The Future of Substations: Centralized Protection and Control

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(ABSTRACT)

Current power system substations rely on a combination of electromechanical and intelligent electronic devices (IED) to operate a multitude of protection schemes. The burden of these numerous devices connected to instrument transformers results in inaccurate sensor measurements that can cause improper system operation. This document explores the current design of substations, identifies known problems, and proposes a solution using a new system architecture based around a Centralized Protection and Control (CPC) unit. This solution includes the introduction of merging units (MUs) as a synchronized data collector for recording accurate measurements of instrument transformers as well as the detailing of multiple other improvements the system would make.

The Future of Substations: Centralized Protection and Control

Adam Thompson

(GENERAL AUDIENCE ABSTRACT)

The infrastructure that connects electrical power generators to consumers utilizes a wide range of equipment to safely and reliably prevent interruption to service. New distributed power technologies have been introduced to the power system, such as solar panels, wind farms, and home batteries, which have caused the way this system become more dynamic then it has in the past. Most of these changes have occurred on the generation and consumption sides of the system, but the equipment that connects those two sides have not evolved very much in the last 50 years. This document explores some of the problems that this can cause and discusses a method to improve called Centralized Protection and Control.

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List of Abbreviations

ADC – analog to digital conversionconverter

CB – circuit breakers

CCVT – coupling capacitor voltage transformer

CPC – centralized protection and control

CT – current transformer

DMS – Distribution Management System

DNP – Distributed Network Protocol

DSE – Dynamic State Estimation

ECT – electronic current transformer

EMS – Energy Management System

GOOSE – Generic Object Oriented Substation Event

GPS – Global Positioning System

HMI – Human Machine Interface

HVDC – high voltage direct current

IED – intelligent electronic device

IF – logical interfaces

IT – information technology

IMU – intelligent merging unit

LPCT – low power current transformer

LPF – low pass filter

MMS – Manufacturing Messaging Specification

MU – Merging Unit

OC – overcurrent

PLC – Power Line Carrier

PMU – phasor measurement unit

PTP – precision time protocol

RCT – Rogowski Coil current transformer

RMS – root mean squared

RTU – Remote Terminal Unit

SCADA – Supervisory Control and Data Acquisition

SCL – Substation Configuration Language

SV – sampled value

UTC(NTSC) – Coordinate Universal Time of National Time Service Center

VT – voltage transformer

Introduction

One of the most complicated systems humanity has built is the one that generates and distributes electrical power over vast expanses of land. Originally devised to provide electricity to small, incongruous regions, these grids have expanded until they interconnect across continents. As more non–traditional generation techniques are added to the grid, this system becomes more dynamic and new techniques for operation and control will need to be developed to insure the robustness of the system. Acknowledging the need to improve existing infrastructure in the United States, the US Department of Energy has invested more than $31 billion from the American Recovery and Reinvestment Act of 2009 to support a wide range of energy related projects around the country [1]. This document aims to suggest a method to centralize protection and control within substations that will increase the reliability and flexibility of the system while building a foundation for engineers to innovate and adapt to the ever changing landscape of power systems.

While high voltage direct current (HVDC) transmission systems are becoming more common in parts of Asia, the majority of the world uses balanced three–phase alternating current (AC). This design utilizes three separate wires to conduct sinusoidal currents of the same magnitude and frequency that are each shifted 120°, illustrated in Fig. 1. This evenly spaced phase shift results in a nearly constant power transfer to a balanced load. When operating under these ideal conditions, the system is said to be balanced. While some configurations of 3–phase AC use an additional neutral wire for reference, it is not necessary for all and only requires three conductors as opposed to the six that would be necessary for three individual phases. In addition to reducing construction costs, the removal of three transmission lines also eliminates their I^2R losses, making the system more efficient then its single phase counterpart.

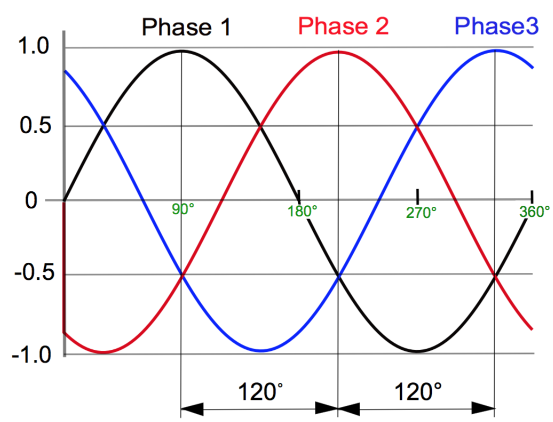


Figure 1: **Normalized 3–Phase Waveforms** [2]

Due to this configuration, during ideal conditions power system can typically be reduced to simple, single line diagrams for analysis, but during abnormal conditions, such as when a fault occurs, the system can become unbalanced and analysis calculations become much more complicated. Over the years, mathematical concepts have been developed to combat these complexities and can be further investigated in the textbook [3].

Examining the power grid in a general way, it can be broken into three main utilities: generation, transmission, and distribution. First, electricity is generated by converting mechanical power to electrical, typically using some form of prime mover. For many reasons, these generators are not usually located near population centers and the power must be delivered to them for use via transmission lines. To connect customers to the system, transmission lines are coupled to a distribution system that feeds power to individual users. A modern vision of this electrical system is illustrated in Fig. 2.

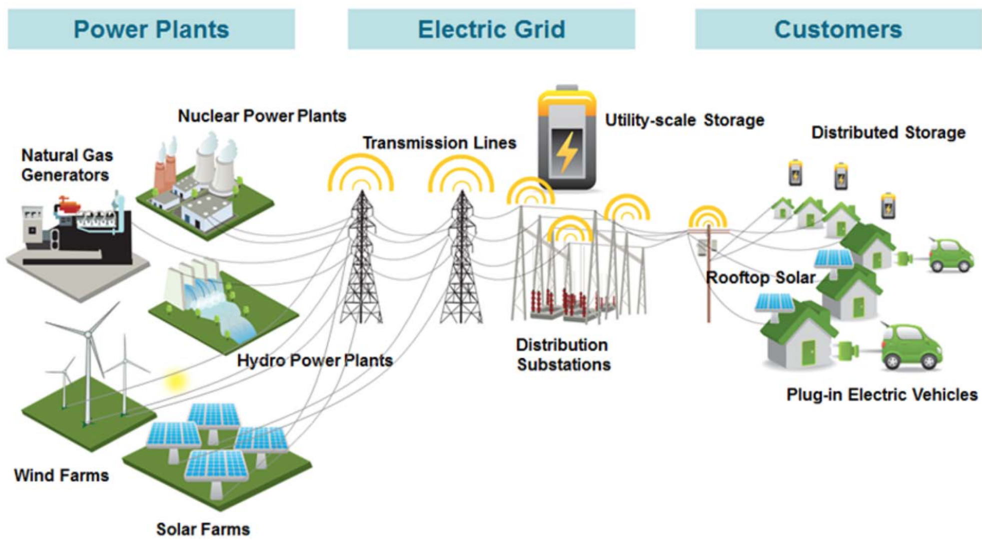


Figure 2: **Sustainable Electrical System** [4] © 2015 IEEE

Traditional power systems used to be one directional with power plants injecting power into the system which then flowed to the consumer, but with the addition of rooftop solar panels, distributed and utility–scale storage, and other new innovations, power flow has become much more dynamic. To conjoin each section of the system, transformers are used to step up or step down voltages to appropriate levels. Once at a common magnitude, buses are used to connect two or more sections together allowing power to be diverted in different directions. These buses and transformers, along with other equipment used for protection and control, are housed in substations.

To normalize the magnitudes of the quantities in each section, power system engineers often express these quantities in per–unit. This representation of the quantity is a percentage of the base value of the system. For example, if the rated voltage of one of the windings of a transformer is 24 kV and the measurement at the terminal is 18 kV, the terminal voltage would be expressed as 0.75 per–unit. While seemingly simple, this system is very helpful for simplifying calculations and rapidly identifying gross errors since there are a wide range of base values within the grid.

One of the major ways the power system infrastructure has aged is the protection equipment used in these substations. While new devices have been introduced to improve the operation and control of the grid, the technology used in protection has not evolved much. Formerly composed of electromechanical and solid state relays, the newer computerized relays simply emulate the older equipment without addressing known problems with the system. This paper aims to identify these areas for improvement as well as suggest an update to substation hardware architecture that would allow for incremental improvements without major costs or down time.

Chapter 1

Substation Overview

In the broadest sense of the term, a substation connects two or more segments of a power system. They are generally described by the function they serve, but the variation of equipment used in the different types is fairly limited. Many substations act as a connecting point of systems and/or areas that operate at different voltage levels. Such substations include power transformers to scale the voltage of one area to match the voltage of the adjacent area. In order to provide adequate reliability to the overall system, protective devices are installed to detect abnormalities and react accordingly in a coordinated way with other devices. To this end, a collection of elements such as current and voltage transformers (CTs and VTs), relays, circuit breakers (CBs), and sectionalizers are utilized. CTs and VTs convert the currents and voltages of the system down to an amplitude that is usable by the relays of the system. Relays then process the current and voltage information and send a signal as to whether the associated CB should change state or not. The following section will discuss the various types of substations and their use within the power grid.

1.1 Types of Substations

Transmission Substations

Transmission substations connect two or more transmission lines to one another. The most simple transmission substation operates at only one voltage level and connects two segments of transmission lines using a single bus. CTs and VTs are placed on either side of the bus and the transmission lines are connected through CBs. In more complicated scenarios, multiple transmission lines of various transmission voltages are interconnected with a greater degree of control and protection.

Distribution & Collector Substations

Having transported power from the generator, it is not practical to distribute it at voltages as high as are used for transmission. Distribution substations step down the voltages from transmission levels to levels more suitable for the feeders into the community. These feeders run both overhead and underground, and connect to the final distribution transformers reducing the voltage to consumer levels. In addition to fault isolation using CBs and transmission line switching, distribution substations are also frequently a point of voltage regulation for the system which also makes use of the aforementioned CTs and VTs.

Similarly, collector substations are effectively the reverse of a distribution substation where many lower voltage sources are collected and then stepped up to higher transmission voltages. These substations are used for applications of distributed generation systems such as wind farms and PV generation, and provide power factor correction, metering, and control of the generation system.

Other Substations

More specialized substations, such as converter and switching substations, exist for various niche roles in power systems. While these different types of substations function to serve very specific roles, the underlying measurement and operation principles do not vary much from the previously discussed substations. Because of this, these substations will not be discussed further in this document.

1.2 Substation Hardware

As discussed in the introduction, the main goal of protective equipment in substations is to detect and correct abnormal conditions, e.g. faults, voltage collapse, swells, sags, surges, overloads, etc. To accomplish this, data is collected in the form of measurements and processed to provide monitoring, control, and protection capabilities. At the heart of these systems lie transformers (CTs and VTs), relays, and CBs, which are used collectively to achieve the desired goal.

1.2.1 The Ideal Transformer

The most basic model of a transformer is the ideal single-phase two-winding transformer which is constructed by wrapping two sets of windings around a magnetic core. This construction is illustrated in Fig 1.1.

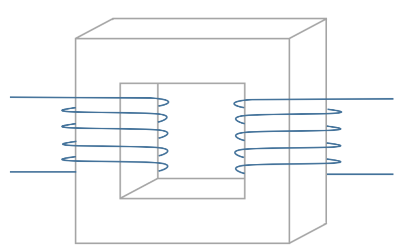


Figure 1.1: **Basic construction of a two–winding transformer.**

For the ideal model, the following assumptions are made [3]:

- The transformer is operating under sinusoidal steady state excitation.
- The windings have zero resistance and therefore have no I^2R losses.
- The core permeability is infinite and therefore there is zero core reluctance.
- All flux is confined to the core and links both windings.
- There are no core losses.

From these assumptions, Ampere's and Faraday's laws can be used to derive the ideal transformer relationships for the schematic representation in Fig 1.2.

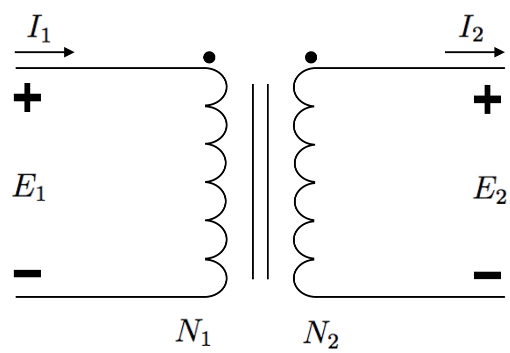


Figure 1.2: **Schematic representation of an ideal transformer.**

$$N_1 I_1 = N_2 I_2 \tag{1.2.1}$$

$$\frac{E_1}{E_2} = \frac{N_1}{N_2} \tag{1.2.2}$$

$$a_t = \frac{N_1}{N_2} \tag{1.2.3}$$

1.2.2 Practical Transformers

While the ideal model may be useful for the basic understanding of single phase, steady–state operation, it is more realistic to use a more detailed model for the dynamic operation of power systems. For this more detailed model, we take the following into consideration [3]:

- The windings have resistance.
- The core permeability is finite.

- All flux is not totally confined to the core.
- There are real and reactive power losses in the core.

The changes to the model are represented in Fig. 1.3.

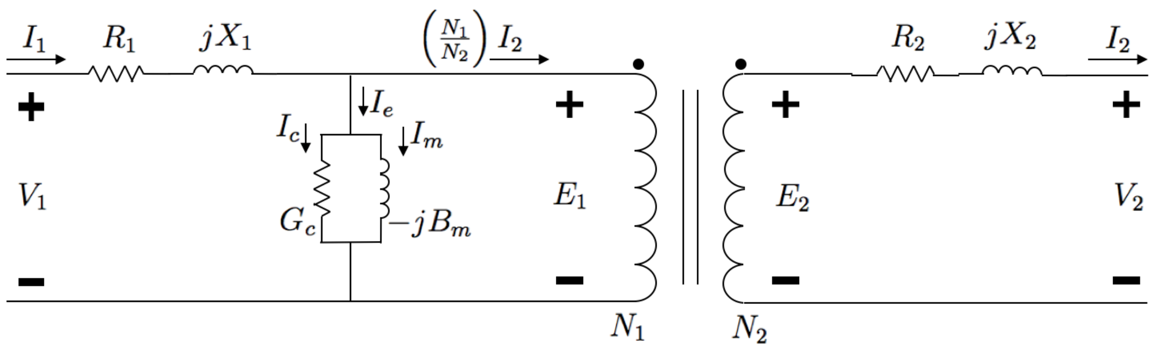


Figure 1.3: **Schematic representation of a practical transformer.**

Compared to the ideal equivalent circuit, the practical model is much more involved: R_1 and R_2 represent the resistance of each winding, and each are in series with X_1 and X_2 respectively, which represent the leakage reactance of each winding due to the flux leakage of the windings that do not link with each other. These components of the model correspond to the first two changes.

To account for the fact that the core permeability is finite and there are losses in the core, the excitation branch is added with the indicated excitation current, I_e. This current is then split into two components: the first one, I_c, represents the core losses associated with the unit and the second component, I_m, is related to the coupled magnetizing flux. The equivalent circuit associated with the magnetizing branch is formed by two parallel elements, one associated with the core loss (G_c) and the other with the magnetizing flux (B_m) which are both expressed in Siemens.

While these changes provide for a more comprehensive model, it is only applicable to non-transient, sinusoidal excitation currents within the rated values of the transformer. As the result of the nonlinear characteristic of the magnetic material, certain conditions must be accounted for or analyzed separately; these include core saturation, inrush current, non–sinusoidal excitation, and surge phenomena.

1.2.3 Power Transformers

As discussed before, one of the main purposes for most substations is to step up or step down voltages for transmission or distribution. It should be noted at this time that for power system applications, three-phase is most often used and transformers are often constructed using three single phase units. As such, these units may be connected in two possible configurations, one called Delta and the other called Wye, illustrated in Fig. 1.4.

Because these configurations each have their benefits and drawbacks, the transformation between the two is often desired.

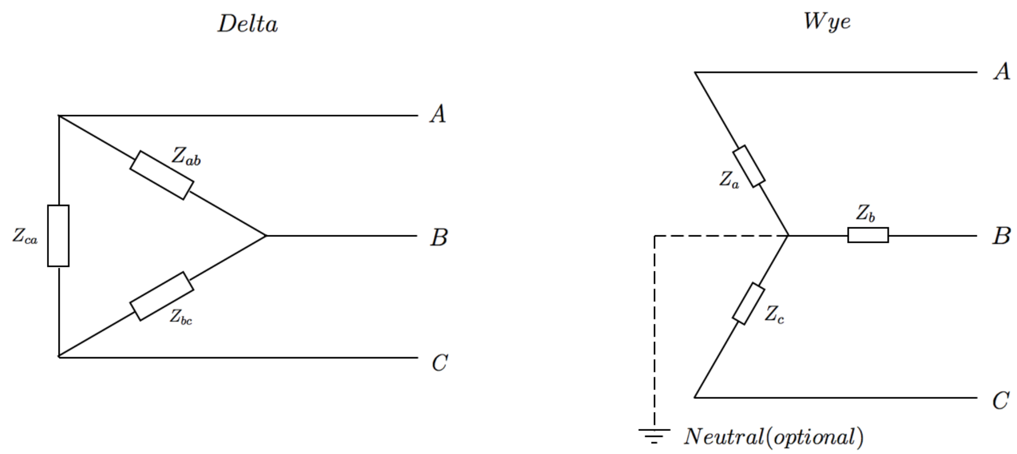


Figure 1.4: **Delta and Wye wiring diagrams.**

1.2.4 Instrument Transformers

Power transformers are not the only types of transformers used in substations, instrument transformers also play an important part in the role of system operation and protection. Instrument transformers have two main purposes in the power system: first, they provide accurate reproductions of current and voltage signals to relays and meters at a suitable amplitude, and second, they provide galvanic isolation between the power system and the protective system, which is to say that they prevent any current from flowing directly between the two systems. These transformers are designed not only to be accurate during normal operation, but also at abnormal conditions during which action on the system is required.

Current Transformers

Unlike the transformers discussed up until this point, CTs are typically constructed with the primary winding consisting of a single turn. To do this, the primary conductor is run through the center of the magnetic core as illustrated in Fig. 1.5. The secondary winding is then wrapped around the core and often tapped at various turn intervals to offer multiple ratio options.

While this transformer is generally modeled using the equivalent circuit from Fig. 1.3, it is frequently simplified (Fig. 1.6) using the following assumptions [6]:

- N_1 always equals 1 and therefore $n = N_2$
- I_1 is dictated by the network and consequently the leakage impedance, R_1 and X_1, have no impact on the performance of the transformer and may be omitted.
- The remaining primary side quantities can be related to the secondary winding with the following equations:

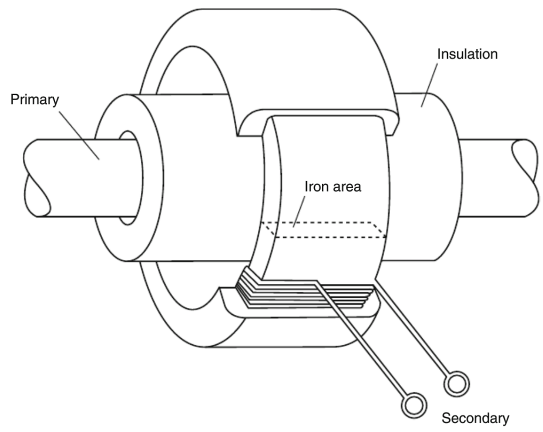


Figure 1.5: **Design of ring CT.** [5]

$$I_1' = \frac{I_1}{n} \tag{1.2.4}$$

$$Z_m = n^2(G_c - jB_m) \tag{1.2.5}$$

$$Z_2 = R_2 + jX_2 \tag{1.2.6}$$

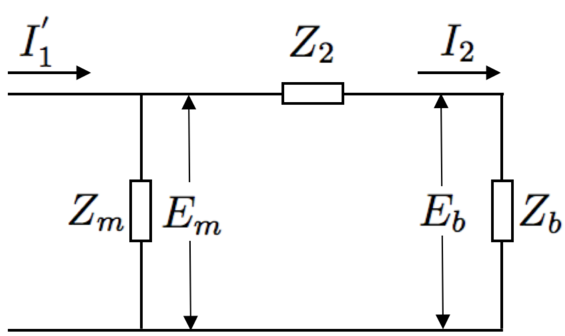


Figure 1.6: **Simplified equivalent circuit of a CT.**

The load impedance or burden, Z_b, is the summation of all the meters, relays, and connecting wiring affixed to the secondary winding. This burden is of much consideration when discussing all the wiring involved in a substation, and the wiring alone is often a significant part of the load impedance. With this simplified circuit, the operating error of the transformer can now be calculated in per–unit with the following equation:

$$\varepsilon = \frac{I_1' - I_2}{I_1'} \tag{1.2.7}$$

The other consideration for the accuracy of CTs is the nonlinear nature of the magnetic core. Fig. 1.7 illustrates this concept by comparing the secondary voltage and excitation current of various CT ratios.

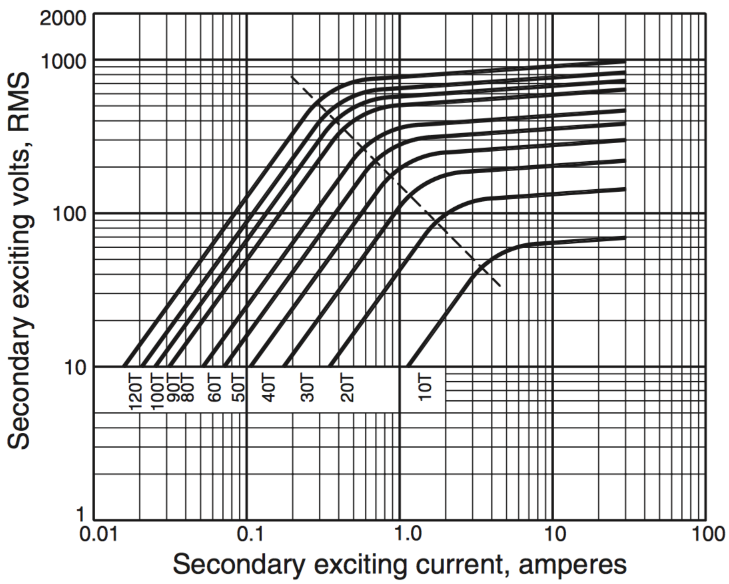


Figure 1.7: **Saturation curve of a multiratio CT.** [7]

During fault conditions, currents may reach as much as fifty times the typical load current for up to a few seconds. This means that CTs designed to be accurate at nominal load current may be wildly inaccurate during fault conditions if the burden of the relay is high.

Using the limiting case where the $Z_b = 0$ and Z_2 is very small, $I_1' \approx I_2$ and therefore the error of the CT is zero. Realistically, the burden of each device can be designed to be small, but the overall burden to the transformer grows with the number of devices added in series. By keeping this impedance low, the voltage of the secondary winding stays small even during fault conditions resulting in low error since the CT does not saturate and stays in the linear region. When too many devices are connected in series, the secondary winding voltage grows and the core can become saturated during fault conditions. The result is that the secondary current increases nonlinearly and disproportionately to the primary winding current, therefore the operation error increases significantly.

With current substation designs relying on many devices all connecting to the same CT, introducing a single, low impedance measurement device that can distribute that information to any other device provides a huge opportunity to decrease the burden being placed on the transformer resulting in more accurate measurements throughout the system. Accurate measurements result in better monitoring and control as well as improved fault location and isolation, all of which are of great value to system operators and maintenance teams.

Non-traditional Current Transformers

While the traditional iron core CT is the most commonly used variation, low power current transformers (LPCTs) and linear couplers such as Rogowski Coil current transformers (RCTs) are becoming prevalent in the design of electronic current transformers (ECTs). Both of these designs have benefits over the traditional magnetic core transformers, but are only now becoming the topic of research as the digitization of a signal has a much lower power requirement than that of an electro–mechanical relay. The basics of both of these designs are to replace the iron ferrite core with one that is less susceptible to magnetic saturation and ferromagnetic resonance. These two designs are most accurate at different signal magnitudes from each other, so there is much research being done on combined ECTs that use data switching methods to use both designs in cooperation to provide highly accurate measurements regardless of the magnitude [8].

Because the output of these devices are low voltage and low current, it makes them ideal for digitization and could be used redundantly with traditional CTs for more robust measurement systems.

Voltage Transformers

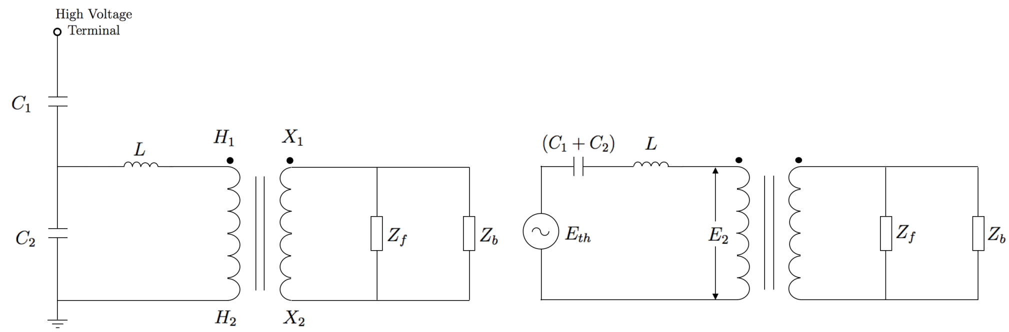
Unlike CTs, VTs are normal, two–winding transformers with the primary winding connected directly to the high voltage device. Abnormal conditions of a power system rarely involve voltages greater than 110% of nominal voltages over sustained periods of time and therefore are considered accurate across all operating ranges [6]. Because of this consideration, VTs are generally modeled as ideal transformers as illustrated in Fig. 1.2.

Although VTs may be modeled ideally, they do have a burden issue similar to CTs. To make voltage readings, devices must be connected in parallel and ideally are sensing an open circuit voltage. Even though voltage measurement devices are designed to have extremely high impedance to emulate an open circuit, as more devices are added to the system the impedance of the burden decreases. As this burden decreases, the current in the secondary winding grows and a voltage drop due to the series leakage impedance develops. The potential at the terminals reflects this voltage drop, which results in an increased operation error. Again, by introducing a single, high impedance device to measure and distribute the measurement information, the accuracy of the system can be increased.

Coupling Capacitor Voltage Transformers

While VTs are typically used for low–, medium–, and high–voltage systems, coupling capacitor voltage transformers (CCVTs) are generally used for extra high voltage systems of 345 kV or greater. Often in power line carrier protection systems capacitor stacks are connected to high voltage transmission lines for the purpose of transmitting a carrier signal between substations. CCVTs work by using the same capacitor stack as a voltage divider between the line and ground, accessing a much lower voltage in the range of 1 to 4 kV. The transformer is then connected to the tap point and a leakage inductance, L, designed to to reduce transient phenomena. These connections and the equivalent circuit of the CCVT are illustrated in Fig. 1.8.

For these diagrams, Z_b is the same burden impedance seen in Fig. 1.6 and Z_f is designed into



(a) (b)

Figure 1.8: **(a) CCVT connections and (b) the equivalent circuit.**

the circuit to dampen ferroresonance that may occur under certain conditions. With the addition of these reactive elements to the circuit, a phase shift between the primary and secondary voltages will occur. To eliminate this issue, the inductance, L, is designed to be in resonance with the equivalent capacitance of the stack for the stead–state frequency, ω, of the system using the following equation:

$$L = \frac{1}{\omega^2} \frac{1}{C_1 + C_2} \tag{1.2.8}$$

When properly designed to be in resonance, the elements $(C_1 + C_2)$, illustrated in Fig. 1.8b, in series with L will result in a zero equivalent impedance. The result is that there is no voltage drop from E_{th} to E_2 and the system can be modeled using an ideal transformer.

1.2.5 Circuit Breakers

If the transducers are the eyes and ears of the protection system, and the relays are the brain, then circuit breakers are the muscle. When faults or other abnormal conditions occur, action must be taken to de–energize the problematic section by breaking the circuit. The most primitive circuit breaking device is the fuse, which acts as both the level detecting sensor and interrupting device. Installed in series with the equipment it's meant to protect, its operation is based upon the melting of a sensitive element in response to elevated current flow. These are one–shot devices, meaning they must be manually replaced once tripped, and are designed to limit the magnitude of the current flowing in a circuit.

Reclosers and sectionalizers are two more devices commonly used for distribution circuit protection. These are self–controlled devices that have built in controls to work in cooperation to clear the fault without interrupting service of non–effected regions. A sectionalizer has no fault interrupting capabilities, it counts the number of times it detects fault currents and opens after a preset amount of times when the circuit is de–energized. Comparatively, a recloser has limited fault interrupting capabilities and recloses automatically in a specific sequence. This device is helpful for clearing temporary faults, such as lightening strikes and transmission lines coming in contact with tree limbs, with minimal interruptions to service.

When all else fails, coordinated action between a relay and circuit breaker must take place in order to interrupt the flow of current in the circuit. For extra high–voltage CBs, fault currents may be in the order of 100 kA at system voltages up to 800 kV may be present. For the CB to insure a successful disconnection, it is necessary that the dielectric strength built between the separated contacts must be greater than the transient recovery voltage, otherwise the contacts will arc and the CB will be forced to reattempt disconnection at the next zero crossing. Once operating conditions have returned to normal, the CB will attempt the reconnection of the circuit. This operation may be manual or automatic depending on the system. While this document will not cover all the designs of the many types of CBs, it is important to understand their purpose in the system.

1.2.6 Relays

As the brains of the system, the relay's job is to detect abnormal conditions and initiate actions on the system to correct them. These devices have evolved throughout the years; when power systems were first built in the 1890s, relays were electromechanical devices. In the late 1950s they progressed to being designed as solid–state hardware, and now are being implemented with micro controllers and microprocessors. Although the hardware has changed over time, most of the operating principles and protection vocabulary have not.

Detailing the various construction and design concepts of traditional relays does not fall within the scope of this document, but a knowledge of the principles of their operation is crucial to understand substation operations. To better understand these principles, it is easiest to divide relays into categories based upon the types of input quantities to which a particular relay responds.

Level Detection

The most simple principle is level detection which works on the basis that abnormal conditions will result in the increase or decrease of current and/or voltage. For an overcurrent relay, a threshold is set to send a signal to take action when this threshold is surpassed and to take no action otherwise. Conversely, an under voltage relay reacts when the voltage drops below the threshold and does not intervene when it is above.

Magnitude Comparison

Another simple principle, magnitude comparison is based upon comparing one or more operating quantities with each other. A tolerance threshold is set and the relay takes action if the magnitude of one quantity is larger or smaller than the other, plus or minus the tolerance.

Differential Comparison

Similarly, differential comparison evaluates the difference of signal from two points in a system and reacts if this difference becomes too great. This type of relay is frequently used on generators to detect faults in the windings. Since the current entering the winding should be the same as the current leaving the winding, any difference in current is the result of a fault. Similarly, differential protection can be applied to substation elements such as transformers, busses, and reactors. During the past years, research has indicated that line differential protection was not feasible due to the timing accuracy required for such a system. However, present application of GPS timing and phasor measurement units (discussed in a subsequent chapter) had shown promise for such an implementation.

Phase Angle Comparison

This category of relay compares the relative phase angle of two AC quantities and can give directionality with respect to the reference angle. For instance, if there is a fault on one of two transmission lines connected to a bus, the phase angle of the fault current on the line with the fault will lag the reference voltage. On the line without the fault, the fault current will lead the reference voltage and senses that the fault is "behind" it.

Distance Measurement

Using the conductor diameter and spacing between phases of a given transmission line, it is possible to determine its positive sequence impedance per–unit length. By taking measurements of the voltage and current of a line at the bus the apparent impedance seen by the relay can be computed. The appropriate ratio of these calculated values can be used to determine if a perceived abnormal operating condition can be deemed as within the operating zone of the relay or out of it.

Pilot Relaying

Pilot relaying involves the use of a communication channel between the two ends of a transmission line. Traditionally, this communication channel is created using power line carrier (PLC), microwave, telephone circuits, or fiber optics, and allows both ends of the transmission line to provide coordinated clearing of 100% of the line.

Harmonic Content

While an ideal power signal is a pure sinusoidal waveform of the fundamental system frequency, the reality of our system is that power electronics, saturation of magnetic materials in generators and/or transformers, and other factors cause deviations, in the form of harmonics, from this ideal during normal system operation. On the other hand, other harmonics occur during abnormal operation. These relays can differentiate between normal and abnormal harmonics, and make the decision whether or not to take action.

Frequency Sensing

Similar to the previous category, some relays use frequency sensors to take action based off deviations from the ideal power signal. Normal power system operation is at 50 or 60 Hz, depending on the country, and deviation from these values mean that a problem exists or is developing.

While there may be a large variety of protection devices, the types of inputs to them are fairly limited. Today's intelligent electronic devices (IEDs) individually connect to the necessary CTs and VTs to make their own measurements, adding to the burden of the system, but this does not have to be necessary. As relays are simply data processing units, there is a big opportunity to remove the measurement aspect of the relay and have the unit receive measurements that have already been digitized. This concept has been explored in the past in [9].

Chapter 2

Data Measurement Device

As the speed of processors increases and the cost to implement digital systems decreases, a larger number of applications which have traditionally been analog are being converted to the digital realm. While sensing and circuit interruption are purely physical processes, relays are essentially just data processing units. To change these devices from electro–mechanical or solid–state to digital, the first step is to approximate the analog current and voltage signals using a collection of subsequent values taken at equal intervals of time.

2.1 Analog to Digital Conversion

The main goal of analog to digital conversion (ADC) is to take an analog voltage signal and convert it to a digital signal that can be transmitted, copied, and reproduced without compromising the original signal. This process is accomplished through sampling and quantization which will be discussed in the following sections.

2.1.1 Sampling

In the simplest terms, sampling is the process of taking snapshots of an analog signal repetitively at a constant speed. This can be imagined much the same way motion picture works in that each frame of film would be the sampled signal and connecting multiple samples together in time generates a moving image. In more precise terms, sampling is the action of taking a continuous time and continuous valued analog signal and producing a discrete time, continuous valued signal.

While this document will only give a brief overview of the most common ADC hardware, it is important to understand the mathematical principles of sampling theory [10]. Sampling theory states that given a signal, $x(t)$, whose spectrum is band-limited to B Hz, the signal can be reconstructed without error from its discrete time samples taken uniformly at a rate of R samples per second with the condition that the minimum sampling frequency is twice the band-limited frequency. Mathematically that is:

$$X(f) = 0 \qquad \text{for} \qquad |f| > B$$

where

$$R > 2B$$

and therefore

$$f_s > 2B \text{ Hz}$$

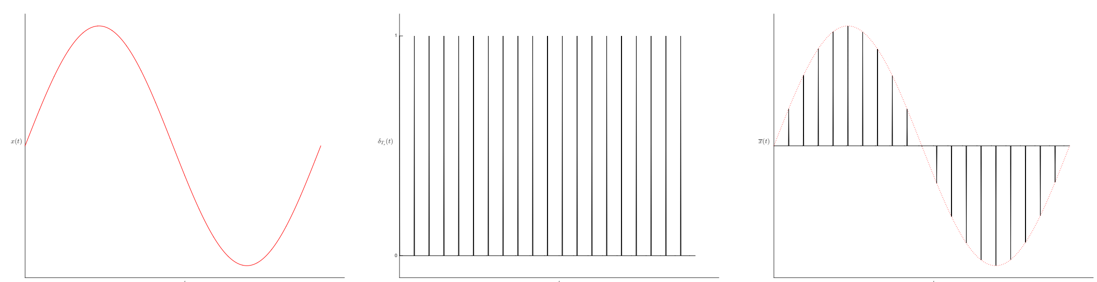
This uniform sampling is ideally accomplished by multiplying $x(t)$ by an impulse train, $\delta_{T_s}(t)$, which consists of unit impulses spaced at a regular interval T_s where $T_s = 1/f_s$. This impulse train can be expressed as the following exponential Fourier series since it is a periodic signal with a period of T_s.

$$\delta_{T_s}(t) = \frac{1}{T_s} \sum_{n=-\infty}^{\infty} e^{jn\omega_s t} \qquad \omega_s = \frac{2\pi}{T_s} = 2\pi f_s \tag{2.1.1}$$

Multiplying $x(t)$ with $\delta_{T_s}(t)$ we get our sampled signal $\overline{x}(t)$

$$\overline{x}(t) = x(t)\delta_{T_s}(t) = \frac{1}{T_s} \sum_{n=-\infty}^{\infty} x(t)e^{jn\omega_s t} \tag{2.1.2}$$

This is represented graphically by Fig. 2.1 below:



(a) $x(t)$ (b) $\delta_{T_s}(t)$ (c) $\overline{x}(t)$

Figure 2.1: **Sampling $\boldsymbol{x(t)}$**

This resulting signal has the desired properties: it is now in discrete time and is continuous valued. Since a digital signal is in discrete time and discrete valued, the resulting signal must then be quantized.

2.1.2 Quantization

In digital systems, data must be stored in binary quantities (i.e. either a 1 or 0) with values limited by the number of bits of storage. When manufacturers describe ADCs, one of the main qualities of the converter is the resolution, given in number of bits. Since the goal of ADC is to store the voltage amplitude of each sample, the resolution of the system is determined by

$$Q = \frac{V_{max} - V_{min}}{2^n - 1} \tag{2.1.3}$$

where Q is the voltage resolution, V_{max} and V_{min} are the maximum and minimum reference voltages, respectively, and n is the number of bits.

To quantize the signal, the sampled signal $\overline{x}(t)$ is compared to voltages scaled to the resolution of the n bit system. Fig. 2.2 illustrates this concept as if this were a 4-bit system.

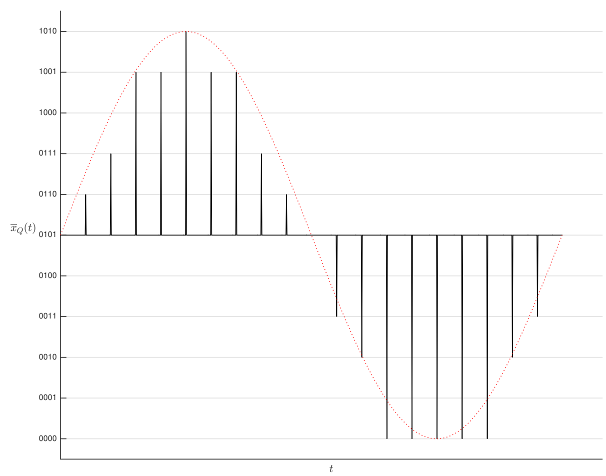


Figure 2.2: $\boldsymbol{\overline{x}_Q(t)}$

While no modern ADC uses such a low resolution for conversion, this example shows how quantization error is one of the main concerns for properly designing an accurate measurement device. In the case of this 4-bit system, quantization error was as high as 35% which would be unacceptable for any reliable product. By comparison, 10, 12, 14, and 16-bit ADCs are commonly found which offer 64 to 4096 times the resolution of a 4-bit ADC.

2.1.3 Aliasing

One of the other main concerns when designing an accurate measurement device is aliasing. Aliasing can best be described as an effect created when two different signals are indistinguishable as sampled data. Fig 2.3 illustrates an example of this phenomena.

As discussed before, one of the qualifications for sampling theory to work is that the sampled signal must be band-limited. In practice, real signals are time-limited, that is to say real signals have a finite duration. It can be demonstrated that a signal cannot be both time-limited and band-limited at the same time, which presents a practical issue when sampling real signals [10].

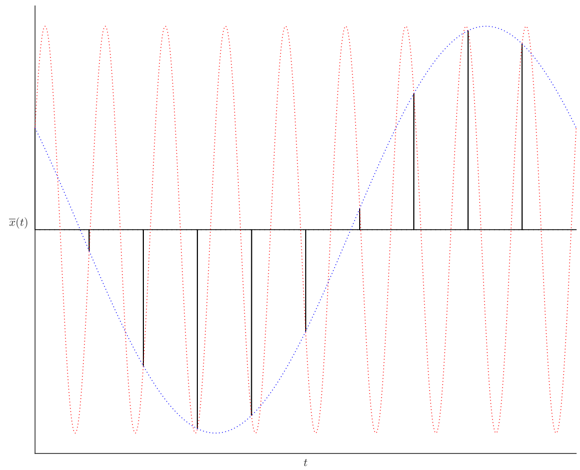


Figure 2.3: **Two sinusoidal signals with the same sample values.**

Recalling Eq 2.1.2 for the sampled signal, $\overline{x}(t)$, we take the Fourier transform to investigate the frequency content of the sampled signal.

$$\overline{X}(f) = \frac{1}{T_s} \sum_{n=-\infty}^{\infty} X(f - nf_s) \tag{2.1.4}$$

The result equates to the spectrum of $X(f)$, illustrated in Fig 2.4, scaled by $\frac{1}{T_s}$ and repeating periodically with a period of f_s, illustrated in Fig 2.5.

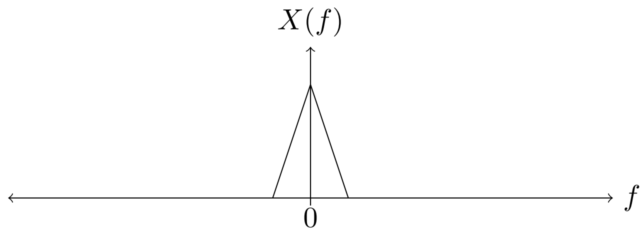


Figure 2.4: $\boldsymbol{X(f)}$

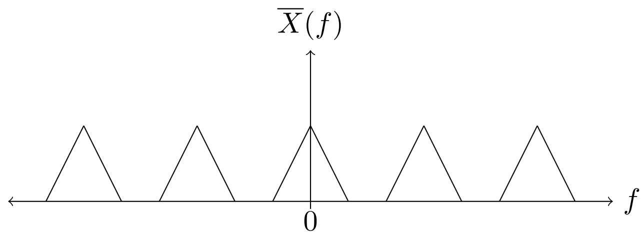


Figure 2.5: **Non-aliasing** $\boldsymbol{\overline{X}(f)}$

In this graphical example, the sample rate fulfills the requirement that $f_s > 2B$, also known as the *Nyquist criterion*, and the repeating spectrums do not overlap. As the sample rate is reduced, the repeating spectrums start to overlap introducing distortion, illustrated in Fig 2.6.

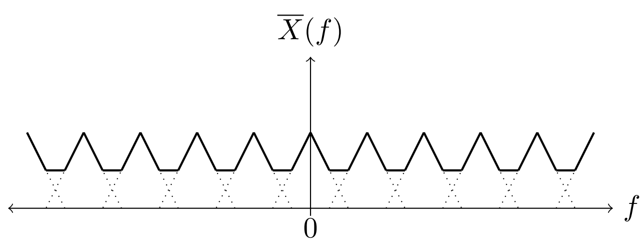


Figure 2.6: **Aliasing** $\boldsymbol{\overline{X}(f)}$

Although an ideal signal in power systems resembles one that is band-limited, the purpose of a measurement device is to accurately depict an analog signal digitally regardless of how ideal the input is. Therefore it is necessary to force the input signal to be band limited using an *anti-aliasing filter*. This filter, typically a low pass filter (LPF), removes content above the Nyquist frequency, $f_n = \frac{f_s}{2}$, which ensures that the resulting band-limited signal can be accurately captured as a digital signal. This process must be accomplished before sampling occurs and is designed into the front-end circuit.

2.2 Front End Circuit

As discussed in Section 1.2.4, the instrument transformers that feed the signals targeted for digitization are still very raw. To prepare these signals for digitization, they must be processed by a front end circuit to protect both the fidelity of the signal as well as the digitization circuit itself. The signal flow of this circuit is illustrated in Fig. 2.7

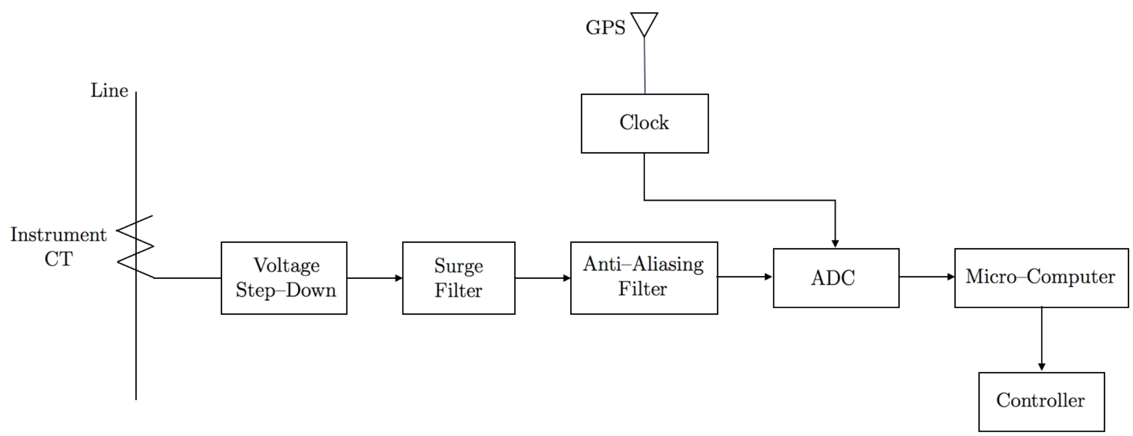


Figure 2.7: **The front end circuit of an ADC.**

Voltage Step-Down

The standard for traditional CTs and PTs is to output 1 or 5 amperes, depending on the region, for CTs and 120 Volts line–to–line for VTs. While this magnitude is acceptable for electromechanical devices, most ADC circuits compare the input voltage to a 1 to 5 V_{DC} reference.

Surge Filter

Of the many irregular operating conditions that may occur in a substation, transient spikes in voltage or current are not unusual. Unlike electromechanical devices, ADCs and microprocessors are much more susceptible to being damaged during these events. By including a surge filter in the front end of the circuit, these electrical quantities can be limited and/or diverted to ground to protect the measurement device.

Anti-Aliasing Filter

As discussed at the end of Section 2.1.3, aliasing can be prevented by band limiting the input signal. This is accomplished using a LPF with a cutoff frequency that's below half the sampling frequency. There are many designs of this filter including both active and passive filters that this document will not discuss, but what is important is to insure the linearity and lack of distortion in the filtered signal.

2.3 Synchrophasors

AC power, as opposed to DC, has a constantly rotating framework. Since the value of an AC signal is dependent on the point in time in which it is measured, signals traditionally had to be instantaneously compared to have any real meaning. This was not a problem when all relaying and operations were limited to a single space, but power systems cover vast areas of land. Since no transmission can be instantaneous, sending these measured values long distances results in transmission delays, or latency, and makes the measurements meaningless at their destination. The advent of the Global Positioning System (GPS) made it possible to give the measurement a universal time value, or timestamp, so that measurements made at any two locations could be compared using the same time reference.

2.3.1 Definition of Phasor

These waveforms are often represented mathematically in the following form:

$$v(t) = V_{max}cos(\omega t + \phi) \tag{2.3.5}$$

where V_{max} is the maximum value of the waveform, ω is the angular frequency, and ϕ is the phase angle. By assuming the same frequency and time reference, the signal from Eq. 2.3.5 can be written in phasor form as:

$$\overrightarrow{\mathbf{V}} = V\underline{/\phi} \tag{2.3.6}$$

where V is the root–mean–square (RMS) value of the signal, calculated $V = \frac{V_{max}}{\sqrt{2}}$. This phasor is represented graphically:

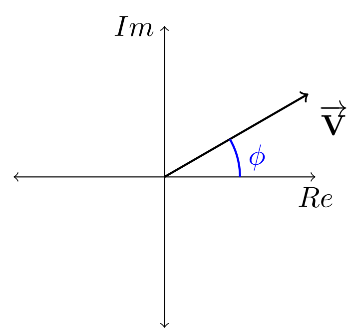


Figure 2.8: **Graphical representation of phase vector (phasor)**

By converting signals into phasors, voltages and currents can be compared in meaningful ways to understand the state of the system. Fig. 2.9 illustrates a phasor drawing of the voltages of a positive sequence, balanced three–phase system. In actuality, the three vectors are rotating in a counter–clockwise direction, but by removing the time dependance of signals they are represented with static vectors.

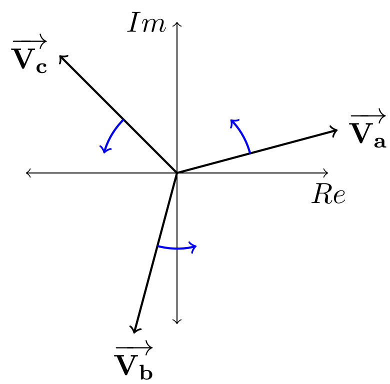


Figure 2.9: **Phasor representation of a balanced 3-phase system.**

2.3.2 History of Synchrophasors

First introduced to the International Electrical College in 1894, Charles Steinmetz coined the term"phasor" in his paper entitled, "Complex Quantities and Their Use in Electrical Engineering," which detailed how the use of phasors would simplify complex calculations used to represent AC waveforms [11]. Although this publication revolutionized how power systems were analyzed, the concept hinged on measuring signals at precisely the same time. The first attempts at synchronized measurements across transmission lines were reported in several papers in the early 1980s using Loran-C (a hyperbolic radio navigation system), Geostationary Operational Environmental Satellite transmissions, and HBG transmissions (a low frequency time signal transmitter) [12]. These attempts were made by synchronizing positive going zero–crossing measurements, which meant they were only able to determine the phase angle difference, and were only accurate to the order of 40 µs, which correlates to 0.864° at a frequency of 60 Hz. In addition to the low precision and inability to record magnitude values, the presence of harmonics could corrupt the zero–crossing measurement. Because of the numerous drawbacks these methods were deemed insufficient.

Around the same time, developments in computer relaying of transmission lines were being made. To determine if any of the many fault conditions were present, six fault loop equations were solved at each sample time. Considering the processors available at the time, this took up a significant amount of computing power. To work around this, efforts were made to discover methods that would eliminate the need to solve these six loop equations. The result was a new relaying technique that relied on symmetrical component analysis of line voltages and currents as described in a paper published in 1977 [13]. While using this technique to develop efficient algorithms for computer relaying, it became apparent how important a part of symmetrical component calculation, called positive–sequence measurement, is to not only relaying but to power system analysis as a whole. These details were first published in 1983 [14].

When the deployment of GPS occurred, it offered a much more effective way of synchronizing power system measurements across large distances. Using this new technology, the first "phasor measurement units" (PMUs) using GPS were developed at Virginia Tech in the 1980s and the first commercial PMUs were being manufactured by 1991 [12]. Since then, PMUs have become an invaluable tool for power system operation and most modern power systems around the world make use of them in wide–area measurement systems. With many different manufacturers of PMUs today, IEEE published the standard C37.118 to govern both the format of the data and performance requirements.

2.3.3 GPS Time Synchronization

Using the most simple method of GPS time transfer methods, called time dissemination, the accuracy of measurement synchronization was reduced down to the order of 100 ns [15]. Using more modern techniques such as satellite common–view, this can be brought all the way down to 5 ns [16]. At 60 Hz, one µs of timing accuracy equals 0.0216°, which means that even using the most simple method, GPS time synchronization is accurate to 0.002 16° and can be improved to ≈ 0.0001°.

Clocking

To keep the time in between each sample uniform, the ADC uses a clock signal which oscillates between high and low at a specific frequency produced from a crystal oscillator. Since no two crystals are identical, each one oscillates at a slightly different frequency. This isn't a problem for devices that aren't synchronized together such as stand alone IEDs, but it is extremely important for networked devices.

For each GPS enabled ADC, every sample taken gets time stamped with the Coordinate Universal Time of National Time Service Center (UTC(NTSC)). Due to cost and line–of–sight considerations, it is impractical to equip every measurement device with a GPS receiver. Instead, precision time protocol (PTP) can be implemented to synchronize multiple devices to the same clock using one GPS receiver as the grandmaster reference to time.

As mentioned at the end of Chapter 1, every modern IED measures and digitizes its input signals individually. That means that each of them have their own front end circuit, and every manufacturer designs this circuit differently. For these real devices, insuring linearity in real time is impossible. Every LPF will introduce a phase shift in the signal that can be accounted for, but every different design will result in a different phase shift. By removing the measurement and digitizing circuit from the IED, there needs to be only one phase shift per signal to account for. If these are all designed the same way, then the phase shift becomes uniform for all signals and is no longer an issue. Similarly, these digital measurement devices could be synchronized using PTP so that every sample taken would have the exact same timestamp and thus be comparable in any variety of ways.

Chapter 3

Communication Networks

Now that the different components of a substation have been examined, it is important to look at how they interact with each other. Before the introduction of communication systems to substations, all action taken required an operator to physically adjust settings or read meters within the substation itself. As the ability to communicate between substations was introduced, new ways to protect power systems were developed and implemented via pilot relaying. Eventually, with the advent of the PMU and inter–networked systems, wide–area management became possible and information was able to be sent and monitored from more central locations.

3.1 Protection Scheme Basics

To best understand how current substations communicate internally and externally, it is important to understand the principles in which they were originally designed. While much has changed in technological terms, the equipment used today largely resembles the same ideologies that have been in use for the last century. In this section we will discuss a basic transmission line protection scheme and how it has evolved over the years. For the purposes of this document, the following four bus example, illustrated in Fig. 3.1, will be used in each case.

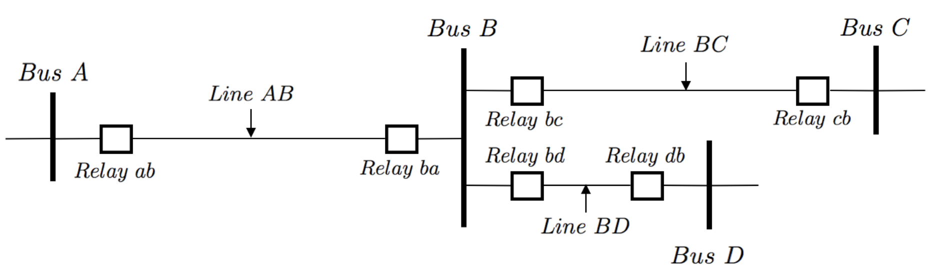


Figure 3.1: **Four bus transmission line example.**

While there is much more to power system protection than transmission line protection, and many books have been written on the subject, transmission line protection presents a larger challenge, in terms of communication and coordination, than schemes that are central to one substation. Many of the concepts presented in transmission line protection apply fundamentally to the protection of all other types of power system equipment, and thus will provide a good foundation for the understanding of substation relaying schemes. The basis of any protection scheme is reliably minimizing the effect any non ideal event or operation condition, most commonly a short circuit or fault in the system.

When designing a protection scheme the goal is reliability, which is a balance of dependability and security. That is to say that the system should react when it is designed to react and not react when it should not. While this statement may seem obvious, accomplishing this goal is not always straight forward and compromises must some times be made.

3.1.1 Nonpilot Protection

As mentioned briefly in Section 1.2.6, pilot relays involve the use of communication between the ends of a transmission line. Nonpilot systems, also known as graded, relatively selective, or nonunit systems, make their decisions solely on the measurements made at the end of the transmission line of which the relay is located [6]. This is accomplished by carefully coordinating the settings of each of the relays in the system to maximize its reliability. Two of the most widely used nonpilot schemes are overcurrent protection and distance protection.

Nonpilot Overcurrent Protection

Simply put, overcurrent (OC) relays react to a current magnitude threshold and force their CB to trip. While the most dependable scheme might have these relays react instantaneously, this is not necessarily reliable or secure. Two faults have now been added to the four bus example:

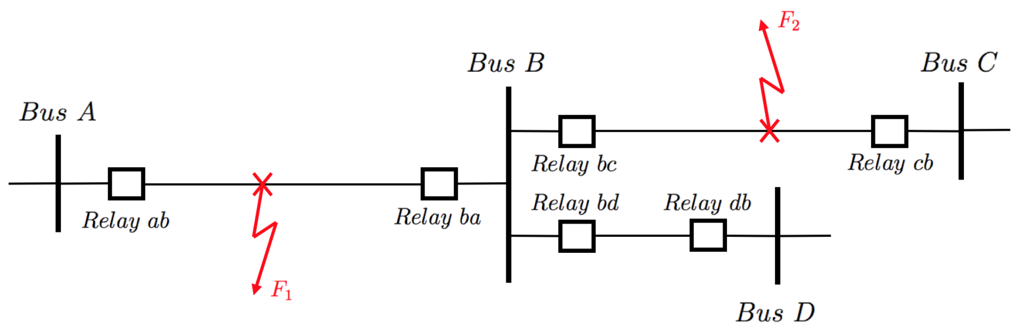


Figure 3.2: **Four bus transmission line with two faults.**

Assume that each of these relays are directional OC relays, in other words they only react to fault currents looking down the line away from the bus. If they were all set to be instantaneous, and a fault, $F2$, were to occur, then both relays ab and bc would react, tripping their CBs, and a section of line that should not necessarily be effected would be disconnected. To prevent this from happening, and as a result making the system more secure, time–delay relays are used instead. In this example, the time–delay relay *ab* would detect the fault, but wait a predetermined amount of time for another relay (in this case *bc*) to react before opening its CB. If the system works properly, *bc* reacts and clears the fault without line AB being effected, but in the case relay *bc* malfunctions, *ab* would react as a back–up and prevent the fault current from doing any further damage down the line.

Nonpilot Distance Protection

Compared to OC relays, distance relays (also known as impedance relays) are much more specific to transmission line protection, but are coordinated in a fashion that is similar to that of time–delay OC relays. Given the conductor diameter, geometric configuration, and length of a transmission line, the impedance of the line can be calculated. By comparing the measurements of the local voltage and current, the relay can calculate an effective impedance of the line and compare this measured value against the calculated value to determine the operating condition of the line. By knowing the configuration of the overall system, the relay can then provide backup protection for various "protection zones" in the system. This is illustrated in Fig. 3.3 below.

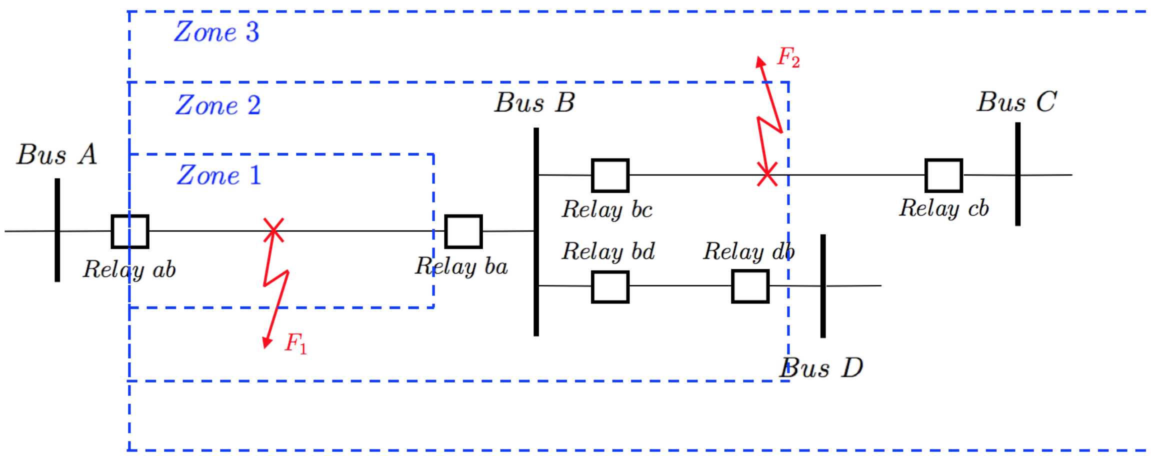


Figure 3.3: **Zones of protection for relay *ab*.**

While more sophisticated than OC relays, designing distance relay protection schemes has some added complications. Distance protection is designed so that Zone 1 covers 85 to 90 % of line AB reacting instantaneously, Zone 2 covers 120 to 150 % of line AB reacting with a time delay in the order of 0.3 s, and Zone 3 covers 120 to 180 % of the next line section and reacts with a time delay in the order of 1 s [6]. One of the requirements of the design of this scheme is that no one zone should overlap the same zone of another relay. This can be the source of complication when a long transmission line is followed by a short one as illustrated in Fig. 3.4. If a fault were to occur in the yellow region, both relays would react to it with a similar time delay which defeats the purpose of coordinating different zones. This is a complicated design issue that has been addressed by academic textbooks [3], [6].

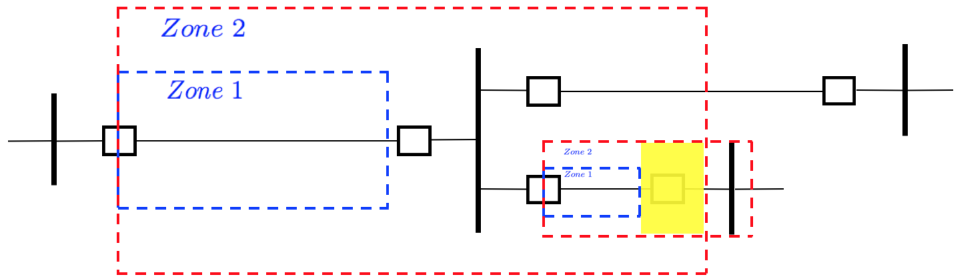


Figure 3.4: **Overlapping zones of protection.**

3.1.2 Pilot Protection

One of the fundamental difficulties of nonpilot protection is the inability to clear a fault from both ends of the line with precise coordination. If a fault occurs near the end of one line, detecting the fault at the remote end will not occur without some time delay due to the difficulty of detecting whether the fault is internal or external to the zone of protection. This complication is due to the fact that there is a degree of uncertainty as a result of the non-ideal operation of the sensors (CTs and VTs) and their associated burdens. This problem is exacerbated when multiple relays, meters, or other monitoring devices are connected as burden to the sensors. From the far end of the line, this additional burden and/or the impedance of the associated faulting element can make it appear that a fault that is within its range of instantaneous action is further down the line. The result is that the relay initiates a timer and does not take action until far later then it should.

The ideal solution to this problem is differential protection between the two ends, but without the computation and communication speeds of modern system this wasn't feasible [6]. Instead, engineers used various methods to create a communication channel between the two ends of the line. The most common method used in the United States has been directional comparison blocking using Power Line Carrier (PLC).

Instead of relying on the implementation of a new physical connection between transmission line ends, PLC utilizes the transmission line itself as the communication medium and operates in an on–off mode by transmitting radio frequency signals in the range of 10 to 490 kHz. By implementing a coupling capacitor at each end, the capacitor offers a low impedance path for the high frequency content of the PLC and a high impedance path for the low frequency power signal. Similarly, a wave trap is implemented on the line to filter the PLC signal, and as a result the PLC (information) signal is "trapped" between the two ends of the transmission line. This signal can be used in either tripping or blocking mode, where in blocking mode the presence of the signal prevents the tripping of the breaker and in tripping mode the signal initiates the breaker trip. When used in PLC systems, blocking mode is overwhelmingly preferred since the fault of a line can prevent or seriously attenuate a trip signal [6].

The directional comparison blocking scheme works by applying a pair of relays at each end of the line, one directional tripping relay and one fault detecting starting relay that may be directional or nondirectional. Again, we will use the previous four bus example to explore how this scheme would react to the two faults.

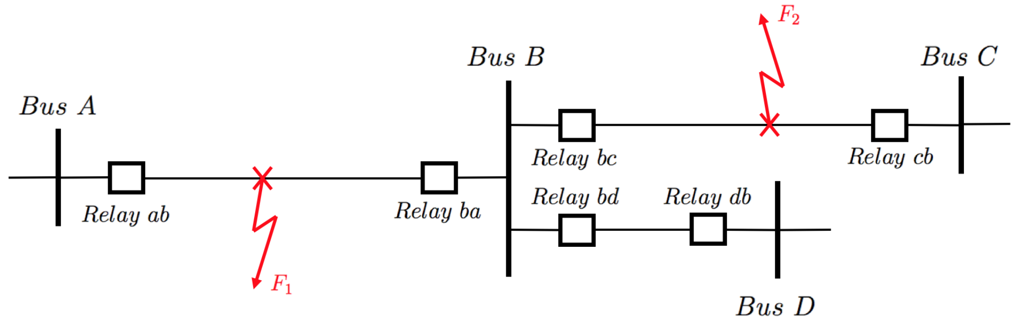


Figure 3.5: **Four bus transmission line with two faults.**

If the fault detecting starting relays are directional, then they are set to see behind the protected line. If a fault occurs at $F1$, the directional relays at ab and ba will trip and because the fault detecting starting relays do not see the fault, neither will send a blocking signal. On the other hand, if the fault detecting starting relays are nondirectional then both will send a blocking signal, but their associated directional relays will stop it. In the case of an external fault at $F2$, the fault detecting starting relay at bc registers the fault regardless of if it is directional or not, and sends a blocking signal to prevent the directional relays at either end from tripping. This provides a simple and logical solution to allow coordinated tripping of breakers at each end of the line this is both dependable and secure.

Communication–based protective schemes other than directional comparison blocking have been implemented as a result of improvements to the communication systems. These include transfer–trip, over–reaching permissive, under–reaching permissive, etc and many of them place a heavier weight on the reliability of the communication network to operate properly.

3.2 Digital Communication Systems

While introducing new technologies into substations, the approach engineers have traditionally taken is to design the control systems for protection and operations in parallel and as separate devices [17]. The protective relaying aspect of this design, as discussed in the previous section, had different needs when considering the technological limitations and capabilities of the first devices and networks compared to that of the Supervisory Control and Data Acquisition (SCADA) portion of the design. While the introduction of the microprocessor has led these two aspects to become more integrated, the parallel development of the two disciplines led to different best practices [17]. One of the main differences between these systems is that communications, or the ability to send and receive information and control commands, is an integral part of SCADA and only an adjunct function for protection and control.

3.2.1 SCADA

While often called “automation,” SCADA is the encompassing term for the ability to collect asset monitoring data, metering data, and equipment status information as well as issue control commands [17]. Unlike the control commands from protection devices, SCADA commands are actively monitored and are issued by operators instead of reactionary algorithms. At the center of the SCADA nervous system lies the SCADA Master, which consists of a Distribution Management System (DMS) or Energy Management System (EMS) located centrally to the power system. Each substation collects data to send to the master and has the ability to assert commands received from the master through a Remote Terminal Unit (RTU).

Since SCADA systems are based on the ability of two or more devices to communicate with each other, there must be a common data format, message system, and use a shared medium between devices. With many different manufacturers producing SCADA devices, approximately 400 different SCADA protocols were developed, with the most popular being Distributed Network Protocol (DNP) [17].

DNP

With the bandwidth limitations of the 1990s, DNP was specifically developed to meet the needs of SCADA and system integration. It uses master-slave communications and includes the ability to broadcast a message to multiple machines, time–stamp all data, and other functions useful for power system operations. This is accomplished by having the master poll for data and broadcast control commands to the slave devices. By using report–by–exception, where the only data returned is data that has changed since the last polling, bandwidth usage is severely reduced.

One of the aspects that complicates the implementation of DNP systems is that it is a register–based protocol. This means that each device is designed to store various pieces of data in specific registers which are not uniform from device to device. To configure the system, each device has a points list of the registers available and the type and format of data associated with each register. These then must be mapped to a table for the master to be able to access the information it is polling. While making them extremely customizable, implementing these systems require significant engineering effort, are highly susceptible to transcription errors, and require a long commission time for verification [17].

DNP data types and formats are defined in the IEEE 1815 Standard for DNP.

3.2.2 IEC 61850

With advances in technology leading to the development of high speed networks and faster microprocessors, it became such that bandwidth was no longer a limiting factor and the major cost component of communication networks became configuration and documentation [18]. Consequently, when engineers went to design the “next generation” in communication architecture, a key requirement was that substation devices would have the ability to describe themselves in terms of services and data. This, along with a list of other requirements aimed to simplify configuration and documentation while expanding system intercommunication, became the groundwork for several different standards groups who would eventually unify and publish the International Standard – IEC 61850 – Communication Networks and Systems in Substations.

Although this standard originally defined various aspects of the communication network "inside" the substation, development and application of this standard has began to expand rapidly to other power system management faculties. This advance is due in part to the abstraction of the definition of data items and services which makes them available to any other device regardless of the underlying protocol. Where as DNP only standardized how bytes of information were transferred along a wire, IEC 61850 also provides a model for how devices should organize, and make available, data across all types and brands [18].

The IEC 61850 model uses a nested data structure. The outer container is the physical device, which is any device that connects to the network and is typically defined by its network address. Within the physical device is contained one or more logical devices. These logical devices may be separate physical devices, which means that the physical device can act as a proxy for multiple devices as a data concentrator. Within the logical device are logical nodes. These nodes are named groups of data and associated services that are logically related to a power system function (e.g. Supervisory Control, Protection, Protection Related, Sensors, etc.). Each logical node contains uniquely named elements of data, determined by the standard and functionality of the power system purpose. For instance, if it was necessary to determine the mode of operation of the circuit breaker XCBR1 for a logical device named "Relay1," the following object would be read:

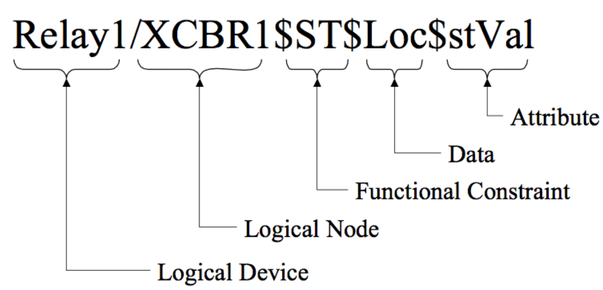


Figure 3.6: **Anatomy of an IEC 61850-8-1 Object Name** [18] © 2006 IEEE

By abstracting data in this manner, it allows all Intelligent Electronic Devices (IEDs) to self–describe data using identical structures that directly relate that data to their functions. Consequently, it also allows devices to describe themselves using an XML based Substation Configuration Language (SCL) file which allows the topology of a substation to be easily identified and configured.

IEC 61850 uses two different methods to share data between devices: a publish/subscribe multicast method and a client/server method using Manufacturing Messaging Specification (MMS). The publish/subscribe method works by packaging data into datasets and then multicasting them at the data link layer of an ethernet network. Other 61850 compatible devices can then subscribe to these datasets and use the data. This method is typically used for Generic Object Oriented Substation Event (GOOSE) and sampled value (SV) messages. GOOSE is a report–by–exception, peer–to–peer method of sending control, status, and alarm data (typically boolean), which is to say that the data is only published when the value or status of the data has changed. SV, on the other hand, publishes samples of analog measurements, such as current and voltages. Because this data is only published to the data link layer of the network, it is only available to devices directly connected to the data layer within the substation.

To access data at a higher level, 61850 uses the MMS protocols of ISO 9506, which was chosen because of its support for the complex naming and service models of the new standard in a straightforward way [18]. Using this method, a 61850 enabled Human Machine Interface (HMI) or gateway establishes a point–to–point connection using IP addresses to directly request the device publish specific data.

A huge benefit of this architecture is that it essentially future–proofs substation design by providing a platform for engineers to build off of. Since the standard is open ended, new devices and equipment types can be designed to work within this framework without having to overhaul the design of a substation when integrating them.

Chapter 4

A Strategy for New Digital Substations

In previous chapters, substations and the various stages of their digitization have been discussed, but as it has been noted there are many vectors for improvement to the system. While there are many solutions for each of the individual problems, there is also an option that would remedy these issues as well as increase the flexibility of they system to an ever changing environment. This next chapter introduces the concept of centralized substation protection and control, identifies the existing problems these potential improvements would address, and discusses the benefits associated with implementation.

4.1 System Architecture

When examining the different philosophies of power system operation and protection, one of the main points of consideration was that the information used by both disciplines was the same even though their goals were different. Furthermore, assurance of the accuracy of the measurements taken was paramount to both. Utilizing the framework set by IEC 61850, a new architecture for substation design based on precise data collection made available throughout the system would improve both services without hindering either. Since the only real difference in the two disciplines is software, their hardware sets could be merged into a centralized protection and control (CPC) device that would allow both disciplines to coordinate more readily.

4.1.1 The Merging Unit

As discussed in Section 1.2.4, CTs and VTs become less accurate as multiple devices are connected to them. Ideally, the CT would be measured by a device with zero impedance, but in reality this is an impossibility. Instead, engineers aim to design the circuit to have as low of an impedance as possible. Since these devices must be wired in series to make accurate measurements, illustrated in Fig. 4.1, the overall impedance across the CT grows as more devices are connected.

Ultimately, this increased impedance creates an undesired voltage on the secondary winding of

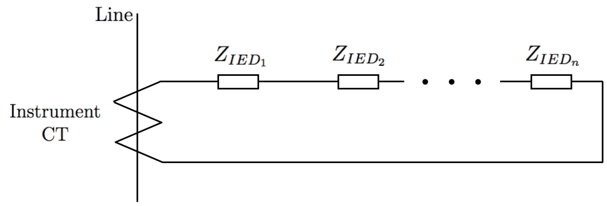


Figure 4.1: **Series connections of IEDs on a CT.**

the CT which can lead to the core of the CT becoming saturated during fault conditions. The consequence of this saturated core is that the relationship between the primary and secondary winding currents become nonlinear, and the current being measured is not an accurate representation of the actual system current.

VTs have a similar problem when a large number of measurement devices are connected to them. Opposite to CTs, VTs are ideally measured by a device with infinite impedance, appearing as an open circuit, which is not feasible. To measure the transformer voltage, devices must be connected in parallel as illustrated in Fig. 4.2.

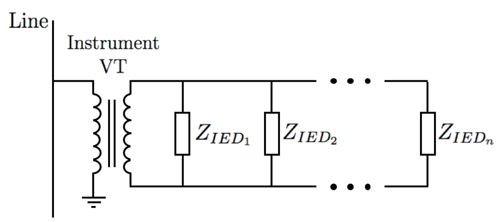


Figure 4.2: **Parallel connections of IEDs on a VT.**

Determining the total impedance of devices connected in parallel isn't as straight forward as when they are connected in series; the following formula is used to make this calculation:

$$Z_{eq} = \left(\frac{1}{Z_{IED_1}} + \frac{1}{Z_{IED_2}} + \cdots + \frac{1}{Z_{IED_n}}\right)^{-1} \tag{4.1.1}$$

The outcome of this relationship is that the more impedances connected in parallel, the lower the equivalent impedance becomes. This lowered impedance results in an undesired current flow on the secondary side, and the series leakage of the transformer introduces a change in voltage on the secondary winding. This voltage is an inaccurate representation of the primary winding voltage, increasing the operation error of the transformer.

In the current design of substations, connections made to CTs and PTs consist of numerous IEDs that reside in the control house. Each of these IEDs has some variation of the same front end circuit that was illustrated in Fig. 2.7. By implementing a singular front end circuit that would measure the signal and distribute the digital version, the number of devices connected to each transformer would be reduced to one; signal flow of this concept is illustrated in Fig. 4.3.

Designing these sensors to be an appropriate impedance would ensure the accuracy of system measurements that can not be offered by the current system.

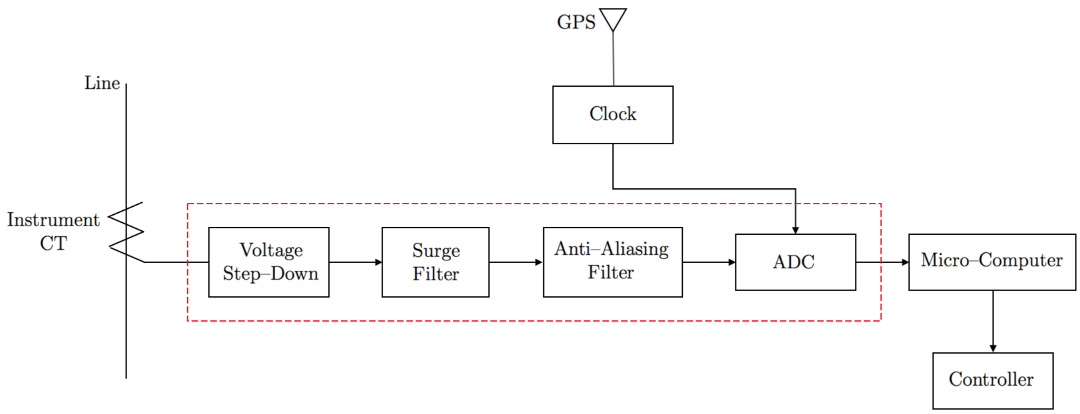


Figure 4.3: **The common front end circuit to be replaced by the Merging Unit.**

As this device would replace the front end of current IEDs, it could easily be installed in the control house using the existing wiring and connections. Illustrated in Fig. 4.4, such a device has been name a Merging Unit (MU) as defined in IEC 61850-9-1:

> "Merging unit: interface unit that accepts multiple analogue CT/VT and binary inputs and produces multiple time synchronized serial unidirectional multi-drop digital point to point outputs to provide data communication via the logical interfaces 4 and 5."

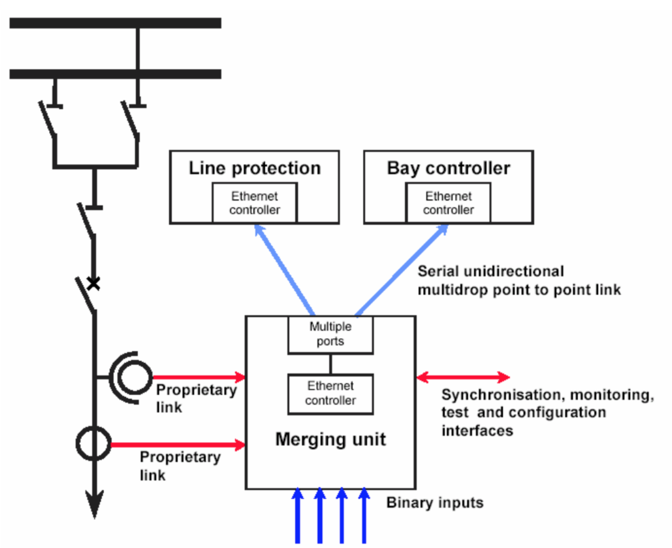


Figure 4.4: **IEC 61850-9-1 Merging Unit** [18] © 2006 IEEE

The logical interfaces (IFs) referenced in this definition are defined in the standard as well and refer to interfaces that enable the exchange of sample data (IF4) and control–data (IF5) between the process and bay levels. This means that the MU not only acts as a front end to the sensors, but also as a status and control interface for primary system equipment such as CBs, transformers, and isolators [19].

These units are synchronized to a GPS receiver using PTP, or newer hardware layer time stamping, resulting in all output sampled values having the same UTC(NTSC) time stamp. Using this standardized sample timing, data from locations all over the grid could be compared with certainty that the data used was measured within $\pm$ 75 ns. More on hardware layer time stamping using Gigabit Ethernet to distribute GPS locked timing signals can be found in conference paper [20].

As of this document, there is an implementation agreement for the sampling rates of MUs of 80 samples per cycle for basic protection and monitoring, and a higher rate of 256 samples per cycle for applications like power quality and high–resolution oscillography [18]. At a system frequency of 60 Hz, this results in a sample rate of 4.8 kHz and 15.36 kHz, respectively. Using this standard, even the slower of the two sample rates is able to detect up to the 40$^{\text{th}}$ order system harmonics and measure transients less than a half of a millisecond in duration. This fidelity far surpasses that of SCADA or electromechanical devices and enables modern digital devices to monitor and record system information of events that may have otherwise gone unseen. Table 4.1 gives a frame of reference for the speed in which these different power system events occur [21].

Table 4.1: **Time Frames for Power System Events** [21] © 2010 IEEE

Time Period	**Event**	**Application**
Microseconds	Switching Surges	Breaker Restrikes
Milliseconds	Harmonics	Variable Frequency Drives
Cycles	Faults	Relays
Seconds	Load Flow Changes	Governor, Exciter Response
Minutes	System Stability	Power Swings
Hours	Load Variations	Generation Schedules
Days	Continuous Data Recording (CDR)	NERC Requirements

Intelligent Merging Units

The next evolution of the MU is the intelligent merging unit (IMU). This version of the MU adds root mean squared (RMS) based overcurrent and overvoltage backup protection. Since RMS values are simple to calculate using sampled values, an additional processing device would be designed into the MU so that primary equipment would not be damaged in the case of total communication failure during abnormal conditions [19]. While these IMUs are not available as of today, they are a topic of future research.

4.1.2 The Process Bus

One of the design aspects of the IEC 61850 framework is the concept of the process bus. This process bus is a data layer within a substation network that connects all the MUs and IEDs in the network.

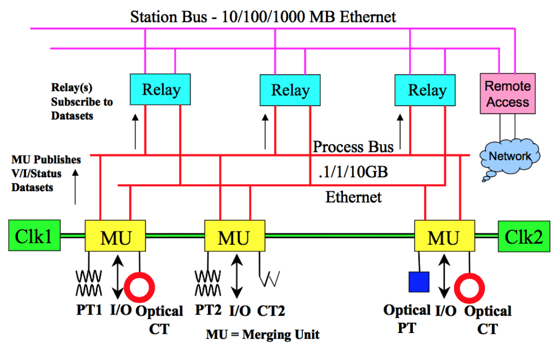


Figure 4.5: **Basic IEC 61850 Process Bus signal flow.** [18] © 2006 IEEE

Because MUs send and receive digital packets, the process bus can be applied redundantly to prevent system outages when equipment malfunction or needs to be upgraded. As illustrated in Fig. 4.5, there are redundant master clocks as well so that if any one part of the system fails, there is a duplicate ready to take over. This can be extended further to the MUs as well, offering multiple lines of defense for device failures. Using redundancies of each system, self checks can be performed to diagnose malfunctioning equipment before the point of failure.

Another benefit of using the ethernet based process bus is the ability to utilize fiber–optic connections instead of copper wiring. The use of fiber–optics, while more expensive, provides optical isolation which would allow for the use of off–the–shelf hardware for the design of centralized protection and control systems.

4.1.3 Centralized Protection & Control

Currently, digital substations are designed to work the same as they were with legacy equipment, incorporating the old with the new, and the new imitating the old. As discussed previously, relays are essentially just data processing units; with the exponential increase in microprocessor speeds, the idea that each protection function needs a dedicated relay is outdated. Instead, a single device could collect data from the process bus and use it in the same way a bevy of relays could. This concept is illustrated in Fig. 4.6.

As a data collector, this CPC device could easily assume the duties of a dedicated SCADA device and coordinate control actions between protection and operations. With the volume of data being collected and processed, it would also act as an information gatekeeper, providing a master intelligent node that would increase the efficiency of substation–to–substation and substation–to–control center communications. This would be accomplished by pre–processing the collected data and reducing the amount of information needed to be transferred to a minimum.

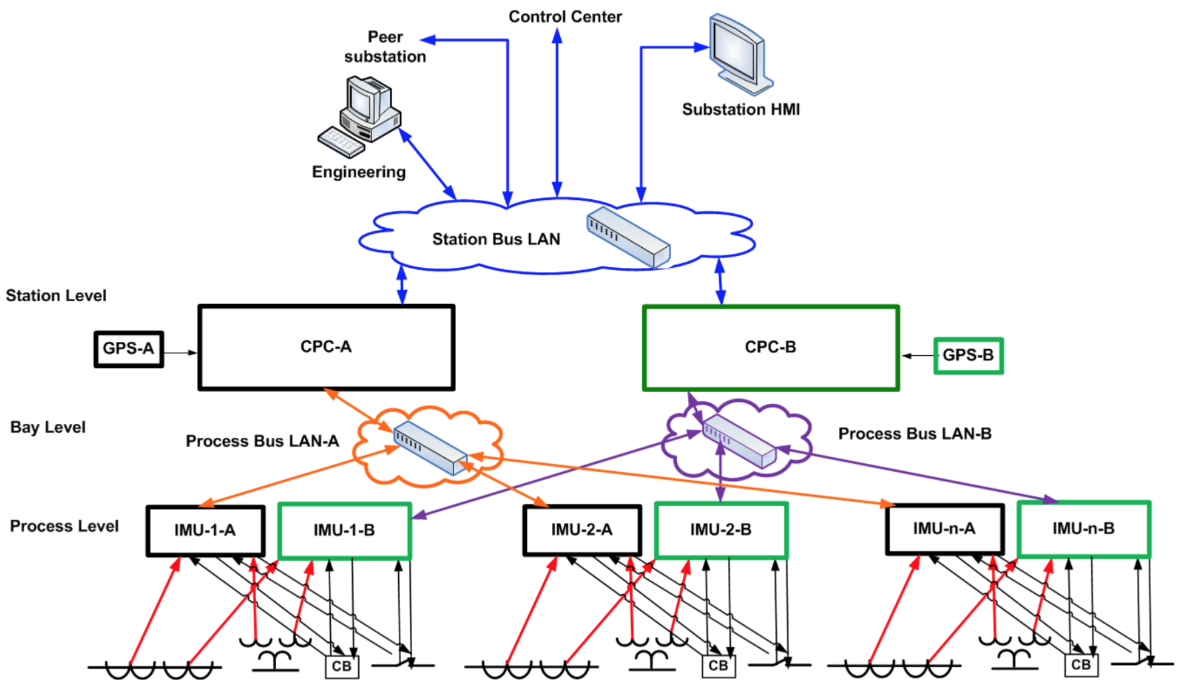


Figure 4.6: **Proposed CPC Architecture** [19] © 2015 IEEE

4.2 CPC Benefits

While providing solutions to problems related to the design of the current system, there are other benefits a CPC architecture would provide that would help to revolutionize how engineers handle substations.

Substation Hardware

One of these benefits is the removal of hardware dependance for protection devices as protective algorithms are just software. This opens up the ability to use the same off–the–shelf, high performance hardware that is already used for energy management systems and other applications. Application of server hardware provides a large advantage in end–of–life management efficiency. As the same server hardware is used across multiple industries, next generation hardware is almost guaranteed to be widely available at competitive costs from multiple manufacturers [19]. This would allow protection engineers to focus on developing specialized CPC software while reducing the cost to repair, upgrade, or replace substation hardware.

Device Management and Maintenance

As discussed in Section 3.2.2, one of the major cost components of legacy communication networks is configuration and documentation. In substations that housed a multitude of relays and IEDs, each one needed to be separately identified, configured, tested, and maintained while records were kept meticulously. The configuration between devices required a high level of training as protocols varied from device to device which meant modifications to the system became very complicated and communication between substations was very limited.

This overhead becomes greatly reduced as the number of devices in a substation is severely limited with CPC architecture. Although experienced, well–trained staff are still required, knowledge and understanding of a wide range of configurations and protocols is not necessary as they are internal to the system. Management of substations with CPC is more akin to information technology (IT) roles then high level power systems engineering.

Protection and Control Applications

While CPC would be able to fully emulate the old system, it would also establish a foundation for advanced applications of protection and control not available as of today. These emerging and future applications are the basis for much new research, and many of them would be impossible to implement without a CPC or high–performance processing within the substation. One example of these advanced applications is Dynamic State Estimation (DSE) Based Protection (a.k.a. setting–less protection) which is an evolution of differential protection.

Where as differential protection monitors the adherence of Kirchoff's current law, DSE monitors all laws that apply to the device being protected. Continuously monitoring terminal data of the component under protection as well as other variables needed to evaluate the physical laws (temperature, speed, etc.), DSE processes the data and checks to see if the results are consistent with the model of the protection zone. More information on DSE and other examples of these new algorithms can be investigated further in [19]. These new applications would make the overall system even more robust and reliable while maintaining flexibility towards future changes to the grid.

Network Security

It has become common knowledge that the use of cyberattacks have become a threat worth serious consideration for any industrial system that is connected to a wide area network. Regardless of the motive, an attack on the power grid would impose a large impact to the country's economy. To minimize these risks, it is crucial to have an understanding of what exactly the risks are as well as the best practices and security principles used to reduce them. Intuitively, it may seem like condensing the necessary IEDs into one device would increase the risk to substation security as there would be only one point to access all information. But by reducing the number of entry points into the system, the few that remain can be more closely managed therefore increasing security. Network security has become the topic of much research, and there are many documents on it such as [22].

Diagnostics

Designing redundancy into the CPC architecture not only provides security to the system in the case of digital equipment failure, but also introduces the ability to diagnose and identify physical hidden failures in ways that were not previously available. Having the substation data aggregated to one location, it can be compared against each other to be on guard for mismatches. When it does occur, further investigation can be taken to identify the source of the bad data and in turn root out its underlying cause. Diagnostics like these would prompt engineers to take action before any catastrophic failure occurs, reducing overall downtime and increasing the reliability of the system.

This sort of redundant data testing is not only useful for detecting underlying problems in primary equipment, but is also helpful in maintaining confidence that the CPCs are functioning as desired. For instance, installing the same CPC software onto two sets of hardware with difference processor types, frequent data checks between the two insure that the computations being made on both are accurate. Again, a mismatch in outcomes would be useful in identifying both computational hardware and software issues before the problem becomes critical.

4.3 Future Research

While the benefits to implementing a CPC architecture in substations look to be plentiful, more research on the subject must be performed to assure its dependability in real world deployment. Using the standards already put in place, the hardware used for CPCs would need to be designed to withstand the wide range of environments in which substations exist. Another point of consideration to investigate is the cost benefit of implementation on a large scale. It is to be expected that the initial installation expense of CPCs would be great, but it would be unsurprising to find that the long term cost benefit to the transition would make it economically viable.

To fully prove the concept of CPC viable, the ability to react in an appropriate time frame would need to be thoroughly tested. Since the reaction time of IEDs have been proven to be fast enough for protective devices, the main additional latency occurs when transmitting data from the sensor to a switch and then to the processing device. While there is a minor amount of propagation delay between the point of transmission, the switch, and the destination (in the order of µs for local area networks), the major bottleneck in the process is the network switch. Using a modern high–density switch such as the Siemens Ruggedcom RSG920P, the worst case scenario in which the link is nearly saturated, the latency is only 123 µs [23]. This was calculated using IEC 61850 SV traffic that uses 100Mbps ethernet ports, but the next generation of the standard could be improved by using 1/10Gbps ethernet to decrease latency. Additionally, computation latency of a full scale CPC should be tested, but it is not unrealistic to expect current computing power to be able to process and react with a sub–millisecond response time.

Some of this research has commenced by groups such as LYSIS LLC, Russia, who have implemented a trial operation of a software based protection, automation, and control system in northwest Siberia, and the IEEE PES Power System Relaying Committee Working Group K15, but further investigation, design, and standardization is necessary to make it ready for large scale implementation.

Chapter 5

Conclusion

Evaluation of the current state of power systems substations shows that there is much room for improvement. Some of these problems include increased operation error due to the burden of the connection of multiple protection devices, poor intercommunication between substations and control centers, and substation hardware that is single functioning and hard for technicians to integrate and maintain. While each of these problems demand unique, separate solutions, rethinking the overall substation architecture will solve these issues while increasing the robustness and reliability of the system.

Currently, every IED connected to an instrument transformer must first digitize the analog signal before processing the data using very similar front end digitizing circuits. Each of these devices worsens the burden on the instrument transformer, resulting in an increased operation error and an inaccurate signal is therefore processed. The use of MUs or IMUs eliminated this problem by reducing the number of devices connected to an instrument transformer down to one and opens up the ability for high accuracy, non–traditional instrument transformers to be used. Using GPS to synchronize the digital measurements, the data collected is therefore compatible with samples taken from any other location.

Having made this sensor information easily accessible to any device in the network, this information is primed to be used in a multitude of ways. Funneling this data into CPCs improves on the current system in many ways. Managing only one device means that the routing and device management of a substation in minimized, reducing operation errors due to improper documentation of a highly customized substation. Having these devices exist virtually means that changing settings or upgrading protection schemes can be managed remotely and with much less difficulty. Furthermore, this central device will be able to communicate more efficiently with peer substations and control centers, facilitating greater abilities for wide–area management and new coordinated protection schemes.

Research into this subject revealed an IEEE PES working group who are evaluating various architectures for implementing digital substations using the international standard IEC 61850 as a foundation. With the speed of microprocessors increasing and the cost decreasing, the amount of research into the subject, and the overall benefits this system would add it seems inevitable that this technology will be implemented in a large scale in the coming years.

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