A FRESH LOOK
AT
DISTRIBUTION PROTECTION

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INTRODUCTION

Electric customers are more often affected by distribution system disturbances than by transmission disturbances. This is due to the closer proximity of the distribution system to trees, human activity, and the load itself.

Distribution monitoring, control, and protection had remained relatively unchanged for years. Capital for monitoring, control, and protection improvements had primarily gone to the transmission system because a disturbance on a transmission line affects more people than a disturbance on a distribution line, in most cases.

Utilities are now starting to upgrade the monitoring and control capabilities of their distribution systems with distribution automation and SCADA -- distribution protection has not lagged behind. New microprocessor-based distribution relays significantly advance distribution protection and reduce utility capital, operational, and maintenance costs. Much of the available information and operational flexibility of these relays is accessible via remote communications.

Most digital distribution relays provide traditional phase and ground overcurrent protection, reclosing functions, and limited metering and event reporting. In this paper, the additional features of more advanced digital distribution relays are discussed.

DISTRIBUTION DYNAMICS

Dynamic Engineering

Protection schemes are constantly being modified and improved. Changing traditional protection schemes often requires purchasing and installing additional equipment.

References 1, 2, and 3 give examples of how some utilities changed their distribution protection schemes from fuse saving to trip saving (fuse blowing) schemes and had to install additional timers. Future changes and enhancements in traditional installations will also require additional equipment.

Philosophy of distribution protection changes over time and differs from utility to utility; sometimes from area to area within the same utility. If a distribution relay meets one utility's requirements, it may not satisfy another's. Making factory modifications to satisfy different utilities is costly, time consuming, and results in "one-of-a-kind" relays.

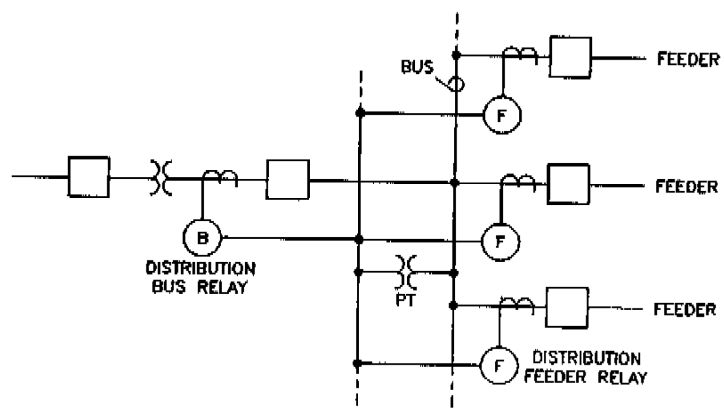

Figure 1: Typical Distribution System Arrangement and Protection

Dynamic Distribution System

An electric power distribution system changes hourly to seasonally:

- Scheduled switching for construction or maintenance projects
- Emergency switching for repairs
- Bus-tie breakers substituting for distribution feeder breakers
- Seasonal load transfers

The resulting system reconfigurations last from hours to months. Many reconfigurations are repeated. The following problems can result:

- Major changes in load or unbalance
- Large variations in fault duties, due to source and feeder changes
- Coordination problems with different protective equipment
- Increased fault duty on conductor, cable, and equipment

Traditional protective equipment does not adapt readily to distribution system reconfigurations. If new settings are needed they have to be manually changed: there are no settings in reserve. The time to make or enter and test new settings slows down emergency responses and risks human error. Sometimes relay settings are not changed for emergency or abnormal switching, because it takes too long or is too difficult. System protection is compromised.

PROGRAMMABLE DIGITAL RELAYS ADAPT TO DISTRIBUTION DYNAMICS

Programmable Logic

Relay design engineers devised user-programmable logic for advanced digital distribution relays. This logic handles future protection schemes as well as the multiplicity of protection schemes that protect different utilities' distribution systems. With these new relays, there is less need for additional equipment as protection schemes are enhanced.

The power of the programmable logic comes from ANDing, ORing, inverting, and timing of relay elements, using Boolean algebra logic equations. Relay elements are combined to make conditional logic for internal functions and output contacts. Relay element combinations can be run through independent timers. Relay elements such as overcurrent elements, reclosing relay states, and inputs are used in this programmable logic. The programmable logic replaces discrete timers, auxiliary relays, diodes, and external interconnections.

Relay programming can be done locally or via remote communications.

Programmable Logic Example

In the following example, relay opto-isolated input IN6 supervises the ground overcurrent elements (51NT and 50NLT) for tripping. Input IN6 can be de-energized during circuit paralleling operations to prevent the ground overcurrent elements from initiating a trip on temporary current unbalance.

51NT	is a ground time-overcurrent element.
50NLT	is a ground definite-time overcurrent element.
IN6	is a relay opto-isolated input.
51T	is a phase time-overcurrent element that is to be unsupervised.
+	is the logical OR operator.
*	is the logical AND operator.

A = 51NT+50NLT	Intermediate ORing level of programmable logic. If 51NT or 50NLT assert, "A" asserts.
E = IN6	Intermediate ORing level of programmable logic (no ORing done in this case). If input IN6 is energized, "E" asserts.
V = A*E	ANDing level of programmable logic. If both "A" and "E" are asserted at the same time, "V" asserts. IN6 supervises "51NT+50NLT".
	Effectively, V=(51NT+50NLT)*IN6.
TR = 51T+V	TR is the TRIP output contact programmable trip variable.
	Effectively, TR = 51T+[(51NT+50NLT)*IN6].
	Close TRIP output contact = TR+ ...

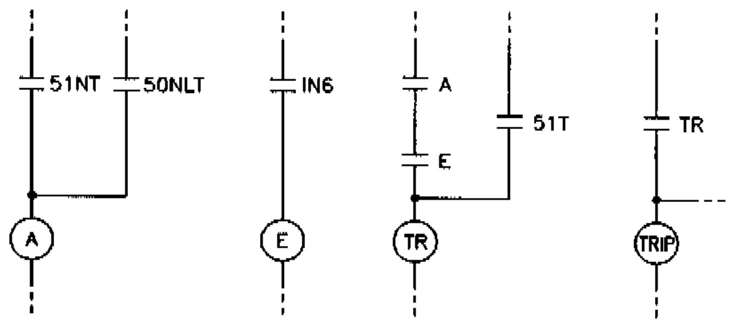

Figure 2: Relay Logic Representation of Programmable Logic Example

Multiple Setting Groups

Advanced distribution relays handle system reconfigurations with multiple setting groups. A specific setting group can be enabled by:

- command via communications port or
- setting group selection opto-isolated inputs

Different setting groups can be programmed to cover many different contingencies. The optimal protection scheme and settings are enabled for highest service reliability.

Operational costs are reduced by not having to make or enter and test new settings. This is done conveniently in advance. For example, in a bus-tie circuit breaker application, the bus-tie relay stores the settings for the feeder relays it replaces (see Figure 3).

References 4 and 5 describe the first relay with multiple setting groups. In new distribution relays, the multiple setting group feature has been expanded to allow the programmable internal logic and output contact functions to change along with the relay element settings.

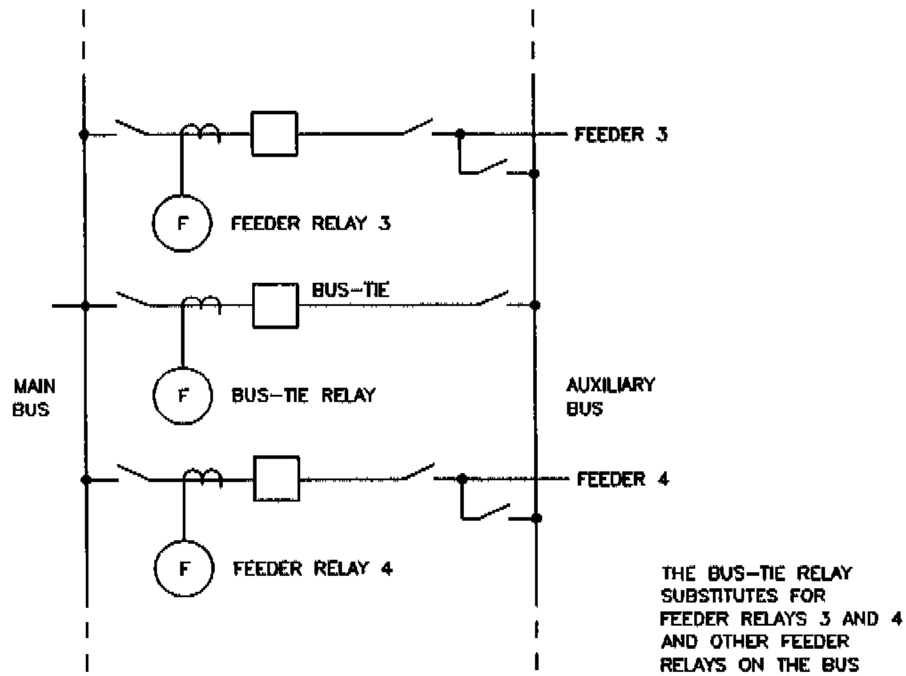

Figure 3: Bus-tie Breaker Substitutes for Distribution Feeder Breakers

OTHER DISTRIBUTION PROTECTION ADVANCES

Faster and More-Sensitive Phase-to-Phase Fault Protection

Negative-sequence overcurrent elements have been added to advanced distribution relays. Negative-sequence overcurrent elements can be set to respond faster and more sensitively to phase-to-phase faults than traditional phase overcurrent protection, because negative-sequence overcurrent elements do not respond to balanced load current.

Like ground overcurrent elements, negative-sequence overcurrent elements can be set below load current levels. On the other hand, phase overcurrent relays must be set above load current levels.

Table 1 shows that negative-sequence currents are generated during unbalanced faults. With the new primary protection coverage offered by the negative-sequence overcurrent elements, phase overcurrent elements are needed for only three-phase faults.

Table 1: Traditional and New Primary Protection Coverage Comparison

System Condition	Currents Generated			Traditional Primary Protection Coverage		New Primary Protection Coverage		
	Phase Current (I_P)	Negative-sequence Current (I_2)	Zero-sequence Current (I_0)	Phase Over-current Elements	Ground/ Residual Over-current Elements	Phase Over-current Elements	Negative-sequence Over-current Elements	Ground/ Residual Over-current Elements
LG Fault	X	X	X		X			X
LLG Fault	X	X	X	X	X		X	X
LL Fault	X	X		X			X	
3-Phase Fault	X			X		X		
Balanced Load	X							

The negative-sequence overcurrent elements can also cover phase-to-phase-to-ground faults where the ground fault resistance is high. High ground fault resistance makes a phase-to-phase-to-ground fault appear as a phase-to-phase fault to a relay.

The setting method for negative-sequence overcurrent elements requires minimal coordination effort (Reference 6).

Event Reporting is Vital to Distribution System Understanding and Improvement

Recreating the sequence of events for a distribution system disturbance with information available from traditional distribution protection equipment is difficult at best. In most instances, targets are the only source of information. Targets can show phase involvement and relative fault current magnitudes (did the instantaneous element operate?), but no time sequence or precise fault current magnitude information. If targets are not reset from a previous operation, the confusion is compounded when the next disturbance occurs.

Sequence-of-events recorders and oscillograms are generally considered too expensive for distribution applications. An experienced operator must interpret oscillogram output.

Engineers now quickly retrieve event reports from advanced distribution relays by telephone modem and review every operation. Event reports simplify event analysis by combining currents, voltages, relay elements, and contact I/O in one report.

Event Report Advantages

- One report contains all information -- several cycles worth.
- One report fits on one or two sheets of paper.
- Report retrieval is fast: only 30 seconds at 1200 baud.
- Event reporting is essentially free: it is part of the relay, and digital relays cost less than electromechanical or static analog relays.

System Knowledge Increased

- Sequence-of-events data are now available at all voltages and points in the system.
- We no longer need to rely on oscillographic data that may be available one or two stations away from the fault.
- The phasor voltage and current data, along with fault location, are being used to verify and improve system modeling.
- Scheme performance is easy to ascertain from the detailed data available after each operation.

System Problems Discovered

- Instrument transformer ratio and polarity errors
- Instrument transformer failures
- High-resistance fault analysis
- Repeated failures to synchronize a generator
- Calculation of zero-sequence impedance of lines

Reference 7 reviews some event reports and illustrates practical analytical tools.

Because event reports are simply text files, it is easy to import them into other programs for editing and additional processing. Several utilities have developed spreadsheet programs for processing event reports (References 8) and commercial packages have been developed for the same purpose (Reference 9).

An example event report is given on the following page (Figure 4).

Fault Locating Reduces Outage Time

Impedance-based fault locating reduces line patrol and outage time. Faulty line section locations are identified by the relay fault locator in distance from the relay location. Problems can be readily isolated and repaired. Transient fault locations can also be identified and repaired before they cause future permanent faults. Fault location distance is given in the event reports.

Power system voltage and current are input into the advanced distribution relays for fault locator operation. No communication channels or source impedance information are needed. Distribution conductor size changes are handled by nomographs.

Reference 10 gives an in-depth discussion of impedance-based fault locating.

Panel Space Savings

One digital distribution relay can take the place of four overcurrent relays (three phase and one ground), a reclosing relay, and demand ammeters in a traditional installation. The panel space savings can be significant.

Many utilities are moving away from mounting relays in cutouts on steel panels and toward mounting relays in 19" or 24" standard, commercially-available racks and cabinets. Rack-mount packages virtually eliminate cutouts. These packages mount directly in the racks and are easily moved or replaced as needed for future requirements or expansion. Such changes do not require cutting or drilling.

```
            Currents                    Voltages            P    Q  N   I   Out  In
             A pri                        V pri
                                                          555T 55 555 D 7B T13A 135
   IR     IA     IB     IC       VA      VB      VC       100C 10 100 E 9K &&&L &&&
                                                           LHI     LH M  R C24R 246

   -5    -82   -288    362    -1613   -9533   11081   .... .. ... . R. .... B35   One cycle of data,
   -0    382   -254   -122    11837   -7279   -4601   .... .. ... . R. .... B35    prefault conditions
    5     77    288   -362     1606    9533  -11081   .... .. ... . R. .... B35
   -0   -379    254    122   -11830    7279    4601   .... .. ... . R. .... B35
                                                                                 Both (B) inputs 1 and 2
   -5    -74   -288    362    -1606   -9540   11081   .... .. ... . R. .... B35    are energized.
   -0    374   -254   -122    11844   -7279   -4615   .... .. ... . R. .... B35   Input 3 (3) is energized.
    5     79    288   -362     1591    9547  -11074   .... .. ... . R. .... B35   Input 5 (5) is energized.
   -0   -377    254    122   -11851    7265    4637   .... .. ... . R. .... B35

   -5    -82   -288    362    -1577   -9554   11066   .... .. ... . R. .... B35
   -0    379   -254   -122    11844   -7250   -4644   .... .. ... . R. .... B35
    5     79    288   -362     1562    9569  -11066   .... .. ... . R. .... B35
   -0   -379    254    122   -11837    7236    4644   .... .. ... . R. .... B35
                                                                                 Reclosing relay
   -7    -77   -288    362    -1555   -9569   11066   .... .. ... . R. .... B35    (dev. 79) is in the
    2    379   -254   -125    11844   -7236   -4658   .... .. ... . R. .... B35    reset state (R).
  124    192    283   -355     1570    9569  -11066   .... .. ... . R. .... B35
  277    -82    228    132   -10800    6818    4349   .... .. p.. . R. .... B35
                                                                                 Overcurrent elements
-1153  -1200   -252    314    -1519   -9634   11066   p... p. pp. . R. .... B35    pick up (p) at phase
 -226     84   -190   -120     8575   -5904   -3686   p... p. pp. . R. .... B35    A-to-ground fault
 2318   2338    218   -269     1361    9742  -11023   p... p. pp. . R. .... B35    inception and start
 -153   -425    178     98    -7265    5342    3298   p... p. pp. . R. .... B35    timing.

-2600  -2614   -211    257    -1246   -9799   10987   p... p. pp. . R. .... B35
  204    470   -178    -96     7106   -5256   -3254   p... p. pp. . R. .... B35
 2639   2650    211   -254     1217    9814  -10987   p... p. pp. . R. .... B35
 -212   -478    178     96    -7078    5242    3262   p... p. pp. . R. .... B35

-2646  -2654   -211    254    -1210   -9821   10980   p... p. pp. . R. .... B35   Ground overcurrent
  216    482   -178    -96     7070   -5242   -3276   p... p. pp. . R. .... B35    element 50NLT times out
 2646   2654    211   -254     1210    9821  -10973   p... p. pp. . R. .... B35    after 3 cycles ("p"
 -221   -487    175     96    -7070    5227    3290   p... p. pp. . R. .... B35    changes to "T"). 50NLT
                                                                                  enabled for tripping.
-2646  -2652   -211    254    -1202   -9821   10973   p... p. pT. . R. T... B35    TRIP output contact
  224    490   -173    -96     7070   -5213   -3298   p... p. pT. . R. T... B35    asserts (T).
 2646   2650    211   -254     1188    9835  -10973   p... p. pT. . C. T.3. B35
 -224   -490    173     96    -7070    5206    3305   p... p. pT. . C. T.3. B35
                                                                                 Reclosing relay is in the
-2646  -2652   -209    254    -1181   -9850   10966   p... p. pT. . C. T.3. B35    reclose cycle state (C).
  226    494   -175    -96     7070   -5191   -3312   p... p. pT. . C. T.3. B35
 2527   2532    199   -242     1159    9850  -10958   p... p. pT. . C. T.3. B35
 -504   -710    110    106    -8129    5602    3650   p... p. pT. . C. T.3. B35   Circuit breaker auxiliary
                                                                                  contact (52A) opens and
-1491  -1498   -115    144    -1166   -9799   10951   p... p. pT. . C. T.3. B3.    input 5 is de-energized
  438    521    -26    -65    10354   -6509   -4342   p... p. pT. . C. T.3. B3.    (input IN5=52A).
  326    331     24    -34     1289    9713  -10966   .... p. pT. . C. T.3. B3.
  -56    -70      5     10   -11678    7049    4745   .... .. p.. . C. ..3. B3.
                                                                                 Overcurrent elements drop
  -44    -43     -5      5    -1382   -9677   10987   .... .. ... . C. ..3. B3.    out after circuit
    7     12      0     -2    11844   -7099   -4802   .... .. ... . C. ..3. B3.    breaker clears fault.
    7      5      0      0     1382    9684  -10987   .... .. ... . C. ..3. B3.
   -0     -2      0      0   -11858    7092    4810   .... .. ... . C. ..3. B3.

Event   : AG T    Location:   2.45    Shot:   0   Targets: INSTAQN       Event Summary - includes
Currents (A pri), ABCQN:   2698    274    271   2616   2655               fault location
```

Figure 4: Example Event Report

Self Testing Improves Relay Availability and Reduces Maintenance Budgets

Well-designed digital relays use fewer components than electromechanical or static analog designs, and thus provide more reliable protection. Failures can still occur, however. In the remote chance that a failure does occur, automatic self testing is almost certain to detect the problem and send operators an alarm via SCADA, etc. The result is much improved relay availability.

Because relay self testing, event reporting, and metering functions provide information about how the digital relays are performing, routine testing is much less important. Before digital relays, routine tests (or misoperations) were the only indicators we had of electromechanical and most solid-state relay problems.

Given that routine-testing resources are limited and digital relays have event reporting and automatic self testing, the overall protection of the power system is improved if these limited resources are applied to devices lacking reporting and self testing functions.

Back Up Several Feeder Relays with a Bus Relay

Use one bus relay to back up several feeder relays (refer to Figure 5 on the following page). A feeder relay $ALARM_F$ output contact can supervise a $TRIP_B$ output contact from the bus relay because backup is required only in the remote chance that the feeder relay fails. An $ALARM_F$ output contact closes if the feeder relay loses power or fails.

Because of this supervision, the bus relay $TRIP_B$ output contact can be set to operate as quickly as the feeder relay $TRIP_F$ output contact.

Time delayed trips from the feeder relays and the bus relay can trip the bus breaker (e.g., via programmable $A1_F$ and $A1_B$ auxiliary output contacts, respectively).

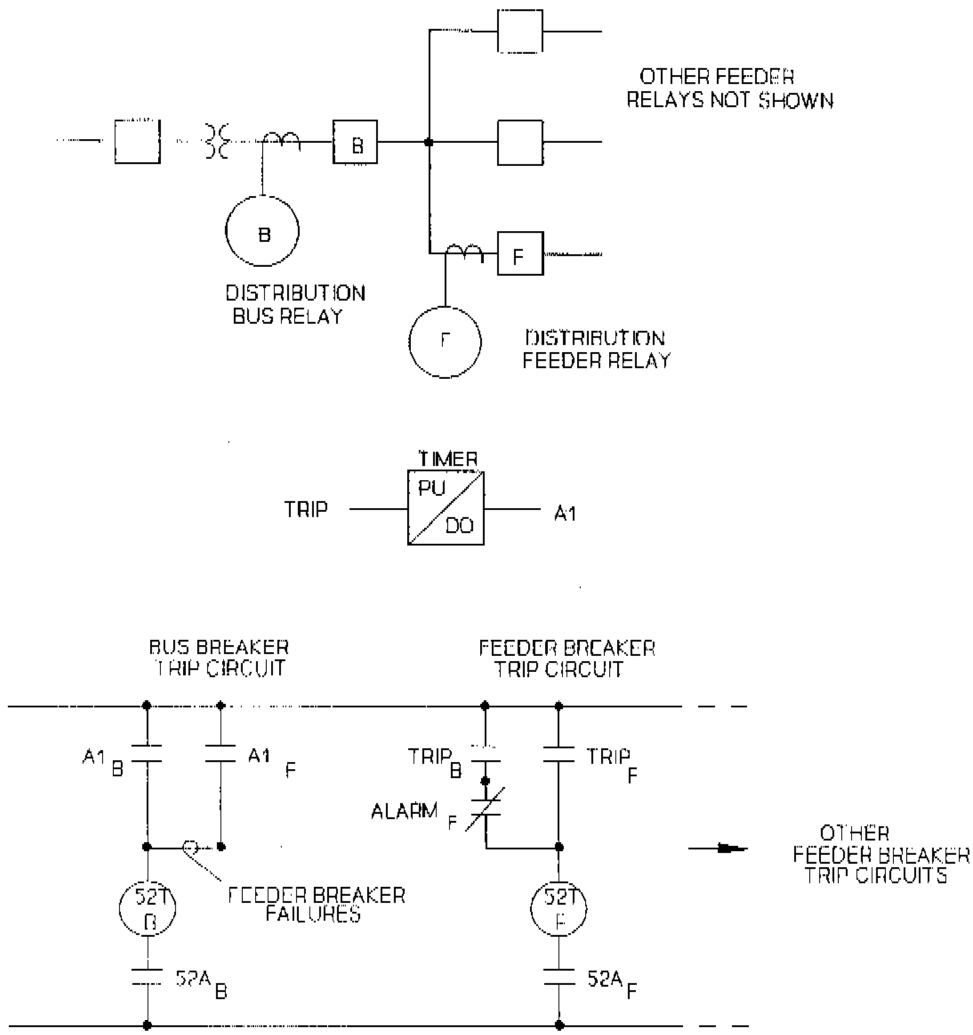

Figure 5: Distribution Bus Relay Backs Up Distribution Feeder Relays

The same protocol incompatibility problems that have traditionally plagued the SCADA industry currently exist at the substation integration level:

> To inter-tie a given vendor's device to a specific integrated network takes special protocol development, and typically happens on sub-networks that are dedicated to the specific device protocol.

An IEEE working group is investigating a standard, and the instrumentation, metering and protection industries are hopeful that they will have an accepted standard sooner than the group that has been trying to standardize the RTU to master protocol for years. There is some justification for this hope; The inter-tie of the other electrical devices adds value to the whole system, and generally RTU manufacturers are not attempting to swallow the protection or specialized instrumentation functions into their RTU. Until a standard is embraced, inter-vendor cooperation may allow a few de facto standards to replace many individual inter-connect protocols.

Features available in relays today have fulfilled some of the predictions made at DA/DSM™ 1991:

- Fault location data is available to feed centralized restoration analysis.
- Remote setting group selection allows adaptation to system topology.

Simply changing settings remotely, rather than selecting pretested setting groups, will not become a reality unless feasible remote testing methods are developed and accepted by protection engineers.

When the entire substation or pole-mount environment is analyzed, some duplicate functions can be eliminated if the data can be shared effectively. In integrating the protective relay functions with an RTU or other device, it is important to maintain the integrity of the protection system, and avoid compromises that could impair the protection of the system. Therefore, the protective subsystem should be able to fully function regardless of the status of the other elements in a local integrated network. Furthermore, the connection to the network must be done with care, to avoid the contingency that the communications connections could be a path for an electrical or software problem to impair protection.

When the overall system is designed, the main-office system that distributes data to the utility users must address the information needs of each user. The department responsible for protective relaying requires detailed data that is not particularly interesting to the operations department (the primary user of a SCADA or EMS system.) While the control center operators are interested in fault location, the protection engineers are interested in event reports, sequence of event recorder (SER) data, and oscillographic data. The protection data are interesting at sample rates and time tags of milliseconds and other fractions of electrical cycles; Most data used in the SCADA/EMS system for operations or metering purposes is based on a much longer sample period. These diverse needs must be addressed in any design to integrate protection data requirements with other data systems.

CONCLUSIONS

Advanced digital distribution relays improve distribution protection and reduce utility capital, operational, and maintenance costs. They can also provide useful system information that is accessible via local or remote communications.

Programmable logic and multiple setting groups provide optimum protection for changing distribution protection schemes and system reconfigurations. Negative-sequence overcurrent elements respond faster and more-sensitively to phase-to-phase faults.

Capital costs are reduced because a digital distribution relay costs less than the host of electromechanical relays which the digital relay replaces. Besides the reduced cost, digital relays provide many more features than electromechanical relays, and the required panel space for installation is much smaller.

Taking advantage of event report and fault location information reduces operational costs. Engineering time is better spent analyzing detailed event report information to more expeditiously find the root cause of system problems, than trying to piece together minimal target information from electromechanical relays and eventual line patrol data. Fault location reduces line patrol and outage time. All this information is available via remote communications, too.

The self testing capabilities of digital relays make routine relay testing less important or necessary -- maintenance budgets can be scaled back. Digital relay self test alarms can be integrated into SCADA, etc. for remote indication to system operators. Relay self test alarm contacts can also be used to supervise distribution feeder backup tripping schemes.

Data exchange with digital distribution relays can be enhanced by connection to an integrated network. These designs should be carefully analyzed to ensure that the reliability and performance of the relay protection functions are not impaired by the network connection.

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