COMMISSIONING NUMERICAL RELAYS

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INTRODUCTION

Modern numerical relays have many new features that were not available in electromechanical or analog designs such as setting groups, programmable logic and adaptive schemes. Although these features make numerical relays very powerful, they also create a need for reviewing commissioning methods. This paper will suggest changes to commissioning tests and revised documentation of relay settings. There are very few standards covering commissioning, so most methods come from experience. There are many methods that give good results. This paper suggests one approach.

Commissioning protective relays requires three primary tasks the relay personnel should perform:

- Calibration of the relays
- Functional test
- In-Service readings

Calibrating the relays confirms that, when voltage and/or currents appear at the relay terminals, the relay will respond according to design and setpoint. The functional test confirms that, when the relay contacts close, the proper breakers trip or close according to the design. The functionality of all AC and DC schemes should also be checked. To close the loop, in-service readings are taken as soon as the equipment is placed in service and has load current flowing. In-service readings confirm that, with a given load present, the proper voltages and currents appear at the relay terminals.

Calibrating relays and functional testing must be done before the equipment is put in service. In-service readings must be taken immediately after load is on the equipment. The equipment is not released to the dispatcher or plant operator until the in-service readings are correct.

There are other commissioning tasks important to protective relays such as testing instrument transformers, meggering control cables, confirming transformer taps, and so on. However, this paper will concentrate on calibration, functional testing and in-service reading. These areas are most affected when using numerical relays.

For the purposes of this paper we shall refer to electromechanical and solid-state relays as "traditional" and microprocessor based designs as "numerical". Although there are significant differences in electromechanical and solid-state devices, the methods used for testing and commissioning are similar, whereas numerical relays must be approached differently.

COMMISSIONING TRADITIONAL RELAYS

Using the simple overcurrent circuit of Figure 1, let's discuss how we would commission this traditional relay.

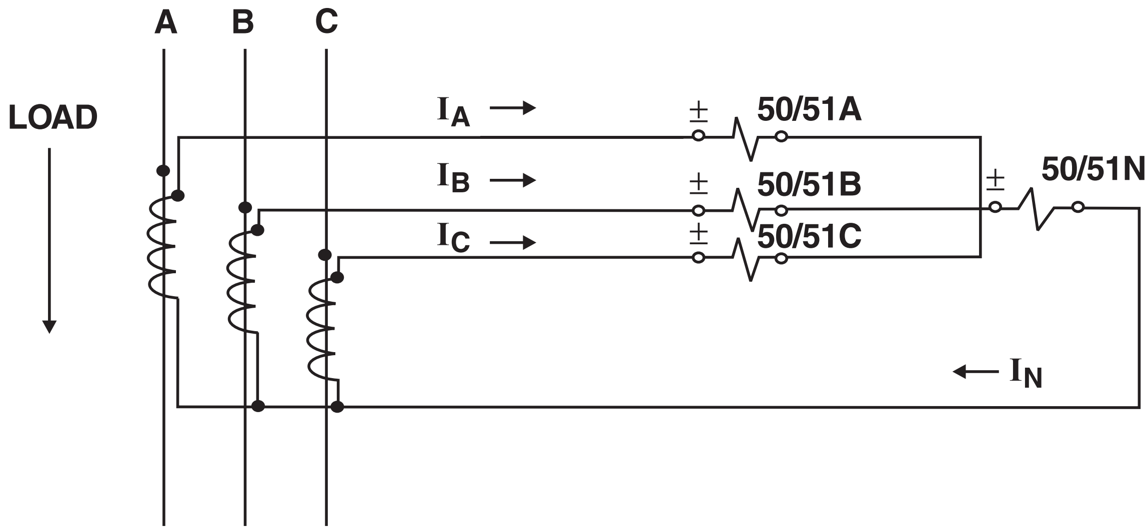


Figure 1: Overcurrent Circuit AC Schematic

Relay calibration is performed using the manufacturer's instruction manual and the relay setting sheets. In our simple overcurrent example the setting sheet would include identifying information about the station name, the feeder number, and relay model numbers. The actual setting is:

- CT ratio
- 50 element current setting
- 51 element inverse time curve selection
- 51 element tap
- 51 element time dial.

This information will easily fit on one sheet of paper, and keeping copies of the setting in either hard copy or electronically is easy.

The settings are put on the relays by selecting taps, adjusting dials or setting switches. Secondary current values are then injected into the relay using a test set. Pickup of the 50 and 51 elements is checked against the setting, and adjustments are made to bring the relay within calibration limits. Timing tests of the 51 element are also made to ensure the time dial and curve settings are correct. The output contacts are monitored during these tests with an ohmmeter or test set to indicate operation.

Functional Testing, also called trip checking, is another keystone activity of commissioning. This is not the place to cut corners. Our intent is to confirm that the protection and controls work as intended and also that they have no unintended consequences. Making checks to see the design works right is called a "positive" test. Making checks to see that the design doesn't work incorrectly is called a "negative" test.

Figure 2 is the schematic diagram for our simple overcurrent scheme. The phase overcurrent relays will trip the breaker directly. The ground relay has a cutout switch that must be closed to trip the breaker. Each overcurrent relay is operated one-at-a time to make certain each one works. The relay contact should be forced to close with the test set instead of applying a jumper across the contact. Targets are confirmed after each trip. Open the ground cutout switch, then attempt to trip with the ground relay; the breaker should not trip. With the ground relay trip contact still closed, turn the ground cutout switch back on and confirm that the breaker trips. This proves the cutout switch prevented tripping and not something else. These are all "positive" tests.

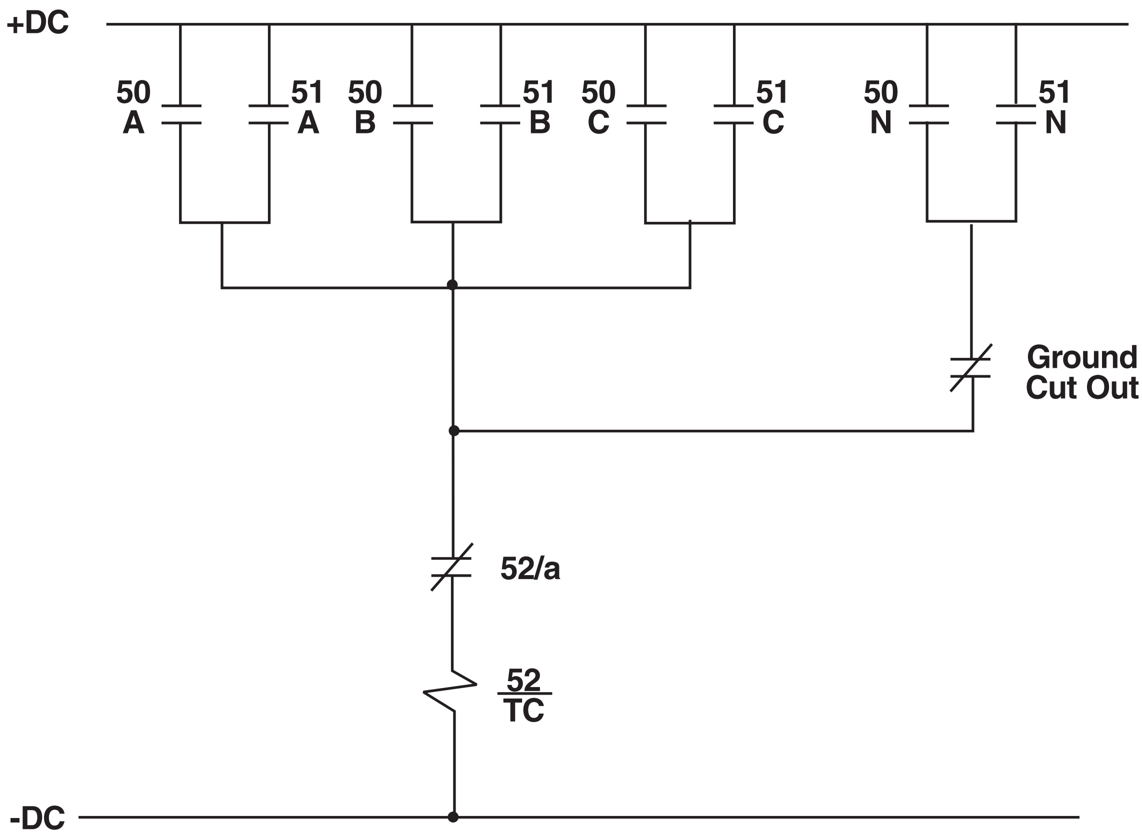


Figure 2: Simple Overcurrent Circuit DC Schematic

The "negative" tests are more difficult to define. We must look for ways the circuit could operate in some unintended manner. For example, suppose we need to take the circuit of Figure 2 out of service to work on it, and we remove the fuses or open the control power to this circuit. Suppose the fuses were not labeled correctly and we remove the wrong ones. While working on the circuit, the breaker is tripped because the fuses were labeled incorrectly and control power was never removed. This is an unintended consequence that cannot be caught by checking that the circuit works correctly with everything normal.

Another example is Figure 3 where our schematic diagram was intended to be like Figure 2 but mis-wired. Instead of cutting out the ground relay, the ground cutout switch opens tripping from all the relays. If we perform only the positive checks we confirm tripping of all the relays with the switch closed and it works correctly. We check the ground relay with the switch off and it doesn't trip, then with the ground relay contacts still closed we turn the ground switch on and the ground relay trips the breaker. If we stop our testing there, we will not discover that the phase relays are also cut out by the ground cutout switch.

To make the negative test for this circuit when the ground relay is off and the ground relay can't trip, confirm that the phase relays can still trip. Complete negative testing involves checking every possible combination and permutation in the circuit. Not too bad with our simple circuit, but it becomes complex when there are 20-30 circuit elements. It may not be practical to check every possible combination; in which case we should concentrate on the ones that would be caused by obvious errors such as improper wiring or identification.

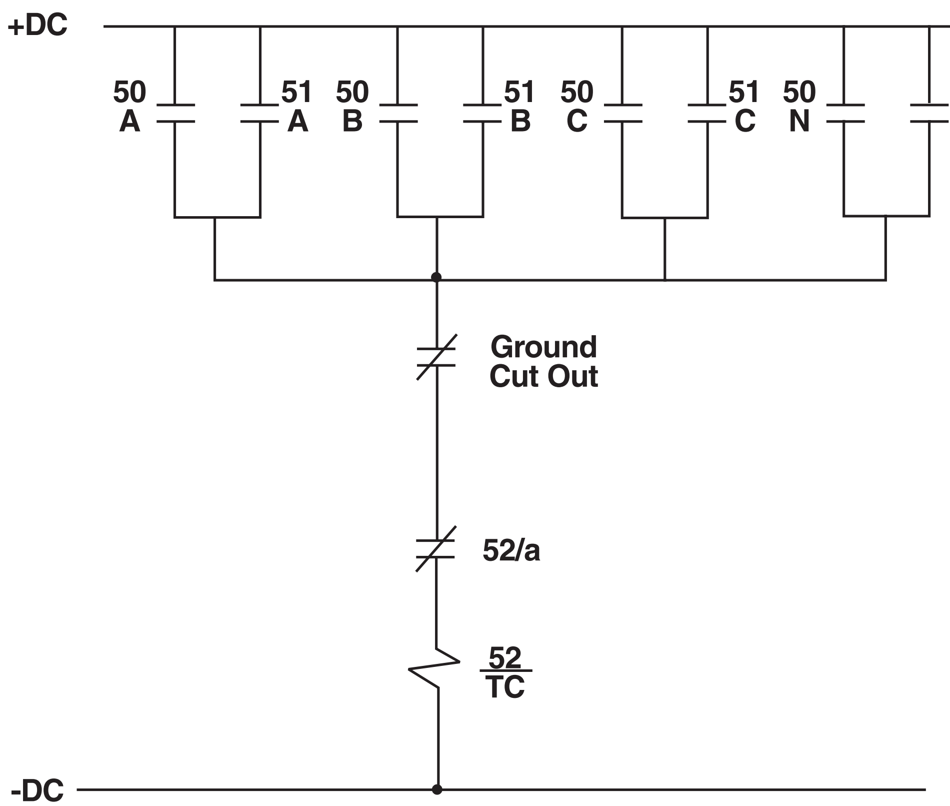


Figure 3: Miswired Overcurrent Circuit DC Schematic

The purpose of in-service readings is to prove, beyond a doubt, that the proper quantities of current and/or voltage appear in the relay. In-service tests are done with a phase angle meter, voltmeter and ammeter. The in-service check will confirm the correctness of the AC wiring, CT and PT ratio, the direction the relay is looking, phasing, direction and magnitude of switchboard metering, and direction and magnitude of SCADA metering. It may have taken weeks to get a line terminal ready for commissioning, but it takes less than an hour to perform a complete in-service test.

We must have some way of knowing the power flow in the primary bushings so we can compare it to our secondary values. In Figure 4, if possible, take primary current readings in the A phase primary bushing with a tong ammeter (on its extension stick). If this is not possible, station metering must be used to predict the load on the feeder. We then take secondary current and phase angle readings in the current coil of the relay with an ammeter and phase angle meter. We compare the two current readings taking the CTR into account; this verifies the CT ratio and that the relay coil is seeing the current. The phase angle reading compares A phase current to a reference voltage to prove the relay is looking at the polarity of A phase current and not some other phase. When we are satisfied that these readings are correct, the equipment can be released for service.

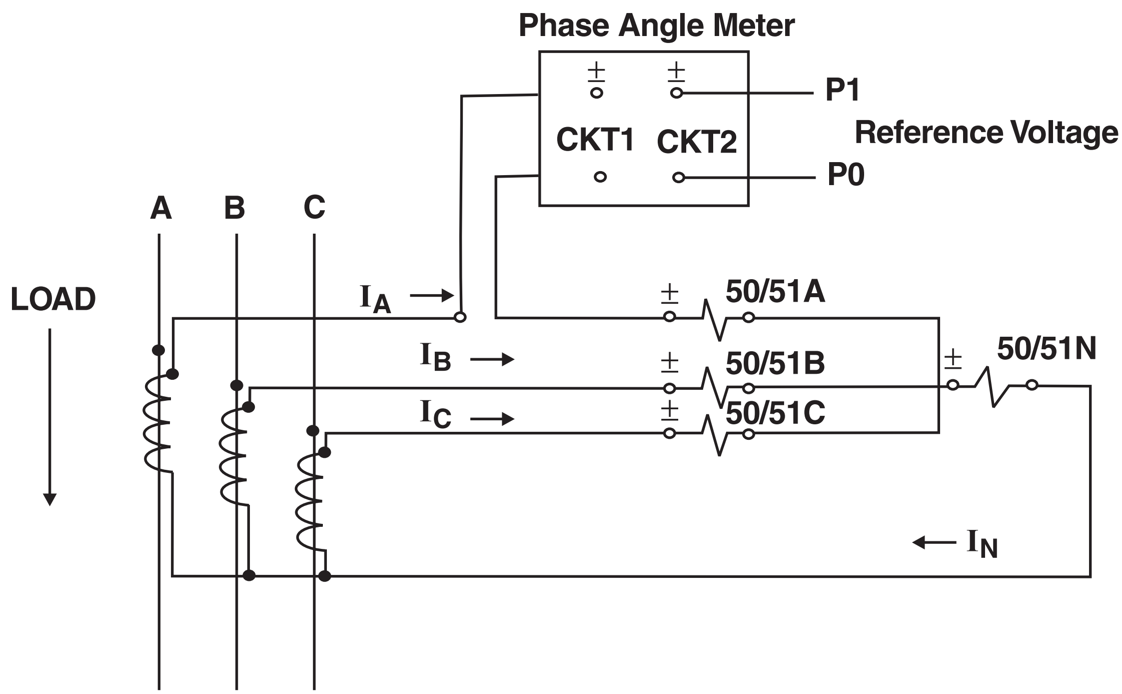


Figure 4: In-Service Readings

COMMISSIONING NUMERICAL RELAYS

The same basic steps apply to commissioning numerical relays:

- Verify proper functioning of the relay
- Functional test
- In-service readings

However, we must make adjustments to our technique to allow for the enhanced capabilities of numerical relays such as multiple setting groups, custom internal logic schemes, built in switches in logic, dynamic setting capability, internal phase compensation, diagnostic screens, communications, security, oscillography, alarms, and so on.

RELAY CALIBRATION

Calibration of numerical relays is usually not required since there are no adjustments to be made. There are no trim pots, switches, or selectors to make settings and adjustments with. If the relay does not operate within tolerance there is no way to adjust it, so calibration, as we know it, is not needed. However, each relay should be checked to make sure it is operating properly. Secondary injection is used to make the test, and the output contacts should be monitored.

Because there is a single algorithm instead of individual measuring elements, there is no need to repeat testing on every phase or every zone. For example, on impedance relays, it should be sufficient to test A phase zone 1, B phase zone 2, C phase zone 3, etc. However, automated relay testing can speed up the process so there is no significant time penalty for testing all phase combinations.

Most numerical relays allow a combination of entering the data from the front panel or through a serial port with the PC. To get full use of the capabilities of numerical relays the user should be able to interface the relay with a PC. In some cases, such as programming custom logic schemes, the PC will be required.

Because the numerical relay has extended capabilities there are more settings to put in the relay. Most numerical relays are multifunction devices that have several relaying functions built into one device. This adds to the number of settings for each relay, and we should think of these devices as systems rather than individual relays because they often include switches, metering, control, and wiring (in the form of logic schemes). We shall see that documentation of the settings will become an important factor in proper commissioning of the numerical relay.

DYNAMIC TESTING

Many numerical relays respond to dynamic conditions and change the way they operate accordingly. Distance relays come to mind initially, but manufacturers have added algorithms to detect dynamic conditions such as CT saturation and use the result to change the response of the relay. Relays that have dynamic characteristics cannot be tested completely with secondary injection of steady state values. The response of these systems can only be measured with tests that simulate the power system condition the relay was intended to measure. This often includes pre-fault load, fault condition with transients, and post fault conditions where all three phase voltages and currents are injected simutaneously. These test cases can be simulated with software or oscillography files. Testing the logic one function at a time in these complex schemes would be extremely time consuming and still may not prove the scheme works. There are many timing and coordination issues that can only be proven by testing the scheme exactly as it will be when it is in service.

If the test cases are played with the help of an automated test set, and the entire line protection panel is connected to the test set, then the entire battery of tests can be made without reconnection. By applying a series of faults that changes incrementally, balance points can be confirmed for every fault type and every phase combination. Since the testing is dynamic, it is not necessary to disable elements for testing as with steady state. It is always preferable to do your testing exactly as the scheme will be in service.

The performance of the distance elements changes with the Source Impedance Ratio. By running additional tests with a variety of SIRs, the performance of the tripping elements can be measured and compared against factory performance expectations. This set of data also gives us baseline information we can use in future tests to see if the scheme still is performing the same as when first installed.

Software is available to generate the more than 100 files needed to run all the cases. These files can then be combined with automated test equipment to run the cases in succession and to record the results. This is, by far, the most cost effective method with meaningful results.

The emphasis of automated testing is on relay characteristics. Control functions such as external cutout switches, auto-reclosing, and SCADA still must be checked as part of commissioning. If the user has standard schemes and has the ability to program the automated testing, these control features could be added to the automated test schemes with prompts to turn on or turn off controls as part of the automated testing and reporting.

Communications-aided schemes can be very difficult to test under actual system conditions, because the real communication signals have channel delay and attenuation characteristics that are difficult to simulate under test. The true proof is to allow the test equipment to communicate via satellite so the fault signal is given to both ends simultaneously. Any other method except for staged fault testing will leave questions about how the communications channels will coordinate with each other.

DISABLING ELEMENTS FOR TESTING

When dynamic testing is not done, testing multifunction relays may require that certain elements be disabled to accommodate steady state testing. For example, if our simple 50/51 relay has both time and instantaneous elements programmed to the same output contact, it may be necessary to disable the 51 element to get an accurate pickup value on the 50 element. This is not a difficult chore in most relays, but it does require making a change to the relay from the in-service setting to make a test. The preferred method of testing any circuit or relay is to test it exactly as it will be when it is in service. Making changes to the in-service settings after they are loaded into the relay requires that the setting be changed back. This may be risky because there may be dozens of settings that need to be changed and human error is a possibility.

One alternative is to begin by loading a copy of the in-service settings in the relay and disable elements for testing as the need arises. When the testing is complete, instead of trying to reverse all the changes, load the original copy of the in-service settings back to the relay. Now we know we are back where we started. File corruption between downloads is a remote possibility.

In applications where the same scheme will be used over and over it may be more convenient to create a setting group used only for testing. In this setting group the relay set points can be the same as the in-service group but with elements programmed to individual output contacts where needed for testing.

TESTING SETTING GROUP CHANGE

This may be one of the most powerful features of numerical relays, the ability to have several groups of relay setting that can be switched on manually or automatically to match the needs of the system. When system conditions change, the relay is notified and the settings can be changed instantly. There is no need to compromise a setting to fit two different system conditions.

However, in most applications we only need one or two setting groups so the others can stay empty having no settings at all. If the relay should inadvertently switch to an unused setting group, the relay would essentially be out of service. This is another instance where making the "negative" test is very important. Just because my settings and schematics show no setting group change, I should make the negative test to ensure that it will not cause an unintended consequence by switching to an unused group.

If setting groups are not used, copy the in-service group settings to all other unused setting groups. If the relay switches to one of those groups, it will still be in service with the proper settings. When more than one setting group is used, copy the default setting to all of the unused groups.

We should also identify any automatic or dynamic functions during the setting and commissioning process so they may be set and tested to work when needed and not work when not needed. It's the lack of a negative test that can cause us trouble on an automatic feature. If the setting group was accidentally programmed to change groups five minutes after the 51 element was at 70% of pickup, we might never encounter this during testing. After installation, when the load gets high, the relay will switch to another setting group and perhaps have no settings.

Using our 50/51 overcurrent relay example, let's say we don't need setting groups for our application. The setting sheet should list the setting group change and whatever set points or commands are needed to program it for "no setting group change". This way the setting engineer and the commissioning engineer have both identified the function so it can be a part of the testing and commissioning. Leaving it off the setting sheet because the function is not needed may mean it will not be checked at all. In this case a setting of zero is important.

DYNAMIC OR ADAPTIVE CHARACTERISTICS

This should be handled in a similar manner as setting group changes. Any preprogrammed feature of the relay that can make changes to the relay while it is in service should be brought out on the setting sheet so it can be confirmed during commissioning, even if it is not being used. These features are often used to cut out instantaneous or ground elements for relay coordination or change the set point of a protection element. If they are identified on the setting sheet, they can be tested to confirm that they operate as intended and don't operate when not wanted.

TESTING PROGRAMMABLE LOGIC

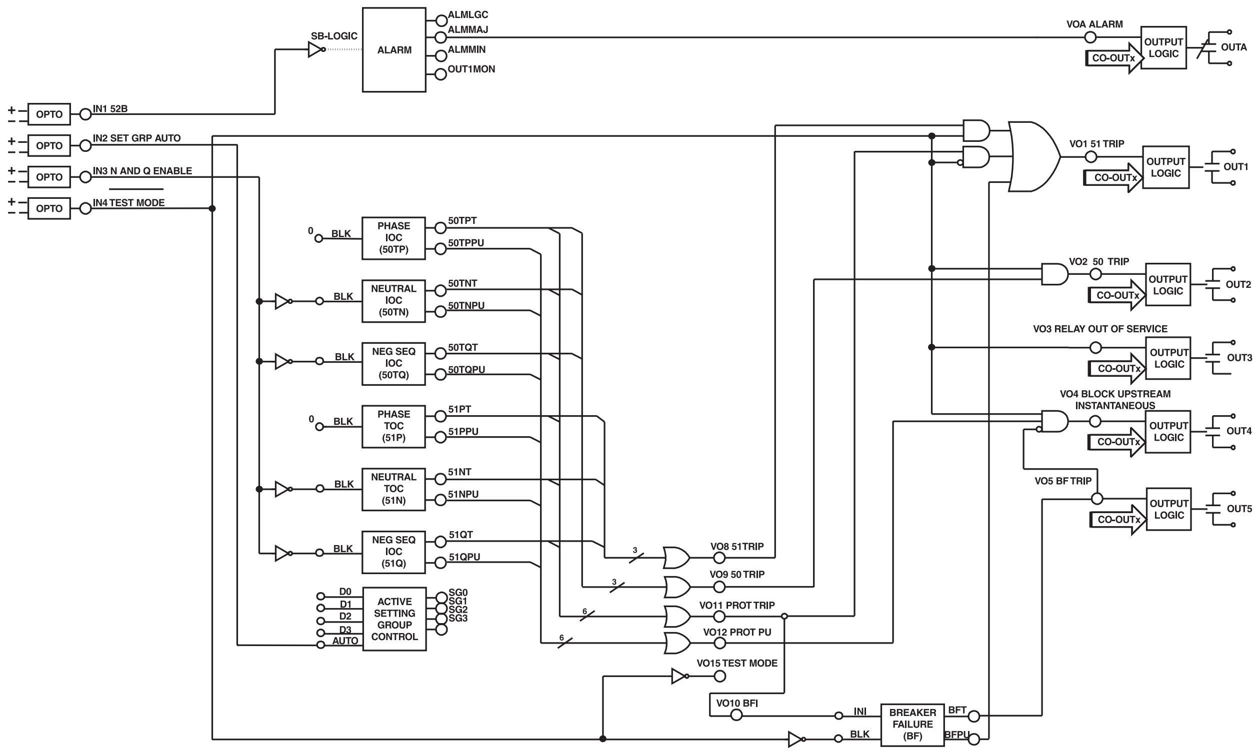
Multifunction relays have, in one device, the equivalent of several single function relays that would be found on the traditional relay panel. The functional schematic of the traditional relay is determined by the wiring from one device to the next. In the numerical relay the programmable logic takes the place of the wiring. Therefore, we should treat the programmable logic the same way we would switchboard wiring. Logic diagrams should be drawn out and documented on blueprints. Those prints should be part of the construction package or settings file. When it is time for the functional testing part of commissioning, testing of the programmable logic should be taken as seriously as functional testing traditional schemes.

Programmable logic is saved and transmitted to the relay electronically, sometimes in the same file as the settings. Saving the programmable logic to a file in advance of commissioning is a time saver, but it should not replace the need to generate a hard copy of the logic diagram to be used during commissioning and a permanent copy in the substation prints for troubleshooting.

Figure 5 shows a typical programmable logic scheme for basic overcurrent protection. This is the level of detail required to perform functional tests. Based on this information the commissioning engineer will be able to start with the inputs and confirm that input 1 changes as the breaker 52b changes state and that the relay correctly identifies the status of the breaker. Input 3 cuts out the ground and negative sequence relays and so on. Notice that there are enough output contacts to program the 51 element to output 1 and the 50 function to output 2. This eliminates the need to disable elements for testing as previously discussed.

The logic should be tested just as we described functional testing for traditional relays. That means we confirm that all inputs, outputs, relay function blocks, controls, alarms, and switches perform as intended and do not operate with unintended consequences (all positive and negative tests).

The sequence of events feature of numerical relays can be used to help sort out the results of logic testing to confirm that the proper elements are asserted, logic has functioned correctly, and timing is proper.



Note: For clarity, multiple variables going to the same OR Gate are shown by a single line into the OR Gate.

Figure 5: Typical Programmable Logic Scheme

Once a numerical logic scheme has been completely checked out, it is not necessary to repeat the internal logic testing every time that scheme is used. The scheme is repeated verbatim electronically. However, inputs, outputs, and operational settings must be checked every time.

TESTING EXTERNAL INPUTS

Most numerical relays use optical isolators to condition the input circuits as shown in Figure 5. These optical isolators have some DC voltage that defines their threshold of operation. The optical isolator should have a threshold higher than half the battery voltage but below the minimum expected DC bus voltage.

If your battery system is ungrounded you should confirm that the optical isolator will not operate with a full positive or negative battery ground. On a 130 volt DC system full battery ground would give half battery voltage or 65 volts to the optical isolator. After you test the input for proper operation at normal battery voltage, you should repeat the test at half battery voltage to confirm the optical isolator will not operate.

Some relays have internal jumpers used to set the optical isolator threshold. Set at greater than half the battery voltage, but less than the minimum expected voltage. If settable jumpers are not available, test the inputs for their threshold level and record this information on setting sheets and blueprints. This will remind others that the inputs may be falsely triggered for battery grounds.

TESTING TARGETS AND OUTPUT CONTACTS

Electromechanical relays commonly used trip and seal-in units in conjunction with the main relay contacts. The main contacts were normally not rated for tripping duty and the combination trip and seal-in took care of tripping duty, and reporting a mechanical target. The seal-in unit will stay picked up as long as trip current is flowing to the trip coil.

The output contacts of a numerical relay are usually individual sealed relays rated for 30a tripping duty. However, they will break less than 1 amp and will be damaged if opened while trip current is flowing. The output contacts are initiated by the internal trip logic of the relay and, therefore, are independent of trip current. To avoid damaging output contacts used for trip and close duty, the manufacturer should supply a hold-up circuit that will allow output contacts to remain closed for 10-12 cycles regardless of what the logic is doing. Once a trip or close has been initiated the contact should remain closed long enough to complete the breaker operation.

This type of setting is easily overlooked and may not be discovered until the relay is in service. This is another item that should be added to the setting sheet document so that it can be properly programmed and checked during commissioning.

In some cases, the targets of numerical relays have programmable features such as report last target, report all targets, report initial fault targets, ignore certain targets and so on. Electromechanical targets are cumulative. If we have five faults since last reset we won't know which targets went with which fault. Numerical relays normally report only the targets for the last fault. Previous target data can be retrieved from event data. Because there may be settings or logic associated with targets they also should become a part of the setting and commissioning procedure.

MAKING CHANGES TO EXISTING SETTINGS

After the numerical relay is in service and a setting change must be made, how much testing should be done? First of all, the field engineer should be armed with the existing settings and the new settings in case there is any question about the as found settings. This will also permit returning to the old settings if there is a problem installing the new ones. This should be in electronic format and hard copy print out.

The next step is to download the existing settings from the relay and check them against the existing setting file we brought with us. Discrepancies should be documented; after all, the reason for the setting change might be a mis-operation caused by a wrong setting in the first place.

If the two existing setting files match, we can load in the new settings. This is usually done electronically but some manufacturers have keypads that allow inputting of relay settings from the front panel. When the settings are loaded we should test all those items that have been changed. If the change is a relay setpoint, then secondary injection testing is indicated. If the change is in the relay's programmable logic, then a functional test should be performed. If the instrument transformer inputs have been disturbed, then in-service tests should be done.

IN-SERVICE READINGS FOR NUMERICAL RELAYS

Most numeric relays display the measured values of current and voltage that are used by the relay for protection. Sometimes these values can be compared to other values in the relay in terms of phase angle. Fundamentally there is nothing wrong with using these displays to perform your in-service readings so long as you leave knowing that the relay is, in fact, connected correctly.

Using these displays is no different than picking up a new phase angle meter. At some point you must confirm the meter display is correct. When you test the relay you will be able to check the display by inputting known current, voltage and phase angle from a test set. If the display is correct with a known source, there is no reason to break out another instrument for in-service tests.

With the test set connected, pay particular attention to the lead-lag convention of the relay and what quantity the relay is using as a reference. For example, if A phase current is used as a reference for the phase angle readings, then the angle for A phase will be 0 degrees. If B phase is 240 degrees, is that lead or lag? There is no standard; you must make note of it before commissioning the relay.

Knowing the lead-lag convention used in the relay will help us determine the phase sequence of the quantities applied to the relay. Most numerical relays can calculate sequence components for use in metering and protective elements. This may not seem important if the negative sequence element is not being used, but that doesn't mean it won't be in the future. Also, proper sequence will make negative sequence metering correct. Others may depend on the metering or may become alarmed at high readings.

Most relays have the capability of setting the normal phase sequence inside the relay either ABC or ACB. This is another setting that should be identified on the setting sheets so it can be confirmed in the testing and commissioning. You should be able to confirm this setting during commissioning by reading the metered value of the negative sequence current. It should be low for balanced load conditions. If not, check the phase sequence setting and CT wiring. If they do not match, relay targets may be incorrect. Correct CT wiring if necessary.

Numerical transformer differential relays have the capability of internally adjusting for the phase shift of a delta-wye connected bank. Keep in mind when using internal compensation that the currents going into the relay will not be 180 degrees out of phase as we expect with traditional relays. With numerical relays there is no physical operate winding, only a calculated value. So external in-service readings can only be taken on the restraint windings. Operating current calculated values are usually displayed by metering or software.

CT POLARITY

Some relays have a setting for CT polarity so the user can reverse the polarity if it is incorrect without re-wiring the CT circuit. Making the correction in the relay normally means the external wiring is incorrect. Changing polarity in the relay will make the relay work correctly but would mean the AC elementary is incorrect in the way the CT is wired to polarity of the relay. Either the AC schematic and setting sheet should be corrected, or the CT wiring should be corrected.

USING THE NUMERICAL RELAY AS A COMMISSIONING AID

Downsizing continues to force users to find new ways to get more accomplished in less time with less personnel. To help gain back some of that lost expertise, numerical relays have diagnostic and commissioning aids built in to help the user determine if the relay is installed correctly or to help diagnose a trip event to determine if it was correct.

CDS 220 Differential Check Record

REPORT DATE	: 11/10/98
REPORT TIME	: 11:10:08.203
STATION ID	: NORTHEAST SUBSTATION
RELAY ID	: TRANSFORMER #1
USER1 ID	: TEST1
USER2 ID	: TEST1
RELAY ADDRESS	: 0
ACTIVE GROUP	: 0

87T Settings	CTR	CT CON	TX CON	GROUNDED
CT CKT1	240	WYE	DAC	NO
CT CKT2	400	WYE	WYE	YES
MINPU	0.20 *TAP			
SLOPE	25 %			
ALARM	50 %			
URO	6 *TAP			

Compensation	Angle	Tap
CT CKT1	WYE	3.12
CT CKT2	DAC	4.68

ALARMS	PHASE A	PHASE B	PHASE C
DIFFERENTIAL:	OK	OK	OK
POLARITY:	OK	OK	OK
ANGLE COMP:	OK	OK	OK
MISMATCH:	OK	OK	OK

MEASUREMENTS	PHASE A	PHASE B	PHASE C
MEASURED I PRI			
CT CKT1:	209 @ 0	206 @ 240	206 @ 121
CT CKT2:	528 @ 211	516 @ 91	528 @ 332
MEASURED I SEC			
CT CKT1:	0.87 @ 0	0.86 @ 240	0.86 @ 121
CT CKT2:	1.32 @ 211	1.29 @ 91	1.32 @ 332
ANGLE COMPENSATED I			
CT CKT1:	0.87 @ 0	0.86 @ 240	0.86 @ 121
CT CKT2:	1.32 @ 181	1.29 @ 61	1.32 @ 302
TAP COMP I			
CT CKT1:	0.28 @ 0	0.27 @ 240	0.27 @ 121
CT CKT2:	0.28 @ 181	0.28 @ 61	0.27 @ 302
IOP:	0.01 *TAP	0.01 *TAP	0.01 *TAP
SLOPE RATIO	4 %	4 %	4 %

Figure 6: Differential Check Report

Figure 6 shows a differential report from a transformer differential relay. This report is triggered after the transformer is loaded to determine if the in-service readings are correct.

The **87T Settings** section reports the existing differential setting on the relay at the time the report was generated. The CTs are connected in Wye and the power transformer is made up with a DAC delta. URO is the unrestrained pickup. The alarm setting is something new. When the slope is at 50% of the trip setting, the user will be alarmed and an event is generated.

Because we have a delta-wye bank we must compensate for the 30 degree phase shift. The **Compensation** section tells us which circuit has the internal compensation applied, whether it is DAC or DAB, and what taps are selected.

The **Alarms** section helps us diagnose the problem if there is an alarm. It can tell us if the problem is with the CT polarity connection, phase compensation, or mismatch (which is a tap ratio problem).

In the **Measurements** section the in-service readings for current and phase angle are given for each phase:

- Primary current
- Uncompensated secondary current
- Compensated secondary current
- Compensated secondary current in per unit
- Operating current in multiple of tap
- Slope ratio

Using this report eliminates the need for external ammeters and phase angle meters to take in-service readings. Once the bank has been loaded, we trigger the differential report, look at the alarms (none in this report), check the per unit values of current and phase angle (equal current and 180 degrees apart), and confirm the slope ratio is minimal. Generation of this report can also serve as documentation of the in-service reading and eliminate some additional paperwork.

DIAGNOSING AN ALARM CONDITION

Figure 7 shows what the report would look like if we had an alarm condition due to improper setting of the phase compensation.

```
CDS 220 Differential Check Record
"
REPORT DATE       : 11/10/98
"
REPORT TIME       : 11:12:42.701
"
STATION ID        : NORTHEAST SUBSTATION
RELAY ID          : TRANSFORMER #1
USER1 ID          : TEST1
USER2 ID          : TEST1
RELAY ADDRESS     : 0
ACTIVE GROUP      : 0

87T Settings      CTR         CT CON      TX CON      GROUNDED
CT CKT1           240         WYE         DAB         NO
CT CKT2           400         WYE         WYE         YES
MINPU             0.20 *TAP
SLOPE             25 %
ALARM             50 %
URO               6 *TAP

Compensation      Angle       Tap
CT CKT1           WYE         3.12
CT CKT2           DAB         4.68

ALARMS            PHASE A           PHASE B           PHASE C
DIFFERENTIAL:     ALARM             ALARM             ALARM
POLARITY:         OK                OK                OK
ANGLE COMP:       ALARM             ALARM             ALARM
MISMATCH:         OK                OK                OK

MEASUREMENTS      PHASE A           PHASE B           PHASE C
MEASURED I PRI
CT CKT1:          206 @ 0           202 @ 240         204 @ 121
CT CKT2:          516 @ 211         508 @ 91          516 @ 332
MEASURED I SEC
CT CKT1:          0.86 @ 0          0.84 @ 240        0.85 @ 121
CT CKT2:          1.29 @ 211        1.27 @ 91         1.29 @ 332
ANGLE COMPENSATED I
CT CKT1:          0.86 @ 0          0.84 @ 240        0.85 @ 121
CT CKT2:          1.29 @ 241        1.27 @ 122        1.29 @ 2
TAP COMP I
CT CKT1:          0.27 @ 0          0.27 @ 240        0.27 @ 121
CT CKT2:          0.27 @ 241        0.27 @ 122        0.27 @ 2
IOP:              0.28 *TAP         0.28 *TAP         0.28 *TAP
SLOPE RATIO       104 %             104 %             104 %
```

Figure 7: Differential Check Record with Angle Compensation Error

The **87T settings** are the same except for TX CON which shows a DAB delta winding instead of DAC as it should be. The **Alarms** shows a differential alarm because the slope is greater than 50% of setting (in, fact it's 104%), and an angle compensation alarm telling us where the problem is. We can also tell from the compensated current readings that the angles are 240 degrees apart and not 180 degrees. Therefore, we can diagnose the problem without any additional instrumentation.

This kind of diagnostic is particularly helpful when working with inexperienced users, perhaps a co-gen facility not familiar with relays or a new employee. We can talk the person through generating the differential check record and diagnose the problem without being there.

DIAGNOSING WITH OSCILLOGRAPHY

Figure 8 shows the use of oscillographic records to determine why a relay tripped upon initial energization. The transformer immediately trips out upon energization. The fault records are observed to determine the cause. The top trace represents the A phase high side and low side currents as seen by a properly wired relay. The bottom trace represents the A phase high side and low side currents as seen by the relay that tripped. It can be seen that, in the lower trace, the high side and low side currents are in phase except for the 30 degree phase shift caused by the delta wye transformer connection. Thus, it can be determined that one of the CTs is wired with the wrong polarity.

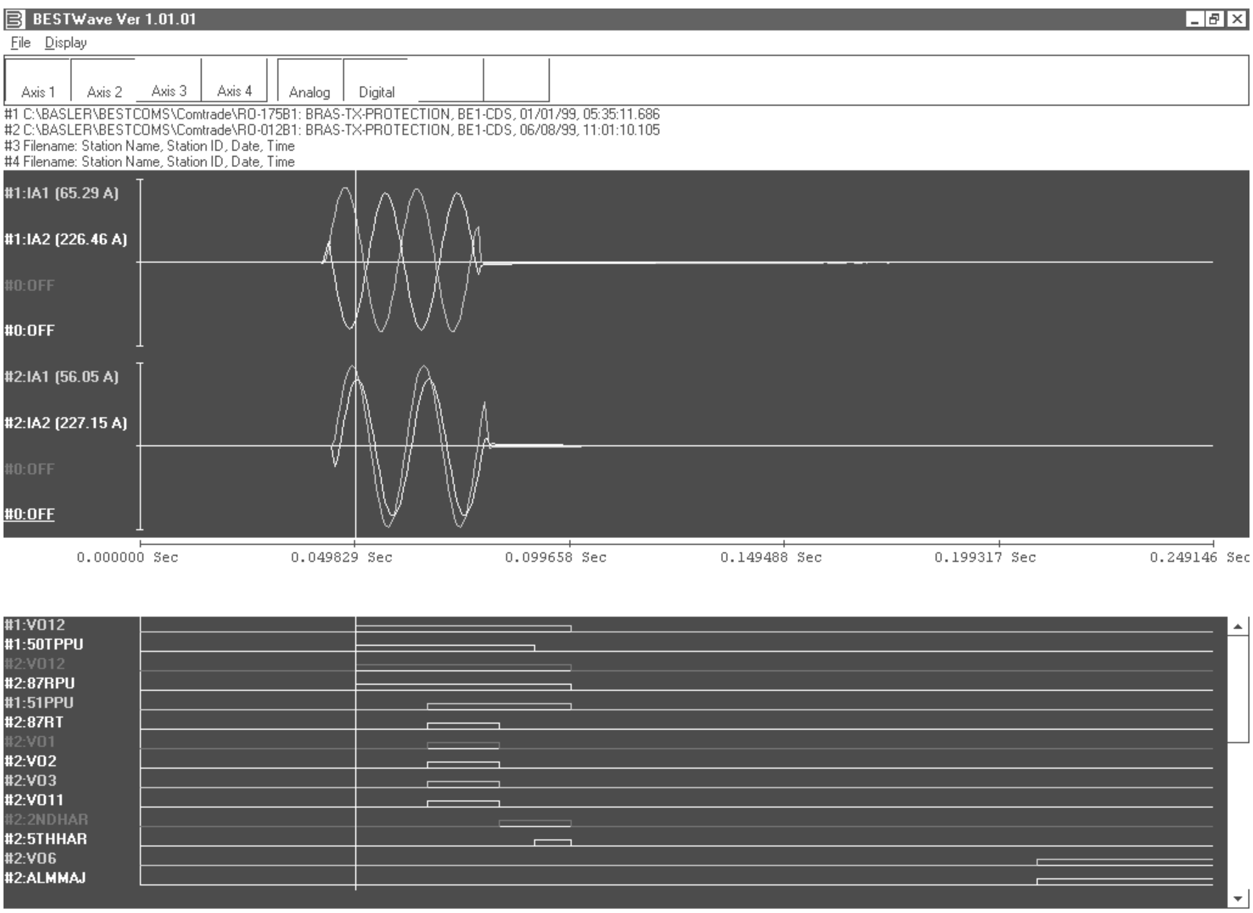


Figure 8: Typical Oscillographic Record

DIAGNOSING WITH SPREADSHEETS

If the trip out in Figure 9 were due to phase compensation error it might be difficult to analyze with the oscllography report. We can use a spreadsheet to take event data and plot phase angles of the currents at the time of the fault. After the fault we download the following event data from the relay:

```
FAULT DATE          : 14-12-00
FAULT TIME          : 19:58:26.671
STATION ID          : NORTHEAST SUBSTATION
RELAY ID            : TRANSFORMER #1
USER1 ID            : TRANSFORMERDIFFERENTIAL
USER2 ID            : ANDTIMEOVERCURRENT
RELAY ADDRESS           : 0
FAULT NUMBER        : 44
FAULT TRIGGER       : VO6
EVENT TYPE          : TRIP
ACTIVE GROUP        : 0
TARGETS             : 87RA,87RC
FAULT CLEARING TIME     : 0.059 SEC
BREAKER OPERATE TIME    : 0.050 SEC
OSCILLOGRAPHIC REPORTS: 1
IA1; IA2                : 62.62A @ 0; 315.2A @ 215
IB1; IB2                : 70.17A @ 254; 394.2A @ 106
IC1; IC2                : 77.71A @ 131; 368.6A @ 332
IN1; IN2                : 0.00A @ 0; 0.00A @ 0
IQ1; IQ2                : 9.59A; 46.95A
IG                      : 0.00A @ 0
>
```

The data is then plugged into the highlighted area of the spreadsheet (see next page).

Blue fields are fields used in the calculations.	
Yellow fields are for information.	

Relay ID	transformer #1
Station ID	northeast substation

CT Settings

	CT Ckt 1	CT Ckt 2
CTR (Turns)	120	400
CT Connection	wye	wye
Tx Connection	dab	dab
Gnd Source	0	0

Compensation Applied

Angle Comp	wye	dab
Tap Comp	2	2

87T Settings

Restr. Min. PU	0.25	* Tap
Slope	29	%
Restraint	Max	Max or Avg?
Unrest. PU	8	* Tap

Primary Fault Currents

	CT Ckt 1		CT Ckt 2	
	Mag	Angle	Mag	Angle
Phase A	62.62	0	315.2	215
Phase B	70.17	254	394.2	106
Phase C	77.71	131	368.6	332

Secondary Fault Currents

	CT Ckt 1		CT Ckt 2	
	Mag	Angle	Mag	Angle
Phase A	0.522	0	0.788	215
Phase B	0.585	254	0.986	106
Phase C	0.648	131	0.922	332
Neutral	0.097	229	0.121	149

Secondary Fault Currents

	CT Ckt 1		CT Ckt 2	
	Real	Imaj	Real	Imaj
Phase A	0.522	0.000	-0.645	-0.452
Phase B	-0.161	-0.562	-0.272	0.947
Phase C	-0.425	0.489	0.814	-0.433
Neutral	-0.064	-0.073	-0.103	0.063

Angle & Zero Seq. Compensated Currents

	CT Ckt 1		CT Ckt 2	
	Mag	Angle	Mag	Angle
Phase A	0.522	0	0.836	255
Phase B	0.585	254	1.014	128
Phase C	0.648	131	0.843	1

Angle & Zero Seq. Compensated Currents

	CT Ckt 1		CT Ckt 2	
	Real	Imaj	Real	Imaj
Phase A	0.522	0.000	-0.216	-0.808
Phase B	-0.161	-0.562	-0.627	0.797
Phase C	-0.425	0.489	0.842	0.011

Tap Compensated Fault Currents

	CT Ckt 1		CT Ckt 2	
	Mag	Angle	Mag	Angle
Phase A	0.261	0	0.418	255
Phase B	0.292	254	0.507	128
Phase C	0.324	131	0.421	1

Tap Compensated Fault Currents

	CT Ckt 1		CT Ckt 2	
	Real	Imaj	Real	Imaj
Phase A	0.261	0.000	-0.108	-0.404
Phase B	-0.081	-0.281	-0.313	0.398
Phase C	-0.212	0.244	0.421	0.006

Iop Current & Slope

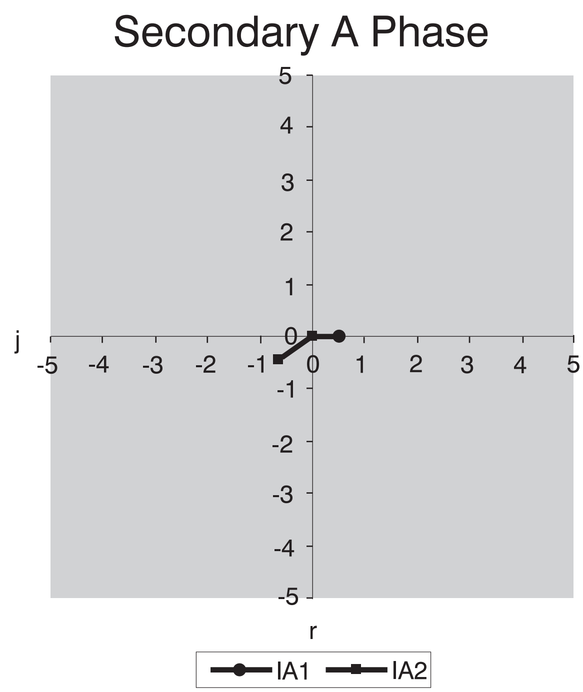
	Iop Current		Slope Ratio	
	Mag	Angle	Max	Avg
Phase A	0.432	291	103%	127%
Phase B	0.411	163	81%	103%
Phase C	0.326	50	77%	87%

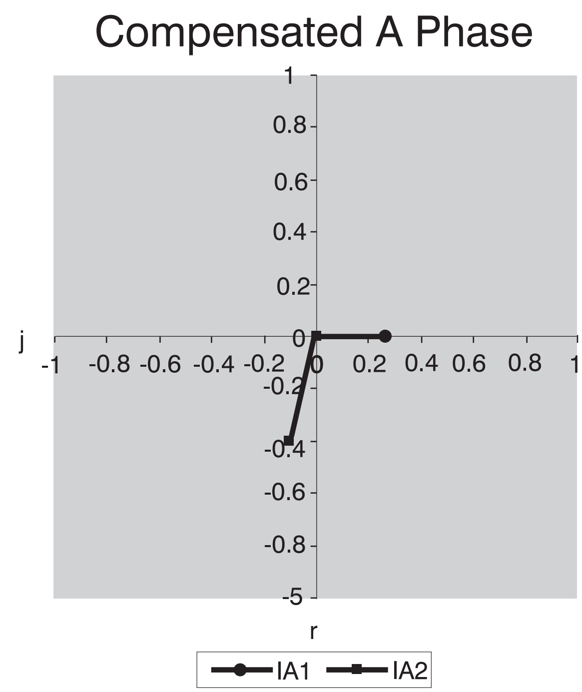
Iop Current & Slope

	Iop Current		Slope Ratio	
	Real	Imaj	Max	Avg
Phase A	0.153	-0.404	103%	127%
Phase B	-0.394	0.117	81%	103%
Phase C	0.209	0.250	77%	87%

This spreadsheet can be used to calculate the quantities used by the differential function based upon the fault currents recorded in the fault summary report at time of trip.

Then the data can be plotted to show the phase angle and magnitude of the compensated currents:





The compensated currents from phase A are 120 degrees out of phase, and they should be 180 degrees. Phase B and C (not shown) gives the same result.

DOCUMENTATION OF NUMERICAL RELAY DATA
Proper documentation of numerical relay settings and logic is extremely important. Because the numerical relay has the capability of being a multifunction relay system including wiring, switches, control, metering, and protection we must keep track of this information in an orderly manner. With traditional schemes we may keep a copy of the substation schematics in the control house. Relay settings could typically be printed on small cards and attached to the relay.

The need to have this information in the substation has not changed. During trouble cases and maintenance the technician will need to know the relay settings and have accurate schematic diagrams. With numerical relays, settings can be easily downloaded from the relay. However, during cases of trouble time is of the essence, so the settings should be readily available in hard copy format in the station.

It is also possible the relay technician does not have a PC available, it won't boot up, does not have the correct serial cable, or it does not have the right software on it to communicate with the relay. Some relays use ASCII for communication which makes the software a non-issue for cases of trouble. You should also consider how you would make changes to the relay settings without a PC in cases of trouble. Most relays have the capability of making changes from the front panel for basic relay settings. By keeping a copy of the settings and logic in the substation in electronic and printed format, you will have the necessary documentation to troubleshoot the existing setting whether the PC is working or not.

It is strongly recommended that a file-naming convention be adopted that will allow all users to organize their data so it can be retrieved quickly and with certainty about the date the setting was generated. With paper files the date defines which setting is the most recent one. There is no reason to invent a new method; add the date somewhere in the filename and everyone will know which setting is the most recent. The rest of the filename can be organized to follow your companies organization:

E255T1_001016.rly

E (Eastern Division)
255 (Substation #255)
T1 (protection for Transformer #1)
001016 (date the setting was issued)

A system like this should prevent the field from having to take two settings with the same name but no date, and check them line by line to see if they are the same. The engineering office where the settings are generated should be responsible for archiving the historical and current records for all the settings. There is a legal precedent as well as a practical one for keeping these records. Multiple backup copies in more than one location is not being too conservative for a relay engineer.

When the settings are actually transmitted to the field it should be done in electronic format and printed copy where possible. The electronic format will save time in entering the settings, and the printed copy can stay in the station as a permanent record of settings. Many companies will find it convenient to email settings to the field. This is certainly no problem from a technical point of view, but some form of electronic or manual record-keeping should be developed to report back to the office what setting was put in the relay and when it was completed.

We have already mentioned the need to properly document logic diagrams such as Figure 5. AC and DC schematics should always show an appropriate level of detail to allow anyone looking at the schematics to determine how the circuit is connected and how it should function. We have all seen schematics that get to a device that is shown as a "black box". If the device is simple with one input and one output, the internal connections may not give us any additional information. For the relay scheme shown in Figure 5 giving us less that a block diagram of the logic, as shown, is simply inadequate.

How this documentation is presented on the blueprints will vary widely, but it truly represents part of the wiring and schematic diagrams and should be shown there.

FIRMWARE REVISIONS

Firmware revision level should be documented on the settings file for each individual relay. It may not be necessary to upgrade every relay on your system to implement a new feature or to fix a software problem. Keeping track of the firmware in each relay will help you to avoid visiting every relay if a change must be made to all relays before or after a certain firmware level.

When new firmware is installed in the relay, all commissioning tests must be done again. In many cases, changes to the software will be minor, but recommissioning confirms that there were no unintended consequences of the firmware change. For this reason, firmware changes are made only when necessary.

One person in each organization should be responsible for tracking all of the firmware changes for each style and manufacturer of product on the system. Many changes are "bug" fixes that do not adversely effect the protective or control functions of the relay. In general, firmware updates are mandatory only if a misoperation of protection or control functions may occur. By tracking the changes, a decision can be made if the new feature or bug fixes are absolutely needed.

SUMMARY

Numerical relays are here to stay so it is in our best interest to adapt our methods and procedures to take full advantage of what they have to offer. This paper has suggested several steps to consider when commissioning numerical relays:

- Identify automatic or adaptive features on test plans so they can become part of the testing and commissioning process.
- Create "test" setting groups where practical to eliminate the need for disabling elements during testing.
- Include configuration and testing of inputs and outputs as part of the commissioning process.
- Make logic diagrams an integral part of the schematic diagrams.
- Develop documentation procedures that will eliminate confusion and keep information at hand in the field.
- Take advantage of the features of numerical relays that make commissioning and troubleshooting easier.

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John Horak received his BSEE degree from the University of Houston in 1988 and his MSEE degree from the University of Colorado in 1995. He worked for nine years with Stone and Webster Engineering and was on assignment for six years in the System Protection Engineering offices of Public Service Company of Colorado. His work has included extensive relay coordination studies and settings, as well as detailed control design and equipment troubleshooting. He has presented technical papers at Texas A&M Relay Conference and Georgia Tech Protective Relaying Conference. John is a Senior Application Engineer for Basler Electric, based in Colorado, and is a member of IEEE, IAS and PES.

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