THE ROLE OF SYNCHROPHASORS IN THE INTEGRATION OF DISTRIBUTED ENERGY RESOURCES

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ABSTRACT

The introduction of M and P class Synchrophasors in the IEEE C37.118.1 standard allows the development and implementation of synchrophasors based protection, automation and control solutions that significantly improve the efficiency of the integration of distributed energy resources in the electric power system.

INTRODUCTION

Distributed Energy Resources are becoming a major part of the drive towards a cleaner environment within the context of the Smart Grid. They are of different sizes and types and are being connected at all different levels of the electric power system – transmission, distribution and low voltage. This introduces significant challenges for protection systems at the transmission and distribution level of the system which need to be considered in the engineering and testing of the protection devices and systems.

Since in many cases the distributed energy resources are not only used to partially cover the energy needs of the user, but also to export power to the electric power system, they need to be integrated into the different protection and distribution automation systems.

The developments of multifunctional intelligent electronic devices for protection and other applications that perform synchrophasor calculations and the improvements in inter and intra-substation communications bring the industry to a time when many specialists are thinking about the use of synchrophasors for protection applications. They can definitely help with the integration of DERs.

The paper describes first the introduction of two synchrophasor performance classes defined in IEEE PC37.118.1. The P class is intended for applications such as protection that requiring fast response, while the M class is intended for applications which could be adversely affected by aliased signals but do not require the fastest reporting speed.

Synchrophasors based applications related to the integration of DERs are later discussed. Examples considered in the paper include differential protection and synchrocheck. The requirements for synchrophasors' reporting rate, time synchronization and communications architecture are discussed.

Feeder protection using synchrophasors for the calculation of the differential current is later described. Requirements for the communications interface between the substations and the DER sites are analyzed. The impact of loss of time synchronization in one of the sites is also discussed.

The testing of synchrophasors based systems is described at the end of the paper.

PROTECTION REQUIREMENTS FOR SYSTEMS WITH DISTRIBUTED GENERATION

Distributed generators are being typically connected to sub-transmission or distribution systems. The definition of such systems varies between utilities and in some cases systems with voltages as high as 138 kV may be considered as distribution. The addition of distributed generators has a significant effect on the system. The levels of short circuit currents, the dynamic behavior of the system following such faults, the coordination of protective relays are affected and have to be considered in the selection of the protection system. Line protection settings and criteria should take into account in-feed effect, possible power swings and generator out-of-step conditions.

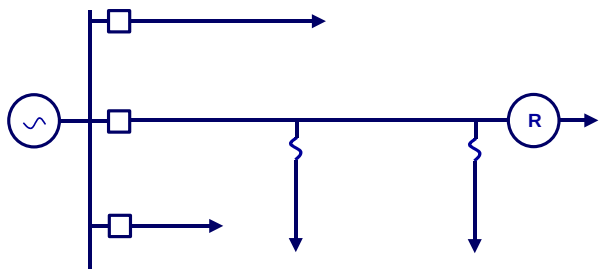

Fig. 1 Typical distribution feeder

The increased fault clearing times that are caused by the in-feed effect of a distributed generator may not be acceptable to customers with sensitive loads. The voltage sag is experienced not only by users on the faulted feeder, but also on the adjacent feeders, connected to the same distribution system.

Figure 2 shows the areas of impact of voltage sags or swells on sensitive equipment and demonstrates that the impact depends on two characteristics. The first characteristic of a voltage sag – the depth – is a function of the type of fault, fault location and the system configuration. It will also be affected by the state of the distributed generator – if it is in service or not. Single phase-to-ground faults lead to voltage sag in the faulted

phase and to voltage swell in the healthy phases. The level of voltage increase is also affected by the grounding of the interface transformer and should also be taken into consideration.

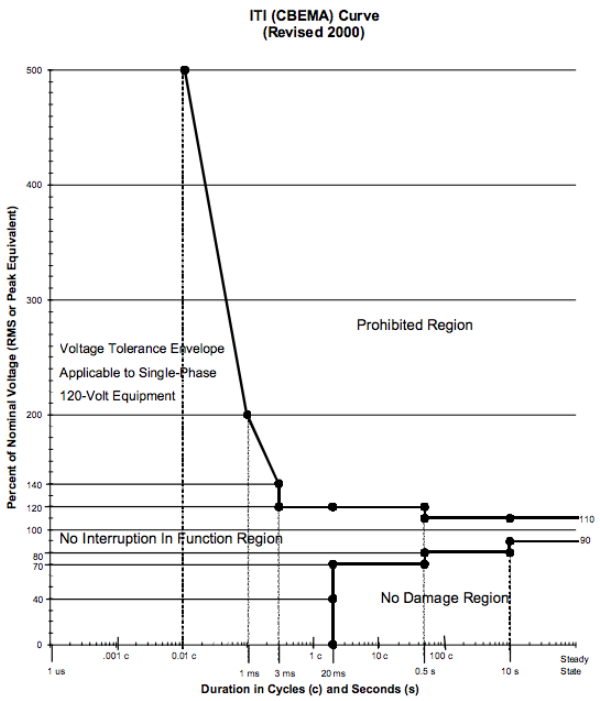

Fig. 2 ITI (CBEMA) curve

The same two characteristics of the fault also have an impact on the ride-through capability of the DER. Figure 3 shows an example of a ride-through characteristic.

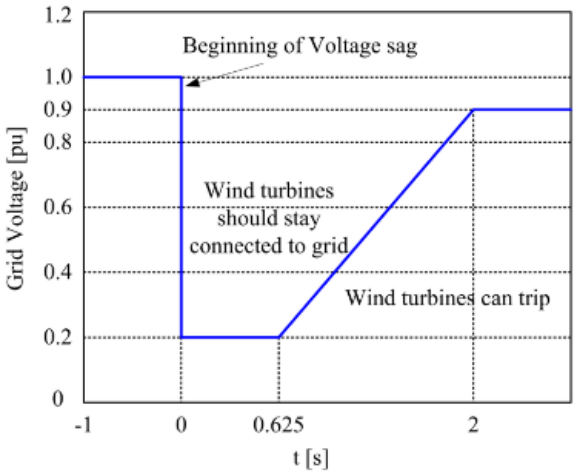

Fig. 3 Ride-through characteristic

This is something that we can't control, but we have to study in order to be able to predict or estimate the effects of different faults on the sensitive equipment. The second characteristic of the voltage sag – duration – is the parameter that we can control by properly applying the advanced features of multifunctional protection relays.

The distributed generator interconnection protection is subject to many papers, as well as standardization work, such as IEEE P-1547. It is clear that the location of the fault and the infeed from the generator will lead to increase of the fault clearing time and coordination problems. This depends more specifically on the type of distributed generator and its interconnection with the electric power system.

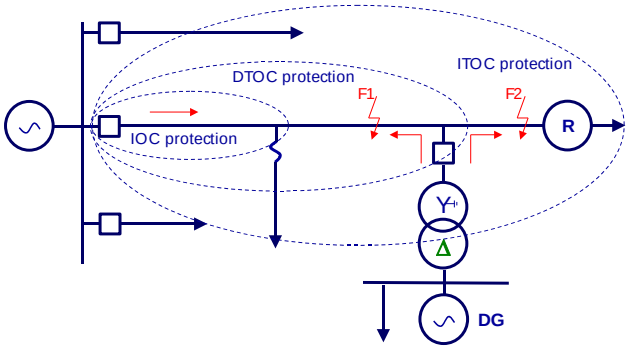

Fig. 4 Distribution system with distributed generator and zones of overcurrent protection

Figure 4 shows the distribution system from Figure 1 with the addition of a distributed generator, connected to the system with a step-up transformer. The typical phase, ground and negative sequence overcurrent protection of a distribution feeder is part of the functionality of most microprocessor based relays. The zones of protection of the different overcurrent elements is shown in the figure as:

- IOC – instantaneous overcurrent protection
- DTOC – definite time-delayed overcurrent protection
- ITOC – inverse time-delayed overcurrent protection

The interconnection transformer is with a grounded wye high-side connection. As a result, there will be infeed for ground faults beyond the interconnection point (F2 in Fig. 4) even when the generator is out of service.

Using some of the advanced features in multifunctional protection relays improves the protection and reduces this time. However, it may still be unacceptable to sensitive loads.

The islanding of part of a distribution system with a non-utility generator is unacceptable in most of the cases. This condition may not be always detected by the protection of the interconnection. That is why, it is a typical requirement to send a Direct Transfer Trip signal from the substation to the generator interconnection breaker in order to ensure that it is disconnected from the system.

The Transfer Trip function requires the availability of communications equipment and channel between the two sites. The communications links can be quite expensive if based on direct fiber over longer distances. For shorter

distances it will be the ideal solution, since it provides high-speed and is not affected by ground potential rise or electromagnetic interference. However the use of synchrophasors can help in the detection of the islanding condition and may change communications requirements. Other less expensive communications options such as spread-spectrum radio, pilot wire or whatever other communications media is available should be considered when analyzing the interconnection of the distributed generator to the utility system.

Since a communications link will be available between the substation and the interconnection point it is worth to take a look into the application of communications based protection and see if it can improve the protection of the circuit with the distributed generator and reduce the total fault clearing time. Multifunctional line differential protection relays can be used for circuits with distributed generation. Their application with different communication channels is discussed in the following sections of the paper.

Depending on the location of the distributed generator and other protection equipment on the distribution circuit, in some cases the differential element may be time delayed with a definite time or inverse time characteristic.

When a trip is issued by the differential element, in addition to tripping the local breaker, the relay will send a differential intertrip signal to the remote relay. This will ensure tripping of both ends of the protected line, even for marginal fault conditions. The relay receiving the intertrip signal will indicate that it has operated due to a differential element.

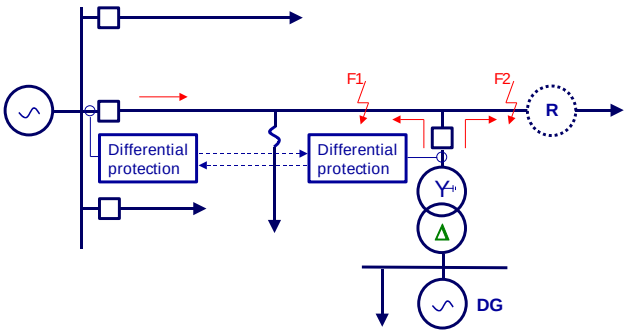

Fig. 5 Differential protection in distributed generation circuit

Since the operation of the differential element is based on the exchange of messages between the relays on both ends of the protected circuit, the operating time will be affected by the communications speed. Later in the paper we discuss how it changes as a function of the available communications link.

Analyzing Fig. 7 we can see that both a fault before the interconnection point (F1) and beyond the interconnection point (F2) will be seen as internal faults to the differential protection. As a result the effect of the infeed that is a problem for the overcurrent protection at the substation is not an issue for the differential protection.

PHASOR MEASUREMENT CONCEPT

PMUs are installed at all important locations of the network to be observed. These PMUs are accurately time synchronized, typically through the Global Positioning System (GPS). Based on this time reference, the magnitudes and phases of voltages and currents at the PMU locations are measured, at exactly the same times in all locations.

The measured quantities are transferred over fast communication links to a monitoring center. In the monitoring center, the data from the connected PMUs are collected, aligned, archived and provided to the SCADA applications.

A new quality of data is obtained by measuring precisely time synchronized signals at different locations in the power network and through the time stamping of the data:

- Measured values of voltages and currents are available as complex phasors
- Synchronously measured values can be directly compared and easily processed

Classical protective relays perform the protection of single elements of a power system, as generators, transformers, lines or busbars. For the protection of such objects, locally measured values are sufficient in most cases. The response times of such devices are typically in the range of one cycle.

SCADA systems however, have system wide view on the power system, but due to limited data rates this view is relatively static. The data from the PMUs enable the SCADA applications to obtain a dynamic view of the network.

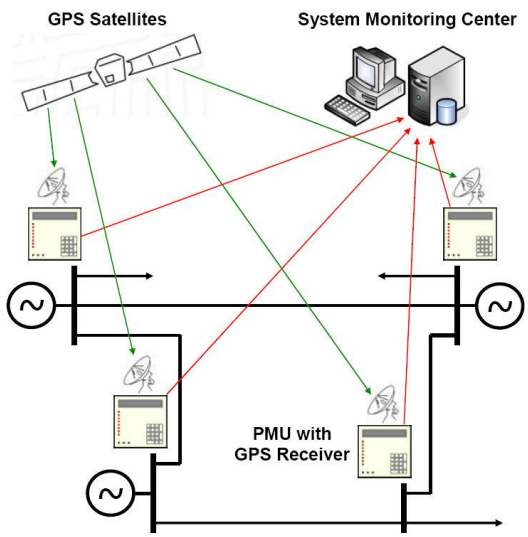

Fig. 6 Differential protection in distributed generation circuit

The dynamic observation of the state of the electric power system can be achieved using synchrophasor measurements in what is known as WAMPCS. This

abbreviation stands for the following main applications:

- Network monitoring and fault analysis (**W**ide **A**rea **M**onitoring)
- Network/System protection (**W**ide **A**rea **P**rotection)
- Network operation and control (**W**ide **A**rea **C**ontrol)

Synchrophasor measurements thus can be also used to monitor the state of individual DERs, as well as the interconnection point of a wind or solar farm with the electric power system.

IEEE C37.118 STANDARD

The IEEE C37.118 standard is currently the only standard world-wide for measuring synchrophasors in electrical energy systems. Throughout the following text, it will be commonly referred as "the standard".

Basically, it defines the following:

- Time reference: UTC
- Rate of measurement
- Phase reference: co-sine
- Accuracy metrics: TVE (Total Vector Error)
- Communication model (format of telegrams)

The standard does not specify:

- Speed of measurement
- Accuracy under transient conditions
- Hardware / Software of the devices
- Measurement algorithms

The specifications allow a simple processing of the synchrophasors from different measuring systems, in real-time as well as off-line.

In 2011, as a result of decisions to harmonize IEEE and IEC standards development, the original standard was split in two standards: C37.118.1-2011 - IEEE Standard for Synchrophasor Measurements for Power Systems and C37.118.2-2011 - IEEE Standard for Synchrophasor Data Transfer for Power Systems.

Definition of the Synchrophasor

According to IEEE C37.118.1 the sinusoidal waveform defined by (1)

$$x(t) = X_m \cos(\omega t + \phi)$$

is commonly represented as the Phasor (2)

$$\begin{aligned} \boldsymbol{X} &= (X_m/\sqrt{2})\, e^{j\phi} \\ &= (X_m/\sqrt{2})(\cos\phi + j\sin\phi) \\ &= X_r + jX_i \end{aligned}$$

The value of φ depends on the time scale, particularly where $t = 0$. It is important to note this phasor is defined for the angular frequency ω; evaluations with other phasors must be done with the same time scale and frequency.

The *synchrophasor* representation of the signal $x(t)$ in (1) is the value $\boldsymbol{X}$ in (2) where φ is the instantaneous phase angle relative to a cosine function at the nominal system frequency synchronized to UTC. Under this definition, φ is the offset from a cosine function at the nominal system frequency synchronized to UTC. A cosine has a maximum at $t = 0$, so the synchrophasor angle is 0 degrees when the maximum of $x(t)$ occurs at the UTC second rollover (1 PPS time signal), and -90 degrees when the positive zero crossing occurs at the UTC second rollover (sin waveform). Figure 2 illustrates the phase angle/UTC time relationship.

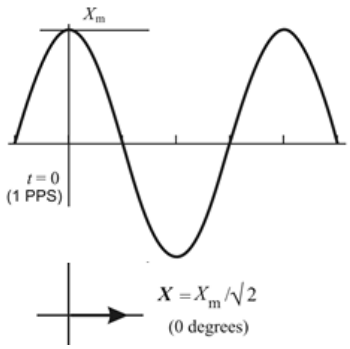

Fig. 7 Synchrophasor measurement principle

C37.118.1-2011 defines synchrophasors, frequency, and rate of change of frequency (ROCOF) measurement under all operating conditions. It specifies methods for evaluating these measurements and requirements for compliance with the standard under both steady-state and dynamic conditions. Time tag and synchronization requirements are included. Performance requirements are confirmed with a reference model, provided in detail. This document defines a phasor measurement unit (PMU), which can be a stand-alone physical unit or a functional unit within another physical unit.

This standard for the first time introduces two performance classes. As the letter indicates, the P class is intended for protection types of applications requiring fast response and does not require explicit filtering. M class is intended for applications which could be adversely affected by aliased signals but do not require the fastest reporting speed, thus the M class requires anti-alias filtering. All standard compliance requirements are specified by performance class. The standard requires that if a supplier provides both P and M class performance in a device, these shall be user selectable.

IEEE C37.118.1 does not specify hardware, software, or a method for computing phasors, frequency, or ROCOF.

Line Differential Protection

Line differential protection is typically achieved based on the calculation of the differential current using the individual current measurements from all ends of the protected line.

The following steps are common:

- Calculation of current phasors
- Communications of current phasors

- Calculation of differential current
- Differential characteristic based operation

The primary protection element of a multifunctional transmission line protection relay should be a segregated phase current differential protection. This technique involves the comparison of the currents of each phase at each line terminal. A communications path is therefore an essential requirement of any such scheme.

The differential current is calculated as the vector summation of the currents entering the protected zone. The restrain current is the average of the measured current at each line end. It is found by the scalar sum of the current at each terminal, divided by two.

Each of these calculations is done on a phase by phase basis differential protection function with transient shift

The level of restrain used for each element is the highest of the three calculated for optimum stability.

When a trip is issued by the differential element, in addition to tripping the local breaker, the relay will send a differential inter-trip signal to the remote terminals. This will ensure tripping of all ends of the protected line, even for marginal fault conditions.

An unrestrained differential high set element can provide high-speed operation in the event of CT saturation. Where transformer inrush restraint is used, the resultant second harmonic current produced from CT saturation may cause slow relay operation.

To calculate differential current between line ends it is necessary that the current samples from each end are taken at the same moment in time. This can be achieved by time synchronizing the sampling. In the case of use of synchrophasors, by their definition they are calculated based on an accurate time synchronization of the PMUs and using a fixed calculation and transmission rate.

Since many line differential relays have been using direct fiber for their communications interface for many years, we can assume that the same approach will be applied when using synchrophasors, i.e. the delay between the relays at all ends of the protected line will be the same with minimal latency.

To calculate the differential and restrain currents, the phasor samples at each line end must correspond to the same point in time. It this case each relay calculating the differential current will need to use the synchronized measured currents with the same time stamp. The need for accurate time synchronization (1 µsec) requires the use of GPS technology.

Using 4 calculations of P class synchrophasor currents per cycle should provide sufficient performance for the line differential protection to ensure the stability of the electric power system.

The communications method in case of direct fiber between the substations at the ends of the line included in the zone of protection is defined as “tunneling” according to IEC 61850 Part 90-1 Use of IEC 61850 for the communication between substations. The message format and the communications are based on IEC 61850-9-2 SV packets.

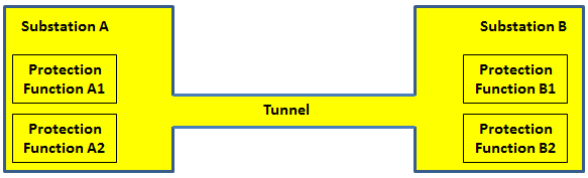

Fig. 8 Communications tunnel between substations

The implementation of such distributed synchrophasor based protection applications using a centralized system (for example located in the substation where the distribution feeders with the DERs are connected) requires the use of a Phasor Data Concentrator which will receive the streams of synchrophasors and feed them into the centralized distribution protection and control system (DSPACS). It can also use the received synchrophasor measurements to perform the synchrocheck functions for the interconnection points to the electric power system.

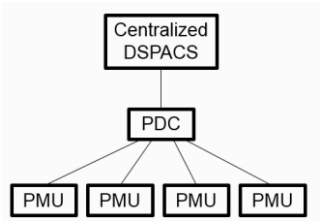

Fig. 9 Communications architecture

TESTING REQUIREMENTS

Testing of synchrophasor based protection schemes for systems with DERs requires good understanding of the functionality and the components of the system.

Different methods are used for testing of the PMUs, PDCs and the protection and control functions of the system.

Bottom-up testing is used at the initial phases of development and implementation of the system and especially for the acceptance of IEDs to be used at the system monitoring and process control levels of the system. Black box and top-down testing can be used during the factory and site acceptance testing stages.

End-to-end testing is required for the final acceptance test of the protection system before it can be put in service.

CONCLUSIONS

The integration of DERs in distribution systems requires a new approach to their protection in order to improve power quality and meet the ride-through requirements.

The availability of P class synchrophasors makes it possible to develop and implement advanced protection, automation and control functions using high-speed peer-to-peer communications.