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APPLICATION OF μPMUS ON LV NETWORKS

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Resumen

En los últimos años, el sistema eléctrico ha sufrido numerosos cambios que han hecho necesario hacer más inteligentes las redes eléctricas. Un claro ejemplo de esto es el sistema eléctrico de baja tensión, que con la inclusión de generación distribuida ha hecho que el sistema de baja tensión tenga flujos de potencia bidireccionales y por lo tanto es necesario tener información en tiempo real sobre el estado del sistema debido a los desafíos. planteados por estos flujos direccionales. Estos flujos direccionales producen numerosos desafíos para el DSO del sistema. Algunos de estos desafíos son la posibilidad de que haya operación en isla en el sistema, picos de tensión por generación distribuida y un mayor efecto por las faltas producidas en el sistema. Por tanto, es necesario contar con métodos que, basados en el mayor número de medidas disponibles, puedan identificar y localizar faltas de baja tensión de manera rápida y eficiente. Para lograrlo, se ha considerado la inclusión de numerosas tecnologías en el sistema.

Uno de ellos es el PMU. Esta tecnología destaca por poder obtener los fasores de tensión y corriente, logrando medidas exactas que no fueron fáciles de obtener, como los ángulos de cada fase. Esta tecnología es capaz de monitorizar grandes áreas del sistema, lo que significa que es posible gestionar las medidas de varias unidades PMU separadas por grandes distancias y seguir obteniendo medidas en tiempo real. Las comunicaciones entre las PMU y las unidades que recolectan los datos se pueden realizar a través de diferentes tecnologías, se espera que se utilice tecnología 5G para esta función debido a todas sus propiedades de rápida transmión de datos. Las μPMU son realmente útiles en el sistema de distribución donde la diferencia de ángulos entre los diferentes buses del sistema es mínima. Existen varios tipos de PMU, cada una de ellas tiene propiedades diferentes en función de la función que realiza para el sistema: operación en isla, monitorización del sistema, etc. Se han diseñado PMU específicas para la red de distribución. Estas PMU denominadas μPMU destacan por ser capaces de realizar las funciones de una PMU genérica (monitorización del sistema, detección de islas, etc.) y tener una mayor precisión en sus medidas de los ángulos del sistema. Esto es realmente útil en el sistema de distribución donde la diferencia de ángulos entre los diferentes buses del sistema es mínima. Hasta ahora no se había pensado en incorporar μPMU en el sistema de bajo voltaje y por lo tanto no existen métodos para localizar faltas usando μPMU.

En el sistema de baja tensión, las faltas más comunes son faltas fase-tierra, aun así, ocurren todas las faltas posibles. Los cables de esta parte del sistema suelen estar enterrados y las averías suelen deberse a problemas en el aislamiento o a que un animal rompe uno de los cables. Esto hace que sea necesario localizar el lugar exacto donde se ha producido la avería porque no es posible reconocer el lugar exacto donde se ha producido una avería por parte de equipos externos. Esta parte del sistema no se ve tan afectada por fenómenos externos como las tormentas. Un factor muy importante a considerar es conocer la cantidad de PMU que se utilizarán y su ubicación. Dependiendo de la función de la PMU dentro del sistema, se debe utilizar un número diferente de PMU. Para la localización de faltas, el número de PMU utilizadas y su ubicación depende completamente del método utilizado. Hay métodos que necesitan PMU en prácticamente todos los nudos del sistema y otros métodos necesitan un número mucho menor de PMU.

Debido a las propiedades de las mediciones de μPMU, se pueden aplicar varios métodos para la ubicación de faltas, estos métodos difieren entre sí debido a sus propiedades. Algunos de los métodos más populares para la localización de faltas usando PMU son los métodos basados en inteligencia artificial y los métodos de medición escasa. Luego de analizar los posibles métodos, se decidió aplicar métodos que, con base en las mediciones, permitirían realizar estimaciones estatales. En este proyecto, se han implementado dos métodos para localizar faltas basados en estimadores de estado. La principal diferencia entre ambos métodos radica en la cantidad de μPMU utilizados. El primer método utiliza una cantidad de PMU que permite tener una observabilidad total del sistema, esto permite realizar varias estimaciones en paralelo. La selección de la línea donde ocurrió la falla se basa en elegir la línea con los residuales de medición ponderados más bajos. El segundo método utiliza el número mínimo de μPMUs necesario para localizar las faltas, funciona realizando un proceso iterativo de estimadores de estado en base a las diferentes medidas de la PMU. Este proceso iterativo se lleva a cabo hasta que el estimador de estado de las diferentes medidas converge en el lugar de la falla. Ambos métodos han sido probados simulando diferentes faltas en varios puntos de un sistema de baja tensión con 14 buses obtenidos de SPEN. Cada método ha podido localizar las faltas con resultados muy precisos. La implementación de estos métodos en el sistema eléctrico de baja tensión podría ayudar a reducir algunos indicadores de desempeño de los DSO como el CML y por lo tanto aumentar los beneficios del DSO y hacer que los clientes estén más satisfechos.

Abstract

In recent years, the electrical system has undergone numerous changes that have made it necessary to make electrical grids more intelligent. A clear example of this is the low voltage electrical system, which with the inclusion of distributed generation has made the low voltage system have bidirectional power flows and therefore it is necessary to have information in real time on the status of the system due to the challenges posed by these directional flows. These directional flows produce numerous challenges to the DSO of the system. Some of them are the possibility of island operation in the system, voltage peaks due to distributed generation and a greater effect due to faults produced in the system. Therefore, it is necessary to have methods that, based on the largest number of measurements available, can identify and locate low voltage faults quickly and efficiently. To achieve this, the inclusion of numerous technologies in the system has been considered.

One of them is the PMU. This technology stands out for being able to obtain the voltage and current phasors, achieving exact measurements that were not easy to obtain, such as the angles of each phase. This technology is capable of monitoring large areas of the system, which means that it is possible to manage the measurements of several PMU units separated by great distances and continue to obtain measurements in real time. Communications between the PMUs and the units that collect the data can be done through different technologies, it is expected that 5G technology will be used for this function due to all its properties. The μPMU are really useful in the distribution system where the difference in angles between different buses in the system is minimal. There are number of types of PMUs, each one of these has different properties depending on what function it performs for the system, island stopping, system monitoring, etc. Specific PMUs have been designed for the distribution network. These PMUs called μPMUs stand out for being able to perform the functions of a generic PMU (system monitoring, island detection, etc.) and have greater precision in their measurements of the system angles. This is really useful in the distribution system where the difference in angles between different buses in the system is minimal. Up to now there has not been thought to incorporate mu PMU in the low voltage system and therefore there are no methods to locate faults using muPMUs.

In the low voltage system, the most common faults are phase-ground faults, even so, all possible faults occur. The cables in this part of the system are usually buried and the faults are usually caused by problems in the insulation or due to an animal breaking one of the cables. This makes locating the exact place where the fault has occurred is necessary because it is not possible to recognize the exact place where a fault has occurred by external equipment. This part of the system is not so affected by external phenomena such as storms. A very important factor to consider is knowing the number of PMUs to be used and their location. Depending on the role of the PMU within the system, a different number of PMUs must be used. For fault location the number of PMUs used and their location depends entirely on the method. There are methods that need PMUs in practically all the buses of the system and other methods need a much smaller number of PMU.

Due to the properties of the μPMU measurements, various methods can be applied for fault location, these methods differ from each other due to their properties. Some of the most popular methods for fault location using PMU are the methods based on artificial intelligence and the scarse-measurement methods. After analysing the possible methods, it was decided to apply methods that, based on the measurements, would be possible to make state estimates. In this project, two methods have been implemented to locate faults based on state estimators. The main difference between both methods lies in the number of μPMUs used. The first method uses a number of PMUs that allows to have a total system observability, this allows to perform several estimates in parallel. The selection of the line where the fault has occurred is based on choosing the line with the lowest weighted measurement residuals. The second method uses the minimum number of μPMUs necessary to locate the faults, it works carrying out an iterative process of state estimators based on the different measurements of the PMU. This iterative process is carried out until the state estimator of the different measurements converge at the fault location. Both methods have been tested by simulating different faults in various points of a low voltage system with 14 buses obtained from SPEN. Each method has been able to locate the faults with very accurate results. The implementation of these methods in the low voltage electrical system could help to reduce some performance indicators from the DSOs as the CML and therefore increasing the benefits of the DSO and making customers more satisfied.

To my mother, for always being there when I have needed her
and being a fundamental pillar for me.

Benjamin Franklin may have discovered electricity,
but it was the man who invented the meter who made the money.
EARL WILSON

Rocks in my path? I keep them all.
With them I shall build my castle.
NEMO NOX

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Acronyms

PMU	Phasor Measurement Unit
DNO	Distribution Network Operator
DSO	Distribution System Operator
WAMS	Wide Area Monitoring Systems
SCADA	Supervisory Control And Data Acquisition
DG	Distributed Generation
DER	Distributed Energy Resources
SE	State Estimator
LWLS	Linear Weighted Least Squares
CI	Customer Interruptions
CML	Customer Minute Lost
GPS	Global Positioning System
PDC	Phasor Data Concentrator
SDC	Super Data Concentrator

PART I

MEMORY

Chapter 1

Intro

SYSTEM reliability and resilience are major goals of the modernization and creation of a smarter grid. The distribution network in recent years has undergone certain changes that have changed its traditional mode of operation. Among the most prominent are the inclusion of renewable electricity generation sources, smart meters, distributed generation, among others. Many of these changes are influenced by concern for the environment and the aim is to reduce the damage that can be caused by electricity generation in the environment [1].

Historically, the low-voltage distribution network was designed for a one-way power flow, which consisted of the energy that came from the transmission system to the consumers. The inclusion of solar panels and other renewable generation sources such as cogeneration has made it necessary to monitor and control the low voltage grid.

There are numerous methods used for locating medium voltage faults, but regarding the low voltage grid, not many methods have been developed. These are due to the fact that the low voltage grid has certain differences with respect to the medium voltage network that makes more difficult to develop it. Some of the most notable are:

- System loads distributed unevenly.
- The system is usually unbalanced making it necessary to consider each phase separately.
- Until recently, limited number of measurements, making monitoring difficult.

The inclusion of methods to detect faults in LV is necessary, it will help to reduce the outages time, this is necessary because the power outages cause immersive amount of annual economic losses in every country, the cost of each outage increases with duration, making necessary to reduce fault duration as much as possible. Automated fault location systems have the potential to reduce outage time and costs to customers by allowing for fast and efficient deployment of repair crews. The main problems related to these outages is that they usually occur on the distribution system, where the cost of undergrounding or heavily instrumenting every feeder also becomes very high. An effective fault location system should be accurate enough to direct maintenance crews directly to the point of the fault and be cost effective such that significant investments are not required to enable the system [2].

The protection system has been developed for each part of the grid and it can be very complex and can differ according to its characteristics. A variety of devices, like breakers, relays, Remote Terminal Units (RTUs), Phasor Measurement Units (PMUs) etc. are deployed for the protection of the grid. The goal is the minimization of the CI (Customer Interruptions) and CML (Customer Minutes Lost), CI being the number of customers interrupted of the electricity provider when an outage occurs and CML being calculated with the product of CI and minutes of outage, of the least amount of costumers, when a fault occurs. The last part can be achieved with the correct cooperation of the protection devices [1]. Since, almost in their entirety, most of the changes of the electric system are taking place in the distribution network, that is the field with the most challenges and opportunities for innovation as well. The most important parts in a distribution grid are the power lines, that can be overhead or underground, the power transformers regulating the voltage level, the bus bars and the various protection devices [1].

Non financial key performance indicators								
P.I	**A. 2019**	**T. 2019**	**A. 2018**	**T. 2018**	**A. 2017**	**T. 2017**	**A. 2016**	**T. 2016**
D.G (GWh)	17.003	N/A	17.547	N/A	17,749	N/A	18,181	N/A
CI	49.3	51.1	41.3	51.6	42.9	51.9	48.5	52.1
CML	35	43.3	31.2	44.8	29.3	45.7	34.8	46.2

Table 1. Non financial key performance indicators from Scottish Power per year

Automatic fault location on the distribution system is an increasing necessity for a resilient grid with fast service restoration after an outage. Motivated by the development of low cost synchronized voltage phasor measurement units (PMUs) for the distribution system, the PMU data stream that can be used for a variety of applications, making it easier to justify the investment in fault location. The accuracy of existing automatic fault location techniques are dependent either on dense deployments of line sensors or unrealistically accurate models of system loads [2].

1.1. DNO vs DSO

The inclusion of PMUs in the distribution network will allow the distribution system operator (DSO) to manage the distribution network in a more optimal way. The DSO (in European countries except UK) is the generic term used for a company that performs a role equivalent to that of a distribution network operator (DNO) in the UK, but it does not necessarily mean they are “smart". The DNOs, from a British perspective, are the companies licensed to distribute electricity. The DNOs are used to distribute electricity in the traditional electrical distribution systems which were not designed with current technologies in mind. This makes that the traditional DNOs have a distribution model focused on the distribution of energy in a directional sense, with an emphasis on upstream and downstream.

The DSO, in the UK, is integral to its meaning. DSOs will have greater visibility and control of assets on their distribution systems, enabling them to get the most from their existing electrical infrastructure by contracting services from distributed energy resources. In this way, they can optimize the existing distribution system thus achieving that it is not necessary a costly network reinforcement. With the inclusion of new technologies they move away from the traditional redundancy-based model of energy systems. In other words, the DSOs have the same obligations and objectives as the DNOs, but with technological improvement they are able to adapt to the new challenges of the electrical system. In the figure below, the main applications of the DSO are shown.

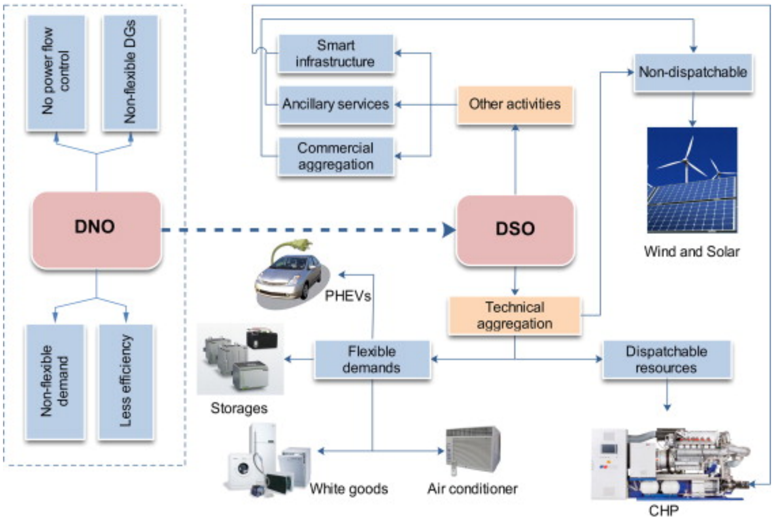


Figure 1. Evolution from DNO to DSO

Regarding their use in the market, DSOs will have numerous applications. Rapidly increasing numbers of connection requests from renewables developers and other low carbon generation technologies with variable outputs are creating technical challenges for DNOs. The evolution to DSO will allow to rapidly increase the requests of renewable generators and other energies with low carbon emissions that their integration into the system (e.g. DER) pose numerous technical challenges for the DNO. This integration of renewable energy sources is beneficial for society, since due to the electrification of society in many fields (replacement of gas boilers with electric boilers) an increase in electricity demand is expected. The integration of these renewable energies will reduce the country's CO_2 emissions. Also the electrification of the society will increase the interaction between the energy, transport and waste sectors. There will be also a need to allow incentives to emerge to enable customers to save money through active participation (e.g. Demand Response). This means DNOs can no longer remain passive when it comes to managing the energy flows on their systems.

The active network management (ANM) will be the cornerstone of the transition to DSO and it is technology largely proven although two key areas still require development. First, the standardisation of solutions and the interface with communication networks to enable innovation. This will also have the effect of reducing the implementation cost for these solutions, driving further efficiency. Second, more advanced optimisation tools, software and data management methods will be required to provide a number of axes of optimisation[75].

Regarding the transition from DNO to DSO, it depends on each DNO. SPEN wants to transition towards becoming a full DSO. This will facilitate an open and inclusive balancing services market at the transmission/distribution interface. Being a DSO will also allow to the efficient balancing of the local system thanks to the distribution network. The use of DERs will be aggregated into virtual power plant (VPP) or virtual balancing mechanism units (VBMUs), which will interface with the system operator to act on balancing instructions. To do this, it will be necessary to have a market for this aggregation, which will demand the development of a mechanism for the remuneration to the DERs due to the services they provide to the system. SPEN says this approach will be critical to ensure that the market is prepared for the emergence of new participants[75].

Another task that will do the DSO is to balance the local distribution network, making effective use of the existing distribution network and, where it is practical to do so, matching local generation with local demand. To achieve this, DER should be promoted to increase its use, Demand Response programs should also be applied to achieve more uniform load curves. The increased information on system use will also act as an investment driver, identifying where further network reinforcement is necessary, thus optimizing the system. The new model of the distribution system will be capable of enacting system balancing actions from the system operator within timescales that best meet the needs of the system operator and the capabilities of the DERs connected throughout its network areas.

It is known that there are several models that could work to balance the distributed generation, but they have in common that they all need an overall coordination from a central position. The UK government, while actively considering all the possible options, they are exploring on how an increasingly independent system operator might work, the government has also said that overall control does not necessarily have to be awarded to one operator, and a more collaborative approach could be employed. It will be useful that the industry come to a resolution quickly as there have already been warnings about the ongoing tensions holding back the ancillary services market. The option of imposition is due to the fact that there are certain precepts that must be complied with and it may not be convenient for certain companies in the electrical industry. For example, Flexitricity spoke up at the LCNI market to warn delegates that the wish of the DSR market to be allowed to have a continuing relationship with the transmission market should not be ignored [75].

The desire of many companies like SPEN of transitioning towards becoming a full DSO is to be able to facilitate an open and inclusive balancing services market at the transmission/distribution interface, while also carrying out local system balancing to efficiently utilise the distribution network. The DSO model will be capable of enacting system balancing actions from the SO within timescales that best meet the needs of the SO and the capabilities of the DERs connected to our network areas. SPENs transition to a DSO will be both modular and proportionate.It will work with key stakeholders to develop and implement a fair and cost effective remuneration mechanism for all DSO services and DER providers. SPEN will undertake trials in two areas. Dumfries and Galloway and Mid and North Wales will be undertaken to test the DSO model and inform its future form. Key policy changes will be necessary to allow the remuneration process for DSOs and enable them to procure services for subsequent re-sale. A decision on whether or not DSOs will be able to own and operate storage DER resources is also needed.

All the changes that the electrical system undergoes, makes certain areas of the system such as the low voltage system will have more importance within the electrical system. Due to this, it will be necessary to increase investments in the low voltage network. With this, it will be possible to have a better control of power flows and in the event of faults, the DSOs will be able to locate them quickly and efficiently, making consumers satisfied.

1.2. Overview of Phasor Measurement Units

PMUs (Phasor Measurement Unit) is a relatively new technology. Due to its properties and possibilities, studies have been carried out on its possible applications in the electrical network. This technology can measure the voltage and current phasor, the frequency with its variations in real time. All data obtained by the PMU is precisely synchronized to a common time reference for all PMUs. The reference is obtained thanks to the GPS. This technology allows real-time monitoring of the system and also increases reliability. In summary, the use of this technology allows us to have a real-time knowledge of the state of the system and allows the system operator to act more quickly in the face of any unexpected event.

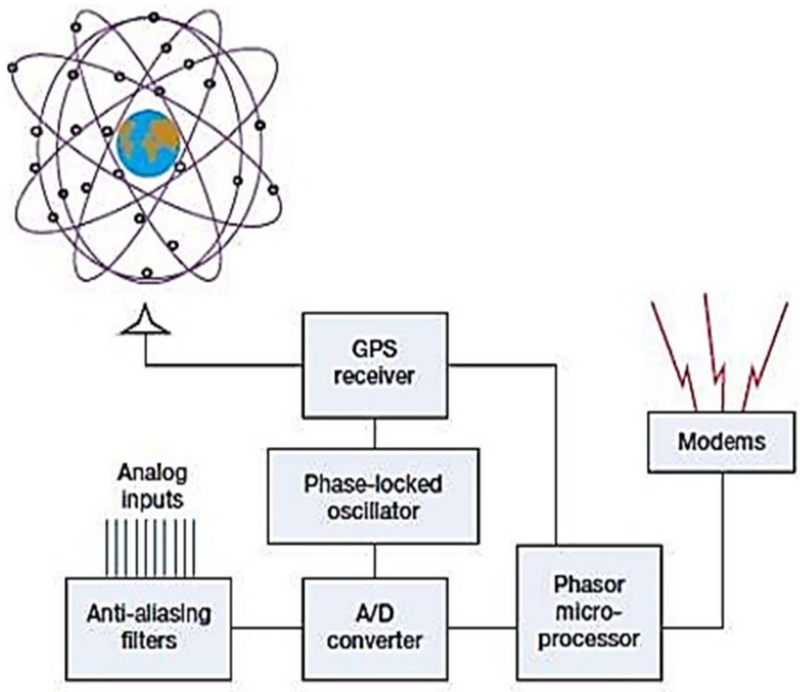


Figure 2. Diagram regarding μPMU [1].

Figure 2 shows the block diagram of the PMUs. This diagram serves to understand the operation of these devices. The analog inputs (the voltage considering each of its phases, current considering each of its phases) are filtered by the anti-liasing filters to avoid aliasing. The outputs of the anti-aliasing filters are collected by an analog to digital signal converter (ADC). These conversions are made at a rate of 100 samples per cycle. Sampling clocks of the ADC are phase-locked to a 1OOS signal of GPS. This means that every second the GPS clock sends a pulse and the phase locked oscillator splits the pulse into a sequence for the ADC sampling. After the ADC has converted the analog signal to a digital one. Then, digital data is sent to a microprocessor which makes the input waveform with DFT algorithms and is able to compute the voltage and current phasors, frequency, ROCOF, and binary information. The PMU gives the phasor data according to the IEEE standard 1344 [10]. The data transmission is done thanks to ethernet or PDC.

The PMU gives the phasor data according to the IEEE standard 1344 [10]. The data transmission is done thanks to ethernet or PDC. The phasor data in a format defined in IEEE standard 1344 are transmitted upstream over Ethernet (TCP or UDP) to PDCs. The most basic function of the PDC is to collect or receive phasor measurements from connected PMUs and to sort them according to the GPS time stamp. Once a time stamp set is complete the PDC forwards the phasor set to the Super PDC. The PDC can also have other functionality, such as error checking and archiving for offline and historical data analysis. PDCs should have storage capability to buffer data for a short time period to allow data alignment and other vital tasks.

The standards regarding the PMUS are: The IEC 61850 standard for the PMU interface, THE IEEE standard C37. 244-2013 is for the requirements of PDC communication and EEE standard C37.242-2013 are the guidelines for testing the installation of the PMU [58].

The algorithms used by PMUs are based on the Discrete Fourier Transform (DFT). To minimize the impact of quantization to calculate the angle, signal processing techniques are used in each of the cycles. It should be noted that the measurements of both the voltage and current phasor and the frequency measurement are very accurate when the system is stable. On the other hand, when the system is in a transient state or with non-nominal frequencies (50 or 60 Hz) there may be serious errors in its measurements. The error in the measurements depends on the differences in the algorithm used to calculate the current and voltage. This algorithm is different for each manufacturer. This is because the signal processing is not included in any of the standards related to PMUs, giving freedom to each manufacturer to develop their own. [58]

This technology has gained popularity due to the fact that is able to do real time measurements in a wide area, when there is measurement system that incorporates PMUs over large distances of the power system. Wide Area Monitoring System (WAMS). Phasor Data Concentrators (PDC) to collect the information and a Supervisory Control And Data Acquisition (SCADA) system at the central control facility. Such a network is used in Wide Area Measurement Systems (WAMS),

The PMUs together with the infrastructure that allows the transit of information, communication and the instrumentation infrastructure is known as SMT, Synchrophasor Measurement Technology. The SMT supposes numerous benefits for the system [57]. These include:

- Voltage and current phasor (magnitude and angle) are obtained in real time, 2880 samples per minute.
- Scattered area measurements can be synchronized thanks to the GPS reference.
- Some measurements as voltage angles are directly measured.

In the late 1990s, systems began to be developed that allowed this technology to be used in large-scale electrical systems. In the last few years, several countries have installed or developing PMUs on their electrical systems due to all the advantages it can provided to the system [57].

The PMU installed in the power systems are mainly used in transmission lines. This is because the synchrophasors are used to monitor grid stability on high voltage transmission systems. It is one of the protections that helps with the fault detection, however PMUs are not generally used in distribution grids. The PMUs are one of the protections use for detection of the fault, this allows that when there is a fault, the system is able to detect it, and a signal is sent to the operational center of the distribution system operator (DNO). The detection of the fault activates a protocol for the restoration of the normal operation of the grid. This process consists in the location of the fault, after is located it must be isolated so it can be repaired. Currently the greatest challenge from a technological point of view, is the fault location. There are many approaches for the fault location, some DNO still follow an outdated model of action concerning the repair of faults, which includes the location of the exact point of the fault through the visual inspection of the whole line by a technical crew, and then its repair. This is slow and not efficient because it slower due that it can be a problem in locating the fault. Due to this and thanks to the advancements of technology and the upgrade of the infrastructure of the network, many novel fault location methods have been developed, which are capable of automatically locate the fault, saving, thus, time and money [22].

There is a great variety of other methods that can be used to detect faults thanks to the PMU. Such methods such as the ones based on the voltage sag caused by the fault, or the hybrid ones that combine the advantages of several techniques to achieve better results will be explained later in its corresponding section. The selection of the method depends on the application, thus, among others, the type of the network, the available equipment, the speed and the accuracy required, the cost-profit analysis etc. The implementation of a new protection in the network it is not an easy task. There are several technical and economic challenges that must be analysed, regarding the micro PMUs there are several challenges that must be faced [13].

Some of the most representative are:

- New technology, it is not totally developed
- Small angle differences between nodes of the network.
- More measurement points
- Limited investment
- Grid not homogenous
- Fragmented comms infrastructure, provoking increased latencies
- The grid is generally poorly modelled

1.2.1. Phasor Representation

A pure sinusoidal waveform can be represented by a unique complex number known as a phasor. A phasor is defined as a vector representation of the magnitude and phase angle of an AC voltage waveform. Considering a sinusoidal signal x(t):

$$x(t) = X_m\, cos(\omega t + \varphi) \tag{1}$$

where X_m is the signal magnitude, $\omega = 2\pi f$, where f is instantaneous frequency and ϕ is the initial phase of the signal, its synchrophasor representation is:

$$X = \left(\frac{X_m}{\sqrt{2}}\right) e^{j\varphi} \tag{2}$$

$$X = \left(\frac{X_m}{\sqrt{2}}\right) (cos(\varphi) + jsin(\varphi)) = X_r + \mathrm{jX}_i \tag{3}$$

where X_r and X_i are real and imaginary components of the complex phasor representation, $\left(\frac{X_m}{\sqrt{2}}\right)$ is the RMS value of the signal and ϕ is its instantaneous phase angle relative to a cosine function at nominal system frequency synchronized to UTC. The phase angle of the phasor is arbitrary, as it depends on the choice of the axis t = 0 [10]. In this case is defined to be 0º when the maximum of x(t) occurs at the UTC time instant. The phasor representation of a sinusoid is independent of its frequency. As actual frequency is not exactly nominal the phasor recorded seems to be rotating with a relative frequency given by the difference between actual frequency and nominal one.

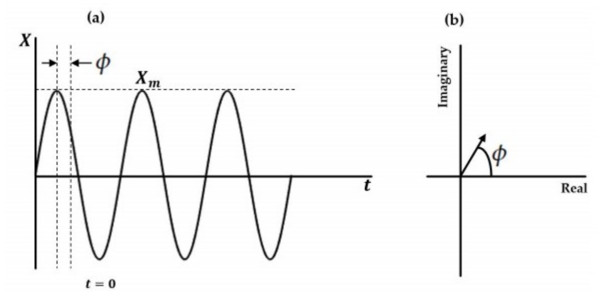


Figure 3. (a) Sinusoidal waveform; (b) phasor representation.

1.2.2. Fault detection

Protective devices on distribution circuits are generally based on overcurrent relays that respond to a combination of current magnitude and duration. This makes it very difficult to detect high-impedance faults, where the fault current is similar in magnitude to load current. Furthermore, once a fault is isolated, its exact location is difficult to determine remotely [6].

The actuation of a particular circuit breaker or fuse only identifies a general section of a feeder where the fault has occurred. The standard approach then is for line crews to physically patrol the length of the faulted line section, looking for damaged equipment. This process is time-consuming and costly, even more so for underground cables.

Algorithms exist for recognizing high-impedance faults as well as for locating faults through proper analysis of monitored data, but the quality of available measurements on distribution circuits is often insufficient to support them. We expect that μPMUs will allow fault detection and location with much greater precision than before, even with relatively few devices deployed on a circuit [3]. This is because voltage angle measurement makes it possible to compute changes in impedance between two measured points and thus diagnose a fault even if the current magnitude is insufficient to trip a protective relay. The impedance between the faulted point and a PMU on either side then also indicates the relative location of the fault. If successful, methods based on μPMU measurements could drastically reduce service restoration times and enhance safety by ensuring reliable fault detection.

1.2.3. Hierarchy and Communication

The PMUs are situated in power system substations and provide measurements of time-stamped positive-sequence voltages and currents as well as frequency and rate of change of frequency of all monitored buses and feeders. The measurements are stored in local data storage devices, which can be accessed from remote locations for diagnostic purposes. The phasor data are also available for real time At the next level, phasor data concentrators (PDCs) are present as shown in the figure below, which gather and record the data, reject altered data, and align the time stamps from several PMUs. PDCs have storage facilities and application functions which need the PMU data available at the PDC. This can be made available by the PDCs to the local applications in real time applications [18].

An another level of the hierarchy is called super data concentrator (SDC) where there is facility for data storage of data aligned with time tags as well as a steady stream of near real-time data for applications which require data over the entire system. The figure below shows the communication links to be bidirectional. As, most of the data flow is upward in the hierarchy, although there are some tasks which require communication capability in the reverse direction. WAMS is the group of assessment application and monitoring that include PMU and PDC [18].

In the figure below, the hierarchy of WAMS is shown. The different layers of this hierarchy are represented with their elements and latency.

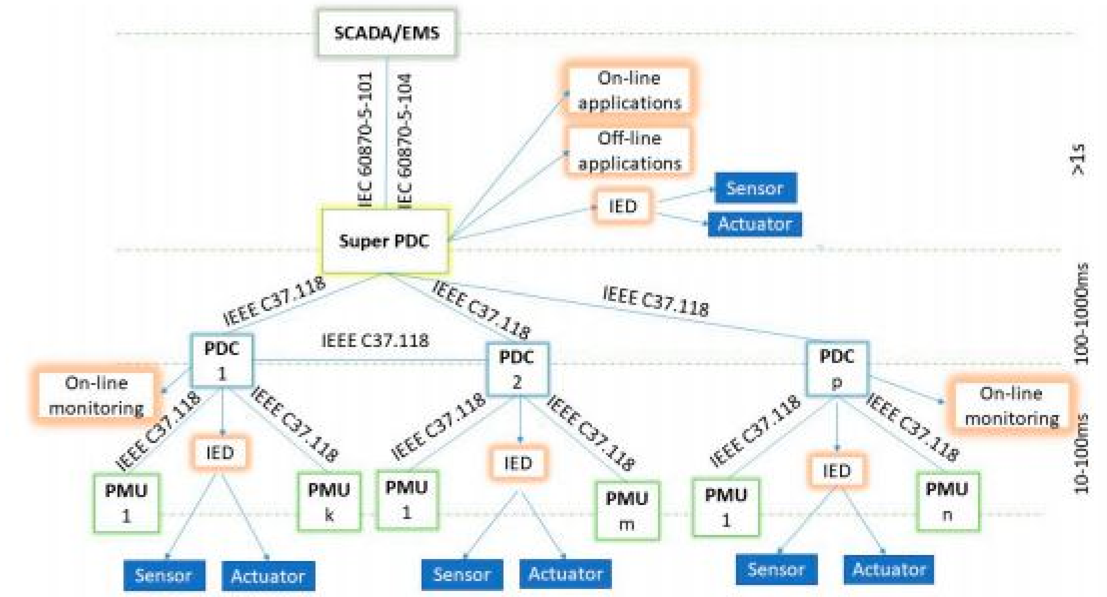


Figure 4. Hierarchy of the WAMS [1].

Regarding the communications facilities, they are essential for applications requiring phasor data at remote locations and also to be able to coordinate the μPMU with the other protections as well as to know in real time the values that are being measured. Generally, two types of data transfer are used in any communication task. Channel capacity is the measure of the data rate that can be sustained on the available data link. The second aspect is the latency, defined as the time lag between the time at which the data is created and when it is available for the desired application. Diagnostic analysis applications require PMU data to help in analysing the power system performance during major disturbances. There have been several communication media used for these purposes. The preferred option is the fiber-optic links. They are used as the medium which have high data transfer rates, unsurpassed channel capacity, and immunity to electromagnetic interference [16].

The communications systems depend on what technology is being used, this means that the SCADA system due to its technical characteristics, it will employ different communications systems that WAMS. Regarding the communications systems used by SCADA systems [43]. The ones that are employed are the power line communication (PLC), coaxial cables, telephone lines, fiber optics, overhead lines, and radio frequencies through, for example, broadcasts, microwaves, and satellites to transfer data. Regarding WAMS, there are mainly two different communication categories that are being used. Wired communication technologies which includes fiber communication and PLC, the other one is based on the wireless communication technologies that include Wi-Fi [44], Bluetooth, WiMAX, microwaves, long-term evolution (LTE), ZigBee [14], cellular communication (satellite), and radio [46]. Each of these technologies has their own characteristics, making them stand out in some fields. For example, fiber optics stands out for its high reliability and its low latency. As negative to this technology, because of the higher capital expenses (CAPEX) and operational expenses (OPEX), it is not always possible to use it and other options are used. For example,the PLC technology is a effective solution and their cost are reasonable, as it does not require extra wires or infrastructure so it makes it a widely used option. In these cases the data can be sent on existing lines that transport electrical power.

Regarding the **PLC** technology, the two main PLC categories are narrowband (NB-PLC) [47] and broadband (BB-PLC) [48]. The frequency range employ for the narrowband reaches 500 kHz, and the frequency range employed for broadband is from 2 to 50 MHz. The data rate for narrowband is up to 200 kbps and that for broadband is over 1 Mbps. Currently, the PLC is mainly used in several applications. For example: the control of lightning, for home automation, in the distributed energy resources (DERs), the smart metering and remote metering infrastructure, electric vehicles (EVs), and in projects regarding the demand responses. In the electrical system, the PLC is used for the communication between the PMUs and substations. Although it has many advantages, the PLC must overcome several challenges, such as signal distortion, noise, and attenuation. Due to numerous factors such as its low cost, an already present infrastructure and a very extensive coverage, the PLC is an option for PMUs and in general for communications in the distribution system (both for low and medium voltage). In recent years, more applications have been developed for PLC, such as island stop in LV and MV, as explained in [50]. Also, it is trying to update as you can see in [45]. This new PLC technology called PLUS (Power Line data Bus) has some advantages over the PLC such as a highly precise time synchronization solution, PLUS-TimeSync (in the range of 500 ns), which is provided by the communication signal, and the communication functionality, which has been developed for MTC smart grid monitoring and automation (MTC-GMA) applications. Furthermore, it has the potential to provide robust and accurate wire-fault detection and load management algorithms.

Regarding **5G** [49], it is considered that the fifth generation of mobile networks can be a very interesting option for different electrical protections such as PMUs. This is because 5G is much faster than 4G (more or less 100 times) and it has a transfer rate of 20 Gbps. Making 5G a technology with high reliability and its low latency. This technology will support various services of vital importance. The most important are:

The first one is enhanced mobile broadband (eMBB), which provides connections with very high peak data rates and moderate rates of cell-edge users [27]. The second one is massive machine-type communications (mMTC). The mMTC will support a massive number of Internet of Things (IoT) devices with the possibility of making connections up to 106 per square kilometre with a less than 1 % packet loss rate [28]. The idea of 5G-based IoT is presented in [29] for DER communication with a control center. The last service that is supported by 5G is ultra-reliability low-latency communications (URLLC), which are very useful for the PMU communications in distribution systems, especially in the case of protection and control, which require more accuracy and very low latency.

The 5G ultra-reliability low-latency communications can be really important for the electrical system. Their application was studied for several cases. The first case was investigated in [30] for PMU communications for state estimation (SE) in a distribution system. Other application was the possibility of using 5G for the secondary load frequency control in a maritime microgrid (MMG), as it was explored in [25]. Based on their study, data measured by PMUs can transmit to a control center every 0.01 s via a 5G network. Currently, this technology has not yet been implemented in any power system so real data about its performance is still unknown. If this technology is going to be implemented in the future, it data security (information data, etc.) must be guaranteed.

In the table below, it is shown the main communications methods with their advantages and disadvantages regarding the PMU.

Communication Method	Advantages	Disadvantages
PLC	Existing infrastructure, good coverage, high capacity, acceptable cost and nornal latency (150-350 ms)	High noise in the measurements due to the noise generated by the corona effect and switching, the signal can attenuate and be distorted
Fiber Optic	Good capacity, not many repeaters, good security, low latency (100-150 ms) with low bit error	High initial inversion and a too elevate service cost for a broad deployment in the LV or MV network
Microwave	Wireless, acceptable cost	Needs a license and a line of sight for the operations, technology influence by the weather, the signal can fade
Wireless (Wi-Fi, WiMAX, LTE)	Flexibility and low latency	Low security, low capacity, low Quality of Service (QoS)
Satellite	Supports a wide geographical coverage and high accuracy	Weather conditions dependency, high initial inversion and high operational cost, high delay (250 ms), really high latency from 1000 to 1400 ms
Radio	Working based either on licensed channels or over non-licensed frequencies	Reliability for industrial use is questionable
5G	Method with lowest latency, less than 1 ms [26], highest data rate (up to 20 Gbps), high spectrum, network efficiency, ultra-reliability	The technology is new and it is under process; high security assurance required

Table 2. Communications options regarding PMU

1.2.4. Performance Evaluation

There are several values that are used to analyse how the PMU performs in the measurements that it realizes. The most important ones are: availability, latency, reliability, message rate, data loss and accuracy, which are described below [5]:

- Availability is defined as that data measured by the PMU can be sent to the PDC in a timely manner.
- The latency also known as the time delay in a network, it is the necessary time to transfer the obtained data from one point of the system to another point of it.
- Reliability is defined as the connectivity and strength of a network in order to have a sufficient level of established performance. It is necessary to have a reliable universal communication infrastructure and achieving this is a crucial challenge both in the structure and in the operation of the WAMS communication systems.
- Message rate o resolution: A PMU is capable of taking many fast physical measurements (samples) of the voltage, current or both at same of the system. It is also capable of calculating the phasor amounts of these samples, and then time stamps and reports phasor for each cycle or two cycles. Synchrophasors measured should be reported for a notification fee, frequently. To indicate the transmission rate, it is used in frames per se.
- Data loss: The data loss in a PMUs may occur due to different reasons, some of the most common are to communication network or GPS signal loss. Generally, PDCs obtain the PMUs data based on the time stamp of the data stream. They also have a time-out function. Therefore, if some of PMU data does not arrive within a specified time, it will be discarded. Based on the results of, most of the GPS loss events recover within a short period.
- Accuracy is the difference between the measured value and the actual value. An accuracy index is using for the magnitude and angle, which is called the total vector error (TVE). The PMU performance standards refer to a 1 % TVE. However, this is changing based on PMU applications.

$$TVE = \frac{\left|\hat{X} - X\right|}{|X|} \tag{4}$$

$$= \frac{\left|\left(\hat{X}_r + j\hat{X}_i\right) - (X_r + jX_i)\right|}{|X_r + X_i|} \tag{5}$$

$$= \sqrt{\frac{\left(\hat{X}_r - X_r\right)^2 + \left(\hat{X}_i - X_i\right)^2}{X_r^2 + X_i^2}} \tag{6}$$

Regarding the previous expressions, X is the true synchrophasor and $\hat{X}$ is the synchrophasor that has been estimated by the PMU. The subindexes i and r indicates the imaginary and real parts of the synchrophasor, respectively. In the figure that it is shown below, it is represented the TVE. Where V is the true phasor that should be measured, V_a is the measured phasor with the magnitude error, and V_b is the measured phasor with the phase and time synch error. The TVE value is influenced and affected by many factors and the most important are the phase errors, synchronization accuracy and amplitude errors.

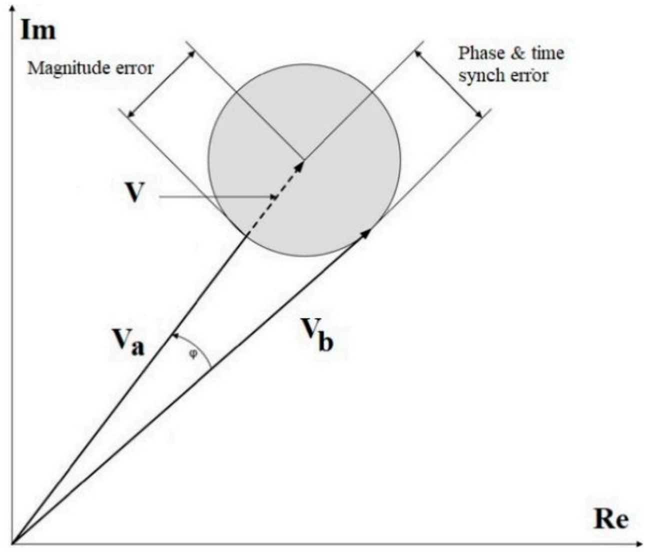


Figure 5. Representation of the total vector error.

1.3. SCADA data VS PMU data

The incorporation of PMUs across various systems around the world is based on that the use of PMU allows to obtain better data than those obtained by SCADA for supervisory control. This is because the PMU allows to manage the measurements in real time of a wide area. The main initial impediment to its use was its cost, but with the improvement of technology in recent years, there has been a substantial decrease in the price of PMUs. The improvement of technology in addition to reducing the price has led to other improvements such as identification of harmonics, stopping of frequency variations, etc. All this synchronized by GPS [12].

Comparison between SCADA and PMU		
Atribute	**SCADA**	**PMU and μPMU**
Resolution	1 sample every $(2-4)$ sec.	$(10-120)$ samples per sec.
Observability	Steady-state	Dynamic/Transient state
Phase angle measurement	No phase angle	Provides phase angle
Time synchronization	Measurements are not synchronized	Time-synchronized measurements
Monitoring and control	Local	Wide-area & Local

Table 3. Attributes comparison between SCADA and PMU

Thanks to the properties of the PMU data measurements it is possible to obtain high-speed coherent data that are not available with traditional SCADA measurements in order to monitor power system dynamics (like angle measurements), this helps for the state estimation. The angle measurements are made directly, while SCADA system measure the voltage angles by calculations using measurements of voltage, measurements of active power, reactive power measurements, network parameters, and a reference angle. Quality of results depends heavily on network quality parameters which are not always precise. Due to this, while Synchronized phasor measurements offer solutions to a number of vexing automation and protection problems (e.g. protection of multiterminal lines, protection of series compensated lines, etc.), while the SCADA system can not provide solutions to problems of protection and automation system.

The image below shows the corresponding differences between the data acquisition of SCADA and WAMS.

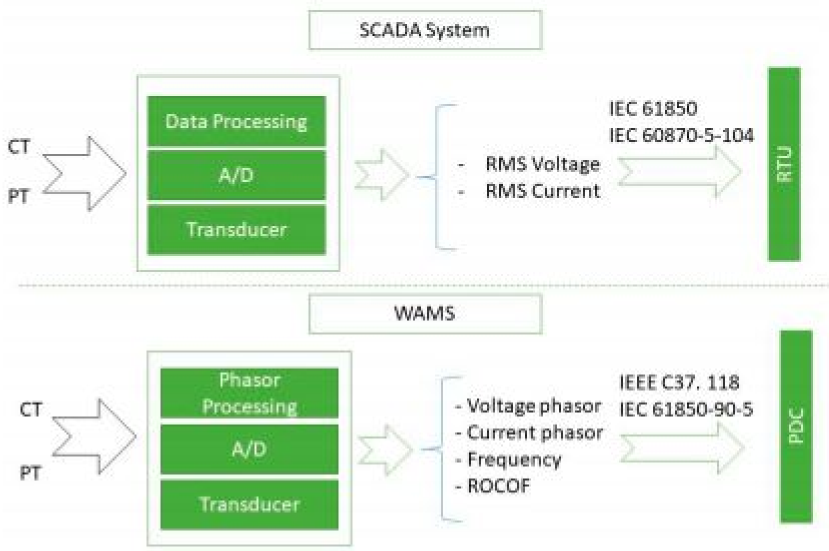


Figure 6. Data acquisition characteristics WAMS vs SCADA [1].

1.3.1. Comparation between PMU and μPMU

Although PMUs are a technology that has been fully tested for their success and operation in the transmission network, their application in the distribution network is not optimal. This is because until recently the PMUs used had been developed for the functions that they could perform in the transmission system and any manufacturer had focused on manufacturing a PMU for the distribution network needs. This makes the μPMU a kind of PMU designed to work in an optimal way in the distribution system. Due to this, in case you it is necessary to know the magnitude and phase of the voltages and currents of the distribution network, it is better to use μPMU than a PMU. The main reasons the μPMU is good for the distribution system are [6]:

Higher degree of accuracy is required for distribution as the angle differences and changes are significantly smaller than in transmission. This is because of the different X/R ratios that have the distribution network compare to the transmission network. μPMU plays an important role in distribution planning and operations as measurement of phase angle and difference in angle between points provides the ability to calculate impedance which is not possible without the μPMU. The ability of being able to calculate the impedance will allow to have more information of the distribution network and also a method of detecting when there is a fault. The phase angle also gives information on the direction of power flow for analysis of topology changes or errors, with the inclusion of DER it is expected to more bidirectional power flows. The line level measurement represents an improvement over smart metering for estimating loads on a per phase basis.

As explained at the beginning of this section, the PMUs are almost exclusively used in high-voltage power transmission. This is due distribution system applications are more challenging, this can be seen in three important respects [6]:

- The voltage angle differences between two locations on a distribution circuit will tend to be at least an order of magnitude smaller than those on the trans-mission network, because the power flows are much smaller, and the reactance between points of interest is also much smaller. Consequently, meaningful measurement of phase angle differences on distribution systems requires much higher precision.

- Distribution system measurements will be fraught with much more noise from which the signal must be extracted. This is simply due to the proximity of a large number of different devices connected per mile of circuit at the distribution level, including loads as well as utility switchgear, transformers, capacitors, that may introduce harmonic distortion and transients.
- The economic value of transmission power flows means that larger investments can be justified, with less pressure on the acceptable costs of instrumentation as well as data transmission and concentration. By comparison, the installed costs Micro-phasor Measurement Units (μPMUs) and Its Applications must be far lower to make a reasonable business case for the installation of multiple PMUs on a distribution circuit, simply based on the amount of connected load whose service quality or reliability would stand to benefit from increased visibility and better understanding of the dynamics on the circuit.

The differences between the μPMU and the PMU can be seen in the following table. In the table, you can see different models and their characteristics. The element that stands out the most is the angle accuracy. As you can see there is an order of magnitude difference between μPMUs and PMUs. In the other values there are no significant differences.

		PSL			Energy DSA	Vizimax
	Characteristics	**µPMU**	**µPMU-LV**	**PQube3v**	**Model 1133A**	**PMU010000**
Voltage	Voltage Measurement Range	0 VAC -750VAC L-E (0 VAC ~ 1300 VAC L-L)	0 ~ 28VAC (L-E), 0 ~ 48 VAC (L-L)	0 VAC -750VAC L-E(0 VAC ~ 1300 VAC L-L)	-	-
	Sampling Rate	25,600 samples/s 50Hz	25,600 samples/s 50Hz	25,600 samples/s 50Hz	-	-
	Isolation	5100VAC isolation to Earth	5100VAC isolation to Earth	5100VAC isolation to Earth	-	-
	TVE (Total Vector Error)	Typical TVE: **±0.01%** Typical short-term TVE stability for differential measurements: **±0.002%**	Typical TVE: **±0.01%** Typical short-term TVE stability for differential measurements: **±0.002%**	Typical TVE: **±0.01%** Typical short-term TVE stability for differential measurements: **±0.002%**	-	-
	Amplitude Resolution	0,0002%FS (2 PPM)	0,0002%FS (2 PPM)	0,0002%FS (2 PPM)	-	-
	Amplitude Accuracy (±% rdg ±% FS)	**±0,050%** (10VAC ~ 750VAC L-E). Typical: **±0,010%** (120VAC ~ 600VAC	**±0,050%** (0.1 ~ 28 VAC L-E). Typical: **±0,010%** (1.0 ~ 28 VAC L-E)	**±0.01%**	-	-
	Angle Resolution	0.001°	0.001°	-	-	-
	Angle Accuracy (±% rdg ±% FS)	±0,010° 1 Standard Deviation Typical : ±0,003°	±0,010° 1 Standard Deviation Typical : ±0,003°	**±0.002°**	±0.01°	±0.05°
Current	Current range	0~6000A	0~6000A	0~6000A	-	-
	Sampling Rate	25,600 samples/s 50Hz	25,600 samples/s 50Hz	25,600 samples/s 50Hz	-	-
(Excluding CT)	Magnitude accuracy	-	-	**±0.01%**	-	-
	Angle accuracy	-	-	**±0.002°**	-	-
Technical Specifications	Power Supply (AC)	24 VAC ±10% at 50 Hz, 1.5A max	24 VAC ±10% at 50 Hz, 1.5A max	24 VAC ±10% at 50 Hz, 1.5A max	-	-
	Power Supply (DC)	±24 ~ 48 VDC ±10%, 1A max	±24 ~ 48 VDC ±10%, 1A max	±24 ~ 48 VDC ±10%, 1A max	-	-
	Latency	Latency: 50 ms typical	Latency: 50 ms typical	-	-	-
	Internal memory	32 GB up to 30 days of synchrophasor data	32 GB up to 30 days of synchrophasor data	32 GB (holds over a year of data)	-	-
	Data backup	16 GB (up to 128GB) micro SD card or USB 2.0 thumb drive	16 GB (up to 128GB) micro SD card or USB 2.0 thumb drive	16GB standard (stores up to 3 years of data under normal use)	-	-
	Communication	Ethernet port RJ-45, 10/100 (optional wireless and cell modem)	Ethernet port RJ-45, 10/100 (optional wireless and cell modem)	Ethernet port RJ-45, 10/100 (optional wireless and cell modem)	-	-
	Communication protocols	FTP or HTTP	FTP or HTTP	FTP, HTTP, SNMP	-	-

Table 4. Comparation between PMU and μPMU

1.4. Motivation

The motivation of this work is that currently there is not enough information about the extent of the use of micro PMUs in distribution networks. This is because it is a new technology that has not been applied on a large scale in any distribution network and therefore it is not known to what extent the use of these devices can be replicated in distribution networks, due to any model of the implementation of the micro PMUs has been done. The main challenge of creating the model is taking into account all the factors that are needed to recreate correctly the network, protection and faults.

The realization of this simulation is necessary, since, if it is correctly done, it would give objective data that will permit to know if the introduction of the micro PMUs is beneficial technically and economical to the grid. In addition, a correct simulation of the distribution grid will allow to make faster simulations of other protections if it is necessary. So, after the project is done, the technical and economic feasibility of the use of the micro PMUs in the distribution network will be understood better. Therefore, it will be possible to know if the use of this protection can reduce CI/CML.

1.5. Project objectives

With the elaboration of this project, it is expected to achieve the following objectives:

1. To design and program a model of the SPEN distribution network that would be able to simulate the normal operation of the network and selected fault scenarios. The model will have incorporated PMUs at various placements and test how they work in the network.

2. The model will facilitate to understand the beneficial of the implementation of the PMUs in the distribution network, the implementation of the PMUs also includes the optimal number of PMUs used and its location in the grid.

3. The creation of a model of the SPEN distribution network will allow to do if it is necessary more simulation regarding other protections, faults, etc. Helping to do more studies that can improve the distribution network.

4. To review the use cases of PMUs and the available products with their specifications

1.6. Work methodology

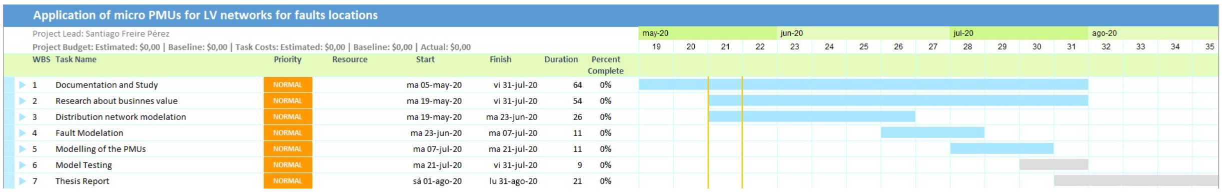
For the correct realization of this master thesis project, a waterfall model will be employed, meaning that to a correct develop of the project, the project will be divided in different stages that have to be done in a successive way to be able to pass to the next stage, although it is a waterfall model, some tasks will be run concurrently like the reading or interviewing activities.

The first stage consists in the study of the protection PMUS and their characteristics (price, electrical conditions, how using the protection, etc), the distribution network characteristics (voltage, resistance value, etc.). It will necessary to study each of those factors from the most appropriate source. Also, it will be necessary the study of regulation that can affect the case. The next stage will be to transform an existing model of an electrical network to the distribution network of SPEN. The model will be a LV distribution network and will have around 14-18 busses.

When the model of the network is done, it is necessary to include in the model to synthesize fault scenarios, after that it will be necessary to include in the model the UMA protections. After their implementation, it will be necessary to check their success in detecting failures. To do this, will be necessary to do several tests with different fault types in the network to check how it behaves with the inclusion of the protections.

During the project realization it will be necessary to interviews with SPEN personnel that will help to realize the business value of the project.

Next, a Gantt Chart with the activities of the project is attached, in the Gantt Chart can be seen each activity, the starting dates of the activities and the duration of the days scheduled for the completion of each activity are established. The duration of the activities is in weeks.



Chapter 2

Faults and Implementation

2.1. Distribution Network Faults

Theoretically, a fault is a variation of one of the values of the power system from its original value, under normal operation. In the power system, the occurrence of a fault can sometimes cause the electrical system to be interrupted as a power outage. A power outage can cause serious economic and social consequences, such as loss of production and risks to safety and health. In technical damage, the costs of restarting power plants, damage to equipment and replacement of certain materials can be very expensive. Regarding the social damages produced by the lack, transportation problems stand out, industrial operations are only one of the cases of system failure [4].

In power systems, the occurrence of a fault can, under certain conditions, result to the interruption of electricity supply, i.e. power outage. Power outages can lead to serious consequences of both economic and societal nature, ranging from production losses to risk to health and safety. More specifically, production losses along with restart costs, equipment damage and raw materials spoilage can be very costly. At the same time, uncomfortable temperatures at work or home, loss of leisure time and risk to health and safety, e.g. interrupting hospital service, transportation or industrial operations, are some of the aspects of social impact of power outages.

To avoid massive system blackouts and ensure safe and reliable system operation, it is necessary to know which events can cause them, so it is possible to prevent them from occurring. There are several causes that originate these events, they can be classified into 2 large groups. Each of these 2 groups can be also classified into several subgroups. The most notable causes are: natural causes, external causes and maintenance [9].

The geographic location, despite not being one of the causes of faults per se, influences the natural threats that can cause a fault. The most common natural hazards are: rainstorms, blizzards, windstorms and lightning storms. There are many more threats, but some are less common, such as a heat wave or tsunami. There are other reasons for faults that are quite conventional, such as technical failures of an element of the system, damage produce by fire, maintenance error, operational failure of and element, etc [20].

In addition to the causes explained above, threats of malice and emergency must also be considered. This is because since the society is becoming increasingly more dependent on the electricity, threats from hacking, sabotage, theft and even terrorist attacks have become more common. These events are also linked to the evolution of the system that increasingly has greater technological advances in telecommunications. This evolution in the telecommunication field has made the system more vulnerable to data attacks, the availability of the network, privatization of information, etc.

Furthermore, the increasing interconnectivity of our societies infrastructures like the electric power system, oil, water, gas, transportation system and telecommunications, makes it possible for the faults produce in one system to translate from one system to another. Finally, an example of interconnectivity as a threat, are the high capacity and long lines that connect different countries. These lines transmit a large amount of power since the interconnectivity of the countries must be at least 10 % of their installed power. This means that the lines usually work with their nominal power and therefore if there is the event that a fault occurs in one of those lines, it can produce a maximum blackout. An example of this is the 2003 blackout in Italy, where a line connecting Switzerland and Italy suffered a fault and a massive blackout occurred in the north of the country.

As these system outages are a frequent phenomenon, it is impossible to classify all the cases that happen. Due to this circumstance, 3 criteria were proposed by [9] in order to distinguish the most important outages from the least important:

1) affected population * duration outage >1.000.000.

2) duration of the outage >1h

3) affected population by the outage >10.000 residents

Thanks to the data collected in the study [9] it is possible to know the number of blackouts that meet the criteria explained above and the causes of the blackout. Observing the Figure 7, it is verified that since the year 2000 there has been an increase in blackouts caused by natural causes, this increase in natural disasters shows the effects of climate change and the risks it can cause to our society. There has also been an increase in blackouts due to malicious causes.

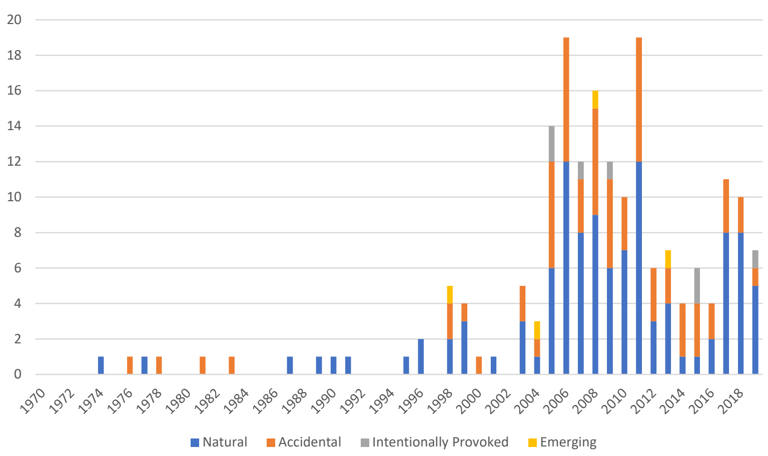


Figure 7. Causes of the different outages per year [9].

2.1.1. Distribution faults

Although faults can occur anywhere in the power system, several studies have reported that most of the outages are produced by a fault in a distribution system (nearly an 80 %). The occurrence of faults is inevitable, this is due the many factors that are uncontrollable, animals, extreme weather events, etc. Knowing the characteristics of the faults based on their cause, can help to identify the place where the faults have occurred and to solve them more effectively. The inclusion of elements such as PMU in the distribution network will facilitate the location of these faults. The figure below shows the reasons for the faults that occur in the electrical system with their corresponding percentage.

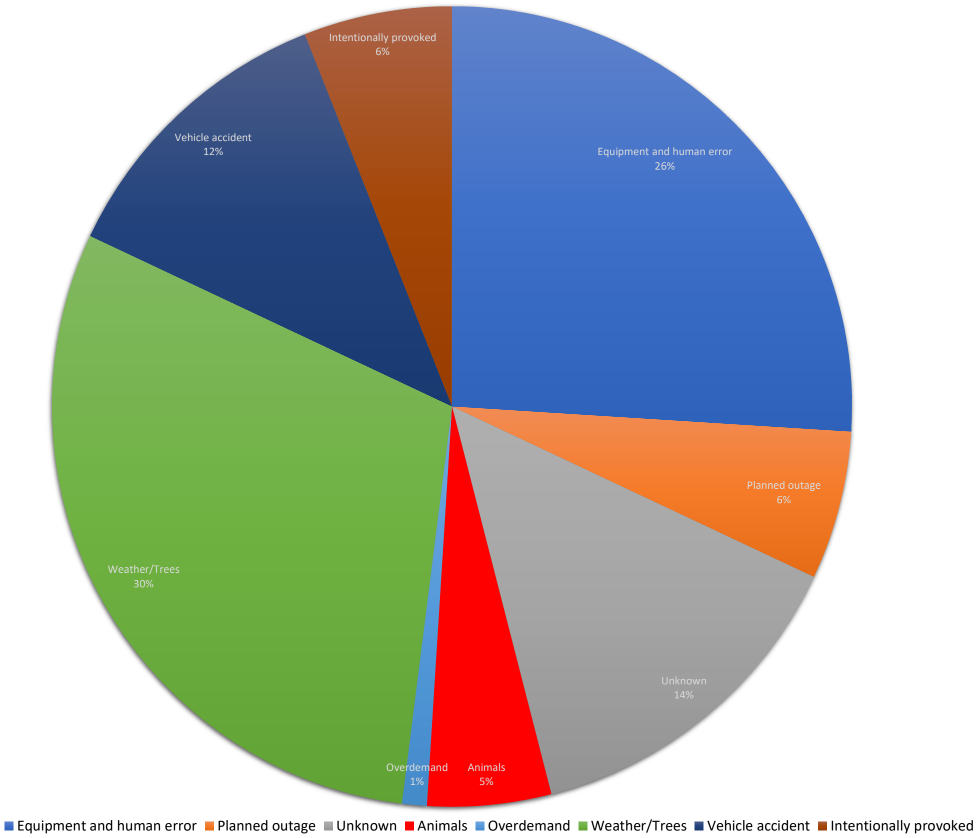


Figure 8. Causes of the faults in the system [70]

Most of the faults in the distribution system occur in overhead lines (50 %). This is because these lines are the ones that are more affect by the climatic catastrophes. The most common cause of failure is due to strong burst of wind that rot in storms and impact trees with lines. The rest of the faults in the different elements of the system are distributed more evenly. The faults in the underground lines are only 6 % faults. But it must also be said that in the event of a fault on those lines it is much more complicated to repair it quickly due to the problems of reaching the cable. The methods designed in this Thesis to locate faults will be able to detect fault in the overhead lines and underground cables, so about a 60 % of the existing faults of the system can be located. In the figure below, the fault percentage associated with each element of the distribution network is shown.

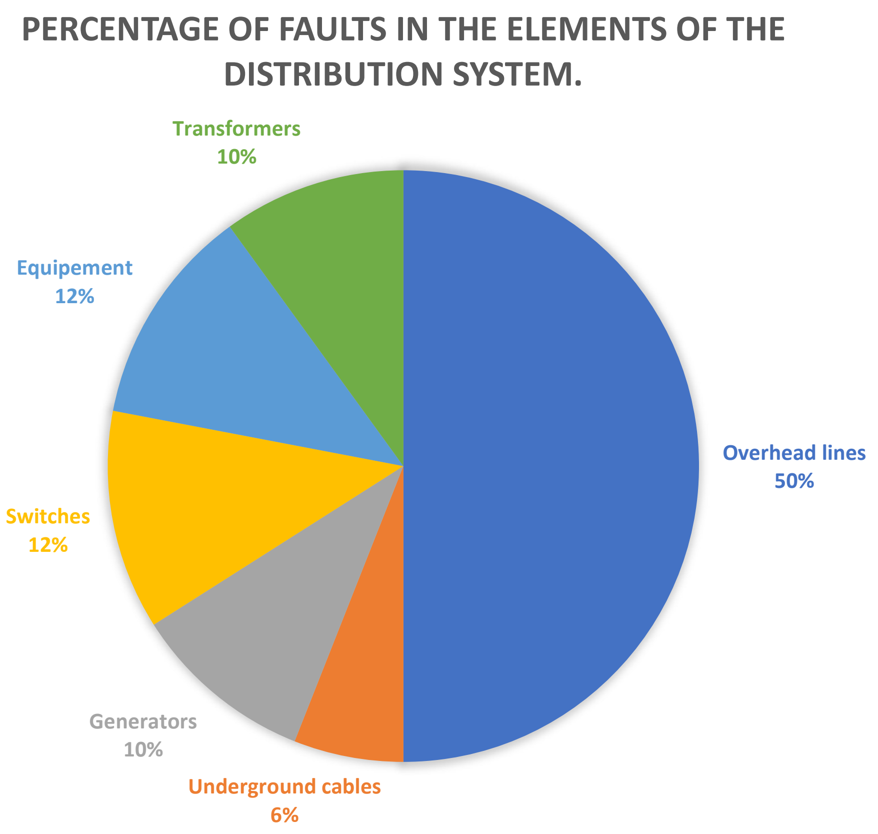


Figure 9. Fault occurrence in the different elements of the MW system [69]

Regarding the type of faults that occur in the distribution network, the most common faults in distribution systems are the single phase to ground faults. These faults account for 70 % of the total fault cases in the system. These faults occur for example when one phase comes in contact with a tree or if an animal makes contact with the ground and the phase, it can also occur if some elements of tower are damaged. The rest of types of failures are much less common but they also occur, the phase to phase fault occur when strong wind brings one phase in physical contact with another. The most severe fault is the three phase fault although they only represent 5 % of the total number of failure cases. The remaining 25 % is divided among the phase to phase faults (15 %) and double phase to ground faults (10 %).

In the table below can be checked the faults types regarding the affected phase with their percentage of each one happening.

Types of fault	
Fault	Percentage
One phase to neutral	63 %
Phase to phase	11 %
Two phases to neutral	2 %
Three phase	2 %
Three phase on the ground	1 %
Two phases one the ground	2 %
One phase on the ground	15 %
Other faults	4 %

Table 5. Classification of faults based on the phase with their percentage [20].

In the figure below a standard classification of the faults is shown.

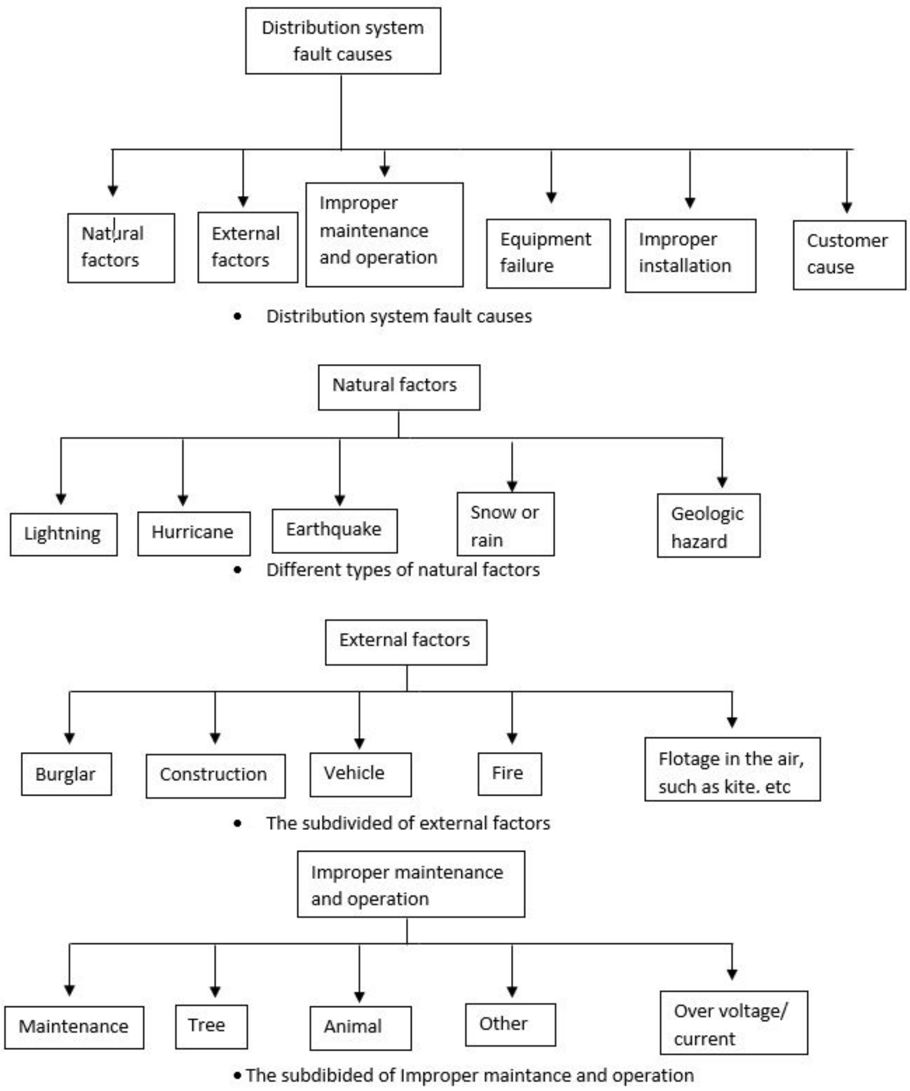


Figure 10. Distribution system fault causes

2.1.1.1. Influence factors

Although the types of faults are the same in all places, their proportions depend on various factors such as the country where they happen and weather conditions [20]. The most influential factors are:

- The differences between the grounding system. Depending in the country, there are differences in the type of grounding system. One type of grounding system employed is a grounding with a low resistance (this is usually used in NA). Another grounding system employed is a system consisting of and non-effectively grounded system including ungrounded high resistance grounded and resonant grounded (employed in Nordic countries).

- The conductor type: depending on whether the line is a underground line, a covered conductor or air cable, makes that the causes of the fault are different. In the distribution networks the most employed lines are underground line and overhead line.

- The environment around the lines is also a factor that influences the faults, the faults that occur in an area with trees are different than in an area without it, also the possibility of fault due to animals changes due to the environment.

- Weather, season, climate: Some events, such as lightning, are more frequent at certain times of the year. Also, the areas with strong winds will suffer more faults due to the trees.

- The last would be with the characteristics of the area. Zones with less development will have a greater possibility of suffering a network maintenance problem and areas in develop will have a greater probability of failure due to construction.

2.1.2. Low voltage network

The LV distribution network is the final part of the electrical system. This part of the electrical system is where the distribution substation connects with the customers. The original concept of the low voltage network is based on the traditional concept of the electrical system. This concept consists of designing the whole system for unidirectional energy flows. In the case of the low voltage network, it is from the distribution transformer to the final consumers.

In recent years, this concept is changing due to the integration of new technologies in the system. An example of them is the integration of electricity generation through renewable sources in consumers. This has made consumers in some circumstances have become generators and therefore the flow of energy has gone from unidirectional to bi-directional. Despite the fact that the integration of these energies are beneficial for the planet, they can pose a problem for the network. This is because the DSOs have to ensure that problems derived from these bidirectional flows (drastic increases in voltage and current in certain nodes of the system, electricity of poorer quality due to the inclusion of harmonics, etc.) do not occur. Historically, the low voltage network was the one that was least monitored, because the power flows were lower and in the event of faults the risk to the system was minimal [72]. But due to the increase in distributed generation in recent years and therefore the increase in consumers that can deliver energy to the grid, it has become necessary to increase the monitoring of this part of the system. For this, Smart Meters have been developed in addition to other systems that helps to have more real time information about the LV system.

The LV network has some characteristics that make its administration more complex than that of MV. The characteristics that most influence this are: The impedances of LV lines can have totally different characteristics between lines that are very similar a priori, they also have a very high R / X ratio (R / X>1). As the impedances of the lines can vary a lot, this makes that this ratio also vary a lot depending in the line. Another aspect that influences the problem to manage the BT network is that the system is often unbalanced and not always all the information of the system is available. This can be an extra problem for detecting and locating the faults in the system [59].

The inclusion of distributed generation in LV network has made it necessary to have more information about them in real time. Due to this, new technologies have been installed in it that have improved the system, making it more intelligent. In other words, the BT network is evolving into a smart grid [71]. This improvement in communications and infrastructure allows a two-way information transit between the devices installed in the BT network and the data acquisition control center (SCADA). Thanks to this communication improvement, in addition to being able to control how the DG is being and therefore being able to better control the system, it also allows to improve other aspects of the system such as fault location.

The improved monitoring of the LV system makes that there is more accurate information available on the needs of the system. In other words, if you want to reinforce the system, more information will be available and therefore the improvements will be more exact and therefore more optimal. Also in the event of faults occurring, due to the greater availability of data, it will be possible to detect and locate the fault better and solve it earlier, therefore the CI and CML ratios of the company will be improved, obtaining more benefits and thus recovering faster the investment made [73].

Faults occur in all the systems. Because of this, a protocol has been developed to follow to be able to restore the system as quickly as possible after a fault. This consists of the FDIR since it allows to minimize the effects on the system [74]. The FDIR consists of:

- Fault detection is the process of being able to recognize that a fault has happened and that the system is not operating as intended.
- Fault isolation is the process of identifying the fault. For example, what kind of fault has happened and localizing it, meaning, finding where exactly the fault happened.
- Fault diagnosis is the combined effort of both fault detection and isolation.
- Fault restoration is the last process of reconfiguration of the grid that is set in action after fault diagnosis in order for the grid to return back to operating condition.

Despite the improvements in electrical systems in recent years and knowing the effects that faults produce (damage to the system, disturbing customers, etc.). Still in certain parts of the system due to lack of information, utilities rely on customers to inform them that a fault has occurred [64]. In these cases, it is necessary to take a group of technicians to locate and fix the fault.

This activity is a long process that can take more than an hour. During that time, customers do not have electrical service, generating mistrust and discomfort in the company. The importance of the new technologies included in the system is due to the fact that it reduces human interference (greater security for company employees) and in numerous faults, when detected quickly, reduces interruption time, so thanks to that it is able to achieve a better service [65]. Therefore, the inclusion of new technologies in the system will reduce the cost of power outages and increase the profits of the companies that use them.

2.1.3. Fault locations methods in MV

Numerous studies have been carried out in order to automate the detection and location of faults. These fault finding methods can be mainly divided into 4 groups.

The first group is the one of the conventional methods. These methods are the ones based on including impedance based method and the traveling wave method. The impedance-based method is one of the most used methods. These methods stand out for having a great variety of them with small differences between them. They are usually used for their low implementation cost and simplicity. There are numerous literature on them [29] [30] [31]. The most popular method is the one-end technique. This method consists in that thanks to the voltage and current measurements that are in the main substation of the system it is possible to calculate the values of the other parts of the system as long as you have knowledge of the topology of the system with its impedances and loads. An example of its application can be seen in Figure 11.

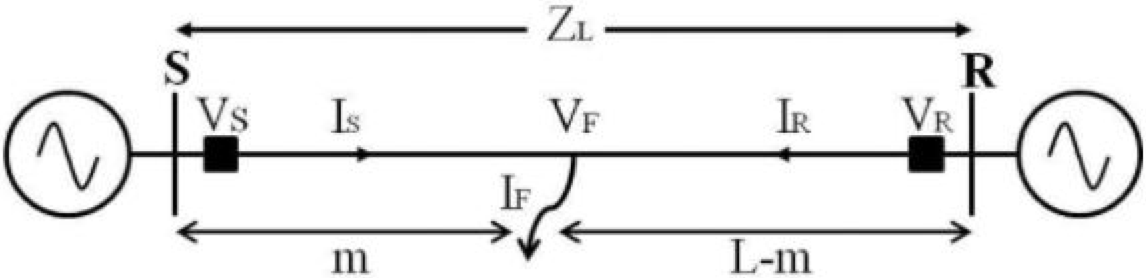


Figure 11. Impedance base method

The distance of the fault would be obtained based on the following expression:

$$f_d = \frac{(V_s - R_f * I_f)}{Z_l} \tag{7}$$

where R_f is the fault resistance, I_f the fault current, V_s the source voltage and Z_l the line impedance in per unit length.

The other conventional method is the traveling wave method. These methods were initially designed for the transmission system, despite this, they can also be applied to the distribution network. These methods are based on the fact that at the moment a fault occurs, transient currents and voltages are produced. These transients propagate in both directions of the line where the fault has occurred. When the waves produced by these transients reach the end of the line, a part of the line returns in the direction of the fault. When it reaches the fault, another part will be refracted and will return to the end of the line and so on. The time differences for the refracted waves to reach the end of the line can be used to calculate the distance of the fault, because the waves move at the speed of light. There is also a large literature on this method [32] [33].

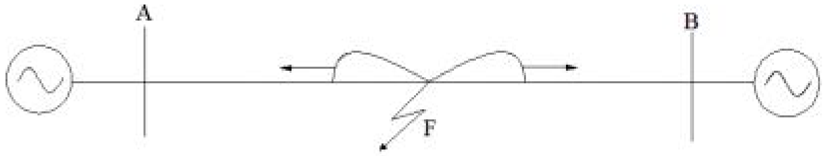


Figure 12. Traveling wave method

The fact that the distribution network is getting smarter, means that more measures are available, that is, more information. This increase in information makes it necessary to manage it. Mainly artificial intelligence is used to do it. Recently, another of the uses that artificial intelligence is being given is to locate faults. There are several methods that are based on artificial intelligence: Fuzzy logic [37], decision trees [36], artificial neural networks [35], genetic algorithms [39], among others.

These methods have in common that before being applied they have to learn, that is, they are trained from a large amount of system data. These data include pre-fault and post-fault system measurements. All types of faults of different characteristics are analysed in different parts of the system. The measurements may vary, also the topology, etc. The advantage of these methods is that they can create associations between measures that normal methods cannot. After being trained, these methods can try to estimate where the faults have occurred. In the figure below it shows an example of a neural network, where in base of some inputs (voltages, fault current, etc.) thanks to associations created in the hidden layers, an output based on those associations is obtained (fault location).

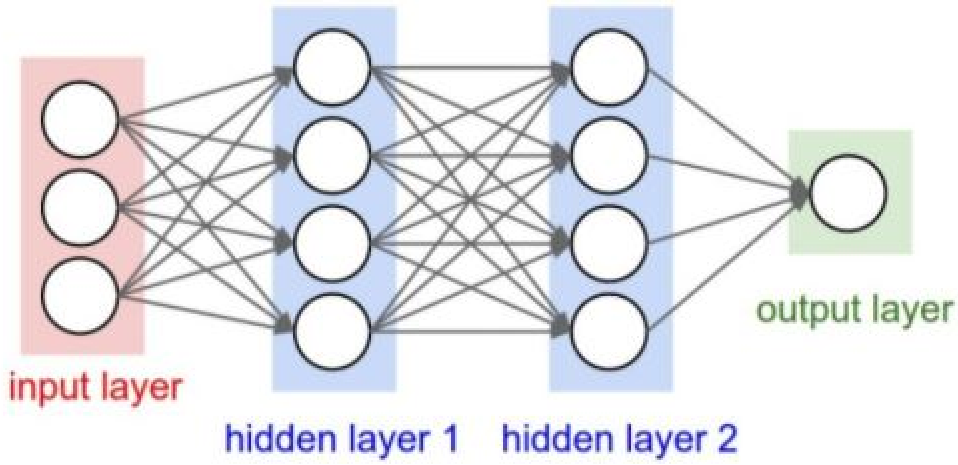


Figure 13. Example of artificial neural network.

The next group is from the scarce-measure-based methods. Thanks to technological advancement and its inclusion in the electrical system, more and more smart grids are available. These networks, due to the improvement of technology, allow us to achieve more measurements and therefore new methods have been developed to locate faults.

Most of these methods are based on a concept called sparse measures. This concept is not uniform, that is, the methods that use this method can differ greatly from each other. Despite this, they are based on the voltage variations of the system. produced after a fault in the different buses of the system. These voltage variations produced by the fault are compared with the pre-fault values and depending on the method, different algorithms are used to locate the faults based on these variations. There are several researches based on this method [61].

The last methods for fault locations are the hybrid methods. The hybrid method, as its name suggests, consists of the combination of the previous methods to be able to detect faults. They usually combine cases of artificial intelligence with conventional methods in order to detect faults. Examples of this can be seen in [60].

2.1.4. Economic Impact

The effects of a blackout have a very large negative effect in several fields such as the economy of the zone where it has happened. The main problem of calculating the total cost of a blackout, it is to the fact that it is really complicated to estimate the cost of certain factors. One example of a factor which the cost of a blackout it is difficult to determine is the loss of consumer confidence in the electricity companies. Due to this, it has been necessary to develop methods that help to estimate the cost of a blackout in the service losses. There are several existing methods that serve to estimate the cost of service losses. One of the most used is the value of the lost load (VoLL). This expresses the value attached by consumers to uninterrupted electricity supply and is traditionally defined as the value attributed by consumers to unsupplied energy [19].

The value of of VoLL depends of several factors than corresponds to a function as f(duration, season, time of day, notice).The variation in prices is notable depending on the current, for example, based on the data of [19], the VoLL for f(1 hour, not winter, no peak, midweek) = 6.95£/kWh while for f(1 hour, winter, peak, weekend) = 11.82 £/kWh.

The other method of estimating the cost of absences is the willingness to pay. Concept that consists of the willingness of a user to pay so it can be possible to avoid an hour without electricity consumption. Depending on the circumstances in which the hour without electricity is, the value of the willingness to pay varies. In the UK, according to the study realize in [19], the data obtained are:

- For avoiding power outages in peak periods: GBP 5.29
- For having power outages during the week rather than the weekend or bank holiday: GBP 7.37
- For avoiding power outages in winter: GBP 31.37

As it is logical, the people are willing to pay more in the most unfordable situation.

2.2. Fault Scenario Modelling

In this project, 2 different methods have been used to detect and locate faults using μPMU. Each method uses a different technique and the number of PMUs used also differs. The second method, a total observability of the system is not available. This is because fewer μPMUs are used. These PMUs will be placed in the main Feeder and in the final bus of each line. Making it necessary for the state estimates made to correspond with the existing μPMU measurements. Therefore, an iterative process will be carried out to ensure that the state estimate in made by the different μPMUs of the system converge in the place where the fault has occurred.

2.2.1. 1º Method

In the first method, it is supposed that the state of the distribution system is observed by being able to measure the nodal voltages and injected current. This is done by the μPMU that is installed in all the work busses of the system. Making this assumption enable the use of linear state estimator (SE). The corresponding formulation for calculating the linear weighted least squares state estimator (LWLS-SE) for a standard distribution system is shown in this section. This method is based in the method developed in [68]

2.2.1.1. Linear weighted least squares state estimator

The state of a distribution system with n buses $x \in \mathbb{R}^N$ $(N = 3n * 2)$ can be expressed with the coordinates seen below:

$$x = \left[V_{1_{re}}^{a,b,c},\ .....,\ V_{n_{re}}^{a,b,c},\ V_{1_{im}}^{a,b,c},\ .....,\ V_{n_{im}}^{a,b,c}\right]^T \tag{8}$$

where:

$$V_{i_{re}}^{a,b,c} = [\ V_{i_{re}}^{a},\ \ V_{i_{re}}^{b},\ \ V_{i_{re}}^{c}\ ] \tag{9}$$

$$V_{i_{im}}^{a,b,c} = [\ V_{i_{im}}^{a},\ \ V_{i_{im}}^{b},\ \ V_{i_{im}}^{c}\ ] \tag{10}$$

Are respectively the three phases of the real and imaginary terms of the voltage phasor at a generic bus i of the system.

The number of buses equipped with μPMUs in the distribution system network is $\mathbb{C}$. The measurement consists of the real and imaginary parts of three phase-to-ground voltage phasors and three injected current phasors of the busses where the μPMU are installed. z is represented as:

$$z = [z_V, z_I]^T \tag{11}$$

where

$$z_V = \left[\ .....,\ V_{i_{re}}^{a,b,c}, ...,\ V_{i_{im}}^{a,b,c},\ .....\right]^T \tag{12}$$

$$z_I = \left[\ .....,\ I_{i_{re}}^{a,b,c}, ...,\ I_{i_{im}}^{a,b,c},\ .....\right]^T \tag{13}$$

Are respectively the three phases of the real and imaginary terms of the voltage and current phasor at a generic bus i of the system. In which $i \in \mathbb{C}$.
To correlate the state variable of the system with the measurements it is necessary to fallow the following equation:

$$z = \mathbf{H}x + v \tag{14}$$

Where H is the measurement matrix and v is the noise of the measurement. Regarding v, it was stablished as a gaussian noise.

$$(v)\ \sim\ \mathcal{N}(0, \mathbf{R}) \tag{15}$$

Where $\mathbf{R}$ is a matrix that their terms are the accuracy of the measurement devices. The accuracy of the μPMU was obtained from several data sheet. The accuracy of the devices will be used as the noise that will be added to the measurements of the simulation. It is considered that the errors of the measurements have not a correlation between each other, because of this, the matrix will be stablished as:

$$\mathbf{R} = diag\left(\sigma_1^2, \ldots,\ \sigma_i^2, \ldots, \sigma_D^2\right) \tag{16}$$

The matrix H consist of 2 submatrix, $\mathbf{H}_V \; and \; \mathbf{H}_I$:

$$\mathbf{H} = \begin{bmatrix} \mathbf{H}_v \\ \mathbf{H}_I \end{bmatrix} \tag{17}$$

The submatrix $\mathbf{H}_v$ links the measurements of the voltage to the state variable. The submatrix terms are ones and zeros that are inferred from (7). The submatrix $\mathbf{H}_I$ links the measurements of the current with the state variable. The submatrix terms are elements of the admittances of the distribution system. The real and imaginary part of the currents of the system can be calculated by the fallowing expressions:

$$I^P_{i_{re}} = \sum_{h=1}^{n} \sum_{l=1}^{3} \left\lfloor G^{pl}_{ih} V^l_{h_{re}} - B^{pl}_{ih} V^l_{h_{im}} \right\rfloor \tag{18}$$

$$I^P_{i_{im}} = \sum_{h=1}^{n} \sum_{l=1}^{3} \left\lfloor B^{pl}_{ih} V^l_{h_{re}} + G^{pl}_{ih} V^l_{h_{im}} \right\rfloor \tag{19}$$

The indexes i and h correspond to the different busses of the system, p and l correspond to the phase indexes, B and G are respectively the imaginary and real terms of the elements of the admittances of the system. From these equations (11) and (12) it is possible to create the submatrix $\mathbf{H}_I$:

$$H_I = \begin{bmatrix} G^{pl}_{ih} & -B^{pl}_{ih} \\ B^{pl}_{ih} & G^{pl}_{ih} \end{bmatrix} \tag{20}$$

The LWLS-SE main objective is to minimize the following objective function:

$$J(x) = \sum_{i=1}^{D} \frac{\left(z_i - \sum_{h=1}^{N} H_{ix} x_h\right)^2}{R_{ii}} \tag{21}$$

To be able to calculate the state estimate with the measurements. First, it is necessary to calculate the Gain matrix:

$$\mathbf{G} = \mathbf{H}^T \mathbf{R}^{-1} \mathbf{H} \tag{22}$$

With this matrix is it possible to calculate the estimated state:

$$\hat{x}_{LWLS} = \mathbf{G^{-1} H^T R^{-1}} z \tag{23}$$

2.2.1.2. Explanation of the fault location method

The method used to detect and locate the faults is based on the following premises:

- A full knowledge of the admittances of the system, making the matrix H exact. Full knowledge of the admittances implies that the parameters of the line and the topology of the electrical system are fully known. The assumption of the knowledge of the parameters of the line is based on the fact that the lines of the distribution network have a standard configuration and the system operator should know the characteristics of the line of the system.

- Regarding the knowledge of topology of the system, it must be clarified that μPMUs can stream and record Boolean variables along with the synchrophasor data. These Boolean inputs may correspond, as is the case for the actual network described in this document, the state of the breakers connected to a supervised μPMU. Once the status of all breakers is collected by the phasor data concentrator, it is simple to determine the incidence matrix of the network and, therefore, its topology and the corresponding admission matrix used in the expression (20). This characteristic is another advantage of using μPMU for protection. This is due to the topology assessment can be easily rebuilt and tagged with limited time latencies.

- The accuracy of the measurement devices used for the noise added to the noise measurements in R is known. This is because the characteristics of the μPMUs employed are totally known thanks to the datasheets of the devices. The number of μPMU employed is equal to the number of busses: C=N. This is based on the fact that lately most of the literature has shown more interest in the employment of μPMU and their several applications, in this literature [40] [41], the issue of using μPMU at all the busses of the system has been discussed.

- Due to simulation characteristics, erroneous data measurements are not considered for the state estimation.

- It has been considered that during the faults an imaginary bus originates in the place where the fault occurs. This bus would be between 2 real buses and would absorb the fault current.

As it was explained before, the system has m-lines and n-buses. There is a μPMU installed in every bus. Considering the measurement set obtained from each μPMU, it is possible to calculate m-parallel state estimators, each state estimator uses a lightly different network topology from the others state estimator. The difference in the topology is based on the position of the fault, in that position the virtual bus will be allocated. The $j^{th}SE(j = 1, ..., m)$ considerate a virtual bus in the middle of the j^{th} line by using an state vector that contemplate the characteristics of the voltage of the virtual bus. The voltage of the virtual bus will be added to the state define in the equation (1).

$$\widetilde{x} = \left[V_{1_{re}}^{a,b,c},\ .....,\ V_{n_{re}}^{a,b,c},\ \ V_{n+1_{re}}^{a,b,c},\ V_{1_{im}}^{a,b,c},\ .....,\ V_{n_{im}}^{a,b,c},\ V_{n+1_{im}}^{a,b,c} \right]^T \tag{24}$$

where: $V_{n+1_{im}}^{a,b,c}$ and $V_{n+1_{re}}^{a,b,c}$ are respectively the imaginary and real terms of the voltage in the virtual bus. The measurement matrix H will be modified based on the location of the virtual bus. If there are normal operating conditions, each of the m-virtual buses will not absorb any current. The different topologies will not influence in the outputs of each SE. In the normal operation conditions, the minimization of the objective function (14) will provide similar results for all the m-SEs so that:

$$\widetilde{x}^j \approx\ x_{true}\ \forall\ j \tag{25}$$

In the case of a fault (it can be any fault, three phase, phase to ground o phase to phase) that happens in the line $L_{h,u}$ between buses u and h. Due to the fault, an amount of current will be lost from an unknown position between buses h and u. The j^{th} SE uses the measurement set z and its own specific topology (namely its matrix $\mathbf{H}^j$) to calculate the estimated state according to (15) and (16). Let assume that the f^{th} SE has the virtual bus placed in the middle of line $L_{h,u}$. The topology of the virtual bus in that line is the closest one to the real network, even if the fault is not located exactly in the middle of the line. Therefore, it provides an estimated state close to the true one:

$$\widetilde{x}^j \approx\ x_{true}\quad \widetilde{x}^j \neq\ x_{true} \qquad \forall\ j \neq\ f \tag{26}$$

Since the fault position is not known at first, it is necessary to identify the SE providing the best estimated state. To determine the best SE, the WMR will be employed:

$$WMR^j = \sum_{i=1}^{D} \frac{\left|z_i - \hat{z}_i^j\right|}{\sigma_{z_i}} \tag{27}$$

where $\hat{z}^j = \mathbf{H}^j \hat{x}^j$.
In the cases where there is no fault, the WMRs of all the state estimators are very close to each other. When there is a fault, the state estimators (except the one of the line where there is the fault) converge to a solution which value differs a lot from its true state, this solution is characterized by a high WMR. The state estimator that has the virtual bus placed in the faulted line has the lowest WMR. Thank to this, it is possible to identify the line affected by the fault.

To be able to detect a fault, it is necessary to compare the mean of the WMRs of all the state estimators, this is called WMR_{mean}. A fault is detected when the difference between the WMR_{mean} of two consecutive timesteps has an abrupt increase. To calculate the estimated fault currents, it is used the state returned by this SE with the admittance matrix. To be able to detect which fault type has happen, it is necessary to check the current in the phases of the virtual bus. The estimated current in the virtual bus that differs from zero are the ones affected by the fault.

The algorithm that summarizes the proposed method is given below. For every new data set coming from the μPMUs, it is necessary to compute the WMRs of the parallel state estimators and their WMR_{mean}. Checking if there has been a sudden increase in the WMR_{mean} of two consecutive time-steps, we are able to detect the presence of a fault. If a fault is detected, the index of the line with the minimum WMR identifies the faulted line. For last it is possible to estimate the fault type and fault current. In conclusion, the employment of this method allows to:

- Detect when a fault has occurred.
- To identify in which line the fault is.
- To identify the fault type
- To estimate the fault current

This method used to detect the faults using PMU can be summarised as the following algorithm:

1. function Fault Identification ($FAULT\ LINE$, $FAULT\ CURRENT$, $FAULT\ TYPE$)
2. for each time-step k do
3. compute $WMR_J \quad \forall j$
4. if mean $(WMRs)|_k \gg$ mean$(WMRs)\,|_{k-1}$ then
5. Fault $\leftarrow 1$
6. j = index of min(WMRs)
7. Faulted Line $\leftarrow$ j
8. $I^j = Y^j E^j$

9. Fault Current ← $I^{j}_{virtual\ bus}$

10. Fault Type ← phases where Fault current $\neq 0$

11. end if

The algorithm at each instant of time calculates the WMR. Depending on the variations, it is able to detect whether there has been a fault or not. Subsequently, the WMR calculated for each line is compared and the line with the lowest WMR is the line in which the fault has occurred. Knowing the fault line, the location of the fault is calculated.

2.2.2. 2º Method

The second method, a total observability of the system is not available. This is because fewer μPMUs are used. These μPMUs will be placed in the main feeder and in the final bus of each line. This method consists in that the state estimation is based on the measurements of each PMU, the state estimation based on each μPMU will converge in the place of the fault. Therefore, an iterative process will be carried out to ensure that the state estimation will converge in the place where the fault has occurred. This method is shown in the following section.

2.2.2.1. State estimator in not fully observable system

Regarding the state estimation of this method, there are many common elements with the previous method. The state of a distribution system with n buses $x\ \in \mathbb{R}^N$ $(N = 3n * 4)$ can be expressed with the coordinates seen below:

$$x = \left[V^{a,b,c}_{1_{re}},\ .....,\ V^{a,b,c}_{n_{re}},\ V^{a,b,c}_{1_{im}},\ .....,\ V^{a,b,c}_{n_{im}}\right]^T \tag{28}$$

where:

$$V^{a,b,c}_{i_{re}} = [\ V^a_{i_{re}},\ \ V^b_{i_{re}},\ \ V^c_{i_{re}}\ ] \tag{29}$$

$$V^{a,b,c}_{i_{im}} = [\ V^a_{i_{im}},\ \ V^b_{i_{im}},\ \ V^c_{i_{im}}\ ] \tag{30}$$

Are respectively the three phases of the real and imaginary terms of the voltage phasor at a generic bus i of the system.

And:

$$I^{a,b,c}_{i_{re}} = [\ I^a_{i_{re}},\ \ I^b_{i_{re}},\ \ I^c_{i_{re}}\ ] \tag{31}$$

$$I^{a,b,c}_{i_{im}} = [\ I^a_{i_{im}},\ \ I^b_{i_{im}},\ \ I^c_{i_{im}}\ ] \tag{32}$$

Are respectively the three phases of the real and imaginary terms of the current phasor at a generic bus i of the system.

The number of buses equipped with μPMUs in the distribution system network is $\mathbb{C}$. The measurement consists of the real and imaginary parts of three phase-to-ground voltage phasors and three injected current phasors of the busses where the μPMU are installed. z is represented as:

$$w = [w_V, w_I]^T \tag{33}$$

where

$$w_V = \left[\ .....,\ V^{a,b,c}_{i_{re}},.....,\ V^{a,b,c}_{i_{im}},\ .....\right]^T \tag{34}$$

$$w_I = \left[\ldots.., \; I_{ire}^{a,b,c}, \ldots.., \; I_{iim}^{a,b,c}, \; \ldots. \right]^T \tag{35}$$

In which $i \in \mathbb{C}$.
To correlate the state variable of the system with the measurements it is necessary to fallow the following equation:

$$w = \mathbf{Z}x + v \tag{36}$$

Where **Z** is the group of impedances and loads of the system connected to the buses and v is the noise of the measurement. Regarding v, it was stablished as a gaussian noise.

$$Z = [Z_line, Z_bus] \tag{37}$$

$$Z_{line} = [z_{line_1}, ..., z_{line_i}, ...z_{line_m}] \tag{38}$$

Where z_{line} is the impedance between two consecutive buses. Each z_{line} is composed by the real and imaginary parts of the impedance:

$$z_{line_i} = [z_{line_{ire}}, z_{line_{iim}}] \tag{39}$$

Regarding Z_{bus}:

$$Z_{bus} = \left[Z_{bus_1}{}^a, ...Z_{bus_i}^b, ..., Z_{bus_n}{}^c \right] \tag{40}$$

The elements of Z_{bus} are only connected to one of the phases in each bus, and they are also composed by a real and an imaginary part.

$$z_{bus} = [z_{busre}, z_{busim}] \tag{41}$$

Z links the measurements of the voltage and current to the state variables. They relation between the estimation and the measurement, use the next expression when they are in the same bus:

$$x_v^{a,b,c} = w_v^{a,b,c} \tag{42}$$

$$x_I^{a,b,c} = w_I^{a,b,c} \tag{43}$$

When the estimation is done in different buses of the measurements, the expressions used for the voltage are:

$$x_{v_{rei+1}}^{a,b,c} = w_{v_{re_i}}^{a,b,c} + w_{I_{re_i}}^{a,b,c} * z_{linere} + w_{I_{im_i}}^{a,b,c} * z_{lineim} \tag{44}$$

$$x_{v_{imi+1}}^{a,b,c} = w_{v_{im_i}}^{a,b,c} + w_{I_{im_i}}^{a,b,c} * z_{line_{ire}} + w_{I_{re_i}}^{a,b,c} * z_{line_{iim}} \tag{45}$$

Regarding the expressions used for the current when the estimation is done in different buses of the measurements

$$x_{I_{rei+1}}^{a,b,c} = w_{I_{re_i}}^{a,b,c} + \frac{x_{v_{rei+1}}^{a,b,c} * z_{busre} + x_{v_{imi+1}}^{a,b,c} * z_{busim}}{z_{bus_{re}}^2 + z_{bus_{im}}^2} \tag{46}$$

$$x_{im_{i+1}}^{a,b,c} = w_{I_{im_i}}^{a,b,c} + \frac{-x_{v_{rei+1}}^{a,b,c} * z_{busre} + x_{v_{imi+1}}^{a,b,c} * z_{busim}}{z_{bus_{re}}^2 + z_{bus_{im}}^2} \tag{47}$$

Following the previous expressions, it is possible to estimate the state of the system buses.

2.2.2.2. Explanation of the fault location method

The method used to detect and locate the faults is based on the following premises:

- A full knowledge of the admittances and loads of the system, making the calculations as exact as possible. Full knowledge of the admittances implies that the parameters of the line and the topology of the electrical system are fully known. The assumption of the knowledge of the parameters of the line is based on the fact that the lines of the distribution network have a standard configuration and the system operator should know the characteristics of the line of the system.

- Regarding the knowledge of topology of the system, it must be clarified that μPMUs can stream and record Boolean variables along with the synchrophasor data. These Boolean inputs may correspond, as is the case for the actual network described in this document, the state of the breakers connected to a supervised μPMU.

- The accuracy of the measurement devices used for the noise added to the noise measurements in R is known. This is because the characteristics of the μPMUs employed are totally known thanks to the datasheets of the manufactures. The number of μPMU employed is equal to the number of system lines plus the main feeder. So for these system C=4. This method is based on using the less number of μPMU as possible and to be able to detect the fault.

- Due to simulation characteristics, erroneous data measurements are not considered for the state estimation.

As it was explained before, the system has m-lines and n-buses. There is a μPMU installed in the main feeder and in the end of the 3 lines of the system. Considering the measurement set obtained from each μPMU, it is possible to calculate the state estimators in all the busses of the system. The state estimation prefault is easy to calculate because all the data of the system are known. The main challenge is to be able to do the estate estimators post fault, because a priori the place where the fault occurred is not known. As the system is not fully observable with the number of μPMUs installed, it makes it necessary to first locate in which of the lines of the system the fault has occurred in order to estimate the values of the areas that are not affected by the fault.

In order to do this, voltage phase variations and voltage drops are analysed in the PMU measurements. Depending on the greater variations between pre-fault and post-fault, it is possible to identify the area where the fault has occurred. Knowing this, the state estimates of the buses are calculated with the PMU measurements without fail. To later locate the branch affected by the fault, an iterative process is carried out. This process consists of using the PMU measurements of the main feeder (from now on called bus s) to estimate the state of all buses up to the end of the line (bus k).

While this estimate is being made, if the voltage of any bus (bus n) is less than that measured in bus k, the calculation of the system state estimate is stopped. Using the measurements of the K bus, the measurements up to the n bus are estimated. After this the n bus is considered the K bus and the process is repeated. If at one point $VE_{k-1} > V_k \quad \&\& \; VE_k < V_k$. It means that the branch where the fault has occurred has been identified and therefore it is possible to perform the calculation to determine the distance where the fault has occurred.

2.2.2.3. Block Diagram

Below is the block diagram that summarizes the operation of the second method. The first step is to detect the fault and, depending on the variations in the measurements, identify the area where the fault has occurred. After this, the iterative process of state estimation is carried out until it is possible to locate the branch where the fault has occurred. After this, it is estimated in which part of the branch the fault has occurred.

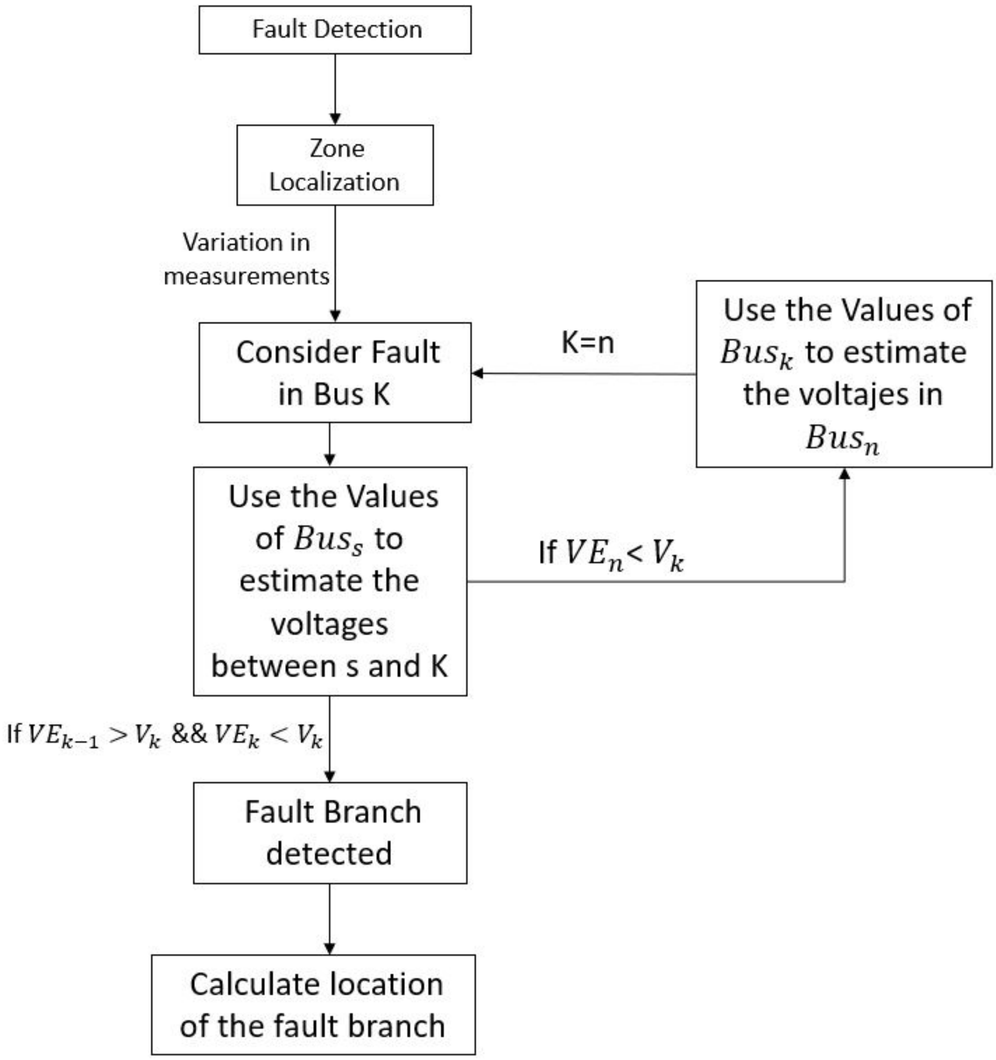


Figure 14. Block Diagram regarding the 2º method.

2.3. Strategy for PMU Placement

Regarding the optimal location of the PMU, numerous studies have been carried out [53] [54]. This is because unlike SCADA, the PMU has the property of being able to measure both the voltage and current phasor of the bus in which the PMU is installed, as well as all the lines that are connected to the bus of the PMU. This allows the installation of a single PMU to have observability of the installed bus and those connected to it. This property makes optimizing the number of PMUs used an interesting option. Since this will allow to have a totally observable system with the lowest associated cost.

Severol methods have been researched to calculate the optimal number of PMUs that a system requires. The most widely used method is the integer linear programming, which stands out for having smaller calculations than other methods. Examples of its application can be checked in[51]- [54]. Many situations have been proposed using this method. One case that is used for it is for systems without conventional measurements. To achieve the measurements in some buses, zero injection is applied to determine the parameters with the applied voltage [54]. It can also be used for cases in which the fault isolates part of the system, the electrical island formed can be detected and measurements of that part of the system can be obtained.

For the application of these methods, each system in which it is going to be applied must be studied separately. In other words, the results obtained for a system cannot usually be extrapolated to another system even if they have a very similar topology. This is due to the fact that the differences between one system and another (buses with DG, buses without load, etc.) make it necessary to study each case separately, making that the optimal PMU location cannot be generalized or extrapolated. Another factor that influences the impossibility of generalizing the optimal location of the PMUs is the role that the PMUs will perform in the system. In other words, despite the fact that with a certain number of PMUs there is a total observability of the system, the PMUs, in addition to monitoring the system, are used for several other applications such as the detention and location of faults. The number of PMUs required for fault location may differ from the optimal number for observability. That is, for each case, the network topology and the applications that the PMU is going to carry out within the system must be studied to be able to determine the optimal number of PMU.

Despite the existence of these methods. Studies have been carried out [40] [41], which highlight that depending on which part of the electrical system in which the PMUs are to be installed, optimization is not necessary and it is better to use PMUs in all the buses of the system, this has been mostly applied in MV.

In each of the 2 methods to detect faults in this project, for the placement of the μPMU, a different approach has been used. The first method was designed originally for MV networks and therefore a total placement of PMU was carried out in all nodes of the system. The second method was designed to use the fewest number of μPMUs in the system with which faults could still be located. Due to this, the second method does not have a total observability of the system and as it was explained their section.

2.4. Evaluation

The following low voltage system has been used in this project.

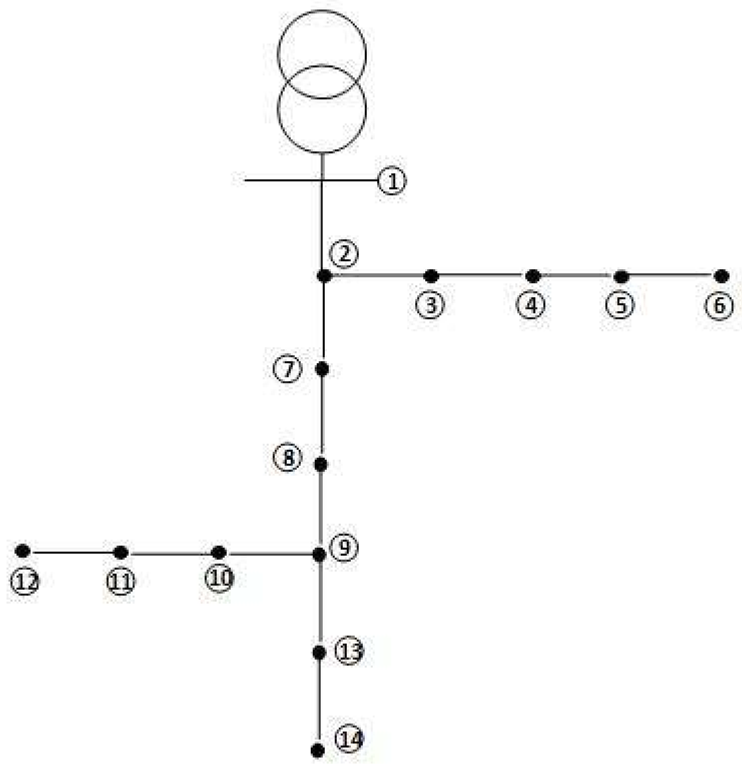


Figure 15. Diagram of the LV system simulated

As can be seen in the previous figure, the system has 14 nodes and 13 branches. This model is based on a SPEN low voltage network. The system represents the typical low voltage system with a total power of 105 kW. Divided between the system buses. This system has been chosen because the simulation was intended to be as real as possible. Thus, achieving the most realistic results. The characteristics of each branch (length, impedance and connecting buses) can be seen in the following table.

Line characteristics				
Sending node	**Receiving node**	**Length (m)**	**R (ohm)**	**X (Ohm)**
1	2	62,9	0,01883	0,00461
2	3	12,3	0,00591	0,00093
3	4	49,2	0,02362	0,00373
4	5	36,9	0,01772	0,00279
5	6	24,6	0,01181	0,00186
2	7	19,7	0,00660	0,00145
7	8	29,6	0,00990	0,00218
8	9	49,3	0,01650	0,00364
9	10	45,7	0,01347	0,00335
10	11	45,7	0,01347	0,00335
11	12	45,7	0,01347	0,00335
9	13	87,8	0,04687	0,00667
13	14	58,5	0,03125	0,00445

Table 6. Line characteristics of the system

As is usual in a low voltage system, it can be verified that the characteristics of the lines do not usually coincide and are not uniform. At each bus of the system there is an associated load. The characteristics of each load (power and connected phase) are shown in the following table.

Bus Demands characteristics			
Bus demand	**Power (kW)**	**P.f**	**Phase**
2	10	0,98	R
3	10	0,98	B
4	5	0,98	Y
5	10	0,98	R
6	10	0,98	B
7	10	0,98	Y
8	5	0,98	R
9	5	0,98	B
10	10	0,98	Y
11	10	0,98	R
12	10	0,98	B
13	5	0,98	Y
14	5	0,98	R

Table 7. Loads characteristics per bus

As can be seen from the table above, the total power foreach phase of the system is different (R = 40 kW, B = 35 kW, Y =30 kW), causing the system to be unbalanced. Because of this, each phase of the system has to be studied separately. Regarding which kind of the faults will be tested, the methods will be tested with different types of faults, although some of them as a fault of 3 phases are very rare. The characteristics of the faults are the following:

System fault characteristics			
Fault line	**Fault type**	**Fault resistance (Ω)**	**Fault Location**
2–3	Y-E	10	30 % from 2
5–6	R-B-Y	5	75 % from 5
7–8	B-Y	50	18 % from 7
10–11	R-B-Y	1	92 % from 10
13–14	R-E	100	55 % from 13

Table 8. Faults tested with the 2 developed methods

To calculate the error of the methods with respect to the calculated distance, the following formula is applied. All line lengths are assumed to be 1p.u length. This formula will be applied to calculate the error in the 2 methods.

$$Fault\ distance\ error\ \ (e) = \frac{|Calculated\ distance - Actual\ distance|}{Line\ length} * 100\,\% \tag{48}$$

2.4.1. 1º Method results

After using the 1º method with the faults described above, the following results were obtained:

Results of the fault testing					
Fault line	**Fault type**	**Fault resistance (Ω)**	**Fault Location**	**Estimated Fault Distance**	**Fault Distance Error (e)**
2–3	Y-E	10	30 %	30.02 % from 2	0.02 %
5–6	R-B-Y	5	75 %	75.23 % from 6	0.23 %
7–8	B-Y	50	10 %	10.29 % from 7	0.29 %
10–11	R-B-Y	1	92 %	91.57 % from 10	0.43 %
13–14	R-E	100	55 %	54.92 % from 13	0.08 %

Table 9. Faults testing results of the 1º developed method

For different types of faults and fault resistances, the results obtained after testing the 1º method showed that all the faults are successfully localized and the fault distance is also being estimated with a maximum error of 0.43 %. Based on the testing results from the table above, this fault location algorithm has been verified and the results also shows that the algorithm is not affected by the fault type and fault resistance.

2.4.2. 2º Method results

After using the 2º method with the faults described above, the following results were obtained:

Results of the fault testing					
Fault line	**Fault type**	**Fault resistance (Ω)**	**Fault Location**	**Estimated Fault Distance**	**Fault Distance Error (e)**
2–3	Y-E	10	30 %	30.09 % from 2	0.09 %
5–6	R-B-Y	5	75 %	75.47 % from 6	0.47 %
7–8	B-Y	50	10 %	10.62 % from 7	0.62 %
10–11	R-B-Y	1	92 %	90.96 % from 10	1.04 %
13–14	R-E	100	55 %	54.79 % from 13	0.21 %

Table 10. Faults testing results of the 2º developed method

For different types of faults and fault resistances, the results obtained after testing the 2º method showed that all the faults are successfully localized and the fault distance is also being estimated with a maximum error of 1.04 %. Based on the testing results from the table above, this fault location algorithm has been verified and the results also shows that the algorithm is not affected by the fault type and fault resistance.

2.5. Conclusions

In this thesis, two PMU-based fault detection and location methods are proposed for the low-voltage network. The 2 methods are based on real-time state estimation. The first method stands out because due to the use of a large amount of μPMU, a total observability of the system is available. Based on this, the SE is based on the topologies of the network that includes a imaginary fault bus. This imaginary fault bus is the one that allows that when comparing the weighted measurement residuals of all the SEs, it is possible to identify the line in which the fault has occurred thanks to the fact that it is the line with the lowest residual. As a negative part of the application of this method is its high cost due to the need to install PMU in all nodes of the system. This makes the application of this method not really economically viable in LV, although in MV it may be more profitable. Despite the cost of this method, it also has many advantages. The total observability of the system means that the topology of the network can be whatever it is and also the presence of DG does not change the performance of the method since the state estimation is not affected by the nature of the loads of generators of the buses.

The second method is also based on SE. Contrary to the first method, there is not a total observability of the system, but by having measurements at the beginning and end of each line it is possible to locate where the fault has occurred by making SE based on those measurements. The fault location is done thanks to an iterative process that consists of SE based on the measurements of the beginning and end of the line, these SEs will be iterated until they converge in the place where the fault has occurred. This method, unlike the first method, is economically feasible because it uses a much smaller number of μPMUs. It works especially well in radial systems since, although few measurements are available, it is possible to perform the SE without difficulty as long as information on the loads of the system nodes is available.

The validation of both methods has been carried out using a 14 bus low voltage distribution network. The power grid and PMUs are simulated in the time domain using Simulink. Noise was added to the measurements obtained based on the characteristics of the μPMU measurement errors. The data obtained from the simulations are implemented in the algorithms corresponding to each method to check its operation. Faults of all kinds have been simulated in different locations of the system. Both methods have achieved acceptable results since they have been able to locate the faults with a small percentage of error. The first method has better results, that was to be expected since having measurements in all the buses of the system, makes the state estimation more exact. Based on these results, the proposed methods can be implemented in the low voltage network to locate faults. If we compare the financial outlay of both methods, the most economical and viable option to implement is the second method despite having slightly lower results.

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PART II

ANNEX: ODS

The Sustainable Development Goals (SDGs) are a collection of 17 global goals designed to be a blueprint to achieve a better and more sustainable future for all.This project influences one of these 17 goals. Next it will be indicated in which this project helps to achieve them. Many of these goals are interrelated and advancing in one of them it is possible to advance in others. The goals most affected by this project are:

Goal 7 is affordable and clean energy. This project allows faults to be detected in the low voltage system, this will allow distributed generation to be easier and therefore to be incorporated without fewer problems. This allows for more generation of clean energy and therefore reduces CO2 emissions.

Goal 9: Industry, Innovation, and Infrastructure. The work consists of the introduction of a new technology in the distribution system. This promotes making the grid smarter. The inclusion of this technology to locate faults is just one of the many applications that this technology can have, that is, the inclusion of this technology in the future could be used in other applications improving the system.

Goal 11: Sustainable cities and communities. This goal is linked to Goal 7. The inclusion of this technology will improve the inclusion of the distributed generation of the system, making consumers more self-sufficient with respect to electricity and less dependent on traditional generation.

The 13 goal: Climate action. As its name suggests, it is related to reducing the impact on the climate produced by man. To achieve this, it is necessary to reduce CO2 emissions. A clear example of how to achieve this is electricity generation through renewable sources such as solar energy or wind energy. The incorporation of these energies to the electrical network supposes numerous challenges. This project helps to overcome one of these challenges, which would be the location of faults that can occur in low voltage and therefore affect the bidirectional power flow that may exist in the low voltage network thanks to renewable technologies.

In conclusion, this work helps in obtaining these goals, favoring the possible integration of renewable energies in the system, as well as including a new technology in the electrical network whose various applications can also help to achieve the SDGs.