Smart Grid Testing for Automatic-Distribution-Restoration Systems – Testing Needs for Modern Relays, Reclosers, Sectionalizers and ADR Systems

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This paper is organized into 5 sections. The order of the sections follows the progression by which most utilities will step through the process of setting up and testing of a Distribution Automation & Restoration (DAR) system. These steps are as follows; Familiarization with the DAR devices used, One Utility's Standardization & Testing process, Testing of individual devices or IED's, and two discussions of testing approaches for different DAR system designs.

1. What are Reclosers & Sectionalizers, why are they used and what needs to be tested?

Think of a Recloser as a programmable, automatic re-setting fuse that can be remotely operated. The Reclosers can interrupt fault currents and are used to reduce the portion of a Distribution system (Number of Customers) affected by a line fault. The Reclosers can be set with different over-current tripping curves and can be set to test the circuit by energizing the line at a selected number of intervals and to leave the line de-energized for selectable periods of time between tests for the fault clearing.

Think of a Sectionalizer as an automatic switch that will detect when a fault has occurred, the line has been de-energized by a source-side device(s), and the conditions are such that the switch must open to isolate a system fault. Sectionalizers are designed to interrupt the expected load currents but not fault currents, so the Sectionalizer should confirm the line is dead (no voltage detected) before it opens.

Reclosures & Sectionalizers (R&S) are designed to be used throughout a distribution circuit such-as; mounted on power poles, or in pad-mount cabinets, or in under-ground manholes. They do not require the real estate, the fences, the special permits, nor the visual impact of a switch yard or substation. They are located along the distribution lines to reduce the area (number of customers) affected by a problem on the system.

The newer R&S can also be used to:

- Automatically reconfigure the circuit(s) to restore service to customers not directly connected to a system problem. (Automatic-Distribution-Restoration system - ADR)
- Protect for under-frequency conditions and drop the required connected non-critical loads.
- Protect against closing two circuits together that are not synchronized. (perform sync-check functions)
- With the higher fault interrupting ratings of Reclosers, they are also used to replace breakers in some substations.
- Trip and re-close only the faulted phase. Such-as: trip one phase, two phases, or all three phases depending on the fault and reenergize that phase as per their programming.
- Reclosers can be programmed to detect evolving faults and change the number of phases to be tripped.
- Many other uses have been implemented too.

R&S are now used as a part of ‘Smart Grid’ automation systems. This means that they not only isolate the problem or fault but, they can be set to reconfigure the circuit(s) to automatically re-energize those customers not directly connected to the problem area of the circuit.

A background on why testing requirements are being changed?

The Reclosers & Sectionalizers have changed

R&S have changed from hydraulic to electro-mechanical to new digital controls with new testing requirements. The wiring is now digital logic; different algorithms (or formulators) may be used for different fault types requiring full 3 phase testing.

The first R&S were hydraulic operation and single phase. The next generation of R&S’s were three phase systems such-as the Kyle GWC Form 1 & 2 Sectionalizers and the McGraw Form 3 Reclosers with electro-mechanical controllers and motor operated switch mechanisms. These controllers still acted upon all faults with 3 or 4 single-function over-current elements.

Several manufacturers & generations of Sectionalizer & Reclosers later, we got digital logic controllers. At first these digital logic controllers still acted upon faults as single phase functions.

For the last few decades, new abilities have been included in these digital controllers. The new functions allow different settings for 1 phase, 2 phase and 3 phase faults to allow higher load carrying ability but still trip most faults at lower current levels. Over & under-voltage protection has been added plus over & under frequency protection.

Now the digital controllers can trip and /or close in 1, 2 or 3 phase modes depending on the fault types and the logic settings. This means that only the faulted phase may be set to trip. They can detect an evolving fault and

change their operation when a fault evolves into a multi-phase fault. They can also detect a defective primary switch then activate a logic to block re-closing.
The latest new applications include a variety of auto-restoration systems used in looped and/or underground systems. With these ADR systems comes the need for checking synchronization of each phase before the circuit is automatically closed.
Now all of these new abilities need to be tested to ensure they correctly operate under the system conditions for which the Recloser or Sectionalizer are intended to protect the system from. Plus we have to test to ensure no miss-operations occur when all of the protected conditions are not met.

Digital Controllers were designed to solve many of the problems of older devices but they introduce different weaknesses which need to be tested.

Digital controllers bring solutions to many of the problems which are common to electro-mechanical and analog solid-state controllers. A few examples:

- The settings are not likely to drift over time.
- The pick-up levels will not cycle with temperature changes.
- The timers will not be slowed by cold temperatures.
- Exposed contacts are not likely to corrode and delay or inhibit tripping and/or closing.

However, digital controllers do have their own set of weaknesses, just like every other man-made device. While these weaknesses usually occur far less often, the only way to detect them before they cause system reliability issues is through routine testing.

Some of these weaknesses and their symptoms are:

<u>Circuit wiring is now virtual wiring or logic</u>

Trip circuits, close circuits, connections between protection functions, as well as other circuits have become logic settings. Some of these logic settings programs are cryptic or at least complex to follow and often the logic settings do not perform as the protection scheme had planned.
This means that the device must be tested without blocking or masking functions to ensure correct performance of the device.

<u>Radio Frequency Interference (RFI)</u>

The wiring is now a programmable logic. The pick-up tap values and time curves are a programmable logic. The timers are a programmable logic. If these programs are corrupted then the device will not work as intended.
While manufacturers have made great improvements in shielding the logic circuits from typical radio signals, etc. Very high RFI from things like radar has caused issues; like scrambling the programs in the devices memory.

<u>Break down of MOVs</u>

All inputs and outputs to a digital controller need to be protected from voltage spikes and this is done with Metal-Oxide-Variable-resistors (MOVs). If an MOV sees very high voltages or many repetitive voltage spikes it will start to break down and provide an unexpected current path. This current path will:

- Become a parallel path for the CT currents so the device sees only part of the CT current. Resulting in higher pick-up test results or longer trip times.
- Act as a current path and partial short across for the voltage inputs. Resulting in loading down the voltage sources.
- Act as a partial short across the output contacts. Resulting in the appearance of the contact being closed when it is not, or the device being controlled by the contact remaining latched after the contact is opened.
- Act as a partial short across the logic inputs. Resulting in the device not seeing a control input or seeing a false input.

<u>Firmware upgrades</u>

As manufacturers are improving and fixing problems with a digital device, they often change the operation of the device with firmware upgrades. These changes can have a range of impacts on if and how well that device will respond with the intended application.
While manufacturers make major efforts to avoid un-intended changes to the way relays or controllers respond to a power system event, there are many reported cases of miss-operations of devices after firmware upgrades have been installed. We have also had customers who had successfully tested a device before a firmware upgrade and the same test failed the device after the firmware upgrade.

It is for these reasons that, using the same tests and/or the same test equipment to performed checks on electro-mechanical controllers or for finding the pick-up with a 3 to 5 % accuracy test system, do little to insure proper operation of a digital controller or find potential problems. Therefore, we need to establish new approaches to testing digital controllers!

Another force driving change

<u>The Aug., 2003 Northeast US- Canada blackout and subsequent blackouts around the world.</u>

Many of the studies looking into the August 2003 outage found that many protection systems were not

properly working plus they had not been tested or maintained on a regular schedule. This included under-frequency load shedding systems, CTs, VTs, breakers, relays, Recloser systems, etc.
We will not get into the issues like; how de-regulation in the 1980's & 1990's required utilities to drastically cut costs & most maintenance programs were slashed, or that the cost of modernizing test systems to keep up with the modern equipment being added to the system was hard to justify in this financial environment.
The Aug. 2003 blackout and subsequence blackouts have resulted in the NERC changing the operating rules for The Reliability Councils of North America. The first round of changes became effective on April 1, 2005. (The NERC rules effectively established a requirement that; the typical Utility's Maintenance practices from the 1980 are to be re-implemented. The selection of what is required to be tested is based upon if the device can impact the bulk power grid. This set of rule changes is considered to be just round one.
All of the Reliability Councils of North America are to implement the NERC rules for their member utilities to follow. The Reliability Councils of North America in turn established rules which all bulk power system operators must implement.
NERC also set up an enforcement leg that is auditing all utilities falling within the guidelines of being able to impact the reliability of the bulk power grid. This can be any one of many items like their total generation, or slow clearing faults causing voltage sags on the transmission system, etc.
NERC and the Reliability Councils of North America have formed committees, who are now working on round two of the new rules. Plus, even before the second set of rules were approved there was talk of round three changes.
Utility commissions across the USA are also imposing testing programs that include R&S. These requirements include testing both the controllers and the primary switches, every few years.
Here is how the utility commissions get involved. As transmission and distribution utilities request rate increases or go before their utility commissions for other reasons; they are being required to demonstrate that their maintenance programs meet the guidelines discussed above.
If the transmission utilities depend on the distribution utilities for load shedding then they may have to show how these distribution utilities' practices meet these guidelines.

At the same time that new government rules are adding to the work load;

- The R&S have become far more complex.
- The controllers for R&S have moved from electro-mechanical devices to digital devices.
- Along with more modern controllers come far more complex operational abilities which need to be tested.
- Communications being added between devices to change the operation of the devices is very common.
- Utilities are finding it hard to hire experienced personnel.

When NERC audits a utility, the utility is required to show detailed documentation to prove their maintenance practices are being followed and being kept on schedule. The substance of their practices is also being evaluated.
Auditors have told utilities with 10 year testing cycles that testing needs to be done in time schedules as short as a few years. Auditors have also told utilities that they need to test CTs & VTs along with the protection devices. Their logic is that if the signals to the device are faulty the protection device will operate improperly.
NERC auditors have told utilities that the equipment being used for testing must meet much higher accuracy standards than may have previously been used; An example: Utilities have been told that frequency monitoring and frequency protection devices must be checked with test equipment which has an accuracy better than 0.001 Hz. (1mHz.)
NERC auditors have told utilities that if the operation (or miss-operation) of a device will cause a problem on the grid, then it needs to be tested to insure proper operation of the device. This includes any and all functions in a device that will impact the grid or transmission system. (voltage sags have been considered an impact to the bulk grid.)
Oh yes, NERC and its auditors issue fines to utilities. These fines can be $10K to $100K per day for each day of non-compliance and repeated for each non-compliance issue.
All of this is happening after the utilities have lost many of their experienced maintenance people and are having a hard time replacing them.
Let us make one point clear: all protection systems will be tested. The only question is if we will do the testing under controlled conditions or nature will do the testing at the worst possible time.
The expanding utility system testing programs require shorter times between scheduled testing cycles, far more complexity of the testing itself, higher accuracy equipment than may have been used before, and the need to perform all of this with a growing lack of "experienced" people.

2. So the future Recloser & Sectionalizer test systems must provide many efficiency, accuracy, and reporting improvements compared to the old single phase, single frequency, single timer, 5 to 10 % accuracy test systems most commonly in use today.

Let us list some of the needed functions of a new test system:

- A test system that can simulate any and all signals & contacts, that the device being tested would see when in service and monitor all critical signals given by the device being tested.
- Ability to set up programs to automatically provide real world system conditions & sequences of system conditions for all conditions to be tested.
- Accuracies of better than 0.1% for voltages & currents.
- Variable frequency with accuracies better than 0.001 Hz.
- The ability to reproduce the same exact test conditions and results year after year and from one device to another.
- Voltage sources with enough VA to energize the voltage elements, the battery charger, and the heater elements in the controller.
- Voltage sources with 3 up to 6 phases.
- Current sources with enough compliance voltage to test the old legacy R&S and the accuracy to detect minor rises in pick-up levels over time.
- Be able to supply between 2 and up to 9(+) programmable dry and/or voltage-wetted contact outputs to the tested device depending on the system being tested.
- Be able to monitor between 2 and up to 10 binary inputs from the tested device depending on the system.
- Ability to operate several test systems in a synchronized mode to perform ADR system testing & troubleshooting. (For many systems at least 4 and often more synchronized test systems are needed.)
- Have DC sources capable of operating the primary switches.
- Ability to automatically record all test results.
- Ability to capture all test signals for easy troubleshooting.
- Ability to easily up-date the tests with the actual Recloser or Sectionalizer settings being used, as changing the device settings for proper testing is not an option.
- For field testing the test system needs to be able to operate when supplied from a portable generator or even better from the inverter in a vehicle without loss of accuracy or repeatability.
- Use high impedance inputs to detect a damaged or leaking MOV across an output before it causes a miss-operation.

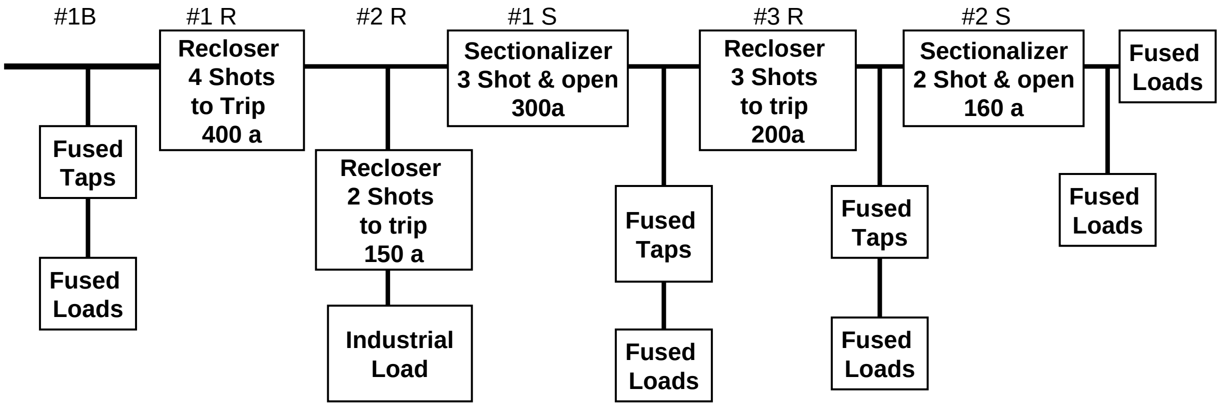
What should the new testing include & what should you look for when you make changes in your testing procedures and are evaluating the test systems?

<u>We first have to ask the questions:</u>

- Is field testing of both the controller & the switch mechanism needed with the new regulations?
- Does testing in the field provide cost advantages to the utilities? Such-as determining precisely which part of the system needs to be removed for repair.
- Is automatic field testing of the controller's pick-up, timing & logic sequence settings for all fault types available?
- Can automatic field testing of the primary switch's timing, including the ability to time first trip vs. a second or third trip time(s), be done in the field?
- Shouldn't test reports provide help to troubleshoot the device being tested?
- Do test reports need to meet NERC requirements?

In short, you need to know all of the details about how the device is intended to operate for each set of problems for which the power system is being protected or restored! The test must confirm that the device operates when there is a problem. The test must also confirm that the device does not miss operation when there is no problem or only part of the intended conditions exist.

Here is an example of an automatic test plan and demo of the actual testing.
We will use this example feeder to see which tests may be needed.



Description of device operations-

Breaker # B1 has no re-closing, so it is set to higher overcurrent levels than the downstream devices.

Recloser # R1 is set for 4 shorts (or 3 re-closes) before it locks out. Single-phase faults are set for faster curves than the multi-phase faults.

Sectionalizer # S1 supplies non-critical loads and is used for level 2 (58.6 Hz) under-frequency load shedding, plus it must open before the 3rd re-close attempt from Recloser #1, but while the Recloser #1 is still open.

Recloser # R2 supplies an industrial load and must lock out before Recloser #1's 3rd re-close attempt.

Recloser # R3 supplies non-critical loads and must lock out before Recloser #1's 3rd re-close attempt. Single-phase faults are set for faster curves than the multi-phase faults and evolving faults go directly to lock out.

Sectionalizer # S2 supplies non-critical loads and is used for level 1 (59.2 Hz) under-frequency load shedding, plus it must open before the 2nd re-close attempt from Recloser #3, but while the Recloser #3 is still open.

All Reclosers' fast trip operation(s) should be faster than their direct downstream tap fuses' damage curves, and the slow (timed) trips should be slower than their direct downstream fuses' max clearing curves. All Recloser controllers must monitor their actual primary switch's clearing time to ensure the switch's integrity for the next operation.

How should we set up a Recloser or a Sectionalizer test plan?

First we need to decide, what do we need to test?

Is the testing being done for qualifying, commissioning a device or for routine maintenance on the device?

- We will assume this is routine testing and we are just testing the in-service device settings.

What protection and operation functions does Recloser #3 perform?

- Different timing tests for fast & slow trips.
- The Recloser #3 has fast & timed overcurrent tests for both single phase and multi-phase faults.
- Evolving faults; A faults starts as a single phase fault but evolves into a 2 or 3 phase fault and causes the Recloser to lock-out.
- A defective primary switch is detected by monitoring a delayed fault clearing, the controller then opens and blocks further reclosing.
- Perform under-frequency load-shedding at level 1 or 59.2 hz and confirm the Recloser opens and stays open even after the frequency returns to normal.

What protection and operation functions does Sectionalizer #2 perform?

- The Sectionalizer # 2- should detect 2 cycles of a high current FOLLOWED by a loss of voltage, (but not the reverse) and it should open after the 3rd high-current & loss of voltage cycles before opening. The time between the 3rd loss of voltage and the trip output should be recorded and should be much less than the 3rd open time of Recloser #1.
- For a level 1 under frequency condition, or 59.2 Hz, the Sectionalizer should open and stay open even after the frequency returns to normal.

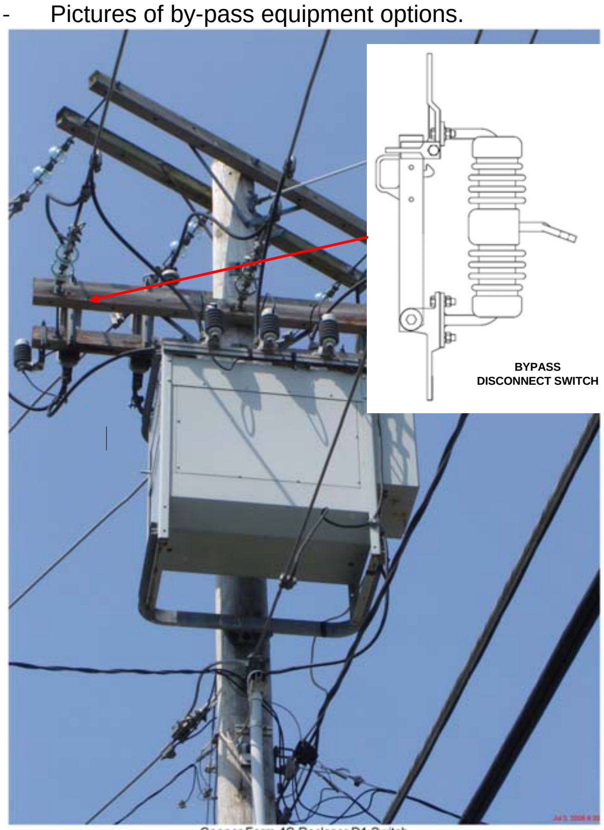
We will now review a few sample test plans to be used in the demo?

Open a sample test

- We will review how they are created
- Here is how we edit the tests to adapt to a different device's settings.

Actual testing of both devices

- Running the tests is only half the story.
- What happens when the device fails to operate properly?
- Now let us look at the troubleshooting tools that are available
- Pictures of by-pass equipment options.



Cooper Form 4C Recloser D1 Switch

Solid disconnect by-pass switch

The solid by-pass allows the circuit to be energized but relies on other devices to provide protection for power system problems while the Recloser or Sectionalizer is being tested.

Fused disconnect switch

The fused disconnect switch allows the circuit to be energized and provides some protection for power system problems while the Recloser or Sectionalizer is being tested.

3. Hydro Québec's Homologation Process with Modern Testing of R&S.

Our Network

Hydro-Québec's Distribution network serves almost the entire province of Québec with 9 municipal networks and one cooperative.

Ninety-four percent of our network uses a 25 kV operating voltage.

The network has 99,000 Km of overhead lines on 2.5 millions poles and 10,300 km of underground lines. On these lines we have installed 536,500 transformers, 21,000 other pieces of equipments and devices like interrupters, Reclosers, and 3.3 million meters.

The operating methods, the safety code and the installation methods define HQD's needs.

To be able to control the quality of selected IEDs for the automation project, rigorous process is followed. Part of that process is to create various documents: local/remote operations, automatic functions and hardware technical specifications. Those specifications define the needs for control, protection, operation and site environment.

The homologation process includes:

- Technical specification
  - BENEX (operational requirements)
  - STG (general technical specifications)
  - STP (particular technical specifications for each device)
- Manufacturers test report validations as stipulated by HQD
- Prototypes are supplied by the selected manufacturer according to the specific HQD requirements. We verify the safe behavior of the equipment when facing realistic operating conditions, in which only one contingency is considered.
- IED validation with laboratory testing
  - Protection functional testing at IREQ (Research Institute of Hydro-Québec)
  - Pole mounting on the test feeder
  - Control testing in the automation laboratory
  - Communications testing with the CED (Distribution operation center) interface in the automation laboratory
  - (IEDs have to be rigorously tested in our test facilities with testing device to ensure good operation)
- Installation, maintenance and operating, write up of standards and methods
  - B41 Installation standards and methods
  - B71 Control and Operating standards and methods
  - B72 Maintenance standards and methods

- A pilot project is defined and authorized. Acquisition of equipment is carried out according to HQD's requirements
- Elaboration of the training plan
  - Laying the training groundwork
  - Training of the workers through courses
  - Workshops for employees to become familiar with the IED's control and maintenance
- Network experience during the Pilot Project: Hydro-Québec buys a certain number of IEDs so it can be installed on the network and leave them there for at least a year. HQD gathers vital information on IEDs during that time. The linemen, electricians and the technicians have to give us their comments on IEDs' behavior. This allows us to exchange ideas with the manufacturer so that we can improve IEDs performance.
- Monitoring quality control: An evaluation grid is created for each product allowing the manufacturer to match HQD's requirements. This is done to ensure that the product quality respects the agreements made between HQD and the manufacturer.
- Product modification follow-up: HQD uses ADPs (problem notification) to provide follow-up on any modification made to the product. With an ADP, HQD can accept it as is, reject it or accept it with corrections.
- Final acceptance: The final acceptance certificate is issued to the manufacturer after analysis of the homologation process results and when the remaining required modifications are done on the IEDs.

Our deployment experience shows us that we have to adjust the device until it reaches its full maturity. All the requirements are not expected to be met during the first deployment phase. Some requirements come up only after a network event. We have decided to wait at least five years before any major changes to the device are made. This process is called a technical evolution step. During this period we record all required modifications if they are not safety issues and all modifications and updates to new or existent IED's have to be rigorously tested in our test facilities with testing device to ensure good operation

Over the years HQD has modified and implemented its Homologation process to cover all the problems generated by the use of microprocessors, our technical requirements are more stringent for communications devices and other new technologies.

EMI: Electromagnetic interference

GPR: Ground potential rise

One of the common elements to all our remotely controlled devices is the batteries. Batteries have a limited lifespan that ranges from three to five years depending on location of the device. We have to integrate an automated validation routine software program to monitor battery failure. Due to the quantity of batteries, a system has been implemented in order to manage battery storage.

Some manufacturer updates are not essential for HQD's applications. Only some of the major updates that cover security issues need to be implemented on the device. Some of the other updates will be implemented during the next technical evolution step.

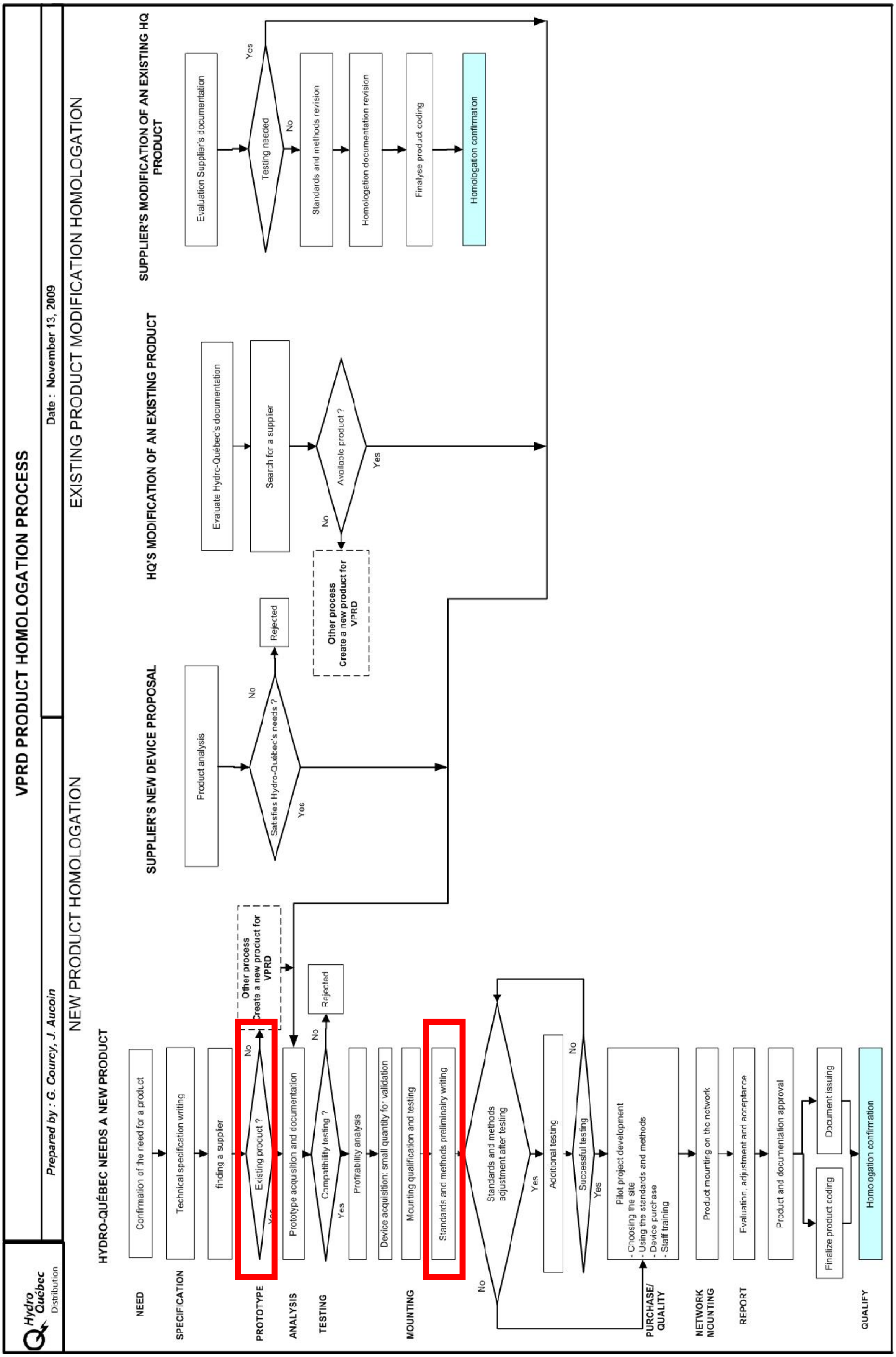
Update implementation on IEDs needs planning and resources. First, we need to evaluate the impact on operations testing. Then we have to define a time sequence for the implementation. Finally, we write the procedures and decide who will do the job.

At HQD preventive maintenance is carried out according to the manufacturer recommendations and to how strategic the equipment is.

Traceability policy is vital to the maintenance practice of the IEDs. We have a database with all the settings, program versions and firmware versions corresponding to all the IEDs installed in the HQD network. The point is how to standardize and manage the IEDs.

In 2009 we started to remotely acquire data from switches installed in the network. We are now studying a way to remotely reconfigure and update the firmware and software of different IEDs.

Hydro-Québec Distribution process schematic summary (B14.09)
The red rectangles indicate that we are using the OMICRON testing devices.



4 - Field testing by Orange and Rockland/ Div of ConEd NYC, NY

This system could be viewed as a central point of control system.

Where all control decisions are made at the Control center via SCADA.

- The pinnacle of advanced equipment testing requires a wide range of knowledge about distribution automation systems. Some of the most complex testing is the synchronized testing of multiple devices using GPS. This requires knowledge of the complete distribution automation system that is being tested.
- Knowledge of the SCADA system that the equipment is connected to.
- Sophisticated knowledge of equipment test plans.
- Thorough knowledge of the communication system being used.
- Test system needs to account for feedback from auto-restoration systems.
- Understanding how instrument transformers work and system dynamics.

Knowledge of the SCADA system that the equipment is connected to.

Generally, field equipment is brought back over a communications system to what is known as a Supervisory Control and Data Acquisition (SCADA) system. To do this, the devices will have an RTU that will be configured for unsolicited reporting, polling or a combination of both. How each SCADA point behaves will affect how the test plans will be created.

Knowledge of equipment test plans.

To make field equipment behave as if they are connected to a real power system, thorough knowledge of system performance must be understood.

Knowledge of the communication system being used.

Depending on the type of communications system being used different parameters will have to be taken into account. Different systems will have fast or slow delays, bandwidth must be understood and knowledge of how much the system can handle for a given fault event. Radio systems can have different issues depending on the frequency and bandwidth of the frequency purchased. Cellular can have service territory dark spots and delays due to dial up delays. Telephone can have time delays with dial up but not being available at each equipment locations. Fiber optic would be the fastest, but not common due to the expense and fiber can fall down with the poles they are on.

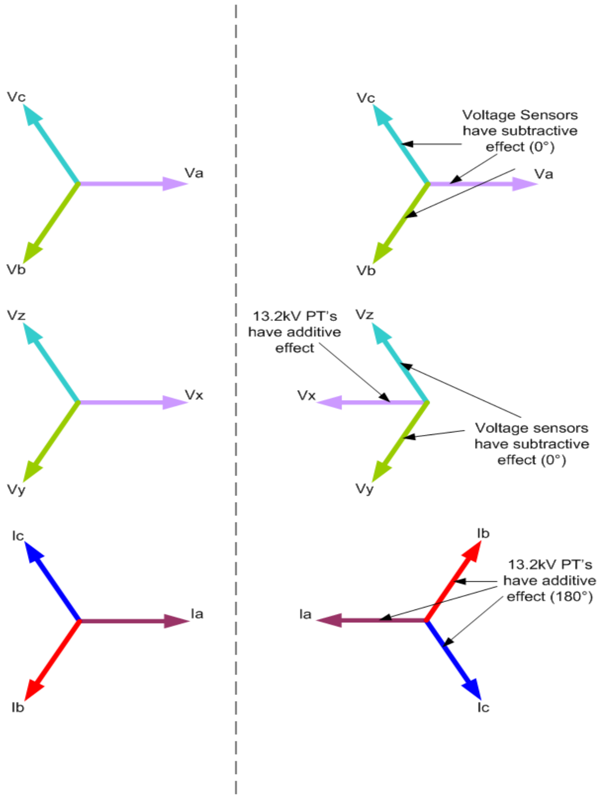
Knowledge of test system needs to account for feedback from auto-restoration systems.

What type of affect the auto-restoration systems can have will determine what the test plans need to be waiting for in terms of external inputs from this system.

Understanding how instrument transformers work and the system dynamics

Bringing back watts, vars and power factors from field equipment requires that the field devices are wired properly to make this happen. Equipment installed on a distribution system require polarity, phasing and rotation to be taken into account. These can be compensated in different ways, but need to be addressed. The following describes some of the issues that can be encountered on equipment on a distribution circuit. One of the more interesting instrument transformer issues encountered at Orange and Rockland is in the 13.2 kV class of equipment. With the advent of voltage resistive devices, they do not follow the rules of additive components. Devices below 8800 volts and less that 250 MVA are additive by industry standards. Voltage resistive devices do now follow this rule.

There is also the cables and equipment that is connected. To test the system properly, you need to know exactly how the instrument transformers affect the inputs to the test equipment and whether there are any phase shifts in the settings. Also, take into account phase ID and phase rotation of the systems for proper calibration of the system.



As a test engineer/ You must have a full understanding of the instrument devices, the wiring from the Recloser to the control, the settings in the controls and all transposition that take place everywhere.

These phase shifts must be taken into account when using them for SCADA. The SCADA testing will test fine while placing them into the control, but will not work properly when placed into service because of these irregularities from the instrument transformers. Some of the functions affected are watts, vars, power factor, distance calculation, oscillography, reverse power and many more.

Resistive impedance in parallel with the sensing of the input to the control.

To get true representation of the primary system, the cable inaccuracies need to be accounted for on the secondary wiring. You can usually find the cable characteristics from the vendor. This impedance values can be added to the testing with the cable contributions.

Control phase shifts to compensate for cable effects and compensate for this phase shift in your test plans when doing SCADA testing.

Seting up the PT to the CTs,

The metering values are generally taken from the source side bushings for the CTs and PTs. Turn the head around to make sure the source bushings are facing the normal source. Once the CTs are oriented correctly, the PTs can be modified to match phasing and polarity if you are using 240 VAC secondaries where there is an X1, X2 and X3 bushing on the secondary.

How to test with OMICRON and recreate the angles as they need to be

True phase ID of the system phases when the bushings do not match true phase ID of the system. Example is where the phase relays do not match the phases on the field device due to transposition in the field that cannot be easily fixed.

Phase rotation of system because the true phasing is rotating backwards from the standard system. Phase rotation will affect distance calculations and "What Else" if not corrected in the settings.

How to do tests with OMICRON equipment-

Need Va as reference when synching other phasors.

Test the units as if they are in the field and have the ability to check targets and reset them after performing the event.

Testing should be made at the standard of relays in a substation. Pick up tests, trip and reclosing times, time current curves and any other function that are used by the field device (reverse power, frequency trip, under voltage, sequence coordination, reclose retry, loss of voltage auto loop for SR and TR. Replay entire events to see how they perform.

Since there are a lot of functions happening at the same time, complex testing should be done to troubleshoot to make sure there are not overlapping functions that compete for a trip.

When a fault takes place on a relay, it may at times be difficult to troubleshoot each device precisely. With COMTRADE files now available with sophisticated testing, the true fault scenario that took place can be replicated to witness how the relay performs for the real fault that took place during the time in question.

<u>Thorough testing by these devices:</u>

Instrument device should be tested for accuracy, performance, saturation etc.

Better understanding of a relay through testing. I thought I would get just a ground fault target when going above just the ground PU level. I wound up getting the phases that contributed to the phase imbalance as well. Cooper and SEL both do it this way. I don't like that because I think I have a fault that I'm looking for now when I actually could have tripped on imbalance. The older electromechanical relay had an individual ground relay, so you could just have a target on the ground. Not the case on solid state relays.

Question on triple singles in Hot Line Tag whether they trip all three phases for a single phase fault and whether all the cans are selected or now.

What does a tie Recloser do when it loses both sources? What happens when one source returns to one side after that during switching?

A Recloser that has a "Switch Mode", what happens if Hot Line Tag is ON and there is a fault? Does it trip or not?

What do the LS lights do when the Recloser had opened for loss of voltage and the voltage is restored before the LS is reset? What is the function of the LS lights that are different that regular voltage lights. You should know the difference when you are creating your SCADA points.

How does the sequence coordination actually work?

How does cold load pickup actually work?

How does Recloser retry work?

Many of these settings are developed by programmer based on engineering specifications. Every scenario for these tests may not always be performed. Utilities act as beta testers for the operations scenarios that they can think of.

Two ways of testing relays:

1. Test the device and disable functions that are in the way during testing.
2. Test the device without disabling anything and create "real world" test environments to push the device to the functions you are looking to test.
   - Example is instead of disabling a zone 1 and 2 test to test for Zone 3, you create and distance scenario that looks like a zone 3 fault with the needed time delay to replicate a zone 3 fault.

This second type of testing is a truer form of testing and may find some anomalies that may not exist when you are disabling functions to perform a test.

- Add electromechanical vs. solid state testing that can operate differently. Use ground target as example
- Put in SCADA testing and synchronization that needs to be done when powering at a pole.
- Things you have to account for at a pole that you don't in a substation (Phasing, direction of Recloser equipment, PT wiring to compensate for CT's internal that can't be changed, power to the control from external source and synch to the source, phase rotation).
- Smart grid testing using GPS and feedback from a centralized intelligence.
- Testing with amps, watts, vars and how I discovered unsolicited due to testing observations.
- In order to have direction to be correct, you can either turn the Recloser around, mess with the wiring in the control or modify the phases in the settings. Each choice has it's challenges and disadvantages.
- Special Test interfaces are needed for speed in wiring and field testing.
- Proper component configuration
- Proper timing of the communication system
- Utilize GPS testing for full automation testing of the entire system.

5. How do we test a peer to peer controlled automatic distribution restoration system?

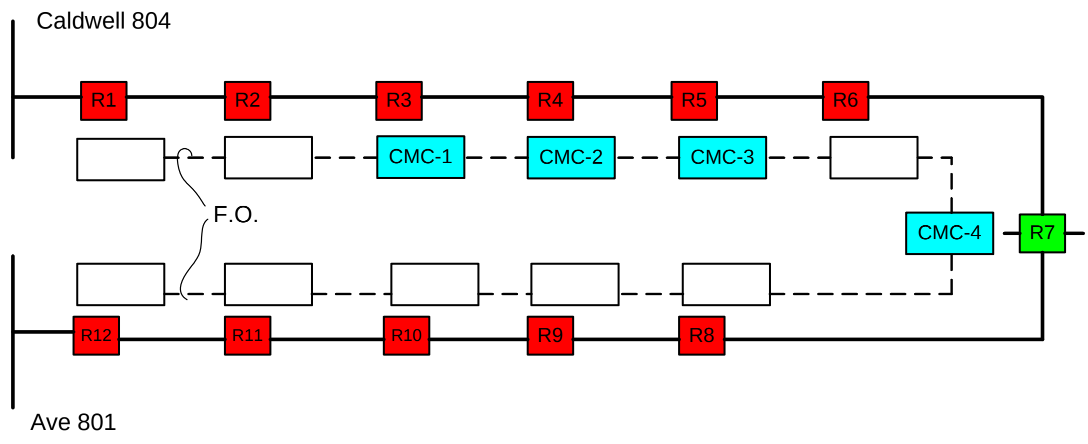
This system could be viewed as a point to point control system. Where some control actions are decided between the IED's in the field; and the SCADA system is used for monitoring and take system wide control actions.

This discussion assumes we are doing synchronized testing of the field devices. We also assume that each Recloser or device has been successfully tested in a stand-alone operation, as described above.

<u>First we need to decide, what do we need to test?</u>

- Are we testing the complete system or selected devices?
- How many devices will be tested at a time?
- Are the devices directly communicating to each other?
- If yes, what are the communication delays or times?
- Is the SCADA data utilizing part of the bandwith and what are its effects on the control comunications?
- Are the communications two way to simple commands?
- Should the tests start with the previous tests to isolate the fault?
- Should the tests be used for testing individual devices be adapted for synchronized testing?
- Are we going to be doing the testing in a lab. Or in the field?
- Are there special considerations for this application? i.e.- Does this device impact other parts of the system?
- Do we need to back-feed the circuits or do we need to by-pass primary switch or provide other protection during the testing?

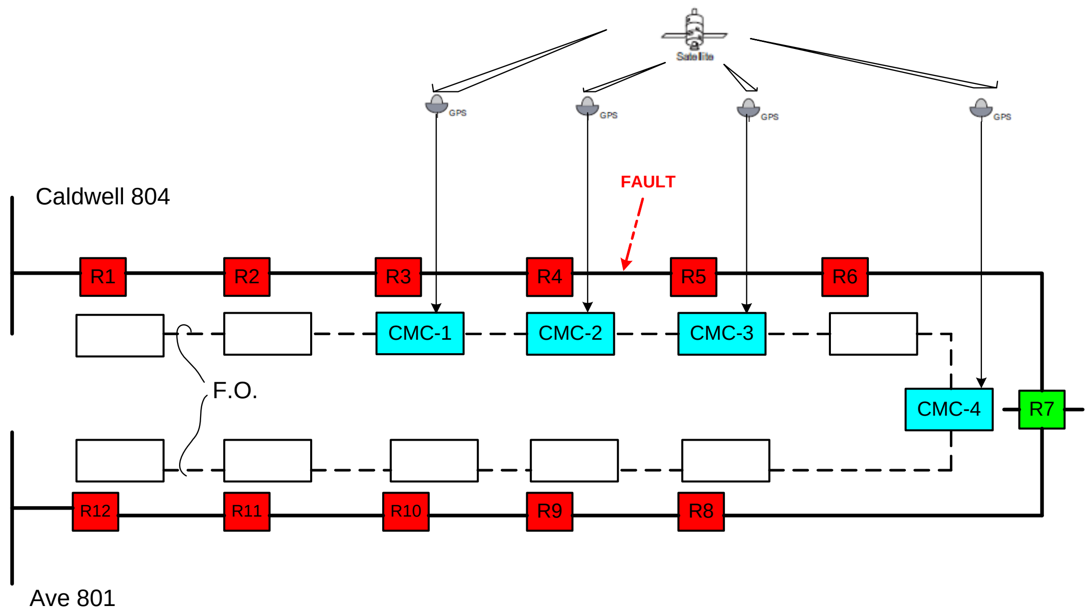
Automatic Distribution System Restoration



Let us look at another distribution circuit.
This circuit is set up for Automatic Distribution Restoration. Here is the circuit before a fault and we show the minimum number of test points.

This system has two trips with one re-close attempt before Recloser goes to lockout. Here is the logic as to how the system works:

- If a Recloser sees a fault down stream, it is to send a block trip command to the previous up-stream Recloser or breaker.
- If the Recloser sees a fault but receives no block command from the down stream device then it trips, and sends an open command to the next down-stream Recloser.
- The first Recloser that does not see a fault and receives an open command will sent a close command to the N.O. Recloser, this message is relayed by each down stream Recloser to the normally open recloser.
- Normally open Recloser closes and sends confirmed closed signals to upstream Reclosers.
- The Recloser that tripped for the fault will re-close one time after it receives a confirmation the adjacent down stream Recloser has opened.
- The Reclosers on each side of the fault then open and interrupt the fault.
- The last Recloser to see the fault will then try one reclose after it receives a confirmation the adjacent down stream Recloser has opened.
- .If the fault persists then the Reclosers on each side of the fault will open and remain open isolating the fault.
- If the fault has cleared then after the open Recloser (R5) sees both circuits energized for a set time; it may reconfigure the system to its normal configuration.

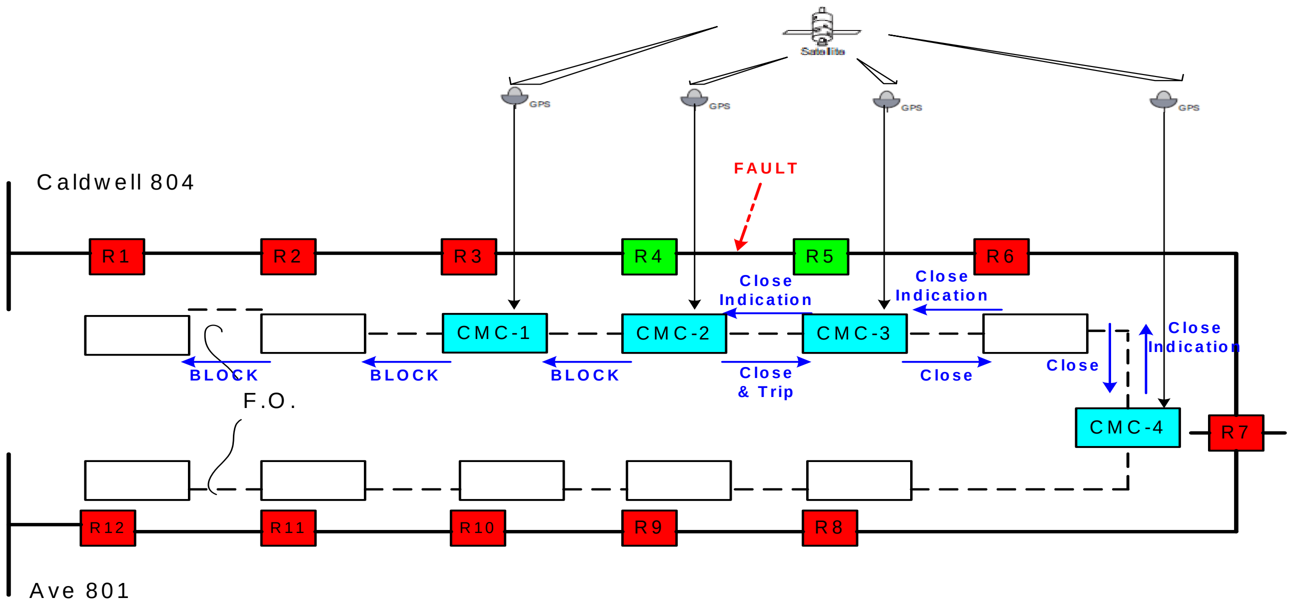


<u>So how do we test this system?</u>

The minimum number of test injection points for a fault at the arrow is 4 points.

1. R3 is checked to confirm a trip blocking signal from R4 inhibits tripping.
2. R4 is checked to confirm tripping for a fault & the reclosing is delayed until R7 is closed & R5 is opened.
3. R5 is checked to confirm that it gets an open command from R4 and opens even though it does it does not see a fault. Plus it sends a close command to R7.
4. R7 is checked to confirm that it gets a close command from R5 and closes, and then sends a close confirmation back to R5 & R4.

This is the circuit status after the fault is cleared and the un-involved part of the system has been restored.



So what does a test sequence for each injection point look like?
We simply set up the conditions that the device being tested should see to give the response that the device is supposed operate or NOT operate for.
Example:

1. R3 tests-

State 1 = 6 phases of voltage, load current, 52 'A' a contact closed

- Wait & Measure GPS Pulse
- State 2 = 6 phases of voltage, Fault current, 52 'A' contact closed
- Wait 0.5 sec & Measure No Trip
- State 3= 6 phases of voltage, no load current, 52 'A' contact closed
- Wait- 2 Sec & Measure No Trip.
- State 4 = 6 phases of voltage, Fault current, 52 'A' a contact closed
- Measure no Trip & Wait 0.5 sec
- State 5= 6 phases of voltage, no load current, 52 'A' contact closed
- Wait 3 sec.

Note: If this Recloser trips during the tests then it did not get block trip signal or did respond to the block trip signal.

2. R4 tests-

State 1 = 6 phases of voltage, load current, 52 'A' a contact closed

- Wait & Measure GPS Pulse
- State 2 = 6 phases of voltage, Fault current, 52 'A' contact closed
- Measure 0.5 sec Trip
- State 3= 6 phases of voltage, no load current, 52 'B' contact closed
- Measure 2 sec reclose
- State 4 = 6 phases of voltage, Fault current, 52 'A' contact closed
- Measure 0.5 sec Trip
- State 5 = 3 phases of voltage, no current, 52 'B' contact closed

Note: If Recloser is slow at tripping then it could cause FD-R3 to operate in back-up mode.

3. R5 tests-

State 1 = 6 phases of voltage, load current, 52 'A' a contact closed

- Wait & Measure GPS Pulse
- State 2 = 6 phases of voltage, load current, 52 'A' contact closed
- Measure 0.7 sec +/- & Trip, & Wait 0.8 Sec
- State 3= 0 phases of voltage, no load current, 52 'B' contact closed
- Measure No Reclose, Wait 1 Sec
- State 3a = 3 phases of load side voltage, no current, 52 'B' a contact closed
- Measure No Trip & No Reclose & Wait 0.7 sec
- State 4 = 6 phases of voltage, no load current, 52 'B' contact closed
- Measure no Reclose & Wait 0.5 sec
- State 5 = 3 phases of load side voltage, no current, 52 'B' contact closed
- Measure No Reclose & Wait 3 sec.

Note: If this Recloser does not open in state 2 then it did not get an open command from FD-R4 or did not respond properly to the open command.

4. R7 tests-

State 1 = 6 phases of voltage, load current, 52 'B' a contact closed

- Wait & Measure GPS Pulse
- State 2 = 6 phases of voltage, load current, 52 ‘B’ contact closed
- Measure No Close, & Wait 0.7 Sec
- State 3= 3 phases of voltage (B side), no load current, 52 ‘B’ contact closed
- Measure Reclose, Wait 1.1 Sec
- State 3a = 6 phases of voltage, load current, 52 ‘A’ a contact closed
- Measure No Trip & Wait 0.7 sec
- State 4 = 6 phases of voltage, load current, 52 ‘A’ contact closed
- Measure no Trip & Wait 0.5 sec
- State 5 = 6 phases of voltage, no current, 52 ‘B’ contact closed
- Measure No Trip & Wait 3 sec.

Note: If this Recloser does not close within state 2 then it did not get a close command from -R5 resent by -R6 or it did not properly respond to the close command.

You could just as easily add a new wait state that ends with another GPS clock pulse and then add another complete test sequence. This can be repeated for up to 99 states!
As you can see if you understand how the Reclosers or Sectionalizers expected operation at each test point then; you can easily set up the correct sequences to prove the devices and all of the logic & communications work correctly operates for the system condition being tested.

Here are the critical points:

1. You must test each Recloser by itself to be sure it is properly working before trying to test the whole system! This keeps the number of possible problem areas down to a manageable level when the system does not correctly operate.
2. All points must have a pre-fault wait state that ends with an incoming GPS Clock pulse to start the active sequence.
3. The second state begins the active sequence for all test points and all points begin at the same time.
4. The total time for the active sequence states must be equal to each other.
5. Measure or check for both the expected Recloser action(s) plus check to confirm unwanted actions do not happen. Example: We need to test to ensure that if a fault clears during the first trip the Recloser does not trip again under load current conditions when it closes.
6. Be sure you have equipment that is accurate enough to give repeatable test results. If a digital controller has a repeatability of 0.1% or better then we need equipment that is at least that accurate.
7. Be sure you have equipment that can have 4 or more test sets synchronized to within 50 micro-sec., worst case, it is much better to be synchronized to within 10 micro-sec. Lets be clear; We are talking about the output signals from each system having a synchronized accuracy of 10 to 50 micro-sec this includes all propagation delays or anything else.

Notes about common problems found:

- Communication system times & delays are a frequent cause of the ADR systems to fail.
- Logic program errors are the next common cause of the system failures. These are both the standard logic for the device and the communications logic errors
- Testing all of the related parts of the system together is the only way to be sure the whole system truly is working the way you expect it to work.
- You can do lab testing but that does not test the actual communications system being used in the field and many problems are found in the field.

Do you have any questions or comments?

Now we will see a simple demo of synchronized testing for these units.

Summary of what the Recloser & Sectionalizer of the future needs to include.

1. The test system that can simulate any and all signals & contacts, that the device being tested would see when in service and monitor all critical signals given by the device being tested. In this case 6 voltages, 3 currents, and all 52a & 52b contacts plus all 69 contacts.
2. Voltage sources with enough VA to energize the voltage elements, the battery charger, and the heater elements in the controller.
3. Current sources with enough compliance voltage to test the old legacy R&S.
4. Be able to supply between 2 and up to 9(+) programmable voltage wetted contact outputs to the tested device (depending on the system).
5. Be able to monitor between 2 and up to 10 binary Inputs from the tested device depending on the system.
6. Have DC sources capable of operating the primary switches.
7. Ability to set up programs to automatically provide real world system conditions & sequences for all test conditions.
8. Variable frequency with accuracies better than 0.001 Hz, for under-frequency testing or frequency monitoring.
9. Ability to set up easily simulations to automatically provide real world system conditions & sequences for all test conditions. The simulations should be easily adapted to adjust for changes to the device settings.

10. Ability to easily up-date the tests with the actual Recloser or Sectionalizer settings being used, as changing the device settings for proper testing is not an option.
11. The ability to reproduce the same exact test conditions and test results year after year and from one device to another.
12. Ability to operate several test systems in a synchronized mode to perform ADR system testing & troubleshooting. (For many systems at least 4 and often more synchronized test systems are needed.)
13. Ability to automatically record all test results in an automatic report.
14. Ability to capture and display all test signals and device responses in a simple to understand way for troubleshooting.
15. High impedance inputs to detect leakage current when the voltage spike protective MOV starts to leak and begins to look like a falsely closed output contact from the controller.
16. Accuracies of better than 0.1% for voltages & currents. High accuracy of the current & voltage sources to detect slowly increased pickup levels, an indication the Voltage spike protective MOV starts to leak and allows the signal to bypass the controller input circuits.
17. Precise timing of programmed states to meet the precise needs of modern controllers.
18. Precise GPS synchronization of 4 to six or more test systems for field testing of the entire system.
19. The ability to test the primary switches to determine the first open or trip operation time and compare it to subsequence open times.
20. The ability to improve the efficiency of expanded testing; NERC required record keeping, and troubleshooting of complex applications.
21. Ability to perform complete simulations of all system conditions to prove any and all protection & operating logic.
22. For field testing the test system needs to be able to operate when supplied from a portable generator or even better from the inverter in a vehicle without loss of accuracy or repeatability.

It should be mentioned that the control design often referred to as Master / Slave designs are another variation of the DAR control systems described above and testing is similar to the above systems.

This paper is offered as tribute to the often forgotten protection group, the Distribution System Protection Group.