Remote Testing of Protection Devices and Schemes – Principles, Applications and Benefits

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Abstract—**The implementation of digital interfaces for protection and control in Substations provides an opportunity to perform remote testing. The paper discusses the principle requirement for isolation of IEDs from the point of view of the maintenance testing in an energized substation. The requirements related to the testing of a specific function element, a local protection scheme or a distributed function are discussed based on a Breaker Failure Protection scheme example. The features in Edition 2 of IEC 61850 are discussed that can be used for virtual isolation of components of the protection scheme. Then, the methods and tools are discussed that can be used to perform the testing based on the IEC 61850 Ed. 2 definitions and how they meet the requirements for virtual isolation from a practical point of view. The benefits and challenges related to remote testing of IEC 61850 communications-based protection, automation and control IEDs and schemes are summarized at the end of the paper.**

***Keywords*—Protection Schemes, Digital Substations, Maintenance, Remote Testing**

I. Introduction

The transition of the electric power industry towards a smarter grid is characterized with significant efforts to improve the efficiency in performing all tasks and reducing the duration of outages in case of events related to the operation of multifunctional protection IEDs.

The wide spread development and implementation of IEC 61850 based substation protection and the increased interest in digital substations based on the Sampled Values interface with the substation process is providing an opportunity to develop and implement protection, automation and control systems that can be tested remotely.

The testing of hardwired protection and control systems requires a crew to drive to (in many cases) a remote location to perform maintenance testing. Replacing the hard-wired interfaces with IEC 61850 based communications interfaces allows remote access to the substation from the convenience of the office that can be used to perform remote testing.

The replacement of part (or all) of the hardwired interfaces with communication links requires the development and implementation of methods and tools that maintain the same level of security during the testing process, while at the same time take advantage of all the benefits that IEC 61850 provides.

II. Digital Substations

Before we start talking about the remote testing, we need do define what a digital substation is and what is the difference between it and other substation types. To do that, we can divide substations in three main categories:

- Conventional substations are most of the substations around the world that are using only hardwired interfaces between the primary and secondary devices in the substation. All protection and control functions are performed by electromechanical or solid-state devices that do not have communication capabilities;
- Hybrid substations are the growing number of substations all over the world that are using microprocessor-based protection and control devices with some communication capabilities that can be used for data acquisition, event reporting, disturbance recording and many others. A more advanced version of hybrid substations are the ones that are using IEC 61850 as the communications protocol and especially GOOSE messages to replace the hardwired signals between the protection and control IEDs;
- Digital substations are the ones where all interfaces between the sensors, IEDs and other devices performing protection, automation, control, measurements, monitoring, recording, etc. are based on digital communications, predominantly using IEC 61850. The only hardwired interfaces are the power supply and the interfaces with the primary equipment – for example circuit breakers and switches, power and instrument transformers. A more advanced version of digital substations are the ones with non-conventional instrument transformers.

Typically, today the digitalization of the analog interfaces of protection, automation and control in substations is accomplished using standalone merging units (SAMU) connected to the secondary of the current and voltage transformers, as shown in Figure 1.

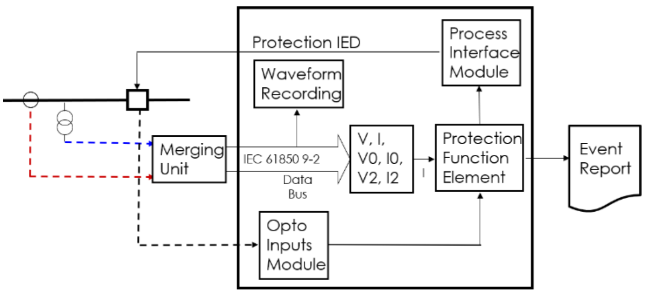

Fig. 1 Analog digitalization using standalone merging unit

The digitalization of the interfaces to the breakers and switches in the substation is achieved using switchgear interface units (SIU). They send information about the status of the circuit breakers and disconnector switches using high-speed peer-to-peer communications defined in IEC 61850 as

GOOSE messages. The SUIs also have a hard-wired interface with the trip coils of the breakers and subscribe to GOOSE messages from the protection IEDs to clear faults or operate the switchgear as necessary. Both SAMUs and SIUs can be combined in what is known as Process Interface Units (PIU).

The architecture of digital substations today is typically distributed as shown in Figure 2. MUs, SIUs or PIUs provide the interface between the primary substation equipment and different protection, control, monitoring and recording devices over the digital substation's process bus. The interfaces between the multifunctional IEDs and between them and the substation level functions are based on GOOSE messages or Client-Server communications over the digital substation's station bus.

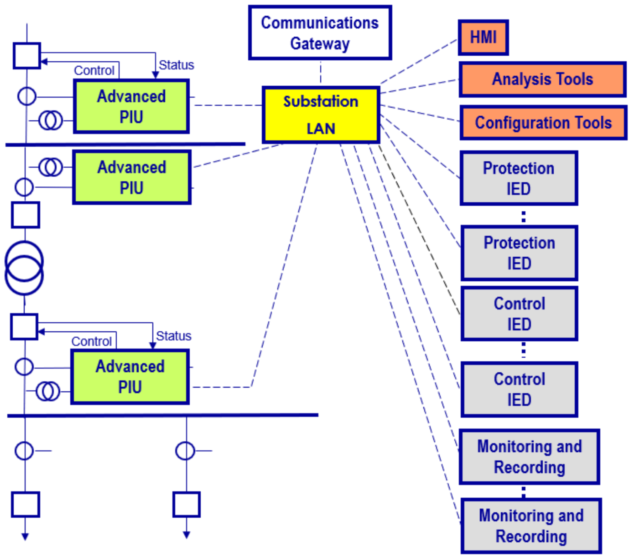

Fig. 2 Distributed digital substation principle

The transition from hardwired to communication-based substations presents great challenges and opportunities for meeting the requirements for improving the reliability, security and efficiency required for the Smart Grid.

III. MAINTENANCE TESTING

Maintenance testing in general is testing which is performed to diagnose and identify equipment problems or confirm that different actions taken to change settings, upgrade or repair the protection device or another component of the fault clearing system have been effective. One of the key requirements for correct maintenance testing is the reason for the test. Maintenance testing can also be related to changes in firmware or addition of new equipment to the substation. In this case it will include installation and commissioning testing, so it is not considered as a topic of this paper.

Problems of the different elements of the fault clearing system can be of two main types – if the system does not operate when it must and if it operates when it should not. These two types of problems are usually detected when the system is in service and an event occurs. The operation needs to be analyzed in order to determine the reason and take some corrective action to prevent future incorrect operation of the system.

The main role of a protection relay is to detect when a fault occurs in the electric power system and to take the necessary actions to clear the fault by disconnecting the faulty equipment from the rest of the system. In some cases, such as transmission line or distribution feeder faults of temporary nature the protection system may also attempt to restore the pre-fault system topology using autoreclosing functions.

Failure to operate under fault conditions may have severe impact on the stability of the electric power system due to the increased duration of the fault caused by the operation of backup protection functions and the switching-off of healthy system components.

As many system disturbances and blackouts have shown, one of their main causes have been operations of the protection system under non-fault conditions. These failures also need to be prevented since they may also have a negative impact on the stability of the electric power system and result in deterioration of the conditions and a wide area disturbance.

The maintenance testing in case of incorrect operation are of two types:

- tests used to determine the reason for the operation;
- tests used to confirm that a required corrective action has been successfully implemented.

Determining the reason for the incorrect operation is typically done using as a first step replay of waveform records available from the relay itself or from other recording equipment at the substation. The second method is preferred for several reasons:

- the record in the failed relay may be affected by the failure of the device itself or a component of the fault clearing system – for example instrument transformers or the wiring between them and the relay;
- the sampling rate of the recording by the relay may be too low which will not correctly represent the abnormal system condition.

In some cases, comparison of the recording from the relay that operated incorrectly and the record from another device can indicate the reason for the operation and which component of the system has failed. After the reason for the incorrect operation has been determined, a corrective action is required, followed by maintenance testing to ensure that the measure has been successful. The maintenance tests in this case can be based on replay of the same files used to determine the cause of the incorrect operation, or some other tests to verify changes in settings or programmable scheme logic using network system simulation.

The main challenge with maintenance testing is that it is performed in an energized substation, which makes the requirements for functional isolation during the tests extremely important.

IV. Requirements and Methods for Isolation During Maintenance Testing

The requirements for isolation in conventional hardwired substations are met using test switches that completely disconnects the tested device and the test equipment from the substation environment.

In an IEC 61850 based digital substation such physical isolation is not possible due to the replacement of the hardwired interfaces with communication messages. That is why it is necessary to find other means for isolation. The IEC 61850 standard includes many different features that can be used to achieve what is known as "virtual isolation". It is based on appropriate use of the Mode of the tested components of the protection and control functions or their elements, as well as the ability to distinguish between the normal messages over the process and station bus in the digital substation and the simulated messages published by the test system.

A. Mode and Behavior in IEC 61850

The behavior of the functions and function elements in IEC 61850 based devices and systems is controlled using the mode data object Mod defined in the standard. Switching between the modes (Mod.stVal) is a result of an operator command to the data object or a local action.

The behavior of a function element depends on its own Mod setting, as well as on the Mod settings of the nested logical devices it belongs to.

The standard defines five modes described in detail in Annex A of IEC 61850-7-4 [1].

TABLE I. Mode and behavior in IEC 61850

Value	*LN mode*	*Behavior*
1	on	The application represented by the LN works. All communication services work and get updated values.
2	blocked	The application represented by the LN works. No (wired) output data (digital by relays or analogue setpoints) will be issued to the process. All communication services work and get updated values. Data objects will be transmitted with a relevant quality. Control commands with Test=false will be accepted. Control commands with Test=true will be rejected (negative acknowledgement with AddCause=Blocked-by-Mode).
3	test	The application represented by the LN works. All communication services work and get updated values. Data objects will be transmitted with q.test=true, except Mod, Beh and Health, that have q.test=false. Control commands with Test=true will be accepted. Control commands with Test=false will be rejected (negative acknowledgement with AddCause=Blocked-by-Mode).
4	test/blocked	The application represented by the LN works. No (wired) output data (digital by relays or analogue setpoints) will be issued to the process. All communication services work and get updated values. Data objects will be transmitted with q.test=true, except Mod, Beh and Health, that have q.test=false. Control commands with Test=true will be accepted. Control commands with Test=false will be rejected (negative acknowledgement with AddCause=Blocked-by-Mode).
5	off	The application represented by the LN doesn't work. All communication services work (output with quality.validity=invalid, except Mod, Beh and Health, that have q.validity=good). No process output will be done. Control commands to the process will be rejected (negative acknowledgement with AddCause=Blocked-by-Mode). Only Mod accepts control commands with Test=false. Settings and configuration attributes are still modifiable.

From Table 1, it is clear that the isolation of the tested function is achieved by setting the mode to test or test/blocked (when there is a physical output to the process, for example from LN XCBR).

B. Simulation of messages

Another feature that has been added to Edition 2 is the possibility to subscribe to GOOSE messages or Sampled Values messages from simulation by test equipment. The approach is explained in Figure 3. GOOSE or Sampled Values messages have a flag indicating if the message is the original message or if it is a message produced by a simulation. On the other side, the IED has in the logical node LPHD (the logical node for the physical device or IED) a data object defining if the IED shall receive the original GOOSE / Sampled Values messages or simulated ones. If the data object Sim is set to TRUE, the IED will subscribe to all GOOSE / Sampled Values messages that have the simulation flag set to TRUE. If for a specific GOOSE message, no simulated message exists, it will continue to receive the original message. That feature can only be activated for the whole IED, since the IED shall receive either the simulated message or the original message. Receiving both messages at the same time would create a different load situation and therefore create wrong test results.

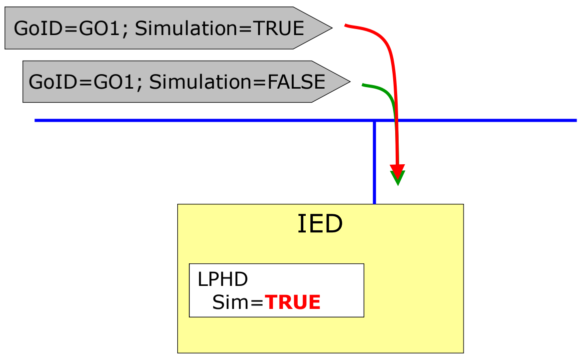

Fig. 3 Simulation of a GOOSE message

C. Mirroring control information

A third feature that allows performing the testing without producing an output to the process is the mirroring of control information. This supports the possibility, to test and measure the performance of a control operation while the device is connected to the system.

A control command is applied to a controllable data object. As soon as a command has been received, the device activates the data attribute opRcvd. The device processes the command and if it is accepted, the data attribute opOk is activated with the same timing (pulse length) of the wired output. The data attribute tOpOk is the time stamp of the wired output and opOk. These data attributes are produced independently if the wired output is produced or not – the wired output shall not be produced if the function is in mode test/blocked.

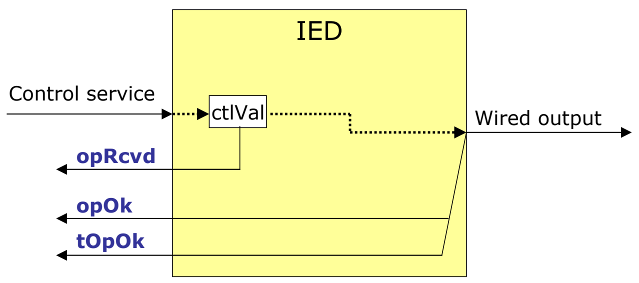

Fig. 4 Mirroring of control information

D. Isolating and testing a device in the system

Combining the mechanisms described in the previous sections, it is possible to test a device that is connected to the system. We will explain that with a short example. Let's assume we want to test the performance of a Main 1 protection that receives Sampled Values from a merging unit. In the LN LPHD of the Main 1 protection relay, the data object Sim shall be set to TRUE, the logical device for the protection function shall be set to the mode "test" and the logical node XCBR as interface to the circuit breaker shall be set to the mode "test/blocked". A test device shall send Sampled Values with the same identification as the ones normally received by the protection relay but with the Simulation flag set to TRUE.

The protection device will now receive the Sampled Values from the test device and will initiate a trip. The XCBR will receive and process that trip, however no output will be generated. The output can be verified through the data attribute XCBR.Pos.opOk and the timing can be measured through the data attribute XCBR.Pos.tOpOk.

The same principle applies when the tested IED receives GOOSE messages. The real data received from a publishing IED or the simulated data received from the test devices will be available on the process bus. The message subscribed by the IED will depend on the value of Sim in LPHD.

The issue with this method is that all IED function elements using the simulated signals must be in Test mode, i.e. they will not be available to detect any abnormal condition during the testing. This can be avoided by using some advanced testing features.

V. REMOTE TESTING REQUIREMENTS AND BENEFITS

IEC 61850 based digital substation allow a significant improvement in the efficiency of maintenance testing. This is the result of the availability of testing related features defined in the standard which allow the isolation of the test object and testing system from the rest of the live substation without the need for physical switching or connections of equipment in the live substation.

One of the benefits of digital substations is that all devices (PAC IEDs, substation computers and test devices) are connected to the substation communications network. If there are testing tools that are connected to the network in the substation on a permanent basis, it becomes possible to perform the tests from a remote location. This can be useful in many cases:

- long distance between the substation and the base of the test team;
- difficult terrain with bad roads;
- difficult weather conditions;
- requirements for reduction of outage time because of maintenance.

The remote testing improves the efficiency by eliminating the need to travel to the substation to perform the testing. This leads to the significant reduction in the time spent by the testing team in relation to a specific maintenance test.

Additional savings in time are the result of eliminating the need for connecting the test equipment to the test object.

The ability to isolate only a function element that is being tested improves the efficiency of operation of the electric power system by eliminating the need for an outage during the testing.

In order to be able to perform remote testing, the system needs to meet the following requirements:

- Analog and digital interfaces between the process and the protection, automation and control system are communications based (IEC 61850 Sampled Values and GOOSE);

- Support of virtual isolation of test objects;
- Ability to test a subset of the protection function elements;
- Remote secured access to the substation's test system;
- Isolation between the test computer and the substation station and process bus.

VI. Remote Testing System Components

In order to develop and implement a remote testing system, we need a set of components that meet the above listed requirements.

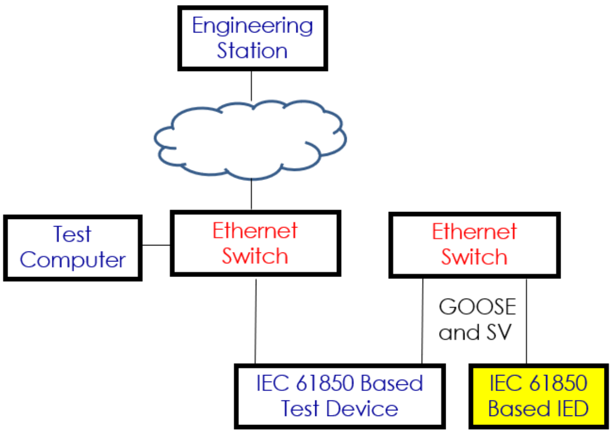

Fig. 5 Remote testing system components

A. *Engineering station*

The engineering station is located at a central or regional office and is used to allow the testing specialist to remotely access the test system in the remote substation. The engineering station should have installed a remote access software with high level of cyber security that will provide access to the remote test system only to personnel with the required credentials.

The decision to use remote control of a test computer located in the substation is driven by the elimination of the latency introduced by the wide area communications between the engineering station and the remote substation.

B. *Substation test computer*

The test computer is the host of the different testing tools, including a wide range of specialized test modules for automated testing of multifunctional protection, automation and control devices.

The test computer interfaces with the remote engineering station over the secure remote access software.

C. *Remote access software*

The remote access software allows the test specialist to take control of the substation test computer over a secure connection. It is very important to use the software with the highest level of cyber security and to enforce strong passwords and authentication.

D. *Testing tools*

The maintenance testing of modern numerical protection devices usually requires the use of different test modules as a function of the reason for the test. The efficiency of the test can be significantly improved if the testing specialists have developed standardized test plans for the different maintenance test use-cases. The testing tools should support all IEC 61850 testing related features described earlier in the article and should allow the control of the test objects' mode as required by the test.

Any number of test modules can be combined in a complete test plan to match the requirements of the functions to be tested. The individual tests are executed in the predefined order through the test devices under the control of the test computer.

The testing tool must ensure that all components of the substation protection and control system will return to their pre-test state after the completion of the test.

The testing tools must be properly configured according to the Role Based Access Control (RBAC) rules in order to minimize the probability for human error, which can be critical when running maintenance tests in an energized substation.

E. *Test devices*

The test computer controls one to many test devices. They are substation hardened and permanently installed test devices with IEC 61850 communications capabilities that can operate as IEC 61850 GOOSE and Sampled Values publishers and GOOSE subscribers in order to perform the testing of different protection functions under the control of the test computer.

The test devices should be capable to operate both as simulators of existing components of the substation protection and control system (used by the source reference of InRef) or as a test device simulating generic test signals (used by the test reference of InRef).

One communication port of the test device is connected to a dedicated Ethernet switch used specifically by the substation test system for the interface with the test computer. A second communication port of the test device is connected to the substation network for exchange of messages with the different protection, automation and control devices. This allows the test device to provide separation between the test computer (controlled from the remote engineering station) and the protection and control substation network.

F. *Test LAN*

The testing network is dedicated to the interface between the remote engineering station, the substation test computer and the permanently installed test devices. This is to ensure a higher level of cyber security considering that the communications between the engineering station and the substation are executed over a wide area network.

G. *Engineering of the test system*

The components of the test system that are permanently installed in the substation to support the remote testing must be included in the overall engineering of the substation protection, automation and control system.

This does not only apply to the communication interfaces that will ensure the required ability of the test system to publish and subscribe to IEC 61850 messages, but also to simulate substation IEDs or act as a generic test device.

VII. CONCLUSION

Maintenance testing is a time-consuming activity performed in an energized substation that requires careful planning and execution, in many cases in remote and hard to reach locations.

Digital substations based on Edition 2 of IEC 61850 support many new features that further enhance the power of the standard and allow the development of methods and tools that improve the efficiency of testing.

Remote testing is the highest level of improved efficiency, since it can be performed from the comfort of an engineering office without the need for an outage and with limited impact on the availability of the protection functionality.

VIII. REFERENCES

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IX. BIOGRAPHIES

Dr. Alexander Apostolov received an MS degree in Electrical Engineering, an MS in Applied Mathematics and a Ph.D. from the Technical University in Sofia, Bulgaria. He has 40+ years' experience in power systems protection, automation, control and communications. He is presently Principal Engineer for OMICRON electronics and Editor-in- Chief at PAC World Magazine. He is an IEEE Fellow, past Chairman of the Relay Communications Subcommittee of PSRC and serves on many IEEE PES Working Groups. He is a member of IEC TC57 working groups 10, 17, 18 and 19 and Convenor of CIGRE WG B5.53 "Test Strategy for Protection, Automation and Control (PAC) functions in a full digital substation based on IEC 61850 applications" and member of several other CIGRE B5 working groups. He is a distinguished member of CIGRE.

Eugenio Carvalheira received his BSc in Electrical Engineering from the UFPE University in Brazil and his MSc in Computational Engineering from the University of Erlangen in Germany. He has 16+ years' experience in Power Systems Protection, Automation and Control (PAC). He spent part of his career as a Project Engineer responsible for the design, implementation and commissioning of PAC systems at Electrical Substations and Power Plants. He joined OMICRON in 2008 as Training and Application Engineer developing test automation solutions for protection relays, providing technical product application support and responsible for the IEC 61850 training courses at OMICRON. He is currently Engineering Manager for North America based in Houston, TX. He is an active member of IEEE PES serving many PSRC working groups.