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Development and Implementation of a Differential Protection Function in the SASensor System of the company Locamation B.V.

Titulación:	Máster Energías Renovables
Alumno/a:	Giménez Sánchez, Miguel Ángel
Director/a/s:	Fuentes Moreno, Juan Álvaro
	Molina García, Ángel

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Introduction

Ensuring the efficient and sustainable use of natural resources is one of the important challenges that Europe is facing today. The improvement of the actual energy infrastructure is a must to achieve this goal. Without serious upgrading of existing grids and metering, renewable energy generation will be put on hold, security of the networks will be compromised, opportunities for energy saving and energy efficiency will be missed, and the internal energy market will develop at a much slower pace [1]. These new upgraded electricity networks are commonly defined as Smart Grids.

Smart Grids

Smart Grids could be described as an upgraded electricity network to which two-way digital communication between supplier and consumer, intelligent metering and monitoring system have been added. [1]

The benefits of Smart Grids are widely acknowledged. Smart Grids can manage direct interaction and communication among consumers, households or companies, other grid users and energy suppliers. It opens up unprecedented possibilities for consumers to directly control and manage their individual consumption patterns, providing, in turn, strong incentives for efficient energy use if combined with time-dependent electricity prices. Smart Grids will be the backbone of the future decarbonized power system. They will enable the integration of vast amounts of both on-shore and off-shore renewables energy and electric vehicles while maintaining availability for conventional power generation and power system adequacy. Smart Grids provide a platform for traditional energy companies or new market entrants to develop new, innovative energy services. [1]

In Europe, over €5.5 billion has been invested in about 300 Smart Grid projects during the last decade (Figure 1. Some of these projects can be seen in [2]). Around €300 million has come from the EU budget. For comparison, the US government has launched a 100 Smart Grid Investment Grant Programme with funding totaling $3.7 billion (2011). The Chinese government is also investing in Smart Grids projects and has so far earmarked $7.3 billion for stimulus loans and grants in 2011. [1]

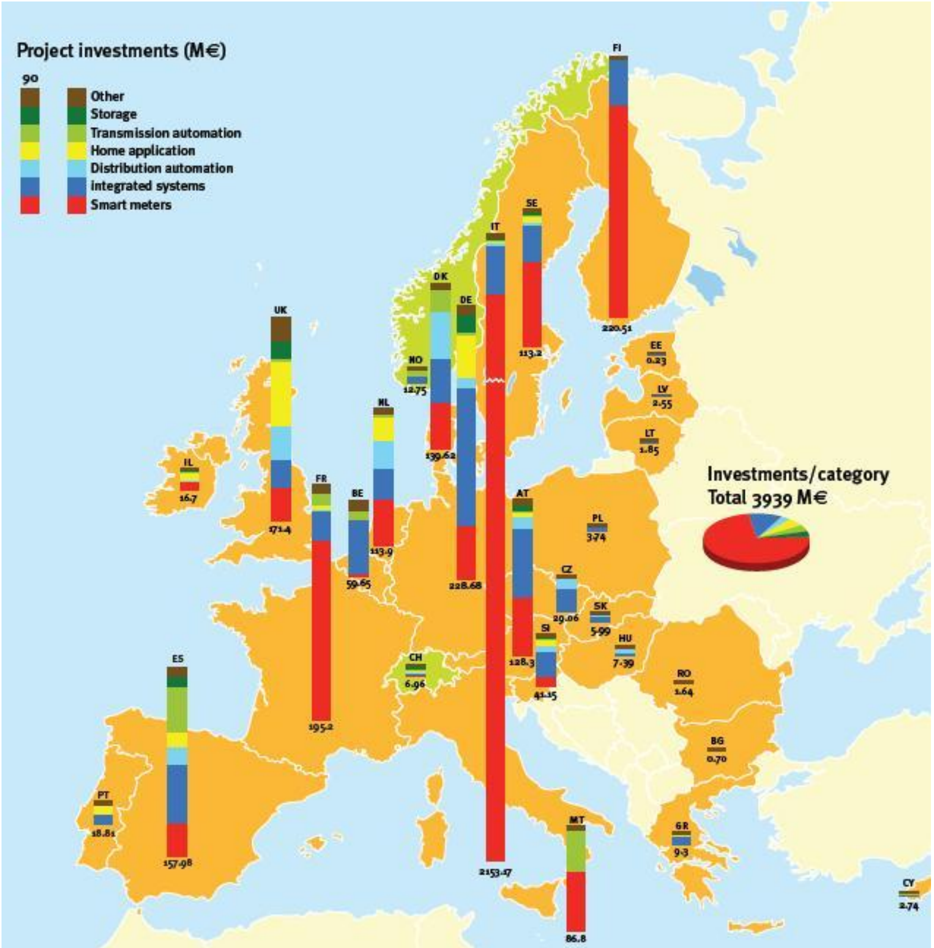


Figure 1. Overview of Smart Grid investment and implementation across the EU (source: Joint Research Center, European Commission)

In this framework of Smart Grids, the Dutch company Locamation B.V. develops innovative solutions to meet the technical challenges presented in this new concept of electric network.

SASensor System

One of the products developed by Locamation is the SASensor system. SASensor is a substation automation system capable of perform the necessary tasks in a medium voltage electric substation.

SASensor offers the following functionality:

- Accurate data acquisition
- Local and Remote Control
- Revenue metering
- Overcurrent protection
- Power Quality monitoring
- Fault localization

- Voltage regulation control
- Alarm and Event handling

System Concept

The SASensor system is based on a modular and scalable architecture. There is a strict separation between the raw data handling (hardware) and functionality (software). This means that the hardware can be combined with different software elements to obtain maximum flexibility in functionality and upgrading. All SASensor devices communicate with each other via 100Base-FX Ethernet fiber optic cables.

The system concept can contain of the following hardware groups:

- One or more Central Control Units (CCU) that serve as typical high-performance central substation controllers.
- The Versatile Communication Unit (VCU) that serves as the versatile gateway to both the Remote Control Center and the office.
- Interface Modules (CIM, VIM, BIM) to measure currents and voltages and for position and alarm indications of a circuit breaker. The modules are connected to the CCU with fiber optics cables.
- The local operating computer (LPC) that serves as the local based graphical workstation with web Browser technology.
- The GPS antenna that forwards the GPS satellite signals to the VCU.

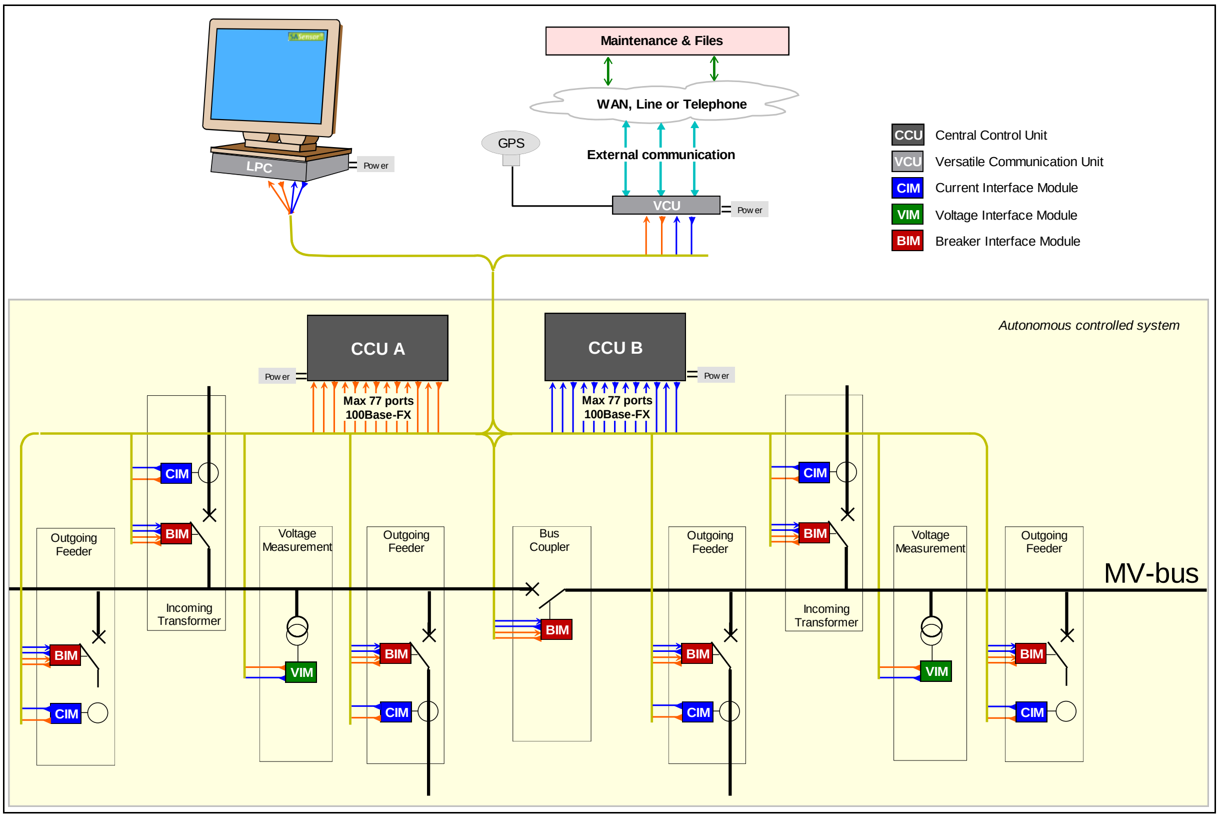


Figure 2. SASensor in a substation

Description of the Hardware Modules

Current Interface Module (CIM)

The CIM is a Current Interface Module to be used within the SASensor system. The function of the module is to digitize the three phase currents supplied by the secondary windings of a conventional current transformer (CT).

Figure 3. Current Interface Module (CIM)

The CIM consists of:

- Three contact-less measurement inputs.
- Three contact-less protection inputs.
- Two ports of 100Base-FX Fast Ethernet with ST connectors for optical fiber with one strand to transmit.
- Power supply capable for wide input AC and DC voltage range.
- Status LED.

The CIM is equipped with two set of AD-converters. One for measurements (M cores) with high accuracy, and the other set (P core) is for protection.

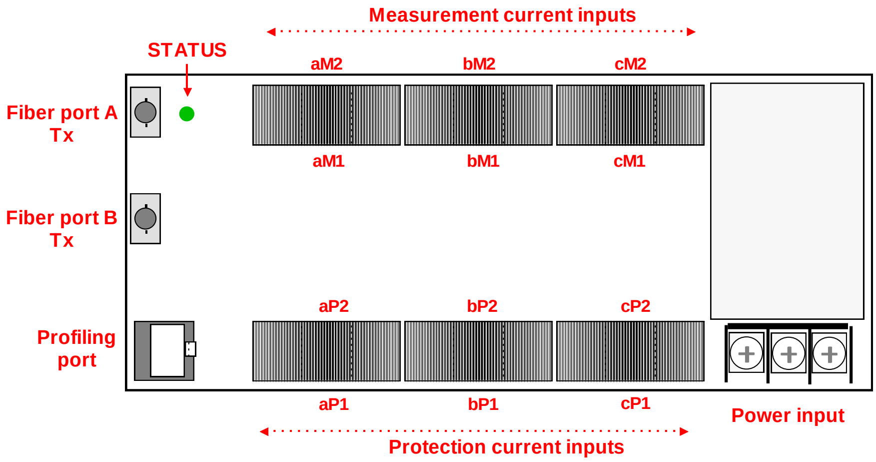


Figure 4. The CIM connectors and ports

The CIM uses Digital Signal Processing (DSP) techniques to digitize the analog input channels. The sampling rate of the samples acquired is of 28 kHz. These samples are packed and sent in portions of 8.

Voltage Interface Module (VIM)

The VIM is a Voltage Interface Module to be used within the SASensor system. The VIM measures and digitizes the three phase voltages supplied by the secondary windings of a conventional voltage transformer (VT).

Figure 5. Voltage Interface Unit (VIM)

The VIM consists of:

- Three voltage input terminal strips.
- Two ports of 100Base-FX Fast Ethernet with ST connectors for optical fiber with a strand for transmit.
- Profiling port to be used by the manufacturer to calibrate the module.
- Power supply capable for wide input AC and DC voltage range.
- Status LED.

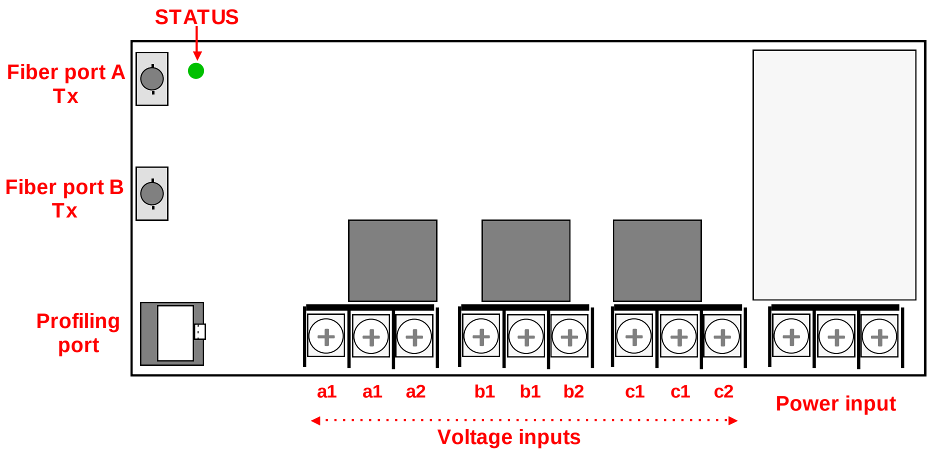


Figure 6. The VIM connectors and ports

Different connections with the voltage transformer are possible: star, delta and three single-phase.

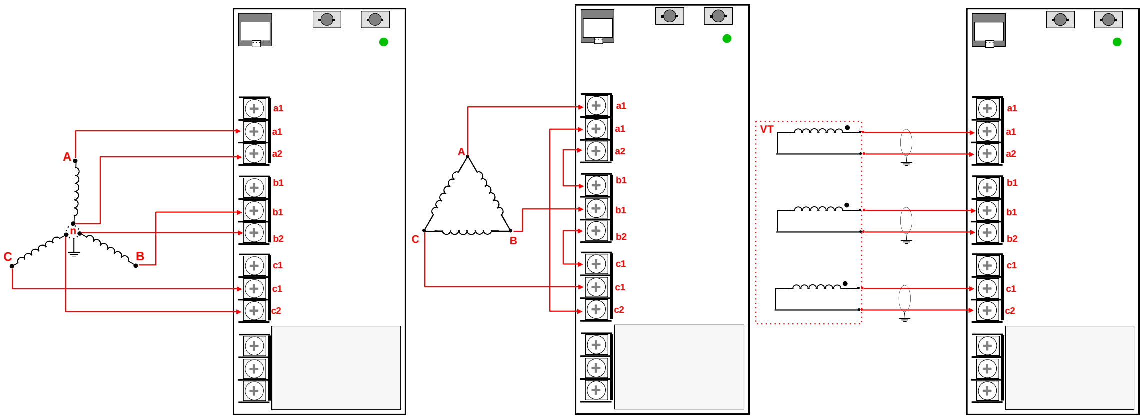


Figure 7. Star, delta and three single-phase configuration of a VIM

The VIM uses Digital Signal Processing (DSP) techniques to digitize the analogue input channels signals. The sample frequency is 28 kHz.

Breaker Interface Module (BIM)

The BIM is a Breaker Interface Module to be used within the SASensor system. The module functions as a compact input/output interface to monitor and operate circuit breakers, disconnect switches, earth switches or alternatively as universal digital I/O module.

Figure 8. Breaker Interface Module

The BIM consist of:

- 10 digital inputs
- 8 relay outputs
- Power supply capable for wide input DC voltage range.
- Two duplex ports of 100Base FX Fast Ethernet with ST connectors for multi-mode fiber optic with separate strands for receive and transmit.

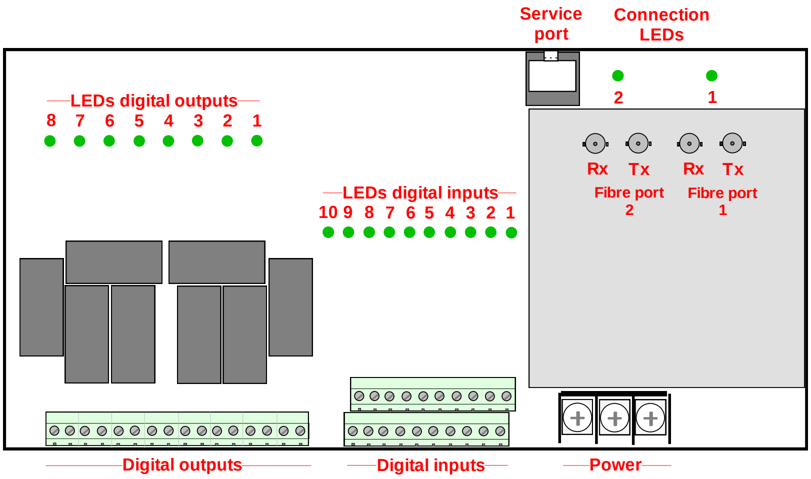


Figure 9. BIM connectors and ports

Central Control Unit (CCU)

The CCU is the heart of SASensor system. It is a "one-box" device with the following functionality:

- Ethernet switching
- Signal processing
- Protection and Control Algorithm
- Web server interface
- Data archiving

In this unit the data from the Interfaces Modules is collected and the applications, like overcurrent protection, are run. When necessary control commands are sent to the BIM, for instance if the overcurrent protection threshold is exceeded a trip command is sent.

The computer of the CCU runs the real-time operating system ARTOS.

Versatile Communication Unit (VCU)

The Versatile Communication Unit is the getaway of the SASensor system, through this unit the system can be remotely operated and maintained. The unit can include RS-232 ports for connection to e.g. Remote Control Centers (RCCs), UTP ports for connection to e.g. the Wide Area Network (WAN) and ST fiber optic ports to enable 100Base-FX Ethernet communication with the CCU or other devices. Optionally, the VCU can contain a GPS receiver.

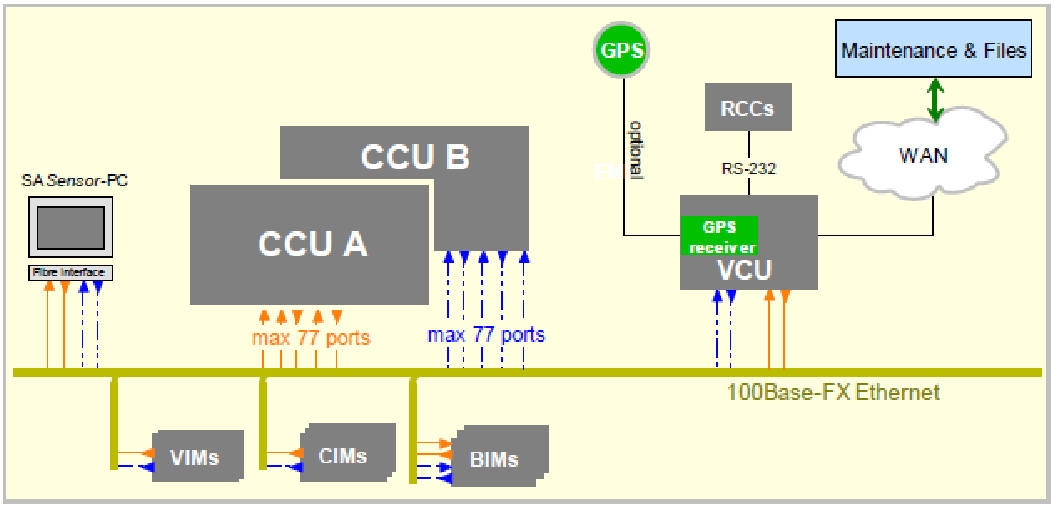


Figure 10. The VCU within the SASensor

Examples of SASensor Applications

Measurements

The application provides accurate power measurements. The busbars and all bays contain VIMs and CIMs to measure the relevant voltage and currents in the station. From this data, the software in the CCU calculates the following measurements values:

- U_{rms} and I_{rms}
- Power frequency (Hz).
- Sequence current and Neutral current.
- Thermal currents I_{therm} and I_{therm}MAX as indication for the load on each bay.
- Active power (W), Reactive power (VAr) and Apparent power (VA).
- Power factor.
- Phase.

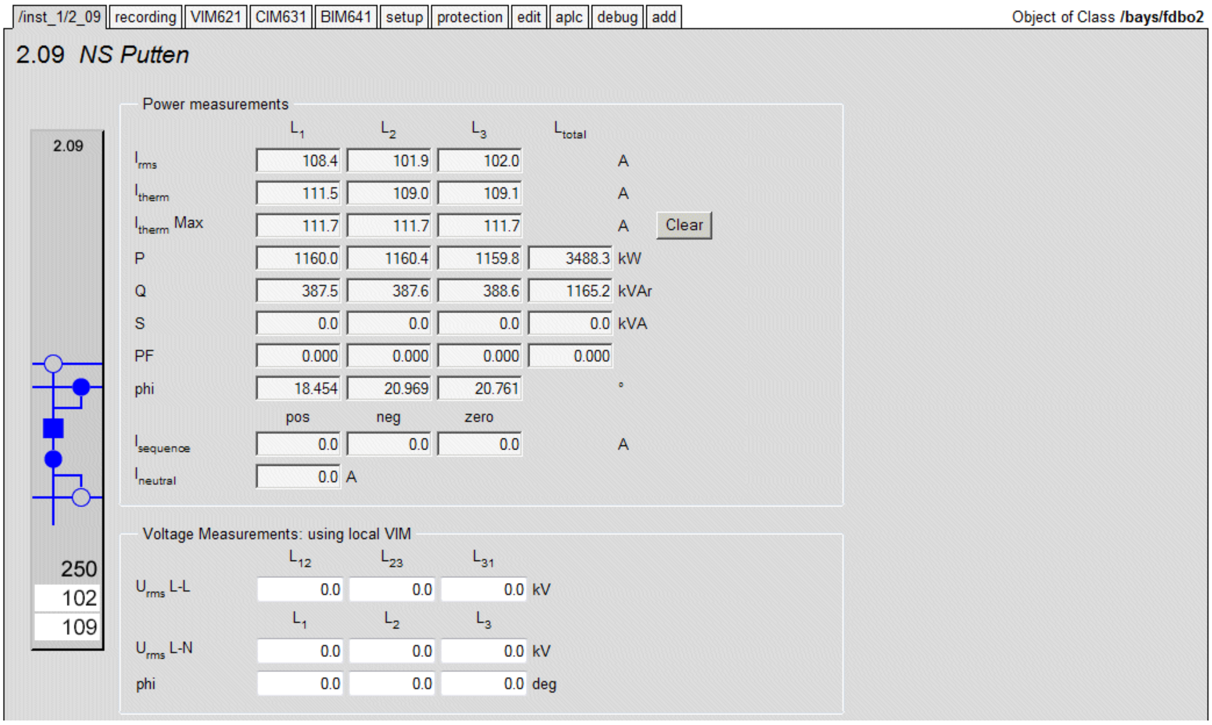


Figure 11. Example of a bay screen showing all measurements results

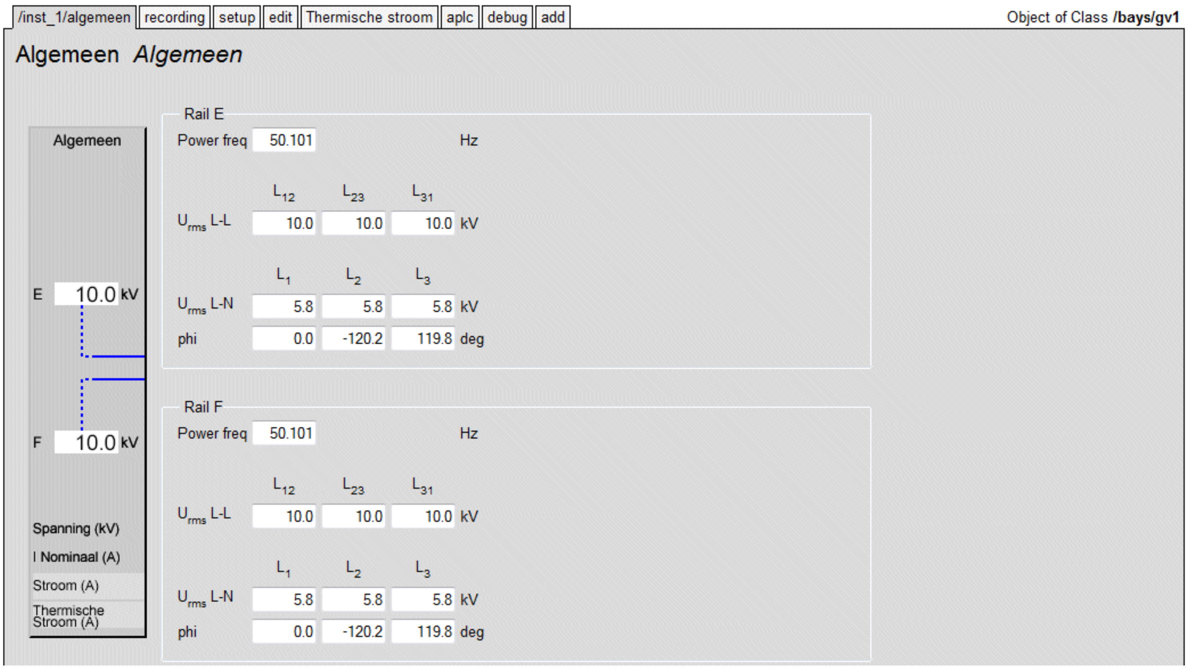


Figure 12. Example of a busbar screen showing all measurements results

Time Overcurrent Protection (PTOC)

The time overcurrent protection application (PTOC) protects substations against excessive loading, caused by short/circuits or overloads of transformers and cables. PTOC is based on phase/selective measurements of the 3-phase currents I_{L1} ,I_{L2} and I_{L3} . The neutral current I_{LN} is calculated from these 3-phase currents. The PTOC application contains two modes definitive-time and inverse-time with or without direction determination. Three protection stages are available for phase and earth fault protection: I>, I>> and I>>>. The first stage can be independently selected as definite-time mode or inverse-time. The two other stages are always definite-time.

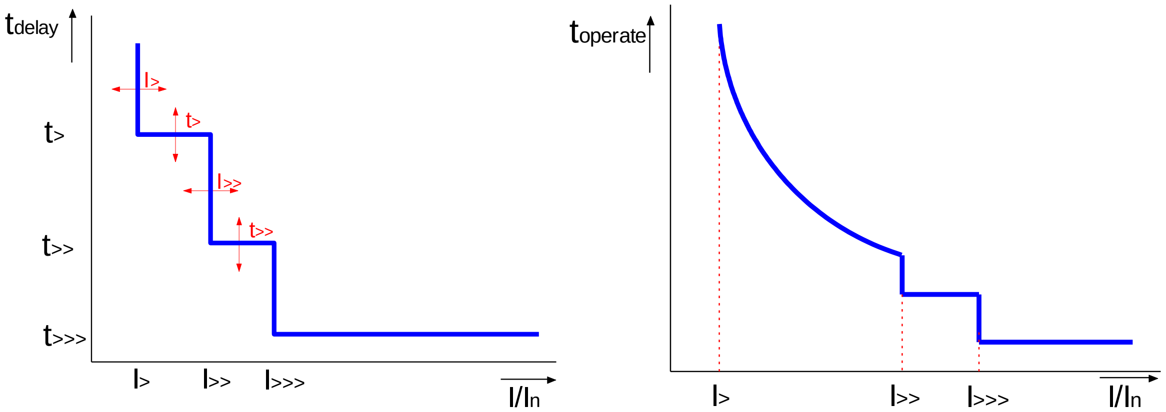


Figure 13. Definitive time overcurrent protection (left). Combined time overcurrent protection (right)

The PTOC application is defined in the SASensor system as represented in Figure 14

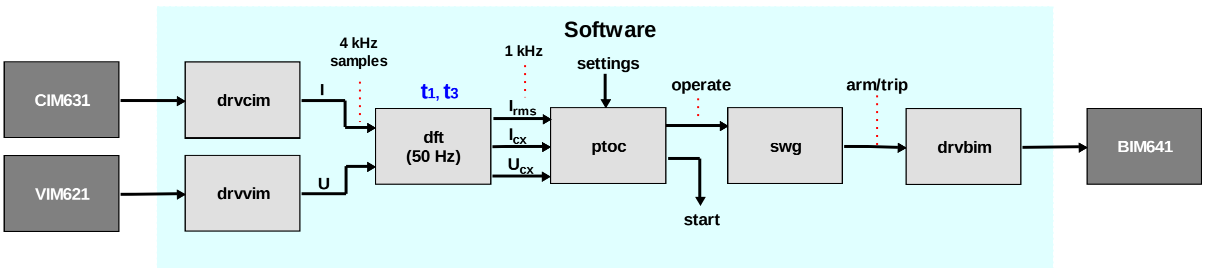


Figure 14. PTOC application in SASensor

The CIM and the VIM deliver the raw data of measured currents and voltage samples to the CCU. The SASensor software module drvcim (driver CIM) and drvvim (driver VIM) convert this 28 kHz raw data into 4 kHz time synchronous samples I and U that are then delivered to the dft (50 Hz) module (DFT= discrete fourier transformer). The dft (50 Hz) module filters the 4 kHz samples and processes the data into 1 kHz filtered values I_{rms} for each phase and neutral that is delivered to the ptoc module. The dft (50Hz) module also generates 1 kHz complex samples I_{cx} and U_{cx} that are used to calculate the forward and reverse direction in the ptoc module.

Settings for different I_{rms} current set points or curves and time conditions determine the behavior of the ptoc module. On a fault, when an I_{rms} value exceeds the pre-defined current set point, the ptoc module generates the signal start. When a time condition is exceeded, the ptoc generates the signal operate. In case of definite time, this time is determined by a chosen time setting; in case of inverse-time, this time setting is determined by the chosen curve setting.

On an operate, this module will generate ARM and TRIP commands, which are send to the drbim (driver BIM) module. The two commands ARM and TRIP are sent in two separate messages and additionally, a TRIP must follow an ARM command within 10 ms. Only then the BIM will trip the circuit breakers.

SASensor Web Interface

Below a brief description of the web interface of SASensor system is made.

The main screen gives a quick overview of the substation.

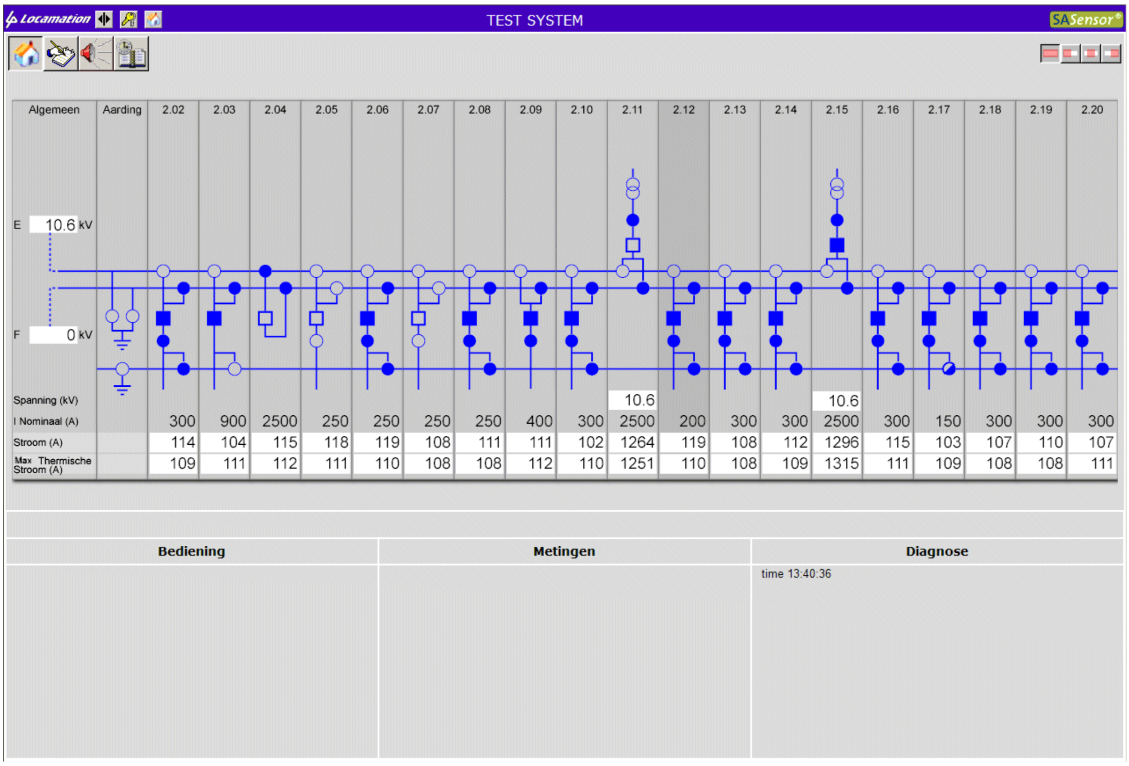


Figure 15. SASensor Web interface

A substation generally contains a general bay, an aerthing bay and incoming and outgoing bays. It shows for each bay the actual voltage, current and thermal currents values. This screen is used to verify the correct functionig of the complete substation.

Symbols on the main screen.

Symbol	Function	Status
	Isolator with or without position indication	connected (IN)
		disconnected (OUT)
		running between connected and disconnected
	Earth switch	connected (IN)
		disconnected (OUT)
		running between connected and disconnected
	Circuit breaker	closed
		open (tripped)
		running between open and off
 *flashing*		concerned bay is not yet initialised

Transformer Differential Protection

Introduction

The interest of Locamation B.V. in developing a new protection application to be implemented in the SASensor system is the reason of the internship that during 5 months myself together with a Dutch student we have been working on.

The internship can be divided in different stages. First, a detailed research into the differential protection issue was made, including possible problems, products on the market, etc. After the research, some tests and simulations were made, using the program Scilab, with a differential protection algorithm. The third stage, which was not completed, is the implementation of the protection function in the SASensor system. Nevertheless, some points and advices to continue with this assignment in the future and implement the proposed solution are explained in the final part of the report.

Research Transformer Differential Protection

Current differential relaying is the most commonly used practice for protection transformers that are rated approximately 10 MVA or more [3] (other type of differential protection can be the power differential relaying, where the power/energy is compared instead of the current). In Figure 16 it is shown a typical current differential relay connection for a single-phase transformer. CT1 and CT2 are the current transformers used to step down the current level to a more manageable value for measuring and protecting issues. An example of current transformer can be defined as:

- 400/1 A   5P60

This current transformer is described in IEC terminology. The ratio is 400/1 A, which means that for a current of 400 amperes in the primary, there will be 1 ampere in the secondary of the CT. The Class 5P60 represents: 5 is the percentage composite error limit, P defines the CT as a protection CT, 60 is the accuracy limit factor.

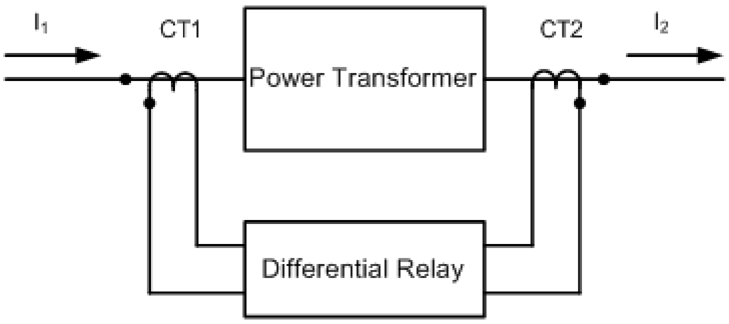


Figure 16. Differential relay connection for a single-phase transformer (source: [3])

For a three-phase power transformer every phase is managed independently in the same way as represented in the Figure 16.

The main operation of a current differential protection relay is made by comparing the vector current in both sides of the transformer. In a normal situation, and not considering possible errors or phase shifts, the magnitude and the phase of the currents in both sides should be the same. When there is a difference between them it may be an internal fault.

But even in a no fault situation the vector current in both sides of the transformer will not have the same value, this is caused by errors such as:

- Power transformers tap change.
- Magnetizing current
- Inaccuracy of CTs
- Saturation of CTs

By using numerical relays, problems like CTs mismatch can be solved mathematically. Also magnitude compensation, due to the ratio of the transformer, and phase shift compensation, in case the transformer introduces a fixed phase shift, can be solved mathematically in the software of the relay.

Magnetizing current creates the magnetic field in the transformer, it is also presented in a no load situation. This current goes into the first winding but it does not appear in the secondary side, as a result there is a differential current value between both sides of the transformer. Magnetizing current stays constant when the current through the transformer increases, a typical value is 5% of the nominal current, or less.

Another error can be produced by the inaccuracy of the CTs. As an example, a CT type 5P20 has an approximate error of 3% for the nominal current, the error increases to 5% for a current 20 times the nominal.

In case the power transformer is equipped with a tap changing to vary the voltage, another error has to be considered. As an example, a tapping change range of 10% produces a 10% error for the nominal current value, if the current increases the error increases as well linearly. If the possibility of monitoring the transformer tap position exists, then this error could be avoided by modifying the transformer data in the relay when the tap position changes.

To cope with the errors that increase when the current trough the transformer gets higher, it is used the percentage differential relays. The basic of the percentage differential relay is the comparison of the differential current with a percentage of another calculated current called restrained current or bias current. This current represents the amount of current that goes through the transformer, when it increases, the errors increase as well. Different alternatives are used for obtaining the restraint current, I_R. Several combinations of the currents at the two terminals of the transformer [3]:

- $I_R = K|I_1 + I_2|$
- $I_R = K(|I_1| + |I_2|)$
- $I_R = \max(|I_1|, |I_2|)$

In these equations, k is a constant that is usually 1 or 0.5.

In Figure 17 a typical curve for the percentage differential protection is shown. Id is the differential current, in per unit value of the nominal current, and Ir is the restraint current. The blue line represents the differential current caused by the magnetizing current, the error caused by the inaccuracy of the CTs is depicted by the green line, and the tap change error by the red one. A possible saturation of the CTs has not been considered. When saturation is taken into account a second slope for high values of I_R is usually included, as shown in the curve of the differential relay of the company ABB (Figure 18). In this curve it is also included a zone in which the tripping time is faster than in the normal zone. This unrestrained tripping is activated when the differential protection exceeds 4.5 times the nominal current, for the relay of Figure 18. The reason of being faster is because when detecting a value over the unrestrained limit, no analysis of harmonics or other discrimination method is made, so fewer calculations are needed. A discrimination method is used to avoid false tripping owing to for example inrush currents. The unrestrained setting should be above the expected value of the inrush current so that not to trip in this situation.

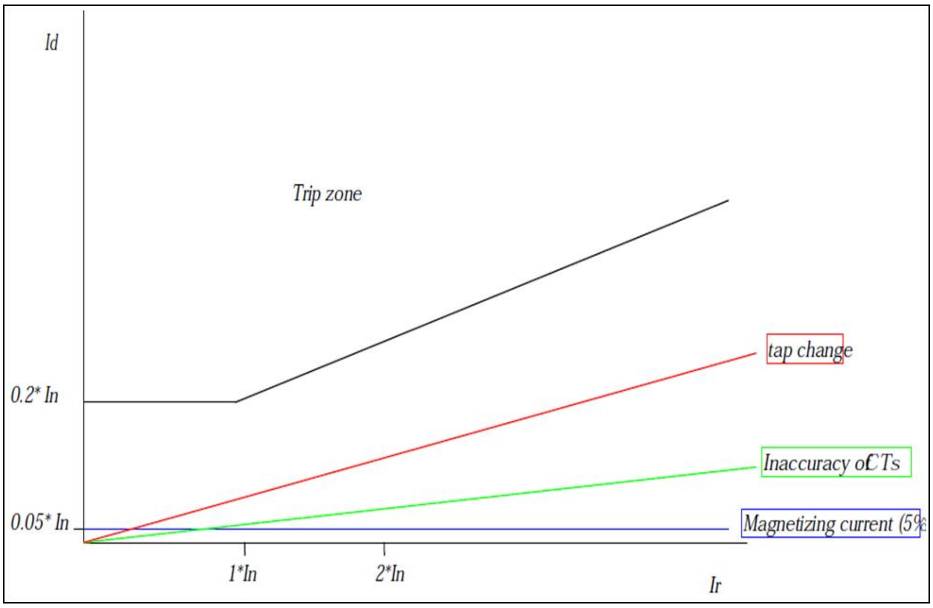


Figure 17. Percentage differential protection. Errors

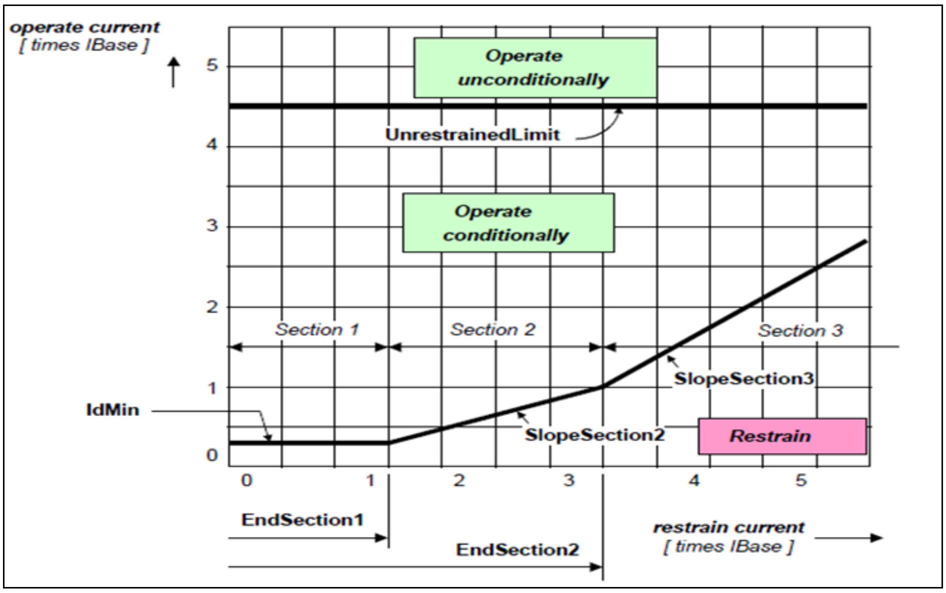


Figure 18. ABB Transformer differential protection curve.

Inrush current

The magnetizing inrush current is set up in the primary winding of a power transformer during its initial excitation. This phenomenon can produce a differential current high enough to trip the relay, when there is not a real internal fault. To cope with this problem many restraint methods have been proposed to avoid the operation of the differential element during an inrush current.

There are also other causes that can create inrush current. When a short circuit fault occurs in the systems it is usually accompanied by a considerable drop in the system voltage. If the fault is cleared, the voltage rises again to a normal value, and during this sudden recovery of the voltage inrush current can occur in transformers connected to the system. When two or more transformers have parallel connected primaries the switching in one of them can initiate an inrush current in the primary of the second transformer already connected.

The inrush current phenomenon is caused when the transformer core saturates and then a large current peak accompanies this saturation of the magnetic circuit. Very related with the magnetic circuit saturation is the residual flux that is presented in the transformer core before switching on. Other factors are: point on the voltage wave at the instant of circuit closure, hysteresis characteristics of the core material and the impedance of the circuit supplying the transformer primary.

According to some research papers the duration of the inrush current, for transformers in the higher kVA ranges, can be over 1 second before the magnitude falls to 50% of the first peak value.

In Figure 19 it is shown one example of inrush current. The three different color signals correspond to the three phases of a transformer. This data was measured by SASensor system in one of the substation where the system is already working.

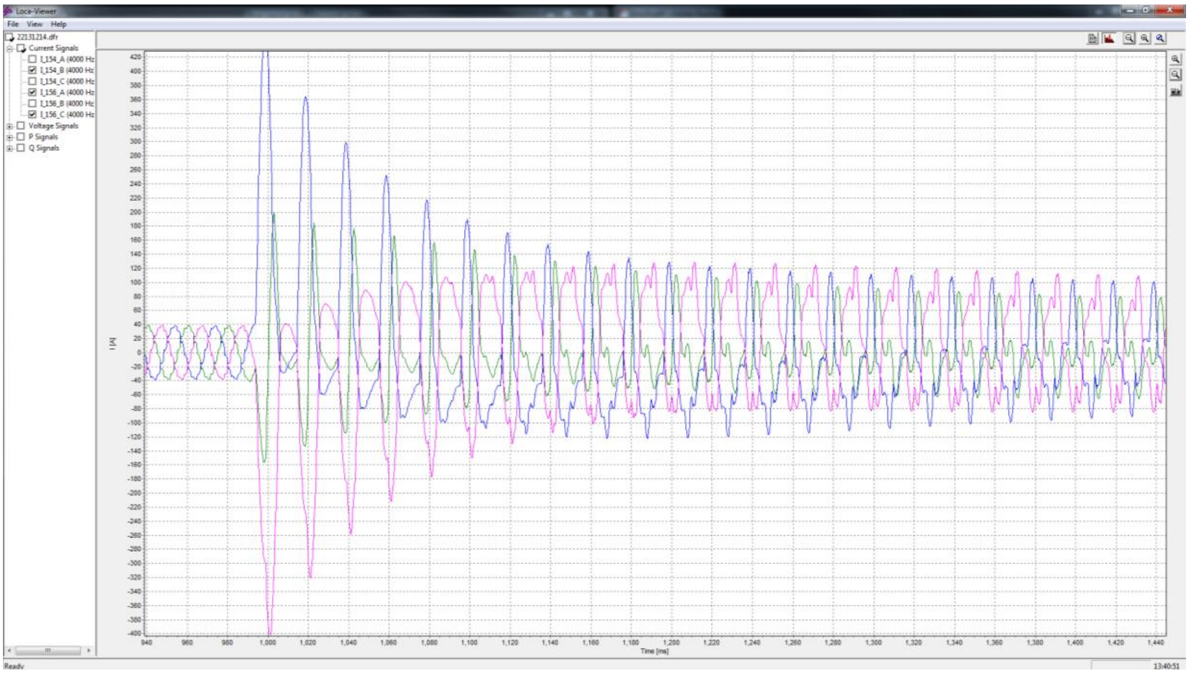


Figure 19. Inrush current

The inrush current is not a big problem for the transformer itself but it can be a problem for the protective relays that could produce an unnecessary trip.

An important point in the assignment was to study the problem with the inrush current. The actual overcurrent protection function, PTOC, does not present problems with inrush currents so we wanted to know if for a differential protection this would be different.

The input of the PTOC function is a filtered signal, a DFT (Discrete Fourier Transform) filter extracts only the fundamental part (50 Hz) of the signal. An inrush current signal normally contains an important second harmonic component, but it is not a perfect 100 Hz signal, so it contains a fundamental (50 Hz) component as well. After the 50 Hz filter, the second and other harmonics are removed but the fundamental component is still there. A test was made in the virtual machine to see how the inrush current of Figure 19. Inrush current could affect the overcurrent protection application. This test is explained below.

Locamation uses a virtual system, called virtual machine, which represents the same environment and functionality of a real system but running virtually. In this environment it is possible to create your own design of a substation and introduce all the applications and functionality that SASensor system provides.

One interesting application that SASensor includes is the protection test, in which a protection function such as overcurrent protection (PTOC) can be tested for determined settings introducing some input data.

We want to test how the inrush current of Figure 19 can influence the PTOC function, so first of all the inrush current DFR (Digital Fault Recording) file is introduced in the system. The input of the PTOC function is the root means square value of the fundamental component (50 Hz) of the measured current. That means that only the fundamental component of the input current can affect the protection function and in the case create a trip signal.

In the next figure it is shown the inrush current in one of the phases (phase A), the lower graph represents the root means square value of the fundamental component of this current. After the signal is filtered by the DFT (Discrete Fourier Transform) filter, it can be seen that the fundamental component is an important part of the signal, in the sense that it could have some effect in the protection function.

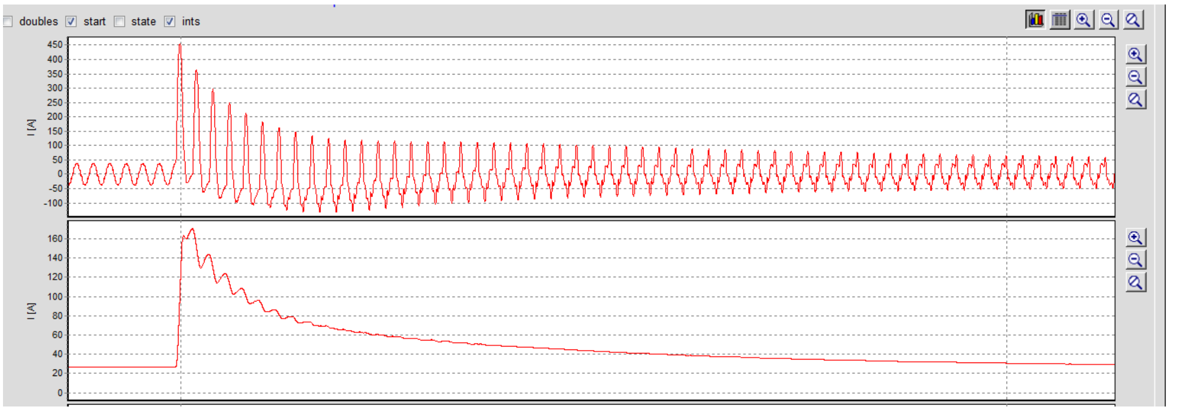


Figure 20. Inrush current in one phase (upper graph). Irms value of the fundamental component (lower graph)

Depending on the settings introduced in the PTOC function, the inrush current may cause a trip. In this example the function used is the definite-time overcurrent protection; the settings introduced are shown in Figure 21. It is supposed a nominal current in the primary of 100 A, the tripping settings are taken from another installation as possible settings that can be used in a real situation.

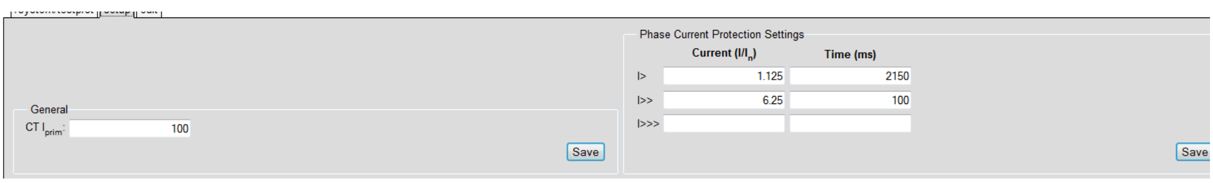


Figure 21. PTOC settings

The results of the protection test are shown in Figure 22. The lower graph depicts the outputs of the PTOC function, it can be seen that a start signal appears because the I_{rms} value exceeds the setting point, but the time this I_{rms} value is over the trip setting point is not enough to generate an operation signal. It can be seen a time delay of 30ms for the start signal to appear, this is caused by the 50 Hz filter.

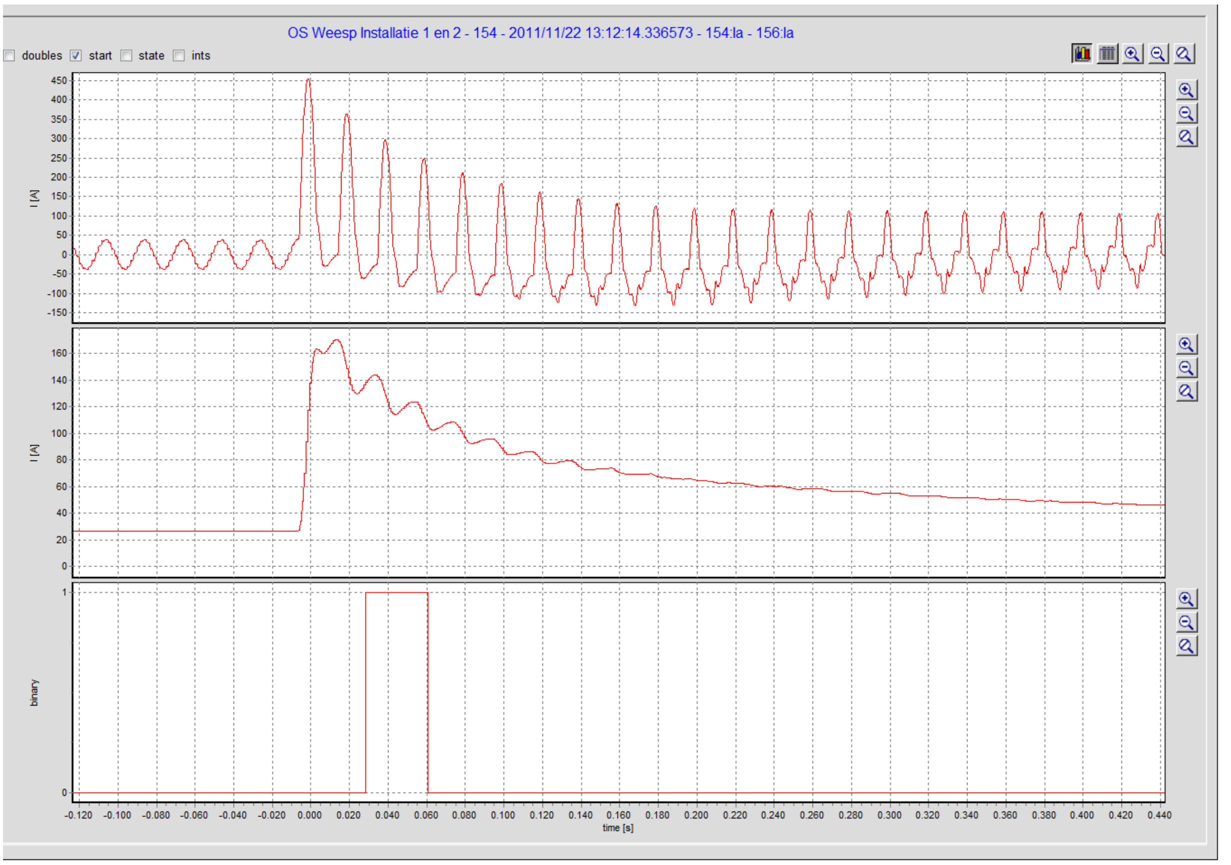


Figure 22. Inrush current effect in the PTOC

According to the results of this test we can see how this particular inrush current, with the settings used, will not generate a trip signal. The PTOC function was also tested by some Locamation's customers for an inrush current situation, with the same result of not tripping.

Because of the time settings normally used in an overcurrent protection, an inrush current cannot generate a trip. The inrush current value can exceeds the protection settings but not for enough time to generate a trip.

In a current differential protection function, the tripping time is faster than in an overcurrent protection function, which means that an inrush current situation could generate a trip. To avoid this undesired trip, different methods are used to discriminate between internal fault and inrush current.

Methods of avoiding false tripping

One common method used in the earlier installations was desensitized the relay during an inrush current situation for a period long enough for the relay not to generate a trip. Using this method the transformer is not protected in the case there is an internal fault during the instant of switching. Also in the situation of an inrush current caused by a voltage recovery (for example after an external fault has been cleared), or when switching a second parallel transformer, the relay cannot be desensitized.

The majority of the methods employed for avoiding the false tripping of protective relays make use of the characteristic shape of the magnetizing inrush current. One method introduced in the 40s but still nowadays widely used is based in the fact that higher harmonics (notably the second) are more pronounced in the inrush current waveform than in that of an internal fault.

Harmonic restraint is one of the methods used. With this method the harmonic content of the differential current, for instance 2nd harmonic, 3rd harmonic, etc., are added to the tripping curve in the way that the harmonic value increases the operation restraint of the relay. Equation 1 represents that function.

$$|\boldsymbol{Io}| > \boldsymbol{s}|\boldsymbol{Ir}| + \boldsymbol{k2}|\boldsymbol{I2}| + \boldsymbol{k3}|\boldsymbol{I3}| + \cdots$$ Equation 1

$\lvert Io \rvert$	Absolute value of the fundamental frequency component of the operating current.
|Ir|	Absolute value of the restraint current.
|I2| , |I3| ,..	Absolute values of the second, third, and higher harmonic components of the operating current.
k2, k3	Constants of proportionality.
s	Slope of the percentage differential characteristics of the relay.

According to this equation the condition to generate a trip signal is that the value of "$|Io|$" has to be higher than " $s|Ir| + k2|I2| + k3|I3| + \cdots$". In the situation of an inrush current this last expression increases, what means that the sensitivity of the relay decrements.

Harmonic blocking is another method used. In this case the harmonic values are independently compared with the fundamental value, when a condition is not satisfied the relay does not operate, it is blocked.

$$|\boldsymbol{Io}| > \boldsymbol{k2}|\boldsymbol{I2}|$$ Equation 2

$$|\boldsymbol{Io}| > \boldsymbol{k5}|\boldsymbol{I5}|$$ Equation 3

Equation 2 and 3 represent the blocking conditions for the second and fifth harmonic.

It is a common practice to use the fifth harmonic of the operating current to avoid the operation of the differential relay when the protected transformer experiences overexcitation. This situation of overvoltage or underfrecuency can drive the transformer into saturation, and can produce a differential current between both sides of the transformer, and so generate a false trip.

2nd Harmonic detection. Simulations in Scilab

The inrush current depicted in Figure 19 is introduced in the program Scilab, where an inrush current detection function has been implemented based on the 2nd harmonic analysis.

First the fundamental and 2nd harmonic component of the signal are filter out. Figure 23 shows the inrush current signal (blue), fundamental (red) and 2nd harmonic (green).

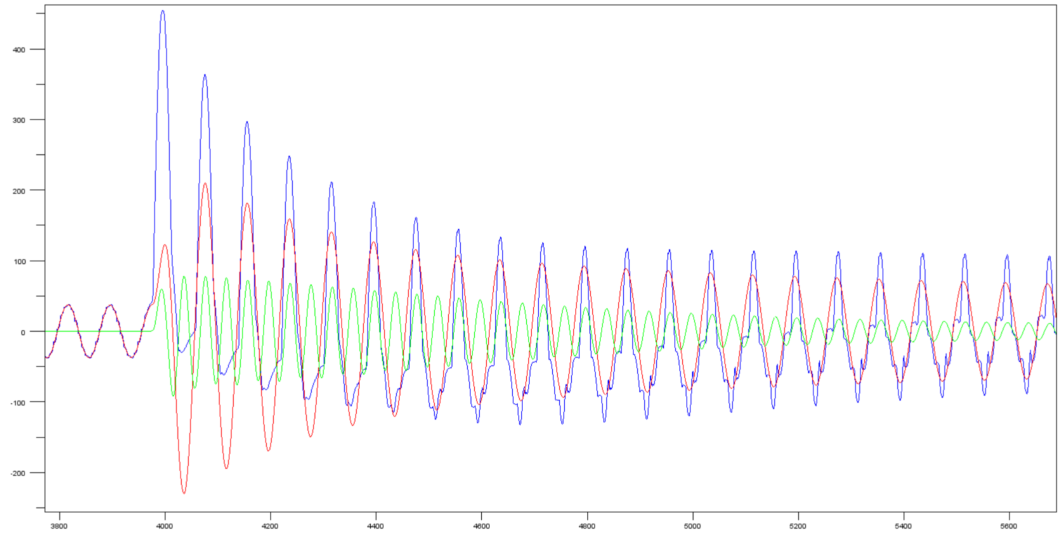


Figure 23. Inrush current. Fundamental and 2nd harmonic

Figure 24 represents the absolute values of the fundamental component (red) and the 2nd harmonic (green).

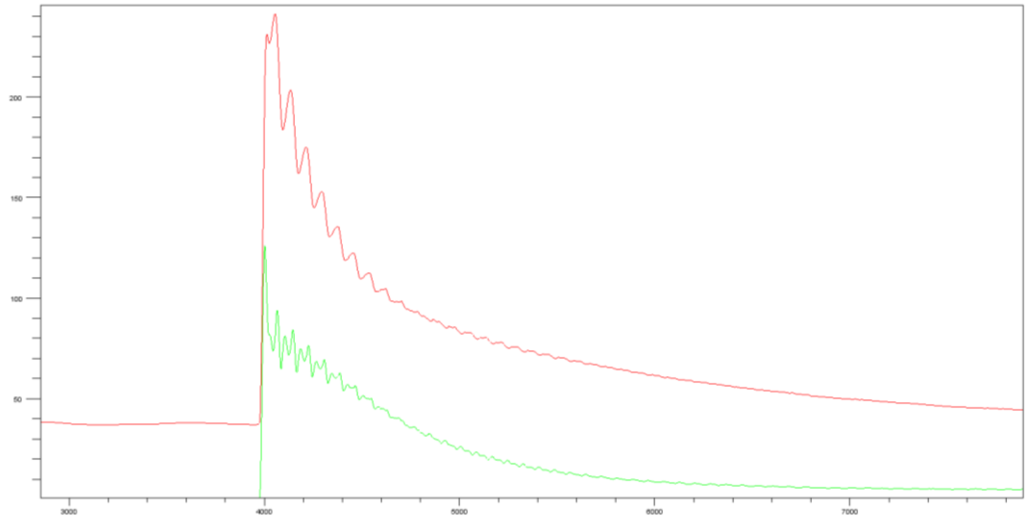


Figure 24. Inrush current. Fundamental and 2nd harmonic absolute values

One of the methods used is blocking the relay if the absolute value of the 2nd harmonic is above a defined amount of the fundamental component absolute value. A typical value of this ratio (I2/I1) is 0.15 (15%). Figure 25 shows this ratio for the inrush current analyzed (blue signal). The red signal represents the value set to block the function (0.15). It can be seen that for an approximate time of 500 ms the differential protection function would be blocked.

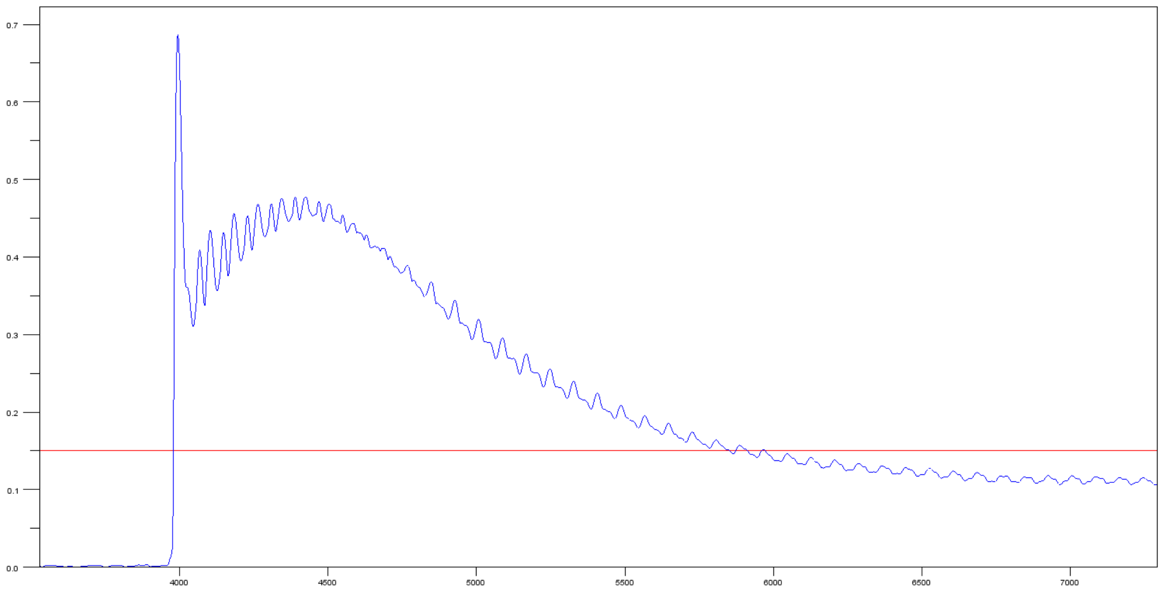


Figure 25. 2nd harmonic ratio

Other detection methods

Others techniques used for the detection of inrush current are based on wave shape recognition methods. One of these methods is the low-current detection method. An inrush current wave is characterized by a time interval in which the current is nearly zero. The length of this interval is higher in an inrush current than in an internal fault (Figure 26).

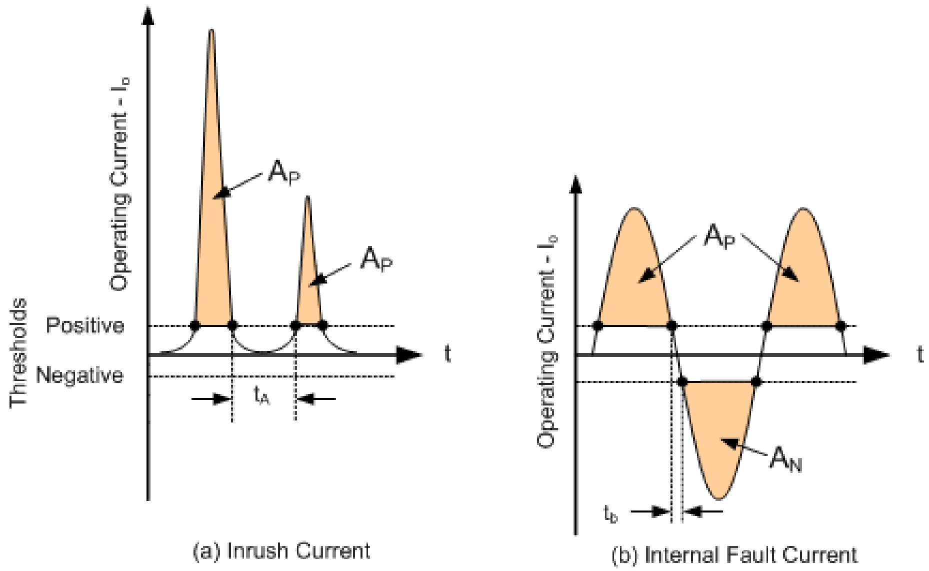


Figure 26. Duration of low-current intervals as a method to detect inrush currents

Other waveform recognition method is based on the dc signal information. The dc component of inrush current typically has a greater time constant than that for internal faults, which is used to discriminate between both signals.

Cross-blocking between phases

In order to improve the blocking effect for an inrush current situation a so called cross-blocking function can be used, which means that one of the three phases can block the rest when detecting an inrush current. This may be useful for transformers that have insufficient harmonics on some phases to block during inrush. However cross-blocking has the downside of the possibility of delaying a trip when energizing a faulted transformer if the healthy phases sense inrush. Usually differential protection relays have the option to switch on/off the cross-blocking function.

Products on the market

Current differential protection is the most common way to protect a power transformer, which is reflected in the great amount of products available on the market. Below some of these products are presented and their main features are explained. Only the differential protection function is considered.

The SASensor system concept is different from the one of the products presented below, in the sense that the SASensor is a system for the whole substation in which the software is implemented in a central control unit (CCU), where the protection algorithms run, and the data acquisition and the tripping actions are done in different modules. A separation between software and hardware exists. In the contrary, the products presented below are “all in one box”, the software and the hardware are both in one device specifically made for protecting transformers. Usually not only a differential protection function is implemented in these relays but also other functions, back up functions, such as overcurrent protection, voltage protection or frequency protection are included as well. In the SASensor system the introduction of a differential protection function for transformers means to implement a new application in the system.

ABB. Transformer protection RET670

The transformer differential protection function of the relay RET670, produced by ABB, presents commonly used features, such as 2nd and 5th harmonic restraint to avoid false tripping caused by inrush current and overexcitation, magnitude and phase shift compensation, or the option to remove the zero sequence current.

Figure 27. RET670 (Source: ABB)

It also has others, no so common, functions like on-line compensation for load tap changer movement, which increases the sensitivity of the relay or the use of negative sequence current for the discrimination between internal or external faults. A waveform restraint function that recognizes the intervals within each cycle with low instantaneous differential current is also included. A cross-blocking function between phases is available as well.

The tripping curve is shown in Figure 18. The main settings of the differential protection function, as well as the tripping time, are included in Table 1.

Name	Range	Default/Typical value	Description
Minimum pickup (IdMin)	0.05 - 0.60	0.30	Sensitivity of the first section of the curve. In per units of the operational current (differential current).
End section 1	0.2 - 1.5	1.25	End of the 1st section of the curve. In per units of the restraint current.
Slope section 2	10 - 50	40	Slope in section 2 of operate-restrain currents. In %.
End section 2	1.0 – 10.0	3.0	End of the 2nd section. In per units of the restraint current.
Slope section 3	30 – 100	80	Slope in section 3 of operate-restrain currents. In %. The reason of using this slope is to prevent false tripping caused by saturation of the CTs.
Unrestraint tripping	1.0 – 50.0	10.0	Unrestraint tripping limit. In per units of the operational current
I2/I1 Ratio	5.0 – 100.0	15	Ratio of the 2nd harmonic to the fundamental in %. Over this ratio the relay considers the situation as an inrush current, so it does not trip.
I5/I1 Ratio	5.0 – 100.0	25.0	Ratio of the 5th harmonic to the fundamental in %. Over this ratio the relay considers the situation as an overexcitation, so it does not trip.
Operate time (restrained function)		25 ms	
Operate time (unrestrained function)		12 ms	

Table 1. Settings parameters RET679

Siemens. SIPROTEC 7UT6 Differential protection relay for transformers, generators, motors and busbars.

The SIPROTEC 7UT6 differential protection relay performs functions such as: restraint against inrush currents with 2nd harmonic, restraint against overexcitation using 3rd or 5th harmonic, fast unrestrained tripping, etc.. An interesting function included in the relay is the detection of a possible saturation of a current transformer during an external fault that could cause a false trip.

In Figure 28 the tripping curve of the relay is represented. The curve can be modified within a range of values that are explained in

Table 2.

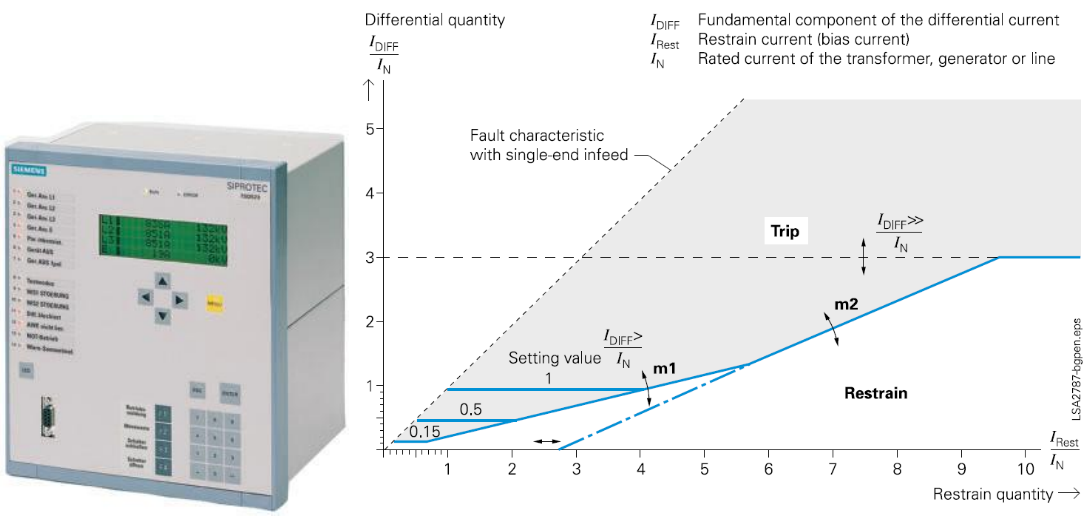


Figure 28. Siemens SIPROTEC 7UT6 differential protection curve (right)

Name	Range	Default/Typical value	Description
Minimum pickup (IdMin)	0.05 – 2.00	0.20	Sensitivity of the first section of the curve. In per units of the operational current (differential current).
End section 1		1.25	End of the 1st section of the curve. In per units of the restraint current.
Slope section 2 (m1)	10 - 50	25	Slope in section 2 of operate-restrain currents. In %.
End section 2		5.0	End of the 2nd section. In per units of the restraint current.
Slope section 3 (m2)	25 – 95	50	Slope in section 3 of operate-restrain currents. In %. The reason of using this slope is to prevent false tripping caused by saturation of the CTs.
Unrestraint tripping	0.05– 35.0	7.5	Unrestraint tripping limit. In per units of the operational current
I2/I1 Ratio	10 – 80	15	Ratio of the 2nd harmonic to the fundamental in %. Over this ratio the relay considers the situation as an inrush current, so it does not trip.
I5/I1 Ratio	10 – 80	30	Ratio of the 5th harmonic to the fundamental in %. Over this ratio the relay considers the situation as an overexcitation, so it does not trip.
Operate time (restrained function)		30 ms 25 ms	(fast relays) (high-speed relays)
Operate time (unrestrained function)		11 ms 6 ms	(fast relays) (high-speed relays)

Table 2. Settings parameters SIPROTEC 7UT6

Schneider Electric. MiCOM P64x relay

The differential protection function of the MiCOM P64x relay presents some commonly used functions like the use of the 2nd and 5th harmonic for inrush and overexcitation respectively, magnitude and phase compensation or fast unrestrained trip.

An interesting technique implemented in this relay is the so called transient bias. This function adds an additional bias (restraint) current quantity to the normal bias measurement during external faults. This increases the stability of the relay.

A CT saturation detection function is included as well. Not only in external faults but also in internal ones CTs could drive into saturation. For internal faults the problem is that when saturation a 2nd harmonic component could be presented in the signal. The relay can interpret this situation as an inrush current when it is an internal fault.

The tripping characteristic curve included in the manuals of the manufacturer is shown in Figure 29.

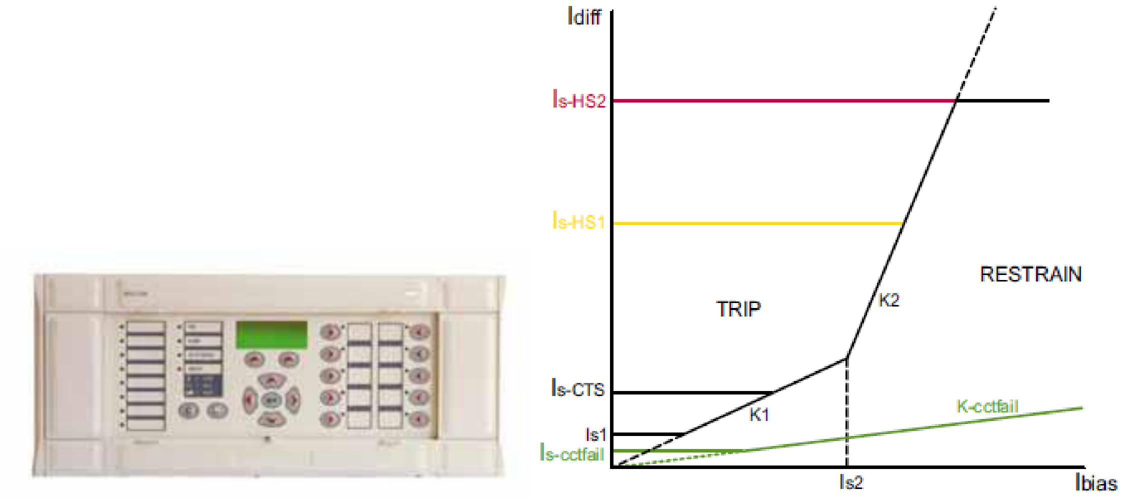


Figure 29. MiCOM P64 (left.)Tripping characteristics(right)

Name	Range	Default/Typical value	Description
Minimum pickup (Is1)	0.1 – 2.0	0.20	Sensitivity of the first section of the curve. In per units of the operational current (differential current).
End section 1		0.1	End of the 1st section of the curve. In per units of the restraint current.
Slope section 2 (K1)		30	Slope in section 2 of operate-restrain currents. In %.
End section 2 (Is2)		4.0	End of the 2nd section. In per units of the restraint current.
Slope section 3 (K2)		70	Slope in section 3 of operate-restrain currents. In %. The reason of using this slope is to prevent false tripping caused by saturation of the CTs.
Unrestraint tripping			Unrestraint tripping limit. In per units of the operational current
I2/I1 Ratio	1 – 40	20	Ratio of the 2nd harmonic to the fundamental in %. Over this ratio the relay considers the situation as an inrush current, so it does not trip.
I5/I1 Ratio	1 – 40	20	Ratio of the 5th harmonic to the fundamental in %. Over this ratio the relay considers the situation as an overexcitation, so it does not trip.
Operate time (restrained function)		20 to 35 ms	
Operate time (unrestrained function)		5 to 20 ms	

Table 3. Settings parameter MiCOM P64x

GE Multilin. T60 Transformer Protection System

The differential protection application of the T60 Transformer Protection System performs well known functions such as phase and magnitude compensation or the use of the 2nd harmonic against inrush current and 5th harmonic against overexcitation.

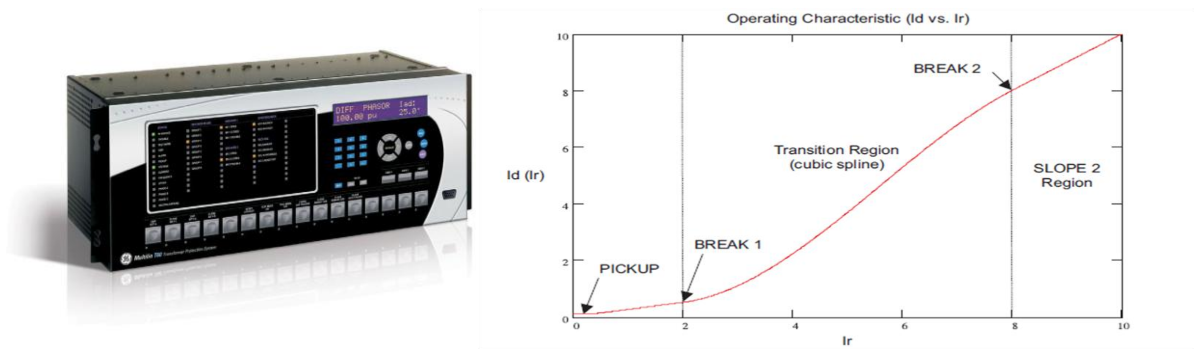


Figure 30. T60 tripping curve (right)

One of the peculiarities in this relay is the tripping curve represented in Figure 30. It contains a region between slope 1 and slope 2, a transition region, which is not a constant slope but a variable one.

Name	Range	Default/Typical value	Description
Minimum pickup (PICKUP)		0.1	Sensitivity of the first section of the curve. In per units of the operational current (differential current).
End section 1			
Slope section 2	15 - 100	25	Slope in section 2 of operate-restrain currents. In %.
End section 2 (BREAK 1)	1.00 – 2.00	2.0	End of the 2nd section. In per units of the restraint current.
Slope section 3 (SLOPE 2 Region)	50 - 100	100	Slope in section 3 of operate-restrain currents. In %. The reason of using this slope is to prevent false tripping caused by saturation of the CTs.
Unrestraint tripping	2.00 – 30.00	8.00	
I2/I1 Ratio	5 – 50	15	Ratio of the 2nd harmonic to the fundamental in %. Over this ratio the relay considers the situation as an inrush current, so it does not trip.
I5/I1 Ratio	0 – 100	35	Ratio of the 5th harmonic to the fundamental in %. Over this ratio the relay considers the situation as an overexcitation, so it does not trip.
Operate time (restrained function)		33 ms	
Operate time (unrestrained function)		21 ms	

Table 4. Settings parameters T60

Transformer Differential Protection Function. Proposal

A proposal for a transformer differential protection function (PTDF, according to IEC61850-5) to implement in SASensor system is explained below. In Figure 31 it is shown how the PTDF function fits in the system. The fundamental component (50 Hz) complex values of the current in both sides of the transformer are the inputs of the PTDF block. These values are the outputs of the dft (50 Hz) module, which filters the fundamental component of the measured signal (4 kHz samples) and delivers the rms value and the complex value of the current (I_{CX}) in 1kHz samples rate. The current phasors of the fundamental component are used to calculate the differential and the restraint currents.

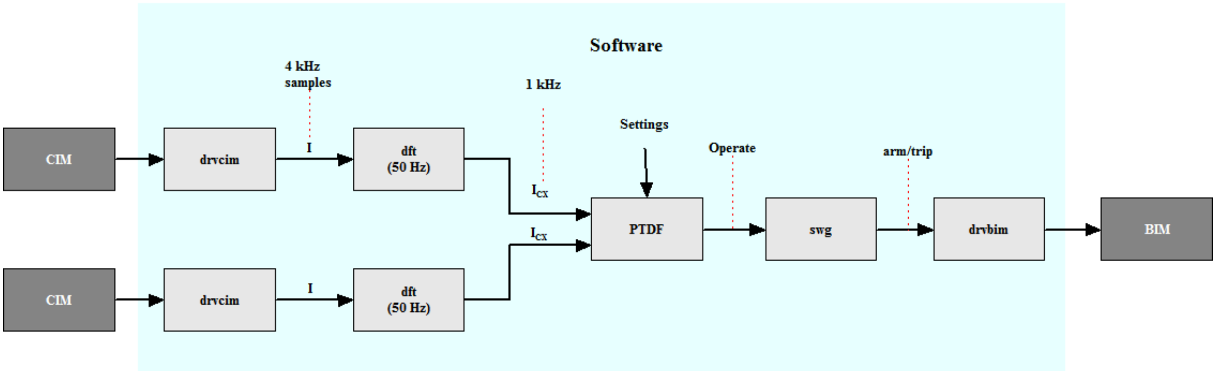


Figure 31. PTDF in the SASensor system

Some settings have to be introduced in the PTDF block, such as the nominal power of the transformer or the vector group. When the conditions for a trip are satisfied and operate signal is sent to the swg (switchgear) software module, which is the model for all types of circuit breakers.

The PTDF block can be divided in sub-blocks or functions (Figure 32). The inputs to the first block are the complex values (magnitude and phase) of the fundamental component of the current in each side of the transformer.

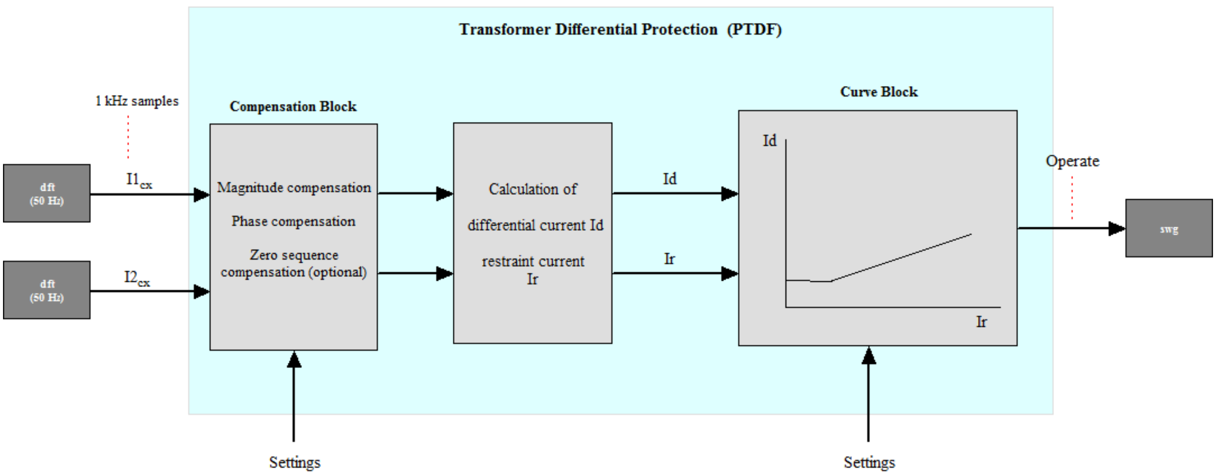


Figure 32. PTDF block

The need to use not only the magnitude of the current but also the phase can be explained in the next example.

Considering the situation of an internal fault fed by the same level of current (magnitude) from both sides of the transformer (Figure 33). In this case $|I_1|=|I_2|$. If comparing just the magnitude of both currents the relay would not detect the internal fault because they have the same value. If comparing the phasors instead, there will be a differential current value because the phase of each signal is different. The relay would detect this situation as an internal fault.

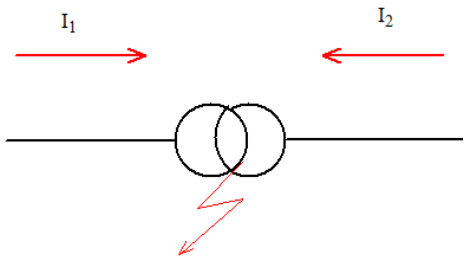


Figure 33. Internal fault example

Before the currents can be compared it is necessary to first compensate them because of the power transformer ratio and a possible fixed phase shift. Optionally the zero sequence current can be removed.

When protecting a power transformer with a ratio different than 1, for example are: 150/10.6 (kV), the magnitude of both currents differs more or less depending on this ratio. Magnitude compensation can be made by multiplying the currents measured in the secondary winding by the transformer ration so the result currents have the same magnitude as the primary side currents (Equation 4. Three phase transformer).

$$\begin{pmatrix} \boldsymbol{IA2'} \\ \boldsymbol{IB2'} \\ \boldsymbol{IC2'} \end{pmatrix} = \frac{\boldsymbol{Un2}}{\boldsymbol{Un1}} * \begin{pmatrix} \boldsymbol{IA2} \\ \boldsymbol{IB2} \\ \boldsymbol{IC2} \end{pmatrix} \qquad \text{Equation 4}$$

$\begin{pmatrix} IA2 \\ IB2 \\ IC2 \end{pmatrix}$	Second winding currents
$\begin{pmatrix} IA2' \\ IB2' \\ IC2' \end{pmatrix}$	Second winding compensated currents
$\frac{Un2}{Un1}$	Transformer ratio

Phase compensation is necessary when the transformer introduces a phase shift between windings. This phase shift is indicated in the vector group. For example the transformer Ynd5 introduces a phase shift of 5*30 (degrees) = 150 (degrees), or Ynd1 introduces 1*30°=30°. This can be compensated by shifting back the current phase mathematically. The first winding is taken as a reference so the second winding currents are shifted back to be compared with the first winding currents. By introducing a matrix (A) in Equation 4 the phase compensation is made (Equation 5)

$$\begin{pmatrix} \mathbf{IA2'} \\ \mathbf{IB2'} \\ \mathbf{IC2'} \end{pmatrix} = \frac{\mathbf{Un2}}{\mathbf{Un1}} * \mathbf{A} * \begin{pmatrix} \mathbf{IA2} \\ \mathbf{IB2} \\ \mathbf{IC2} \end{pmatrix}$$ Equation 5

The values to introduce in the matrix depend on the type of transformer to be protected. For a transformer with a vector group Ynd5, the matrix is:

$$A = \frac{1}{\sqrt{3}} * \begin{pmatrix} -1 & 0 & 1 \\ 1 & -1 & 0 \\ 0 & 1 & -1 \end{pmatrix}$$

For transformers with an earthed starpoint, a zero sequence current, created for instant during an external earth fault, could be introduced in the transformer, and since this current is not properly transferred from one side to the other, a false trip could be created. In order to avoid this situation, the zero sequence current, calculated by Equation 6, can be removed from the measured current in one or both sides of the transformer (Equation 7).

$$\mathbf{I_0} = \frac{\mathbf{1}}{\mathbf{3}} * (\boldsymbol{I_A} + \boldsymbol{I_B} + \boldsymbol{I_C})$$ Equation 6

$$\begin{pmatrix} \mathbf{IA'} \\ \mathbf{IB'} \\ \mathbf{IC'} \end{pmatrix} = \begin{pmatrix} \mathbf{IA} - \mathbf{I_0} \\ \mathbf{IB} - \mathbf{I_0} \\ \mathbf{IC} - \mathbf{I_0} \end{pmatrix}$$ Equation 7

The zero sequence current removal can be included in the matrix of Equation 5.. Tables with the matrices for phase compensation and optional zero sequence removal can be found in every manufacturer manual, as well as in “IEEE. Guide for Protecting Power Transformers”. Figure 34 shows the matrices of the relay RET670 of the manufacturer ABB.

	Matrix with Zero Sequence Reduction set to On	Matrix with Zero Sequence Reduction set to Off
Matrix for Reference Winding	$\frac{1}{3}\cdot\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix}$ (Equation 3)	$\begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix}$ (Equation 4)
Matrix for winding with 30° lagging	$\frac{1}{\sqrt{3}}\cdot\begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix}$ (Equation 5)	Not applicable. Matrix on the left used.
Matrix for winding with 60° lagging	$\frac{1}{3}\cdot\begin{bmatrix} 1 & -2 & 1 \\ 1 & 1 & -2 \\ -2 & 1 & 1 \end{bmatrix}$ (Equation 6)	$\begin{bmatrix} 0 & -1 & 0 \\ 0 & 0 & -1 \\ -1 & 0 & 0 \end{bmatrix}$ (Equation 7)
Matrix for winding with 90° lagging	$\frac{1}{\sqrt{3}}\cdot\begin{bmatrix} 0 & -1 & 1 \\ 1 & 0 & -1 \\ -1 & 1 & 0 \end{bmatrix}$ (Equation 8)	Not applicable. Matrix on the left used.
Matrix for winding with 120° lagging	$\frac{1}{3}\cdot\begin{bmatrix} -1 & -1 & 2 \\ 2 & -1 & -1 \\ -1 & 2 & -1 \end{bmatrix}$ (Equation 9)	$\begin{bmatrix} 0 & 0 & 1 \\ 1 & 0 & 0 \\ 0 & 1 & 0 \end{bmatrix}$ (Equation 10)
Matrix for winding with 150° lagging	$\frac{1}{\sqrt{3}}\cdot\begin{bmatrix} -1 & 0 & 1 \\ 1 & -1 & 0 \\ 0 & 1 & -1 \end{bmatrix}$ (Equation 11)	Not applicable. Matrix on the left used.
Matrix for winding which is in opposite phase	$\frac{1}{3}\cdot\begin{bmatrix} -2 & 1 & 1 \\ 1 & -2 & 1 \\ 1 & 1 & -2 \end{bmatrix}$ (Equation 12)	$\begin{bmatrix} -1 & 0 & 0 \\ 0 & -1 & 0 \\ 0 & 0 & -1 \end{bmatrix}$ (Equation 13)

	Matrix with Zero Sequence Reduction set to On	Matrix with Zero Sequence Reduction set to Off
Matrix for winding with 150° leading	$\frac{1}{\sqrt{3}}\cdot\begin{bmatrix} -1 & 1 & 0 \\ 0 & -1 & 1 \\ 1 & 0 & -1 \end{bmatrix}$ (Equation 14)	Not applicable. Matrix on the left used.
Matrix for winding with 120° leading	$\frac{1}{3}\cdot\begin{bmatrix} -1 & 2 & -1 \\ -1 & -1 & 2 \\ 2 & -1 & -1 \end{bmatrix}$ (Equation 15)	$\begin{bmatrix} 0 & 1 & 0 \\ 0 & 0 & 1 \\ 1 & 0 & 0 \end{bmatrix}$ (Equation 16)
Matrix for winding with 90° leading	$\frac{1}{\sqrt{3}}\cdot\begin{bmatrix} 0 & 1 & -1 \\ -1 & 0 & 1 \\ 1 & -1 & 0 \end{bmatrix}$ (Equation 17)	Not applicable. Matrix on the left used.
Matrix for winding with 60° leading	$\frac{1}{3}\cdot\begin{bmatrix} 1 & 1 & -2 \\ -2 & 1 & 1 \\ 1 & -2 & 1 \end{bmatrix}$ (Equation 18)	$\begin{bmatrix} 0 & 0 & -1 \\ -1 & 0 & 0 \\ 0 & -1 & 0 \end{bmatrix}$ (Equation 19)
Matrix for winding with 30° leading	$\frac{1}{\sqrt{3}}\cdot\begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix}$ (Equation 20)	Not applicable. Matrix on the left used.

Figure 34. Phase and zero sequence compensation matrices (Source:ABB RET670)

In the next block the differential current I_d and the restraint current I_r are calculated (Equation 8 and 9), and expressed in per unit value, taking as a reference the primary winding rated current.

$$I_d = \frac{|I1-I2|}{I1rated} \qquad \text{Equation 8}$$

$$I_r = \frac{1}{2} * \frac{(|I1|+|I2|)}{I1rated} \qquad \text{Equation 9}$$

The previous values are introduced in the curve block where they are both compare. The tripping settings are specified in this block. The errors to be considered are shown in Figure 17. Percentage differential protection. Errors. The error caused by the tap change could be removed by monitoring the position of the tap. It seems a feasible function to implement in the SASensor system since some taps are already controlled by this system. Considering the rest of the errors and the settings usually used in others relays analyzed, a setting curve for the differential transformer protection function is proposed (Figure 35). A typical value for Idmin is 0.2 times the nominal current In. For the slope a common value used is 0.25. Saturation of CTs is not considered, because of that there is not a second slope in the curve.

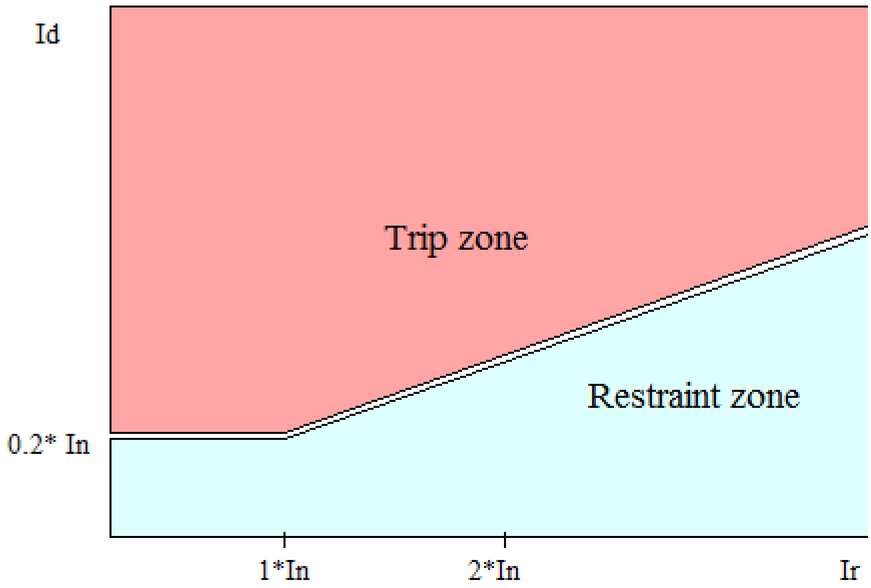


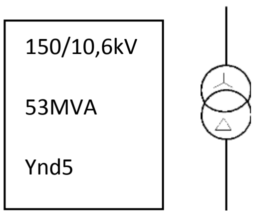
Figure 35. Tripping curve

This is the main part of the PTDF function. Possible problems due to inrush current or overexcitation are not considered.

Test Simulations

In order to test the algorithm of the proposed differential protection function before implementing in the SASensor system, the program for numerical computation Scilab was used. Scilab is similar to Matlab but it is open source.

The characteristics of the power transformer used in the test are:



This power transformer introduces a phase shift of 150°, which is useful to test if the phase shift compensation function works. Magnitude compensation is also tested since the transformer presents a ratio of 150/10,6 . Zero sequence compensation is not considered.

In Current winding1 (Blue) and winding2 (red) the currents in one of the phases, for the nominal power, in both sides of the transformer are shown. The blue signal represents the current in the high voltage side (150kV), the red one is the current in the low voltage side (10.6 kV). The simulated signals do not contain harmonics, only the fundamental component (50 Hz). It can be seen a different in magnitude, caused by the transformer ratio, and a phase shift between them (the red one lagged the blue one by 150°).

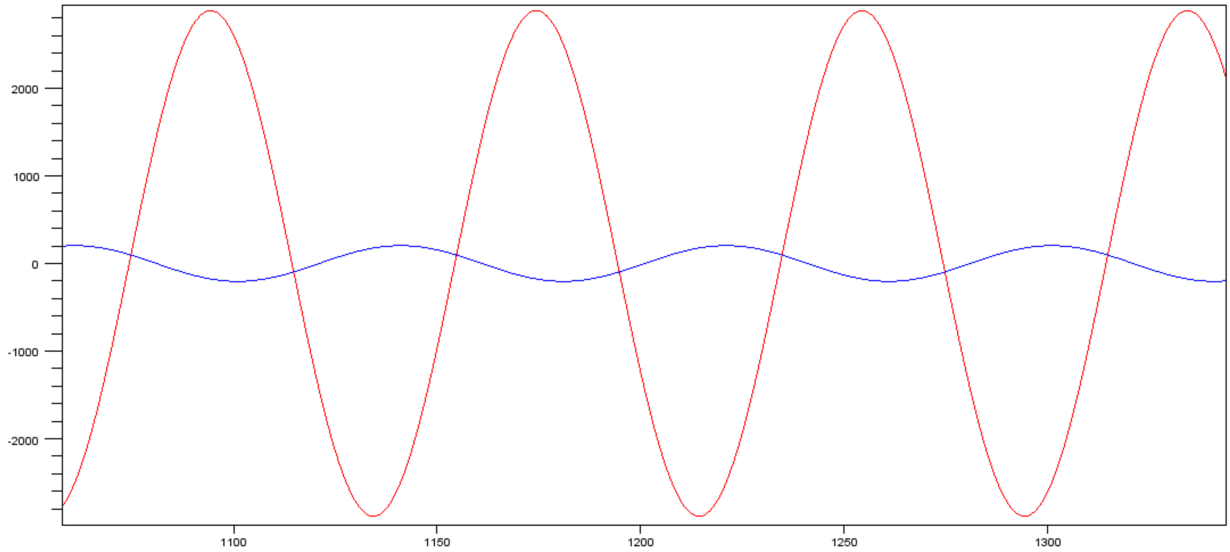


Figure 36. Current winding1 (Blue) and winding2 (red)

The result after magnitude compensation is shown in Figure 37

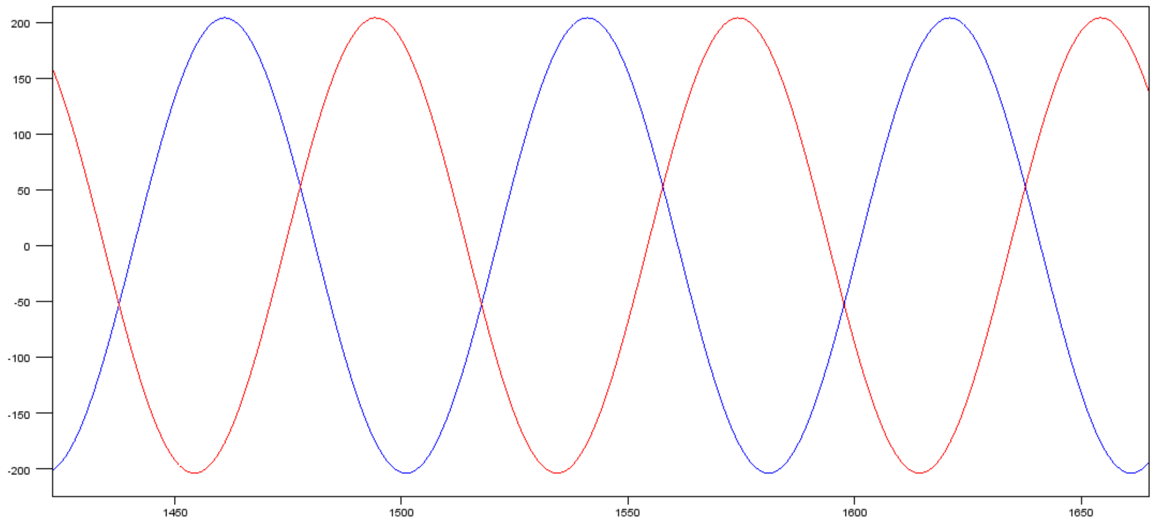


Figure 37. Magnitude compensation

The result of using magnitude and phase compensation is shown in Figure 38. Both signals appear overlapped so the blue signal cannot be seen.

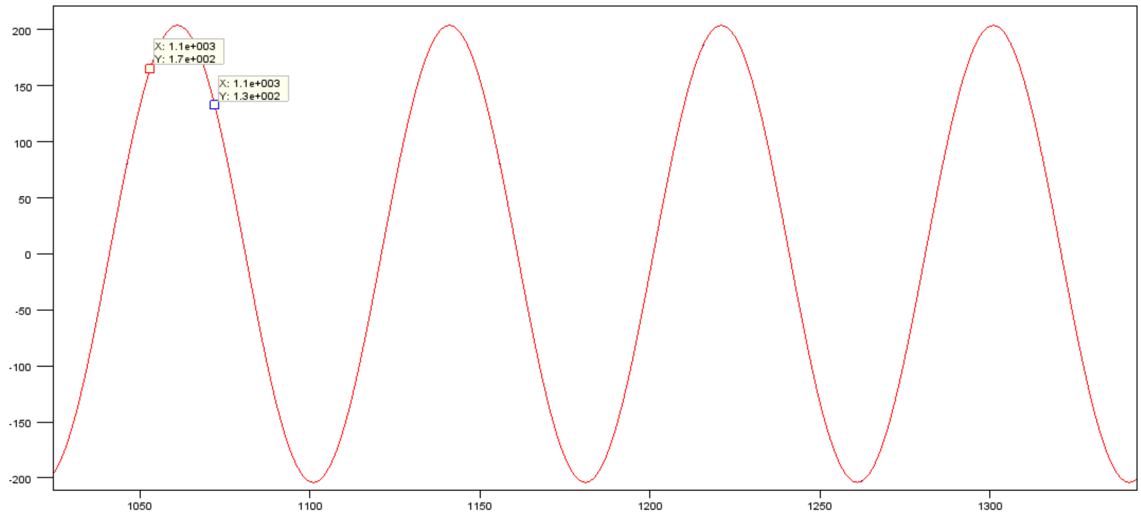


Figure 38. Magnitude and phase compensation

Once the magnitude and the phase are compensated, the differential and the restraint current can be calculated. The primary side nominal current is taken as a reference to use per unit values. In this case 204 amperes.

In Figure 39 it is simulated an internal fault. In the upper graph of this figure it is represented the current in one side of the transformer (high voltage side), the graph in the middle represents the compensated current in the secondary side of the transformer (low voltage side). The graph below represents the restraint current (Ir, green signal), differential current (Id, blue signal), and operate signal (tripping signal, red). For the value of the restraint current in this example, the relay is working in the first zone, when the differential current is higher than the set value (0.2), a trip signal is generated. It can be seen that there is a delay in generating the trip signal, this delay of 30 ms is used in the actual overcurrent protection application in the SASensor system. 20 ms are necessary for the filter to give a trustful value; 10 ms are added to cope with some special signals that could mislead the relay.

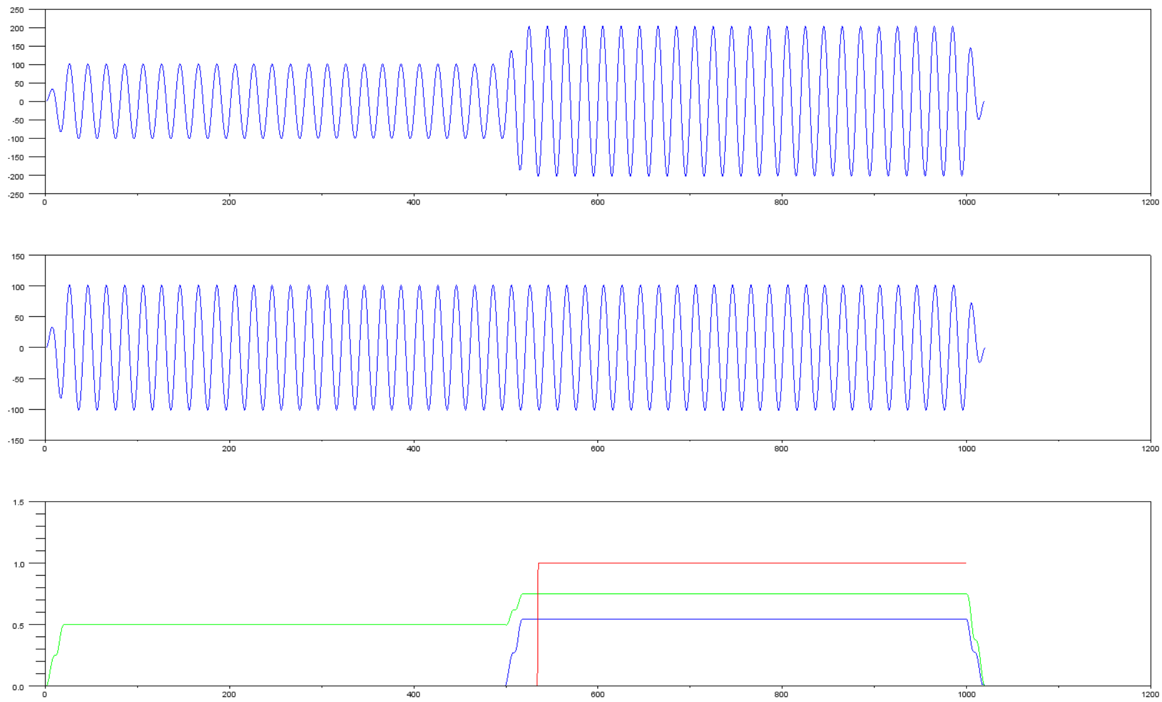


Figure 39. internal fault 1st zone

In Figure 40 it is represented the behavior of the relay when working in the slope zone (2nd zone). It can be seen that before the fault, the current trough the transformer is higher than in the case of Figure 39, this time the current is 1.5 times the nominal current. This situation decreases the sensibility of the relay to cope with errors that could cause a false trip. A trip signal (red) is generated when the differential current (blue) is above the settings

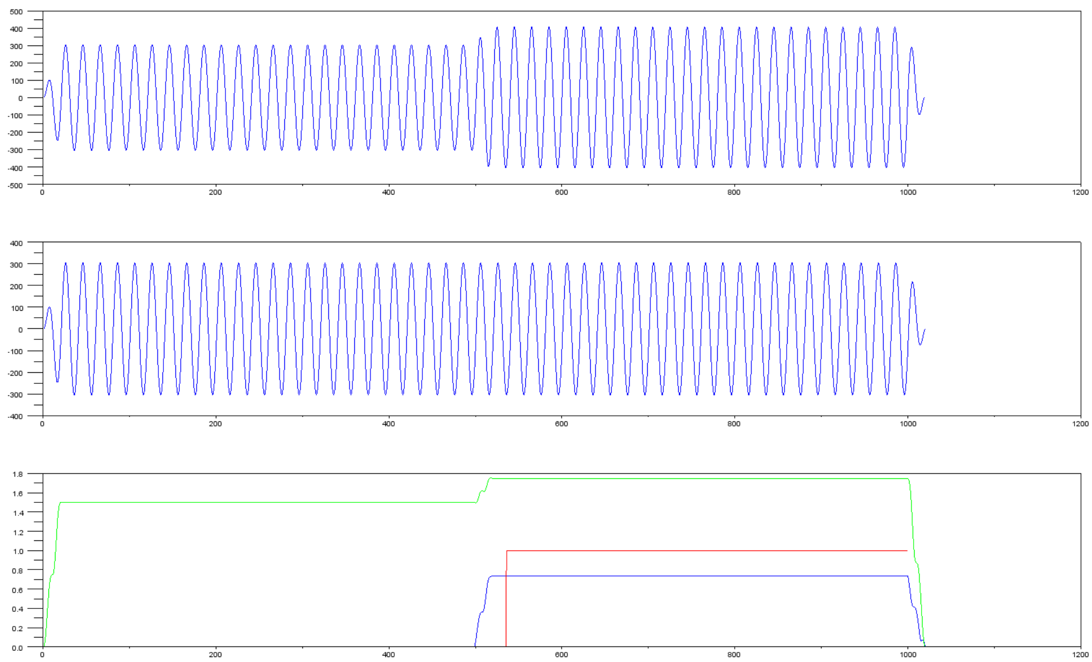


Figure 40. Internal fault 2nd zone

Setup screen in SASensor system

One part of the implementation of the differential transformer protection function in the SASensor system is the creation of a setup screen to introduce the settings in the system. To make this screen, html, css and javascript languages were used.

The necessary settings to configure the differential protection for power transformers are:

- Information about the power transformer.
  - Rated power
  - Rated primary winding voltage
  - Rated secondary winding voltage
  - Vector group

53MVA

150/10,6kV

Ynd5

- Tripping settings
  - Idmin, differential current 1st sector
  - End1, restraint current value, end of the 1st sector
  - Slope1, slope 2nd sector

0.2 In

1.0 In

25%

In Figure 41 it is shown the setup screen created to introduce the settings of the differential protection function.

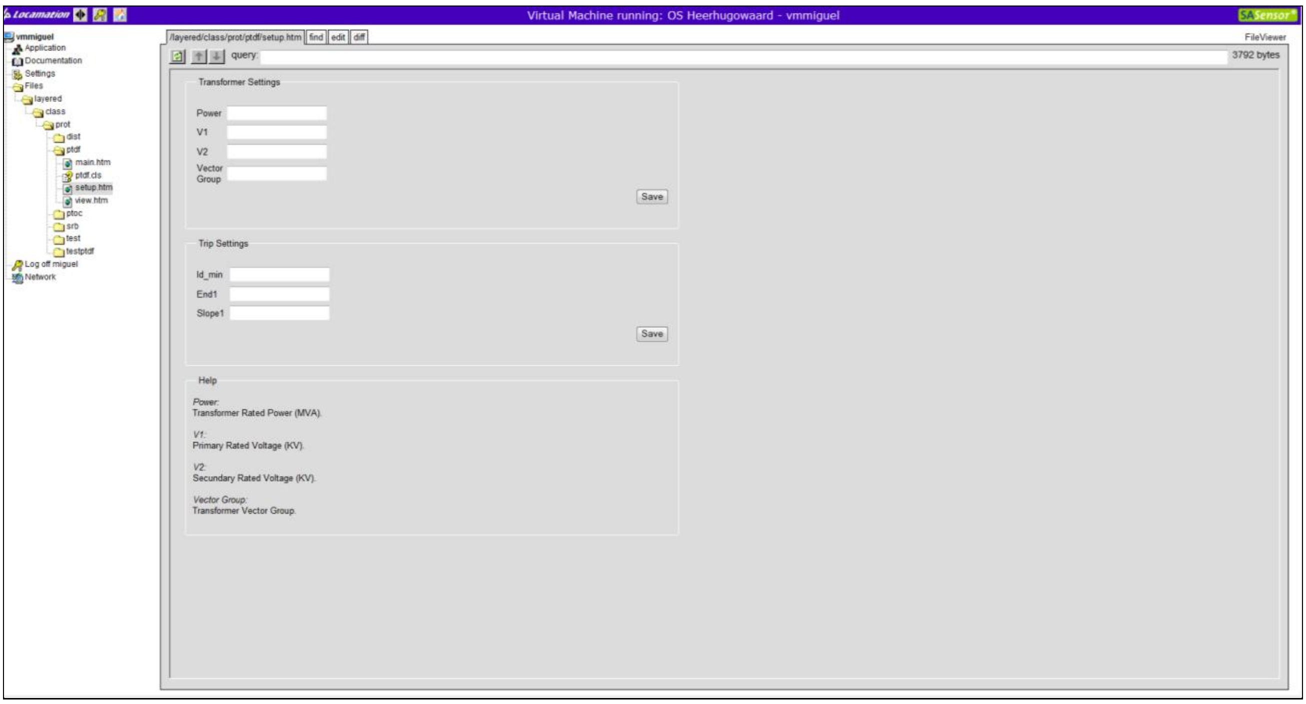


Figure 41. Setup screen PTDF

Power differential protection

The most common used differential protection relay for power transformers is based on the comparison of the vector current in both sides of the transformers. All the relays found on the market use current differential protection. But it may have some advantages to compare the energy or the power instead of the current. When comparing the currents it is necessary first to compensate the magnitude and a possible phase shift, which is not needed in the case of power differential protection. Other advantage is that the tap change of the transformer does not influence in the power value.

As stated before, no products were found on the market based on power comparison, only some research papers. Maybe the main reason is the necessity of measure the voltage in both sides of the transformer. In many installations it is only possible to measure the voltage in the secondary side and not in the primary.

Protection applications in the SASensor system present some differences comparing with commonly used protection relays. The system architecture introduces more functionality, all the data collected in different points of the installation can be used in one protection algorithm, and this is not possible in the '' all in one box'' relays. With this extra functionality it may be possible to introduce alternatives solutions with better performances than the ones used nowadays. And then it can be worth it to research new protection alternatives like power differential protection.

Transformer Modeling

In order to create an algorithm to protect a power transformer against internal faults, it would be very useful to have a model of the transformer in which simulate internal and external faults, inrush current, etc..., and test the algorithm within this model.

There are plenty of research papers and literature about modeling electrical systems like a power transformer. There are also different programs to create and simulate an electrical model, such as Matlab/Simulink with the special library Simpower, Scilab, ATP (Alternative Transient Program), etc... These programs can simulate the electromagnetic transient behavior of an electric system.

Interesting for modeling physical systems is the Modelica language. This is a non-propietary, object-oriented, equation based language to model complex physical systems, such as electric systems. Some modelica simulation environments are available free of charge, such as OpenModelica. [4] [5]

Conclusions and Recommendations for future work

Current differential protection is the commonly use method to protect power transformers against internal faults. A deep research into this type of protection, including products on the market and also different research papers, was made as the first step in this assignment. Based on this research a differential protection function has been proposed.

The main part of the function was implemented and tested in Scilab. It was shown how the function compensates the magnitude and phase shift, necessary tasks before comparing the currents. The tripping algorithm is based on the comparison of the differential current and a restraint current, in order to cope with problems caused by high currents through the protected zone.

One interesting function to include in future works is the monitoring of the tap change of the transformer. The transformer ratio value changes as the tap moves from one position to other. If this new value is known in the system it could be introduced in the protection function, avoiding introducing the error caused by the tap change, and so making the relay more sensitive.

The influence of the inrush current in the differential protection function has been analyzed. The introduction of a function to detect the inrush current is necessary. The 2^{nd} harmonic detection has been widely used among manufacturers for many years. In order to use this method it is necessary to create a 100Hz filter in the system to get the 2^{nd} harmonic component.

If the power transformer can suffer overvoltage or underfrecuency situations it is necessary to include a method to detect these situations. The 5^{th} harmonic detection is the most common used method. In this case a 250Hz filter has to be included in the system.

Current differential protection is the method normally used. All the products found on the market use this method. Nevertheless, researching on alternative solutions, like power differential protection, that could improve the performances of conventional relays, is a possible line to work in the future.

A dynamic model of a power transformer, with the possibility of simulate internal faults, would be necessary to understand more accurately the behavior of the transformer during fault situations. This would help to develop an alternative and innovative solution that could stand out of the common relays.

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