Advances in Microprocessor-Based Distribution Relays

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INTRODUCTION

Advanced microprocessor-based distribution relays have features that improve distribution protection and aid in event analysis and testing [References 1, 2, 3, and 4]. Significant relay advancements also handle system disturbances, relay failures, changes in protection philosophy, and changing system conditions.

SYSTEM DISTURBANCES AND EVENT REPORTING

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.

Technicians now quickly retrieve event reports from advanced distribution relays locally or 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. This is an aid in testing, also.

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 5 reviews some event reports and illustrates practical analytical tools. An example event report is given in Figure 1.

SHOULD SELF TESTING AND EVENT REPORTING CHANGE TESTING PHILOSOPHY?

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. Before digital relays, routine tests (or misoperations) were the only indicators of electromechanical and most solid-state relay problems.

Relays with automatic self testing and event reporting require less testing to ensure they are operating properly. Technicians can now better allocate their limited resources to relays without self testing and to analyzing event reports from relays having event reporting. When technicians review relay event reports, they are reviewing data from a test of the system created by a real fault. Technicians add more value to the electric power system, because they are checking not only the relay, but the surrounding equipment. Did the relay get proper voltages and currents? Did the circuit breaker auxiliary contact respond correctly?

CHANGES IN PROTECTION PHILOSOPHY AND PROGRAMMABLE LOGIC

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

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

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

Internal relay elements (e.g., overcurrent, voltage) can be programmed to control output contacts. This flexibility aids technicians in "isolating" and testing relay elements.

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. Figure 2 shows the example in relay logic form.

A = 51NT+50NLT	If 51NT or 50NLT assert, "A" asserts.
E = IN6	If input IN6 is energized with nominal control voltage, variable E asserts.
V = A*E	If both variables A and E are asserted at the same time, variable V asserts.
	Effectively, V=(51NT+50NLT)*IN6.
TR = 51T+V	TR is the TRIP output contact programmable trip variable. 51T is a phase overcurrent element. If 51T or V asserts, TR asserts.
	Effectively, TR=51T+[(51NT+50NLT)*IN6]
	Close TRIP output contact = TR+ ...

CHANGING DISTRIBUTION SYSTEM AND MULTIPLE SETTING GROUPS

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 derive, 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.

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 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 derive, 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 6 and 7 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.

CONCLUSIONS

Event reports, self testing, programmable logic, and multiple setting group features in advanced microprocessor-based distribution relays improve distribution protection and aid in event analysis and testing.

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BIOGRAPHIES

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          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
                                                                                      Ground overcurrent
-2646  -2654   -211    254    -1210    -9821    10980    p... p. pp.. . R. .... B35    element 50NLT times out
  216    482   -178    -96     7070    -5242    -3276    p... p. pp.. . R. .... B35    after 3 cycles ("p"
 2646   2654    211   -254     1210     9821   -10973    p... p. pp.. . R. .... B35    changes to "T"). 50NLT
 -221   -487    175     96    -7070     5227     3290    p... p. pp.. . R. .... B35    enabled for tripping.
                                                                                       TRIP output contact
-2646  -2652   -211    254    -1202    -9821    10973    p... p. pT.. . R. T... B35    asserts (T).
  224    490   -173    -96     7070    -5213    -3298    p... p. pT.. . R. T... B35
 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. T.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 1: Example Event Report

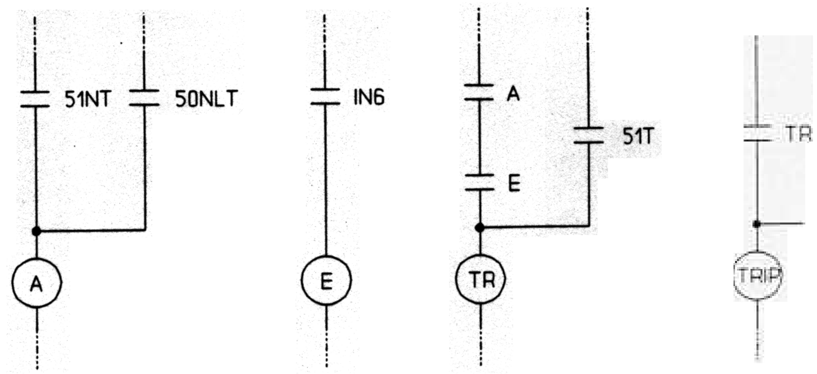

Figure 2: Relay Logic Representation of Programmable Logic Example

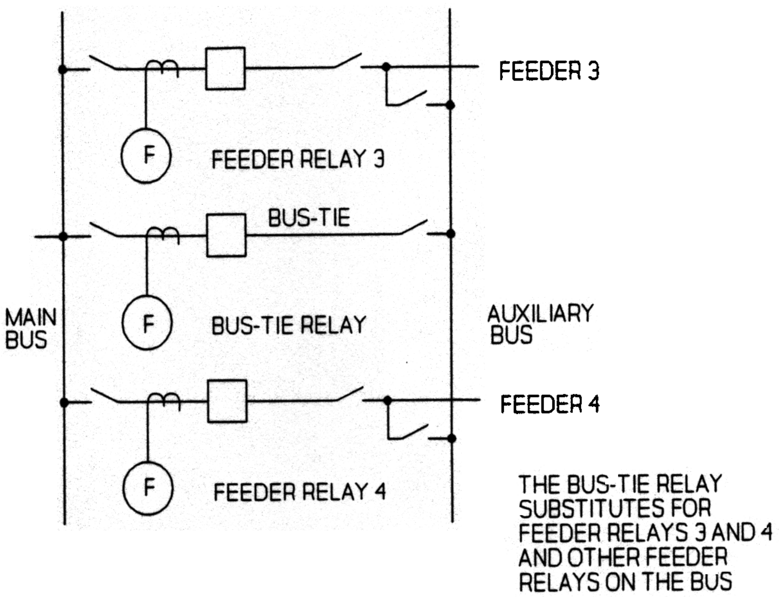

Figure 3: Bus-tie Breaker Substitutes for Distribution Feeder Breakers