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Cambio de paradigma en la puesta en servicio y mantenimiento de subestaciones con IEC 61850

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Abstract – More than 10 years spent in commissioning, troubleshooting, post-fault analysis and consulting customers worldwide with IEC 61850 protection application issues, have shown that IEC 61850 stations require new tools and new competence in order to be successfully specified, designed, commissioned and maintained. In the IEC 61850 scenario the underlying operating principles of the Power Systems is still the same, but the mediums and platforms have changed tremendously. The communication technology replaces the copper wires, thus the traditional multimeter that informed about the analog information need to be replaced by IT compatible tools, that should be as reliable and user friendly as the conventional simple multimeters. This is critical in order to maintain a safe environment, and allow to take appropriate decisions. Computers cannot be connected live to the substation buses as the IT security and integrity is critical to the reliability of the system. Moreover the competence of the Power System engineers can't be replaced with IT, thus the need of tools that bridge the gap between the IT world of IEC 61850 into Power system engineer's domain. This paper is presenting some of the new methodologies and tools that contribute to maximize the benefits of IEC 61850 applied to maintenance and commissioning of power system automation.

Keywords: IEC 61850, Commissioning, Maintenance, New Tools, Numerical Substations, GOOSE, Sampled Values, Substation Bus, Process Bus

1. INTRODUCTION

Starting from the consideration that maintenance tests are performed in order to make sure that the system is running correctly, they can be said to be a subset of the commissioning tests, which are more finalized to setting-up the system and validate its functionality. Figure 1 shows a schematic representation of the process involving commissioning and maintenance tests.

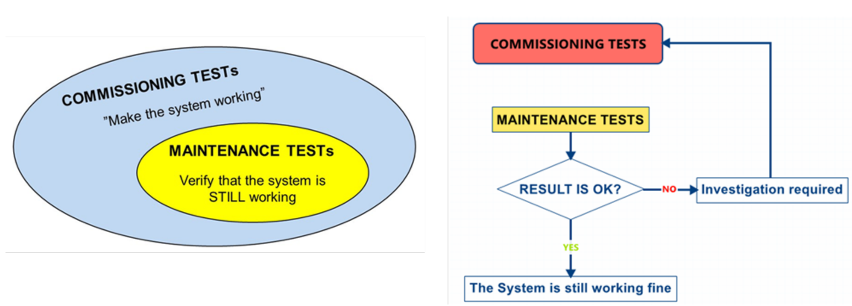

Figure 1 – Commissioning and maintenance tests. Symbolic representation and flow diagram.

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One IEC 61850 substation is built with numerical devices, hence it seems appropriate to make use of the numerical technology to get information about the status of the substation. Key procedures for maintenance can then be based on comparison actions: compare the previous correct status of the system with the actual "unknown" status; if the comparison gives "No differences", it is likely that the system is still running correctly. If there are some differences, some investigations are then needed to find the cause of the difference. This activity can be seen as a sort of numerical "checksum". Once defined the key parts of the system object of comparison, if all the comparisons are "ok", the system is still running properly.

Not all the concepts described in this paper are strictly connected to the IEC 61850 standard. The IEC 61850 standard gives anyway the instruments, mechanisms and rules to implement the concepts described in this paper, but does not state if it has to be implemented or not. This decision, as also the majority of the application decisions, are still governed by the engineers.

Several concepts available in the standard are indicated as "optionals", which means they are not mandatory. There has been in the past the culture of implementing only mandatory parts of the standard by several equipment manufacturers and system integrators. Mainly because of lack of strategy and specification at Utility level (or more generally at user's level).

Experience has shown that maintenance and operation considerations should be included already at the design phase in order to ensure efficient ownership and harmonization between substations supplied by different vendors. A clear Utility strategy on the implementation of IEC 61850 is the key for successful operation, maintenance and future-proof substations. What is not mandatory in IEC 61850 standard can easily become mandatory in the procurement specification of a particular Utility -without breaching the standard- establishing a sort of "profile" for the particular Utility.

All the described concepts have been and are applied in practice. Several concepts have been manually applied in the past, because of lack of tools and equipment that are now available.

2. METHODOLOGIES AND TOOLS FOR MAINTENANCE AND COMMISSIONING

2.1 Extended use of supervision mechanisms.

The IEC 61850 standard expects IEC 61850 devices to perform self-supervision tasks; as example in the quality string of the data attributes there is one bit dedicated to "failure" (see Figure 2). This bit is intended to be raised when the device detects an internal failure, hence it is the result of the self-supervision in the device. Many more other similar examples can be found in the standard.

Bit(s)	IEC 61850-7-3		Bit-String	
	Attribute name	Attribute value	Value	Default
0-1	Validity	Good	0 0	0 0
		Invalid	0 1	
		Reserved	1 0	
		Questionable	1 1	
2	Overflow		TRUE	FALSE
3	OutofRange		TRUE	FALSE
4	BadReference		TRUE	FALSE
5	Oscillatory		TRUE	FALSE

Bit(s)	IEC 61850-7-3		Bit-String	
6	Failure		TRUE	FALSE
7	OldData		TRUE	FALSE
8	Inconsistent		TRUE	FALSE
9	Inaccurate		TRUE	FALSE
10	Source	Process	0	0
		Substituted	1	
11	Test		TRUE	FALSE
12	OperatorBlocked		TRUE	FALSE

Figure 2 - The "quality string" associated to a data attribute, part 7-3 of the IEC 61850 standard.

The correct use of the quality during the substation design is a very important concept to simplify the testing procedures for commissioning but especially for maintenance, where it is important to be able to pinpoint in a short time which parts of the system may be affected by a failure.
Also at Station HMI level, it is very important to clearly specify the desired processing of the data quality indication, which contains many more information that the one described in the above example. Also the time contains quality information and the SCADA system should be able to interpret it and give relevant messages to the operator.

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The horizontal substation communication (GOOSE) can also be supervised and correct information can be sent to SCADA system (Station HMI) activating the investigations when they are really needed. The communication protocol for GOOSE messages allows the possibility of implementing supervision of the horizontal communication at the receiving IED. This means that the receiving IED is able to understand if the “sender is lost” for any reason (interruption of the communication path, failure in the sender).
This method is based on the supervision of the repetition GOOSE messages (see Figure 3).

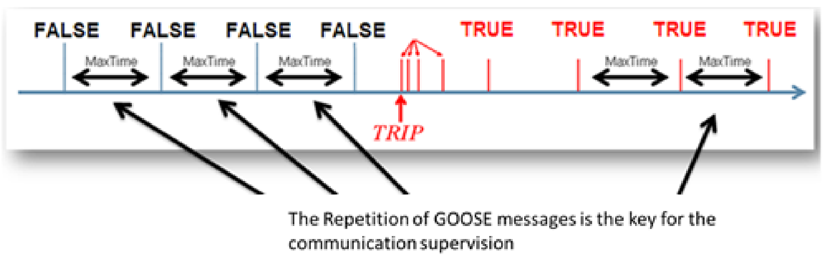

Figure 3 - The “repetition mechanism” of GOOSE messages allows implementation of the supervision of the communication path between the sender (publisher) and the receiver (subscriber). We here show the change from a FALSE to TRUE after a TRIP

The mechanism of the communication supervision can be explained in this way: when a GOOSE message is received, the receiver looks at the “timeAllowedtoLive” written in the message (this value is directly related to the SCL attribute “MaxTime” for the GOOSE message). Typical values of these times are of the order of seconds. Supposing the value to be 5 seconds (5000 ms), this means that the next GOOSE message must be received within 5000 ms. If a new GOOSE message is NOT received within this time, the communication with the sender is lost and a warning signal can be raised in the receiving IED.
The detection of a failure in the horizontal communication has several benefits for the behavior of the substation: for maintenance purposes it is possible to have information about failures in the communication between two particular IEDs; for the protection and control application this detection can be used to increase the security of the protection scheme whenever the GOOSE messages are used for the implementation for schemes like direct intertrip, reverse blocking etc. avoiding for instance unwanted trips due to lack of functionality in the communication scheme (a very common situation in the conventional technology, unfortunately).
There are already instruments on the market that detect the loss of communication based on the above mechanism. Figure 4 shows some warning icons (Ghosts) informing that the particular GOOSE messages have been lost, so they did not reach the test instrument within the expected time.

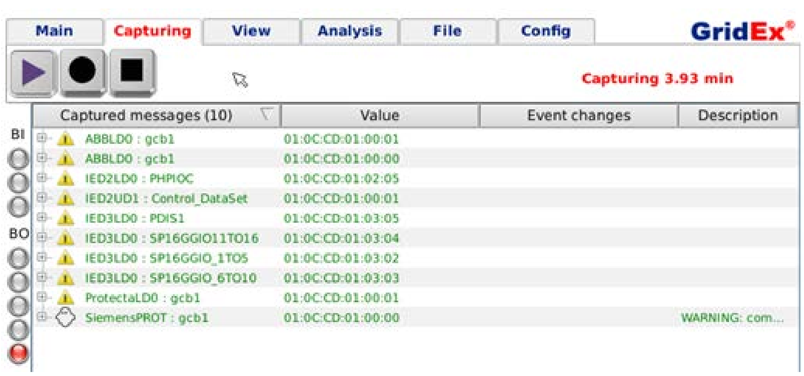

Figure 4 – Example of detection of loss of reception of a particular GOOSE message, indicated with a “Ghost” icon. (Courtesy of FMTP Power, Sweden)

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Figure 5 shows a graphical representation of an analog signal (frequency measurement) sent through a GOOSE message together with its quality attribute. The quality is represented in the line below the value of the signal. It can be seen that the frequency was almost 50 Hz for a while, and the quality is good (black color). Something then happened and the delivered frequency was negative. The publishing IED was informing that the published value was not trustable (quality invalid, red color), so the receiving IED was supposed to not report that negative vale of the frequency on its local HMI (which it did instead). The publishing IED was removed from the network (pink area) and later on reconnected to the network in test mode (yellow quality). At the end it was put in normal service again. Without entering in the details of the troubleshooting of this situation, it appears clear that a simple visualization of information and the reporting of it allows to pinpoint the possible source of the problem and efficiently address the technical resources to its solution.

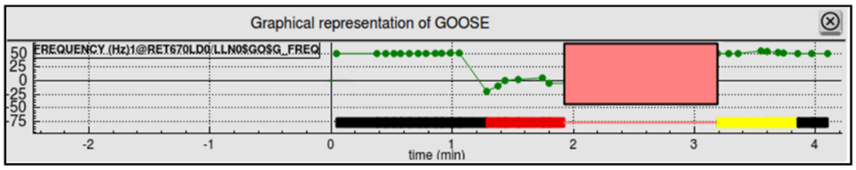

Figure 5 – Graphical behavior of an “analog GOOSE” carrying the power frequency value and its quality. (Courtesy of FMTP Power, Sweden)

The successful implementation of the horizontal communication supervision requires a correct specification of it, it needs dedication during the design phase as well as it needs to be tested during commissioning.

The Vertical Communication (communication between Station HMI and Station devices) can be also be supervised with relatively simple client / server TCP/IP based “ping” mechanisms. Once this is implemented it is very easy to understand, when the substation is in service, which parts of the system are not communicating anymore. Even in this case it is never enough to stress the fact that this implementation, technically possible, must be specified, engineered and tested.

2.2 Protection Relay setting comparison.

The concept here is always related to the “comparison”. The protection relay master settings are stored in a central database. These are the finally approved settings that are also stored in the protection and control devices (protection relays, bay controllers, switches, substation clocks etc).
The activity maintenance is based on comparing those settings with the setting values that are read directly from the protection devices. A warning flag is raised by the maintenance activity in case this comparison should give some differences, and of course investigations are started to understand the cause of the difference.

The role if IEC 61850 standard in the above procedure is to provide the technical community with a standardized way to store the relay protection settings in the SCL files. This would allow easier methodology for storing the relay protection settings in what is already accepted by IEC 61850 community that SCL files are the key of the engineering and documentation processes.

Apart for IEC 61850 standard, implementing this concept requires Utility strategy, database tools and vendor tools for the protection and control IEDs that allow this comparison to be done. These tools exist already and are used by several utilities in the world, but not all protection devices have tools with such comparison capability, and this of course restricts the choice of the devices to be used in the substation.

2.3 Compare the GOOSE traffic with the substation master SCD file (consistency check).

The as built drawing of an IEC 61850 substation is represented by the Substation SCD file. As

maintenance activity, a network scanning of the network traffic and the comparison with the network traffic described in the SCD file is a good indication if the result shows “no differences”. In case of differences, it is very important that the tool responsible for the comparison gives focused information on where it has to be investigated.
This activity is already in use for FAT / SAT, where there is the need to validate the SCD file provided by the system integrator to the customer. If the comparison shows that there are some missing GOOSE messages or too many GOOSE messages or some messages are slightly different to what described on the Substation SCL file, the file cannot validated.

Figure 6 shows one example of comparison between the GOOSE traffic in the substation network and the SCL file describing the substation (SCD file). Green result means that there are no differences between the GOOSE message detected on the network bus and the GOOSE message described on the SCL file, Red and Yellow results mean that several differences have been found, so in these cases that differences need to be explained. The yellow cases try to help the user in understanding what the difference could be and why. These detailed information are also shown in the final report.

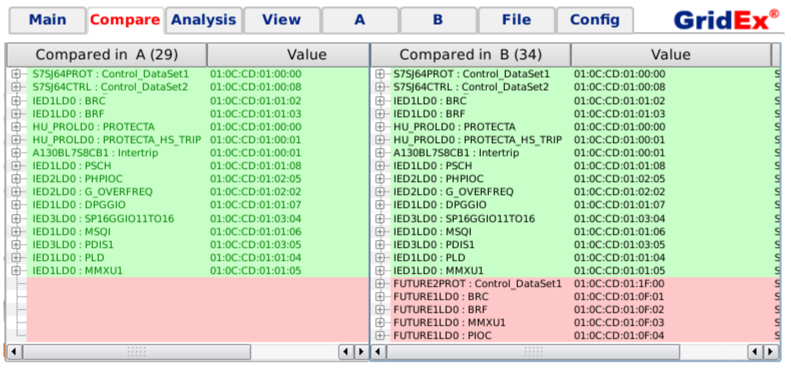

Figure 6 – Example of comparison between network GOOSE scan (left column) and SCL description of the GOOSE traffic (right column). (Courtesy of FMTP Power, Sweden)

2.4 Compare the GOOSE traffic scan with previous network scan

The horizontal communication traffic (GOOSE traffic) can be compared, from the functionality point of view, to the “binary input / binary output traffic” of conventional substations, where the binary outputs of several devices and apparatuses are connected to binary inputs of other devices or apparatuses, as well as SCADA/RTU equipment. This is done for signaling purposes, interlocking schemes as well as for protection schemes.
Some important parts of this “traffic” are usually monitored in the conventional technology, typical example is the so called trip circuit supervision. It is not common –however- to monitor all the binary inputs and outputs of the relays and compare the result of this monitoring with the result of a previous monitoring. It would be too expensive, too complicated and also probably not feasible.
The GOOSE traffic can be monitored in a relatively easy way (network sniffing), and the comparison with a previous network scan is -in principle- not complex. Also with this activity, if everything is the same, it’s a good sign. If some differences are found, investigations are needed and again it is very important that the tool gives good and significant information on where the differences are.

Figure 7 shows an example of comparison of two different scanned GOOSE messages in the network. Green result means that no differences have been found, Red and Yellow results mean that several differences have been found, so in both cases the differences need to be explained. The yellow cases try to help the user in understanding what the difference could be and why. These detailed information are shown in the report.

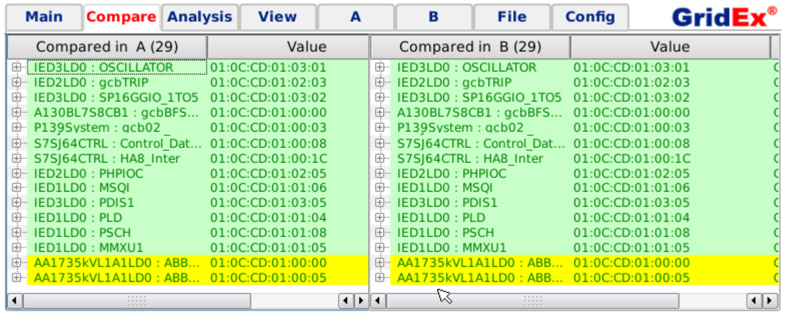

Figure 7 – Example of comparison between two different GOOSE scans of the same substation. (Courtesy of FMTP Power, Sweden)

2.5 Extended use of post-event analysis for preventive maintenance.

Disturbance Recorder Files (DFR) contain important power system information like the waveforms of currents and voltages after and before the ”perturbance” or the event and the Sequence Of Events (SOE) like relay operation (trip) with open command, autorecloser start, autorecloser close command, blocking signals sent to other relays, important internal relay device signals, position of primary apparatuses. The combination of all this information, together with the information from disturbance recorder files from other devices (in the same bay, in different bays or in a different substation), allows to perform a post-analysis to verify the correct/wrong behavior of the protection system and decide actions to improve the system performance or pinpoint deficiencies/defects in equipment and apparatuses. It is important that the events from different devices can be time-correlated, i.e. that the devices in the substations and possibly in different substations are time synchronized.

Through the post-fault or post-event analysis activity it is possible to:

- detect incorrect relay settings and give facts supporting their improvement
- verify relay coordination
- verify relay and primary objects performances
- determine the position of the fault (fault location)
- perform asset condition monitoring (preventive maintenance)

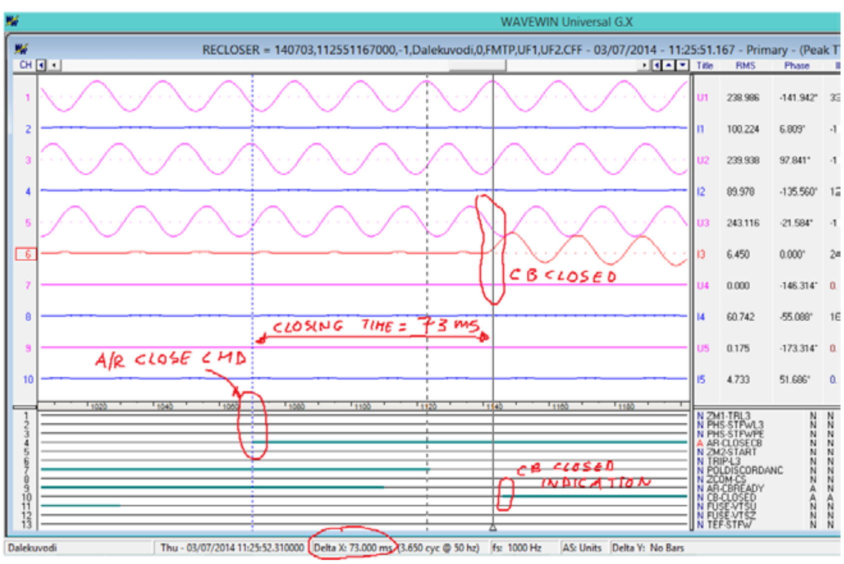

Figure 8 – Simplified post-event analysis where the circuit breaker closing time has been measured based on the available recorded events and analog quantities. (Courtesy of TSO MEPSO, Macedonia and Softstuf USA)

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Figure 8 shows one example of simplified post event analysis from which it has been possible to understand that the circuit breaker performed the close operation in its nominal time (within the time it is expected to do it, roughly 70 … 80 ms, and within the range it has been doing it all the time). The fact that "everything behaved in the expected way" is a result of the maintenance activity. If the circuit breaker (considering the same example) had closed in 120 ms for instance, the engineer responsible for this analysis would have triggered the need of a deeper check on that particular circuit breaker.

Retrieving the disturbance files has been a complex task in the past: proprietary vendor software was necessary to retrieve the information, proprietary communication protocol, lack of fast and reliable communication structure to transmit the disturbance files to a central location. The IEC 61850 standard provides all the elements to facilitate this process by providing these standardized elements for all vendors:

- the definition of Logical Nodes associated to disturbance recorder (RDRE, RADR, RBDR)
- the communication protocol for file transfer (FTP or MMS)
- the communication media (Ethernet, 100 Mbit/s or 1Gbit/s)
- the file format to store the recorded waveforms and binary signals (COMTRADE)
- the location where the files are stored in the IED (root, folder COMTRADE)
- the time synchronisation method for IEDs accurate enough to perform this activity (SNTP, practical order of accuracy +/-1 ms)

It can be said that the IEC 61850 standard has made it difficult to justify the absence of this type of data collection. The rest that needs to be done is to slowly change the attitude towards preventive maintenance based on post-event analysis by understanding that in the long term this activity heavily contributes in reducing the costs associated to maintenance by reducing the activities during periodic maintenance and also by prolonging the time interval between the activities.

2.6 Equipment and tools to allow a secure connection to the substation buses

Security is a very hot topic when the maintenance of an IEC 61850 substation is addresses. In order to be able to perform the majority of the tests mentioned in this paper it is necessary somehow to connect one instrument to the network buses. Maintenance engineers are often scared about this connection, and the majority of Utilities simply do not allow for example any PC connection to the substation bus.
New test equipment are emerging on the market, with the purpose of contributing to some solutions to these problematics. These devices are completely stand alone, they do not need any PC to run; the firmware cannot be upgraded if not by a special procedure, no installation of anything is possible by the user. The device (Figure 9) is also fully "passive", which means it does not (per design) inject (send) any IEC 61850 signal in the network that it is "listening to". This allows the maintenance engineer to comfortably connect the device to the substation network when the substation is energized, with the 100% certainty that if "something happens" after this connection, the cause of it shall not be searched in the device itself.

Figure 9 – A stand-alone IEC 61850 test equipment. (Courtesy of FMTP Power, Sweden)

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3. CONCLUSIONS

All the activities described in this paper need instruments and tools to be allowed to be performed in an easy and efficient manner. They also require a clean strategy in the application of the IEC 61850 standard, which means a clear technical specification providing engineering workflow methodology (SCL Engineering, as built SCD file as part of the Substation delivery), direct engineering guidelines (use of the "quality" for instance, to remain within the themes discussed), provision of one "substation network access point" to allow maintenance activities to be performed or one dedicated service computer for the same purpose. Instruments and tools are available on the market, and more will come to further contribute to maintenance and any other activity.

Clear Utility strategies on the implementation of the standard are seen to grow in several parts of the world but they should probably grow more to allow a smooth engineering, commissioning and maintenance.

The IEC 61850 substation, in very few words, can be considered as a standardized numerical system. As numerical technology is the basic competence of the new generation of engineers, they are here to stay. The best is to contribute to make them to grow in the correct direction so that we all can get the best of their advantages.

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