



IEC 61850 Based Bus Protection Applications

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1 INTRODUCTION

The behavior of bus protection systems during different fault conditions is critical to the stability and security of the electric power system due to the tripping of the multiple lines and transformers connected to the bus. Fast fault clearing for faults on the bus is very important, while at the same time operation of the bus protection for external faults must be avoided in order to reduce the probability for a system disturbance.

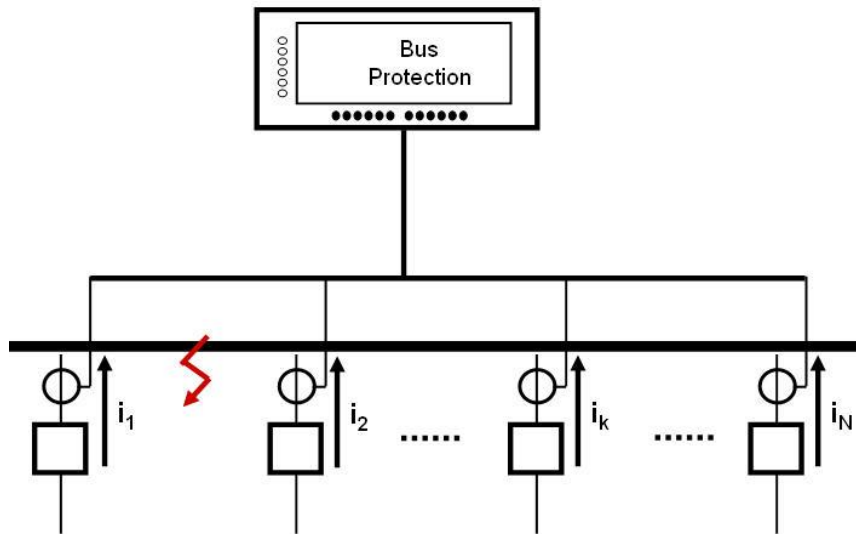


Fig. 1: Conventional bus differential protection relay

For many years transmission bus protection systems were based on a centralized principle using physical summation of all incoming currents into the bus differential relay.

The differential current is defined as:

$$I_{diff}(t) = i_1 + i_2 + \dots + i_N \quad (1)$$

High or low impedance relays with fast operating times protected busses at different voltage levels. This principle is quite simple, but requires all current transformers to be more or less identical and is susceptible to the impact of CT saturation for high current external faults.

Low impedance bus differential protection relays with multiple restrained inputs significantly reduced the impact of CT saturation and the allowed using current transformers with different CT ratios. They typically work based on single or multi-slope characteristic defined by an operating I_{op} and restrained I_{bias} current, where:

$$I_{diff}(t) = |i_{diff}(t)| = |\sum i| \quad (2)$$

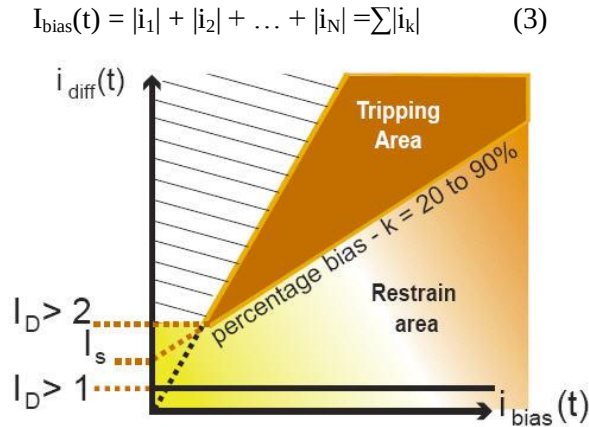


Fig. 2: Restrained differential characteristic

However, the high cost limited their application to a relatively small number of critical substations.

Advancements in communication technology have resulted in significant changes in the design and implementation of bus protection for transmission substations. The conventional centralized bus protection relays are being replaced by communications based distributed bus protection systems that are the subject of this paper. Two main types of bus protection are discussed:

- Based on remote (peripheral) units that provide the interface with the process and a central unit that performs the bus bar differential protection function
- Based on remote (peripheral) units that provide the interface with the process and determine the direction of the fault and a central unit that performs the bus bar directional comparison protection function

The remote units in both cases can be multifunctional IEDs by themselves. In the case of IEC 61850 based systems a new type of device – the merging unit – is introduced.

IEC 61850 has significant impact on the way distributed bus protection systems can be designed and implemented. The paper analyzes such systems and discusses the methods and tools for their testing. Comparisons between the conventional and IEC 61850 based cases are presented.

2 DISTRIBUTED BUS DIFFERENTIAL PROTECTION

While bus differential protection in the past was centralized, based on a summation of currents from all current transformers defining the zone of protection, the introduction of advanced high-speed substation communications has resulted in the development and implementation of a new generation of bus differential relays with distributed architecture.

The numerical technology and its implementations to bus protection offer some significant advantages. The classical bus differential schemes have more or less a fixed zone of protection because they have a single current input that is the sum of all current circuits wired into the relay. Modern distributed schemes can easily change the zone of protection based on the knowledge of the substation topology and the state of breakers and isolators.

While the classical schemes need all current transformers to have the same CT ratio, the modern schemes can accommodate different CT ratios throughout the protected zone. This mismatch must be accounted for by the scheme.

Communications based distributed bus differential protection started with proprietary solutions that are using two types of devices (Figure 3):

- Peripheral units
- Central unit

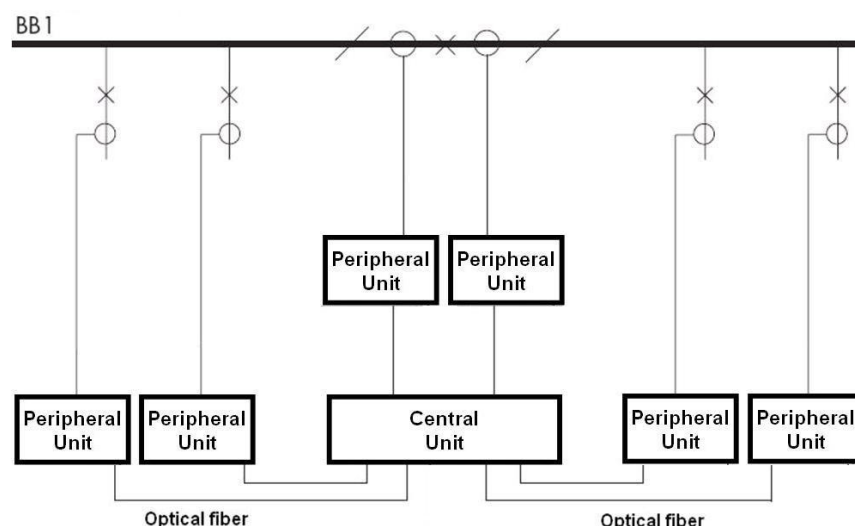


Fig. 3: Distributed bus differential protection

Bus protection relays perform more functions than basic bus differential protection. These functions are also distributed between the peripheral units and the central unit. The types of such functions can vary from one manufacturer to another. The following is an example of such additional functions and their distribution:

Central unit:

- Substation topology determination
- Summation of currents
- Busbar differential protection
- Breaker failure protection tripping decisions
- Peripheral units:
- Current signals processing
- Breaker status monitoring
- Isolators status monitoring
- Breaker control
- Breaker failure detection
- Saturation detection
- Overcurrent protection, totally independent of the central unit

The central unit is connected to the peripheral units using fiber cables that ensure broadband communications, while at the same time are not affected by any electromagnetic transients that may occur in the substation. One of the most important requirements for such distributed applications is the synchronization of the data acquisition by the peripheral units. To ensure that the sampling is synchronized at all peripheral units the central unit sends simultaneously frames over the optical fibers. They receive the data at the same instant and this reception signal starts the acquisition of the current signals.

The main signal processing algorithms may include:

- Flux calculation and prediction algorithm to detect CT saturation
- Zero sequence supervision
- Detection of signal variation
- Local threshold to block bus protection on external fault

All this information is transmitted to the central unit together with the sample of current (magnitude and angle), so that the central unit can sum all currents, thus calculating the differential current and making a decision of a fault is within the zone of protection,

They also can handle much better saturation of a current transformer that may result in an undesired relay operation for external faults. The algorithms for CT saturation detection are executed in the peripheral units. Different algorithms are being implemented individually or in combination. For

example, it calculates the derived current and compares it to the magnitude of the waveform based on a maximum variation between two successive samples defined as a function of the sampling rate of the unit.

The knowledge of the general topology of the substation is essential to the definition of the zones of protection and the execution of tripping in case of breaker failure protection. This is an important responsibility of the central unit that runs topology algorithms which determine dynamically the electric scheme of the substation. They are based on information from the auxiliary contact of circuit breakers and isolators monitored by the individual peripheral units.

An important benefit of such distributed schemes is that the peripheral units can be installed at the breaker cabinets in the substation yard thus significantly reducing the burden on the CTs and reducing the probability for CT saturation.

3 IEC 61850 PROCESS BUS BASED BUS DIFFERENTIAL PROTECTION

While the above described bus differential protection system is based on proprietary communications of current phasor measurements between the peripheral units and the central unit performing the differential protection function, IEC 61850 allows the implementation of distributed bus differential protection systems using sampled analog values over the substation process bus. The architecture of such a system is shown in Figure 4.

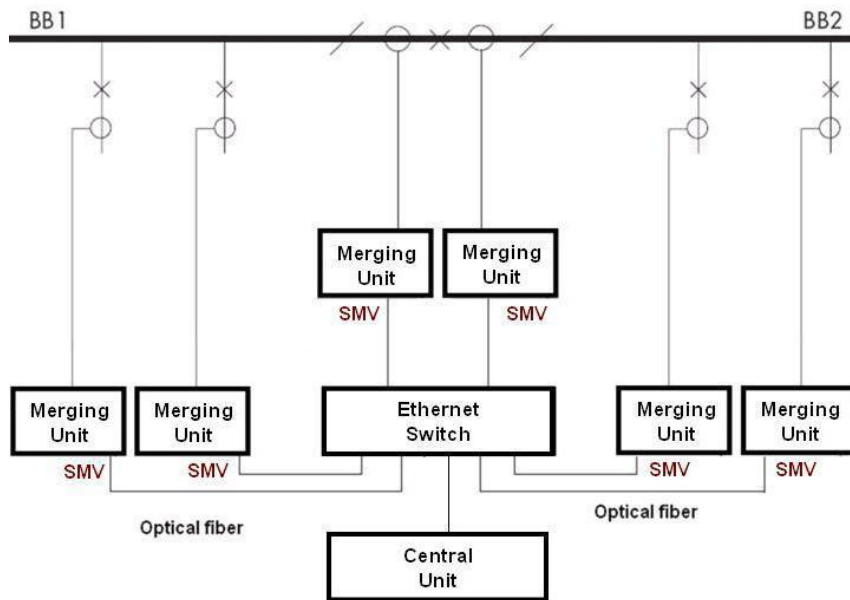


Fig. 4: IEC 61850 process bus based bus differential protection

The peripheral unit in the previous differential protection system is replaced by the Merging Unit in the IEC 61850 solution. The merging unit has the task to convert an analog signal from a non-conventional or conventional sensor to sampled values that can be transmitted over the fiber cables to the central unit that performs the differential current calculation and makes a decision if there is a fault within the zone of protection.

Interoperability between merging units and protection, control, monitoring or recording devices is ensured through documents providing implementation guidelines. Two modes of sending sampled values between a merging unit and a device that uses the data are defined. For protection applications the merging units send 80 samples/cycle in 80 messages/cycle, i.e. each Ethernet frame has the MAC Client Data contain a single set of V and I samples. For waveform recording applications such sampling rate may not be sufficient. That is why 256 samples/cycle can be sent in groups of 8 sets of samples per Ethernet frame sent 32 times/cycle [2].

The sampled analog values model applies to the exchange of values of a DATA-SET. The difference in this case is that the data of the data set are of the common data class SAV (sampled analogue value as defined in part IEC 61850-7-3). A buffer structure is defined for the transmission of

the sampled values that are the output from the instrument transformer logical nodes TCTR and TVTR (Figure 5).

The information exchange for sampled values is based on a publisher/subscriber mechanism. The publisher writes the values in a local buffer at the sending side (see Figure 5), while the subscriber reads the values from a local buffer at the receiving side. A time stamp is added to the values, so that the subscriber can check the timeliness of the values and use them to align the samples for further processing. The communication system shall be responsible to update the local buffers of the subscribers. A sampled value control (SVC) in the publisher is used to control the communication procedure.

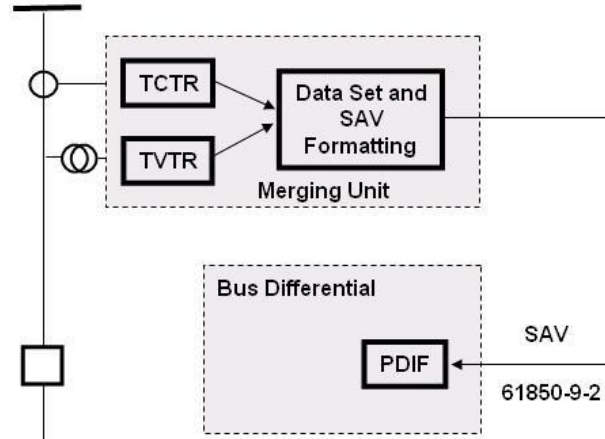


Fig. 5: Bus differential based on Sampled Analog Values

The currents and voltages from TCTR and TVTR accordingly are delivered as sampled values over the substation LAN using one of the communication modes described earlier in the paper. In this case the network becomes the data bus that provides the interface between the instrument transformer logical nodes and the different logical nodes that are used to model the functional elements of the IED.

The status of the breakers in the substation is modeled using the XCBR logical node. It will provide information on the three phases or single-phase status of the switching device, as well as the normally open or closed auxiliary contacts to be used to determine the topology of the substation and zones of bus protection. Figure 5 shows a simplified block diagram of the logical nodes used to model the different components of the bus differential protection function. As can be seen from the figure the TCTR, TVTR logical nodes are implemented in the merging unit. Interface units may be used instead of merging units due to the fact that such devices have binary inputs in addition to the analog inputs typically available in merging units.

PDIF is the logical node representing the bus differential element in the central unit. The differential current is calculated based on the samples with the same time stamp received from the individual merging units used in the system.

The transmission of sampled values requires special attention with regard to the time constraints. The model provides transmission of sampled values in an organized and time controlled way so that the combined jitter of sampling and transmission is minimized to a degree that an unambiguous allocation of the samples, times, and sequence is provided.

In the case of the distributed bus differential protection described in the previous section of the paper the data acquisition in the peripheral units is synchronized by the central unit. That is not the case with process bus. In this case the time synchronization of the individual merging units has to be better than 1 microsecond. Since SNTP does not allow such accuracy, the merging units at this stage of implementation of IEC 61850 are synchronized using any suitable method selected by the manufacturer.

Another benefit of the use of IEC 61850 is that it provides a standard format for the description of the substation topology. It is based on the substation configuration description (SCD) file.

The distributed bus differential protection system architecture includes four types of devices:

- Central unit performing the differential, and all other related functions
- Merging Units, providing the analog signal processing functions

- Ethernet switch
- Synchronization device

The synchronization device (or synchronizer) is used to ensure that the waveform recording system meets the requirements for time-synchronization according to the implementation guidelines in. It sends a 1 pulse per second (1PPS) signal through a RS485 network to all interface devices included in the system. Time-synchronization accuracy better than 1 microsecond is achieved by this solution.

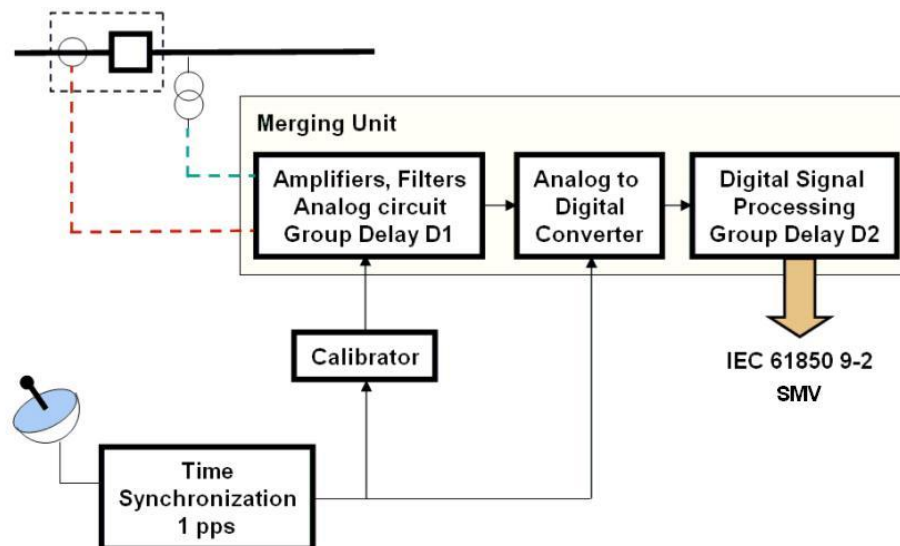


Fig. 6: Merging unit in IEC 61850 based system

The requirements for standardization of the time synchronization and elimination of a dedicated to this function network in the substation resulted in the creation of a new working group in the IEEE Power Systems Relaying Committee with the task to develop a profile of the IEEE 1588 standard for accurate time synchronization over Ethernet.

Each merging unit is connected to an Ethernet switch that in this case is dedicated to the Process Bus.

The central unit receives from the switch all Ethernet messages from the merging units included in the system. Considering the size of the Ethernet frames and the number of lines and transformers connected to the bus, the number of Ethernet ports may need to be increased.

Another alternative solution for a large number of merging units in a big substation is to use a central unit with 1Gb/sec Ethernet port connected to a 1 Gb/sec Ethernet switch with 100 Mb/sec ports connected to the merging units.

A benefit of the IEC 61850 solution is that it is more reliable than a proprietary system because the central unit can subscribe to a second merging unit in case of failure of the one normally used to provide the current samples from an instrument transformer in the field.

4 IEC 61850 BASED DIRECTIONAL COMPARISON BUS PROTECTION SCHEME

Transmission buses are typically protected by bus differential protection relays. As described earlier in the paper they require current signals from each primary equipment connected to the bus to be available at the central location of the bus differential protection in a centralized or distributed protection system. The typically used low impedance bus differential schemes are more complicated and expensive if the current transformer ratios are different. Things get even worse if the bus differential protection is used in substations where the bus configuration may change.

Because of the high cost and the increased requirements for maintenance, in many cases bus differential protection is not installed on distribution or sub-transmission buses. As a result, bus faults are cleared by backup relays with longer fault clearing times. This becomes a significant power quality problem because of the increased duration of deep voltage sags.

Using IEC 61850 process bus significantly reduces the cost of such schemes, since it removes the need for dedicated peripheral units and replaces them with the merging units described in the previous section. However, if process bus is not available in the substation, a low impedance bus differential protection will still need to be used if high speed bus fault clearing is required.

An alternative method for protecting the busbar in IEC 61850 based substations using station bus is a directional comparison bus protection scheme. Applying the concept of Distributed Applications defined in IEC 61850, combined with the use of advanced high speed directional detection algorithms based on superimposed components of the currents and voltages calculated by multiple protective relays connected to the substation LAN provides an excellent solution as a distributed bus protection. This application is based on the high-speed peer-to-peer GOOSE communications.

In case of a fault on any of the protected elements, one or more IEDs will see a fault in the forward direction. Each of the relays protecting transmission lines or transformers, or installed on tie breakers connected to the protected bus will send a GOOSE message indicating the detection of a fault, combined with the fault direction determined by the relay. In this case one or more relays will detect a forward fault and the rest will see a reverse fault, indicating to the central unit performing the directional comparison scheme that this is an external to the bus fault.

If the fault is on the bus, all IEDs will see a reverse fault or no fault (if connected to a weak source), i.e. no IED will see a forward fault.

The central unit has to be programmed to subscribe to GOOSE messages from all protection devices with high speed directional detection elements connected to the protected bus. In case of a fault, the distributed bus protection function in the bay controller IED monitors the GOOSE messages coming from the individual relays included in the distributed bus protection function of the system.

If all messages indicate reverse or no-fault condition and none gives a forward fault direction, the bus protection function identifies a bus fault and sends a communication message to trip all breakers connected to the bus. A small time delay is required in order to ensure that all relays have had sufficient time to detect the fault and determine the direction of the fault.

5 SUPERIMPOSED COMPONENTS BASED DIRECTIONAL DETECTION

The high speed detection of the direction of the fault is a very important factor to be considered during the evaluation of the distributed bus protection system.

Typically the directional element in a multifunctional protective relay is based on the phase relationship between phase or sequence currents and selected polarizing quantities, such as zero sequence currents or zero and negative sequence voltages.

However, changing system configuration may affect the polarizing quantities used for directional determination and result in relay misoperation. For example, if the directional element is negative sequence voltage polarized and the source behind the relay has low negative sequence impedance, the measured negative sequence voltage at the relay location can be very low.

Superimposed currents and voltages that are directly related to the fault may also be used with great success to determine the direction of the fault.

A further development of the method based on the sign of the ratio of Δi and Δv is to use the product of Δi and Δv , i.e. the transient power or even further integrate this transient power over certain period of time directly after the fault inception to derive the transient energy.

The direction of the transient energy is based on the three phase products of the superimposed phase currents and voltages. The direction of the fault is determined by the sign of the transient energy caused by the inception of the fault, given by

$$S = \int U \cdot I \, dt \quad (4)$$

The three phase energy transition is given by

$$S = \int (\Delta U_a \cdot \Delta I_a + \Delta U_b \cdot \Delta I_b + \Delta U_c \cdot \Delta I_c) \, dt \quad (5)$$

which is calculated in the relay as

$$S = \sum (\Delta U_{ai} \cdot \Delta I_{ai} + \Delta U_{bi} \cdot \Delta I_{bi} + \Delta U_{ci} \cdot \Delta I_{ci}) \quad (6)$$

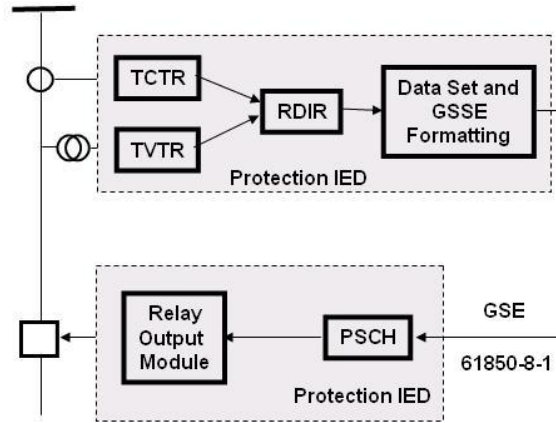


Fig. 7: GSE use for directional comparison bus protection scheme

This method allows accurate directional detection under varying system conditions and is not affected by series compensated transmission lines or mutual coupling. Therefore, it reduces the probability of relay misoperation and provides a very fast (between $\frac{1}{4}$ to $\frac{1}{2}$ of a cycle) and reliable directional decision that can be used by a distributed bus protection system.

The directional detection function is represented in IEC 61850 by the RDIR logical node.

The transient energy directional detection method has been successfully implemented in numerical transmission line protection relays.

6 DIRECTIONAL COMPARISON BUS PROTECTION SYSTEM

All relays protecting primary equipment connected to the bus act in this application as the directional detection devices (sending IEDs), while the central unit is the receiving IED.

The directional comparison bus protection system architecture includes three types of devices:

- Central unit performing the directional comparison and all other related functions
- Directional detection devices
- Ethernet switch

A small time delay (0.25 cycle) is used in the distributed bus protection relay (timer started by the first received message indicating reverse fault condition) in order to provide a safety margin for the pick-up of the different IED's directional fault detectors in all primary equipment relays.

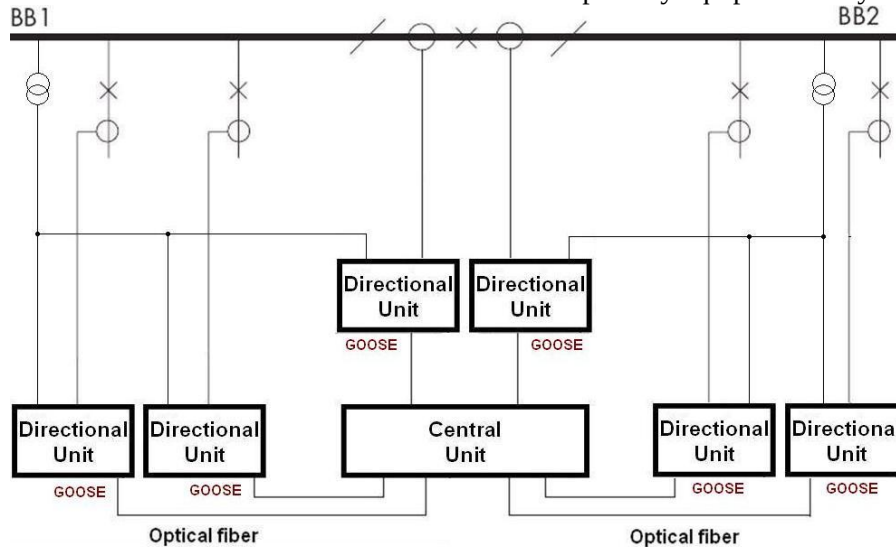


Fig. 8: Directional comparison bus protection scheme

The peer-to-peer communications based bus protection requires an operating time for the directional detection of less than 0.5 cycles for the relays involved. The addition of 0.25 cycle (4-5 ms) for the communication message and the time delay of 0.25 cycle in the bus protection relay ensures a total operating time of about 1 cycle.

The benefit of the peer-to-peer communications based distributed bus protection is that it provides fast fault clearance for sub-transmission and transmission bus faults without the need for any additional protection equipment (if the function is implemented in a bay controller IED). It replaces a high or low impedance transmission bus protection device and in some cases may eliminate the need for addition or replacement of current transformers.

The distributed bus protection is easily adapted to changes in the substation bus configuration, since it will receive GOOSE messages containing information on any switching in the substation. Based on this information the bay controller IED will dynamically change its subscription list in order to receive messages only from the IEDs connected to the protected bus.

Another important benefit of this scheme compared to the process bus based bus differential protection is that it does not require the accurate time synchronization, i.e. no need for a separate synchronization network.

7 IEC 61850 PROCESS BUS BENEFITS

Process bus based applications offer some important advantages over conventional hard wired analog circuits that are especially important in the case of bus protection. The first very important one is the significant reduction in the cost of the system due to the fact that multiple copper cables are replaced with a small number of fiber optic cables.

Using a process bus also results in the significant reduction in the possibility for CT saturation because of the elimination of the current leads resistance. Traditionally the CT knee-point voltage is a function of the resistance of the different components of the current circuit:

$$V_K = f(R_{CT}, R_L, R_{RP}) \quad (7)$$

where:

V_K = Required CT knee-point voltage (volts)

R_{CT} = Resistance of the current transformer secondary winding (ohms)

R_L = Resistance of a single lead from relay to current transformer (ohms)

R_{RP} = Impedance of a relay phase current input

In some cases R_L is multiplied by 2 and plays a key role in determining the CT requirements.

In this case the CT secondary is connected to the phase current inputs of the Merging Units and R_L is practically equal to zero. The knee-voltage then will be only dependent on

$$V_K = f(R_{CT}, R_{RP}) \quad (8)$$

The impedance of the merging unit current inputs R_{RP} is very small, thus resulting in the significant reduction in the possibility for CT saturation and all associated with it protection issues.

Process bus based solutions also improve the safety of the substation by eliminating one of the main safety related problems - an open current circuit condition. Since the only current circuit is between the secondary of a current transformer and the input of the merging unit is located right next to it, the probability for an open current circuit condition is very small. It becomes non-existent if optical current sensors are used.

Last, but not least, the process bus improves the flexibility of the bus differential protection. Since current circuits can not be easily switched due to open circuit concerns, the application of bus differential protection becomes more complicated. The above is not an issue with process bus, because any changes will only require modifications in the subscription of the protection IEDs receiving the sampled analog values over IEC 61850 9-2.

8 CONCLUSIONS

The paper analyzes the modern trends in development of distributed bus protection systems and focuses on the impact of IEC 61850 on bus protection design.

Bus differential protection based on IEC 61850 9-2 process bus and directional comparison bus protection using high-speed peer-to-peer communications are described.

Modern distributed bus protection systems based on the IEC 61850 communications standard offer some significant advantages compared to conventional bus differential protection devices:

- Reduced wiring, installation, maintenance and commissioning costs
- Easy adaptation to changing bus configuration in the substation and practical elimination of CT saturation and open circuit.