analyzing abnormal or fault conditions - this information could be called "Cardiogram of a Kilowatt" because it provides a picture and history of events seen by the protection.

III.8.4 Use of communication links to permit remote access to read instantaneous operating currents or demand currents; gather analysis data or change operating points of elements. (The breaker should be open when changing operating points to avoid the possibility of incorrect operation, even though some multifunction packages will block setting changes when they are within ten to twenty percent of the pickup of an operating element set point.)

III.8.5 For multifunction relays with both current and voltage elements

III.8.5.1 Directional elements in multifunction relays with voltage inputs and elements to prevent operation of feeder protection for high backfeed for DG to faults on feeders connected to the same bus

III.8.5.2 Synchronism check, device 25, and dead line close restrictions, device 27P, to prevent out of sync closing that could damage the DG

III.8.5.3 Directional power, device 32, elements to alarm or open the intertie for power flows outside contract agreements

IV. Conclusion

The effects of the addition of Distributed Generation to a feeder can be minimized by having digital multifunction overcurrent with voltage protection schemes already installed as standard feeder protection. Savings in initial cost of protective relaying, engineering design, installation time plus conservation of physical space for mounting equipment and periodic maintenance will be realized from this multifunction protection package. The additional protective elements available in these packages will solve the protection related effects of Distributed Generation, regardless of the size or number of DG's added to your circuit.

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