Gas Insulated Substation Control and Monitoring

Course No: E04-042
Credit: 4 PDH

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This course includes GIS monitoring topics including gas monitoring, partial discharge tests, and circuit breaker monitoring. The control topics of bay controllers and control diagrams are also discussed. The fundamentals of gas monitoring including the related alarms are described and gas monitoring routines are presented. The partial discharge monitoring paragraph also includes the types of faults causing partial discharges and provides details on partial discharge measuring procedures, where electric, acoustic, chemical specific routines of partial discharge monitoring with GIS are presented.

Local control cabinet paragraph provides details on different types of GIS technology that is currently used. Current and voltage transformer wiring including mimic schemes are presented. The function of the bay controller with all its basic elements is presented. Control diagrams of different mode selections and interlockings are provided and examples are presented.

Paragraphs related to digital communication show the impact of digital communication to GIS, which is based on IEC 61 850. Fundamental digital communication standards are presented and their relations to other standards are discussed. Switchgear related communication standards of GIS are presented and the locations of the controls in the GIS and their timing operations are given. Procedure to measure and test digital communication in GIS is also provided.

GIS Equipment Monitoring

GIS equipment can be supervised in several ways and for different purposes needs. Many of these techniques are not unique to GIS equipment and can also be found on other switchgear and breaker elements. The most frequent monitoring arrangement is typically gas monitoring. Gas monitoring will exist on almost every device that uses SF6 gas, including GIS bus and breakers. Another typically used monitoring arrangement involves the circuit breakers. Breaker supervision is not restricted to GIS equipment and there are a number of commercially available products, both from OEMs and third party suppliers. The easiest form of breaker supervision (e.g., monitoring the number of operations) will exist on almost every circuit breakers.

Nevertheless, more advanced monitors are also available and are widely used, even though all of the available functions are not used by some users. Lately, partial discharge (PD) monitoring has earned interest as it promises to have the possibility to warn of developing insulation problems in the GIS installations. There are just a few commercially available solutions since data assessment typically requires expert interpretation.

Gas Monitoring

In GIS installation, the SF6 gas gives electrical insulation and, in the breakers, arc-quenching capability. These characteristics depend on the SF6 gas density. Nevertheless, gas pressure is typically quoted in lieu of density. For instance, different documents frequently use terms such as “fill pressure” or “normal working pressure.” Pressure is used because it can be easily measured and is intuitive, but it is gas density that is the crucial parameter. Pressure is strongly dependant on temperature but density is not (in the case a state change is not involved).

Gas monitoring is primarily used to make sure that sufficient quantity of SF6 gas is provided to meet the equipment’s requirements. This typically involves some form of gas density monitoring. Nevertheless, gas density measurements have limitations. Gas density is observed at one point within the GIS installation, typically at the enclosure. While it can be considered that the gas pressure is constant throughout the gas enclosure, there may be density differences resulting from variations in temperature. For instance, for GIS installation under load, the gas temperature may be greater closer to the central conductor as opposed to at the enclosure, where the gas density monitor is typically placed. Therefore, a measure of density at the enclosure may tend to overrate the density at GIS live parts. In some situations, there may also be problems such as convective flow within the cylinder, solar gain (in the case of outdoor installations), that may impact the temperature and density distribution within the equipment. In most situations, these density differences are considered secondary and SF6 density thresholds are based with adequate margins to consider these secondary impacts. In reality, gas density monitoring systems can be set up to give one or two types of outputs:

1. Permanent output signal. These signals can be used for trending for diagnostic

requirements. For example, previous records could distinguish between a slow leak happening over a long period of time in comparison to a recently developed leak of bigger severity. Trending data can also be used to observe SF6 emissions to help meet environmental requirements and standards. Since the SF6 gas is a considerable greenhouse gas, the importance of monitoring emissions cannot be understated.

2. Threshold alarms. An alarm signal is started when the gas density decreases below a certain predefined limit. Normally, two thresholds are used. The first threshold is a warning to signal low gas. The second level is typically a control signal used to block switchgear service or, in some situations, to completely disconnect the affected equipment. The second signal is typically tied to the minimum density needed to ensure adequate equipment operation. Different technologies are available to complete these functions. These technologies include:

1. Simple pressure switches. Since pressure is not density, this technology is only used in certain equipment with inherently big design margins where the threshold pressures, given the expected temperature change, still ensures adequate gas density for proper service. Certain medium voltage equipment uses such switches, calibrated to one or both above discussed threshold levels.

2. Temperature compensated pressure gauges. A separate temperature signal is used to change the response of a pressure sensor. These sensors typically have a visible gauge (set to read true pressure or compensated pressure) but the signaling is accomplished via relays or switches set to the two density threshold levels.

3. Gas monitor with reference gas. Reference gas in a sealed enclosure interfaces with the relevant gas via a mechanical bellows. Since temperature variations equally affect both the measured and reference gas, variations in pressure also equally affect them and the effect of temperature is eliminated. The bellows will react to differential pressures that would be related to density and cause microswitches to function.

4. Direct density measure. Sensors equipped with tuning forks change their resonant frequency when gas density changes. These sensors give a permanent signal, which

tracks density. Nevertheless, the signal is also interfaced to relays to give the threshold alarms.

It is important to note that advanced monitoring systems that measure pressure and temperature separately could use state equations to calculate density. Sometimes, it is also feasible to include thermal models to give better indications of gas density at various parts of the GIS equipment. Such installations have the potential to monitor and quantify small gas leakages more precisely. Nevertheless, at the moment, this method is not used in commercially available systems.

Gas Monitoring Methods

Most gas density monitors installed as part of the GIS are of the “relay” type. They use contact closures to signal that defined gas density thresholds have been reached. Visual displays on the devices themselves typically consist of color-coded status indicators, but do not give a quantified density value. With this equipment type, low-gas alarms are typically the only available form of monitoring. Manual observation of the indicator status can also be completed during regular inspections. With these installations SF6 loss is done by tracking the gas quantity added when low gas is detected. More accurate tracking of SF6 loss is only possible if SF6 quantified values of density are recorded at defined intervals. Even though such records could be manually kept, the process makes sense only with automated systems.

Partial Discharge

Partial discharges (PDs) are small electrical discharge processes that happen in some types of electrical insulation systems. In some situations, particularly with advanced multicomponent setup, PD is almost considered a normal occurrence. Nevertheless, in many situations, PD is an indication of an insulation defect and its presence shows some form of deterioration. Generally, GIS fits into this category – GIS should be PD free. In reality, detection sensitivity limitations factor into this analysis. Also, some types of low level PD might not be of consequence within the anticipated equipment lifetime. Therefore, for acceptance testing, upper bounds on PD levels are typically adopted. Any PD lower than this level is typically considered to be of little consequence to the overall equipment health.

Nevertheless, from a monitoring perspective, the objectives are slightly different. Monitoring is used to determine if major insulation deterioration is developing over time and to assist in analysing this situation. Ideally, monitoring is used to assist addressing the following:

- Is there a developing insulation issue?
- Where within the device is this problem happening? What elements are suspected?
- How serious is the problem? What are the effects?
- How much time is needed to resolve the problem?

The first question refers to detection. Since GIS, needs to be PD free, any detection of PD above a minimum threshold is construed to be reading of a developing problem. Nevertheless, reading has to be followed up with the second issue of location, particularly if the sources of the PD can be found. PD from different elements need to be differently interpreted and analysed. If the PD source is found, an assessment can typically be done. The last question referring to the available time would be very useful to many end users (since it allows for planning) but is the most challenging to answer, particularly as random processes are involved. For example, some insulator defects types that create PD can cause failure almost instantly but might also last for many months or years without causing any issues. For most monitoring plans, practical objectives would focus on detection and location, from which analysis can follow with proper and educated interpretation.

Failure Types

In GIS installation, there are different defect types that could create PD.

1. Metallic particles. Metallic particles are, by far, the most defect type found in GIS installation. Nevertheless, metallic particles are mostly the problem during commissioning since they are typically introduced during the assembly process. For in service monitoring, metallic particles are less of an issue. Nevertheless, particles in

relatively harmless areas could be physically moved into more active locations through vibration and other mechanical forces that are created by breaker operation. Also, enclosures with moving parts will occasionally create their own particles over time through wear, particularly if some mechanical deficiency exists. Particles "free" to move inside the GIS installation are relatively simple to detect. Movement due to acquired charges in the applied electric field will cause the particles to "bounce" along the GIS cylinder, creating both acoustic and electrical signals on contact. Nevertheless, metallic particles that become adhered to an insulator surface are especially dangerous. These metallic particles can, start surface tracking on the insulator and lead to failure. However, the PD related with such development in the early stages can be very low and challenging to detect.

2. Floating elements. Many GIS installations use shielding to protect specific high stress locations. These shields must be electrically linked to a conductor of known potential, whether it is the main high voltage conductor or the earthed cylinder. In some situations, the contact is made using low force springs or clips. If the contact is poor through damage or contamination, electrical contact could be lost, resulting in a shield at floating potential. Partial discharges will typically happen between these floating elements and one of the other conductors. In the early stages, the PD could be very insignificant and intermittent. Nevertheless, when completely realized, the floating element discharges are big and can be discovered easily both electrically and acoustically. Floating element discharges, when completely active, are rather hazardous and could cause damage in a relatively short period of time. The constant discharging can create local SF_6 gas decomposition – the resulting corrosive byproducts will attack nearby insulators and may cause them to collapse. In severe situations, the discharging will also create conducting and non-conducting particles, as the contact material wears away.

3. Insulator failures. Defects in the insulator typically involve small manufacturing issues, such as voids, that were missed during manufacturing quality control or were still during initial testing. PD from such issues is typically quite small but may sometimes cause damage after some time in service. However, manufacturers have taken measures to improve manufacturing quality and failures of this type are not common. Other internal failures, such as internal metallic contamination in solid

insulator structures, can also cause premature damage. Nevertheless, PD happening from such failures may be very small and nearly impossible to discover until some seconds to minutes before the failure. These failure types are not that common in modern designs. On occasion, insulators could also become damaged during service as a result of uncommon external forces or thermal stress – depending on the damage type, detectable PD may also happen.

Partial Discharge (PD) Measurements

PD monitoring demands some type of measurement. In order to complete PD measurements, the small electrical discharge of PD must be discovered. As PD is an electrical process, majority of used measurement techniques are electrical. Nevertheless, the discharge will also create acoustic energy and acoustic PD techniques are also possible. Over time, the electrical discharges can also decompose the SF6 gas, in which case the decomposition by-products can be discovered by chemical methods. The development of PD measurement technologies has been driven by the requirement to optimize detection sensitivity and the requirement to interpret the results. The requirement for bigger detection sensitivity and to differentiate a true signal from many sources of noise and interference has led to many of the nonconventional techniques. These are discussed in the following paragraphs. The most recent advancements focus on PD signal classification on a pulse-by-pulse basis in order to differentiate PD signals belonging to various sources in order to enhance the assessment of the PD measurement. Nevertheless, some monitoring systems may focus on a simpler detection technique intended to discover and indicate a need for more advancement measurements done manually.

Electrical Measurement Techniques

The partial discharge happens very quickly and can last for 1–2 ns. As the coaxial arrangement of GIS is capable of supporting high frequency signals, it is possible to discover PD pulses with high fidelity. Nevertheless, as the PD spreads throughout the system, some attenuation and distortion may happen. For high sensitivity, PD discovery can be completed using ultrahigh frequency (UHF) techniques with detection bandwidths extending to 1000MHz or more. Nevertheless, as the highest frequency components suffer the biggest propagation loss, UHF techniques may be limited to situations where the sensor is in close proximity to the affected source (commonly within 10–20 m). Another technique is to use a lower frequency band (up to a few hundred MHz), which provides a good compromise between sensitivity (i.e., signal-to-noise) and sensor installation location. Both of these are considered to be advanced techniques and may need sensors specially adapted to the GIS.

Common PD measurement techniques use a decreased bandwidth of about 100 kHz. These techniques are completely described in standard IEC 60480 and are typically used on GIS elements and some subassemblies. Nevertheless, because of challenges in accomplishing a good signal-to-noise ratio, these techniques are less appropriate for big assemblies and field testing.

Acoustic Measurement Techniques

The micro discharges related with PD will emit acoustic energy in addition to electrical signals. The acoustic waves created by PD happening in the SF6 gas will transfer energy to the GIS enclosure – the signals can be discovered on the enclosure using acoustic emission (AE) sensors. Acoustic techniques make it challenging to relate PD to typically used electrical quantities (such as pC). Nevertheless, the method has been used successfully to analyse the condition of GIS installation in the field. Acoustic PD measurements will need some expert interpretation as the signal magnitude does not always relate with the defect severity. For instance, discharges happening within solid insulation are very challenging to discover, as the insulator will often attenuate acoustic signals. However, acoustic techniques are extremely sensitive to metallic particle contamination. When voltage is applied to the GIS installation, metallic particles will usually elevate and “dance” inside the GIS installation. Even though, PD will happen as the particles discharge to other metallic structures, the physical contact of the particle against the enclosure creates an easily detected and distinctive acoustic signal. A related technique involves the application of a portable ultrasonic detector with a contact probe. The detector’s metallic probe tip is pressed on the GIS cylinder to pick up acoustic signals. The detector’s output is electronically transferred to the audible range and fed into headphones for the operator’s use. This technique still demands expert interpretation for many discharge signal type but is relatively simple to use for metallic particle detection. This technique has the added benefit in that the probe is simply moved from location to location, allowing big sections of GIS or GIL to be scanned quickly. Acoustic PD testing is completed during the application of AC high voltage using a test generator. During the test, the probability of test flashover is increased. Such a breakdown during testing will cause a momentary transient voltage on the earthed enclosure that could create an electrical shock to a person using an ultrasonic detector whereas the operator of fixed-sensor systems is typically isolated from the GIS enclosure. Previous experience suggests that the danger is primarily one of being startled and not a direct risk to health and safety. When using a handheld sensor, the risk of a shock can be decreased by minimizing the contact time with the GIS container. If the measurement is applied during conditioning, waiting several minutes at each voltage level prior to the start of the test is suggested.

Chemical Measurement Methods

Partial discharges that happen in the SF6 gas will cause the gas to decompose and create byproducts in trace quantities. Detection of these by-products can be used to discover the presence of PD. As the rate of production of the by-products is small, this detection form is only appropriate for diagnostic purposes in service and not as a short term testing tool. An extended period of time is typically needed to give measurable results. The chemistry of SF6 decomposition can be complex but the most commonly assessed byproducts are:

- Thionyl fluoride (SOF_2)
- Sulfuryl fluoride (SO_2F_2)
- Sulfur dioxide (SO_2)

Measurements can be completed either by taking SF6 gas samples that are sent to a laboratory for assessment or by using some form of portable sensing equipment. The first method is analogous to the dissolved gas assessment completed on transformer oils. Laboratory assessment will typically give by-product levels to a few parts per million (ppm).

Portable devices can be of a kind that makes use of chemically sensitive detector tubes that change color in the presence of specific gases. By controlling the time and flow rates through these tubes, quantitative analysis can be completed. Commonly, SO2 detector tubes are used, as most of the other by-products will additionally decompose into SO_2 in the presence of trace quantities of moisture. More recently, a number of commercially available devices have become available that provide similar functionality. Many of these sense hydrogen fluoride (HF), which is a by-product created by secondary decomposition of the products listed above.

Typically, laboratory assessment gives better details as individual and specific byproducts are assessed. Nevertheless, portable devices provide more rapid analysis at the expense of a simpler measurement. Generally, GIS equipment needs to be PD free and hence free of SF6 decomposition by-products. Detection sensitivity of a few ppm is sufficient for this requirement. Chemical techniques have numerous problems, which need to be considered:

- Gas enclosure volume. Big volumes will “dilute” by-product concentrations and sensitivity is decreased.

- Switching cylinders will create by-products “typically” making PD detection nearly impossible in these cylinders.

- Some cylinders are equipped with absorbing materials (molecular sieve, etc.). These will absorb the by-products created by PD and interfere with the assessment.

- Internal failures will create big quantities of byproducts. PD assessment on faulted chambers cannot be completed.

- As the by-products created by PD are similar to those created by internal faults, the same methods and equipment can typically be used for both as long as the differences in byproduct levels are considered. By the same token, as decomposition by-products are highly toxic, the precautions used for gas assessment for faulted chambers needs to be considered for PD detection.

PD Monitoring Techniques

Complete systems used to complete PD monitoring can be complex as numerous sensors are needed at close spacing for the best coverage of the GIS installation. Electrical PD sensors are typically designed couplers and are normally part of the GIS installation. As a compromise between sensitivity and cost, a spacing of no more than 20 m between couplers is advised. If couplers are a part of the initial arrangement, the incremental cost can be low, but retrofitting couplers on existing equipment can be expensive. Some specific, easy-to-install couplers that take advantage of existing electrical devices in the GIS installation are available but, in principle, their response may be less than optimal. The availability of couplers can be a problem but a bigger issue is how they might be used for monitoring needs. Each coupler could be:

- Permanently wired into a central measuring equipment. Owing to the distances involved and signal attenuation, measurement bandwidth might be limited.

- Permanently wired to nearby local measuring equipment. Numerous measuring devices would be needed for station coverage. In addition, a communication technique from each device to a central hub might also be needed.

- Used with portable equipment. Monitoring is accomplished manually at intervals defined by the user.

In all of these situations, the information collected needs expert interpretation to derive value. As with many monitoring arrangements, collecting data and information has not been a problem but drawing meaningful conclusions to base operating decisions is challenging.

The above listed comments typically apply to electrical measurement based monitoring systems.

The same issues apply with acoustic measurement based systems but, since acoustic sensors are easily installed almost anywhere on the outside of the enclosure, acoustic systems are primarily used as portable equipment.

A completely installed monitoring system can be complex and could be expansive. Implementation decisions are typically based on the perceived value of the anticipated outputs and the cost/ benefit at that installation. At the most critical GIS installations, a complete monitoring system might be warranted. Nevertheless, in other situations, a user might select to only install monitoring on limited parts of the installation. Another approach would be to use a less invasive monitoring system, such as infrequent gas sampling or periodical surveys with portable equipment, and only apply continuous monitoring when problems are suspected. Nevertheless, with increased reliability of modern GIS equipment, the requirement for PD monitoring is decreased and many end users choose not to install such systems.

Circuit Breaker Monitoring

GIS installation that includes switchgear elements, such as circuit breakers, may use some form of circuit breaker monitoring. A number of extra circuit breaker monitors are readily available but these are not specifically for GIS breakers. These elements range from simple add-on devices to advanced systems completely integrated into SCADA with web based user interfaces. Majority of breaker monitoring systems focus on characteristics related to contact wear or mechanical aspects of breaker operation. Common monitored parameters may involve:

- Operation counter
- Arc interruption time
- Accumulated fault current (I_t or I^2t)
- Breaker timing (open/close times) values

Certain systems may also integrate other functions, such as gas monitoring, within the same package.

In many situations, manufacturers will include a monitoring element with the breaker, which users will integrate into their operations. As with many monitoring installations, a great amount of potentially useful information is available. Nevertheless, the user must use and assess the information to extract useful data. An example of this is the I^2t monitoring as a measure of contact wear. Manufacturers might provide guidelines correlating accumulated I^2t values to the need for maintenance. Nevertheless, for best results, users should make their own selection gained through gathering their own information and experience, particularly as operational conditions could vary from user to user.

Other Monitoring

In addition to the above, other monitoring types could be found in GIS installations. These could involve:

- Monitoring by video camera of disconnector and earth switch positions via viewports. Some end users will use video imaging in viewports to confirm open/closed positions of switch contacts. This would be done in addition to other signals typically used with SCADA systems.

- Thermal monitoring of GIS installation and conductor contacts. Even though IR thermography might not be able to solve contact problems on enclosed parts, general trends in temperature might be capable of discovering some forms of strange heating patterns. Permanently installed infrared (IR) systems are also helpful in finding earth faults in GIS installation, as high current faults will create localized heating of the enclosure detectable for some minutes after the fault.

- Monitoring of air ventilation systems for indoor GIS installations. In some situations, SF6 detectors are applied to monitor and automatically trigger forced ventilation in indoor GIS installations. This method addresses the case of enclosure burn-through or operation of pressure-relief elements, in which case a big amount of SF6 gas and possible toxic decomposition by-products could be let go into the ambient.

Numerous monitoring arrangements take the form of a measured quantity “hard-wired” to complete a specific action. Nevertheless, recent trends include the acquisition of information, used to collect intelligence on a specific aspect of GIS service. With modern technologies, the latter form of monitoring has become feasible with great potential to give useful benefit to the user. Nevertheless, these systems are only beneficial if time and effort is invested in assessing the collected information.

Local Control Cabinet

Each circuit breaker of the GIS installation is equipped with a control cabinet for local control and monitoring of the specific bay and is typically put in front or adjacent to their GIS bays depending on the voltage level. The control cabinet is metal enclosed, free standing and provided with a lockable hinged door and door operated lights. The local control cabinet has all needed control switches, local/off/remote lockable selector switches, close and open switches, measuring devices, disconnect switches and earthing switches, alarms, AC and DC supply terminals, control and auxiliary relays, etc. The cabinet is completely designed as per IEC 60 439 or IEEE C37.123 standards.

The control cabinet is made in such a way as to facilitate complete and independent control and monitoring of the GIS locally. All electronic elements inside the bay control cabinet are made to work satisfactorily for the specified project demand. At least 20%of each spare contacts are provided with an auxiliary relay for future use. All CT secondary taps need to be linked to the local control cabinet. The CT terminal block is such that it will give isolation and testing facilities of CT secondaries at the cabinet. For multi ratio CTs the terminal block is given on the LCC as per IEEE C57.13 standard to facilitate connection of different taps. Facility is provided in the LCC for shorting and earthing of secondary terminals.

Voltage transformer (VT) secondary windings are terminated at the local control cabinet through a terminal box. For VT wiring in the LCC, each phase of each circuit is equipped with a miniature knife switch and a high rupturing capacity (HRC) fuse/supervised mini circuit breaker (MCB). Knife switches are installed on the VT side of fuses. Separate terminals are provided for VT fuse supervision. The control cabinet is fitted with a mimic scheme on the front of the cabinet. It shows:

- A mimic scheme presenting the arrangement of electrical elements in the bay including bus bar isolating links.

- Position indicators presenting the position of all circuit breakers, disconnect switches and earthing switches.

- Overriding interlock switch between disconnects and earthing switches related with circuit breakers (depending on the user's demands).

- The colour of the mimic bus needs to be according to the user's demands.

- Control switches and local/off/remote changeover (lockable) for operation of all circuit breakers, disconnect switches and earthing switches.

- SF6 gas zones.

The cabinet is fitted with a thermostatically controlled anti-condensation space heater along with a cabinet light, door switch and receptacle. The placement of element within cubicles is such that access for maintenance or removal of any element should be possible with minimum disturbance of related devices.

All control power circuits are protected by miniature circuit breakers in each cabinet. Other circuits supplying loads, receptacles or lights, have different overload protection. The cabinet is earthed with a proper copper bus and the hinged door of the cabinet is earthed by a flexible earthing connection.

Alarm/annunciators are of the window type and are made as per IEC 60 255 or IEEE C37.1 standards, with a minimum of 20% spare windows for use. The alarm/annunciator system is made for permanent operation of all alarms independently and simultaneously.

The following minimum alarm is given as a local alarm in the LCC:

- Loss of DC supply to circuit breaker motor

- Circuit breaker mechanism failure

- VT supply fail (VT MCB trip)

- Spring overcharged for the circuit breaker mechanism

- Loss of DC for the trip and close circuit

- SF6 gas pressure Low–Low, Stage 1 alarm for each gas zone/area (in the case of a single phase fault, an alarm is provided for each phase)

- SF6 gas pressure Low–Low, Stage 2 alarm for each gas zone/area (in case of a single phase fault, the alarm is grouped for all phases)

- Extra run time of the motor for the circuit breaker, disconnecting switch, and earth switch

- Circuit breaker trip

- Loss of AC supply

- Local/remote switch

- Pole discrepancy operated (for single-phase breaker)

- Trip circuit failure

Bay Controller

The bay controller element is put in the local control cabinet (LCC). There is hard wiring from the GIS to the LCC/bay control unit including CT and VT wiring. The high voltage equipment within the GIS is operated from various places with a preset hierarchy.

The following functions are part of the control unit:

- Bay control unit (BCU) interlocking and blocking

- Measurement display

- Transformer tap change control and indication

- Device position indication (circuit breaker, disconnect switch, ground switch)

- Alarm indication
- Interlocking and blocking
- Double command blocking
- Auto reclosing
- Control mode selection
- Synchrocheck and voltage selection
- Motor excessive run
- Monitoring pole discrepancy and trip function
- Display of interlocking and blocking
- Data storage Interface to the station level

Software interlocking is done through bay control IEDs. In the case where an "interlock override" option is provided as part of the software interlocking arrangement, registered users can only access it using a strong password and other security options. Double operation interlocking is made in software interlocking design where separately dedicated IP address/subnets are appointed for each voltage level in each substation.

Control Arrangements

Control Mode Selection

In this mode the operator gets the operation access at bay level and allows the operation of all switching equipment through control IED. Typically, operation is performed through the local HMI.

Remote Level Mode - Control in this mode is done from the highest level (SCADA) and the installation can be remotely controlled via the station HMI. Service from lower levels is not possible in this operating arrangement.

Local (BCU) Mode - Operation is completed from the BCU directly and operation from other places (e.g., HMI/ REMOTE) is not possible in this operating mode.

OFF Mode - In this mode it is not possible to operate any equipment, neither locally nor remotely.

Interlocking

The interlocking arrangement is incorporated inside the cabinet for reasons of safety and convenience of service, and also to prevent incorrect switching sequences that could lead to a dangerous situation to plant, equipment or staff. The electrical interlocking arrangement is efficient under both local and remote operations. Some of the common interlocking requirements are:

- Manual service of disconnect and earthing switches is only possible under electrical interlock release conditions. A key switch for over-riding interlocks between disconnect and earth switches related with circuit breakers during maintenance is provided in the control cabinet.

- Mechanical and electrical interlock between disconnect and earth switch operation is given.

- The electrical interlock arrangement is fail-safe to prevent loss of interlock function upon loss of control voltage. Electrical interlock between the line VT secondary voltage and respective high speed earth switch operation is provided through under-voltage relay contacts. The feeder earth switch is interlocked with the corresponding circuit breaker and disconnect switch. The bus bar earth switch is interlocked with all disconnect switches on the same bus bar section. The high speed earth (fast-acting earthing) switch is interlocked with the related circuit breaker open.

Synchronism and Voltage Selection

The synchro-check function is bay-oriented and depends on voltage, phase angle, frequency, and live line-lie bus. Determination of live line/dead line or dead bus/live bus is accomplished at the IED level for particular bays with related circuit breakers and disconnect and earth switches.

The correct voltage for synchronizing is derived from the auxiliary switches of the related circuit breaker, disconnect switch, and earth switch and related VTs. Automatic selection is completed by the bay control unit IEDs or through VT selection relays in the case of the conventional LCC.

Autoreclosing and Related Synchrocheck

Autoreclosing and synchrocheck functions are typically completed through the bay control IED or different relay or are built into a protection IED. The autoreclosure can be set for the following modes:

- Single-phase autoreclose
- Three-phase autoreclosure
- Single-/three-phase autoreclosure

The three-phase autoreclosure sequence can complete with or without the synchrocheck.

Pole Discrepancy Monitoring

All single-pole circuit breakers are provided with a pole discrepancy protection arrangement. The pole discrepancy protection for CB is of the two-stage type. The pole discrepancy monitoring function is supplied based on measurement of phase over-currents and current differences between phases.

Digital Communication

Digital communication in substations includes high voltage switchgear, associated control gear and various assemblies. The basic standard for digital communication is IEC 61 850. In this standard the communication arrangement is described and finds world-wide application. The provided will assist the GIS substation planning engineer to get a better understanding of demands related to digital communication. Special data for digital communication in GIS substations is described in IEC 62 271–3.

Digital communication today has spread and almost all GIS installations are provided with these technologies. The advantages of digital communication are encountered more often in substation projects, where nonconventional instrument transformers will be used. Normally, copper wiring is replaced by optical fibers and field bus systems. Interchangeability between manufacturer arrangements has been also provided. The guideline for the digital communication is provided by the IEC 61 850 standard series as a horizontal standard for the communication devices, high voltage switchgear and assemblies, control gear, and the associated testing requirements.

Special rules and demands mainly for on-site GIS testing are covered by IEC 62 271–3 and are described here. This standard describes relevant aspects of high voltage switchgear and control gear and relevant assemblies, with serial digital communication interfaces according to IEC 61850.

Basic Digital Communication Standard

Standard IEC 61850 describes the communication networks and system requirements as they are applied for power utility automation. The series of IEC 61850 standards has more than 10 parts. They are describing substation automation systems and it defines the digital communication between intelligent electronic devices (IEDs) in the substation and the related system requirements. Table 1 presents different parts of IEC 61850.

Table 1. IEC 61 850 series on communication networks and systems for power utility automation

Part	Title
1	Introduction and overview
2	Glossary
3	General requirements
4	System and project management
5	Communication requirements for functions and device models
6	Configuration description language for communication in electric substations related to IEDs
7-1	Basic communication structure for substation and feeder equipment – principles and models
7-2	Basic communication structure for substation and feeder equipment – abstract communication service interface (ACSI)
7-.3	Basic communication structure for substation and feeder equipment – common data classes
7-4	Basic communication structure for substation and feeder equipment – compatible logical node classes and data classes
7-	Basic communication structure for substation and feeder equipment – hydroelectric power

410	plants – communication for monitoring and control
7-420	Basic communication structure for substation and feeder equipment – basic communication structure – distributed energy resources logical nodes
8-1	Basic communication structure for substation and feeder equipment – specific communication service mapping (SCSM) – mappings to MMS (ISO/IEC 9506, Part 1 and Part 2) and to ISO/IEC 8802-3
9-2	Basic communication structure for substation and feeder equipment – specific communication service mapping (SCSM) – sampled values over ISO/IEC 8802-3
10	Basic communication structure for substation and feeder equipment – conformance testing
90-1	Use of IEC 61 850 for communication between substation and technical reports (TRs) with number like IEC 61 850-80-x and IEC 61 850-90-x

Overall introduction for digital communication is provided in Parts 1 and 2. Structure of IEC 61850 is defined as well as the principles of data structures and concepts. Part 3 describes general requirements for the hardware, the software, and the elements used in the substation requirement. The requirements for device models, the configuration language, and system and project management are provided in Parts 4, 5, and 6. Parts 8, 9, and 10 provide details on the basic information structure of different devices used in substations. Data models are described with data classification in Parts 8, 9 and 10. Specific information is provided for hydroelectric power plants and distributed energy resources.

Special communication service mapping associated with ISO/IEC 9506, Part 1 and Part 2 and to ISO/IEC 8802-3 is presented. The latest Part 90-1 presents digital communication between substations. On the station bus and process bus levels the IEC 61850 standard is used to determine equipment models and models of functions and to document them in a standard format for easy exchange with the client server's interactions. On the devices level special standards are available for high voltage switchgear (IEC62271-3), current and voltage transformers (IEC 61869). The graphic in Figure 1 presents the principle function of a GIS within the dotted line on the left side.

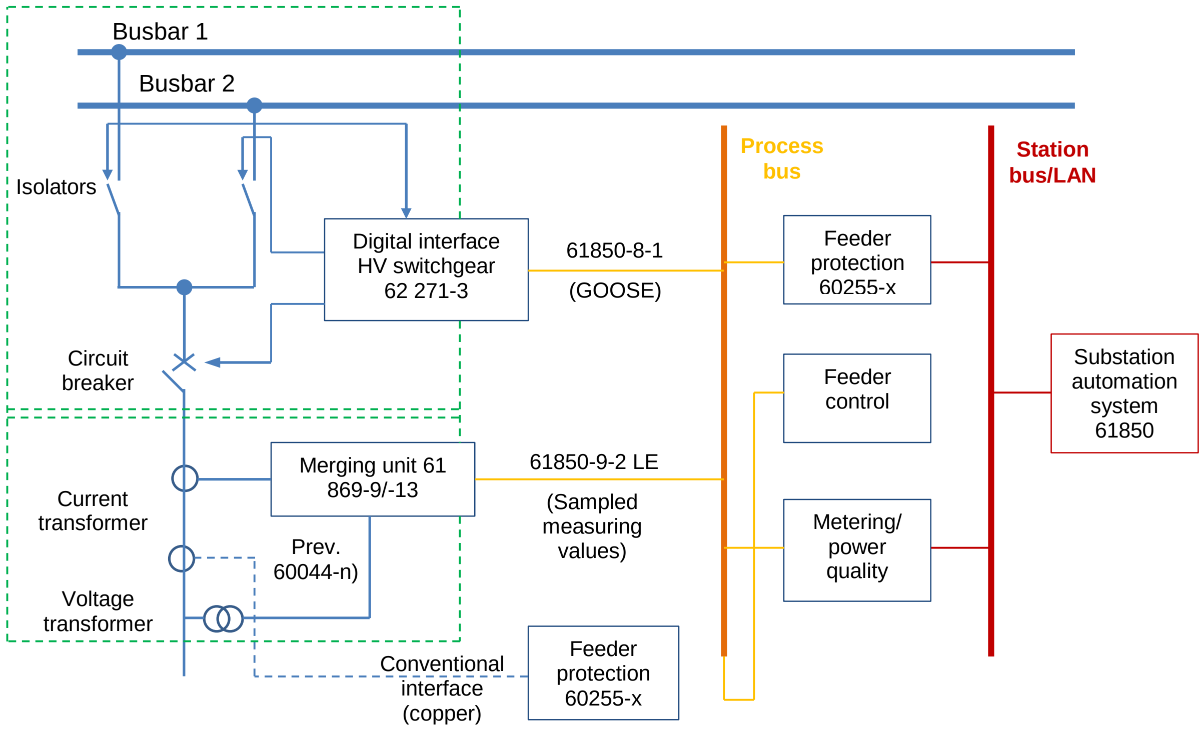


Figure 1. IEC 61850 relation to other relevant IEC standards

The connection of the switching elements to the process bus is described in IEC 62 271-3 and the connection of voltage and current transformers is described in IEC 61 869 Part 9 and Part 13. The switching devices in a substation use Part 8-1 of IEC 61 850 for the software interlocking models and the voltage and current transformer use Part 9-2 of IEC 61 850 for sampled measuring values. Established interfaces are connected by the feeder protection standard IEC 60 255 series.

Communication Requirements

The communication demands of all known functions are described in Part 5. A description of functions is used to precise demands for communication between IEDs within the substations, between substations, and between substations and higher level remote operating places and interfaces to remote technical services. The objective is to have a seamless communication system for the complete power management system and for interoperability between elements of different manufacturers. The categories of functions are presented in Table 2.

Table 2 Categories of functions

Category of function	Type
System support functions	Time synchronization, network management
System configuration or maintenance functions	Software and configuration management, node identification, test mode, system security management…
Operational or control functions	Synchronous switching (point on wave switching), access security management, control, alarm/event management and recording…
Bay local process automation functions	Bay interlocking, protection functions (overcurrent, distance), measuring/metering and power quality monitoring
Distributed process automation functions	Distributed synchrocheck, station wide interlocking, load shedding, breaker failure, automatic protection adoption, automatic switching sequences….

All functions of a substation need to be defined and it is mandatory to establish the communication requirements within the substation. Advanced functions have to be divided into pieces with inseparable core functionality. These core elements are appointed to high level data objects (logical nodes) holding all information to be exchanged (PICOM) (see Figure 2).

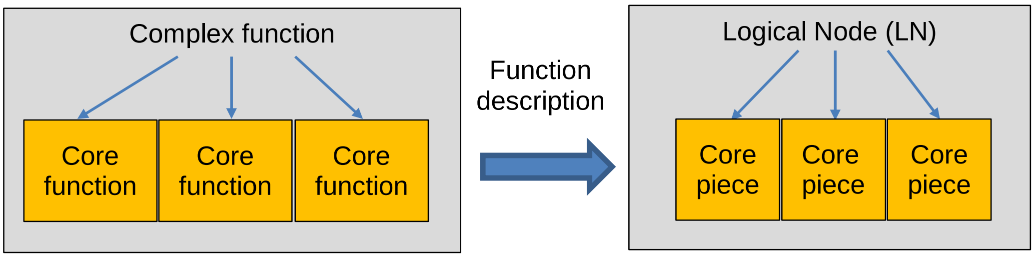


Figure 2. Advanced functions to be transferred in core pieces of logical nodes (LNs)

The function description gives the data presented in Table 3. A logical node (LN) function is an abbreviation as specified in IEC 61 850-5 with the systematic syntax in IEC 61850 focused on functional demands. A logical node (LN) class is an abbreviation or acronym as determined in part IE C 61850-7- 4 with the systematic syntax introduced in IEC 61850 focused on object oriented modelling .

Table 3. Data of function description

Function	Description
Task	Names the task
Starting criteria	Gives criteria to start
Result or impact	For instance, operating a breaker, trigger another function
Performance	For instance, overall requested response time
Interaction with other functions	If other function is requested
Function decomposition	How a function can be decomposed in logical nodes (LN)

Switchgear Associated Communication Standard

Based on the basic standard for digital substation communication IEC 61850 series, a special standard for high voltage switchgear has been published as IEC 62 271-3. In this the digital communication demands of circuit breakers, disconnecting switches, and earthing switches are described. According to IEC 62 271-1 standard this refers to all high voltages above 1 kV. Practically, this means that medium voltage equipment of 1 kV up to and including 52 kV is described in this standard.

Control Locations

The location of control and communication elements may vary with manufacturer arrangement. To ease the readability of the standard the design presented in Figure 3 has been selected as an example for the GIS.

A common arrangement of GIS with switchgear controllers and communication elements as presented in Figure 3 has a circuit breaker controller (CBC) and a disconnector or earth switch controller (DCC) for the three -phase pole arrangement.

The CBC commonly uses the logical node XCBR for the circuit breaker control and the DCC typically uses the logical node XSWI for the disconnector or earth switch control. In the GIS sensors for monitoring and diagnostic for partial discharge are installed.

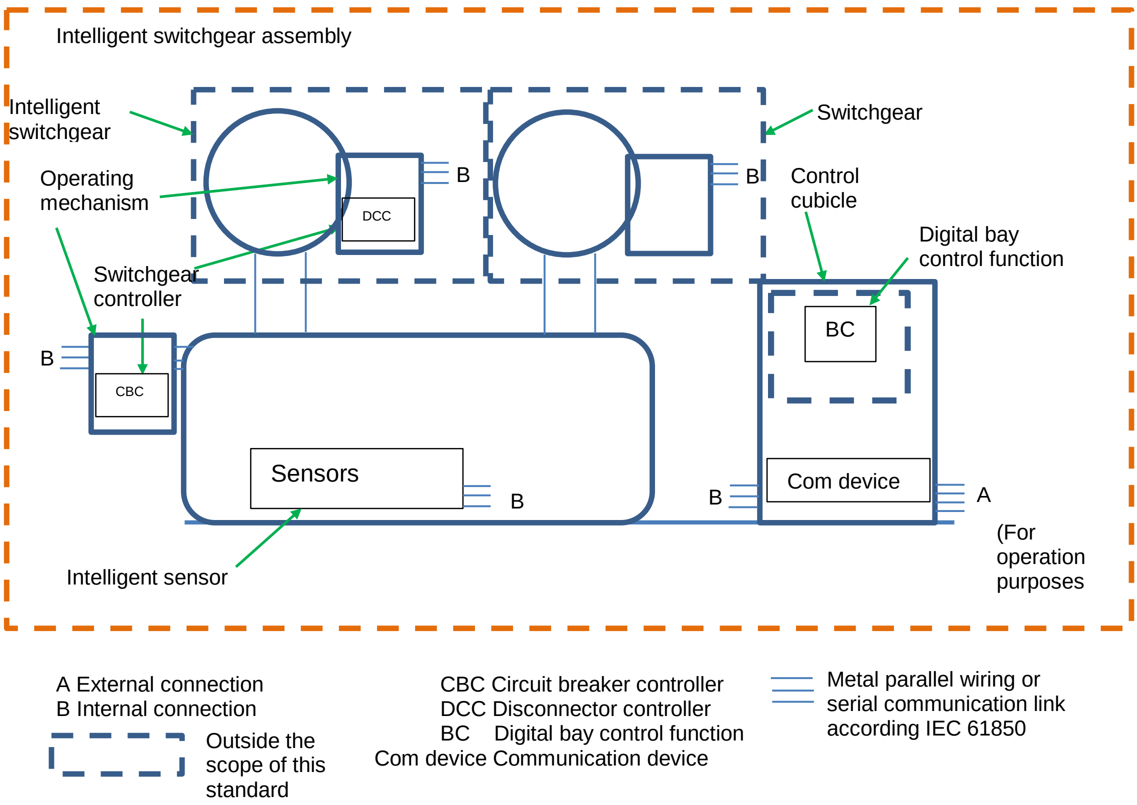


Figure 3. Location of control and communication GIS devices

For instance, bay control functions, bay interlocking, local human machine interfaces, may also be installed inside the GIS control enclosure. Their communication link to the station level is outside the scope of IEC 62 271-3. Outside communication is described in IEC 61850 standard.

The interconnection between switchgear controllers and other substation elements is accomplished via serial communication links. A common example of how the communication network inside a GIS may be achieved is presented in Figure 4.

A switchgear controller may have type A or B external or internal connections as described in IEC 62271-1 (please note A and B in Figure 4). The interface point “A” can be placed on a part of the relevant communication device “com device” or directly at the switchgear controller “CBC” or “DCC”. Any external link for testing and operation requirements has to be in line with IEC 61850-8-1. An internal connection type “B” as presented in IEC 62271-1 for a switchgear controller has to be in line with IEC 61 850-8-1. External connect ions has to be available by means of a communication element.

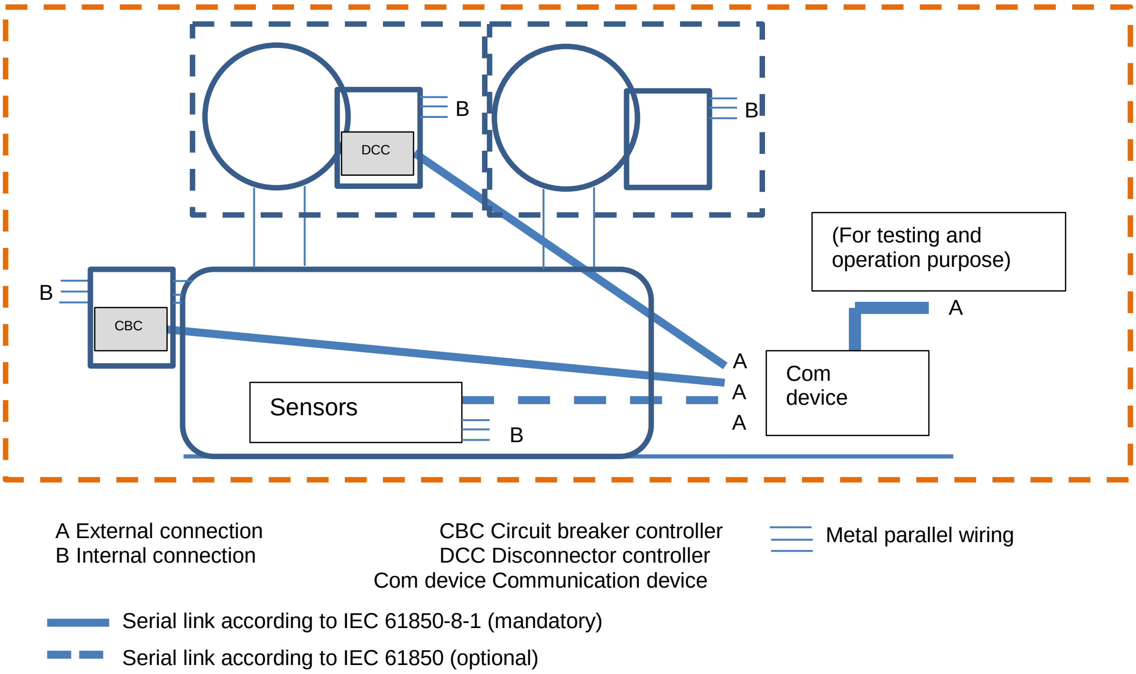


Figure 4. Common example of a communication network inside a GIS installation

Switchgear Operation

Opening/Closing Command

The operation principle of switch gear is presented in Figure 5 for a circuit breaker. The serial input generator sends the first telegram of a software interlocking message carrying the trip command to the circuit breaker controller at the operating mechanism. The digital message is then transferred to the electric trip command to trip the circuit breaker of the intelligent switchgear. Opening and closing commands are performed.

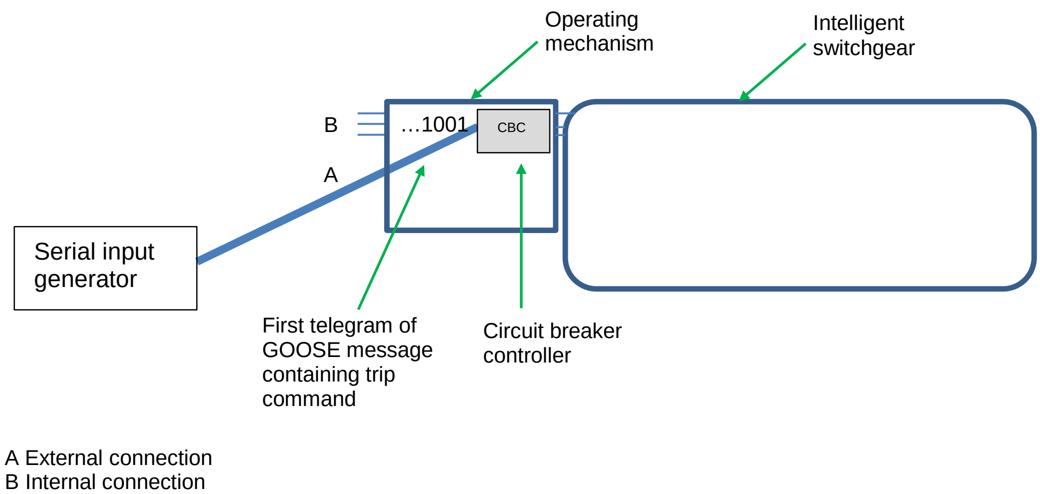
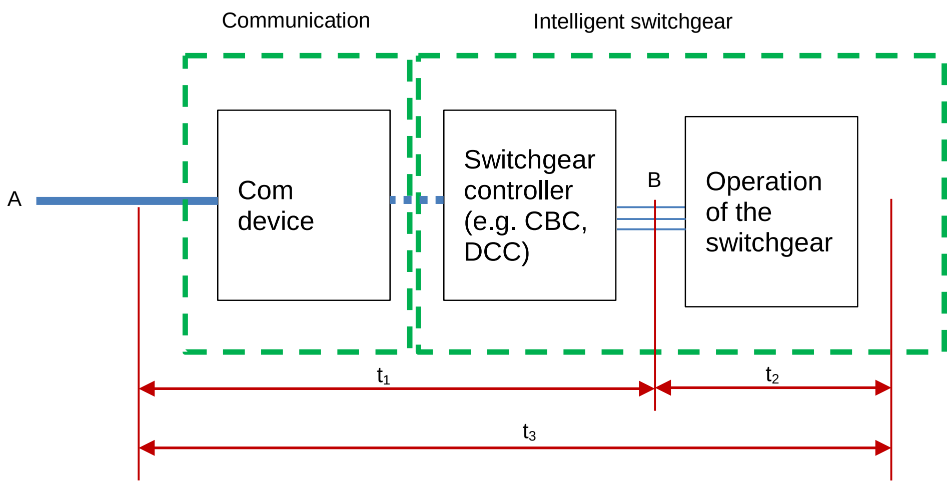


Figure 5. Opening/closing control of intelligent switchgear

Operation Time Calculation

The method of computing the operating times of intelligent switchgear is presented in Figure 6. The overall processing time covers the time when the digital message reaches the communication element (com device) until the switchgear has been operated. The intelligent switchgear complete operating time is a mechanical fixed time, subject to the design and the switchgear standards demands, with IEC 62 271-100 for circuit breakers and IEC 62 271-102 for disconnecting/grounding switches. The overall processing delay time includes the time from the arrival of the digital message at the com elements until the operation command (opened or closed) arrives at the internal connection point " B."



A External connection
B Internal connection
DCC Disconnector controller
CBC Circuit breaker controller

t_1 Total processing delay
t_2 Switchgear operating time
t_3 Intelligent switchgear total operating time
Serial link according to IEC 61850-8-1 (mandatory)
Serial link according to IEC 61850-8-1 (optional)

Figure 6. Intelligent switchgear operating times

Measuring Operation Time

The methodology presented in IEC 62271-3 to measure the operation time of high voltage switching elements of intelligent switchgear is presented in Figure 7. A switch is linked in parallel to the serial input generator and communication analyzer. The overall processing delay time is measured by the communication analyzer (incoming signal) and the time at the internal connecting point "B" (outcoming signal). To find out the operation time of the switchgear a test message 1 is used, which corresponds to the frame representing the sampled value of one measuring point (four currents and four voltages), as described in IEC 61850-9-2. A test message 2 may be used as described in IEC 61850-8-1 where the transfer request is initiated for a transfer file with a length of 2 MBytes.

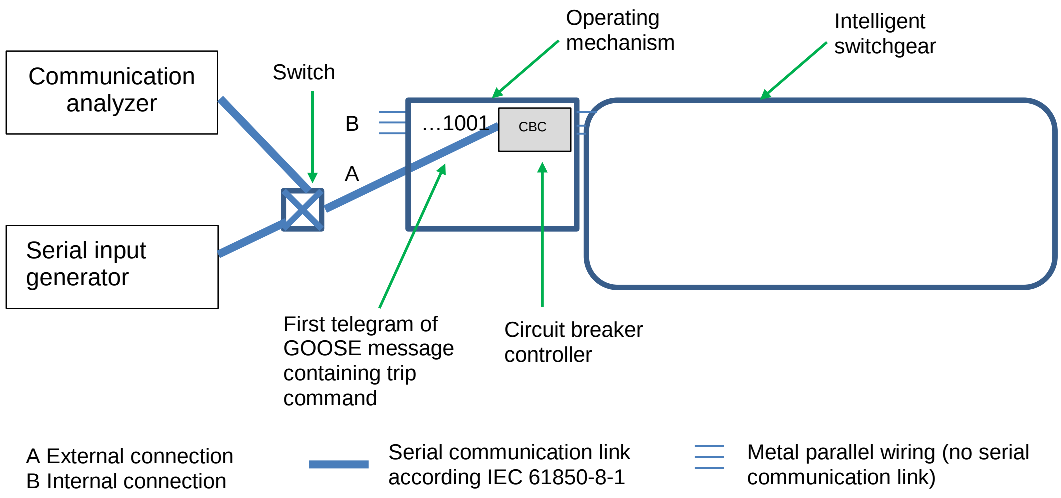


Figure 7. Operating time measurement

Type Tests

The type tests for digital communication of high voltage switchgear as described in IEC 62271-3 has the objective of explaining test processes for the GIS to demonstrate the full functionality at the required operation timing of the manufacturer's design. The tests described in this clause require an opinion of experts familiar with the switchgear testing, particularly the time measurement of circuit breakers, and of experts familiar with serial communication in substations, particularly the standards of the IEC 61850 series. The relevant switchgear product standards of the IEC 62 271 series are generally valid. Digital interfaces need to be taken into consideration where applicable.

This test is completed in order to check the proper operation of an IED by the use of system tested software under the environmental test conditions corresponding to the technical information of the equipment under test in IEC 61850-10. The objective of the tests described in this clause is to show that the opening and closing times are within the rated limits. In the configuration presented in Figure 6, commands (e.g., opening or closing commands) are directly issued from the serial input generator to the switchgear controller (circuit breaker controller). These commands are sent via GOOSE messages. The relevant return indications are caught by a communication analyzer, via the serial communication link. The input generator for the type test makes the commands and information for background traffic of the communication network. The test message has a rate of 8 kHz, which represents the load of two measuring points sampled at 4 kHz each. Then there is a repeated request of a file upload from the tested device. The background traffic should be applied at least one minute before sending the command.

The test has two parts. One part compares the opening time declared by the manufacturer against the measured time. The second test compares the closing time declared by the manufacturer against the measured time. Both tests have to be repeated 5 times. Commands (e.g., opening or closing commands) are sent from the serial input generator to the switchgear controller of the tested equipment via the communication network. Those commands are sent via digital messages. The relevant return indications are taken by a communication analyzer.

In addition to the background traffic the test generator issues commands to send a test message 1 with 8 kHz, repeatedly asks for a file upload from the tested device, and repeatedly request a file upload from another switchgear controller. The background traffic is applied for at least 1 minute before issuing the command. The command is sent from the serial input generator right after the request for a file transfer. This is to implement a worst-case scenario for the tested device. The load generation for the background data traffic is using test message 1 as described in IEC 61850-9-2 that represents sample values of 1 measuring point (4 currents and 4 voltages). The test message 2 represents the request for a transfer of a file with a length of 2 Mbytes as described in IEC 61850-8-1.

Routine Tests

The routine tests applied to digital communication of high voltage switchgear as described in IEC 62271-3 have the objective to define routine test processes for the application at the factory after assembly of the GIS for functional and dielectric routine tests to demonstrate the correct manufacture and assembly of the GIS.

Routine tests are done with the objective of discovering faults in material or construction. They do not impair the characteristics and reliability of a test object. The routine tests shall be done wherever reasonably practicable at the manufacturer's works on each apparatus manufactured, to make sure that the equipment is in line with the equipment on which the type tests have been passed.

By agreement, any routine test may be done on site as defined in IEC 62271-1. The relevant switchgear product standards of the IEC 62271 series are generally applicable. Digital interfaces should be considered where applicable. There are two tests that can be used.

Timing Demands

Opening and Closing Times for Circuit Breakers

For circuit breakers, the definitions of opening and closing times presented in IEC 62271-100 are applicable, with the following additions.

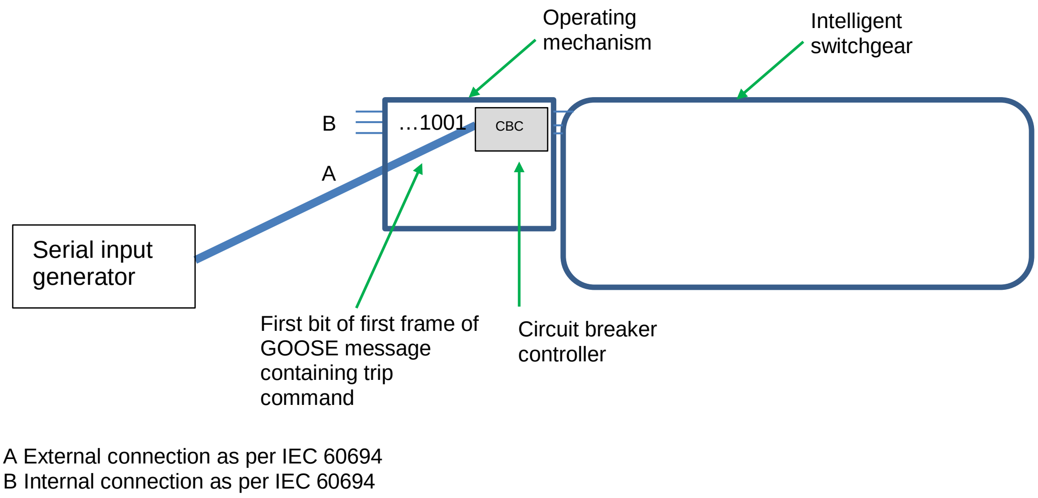


Figure 8. Timing of opening/closing command to intelligent switchgear

For intelligent switchgear, the opening time has to be the time from the reception of the first bit of the first frame of the trip command via the interface according to the IEC 61850 series, the circuit breaker being in the closed position, to the instant when the arcing contacts have separated in all poles. The reception of the first bit of the first frame of the trip command can be evaluated by using a communication analyzer.

Opening and closing times are both examples of intelligent switchgear overall operating times, presented in Figure 8.

Opening Operation

The timing definitions for the opening function of an intelligent circuit breaker are presented in Figure 9.

Closing Operation

The timing definitions for the closing function of an intelligent circuit breaker are presented in Figure 10. For intelligent switchgear, the closing time has to be the time from the reception of the first bit of the first frame of the close command via the interface according to the IEC 61850 series, the circuit breaker being in the open position, to the instant when the contacts touch in all poles. The reception of the first bit of the first frame of the close command can be evaluated by using a communication analyzer. In the situation of time measurements, coherence has to be assessed between the position indication via the serial interface in the secondary system and the real position of the intelligent switchgear.

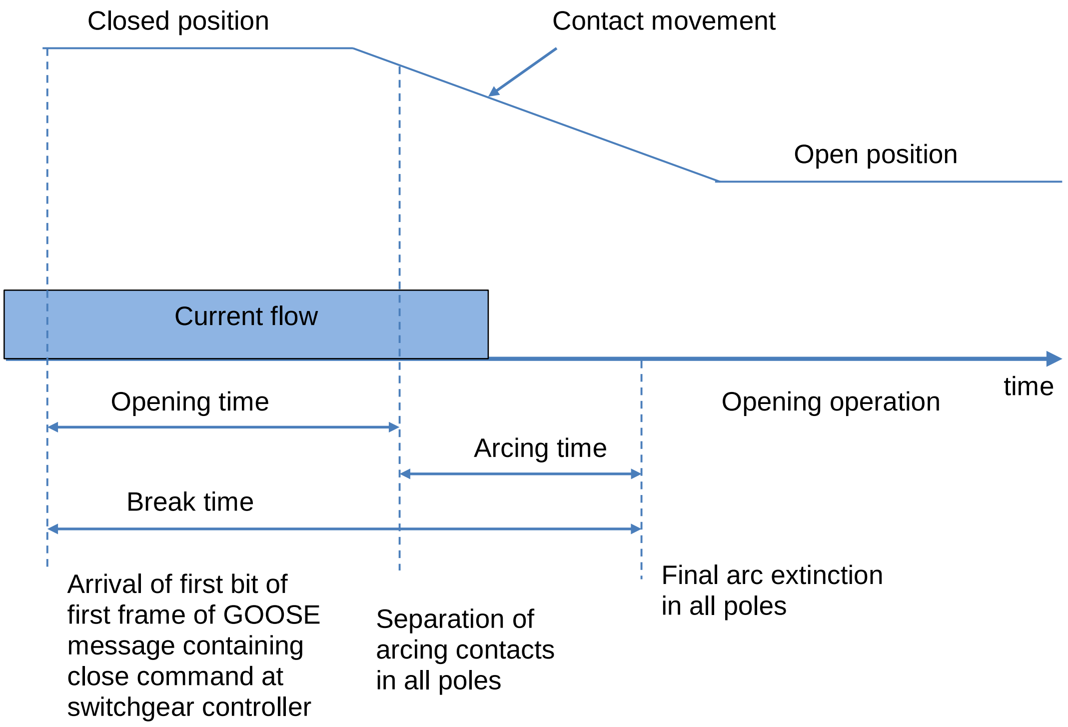


Figure 9. Opening function of an intelligent circuit breaker

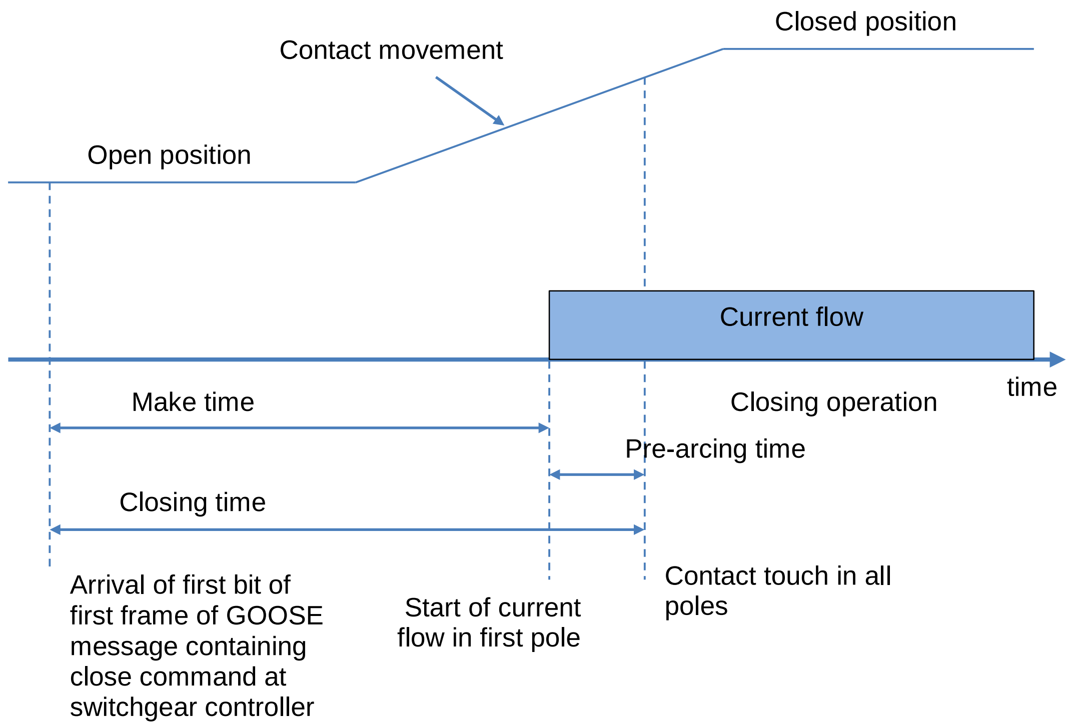


Figure 10. Closing function of an intelligent circuit breaker