The Substation of the Future: A Feasibility Study

Final Project Report

Power Systems Engineering Research Center

Empowering Minds to Engineer the Future Electric Energy System

Substation of the Future:
A Feasibility Study

Final Project Report

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Power Systems Engineering Research Center

The Power Systems Engineering Research Center (PSERC) is a multi-university Center conducting research on challenges facing the electric power industry and educating the next generation of power engineers. More information about PSERC can be found at the Center's website: http://www.pserc.org.

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Executive Summary

Digital technologies for data acquisition, automation, and control have been continuously evolving for the last three decades. We propose a revolutionary utilization and integration of existing technologies, including incremental improvements and innovations, for the design of the substation of the future. The proposed approach is based on the concept of equipping each component (i.e., potential transformers, current transformers, breakers, etc.) with a universal GPS-synchronized meter that transmits data to a set of redundant substation computers. The data are processed locally and then transmitted to the control center where it becomes available to all shareholders. This report describes the overall scheme and provides performance metrics for this approach. The report illustrates that it is possible to design the proposed system with existing technology or slightly modified present day technologies.

Section 1 of the report provides a background and an assessment of present day technologies for substation automation and their interfacing to the control center and the enterprise. While the practice varies from utility to utility (i.e., some utilities have invested in automation more than others), this section tries to capture the most advanced practices today. Advanced practices include using numerical relays to perform the functions of SCADA and integrated communications between substations and control centers as well as enterprise communications. This section also discusses the proposed approach for a more integrated and automated acquisition of data and processing as an extension of the present technologies.

Section 2 describes the proposed data acquisition and processing at the substation using the next generation of merging units. Specifically the scheme involves placing merging units at each instrument transformer, providing GPS synchronization and collecting data independently but GPS synchronized with minimal latency. Since communications are confined within the substation for this part, overall time latencies can be easily remain below one millisecond. The use of standardized protocols is discussed. In particular, the IEC 61850 standard is used as the preferred standard for communications and data processing. It is also proposed that at each substation two types of data should reside at two different data buses. First, a process bus that processes time waveform data at the sampling rates of the various merging units. The system supports different data rates as the various merging units may have different rates. Second, a substation bus which accommodates compressed data, such as phasors, magnitudes, power, etc. This data are derived from the data on the process bus and they are computed at much slower rates. The process bus data and the substation bus data can accommodate all foreseen functions in a substation. These functions may include protection, power quality analysis, SCADA functions, state estimation at the substation level, fault disturbance analysis, among other functions.

Section 3 provides a feasibility study of processing the data for validation and calibration. The main tool for this study is a substation level state estimator. The state estimator has been developed under previous projects and is simply utilized in this project. Because of the presence of GPS synchronized measurements, the results of the substation level state estimation are globally valid (i.e. they can be used by any other substation). For example the estimated operational states from each substation are sent to

the control center where the state of the overall system is synthesized by simply combining the estimated states of all substations. This process negates the need for a central state estimator. The end result is that the data are validated, the bad data are rejected, the state of the substation is defined and the accuracy of the states is quantified. The procedures described in this section of the report can be performed at very high rates. For example, the processing of all data in a substation can be performed in less than 20 milliseconds for typical substation sizes. This will allow the validation and filtering of the data at rates more than 30 times per second. An important advantage of this approach is that it is fully scalable. The response times are the same independent of system size because the bulk of the data processing is performed at the substation level.

Section 4 provides an application of the validated data: protection functions. With this application, the protection function is based on all substation data . Thus, the protection algorithm can determine the appropriate protection action with greater dependability and reliability. This section of the report described a feasibility study of the speed by which the protection functions can be achieved using the entire substation state. No appreciable delays are anticipated as compared to the present approach of using dedicated relays trying to determine the protection action using only limited information. As a result, the protection functions can be improved with the proposed approach from reliability and security points of view.

Section 5 describes how the proposed approach can be used to provide power quality analysis for the entire substation. The system that performs power quality analysis uses the data available at the process bus. Since this data can be corrected and validated with the state estimation methods provided in section 3, the power quality analysis based on this data is more reliable than simply using raw data collected with intelligent electronic devices (IEDs). The process can also include disturbance play back by appropriately storing the retrieving process bus data.

Section 6 provides the performance of the proposed approach for wide area monitoring. Wide area monitoring systems are required for a variety of applications such as system protection, visibility of the system, stability and analysis of the system. We describe how the wide area monitoring system of the future can be structured. Since the proposed approach provides the validated substation state at each substation with minimal time latencies, the proposed wide area monitoring system is based on sending the substation state to the central controller. This approach minimizes data rates without loss of information. In addition, the information is validated and its accuracy is quantified. These attributes should be compared with present approaches in which raw data (which may have errors) is used. The data can be fed into various applications for wide area monitoring and control at rates appropriate for the application. By minimizing the amount of data to be transmitted, the time latencies are also minimized.

Section 7 describes the impact on control center operations. First the impact on the state estimator requirements at the control center is beneficial. A two level state estimator at the control center is described and the data flow is analyzed. The overall impact on data base organization and execution times is favorable.

Section 8 describes the impact on company enterprise needs. The distributed communication system coupled with the availability of filtered and validated data results in the minimum communication traffic since only information is transmitted versus raw data. The quality of the information is superior to present approaches. Databases can be better organized and utilized. Overall, the company enterprise benefits from the filtered and validated data. Response times to request can be faster than traditional systems.

Section 9 provides a discussion on cyber security issues. Again by communicating information only, cyber security approaches can be facilitated.

Summary and Future Research Issues:

The proposed structure of the substation of the future will benefit all aspects of system operation. While present practice in substation design may not be close to the vision presented in this report, it certainly moves towards this direction. Many manufacturers developed and offer merging units with characteristics that will enable the approaches described in this report. It is also apparent that these technologies have the potential of reducing the cost of substation automation while they provide better applications. We are confident that these technologies will continue to evolve and our vision of the substation of the future will materialize in some form. For example this research project has identified certain desirable characteristics of merging units that will enable the functions described in this report. An immediate research project will be to design and develop prototypes of the next generation of merging units.

As discussed in the report, present utility practice indicates that substation technologies include old designs to the latest in substation automation. There is a plethora of substations that represent old-aging infrastructure. The critical and challenging problem is maintenance and upgrading of these facilities as well as managing the planning and execution of aging asset replacement. There are many challenging issues associated with compliance to various standards such as required clearances, commissioning tests, etc. These issues were not addressed in this report and constitute a natural extension of this research project. Since the design of the substation of the future includes a 3-D model of the substation, it can be used to compute any desirable attribute of the substation at any stage of an upgrading plan, such as clearances, transients and insulation coordination.. Demonstration of this capability would be a worthwhile research project since it could lead to a product that can be used in any substation upgrading project.

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Nomenclature

AGC	Automatic generator control
CB	Circuit breaker
CCVT	Coupling capacitive voltage transformer
CIOC	Communication input and output computer
CT	Current transformer
DFR	Digital fault recorder
GPS	Global positioning satellite
ICCC	Inter control center communication
IRIG	Inter-Range Instrumentation Group
IED	Intelligent electronic device
LAN	Local area network
MU	Merging unit
NYPA	New York Power Authority
OASIS	Open access same-time information system
PMU	Phasor measurement unit
PT	Potential transformer
RTO	Regional transmission organization
RTU	Remote terminal unit
SA	Substation automation
SCADA	Supervisory control and data acquisition
SCC	Substation control computer
SE	State estimation
UGPSSM	Universal GPS time-synchronized meter
WAN	Wide-area network

1. Introduction

This chapter provides background description of power system data acquisition, protection, state estimation (SE), and substation automation (SA) technology. These three technologies have evolved into mature digital technologies that present an opportunity for integration to realize improvements in power system control and operations.

The introduction chapter continues with a description of the problems addressed in this report. Specifically, we proposed a novel SA structure that will address well known issues with centralized state estimation (SE). These well known issues limit power system control and operation functions that rely on the results of centralized SE. The proposed SA structure also addresses future goals of power system operations. Both current problems and future goals are outlined in this chapter.

Finally, the introduction chapter provides a description of the technical approach developed in this report. The technical approach starts with a description of the physical components of the proposed SA structure and the flow of data between the physical components. The technical approach ends with a description of the key functions performed by the proposed structure, which are expanded within the remainder of this report.

1.1 Background

Digital technologies for power system data acquisition, control, and automation have been continuously evolving for the last three decades. We propose a revolutionary utilization and integration of existing technologies for the design of the substation of the future. Background of relevant technology is provided in this section.

1.1.1 Power System Data Acquisition

Power system data acquisition is the basic process where power system data is collected for all power system control and operation functions. The technologies utilized in power system data acquisition have gone through many changes since the origins of the power system.

From the 1920's till around the 1970's each substation indication and control function involved a unique discrete component (electromechanical relay) within the substation control house. Each indication and control function required point to point wiring for data acquisition for each function. Add to this the requirement of redundant equipment (primary and back up) for critical functionality and the number of wires and handmade connectors can be imagined.

In the 1970's the first multifunction relays were introduced to simplify wiring requirements of data acquisition. The most recent attempt to simplify the wiring requirements of data acquisition is to use standardized connectors and interface equipment. Whereas, the wiring become slightly simplified with the most recent methods the troubleshooting process remains, for the most part, unchanged and very daunting.

The basic infrastructure of power system data acquisition is the instrumentation channel. All control house equipment relies on instrumentation channels for data acquisition. Instrumentation channels include instrumentation transformers, control cables, burdens, attenuators, and digital processors. Typical voltage and current instrumentation channels are shown in Figure 1.1.

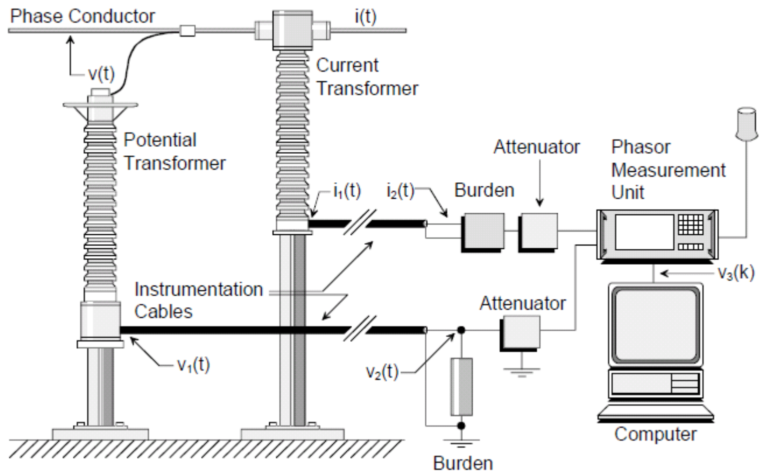


Figure 1.1: Typical instrumentation channel for data acquisition.

The digital processing device shown in Figure 1.1 is a phasor measurement unit (PMU); however, this device could be any control house equipment commonly called intelligent electronic device (IED). The most accurate measurement data are available from global positioning satellites (GPS) time-synchronized measurement equipment. Today GPS time-synchronized measurement equipment includes relays, meters, digital fault recorders (DFRs), and other special equipment; a common term for GPS time-synchronized measurement equipment is PMU.

The advantage of data acquisition using GPS time-synchronized measurement equipment is enormous and is utilized only on a limited basis. For a long period of time (1992 to 2002), the only GPS time-synchronized equipment was the Macrodyne PMU [1.1]. Recently additional GPS time-synchronized equipment has been introduced into the market. Yet, standards that determine what the accuracy of the phase measurement should be do not exist.

GPS time-synchronized measurement equipment enables measurements to be taken asynchronously and then processed synchronously at a later time. Data acquisition using GPS time-synchronized measurements can be done with timing accuracy of one microsecond and magnitude accuracy 0.1%. This potential performance is not achieved in an actual field installation because of two reasons:

1. different vendors use different design approaches that result in variable performance among vendors, for example use of multiplexing among channels result in timing errors much greater than one microsecond, and
2. GPS time-synchronized equipment receives inputs from instrument transformers, control cables, attenuators, etc. which introduce magnitude and phase errors that are much greater than the accuracy of PMUs.

Conceptually, the overall precision issue can be resolved with sophisticated calibration methods. This approach is quite expensive and faces difficult technical problems. Specifically, it is extremely difficult to calibrate instrument transformers and the overall instrumentation channel in the field. Laboratory calibration of instrument transformers is possible, but a very expensive. In [1.2] a calibration procedure for selected New York Power Authority (NYPA) high voltage instrument transformers was developed. From the practical point of view, this approach is an economic impossibility. An alternative approach is to utilize appropriate filtering techniques for the purpose of correcting the magnitude and phase errors, assuming that the characteristics of the various GPS time-synchronized pieces of equipment are known and the instrumentation feeding this equipment is also known.

Can present practices be simplified while maintaining functionality and reliability? Can cost be reduced and at the same time improve performance?

Significant challenges were faced in the SuperCalibrator demonstration projects in interfacing equipment from multiple vendors with a single computer housing the SuperCalibrator software. The challenge originates from the fact that various relays, PMUs and meters all use different protocols and physical media for communication.

It is important to recognize that the next generation of substations will have standards such as the IEC 61850, which will make available all the data from relays, PMUs, SCADA, meters, etc on a common bus accessible from any other device. In this case the proposed system will simply access the 61850 bus to retrieve the data and perform the estimation.

In summary, how are modern technology best utilized to achieve the substation of the future. Specifically, how can the advantages of GPS-synchronized data collection be utilized? How can present data wiring, relaying, and communication be simplified while maintaining functionality and reliability? Can the cost be reduced and at the same time improve performance? The remainder of this report will describe a proposed solution to these and related problems.

1.1.2 Power System Protection

Electric power systems unavoidably incur faults and equipment failures that result in unsafe conditions and can damage equipment if the condition persists. It is imperative to disconnect the faulty equipment as fast as practicable. Since the early days of electric power systems, technology was developed to achieve this goal. The key components of the protection technology include fuses, relays, and breakers. The technology has evolved into very sophisticated protection components with remarkable capabilities. A key component of the protection technology system is the protective relay that performs system protection: monitoring of the system, identifying of faulty or intolerable conditions, and making decisions as to when to interrupt circuits or initiate shut down procedures. We refer to these procedures as protective relaying. The objective of protective relaying is to selectively isolate a faulty power system component in the minimum possible time so that

1. exposure of the system to fault conditions will be minimized;
2. damage avoidance will be maximized; and
3. safety hazard to persons in and around the faulty power systems will be minimized.

The electric power system is occasionally disturbed with faults, failed equipment, and other abnormal operating conditions. The number of possible types of disturbances is extremely large. A protection system monitors specific quantities of the power system and it is expected to determine from the collected data the status of the system and an action should be taken. Some conditions are easily determined (for example a short circuit) while others require more sophisticated processing of the data (for example out of step generator). Because the power system is a complex dynamical system, the monitoring and the classification of the system condition may be difficult in certain cases.

Initially, electromechanical relays were introduced at the early stages of the electric power industry. Electromechanical relays are electromechanical systems that are designed to perform a logic function based on specific inputs of voltage and currents. This technology started with the very simple plunger type relay and evolved into highly sophisticated systems that performed complex logical operations, for example the modified mho relay is a system that monitors the impedance of the system as "seen" at a specific point in the system and will act whenever the impedance moves into a prespecified region. In the early years of the electric power industry, the inverse time delay overcurrent relay was developed based on the induction disk (Westinghouse) or the induction cup (GE).

The invention of the transistor in the 40's and the subsequent solid state technology provided an opportunity to replace the bulky electromechanical relays with solid state based relays. By the time that solid state relays started becoming acceptable to the industry, the microprocessor was introduced. The microprocessor provided the capability to implement extremely complex logic functions in a very small package. In addition, it provided the capability to implement multiple logic functions with only a single microprocessor. Today the digital (or numerical) relay is a well designed component with very high reliability, capable of operating in the harsh electromagnetic environment of an electrical installation and with computing power that is remarkable. A digital relay is typically a multifunctional relay, i.e. it performs several relaying functions within a single device.

Judicious application and design of protective systems requires that the operating characteristics of the electric power system are well understood. The basic principle of protective relaying is to be able to identify all possible intolerable conditions and disconnect the source of the problem. This is achieved by extensive study of the system to be protected so that the correct prognosis is performed and the root cause of the problem be identified so that the correct device is disconnected. Many times, oversights result in misdiagnosed problems that may lead to relay operation on healthy parts of the system. The power system is a complex system and many things can occur.

Protection functions become increasingly challenging as the complexity of the power system increases. For example, in networked systems containing many generating sources, the task of correctly identifying which part of the system is causing the disturbance and whether this disturbance is tolerable cannot be accomplished by monitoring a single quantity of the system (such as electric current).

On the other hand, in radial power systems (for example distribution systems), it is generally easier to achieve the protection objectives. Yet, in recent years, we have seen new challenges in distribution systems as the potential of distributed generation is becoming a reality. New challenges arise from the fact that now the system is not radial anymore and in addition the new generating resources are normally interfaced with the distribution system via converters that they are presenting totally different characteristics from the traditional power apparatus, such as lack of inertia and limited fault currents.

1.1.3 Power System State Estimation

The need for reliable and accurate SE has been emphasized in the recommendations made after significant blackouts including the events on November 9th 1965 and August 14th 2003 [1.3]. The primary purpose of SE is to provide a reliable real-time system model and to provide a real-time snapshot of the systems operating condition for control functions utilized in remote centralized control centers. Figure 1.2 provides a conceptual view of the infrastructure used in power system control center operation to collect the data required for SE, the hardware used to compute the SE, and the displays utilized by power system controllers.

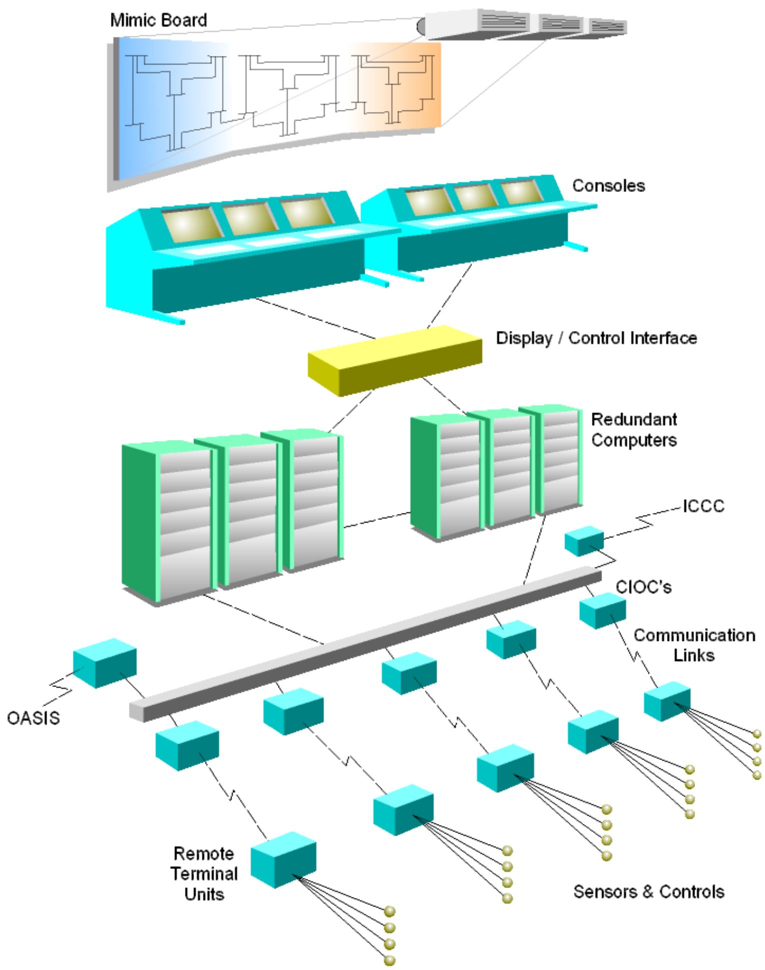


Figure 1.2: Conceptual view of power system control center operations.

In the lower part of Figure 1.2 the “Sensors & Controls” represent substation data acquisition systems; including current transformers (CTs), potential transformers (PTs), meters, and other data acquisition sources. The “Remote Terminal Units” aggregate system data and provide communication from each substation to the control center. The communication input and output computers “CIOC’s” provide receivers in the control centers for the remote terminal units from each substation. The dashed lines represent “Communication Links” of various medium and geographic distances. These components represent the infrastructure used in power system control center operation to collect the data required for SE.

The power system control center includes the following components in Figure 1.2. The “Redundant Computers” in that perform the SE and the “Consoles” and “Mimic Board” that provide graphical user interfaces for operators routed through the “Display / Control Interface”. This equipment computes the SE results and displays the state of the system to operators. Additional functions performed at the control center include

1. congestion managing;
2. dynamic line rating;
3. economic dispatching;
4. load forecasting;
5. optimal power flow calculating;
6. power balancing, security assessing;
7. spot and transmission pricing;
8. transient stability analyzing;
9. etc.

Notice, that all of these functions utilize the data collected and transmitted to the control center.

The remainder of the equipment in Figure 1.2 represents equipment used for communication to other data centers. The communication to other data centers is facilitated by the inter control center communication “ICCC” and the open access same-time information system, “OASIS”.

This centralized approach has served the industry with reasonable success; however, the reliability and speed of the centralized approach is not totally satisfactory. Surveys have shown that on average the reliability of the centralized SE is about 95% for US utilities [1.4]. This means that the model of the system in real time may be unavailable 5% of the time. Because of the required long distance communications and the computational complexity of a centralized state estimator the response time of the centralized version are typically long, on the order of minutes.

The ability to perform GPS time-synchronized measurements with time accuracy of one or two microseconds [1.1] has opened up many possibilities towards improving SE. Efforts to enhance SE with PMU measurements have been dated back to 1993.

Presently, there are two main approaches to improve the performance of SE with PMU measurements. The first approach is to utilize existing state estimator technology and augment the measurement set with GPS time-synchronized measurements. This approach results to what we refer to as PMU assisted state estimator or as a hybrid state estimator. The approach improves the performance of the state estimator but does not address the biases of the estimator from unbalances and asymmetries. The second approach is to drastically change the model and the measurement set. Specifically, to use a three-phase model for the system and use three-phase measurements. In this way, the biases from unbalances and system asymmetries are alleviated. In addition, since GPS time-synchronized equipment are higher accuracy than conventional supervisory control and data acquisition (SCADA) system it is important to consider and correct for errors from the instrumentation channels. This approach led to the concept of the SuperCalibrator [1.5]-[1.11].

The concept of the "SuperCalibrator" was introduced in [1.5] and represents a substation based state estimator based on a detailed three-phase breaker-oriented substation model, with explicit representation of the instrumentation channels. The concept of the SuperCalibrator is an extension of the harmonic measurement system developed for NYPA in the early 90's using the Macrodyne PMU and appropriate error correction algorithms [1.12]. The overall approach consists of execution of the SE locally at each substation and transmission of the local state estimate results to the control center for reconstruction of the system wide operating conditions.

Today, the SuperCalibrator methodology is a distributed dynamic state estimator. The SuperCalibrator performs SE within a substation utilizing all available data and can transmit the results from each SuperCalibrator enabled substation to a centralized location where the results can be pieced together to so that the entire state of the system can be visualized with no additional processing, i.e. distributed state estimator. Further, the estimated states are functions of time; i.e. dynamic state estimator.

The SuperCalibrator has been extensively discussed in open literature; and achieved successful demonstration on

1. a two substation subsystem of NYPA,
2. a two substation subsystem of ENTERGY, (both demonstration projects are described in [1.6]-[1.8]),
3. a laboratory scale demonstration [1.9], and
4. a five substation system in the US Virgin Islands.

The US Virgin Islands demonstration is described in Appendix B. The results collected at a centralized location can be utilized in visualization methodologies characterization of stability swings of a power system in real time [1.10] which leads to the dynamic SE methodology [1.11].

The basic idea is to provide model based error correction of substation data. Specifically, a high fidelity model of the substation, (three-phase breaker-oriented, and instrumentation channel inclusive substation model) is utilized in a three-phase distributed dynamic SE algorithm. All measured data, PMU, meter, relay, SCADA, etc., either GPS time-synchronized or not is expressed as a function of the state of the high fidelity substation model from which a weighted least square approximation can be performed.

The overall distributed state estimator methodology consists of the following procedures (a) perform SE on each subsystem using all available data from SCADA, relays, PMUs, meters, etc. and a three-phase breaker-oriented, instrumentation inclusive model; (b) perform bad data identification and rejection as well as topology error identification on each subsystem; (c) perform alarm processing on each subsystem to identify root cause events; and (d) assess the performance of the SE procedure at each substation (this is accomplished by examining the errors on the common states among the various substation states). In case of errors greater than justifiable by the accuracy of the relays, PMUs, etc. then the subsystems are expanded to several substations and the method is applied to subsystems that include an arbitrary number of substations. This part requires communications among substations while the basic approach does not require sharing information among substations and can be performed during a commissioning period.

The presence of at least one GPS-synchronized measurement at each substation makes the results of the SuperCalibrator globally valid. Specifically, the results from the SuperCalibrator in substation A are comparable (on the same time reference) as the SuperCalibrator results from substation B. The implications of this observation are very important. The results of the SuperCalibrator from the various substations can be brought into the control center where they can be combined to form the system wide real-time model of the system without any additional processing. This forms the basis of the fully distributed state estimator. The technology therefore is scalable to any size system since all the SE processing is done at the substation level, independent of the overall system size.

The SuperCalibrator computes the state of the system from a high level of redundant measurements. Thus, the state results can be computed at accuracy better than individual measurements offering two advantages (a) accurate state results for operators to view and (b) highly compressed data throughput with no loss of system visibility. Additional benefits with using all available substation data includes (a) sharp bad data detection and identification, (b) topology error detection and correction (symmetric and asymmetric), and (c) alarm analysis with root cause identification. At the substation level there is greater redundancy of data than a typical centralized state estimator based on SCADA data alone. This redundancy facilitates sharp bad data detection and topology error detection. In addition, the distributed SE problem is much smaller in size and therefore the powerful hypothesis testing method is applied for sharp bad data identification and topology error correction without substantial deterioration of the computational efficiency. Note that, comprehensive hypothesis testing in centralized SE for large power systems is computationally impossible. The use of the three-phase breaker-oriented model facilitates the identification of symmetric and asymmetric topology errors (one pole stuck, etc.). The traditional symmetric state estimators cannot identify asymmetric root cause events.

The results of the SuperCalibrator from each substation are transmitted to the control center where the state of the overall system is constructed. After commissioning there is no additional processing of the data at the control center. The state of the overall system can be used to create visualizations of the operating condition of the system. Several options for visualizations have been developed. Storage of the SuperCalibrator results at the control center allows data playback to study power system events in detail offline.

For this project the SuperCalibrator is used to filter and calibrate substation data.

1.1.4 Power System Automation

The integration of data in substations and throughout the power system enterprise has been the topic of intense research and development for many years. This research thrust has been called SA. The basis of SA is based on the use of IEDs to collect data, digitize it, and interface the data via common communication protocols.

The main goal of SA is to integrate all substation sub-systems utilizing the existing structure of wiring and equipment. Substation sub-systems include protection, fault recording, SE, SCADA, etc. SA attempts to maximize the use of available substation data and minimize the capital costs for equipment purchasing, wiring, and commissioning. Substation equipment includes relays, meters, DFRs, PMUs, etc.

1.1.5 Legacy Substation Design and Limitations

The current concept of what a substation entails is described in Figure 1.3. Each block in Figure 1.3 represents an independent physical device in a traditional substation and the arrows represent the exchange of information between the functional components.

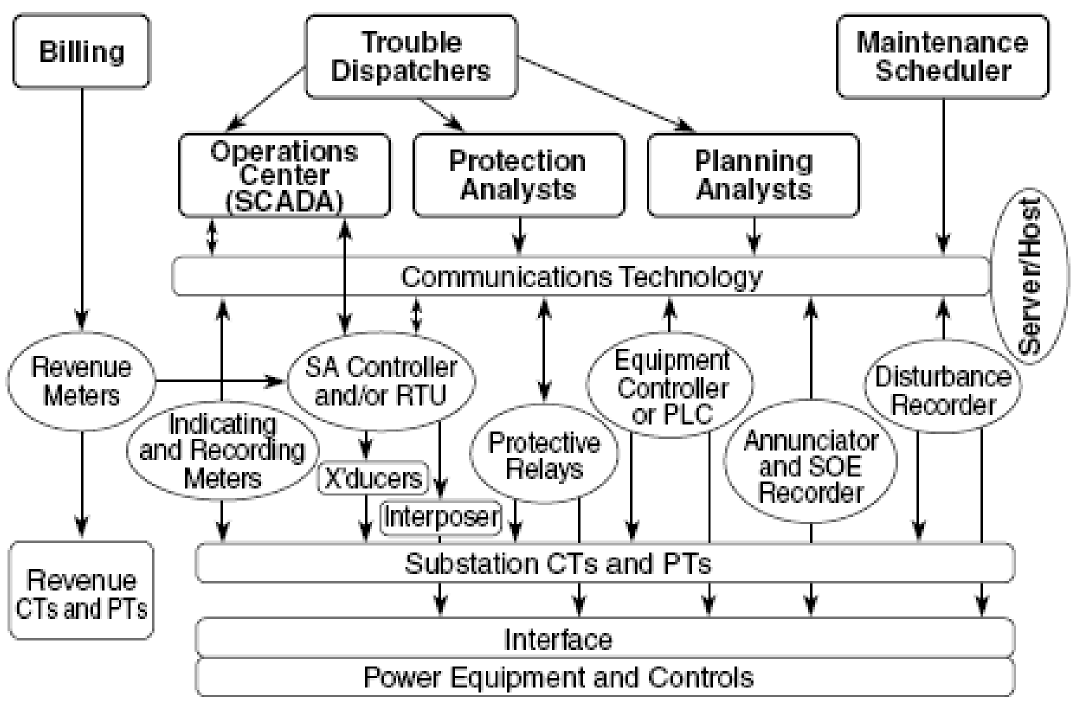


Figure 1.3: Modern substation automation (SA) functional diagram [1.13].

The basic functionality of a substation includes electrical protection, equipment control, metering, and monitoring [1.14]. Electrical protection involves the detection and isolation of abnormal system events to minimize human and electrical component harm. Equipment control is self explanatory. Metering involves measuring analog signals (eg. voltage, current, power factor, harmonics, and temperature) and monitoring digital signals (eg. electric equipment alarms). Monitoring involves tracking the current state of the electrical equipment within and surrounding a substation.

Based on the four functions electrical protection, equipment control, metering, and monitoring the components in Figure 1.3 can be subdivided to illustrate the operation and division of labor in a traditional modern substation. The functional components “Billing”, “Trouble Dispatchers”, “Operations Center (SCADA)”, “Protection Analysts”, “Planning Analysts”, and “Maintenance Scheduler” are interpreted to be functions occurring at a central control station, i.e. extra-substation, functions, and do not directly correspond to physical equipment within a substation nor to the functionality of a substation itself. In this context the acronym SCADA stands for supervisory control and data acquisition. Obviously, the “Protective Relays” component represents device/s utilized to realize the electrical protection function. The devices in Figure 4.1 which are utilized in control functions include the “SA Controller and/or RTU” and the “Equipment Controller or PLC”. In this context the acronym RTU stands for Remote Terminal Unit and the acronym PLC stands for Programmable Logic Controller. Metering equipment includes “Revenue Meters”, “Indicating and Recording Meters”, “Annunciator and SOE Recorder”, and “Disturbance Recorder”. In this context the acronym SOE stands for series of events. Monitoring is achieved differently within different organizations; a commonly used description of the end product of monitoring functions is state estimation and is typically performed extra-substation. Thus, all of the data from the discrete substation devices via the “Communication Technology” is utilized in a state estimation routine to create a model representation of the state of the electrical system. The remainder of the equipment including “Revenue CTs and PTs” and “Substation CTs and PTs” are utilized to convert high voltage and current signals in the “Power Equipment and Controls” to instrumentation level signals utilized in all of the intra and extra-substation functions. In this context the acronym CTs stands for current transformer and the acronym PTs stands for potential transformers.

Improving the security of the power grid depends largely on (a) system visibility and situational awareness of the system, (b) the fast and reliable real-time system control, and (c) accurate, reliable, and secure system protective schemes. The visibility and control functions are traditionally performed at a centralized location where all the data is collected and then processed to provide the real-time model of the system. The protective functions are the responsibility of the protective system and traditionally the protective system is physically separated from all other systems.

1.1.6 Smart Substation Goals

The Smart Substation is intended to serve the following major goals:

1. Overcome the above listed limitations of the traditional substation approach.
2. Provide additional capabilities to a traditional power system, including improved situational awareness, reduced communication utilization, and better robustness.
3. Provide a low-impedance path to future requirements and standards of the Smart Grid, as laid out in [1.15].

1.1.7 Smart Grid Required Functional Areas

In [1.15] the following major Functional Areas for the Smart Grid are identified. The design of the substation of the future should accommodate these requirements. The major functional areas are listed below.

1. Wide area situational awareness (WASA)

   In a Smart Grid, all entities on the grid must have an awareness of the state of the grid and its present capabilities. Different grid functions may require access to different data and at different rates.

2. Demand response (DR)

   The Smart Grid must support features that allow entities on the grid to change their demand or response based on the present level of demand on the grid.

3. Electric storage

   The Smart Grid must support the large scale deployment and management of electric storage elements, including distributed storage elements.

4. Electric transportation

   The Smart Grid must support the large scale deployment and management of electric transportation, such as Pluggable Hybrid-Electric Vehicles (PHEVs).

5. Advanced metering interface (AMI)

   The Smart Grid must support the large scale deployment and management of AMI, which will allow customers to directly interact with the grid and get real-time status information.

6. Distribution grid management (DGM)

   The Smart Grid must be capable of large scale deployment and management of distributed energy resources (DERs) on the grid, including non-deployable renewable energy resources such as Photovoltaics (PV), wind turbines, etc.

1.2 Smart Substation Functional Requirements

The Smart Substation will be a major hub in the implementation of the Smart Grid, and must support all of the functions listed in the previous section. Many of these functions may eventually be performed primarily in the Smart Substation. The specific functional requirements for the Smart Substation are as follows:

1. Modular design.
2. Ease of upgradeability.
3. Plug-and-play power equipment and topology.
4. Support different types of substations.
5. Support substation generation.
6. Support substation storage.

7. Receive GPS time synchronized measurements from equipment and subsystems.
8. Provide protection based on substation state.
9. Support detailed fault diagnostics/prognostics.
10. Support DERs.
11. Support PHEVs.

The Smart Substation is based on digitization and local processing of data available in a substation. A traditional substation performs measurements on local equipment, then forwards a selected subset of those measurements to a remote utility control center, and receives control commands back from the remote control center. A Smart Substation instead digitizes all local data, which is forwarded to a local substation control computer (SCC). The SCC performs state estimation, electrical protection, equipment control, metering, and monitoring; reducing communication burden and allowing the substation to act as an autonomous agent. In addition, the local availability of data and processing allows the substation to perform functions required by the Smart Grid, which are impossible in the traditional approach.

Figure 1.4 shows a high-level functional architecture of the Smart Substation. The section at the top of the diagram represents the substation local area network (LAN). Substation equipment, generators, instruments, etc. are all connected to this network via UGPSSM devices. The UGPSSMs digitize and GPS synchronize measurements from substation instruments, and transmit it to the SCC via the substation LAN. Control commands are sent by the SCC back to substation equipment via the same substation LAN. This brings all of the substation data so that it is available in a single location (the SCC) and time synchronized, so that it can be processed in software to provide any needed functionality. It also allows substation functionality to be adjusted or upgraded by a simple software change, significantly reducing the impedance to new technology or features.

Once in the SCC, processing of Substation data, commands, and communication with the power system WAN is automated by software intelligence. This software intelligence is divided into four major areas of functionality:

1. Substation situational awareness.
2. Substation automation.
3. Distribution grid management (DGM).
4. Wide area interface.

Each of these functional blocks is described in detail below.

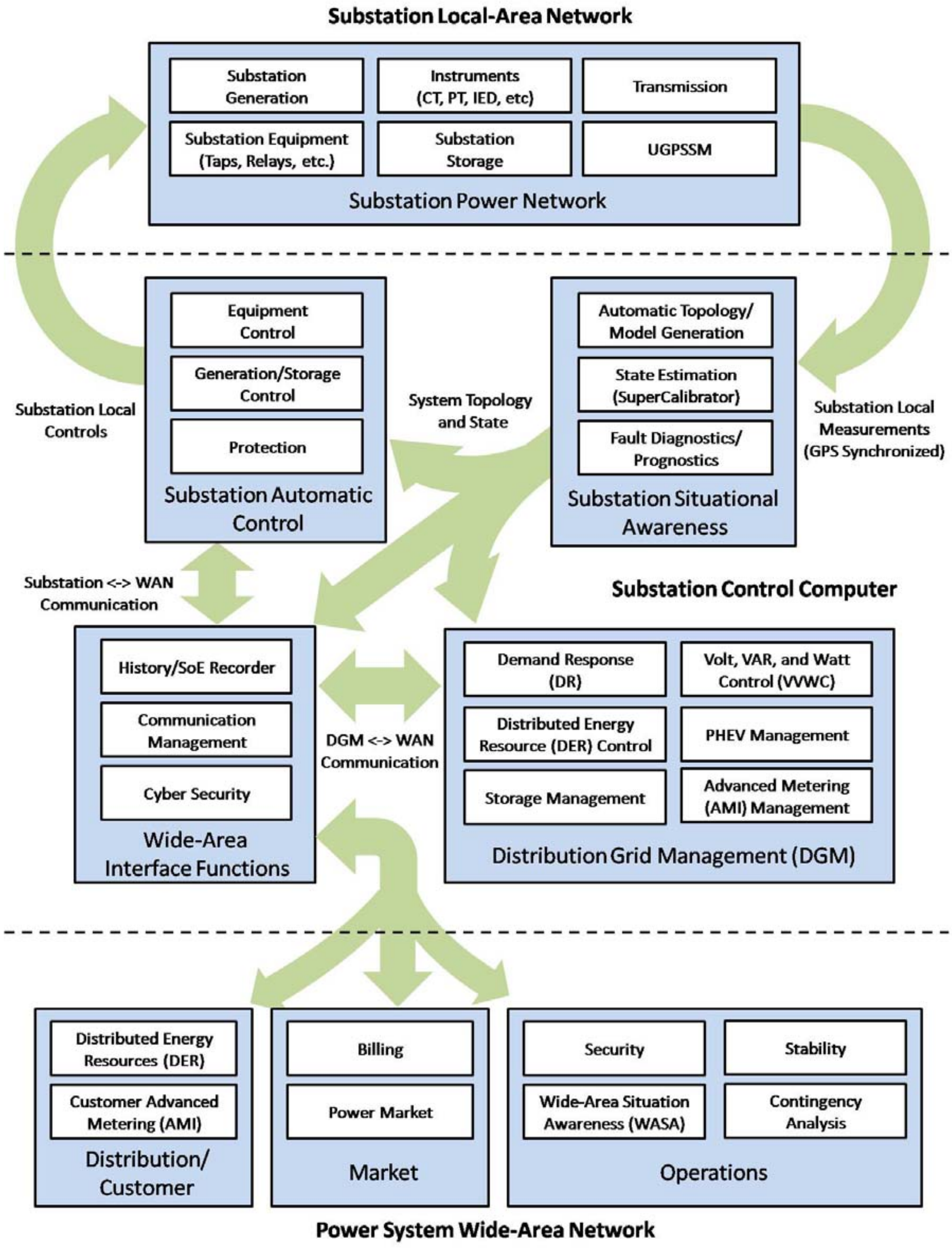


Figure 1.4: Smart substation functional architecture [1.15].

1.2.1.1 Substation Situational Awareness

The substation situational awareness functional block is responsible for determining the topology, state, and fault status of the substation. Once this data has been determined, it is recorded and made available to other functions. It may also be made available to other Smart Grid entities via the power system WAN (through the wide area interface functional block). As a part of the larger Smart Grid, the substation situational awareness block is a part of the wide-area situational awareness (WASA) Smart Grid functional area.

The substation situational awareness functional block receives all measurements from substation equipment from the UGPSSM devices via the substation LAN. In addition, it receives information on the identity, capabilities, and status of all devices in the substation from the UGPSSM devices. Using this information, it is able to develop a real-time map of the topology and capabilities of the substation. This enables plug and play capability: as power equipment is added or removed from the substation, as failures occur, or as topology is adjusted, the substation situational awareness block updates the topology to account for these changes. It also creates a real time 3-phase, breaker oriented model of the substation, which is an input to the SuperCalibrator state estimation process.

State estimation is performed by the SuperCalibrator state estimator, using the 3-phase breaker oriented substation model generated from the real-time topology. This state estimation is based on the measurements received from substation power equipment. Because of the high level of redundancy available in the substation measurements, their GPS synchronization, and the real-time nature of the model, this state estimate can be very accurate and have high immunity to measurement error or equipment calibration or failure. The resulting substation state estimate is passed to the other functional blocks of the SCC.

Finally, the substation situational awareness block is capable of detecting and diagnosing faults that may occur in substation power equipment or measurement. T his can be done by analyzing the substation topology and state; and can identify specific faults, rather than depending on multiple alarms from relays, etc. In addition, it may be able to perform prognostic functions on substation equipment, i.e. by detecting instruments moving out of calibration, power equipment out of spec, etc. This may allow targeted preventative maintenance.

1.2.1.2 Substation Automation

The substation Automation functional block is responsible for determining the control commands that will be sent to Substation power equipment. This is determined based on the Substation topology and state received from the Substation Situational Awareness block, and possibly on commands received from a Utility Control Center via the Power System WAN. It provides Equipment Control and Protection functions, and can be extended to control Substation generation, storage, etc.

1.2.1.3 Distribution Grid Management (DGM)

The DGM functional block is intended to provide future smart functions, in which a Smart Substation may act as a hub on the Smart Grid network or even manage Distributed Energy Resource (DER) on its associated distribution grid. When the Smart

Substation is deployed in a legacy power system, this block might be very simple or not present, but as the Smart Grid is deployed and DERs become more common, this block may be more complex depending on the needs of the particular system. This block provides demand response (DR), DER management, pluggable-hybrid electric vehicle (PHEV) management, distributed storage management, interface to customer Advanced Metering Interface (AMI), or even manage and independent microgrid with its own volt, VAR, and watt control.

1.2.1.4 Wide Area Interface

The Wide Area Interface functional block provides the interface for the Smart Substation to the larger power system WAN. It records all data and status generated by the substation, manages communication between the Smart Substation and other entities on the WAN, and provides firewall and cyber security functions for the Smart Substation.

1.3 Proposed Future Substation Architecture

A key feature of the future substation is GPS synchronization of Substation state and measurements. While calculated locally within the Substation, this state information is globally valid to the entire power system, because it will be time stamped using GPS synchronization technology. This is allowed by the use of universal GPS synchronized meters (UGPSSM). A UGPSSM is a device which can be attached to any power system measurement device such as a potential transformer (PT), current transformer (PT), circuit breaker, or any other intelligent electronic device (IED). It performs digitization of measurement or feedback data, and timestamps all measurements using a GPS time signal. This insures that this data is globally time valid. In addition, the UGPSSM tracks the identity, capabilities, and status of the device with which it is paired. It provides this data to the SCC, allowing the SCC to form a real-time topology and capability model of the substation. A physical diagram of the utilization of UGPSSM is shown in Figure 1.5.

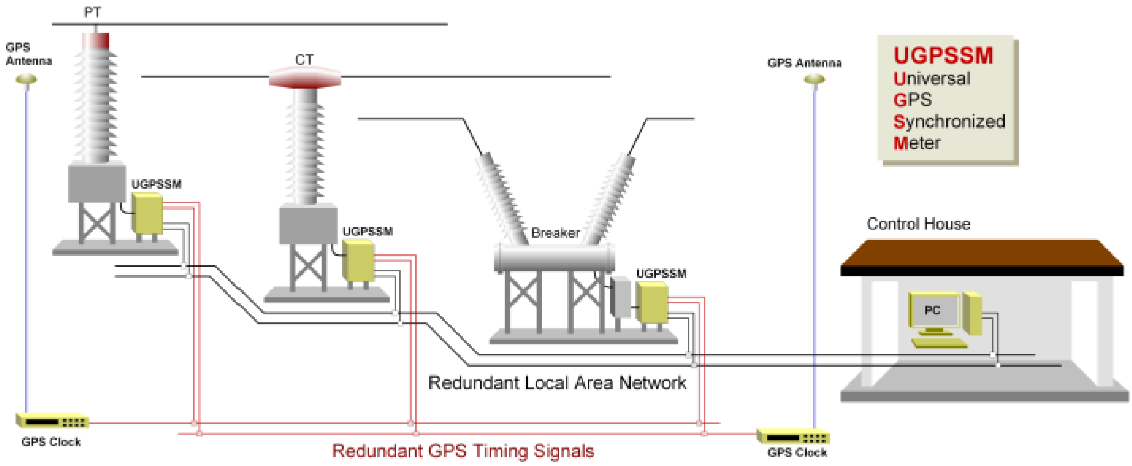


Figure 1.5: Future substation physical diagram.

In Figure 1.5 notice the "Redundant Substation Local Area Network", which connects all substation measurement and power devices to the SCC via a digital network. In addition, note the presence of a UGPSSM device on each high power device. The UGPSSM performs digitization and time synchronization of measurements and communicates the time tagged information to the SCC. Finally, the SCC communicates with the power system wide-area network (WAN) via a single communication channel. This allows the SCC to communicate with external power system entities, such as a Utility Control Center or other Smart Substations, to provide data necessary for Smart Grid wide-area functions.

The existing paradigm of SA is illustrated in Figure 1.6 representing a continuous evolution of technology over the last three decades.

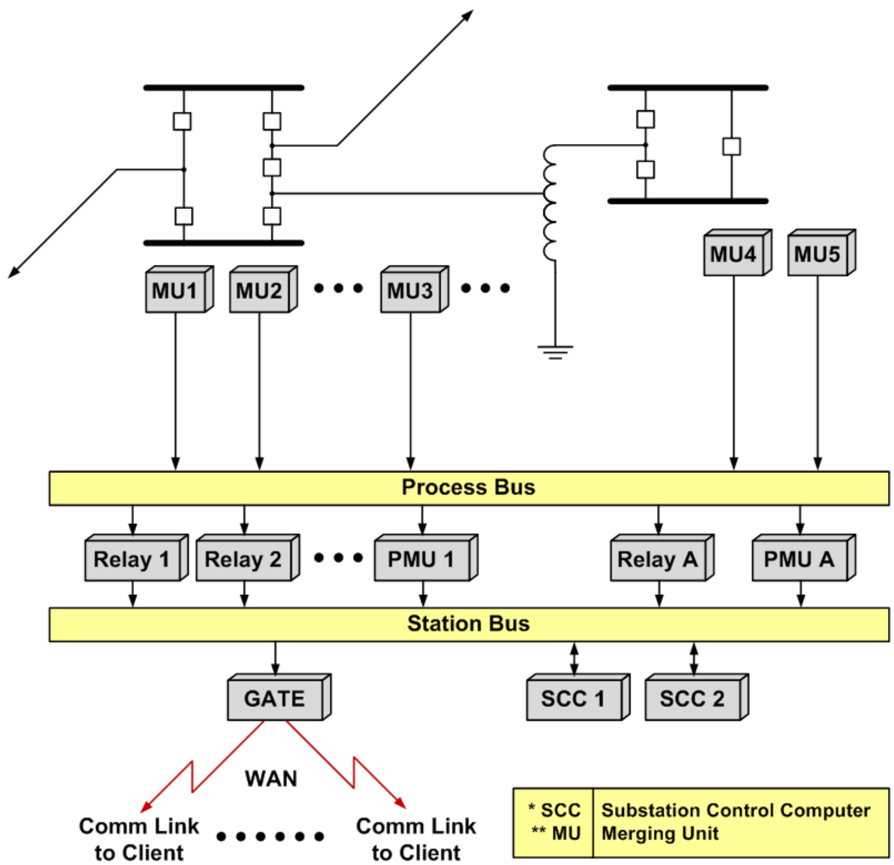


Figure 1.6: Combination of technologies typically found in present day SA systems.

In Figure 1.6 the equipment on the right-hand side including merging unit (MU) and process bus illustrates a modern IEC 61850 SA structure [1.16]. Whereas in Figure 1.6, the equipment on the left-hand side including analog instrumentation channel, relay and PMU illustrate a more antiquated system possibly containing electro-mechanical or digital protection equipment. The remainder of the equipment in Figure 1.6 includes communication gateway for external communications and local human interface machines (substation control computers, SCC). This heterogeneous mixture is common in substations today and is a major challenge for SA progress.

The proposed SA structure is required to deal with several well known limitation of centralized SE and to preemptively address future goals of power system operations. It is well known that centralized SE for power system operation and control suffers from several disadvantages:

1. it needs high-fidelity communication channels that are continuously utilized;
2. it is vulnerable to partial loss of the transmitted data that, in extreme cases, can cause significant errors in the real-time results;
3. it requires significant centralized computation resources to analyze all the collected data that generate a bottle-neck in the system;
4. it generates numerous alarms during abnormal events that overwhelm system operators and obscure the root cause of abnormal events;
5. it utilizes complex and vague bad data detection that result in the utilization of erroneous data in computing control actions; and
6. it includes high cost partial failures that result from the systems centralized nature.

Improving the functionality of substations will preemptively address future goals of power system operations:

1. improved performance using power infrastructure at or nearing its designed lifespan;
2. increased utilization of distributed energy resources;
3. simplified upgradability using plug-and-play functionality of switch yard equipment; and
4. heightened data security.

Presently, the infrastructure of data collection, protection, fault recording, SE, etc. have a common denominator: the instrumentation transformers, control cables, etc. that converts the high voltage and currents into instrumentation level voltages and currents; the entire measurement circuit is described as instrumentation channel. These voltages and currents are fed into devices such as relays, PMUs, meters, fault recorders, etc. Applications such as SE and others utilize data from the various devices. At the same time devices such as relays make decisions on the basis of the information they receive, typically a limited number of inputs.

The technologies involved in this basic infrastructure of the electric power system have evolved to the point that it makes sense to reevaluate the basic approach. One glaring issue is the separation of the protection system from the "visibility system", i.e. the infrastructure for identifying the real-time state of the system and subsequent control and operation functions. Recent technological advances and concurrent developments make it possible to integrate the two systems.

In this new vision, the substations can be viewed as autonomous agents in the power system that are equipped with local state-estimators, alarm processors, fault recorders, protective relaying, and a communication node to exchange this information with the control-center and other entities for global system control.

Certain advantages of the proposed system are apparent. Since the data acquisition devices are at the instrument transformers the errors introduced from long control cables and electromagnetic transients on long control cables are practically eliminated. In addition, the costly practice of wiring between instrument transformers and control house is also eliminated. Communications within the substation are via a fiber local area network, the system is secure from cyber attacks – at least the part within the substation.

The proposed scheme can be implemented independently of the size of the system (scalability) since it is a distributed system. This is a major advantage for large RTOs over the competing centralized schemes. The amount of data to be transmitted between the substation and the control-center and its frequency of transmission are fixed today but the proposed scheme can make this completely flexible with the data amount and frequency adjusted to the particular control-center application which can also be made to run more or less often depending on the state of the system. The proposed scheme enables wide-area protection and wide-area control which can be designed and implemented more easily if these substations can also exchange data as needed for such applications.

The quantitative evaluation of the proposed scheme from a variety of perspectives such as reliability of measurements, reliability of time tagging, speed of data availability, speed of local (within the substation) communications, speed of communications with the control-center and making data available to the company enterprise, and impact on cyber security will have a profound impact on substation automation and control-center operations as well as the safety and security level of the power grid as a whole.

1.4 Technical Approach

We propose a new structure for SA: data acquisition; local processing; and data exchange and communications between the substation and the control-center and company enterprise. Data acquisition within the proposed SA structure is performed via a new device called a universal GPS time-synchronized meter (UGPSSM). Specifically, each instrument transformer and active power device (circuit breaker, transformer, and capacitor bank) is equipped with a UGPSSM that processes all measurements and provides a common interface for all control signals. Local processing is facilitated using the SuperCalibrator. Protection is performed using the SE output of the SuperCalibrator. Power quality monitoring is performed using calibrated measurements. Data exchange and all external communications are done using the filtered results of the SE.

A block diagram of the switch yard equipment and the control house interface in the proposed SA structure are shown in Figure 1.7.

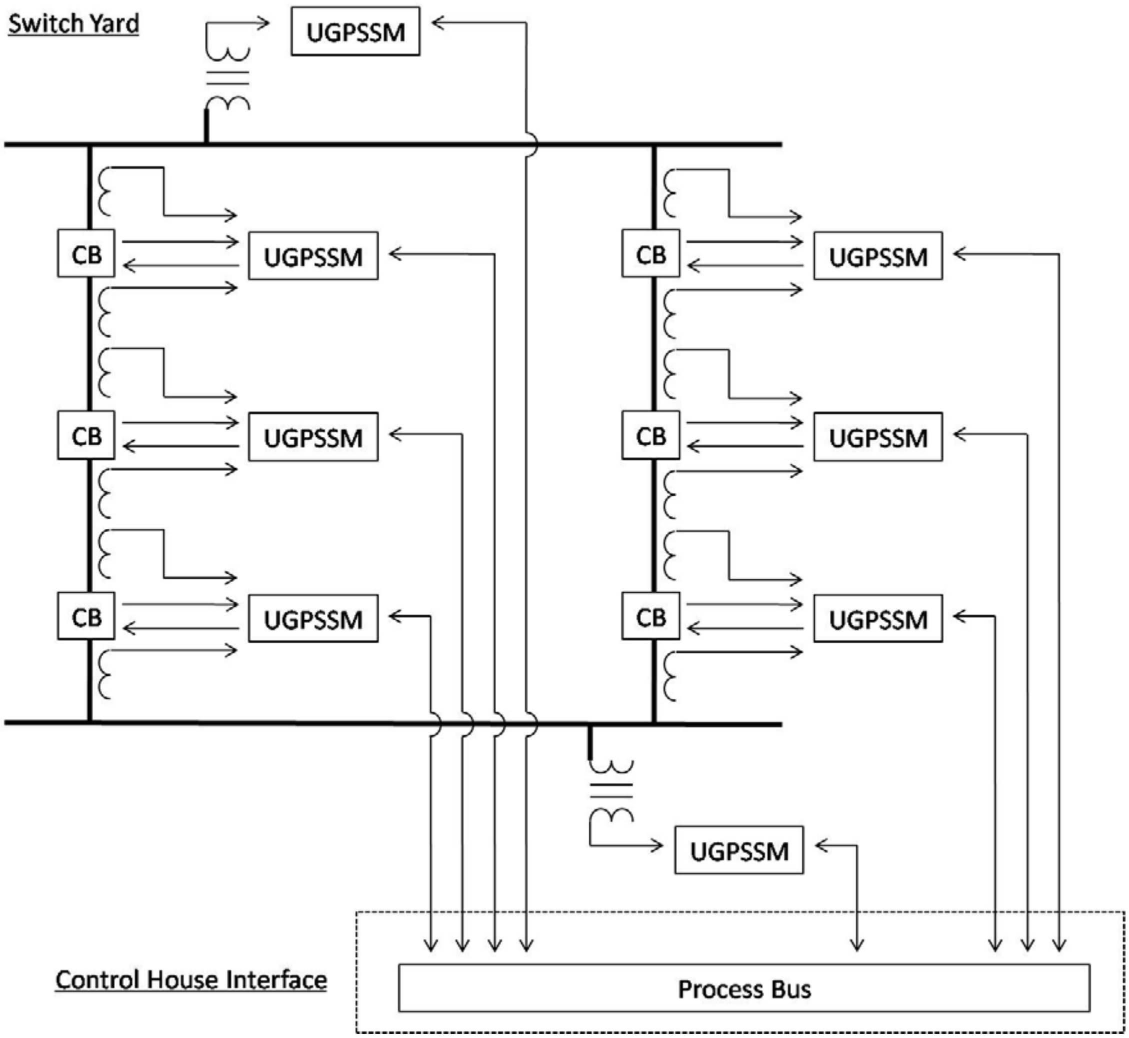


Figure 1.7: Block diagram of the switch yard equipment and the control house interface in the proposed SA structure.

In Figure 1.7, the switch yard equipment includes PTs, CTs, circuit breakers (CBs), and UGPSSMs. The PTs and CTs provide analog measurements that are conditioned via the UGPSSMs. The CBs provide a digital measurement (auxiliary contacts) and a control connection.

Two types of UGPSSMs are shown in Figure 1.7. The first type is connected to two three-phase CTs and one circuit breaker; requiring 6 analog inputs (one for each phase current), one digital input (circuit breaker auxiliary contact), and one output (control connection for the CB trip signal). The second type is connected to a single three-phase PT; requiring 3 analog inputs (one for each phase voltage).

Note that, the interface between all the control house equipment and all of the switch yard equipment is a single device, the UGPSSM, suggesting an interoperable environment for multivendor equipment. Further description of the UGPSSM is provided in the description of the data acquisition function of the proposed substation automation structure.

A block diagram of the control house equipment and the switch yard interface in the proposed SA structure are shown in Figure 1.8.

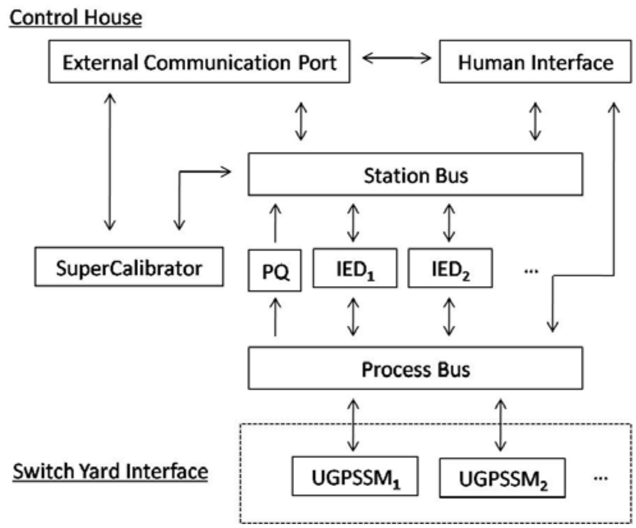


Figure 1.8: Block diagram of the control house equipment and the switch yard interface in the proposed SA structure.

In Figure 1.8, the control house equipment includes process bus, SuperCalibrator equipment, power quality (PQ) monitoring equipment, intelligent electronic devices (IEDs), station bus, external communication port, and human interface equipment. The process bus is a data communication network used to communicate between the switch yard equipment and the control house equipment. The data within the process bus is high frequency, high redundancy, and possibly corrupted. The SuperCalibrator equipment consists of a high end personal computer and performs local state estimation; measurement channel error quantification; bad data identification and removal; and alarm processing and root cause identification. The output of the SuperCalibrator consists of three-phase state estimations and is used for protection and all external communications. The measurement error quantification is utilized to calibrate all measurement signals. Calibrating the measurement signals results in higher accuracy PQ monitoring and IED calculations. The PQ monitoring equipment provides harmonic spectrum and transient event monitoring. The control house IEDs provides processing of the sampled and time-stamped data from the process bus. The IEDs generate station bus data, including phasor, magnitudes, phase angles, sequence quantities, etc. The station bus network is a data communication network used to communicate all substation data to the SuperCalibrator equipment, external communication port, and human interface equipment. The external communication port provides a single port for all external communications. The human interface equipment provides a local terminal for an operator to access all available substation data and functions.

The data validation procedures have been in development since the early 1990s. In [1.5] a data validation algorithm, the SuperCalibrator, was introduced that integrated data from supervisory control and data acquisition (SCADA), relays, phasor measurement units (PMUs), meters, and fault recorders. The integrated data, representing all available substation data, is filtered such that the results, the state of the substation, are of higher accuracy then the most accurate measurement channel in the substation. This technology has been developed over many years and has been more recently applied as a distributed state estimation (SE) method. A successful demonstration project in a small five substation utility showed that the distributed SE method performed significantly faster than any other SE system, the distributed SE method results were highly accurate, and that the distributed SE method could be expanded to a system of any size.

The SuperCalibrator utilizes a detailed model of the substation and is a hybrid SE method. It is a substation based state estimator that relies on a detailed three-phase breaker-oriented model of the substation. The substation model includes explicit representation of the instrumentation channels. The SE method can utilize a mixture of both global positioning satellite (GPS) synchronized and non-synchronized measurements, i.e. a hybrid methodology. The results of the SuperCalibrator are a real-time model of the system.

The SuperCalibrator concept compensates for the common disadvantages of traditional state estimators; such as (a) biases from imbalances in the system, (b) biases from system asymmetries, (c) substantial errors from instrumentation channels, and (d) non-simultaneity of SCADA data. Since the method is based on a three-phase breaker-oriented model of the substation, it provides a powerful approach for identifying the root cause of alarms (identification of root cause events, symmetrical or asymmetrical, i.e. stuck pole, etc.) and therefore provides meaningful root cause information to the system operators.

This will lead to a brand new and revolutionary scheme for substation automation (SA), i.e., monitoring, modeling, and protection. Figure 1.9 illustrates the proposed scheme for the substation of the future. Each instrument transformer and active power device (circuit breaker, transformer, and capacitor bank) is equipped with a universal GPS-synchronized meter (UGPSSM) that converts the output of the instrument transformer into a digital form that is time tagged with GPS accuracy. All the UGPSSMs within the substation are interconnected via redundant LANs. For reliability there are also redundant GPS clocks that provide the GPS time signal to the UGPSSMs. Redundant personal computers at the substation control house perform the SuperCalibrator and therefore provide in real time the state of the substation. Present day technology can achieve this process with minimal time latencies.

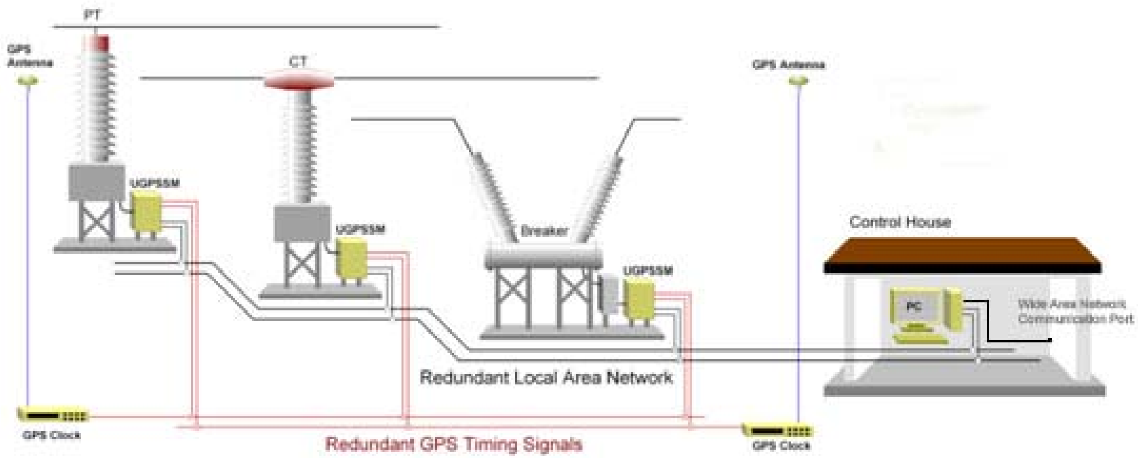


Figure 1.9: Conceptual view of the proposed substation of the future.

By utilizing the SuperCalibrator for all external communications power system operators will know directly the root cause of the alarm conditions. The imbedded protective relaying module has the potential of becoming more reliable, secure, and selective since it can utilize information from the entire substation as opposed to the present practice of using individual relays that monitor only a small number of data.

The amount of data to be transmitted between the substation and the control center and its frequency of transmission are fixed today but the proposed scheme can make this completely flexible with the data amount and frequency adjusted to the particular control center application which can also be made to run more or less often depending on the state of the system. The proposed scheme enables wide-area protection and wide-area control which can be designed and implemented more easily if the substation of the future can also exchange data as needed for such applications.

The major task of the feasibility study is a quantitative evaluation of the proposed scheme with respect to the followings:

1. data collection, validation, and communication
    a. substation level data acquisition
    b. substation data filtering and calibration
2. protection based on validated data
3. power quality monitoring based on validated data
4. wide-area monitoring and system protection
5. data dissemination
    a. control-center operations
    b. company enterprise needs
6. cyber security requirements

In summary, we propose to conceptually design a new scheme for SA with implications on the overall operation of the power system. The conceptual design of this system will be driven by a comprehensive analysis of data requirements for all substation functions as well as control-center functions and company enterprise operations. This analysis will determine the desirable properties of the collected data in terms of sampling rates, accuracy, validation, etc.

1.4.1 Data Collection, Validation, and Communication

The first major task of the feasibility study is a quantitative evaluation of the proposed scheme with respect to (a) inter-substation communication hardware, (b) feasibility of providing protective functions using a distributed SE algorithm, and (c) feasibility of providing power quality monitoring functions using a distributed SE algorithm. The tasks of the feasibility study with respect to these issues are described next.

1.4.1.1 Substation Level Data Acquisition

One of the basic components is the UGPSSM. It is proposed to equip each instruments transformer (whether stand alone or integrated in breakers or other devices) with one UGPSSM. The conceptual design for the UGPSSM will be developed in this project. The design will be based on individual channel GPS synchronization from redundant GPS timing signals (1 kpps, IRIGB, from two different GPS clocks, etc.), common mode rejection filter with optical isolation, high end (16 or 24 bit) A/D sigma/delta modulation converter and relatively high sampling rates to be determined from an analysis of data structure requirements.

1.4.1.2 Substation Data Filtering and Calibration

The collected data at the substation computers will be validated with techniques developed previously (the SuperCalibrator software). The SuperCalibartor is a model based filtering procedure. The SuperCalibrator uses a detailed three-phase breaker-oriented model of the substation, with explicit representation of the instrumentation channels, with both GPS-synchronized and non-synchronized measurements in order to derive an accurate real-time model of the system. In this case, all the measurements will be GPS synchronized and the filtering process will be direct. The filtering procedures of the SuperCalibrator consist of two main algorithms: (a) a state estimation algorithm that works with the measurement phasors and (b) a dynamic state estimation algorithm that considers the transients of the system. It is expected that both procedures will be running in parallel and their output will be used by the appropriate applications. It is important to emphasize the ability to validate the data, i.e. bad data identification and rejection. The feasibility study will conceptually design a system of alarm generation based on the outputs of the SuperCalibrator. The knowledge of the substation state will provide information of whether the operation is normal or abnormal. Triggering and alarming will be defined on the basis of the substation state. In the case of a trigger event, the system will be conceptually designed to store waveforms of proper duration (with pre-trigger information). In addition, visualization methods will be conceptually designed to illustrate the event in a detailed visualization manner as it evolves.

1.4.2 Protection Based on Validated Data

The proposed approach will be compared to the present practice of dedicated relay devices to perform specific protective and control functions using only limited information (for example only one set of three phase voltages and one set of three phase currents). One expects that the protective and control functions can be performed with higher reliability, security, and selectivity since all the substation information can be used. The feasibility study will focus on the additional flexibility in performing the protective relaying and control functions and the impact of the time latencies on the overall protective scheme. In this analysis substations of different configurations will be considered, i.e. breaker and a half, ring bus, etc.

1.4.3 Power Quality Monitoring Based on Validated Data

It is many times important to monitor power quality provided by the substation. The proposed scheme provides a structure for validating waveform data and then performing power quality functions on validated data. This process is described in section 5.

1.4.4 Wide-Area Monitoring and System Protection

The proposed structure of substation data is not different than a dedicated wide-area monitoring and control scheme (or any other control-center). Although we are used to thinking of a control-center as a particular location where many application functions have been centralized, the proposed scheme enables various applications to reside in various places. The main difference with wide-area protection and control schemes and present day control-center functions is that the latter work at much slower speeds. In this task the data flows for various wide-area control schemes will be examined and the feasibility of such schemes will be studied.

1.4.5 Data Dissemination

The second major task of the feasibility study is a quantitative evaluation of the proposed scheme to meet the needs of (a) control-center operations, (b) company enterprise needs, (c) wide-area monitoring and system protection, and (d) cyber security requirements. It is important to note that the proposed scheme provides for (a) a single port of communications with the external world as opposed to each relay or each intelligent electronic device having the capability of communication and (b) the data to be communicated from the substation have been filtered and reduced to information as opposed to collected raw data – this process drastically reduces the throughput requirements. The tasks of the feasibility study with respect to these issues are described next.

1.4.5.1 Control-Center Operations

At present control-centers use a round-robin polling of all the remote terminal units (RTUs) at the substations at relatively slow rates. If the RTU is replaced with a new platform that has all the possible substation data available, the paradigm changes completely. All of the data from every substation is not needed; in fact, the data amount and frequency can be selected according to the application at the control-center. If it is for monitoring, contingency analysis, or automatic generator control (AGC); the data reaching the control-center can be customized for each. This task is to determine the different flow patterns needed for the different applications at different control-centers. A conceptual design for this new type of data acquisition will be developed and its feasibility will be tested by simulation.

1.4.5.2 Company Enterprise Needs

Although the need for this data in operation and control is very sensitive to latency, a much larger set of engineering and business functions need this data not as urgently. Thus, this data needs to be stored in a historical database that can be accessed by many functions and people inside and outside the enterprise. In this task we will examine the storing of data in each substation and how this will be made available to all enterprise needs. It is not possible to think of and study all such functions but the generic needs of a multitude of functions will be studied. For example, some functions may only need a few pieces of data from many substations while another function may need all the data from only a handful of substations. A conceptual design of a networked historical data base will be developed and its feasibility determined.

1.4.6 Cyber Security Issues

The security of the computation and communication system is a major concern these days. Thus, much larger data flow volumes within the substation and between substations have to be carefully designed to ensure data security. For example, the real-time data flows for operation and control may require a higher level of security with much more restricted access than the enterprise need for historical data. Actually, firewalls between real-time data and historical data would be part of the design. In this task we will look at the conceptual design of the data servers and data networks and study the level of security that can be ensured.

2. Substation Level Data Acquisition

This chapter reviews substation level data acquisition architecture and communication protocol described in IEC 61850 [2.1]. IEC 61850 is the current international standard for substation automation (SA). The focus of IEC 61850 is to provide an interoperable standard for multivendor substation equipment to communicate. To date, proprietary communication protocol has handcuffed the utilization of heterogeneous mix of substation equipment.

The description of IEC 61850 is a frame of reference from which three proposed substation level data acquisition architectures can be compared. Here substation level data acquisition architecture is used to describe the physical connection of devices and the flow of data within the system; whereas, communication protocol is the language utilized to communicate information over the network. Both of these issues impact the overall substation level data acquisition with respect to fidelity, latency, and reliability.

The substation level data acquisition system transmits data from the UGPSSMs to the control house. This functionality can be performed via multiple architectures. Three such architectures will be described in terms of the flow of data in a typical substation. The three architectures described are point to point, networked, and wireless.

In the proposed substation of the future all collected data is initially processed via universal global positioning satellite (GPS) time-synchronized meter (UGPSSMs). The UGPSSM device is similar to the IEC 61850 merging unit [2.1]. The processing of each UGPSSM is to sample, digitize, and GPS time-stamp all substation data. This chapter describes the functionality and proposed hardware of the UGPSSM.

2.1 IEC 61850 Substation Level Data Acquisition Overview

2.1.1 Data Flow

A conceptual diagram of the substation level data acquisition system outlined in the IEC standard 61850 “Communication Networks and Systems for Power Utility Automation” [2.1] is shown in Figure 2.1. An example of technology, currently available, utilizing this approach is the GE HardFiber technology [2.2].

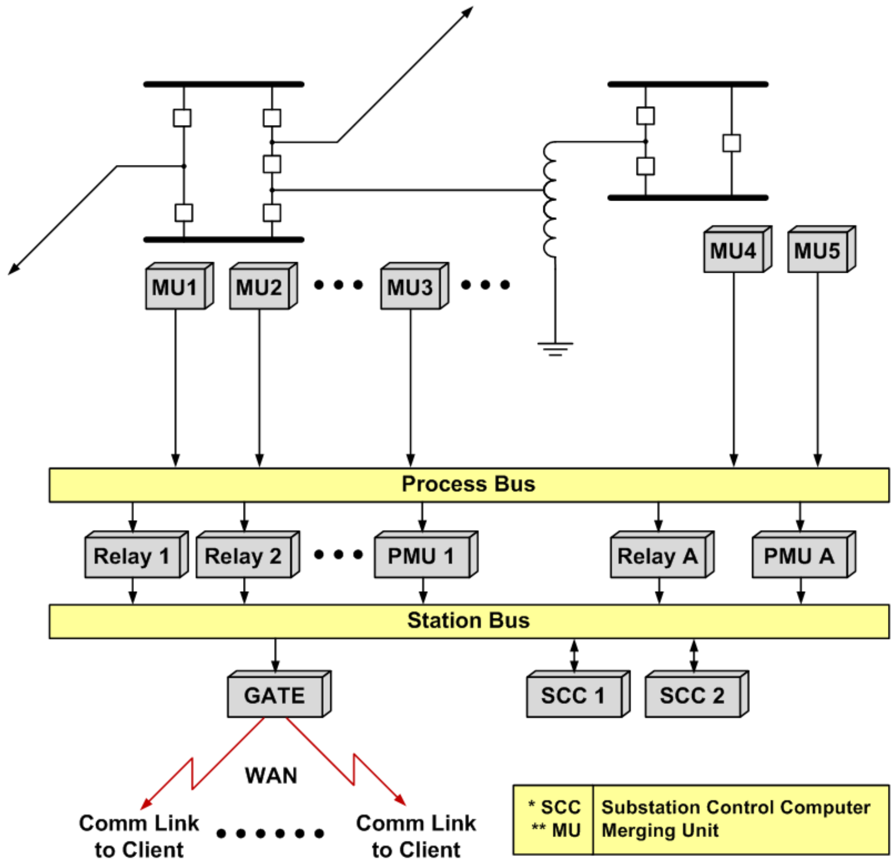


Figure 2.1: Conceptual design of 61850 standard substation level data acquisition.

In Figure 2.1 the merging units (MUs) are analog to digital data collection devices which sample and digitize electrical quantities. The electrical quantities are analog or digital signals which are of interest. Analog quantities include voltage and current signals from potential transformers (PTs) and current transformers (CTs), transformer temperature signals from resistance temperature detectors (RTDs), transformer turns ratios from potentiometers, etc. Digital quantities include auxiliary contact outputs, etc.

The MUs are placed physically close to the signals which they monitor. This arraignment minimizes the potential for signal corruption. Within the GE HardFiber system the MUs are called Bricks. The GE Bricks include a weatherized exterior suitable for outdoor and extreme physical conditions common in substations.

In Figure 2.1 communication from each MU to the process bus is provided via point to point communication. The rate of data transmissions in this portion of the system is very high. This requirement demands a point to point communication medium. Within the GE HardFiber system prefabricated fiber optic cabling is used between the Bricks and the termination points for the substation yard fiber optic cable the Cross Connect panels.

The Cross Connect panels are located within the substation control house and are used to connect Bricks to protection relays, meters, and any other intelligent electronic devices (IEDs). The Cross Connect panels, as suggested by the name, allow fiber-optic cables to be patched between ports from the substation yard Bricks and control house IEDs. The setup creates a dedicated fiber-optic communication channel between each Brick and corresponding IED.

In Figure 2.1 the process bus block represents the interconnection of MU data pathway to individual substation IEDs. The substation IEDs utilizes the digital data provided by the MUs to generate additional data. Within the HardFiber system prefabricated fiber optic patch cords are utilized within the Cross Connect panels to create a continuous fiber optic channel between the Bricks and IEDs.

In Figure 2.1 each the relays and PMUs provides additional data to the station bus including voltage and current magnitude, root mean square, etc. based on the data from the MUs. This additional data requires multiple sampled data point; e.g. computing the magnitude from sampled data requires a full period of samples. Thus, the station bus transmits data significantly slower than the process bus. This allows a networked architecture at the station bus.

In Figure 2.1 the station bus facilitates data flow between all substation IEDs, substation control computers, and GATE hardware. This allows inter IED messaging, human machine interfacing, and communication with external stakeholders.

Key advantages of the HardFiber system include [2.2]:

1. standardized optical fiber cabling;
2. prefabricated off the shelf components;
3. engineering, installation, commissioning, and operating utilized existing skill sets;
4. GE UR-series relays and other 61850 compatible IEDs can be utilized; and
5. different IEDs can record sampled data at independent sampling rates.

IEC 61850 allows for legacy equipment to operate within the same substation with newer equipment. This is shown in Figure 2.1 where Relay A and PMU A monitor voltages and currents via analog instrumentation channels.

2.1.2 Communication Protocol

IEC 61850 is more than a typical communication protocol. IEC 61850 includes specifications on how to communicate data. It also specifies what data is to be communicated in an object orientated manner.

An overarching goal of the creators of IEC 61850 is to create a communication protocol which allows interoperable performance between all substation equipment vendors.

2.2 Substation Level Data Acquisition Architectures

Within all substations data is utilized locally and data is sent to external stakeholders. The architecture utilized to collect local data varies significantly from one substation to the next. Three possible data collection architectures for the substation of the future are described next.

2.2.1 Point to Point

A conceptual design of the point to point architecture is shown in Figure 2.2.

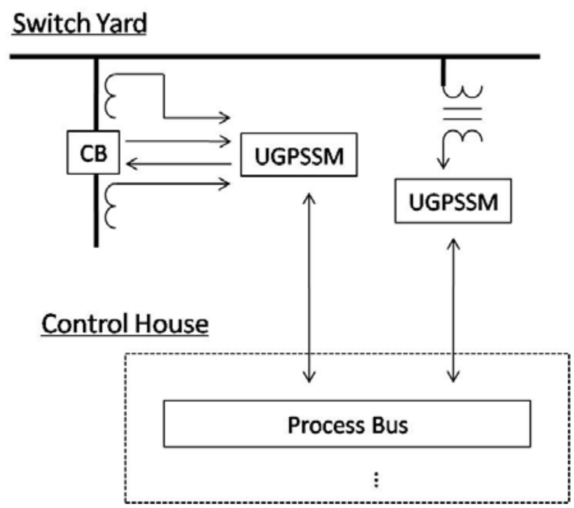


Figure 2.2: Conceptual design of point to point data collection architecture.

In Figure 2.2 the UGPSSMs communicate via point to point fiber-optic or copper data link. Periodic data are provided from each UGPSSM.

Advantages of point to point communication includes:

- highest speed throughput

Disadvantages of point to point communications includes:

- demands the most raw material for the communication channels
- demands the most infrastructure for communication right of way

A second method utilized to collect substation data is the networked architecture, described next.

2.2.2 Networked

A conceptual design of the networked architecture is shown in Figure 2.3.

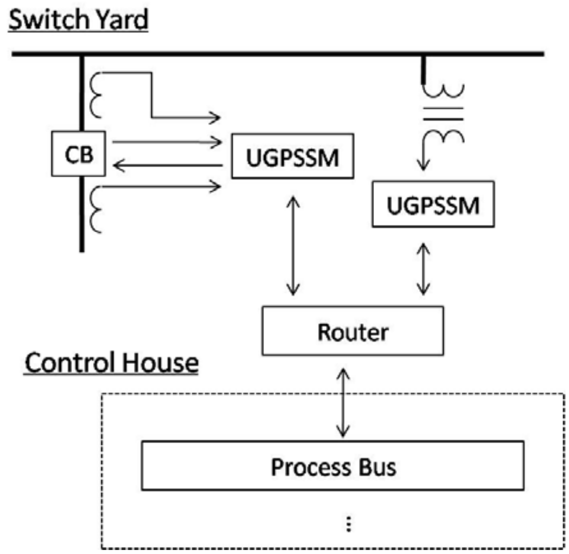


Figure 2.3: Conceptual design of networked data collection architecture.

In Figure 2.3 the output of each UGPSSM is routed via the router to the control house. The use of switched communication minimizes the amount of network link material. However, this type of networked communication requires an additional component impacting the reliability of the communication system. Further, the switching communication increases the latency of the data flow.

The networked architecture has considerable market share of industrial and commercial communication infrastructure. The use of networked communication infrastructure in substation environment is limited. The reliability and latency of this form of communication is questioned for the hard real-time systems utilized in power system automation.

Advantages of networked architecture includes:

- lower requirement on communication channel material,
- lower requirement on communication infrastructure.

Disadvantages of networked communications includes:

- communication collisions cause delays.

A third method utilized to collect substation data is the networked architecture, described next.

2.2.3 Wireless

A conceptual view of the wireless architecture is shown in Figure 2.4.

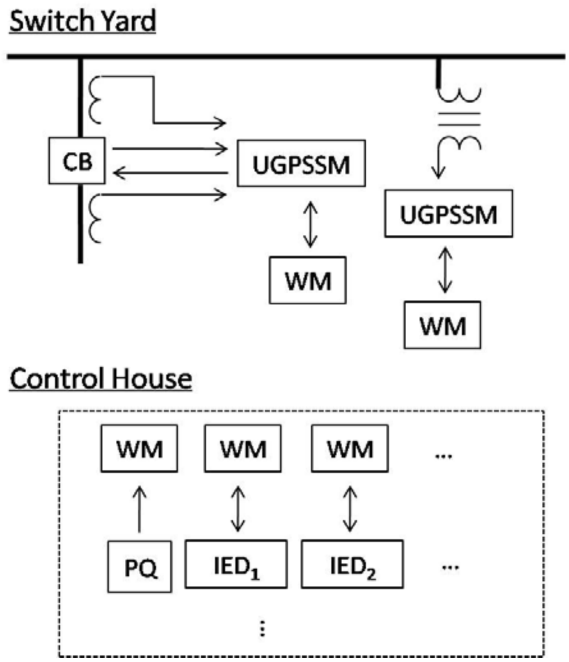


Figure 2.4: Conceptual design of wireless data collection architecture.

The wireless architecture has similarities and differences from the last two substation level data acquisition architectures. To date wireless based substation level data acquisition methodology has not been utilized. Wireless based data transfer is utilized in other applications for power system operations and in many other technical areas.

In Figure 2.4 wireless modems are used to send the UGPSSM data to the control house. With wireless communication security is of primary concern. We propose the use of directional antenna; so that, availability of the transmitted signal outside of the substation is impossible.

Wireless communication requires only modems to be placed at each measurement location; thus, limited infrastructure investment is required. The distances of typical substation data transmissions allow highly reliable point to point data transfers. The use of wireless modems result in a measurable reliability concern that can be continuously monitored via the existence of transmitted data.

Advantages of wireless architecture includes:

- lowest requirement on communication channel material,
- lowest requirement on communication infrastructure.

Disadvantages of wireless communications includes:

- cyber security concerns,

- speed (this is not a disadvantage with new systems)

2.2.4 Communication Protocol

Multiple communication protocol exist which are applicable to substation level data acquisition. A partial list of existing standards is provided below.

1. DNP3
2. MODBUS
3. IEC 60890-5-103
4. IEEE C37.118
5. SEL Fast Message Protocol

The challenge of the substation of the future involves requiring high speed and reliability digital communications within the demanding environment of high voltage substations.

2.3 Substation Level Data Acquisition Architecture Overview

Of the three reviewed substation level data acquisition systems (point to point, networked, and wireless) the advantages of the wireless architecture are significant.

2.4 Universal GPS Time-Synchronized Meters

The UGPSSMs provide a common interface for all input and output data, between the switch yard equipment and the control house equipment, in the proposed substation automation structure. In general, the UGPSSM is similar to the IEC 61850 merging unit [2.1]. The UGPSSMs process all analog measurements, digital measurements, and control signals. This processing for analog measurements includes sampling, digitizing, and GPS time-stamping. This processing for digital measurements includes appropriate sampling rate compression/upsampling and GPS time-stamping. A block diagram of the analog measurement channel within the proposed UGPSSM hardware is shown in Figure 2.5. The digital measurement channels include optical isolation, microprocessor (μP), phase lock loop (PLL), and GPS clock signal. The control channels include optical isolation and μP only.

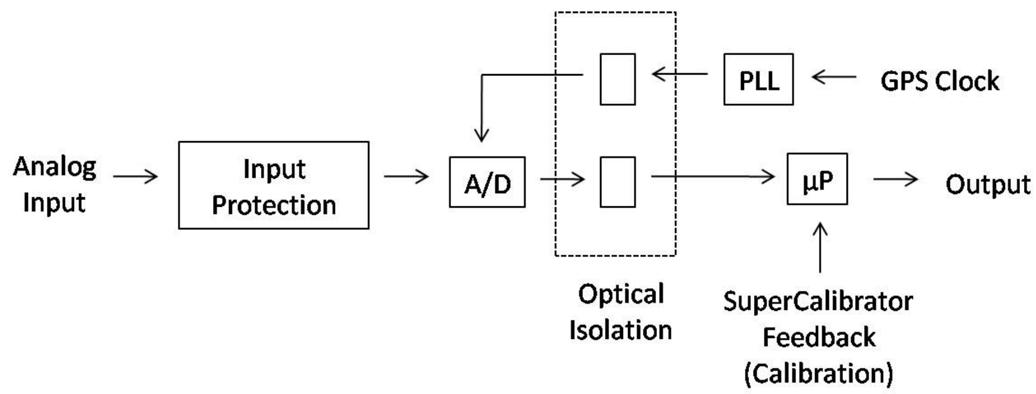


Figure 2.5: Block diagram of the analog input channel within the proposed UGPSSM.

The blocks in Figure 2.5 provide the operation of the UGPSSM. Input protection is provided in similar fashion as in [2.3]. Digitization (A/D) is provided by a 16 bit sigma/delta modulated analog to digital converter. GPS time-stamping is added to each measurement using a GPS clock signal. UGPSSMs also provide optical isolation between all low voltage hardware and the switch yard equipment. In general, the UGPSSMs are placed physically close to the switch yard equipment which they monitor to minimize any low energy analog signal corruption.

The SuperCalibrator feedback signal in Figure 2.5 is utilized to automatically calibrate the measurement channels; leading to a self correcting measurement channel within the proposed substation automation structure. The SuperCalibrator provides measurement channel error quantification, monitoring the variance of the measurement channels leads to the quantification of the health of the measurement channels. This quantification can be utilized to derive a feedback signal to automatically increase the accuracy of all measurement channels. By increasing the accuracy of the measurement channels results in higher accuracy local processing within the substation.

3. Substation Data Filtering and Calibration

Substation data filtering and calibration in the proposed substation automation (SA) structure is achieved via the SuperCalibrator. The advantages of the SuperCalibrator stem from the high levels of redundant data at the substation level. By leveraging the high level of redundant data within a substation the SuperCalibrator computes a set of high fidelity state quantities from which state based protection and simplified external communications can be performed. The substation data filtering is performed via state estimation (SE), where a weighted least squares algorithm is used to compute accurate state results from error prone measurements. The substation data calibration is performed via measurement error quantification, a post processing portion of the SuperCalibrator.

This chapter provides an overview of the SuperCalibrator method, including description of the pseudo measurement formulation and measurement accuracy quantification.

3.1 SuperCalibrator Overview

The SuperCalibrator is conceptually very simple. The technology is based on a flexible hybrid SE formulation. This is a combination of the traditional SE formulation and the GPS time-synchronized measurement formulation, which uses an augmented set of all available substation data. The basic idea is to provide a model based error correction methodology within the substation. Specifically, a detailed model of the substation, (three-phase, breaker oriented model, instrumentation channel inclusive substation model) is utilized in a statistical procedure (state estimation) to fit all available substation measurements (potentially corrupted data) to the system model.

This approach leads to a substation level state estimation methodology. A block diagram of the SuperCalibrator is shown in Figure 3.1.

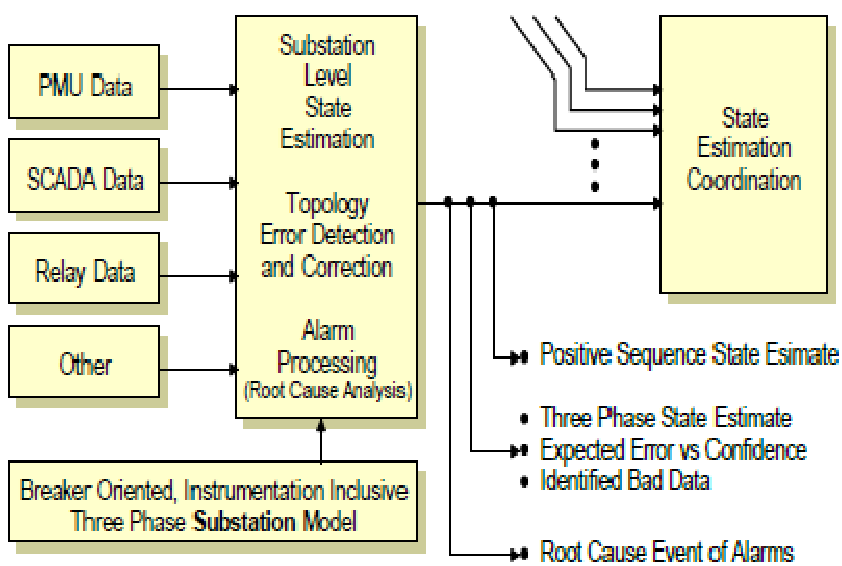


Figure 3.1: Block diagram overview of the SuperCalibrator.

In Figure 3.1, the SuperCalibrator measurement set is illustrated with the four input blocks PMU data, SCADA data, relay data, and all other local substation measurements. This measurement set is augmented with additional pseudo-measurements, described further below. In Figure 3.1 the substation model block represents a detailed substation model (three-phase breaker-oriented, instrumentation channel inclusive substation model). The results of the substation level state estimation procedure results in a three-phase state estimate. These results are then utilized to compute a positive sequence state estimate; state estimate confidence level quantification; and measurement confidence level quantification; sharp bad data identification and removal; and topology error correction and alarm processing and root cause identification.

Each component of this methodology will be described in this chapter.

3.1.1 Measurement Set

The first step in performing the SuperCalibrator is to collect all available substation measurements. In Figure 3.1, the SuperCalibrator measurement set is illustrated with the four input blocks PMU data, SCADA data, relay data, and all other local substation measurements. The measurement set is comprises of

1. traditional, non-synchronized measurements (voltage magnitude, active and reactive line flows and bus injections, and other standard SCADA data);
2. GPS time-synchronized measurements of voltage and current phasors for each phase;
3. GPS time-synchronized measurements of frequency and rate of frequency change; and
4. appropriate pseudo-measurements.

Typical measurements are illustrated in Table 3.1.

Table 3.1: List of measurements.

Phasor Measurements Description	Non-synchronized Measurements Description
Voltage Phasor, $\tilde{V}$	Voltage Magnitude, V
Current Phasor, $\tilde{I}$	Real Power Flow, P_f
Current Injection Phasor, $\tilde{I}_{inj}$	Reactive Power Flow, Q_f
Frequency, f	Real Power Injection, P_{inj}
Rate of frequency change, df/dt	Reactive Power Injection, Q_{inj}
Other	Other

PMU data consists of the left hand column in Table 3.1. SCADA and relay data consists of the right hand column in Table 3.1. All other data consists of both phasor and non-synchronized measurements and are shown in Table 3.1 in the last row of both columns.

This category includes circuit breaker auxiliary contacts, transformer temperature measurements, transformer tap ratios, etc.

The presence of at least one GPS time-synchronized measurement at each substation makes the results of the SuperCalibrator globally valid. Specifically, the results from the SuperCalibrator in substation ‘A’ are comparable (on the same time reference) as the SuperCalibrator results from substation ‘B’. The implications of this observation are very important.

The results of the SuperCalibrator from the various substations can be brought into the control center where they can be combined to form the system wide real-time model of the system without any additional processing. This forms the basis of the fully distributed state estimator.

3.1.2 Substation Model

The last input to the substation level state estimation block in Figure 3.1 is the substation model. The SuperCalibrator substation model is a three-phase breaker-oriented instrumentation inclusive substation model. The model of the system is defined in terms of the model of each individual component within the system of interest. The system of interest comprises a substation and all the transmission circuits up to the next substations.

A three phase model is utilized to correct for system imbalances and system asymmetries. A physically based model, from which the three-phase breaker-oriented model is extracted, is utilized with the SuperCalibrator. The physically based model is a three dimensional model of the system inputted with a variety of user interfaces. Once the physical model is entered the mathematical model of the three-phase breaker oriented model is automatically constructed. This eliminates or minimizes human error in the construction of the model.

Ongoing work focuses on the development of automatic model parameter recognition. In general, this research focus is to develop the capability of having new equipment installed within a substation be automatically recognized by the local processing system analogous to how a personal computer automatically recognizes plug-and-play compatible peripheral hardware. Therefore parameter estimation of various substation components can be integrated within the overall state estimation process.

Models of all the instrumentation channels are integrated with the three-phase breaker-oriented model to provide a detailed substation model. The instrumentation channel model includes current transformer (CT) and potential transformer (PT) instrumentation cables, burden, attenuator, and phasor measurement unit (PMU) components. A diagram of the components of a typical voltage and current measurement channel are shown in Figure 3.2.

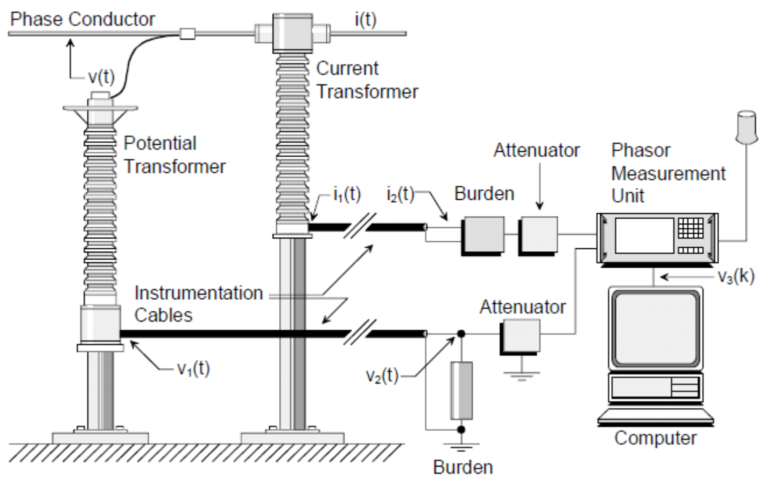


Figure 3.2: Components of a voltage and current instrumentation channel.

The PMU in Figure 3.2 (representing any control house IED) use a system of instrument transformers (CTs and PTs) to scale the power system voltages and currents into instrumentation level voltages and currents. Standard instrumentation level voltages and currents are 67V or 115V and 5A respectively [3.1]. These standards were established many years ago to accommodate electromechanical relays. Today, the instrument transformers are still in use, but because modern IEDs/PMUs/relays operate at much lower voltages, it is necessary to apply another transformation (attenuator) from the previously defined standard voltages and currents to another set of standard voltages of 10V or 2V. This means that the modern instrumentation channel consists of typically two transformations and additional wiring and possibly burdens.

It is well known that measurement channels are prone to error. Instrumentation channels are designed to provide a scaled version of the input (v(t) and i(t) in Figure 3.2) at the output ($v_2(t)$ and $i_2(t)$ in Figure 3.2). Each component within the instrumentation channel generates small random error under normal operating conditions; whereas, harmonic content and transient events can cause significant errors. The instrumentation channels models are described in detail in [3.2]. CT and PT devices are prone to saturation. Coupling capacitor voltage transformer (CCVT) include complex circuitry which is prone to problems involving resonate circuits and parameter drifting. IEDs include numeric errors due to finite bit length floating point arithmetic.

In general, the each component within the substation of interest is model by a set of algebraic and differential equations, which express the dynamics of the system and are defined in Equations (3.1) and (3.2).

$$\frac{d\tilde{x}(t)}{dt} = f(\tilde{x}(t), \tilde{y}(t), t) \tag{3.1}$$

$$0 = g(\tilde{x}(t), \tilde{y}(t), t) \tag{3.2}$$

In Equations (3.1) and (3.2) $\tilde{x}(\cdot)$ and $\tilde{y}(\cdot)$ are the dynamic and algebraic states of the system respectively, $f(\cdot)$ and $g(\cdot)$ represent non-linear vector functions differential and algebraic equations which depend on the devices which make up the substation of interest. The notation in Equations (3.1) and (3.2) are such that a lower case complex value indicates a vector containing at least one complex value and the vector functions are designated as lower case letters.

The three-phase breaker-oriented instrumentation inclusive substation model described in this section is utilized with the measurement set described in the previous section to perform substation level state estimation, which is described in the next section.

3.1.3 Substation Level State Estimation (SE)

The dynamic SE algorithm utilizes the integrated model of the three-phase breaker-oriented instrumentation channel inclusive model and the set of measurements to perform a SE, bad data detection and identification, topology error detection and identification for the purpose of extracting the real-time model of the system. The dynamic state estimator is applied to the integrated dynamic model of the power system. The model is based on a detailed three-phase, breaker-oriented and instrumentation inclusive dynamic representation of the substation configuration, the generating units and the interconnected transmission lines.

A block diagram of the dynamic state estimation methodology is shown in Figure 3.3.

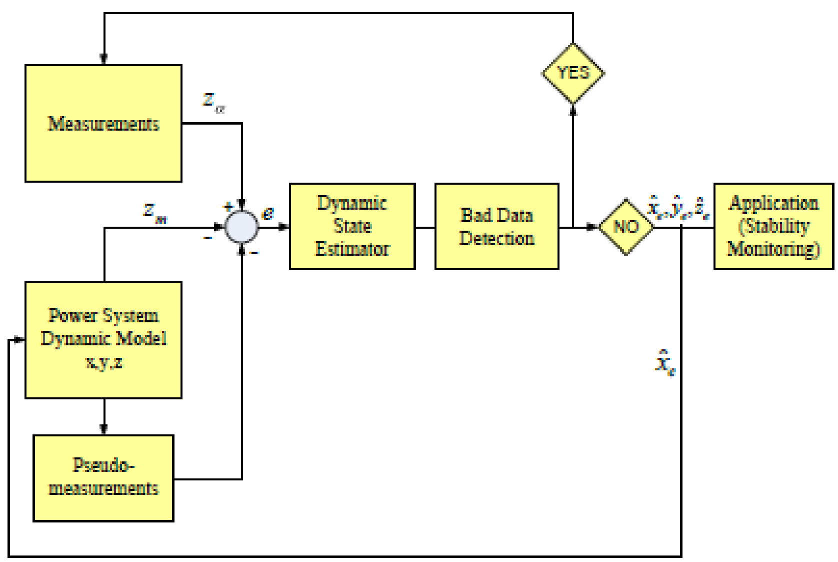


Figure 3.3: Block diagram of dynamic state estimator.

In Figure 3.3, the set of physical measurements $\tilde{z}_a$ are obtained from PMUs, relays, and other metering devices at the substation level. These values are then compared with the "model" values $\tilde{z}_m$ that are obtained from the dynamic model of the power system and with the pseudo-measurements $\tilde{z}_p$, forming a measurement error e, defined in Equation (3.3).

$$\tilde{e} = \tilde{z}_a - \tilde{z}_m - \tilde{z}_p \tag{3.3}$$

The resulting error $\tilde{e}$, in Equation (3.3), is used in the dynamic state estimator to minimize the sum of the errors squared. The result of the minimization is filtered by a procedure that identifies bad data [3.3]. If the dynamic state estimator results are not satisfactory, this indicates the presence of bad data. The bad data are identified, removed from the measurement set and the procedure is repeated. Otherwise, the best estimates of the system states and measurements denoted by $\hat{x}$, $\hat{y}$, and $\hat{z}$ are calculated. In addition, the estimated values of the dynamic states of the system $\hat{x}$ are fed back to the mathematical model to be used as the previous states for the differential equations. These estimated states can also be utilized as inputs to various computational applications such as stability monitoring and prediction [3.4].

The substation level state estimation postulates that the measurements $\tilde{z}$ are related to the states via a non-linear vector equation $h(\cdot)$. The measurement model is defined in Equation (3.4).

$$\tilde{z} = h(\tilde{x}(t), \tilde{y}(t), t) + \tilde{\eta} \tag{3.4}$$

In Equation (3.4), the measurement error $\tilde{\eta}$ is assumed to be a Gausian random value.

3.1.4 Three-Phase State Estimation

In general, the three phase state set represents the set of states for all buses within the system. The system utilized for simplicity is a single substation and the buses at all adjacent substations for all outgoing transmission lines. Each state represents the phasors of the three phase voltages and the average frequency of the three phases of a single bus. Therefore each state represents a four by one complex vector. The state of a general bus-k is defined in Equation (3.5).

$$\tilde{v}_k = \begin{bmatrix} \tilde{V}_{k,A} & \tilde{V}_{k,B} & \tilde{V}_{k,C} & \bar{f}_{Hz}(\tilde{V}_k) \end{bmatrix}^T \tag{3.5}$$

The notation in Equation (3.5) such that a capital complex value indicates a single complex value. Further, the vector elements in Equation (3.5) are defined in Equations (3.6), (3.7), (3.8), and (3.9).

$$\tilde{V}_{k,A} = V_{k,A,r} + j \cdot V_{k,A,i} \tag{3.6}$$

$$\tilde{V}_{k,B} = V_{k,B,r} + j \cdot V_{k,B,i} \tag{3.7}$$

$$\tilde{V}_{k,C} = V_{k,C,r} + j \cdot V_{k,C,i} \tag{3.8}$$

$$\bar{f}_{Hz}(\tilde{V}_k) = \frac{1}{3}\left[f_{Hz}(\tilde{V}_{k,A}) + f_{Hz}(\tilde{V}_{k,b}) + f_{Hz}(\tilde{V}_{k,b})\right] \tag{3.9}$$

Where $V_{k,p,r}$ indicates real component and $V_{k,p,i}$ indicates imaginary vector component of phasor $\tilde{V}_{k,p}$ in Equations (3.6), (3.7), and (3.8) (the subscript p is used as a general representation for all phases: A, B, and C). The function $\bar{f}_{Hz}(\tilde{V}_k)$ indicates the average frequency of the three phase voltages: $f_{Hz}(\tilde{V}_{k,A})$, $f_{Hz}(\tilde{V}_{k,B})$, and $f_{Hz}(\tilde{V}_{k,A})$.

The dynamic state estimator provides estimates, in real time, of the state of each bus in the substation of interest and, through the use of pseudo-measurements, the state of the busses where all outgoing transmission lines terminate at the next substations. This concept is illustrated in Figure 3.4.

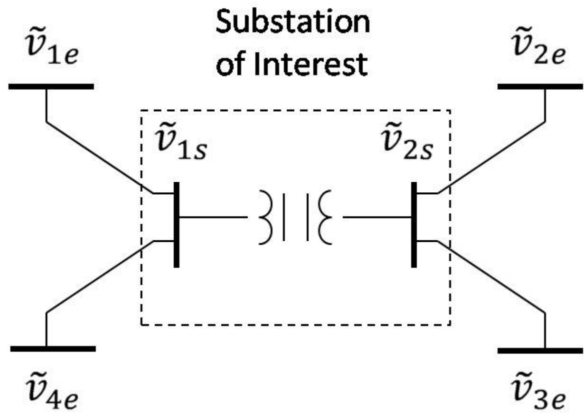


Figure 3.4: Generic substation used to describe the SuperCalibrator substation model.

In Figure 3.4, the states within the substation are $\tilde{v}_{1s}$ and $\tilde{v}_{2s}$ and the states outside the substation are $\tilde{v}_{1e}$, $\tilde{v}_{2e}$, $\tilde{v}_{3e}$, and $\tilde{v}_{4e}$. Thus the state set $\tilde{x}$ for the system in Figure 3.4 is defined in Equation (3.10).

$$\tilde{x} = [\tilde{v}_{1e} \quad \tilde{v}_{2e} \quad \tilde{v}_{3e} \quad \tilde{v}_{4e} \quad \tilde{v}_{1s} \quad \tilde{v}_{2s}]^T \tag{3.10}$$

3.2 Pseudo-Measurement Set

Pseudo-measurements are used to estimate voltages at all adjacent substations for all outgoing transmission lines; to estimate phase voltages for phases where measurements are missing or unavailable; to estimate neutral/shield wire currents; and to estimate neutral/ground voltages. Kirchoff's Current Law can also be applied to derive pseudo-measurements. The calculations used to make these estimations will be described next.

Voltages at all adjacent substations for all outgoing transmission lines are estimated using a generalized pi-equivalent circuit model for the transmission line, locally measured voltages, and locally measured currents. Utilizing measured values for the local bus voltage $\tilde{V}_p$ (single phase measurement of a general phase-p) and outgoing line currents $\tilde{I}_p$ (single phase measurement of a general phase-p) and the 3-phase transmission line model for the transmission line, the voltage at the other end of the line $\tilde{V}_p^{\text{pseudo}}$ can be calculated and utilized in the SE calculation, defined in Equation (3.11).

$$\tilde{V}_e^{\text{pseudo}} = (I - Z_{22} \cdot Y_{22})^{-1} \cdot Z_{21} \cdot \tilde{I}_s + (I - Z_{22} \cdot Y_{22})^{-1} \cdot Z_{21} \cdot Y_{21} \cdot \tilde{V}_s \tag{3.11}$$

The transmission line model utilizes is a generalized pi-equivalent form, where in Equation (3.11) Y_{11}, Y_{12}, Y_{21}, and Y_{22} are admittance matrices for the transmission line; Z_{11}, Z_{12}, Z_{21}, and Z_{22} are impedance matrices for the transmission line; and I is the identity matrix. Notice that, the transmission admittance matrix is the inverse of the transmission line impedance matrix, defined in Equation (3.12).

$$\begin{bmatrix} Z_{11} & Z_{12} \\ Z_{21} & Z_{22} \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} \\ Y_{21} & Y_{22} \end{bmatrix}^{-1} \tag{3.12}$$

Missing or unavailable phase measurements are estimated using the measured phase values that are available and assuming balanced system operation at the particular measurement point. For example if the phase A voltage measurement ($\tilde{V}_a$) is available and the phase C voltage measurement is missing or unavailable from the same bus the pseudo-measurement ($\tilde{V}_c^{\text{pseudo}}$) can be estimated from the phase A measurement by adding the required phase shift of 240 degrees, defined in Equation (3.13).

$$\tilde{V}_c^{\text{pseudo}} = \tilde{V}_a \cdot e^{-j\cdot 240°} \tag{3.13}$$

Given a line model the ratio of shield/neutral current ($\tilde{I}_{s/n}$) over the return current ($\tilde{I}_a + \tilde{I}_b + \tilde{I}_c$) is $\tilde{\alpha}$, defined in Equation (3.14).

$$\tilde{\alpha} = \frac{\tilde{I}_{s/n}}{-(\tilde{I}_a + \tilde{I}_b + \tilde{I}_c)} \tag{3.14}$$

Thus, the pseudo-measurement for the shield/neutral current is $\tilde{I}_{s/n}^{\text{pseudo}}$, defined in Equation (3.15).

$$\tilde{I}_{s/n}^{\text{pseudo}} = -\tilde{\alpha} \cdot (\tilde{I}_a + \tilde{I}_b + \tilde{I}_c) \tag{3.15}$$

The neutral/ground voltage is estimated as the product of the substation ground resistance (R_g) and the substation earth current. The substation earth current is the sum of the earth current of all transmission lines connected to the substation. Let S be the set of all transmission lines connected to the substation in question; $\tilde{\alpha}_i$ is the ratio of shield/neutral current over the return current for transmission line-i; and $\tilde{I}_{a,i}$, $\tilde{I}_{b,i}$, and $\tilde{I}_{c,i}$ are the phase currents for transmission line-i. Thus, the pseudo-measurement for the neutral/ground voltage is $\tilde{V}_g^{\text{pseudo}}$, defined in Equation (3.16).

$$\tilde{V}_g^{\text{pseudo}} = -R_g \cdot \sum_{i \in S} (1 - \tilde{\alpha}_i) \cdot \left(\tilde{I}_{a,i} + \tilde{I}_{b,i} + \tilde{I}_{c,i}\right) \tag{3.16}$$

Note that, under normal operating conditions the neutral/ground voltage is negligibly small; however, during fault conditions the neutral/ground voltage may be substantial.

The last pseudo-measurement utilized is the application of Kirchoff's Current Law (KCL) to the substation circuit. In general, KCL states that the sum of the current into a single bus equals to zero. Using the current definitions in Figure 3.5, KCL can be utilized define Equations (3.17), (3.18), and (3.19).

$$\tilde{\imath}_1 + \tilde{\imath}_2 + \tilde{\imath}_6 = 0 \tag{3.17}$$

$$\tilde{\imath}_3 + \tilde{\imath}_4 + \tilde{\imath}_5 = 0 \tag{3.18}$$

$$k_1 \cdot (\tilde{\imath}_3 + \tilde{\imath}_4) + k_2 \cdot (\tilde{\imath}_1 + \tilde{\imath}_2) + \tilde{\imath}_m = 0 \tag{3.19}$$

Note that in Equation (3.17), (3.18), and (3.19); each current ($\tilde{\imath}_1$ through $\tilde{\imath}_6$ and $\tilde{\imath}_m$) represents a vector of three complex values (a single complex value for each phase) and $\tilde{\imath}_m$ is the transformer magnetizing currents. In Equation (3.19), the coefficients k_1 and k_2 represent the nominal voltage levels on the high voltage and low voltage terminals, respectfully.

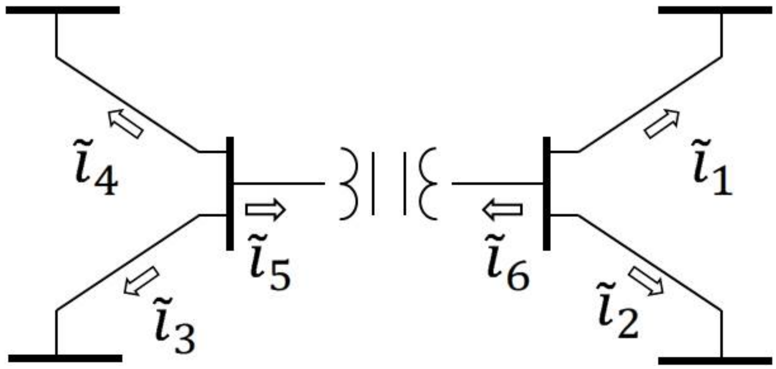


Figure 3.5: Pseudo-measurements from Kirchoff's current law.

3.3 SuperCalibrator Measurement Accuracy Quantification

The measurement accuracy quantification of the SuperCalibrator computes the variance of the measurement channels. This accuracy quantification can be utilized to commission the substation and used to monitor the ongoing health of the measurement channels within the substation.

It is expected that all measurement channels contain an amount of statistically reasonable measurement errors. An abnormally high level of measurement channel variance indicates improper settings, improper connections, or device malfunctioning during commissioning. This quantification can be leveraged to direct technicians trouble shooting efforts to minimize the time required to debug the settings and connections within the substation.

As the substation operates it is expected that the functioning of the measurement channels will evolve. It is conjectured that a SuperCalibrator feedback signal could be utilized by the UGPSSMs to automatically calibrate the measurement channels; leading to a self correcting measurement channel within the proposed substation automation structure. The SuperCalibrator provides measurement channel error quantification, monitoring the variance of the measurement channels leads to the quantification of the health of the measurement channels. This quantification could be utilized, in the future, to derive a feedback signal to automatically increase the accuracy of all measurement channels. Increasing the accuracy of the measurements from the UGPSSMs would result in higher accuracy local processing within the substation. The variance of the measurements, the measurement channel error quantification, provides quantified feedback on the ongoing health of all the measurement channels and can be utilized as an indication of when service is required. The remainder of this section will derive the measurement variance.

The accuracy of the measurements is expressed with the covariance matrix of the modeled measurements. Specifically, let $\bar{b}$ be the true, but unknown, measurements, and $\hat{b}$ be the modeled measurements given the solution to the least squares problem $\hat{x}$. Where $\hat{b}$ is defined by substituting $\hat{x}$ into Equation (3.4) and results in Equation (3.20).

$$\hat{b} = h(\hat{x}(t), y(t), t) \tag{3.20}$$

The definition of covariance of $\hat{b}$ is shown in Equation (3.21).

$$\mathrm{cov}(\hat{b}) = \mathrm{E}\left\{(\hat{b} - \bar{b}) \cdot (\hat{b} - \bar{b})^T\right\} \tag{3.21}$$

Note that, the difference $\hat{b} - \bar{b}$ in Equation (3.21) can be approximated in Equation (3.22).

$$\hat{b} - \bar{b} = h(\hat{x}(t), y(t), t) - h(\bar{x}(t), y(t), t) \tag{3.22}$$

3.4 Latencies

The distributed state estimator based on the SuperCalibrator operates at each substation independently. As such the implementation is scalable to any size system with minimum impact on performance. The response time will be limited by only the largest substation and the speed of communications between a substation and the control center. The substation/control center communication speed depends on the infrastructure of the specific utility.

The focus here is on the performance at the substation level. The response of the overall state estimation will be limited by the speed of computations at the largest substation. For the VIWAPA system the Longbay substation is the one with the largest number of equipment and measurements. Specifically, there are 318 analog measurements and an additional 72 pseudo-measurements. The total number of states required for this substation is 44. The redundancy (number of available measurement data over the total number of states to be estimated) is 882%. The estimate number of multiply-adds for this substation is 18,000 for one iteration. The SuperClaibrator algorithm converges on average in two iterations. These numbers translate into a total execution time of 4 ms per execution of the state estimator on a high end personal computer.

For comparison, the same analysis is performed for a hypothetical large substation. It is assumed that the substation may include three kV levels, 70 numerical relays of which 5 have PMU capability, 35 breakers and six next substations. Assume that, there are 1840 measurements and 119 states (redundancy of 1546%) The estimate number of multiply-adds for this substation is 220,000 for one iteration. The SuperCalibrator algorithm converges on average in two iterations. These numbers translate into a total execution time of 44 ms per execution of the state estimator on a high end personal computer. Note that, even for this large substation the response is sub-second.

3.4.1 Feasibility of Continuous Filtering

3.4.2 Performance Metrics

Substation data calibration is achieved via separate mechanisms of the SuperCalibrator. Substation data calibration is first performed during system commissioning where the results from two adjacent substations can be compared. Second, each state result of the SuperCalibrator can be quantified in terms of accuracy. A historical monitoring the state estimation results in second substation data calibration.

4. Protection Based on Validated Data

The proposed scheme for state based protection is an entirely new scheme for protection. The basis of the proposed scheme is to compute protective decisions based on the state of the substation. This is entirely different from traditional protective relaying. The traditional approach uses only a small set of the data available in the substation to compute each discrete protection function. Further, this small set of data contains measurements with no quantification of the accuracy of the measurements.

The state of the substation is computed using the SuperCalibrator. The SuperCalibrator computes highly accurate three-phase state results using highly redundant substation measurements. The basis of the SuperCalibrator is a weighted least squares algorithm with bad data identification and removal.

Conceptually, the advantages of the proposed scheme are tremendous. Computing protection based on the state of the substation involves the use of highly accurate protection inputs. All state results of the SuperCalibrator are quantified in terms of the variance of the state. Low variance indicates accurate state estimate. High variance indicates poor accurate state estimate. Because of the high redundancy of measurements within a typical substation the SuperCalibrator state results will be, in general, very accurate. The use of bad data identification and removal increases the accuracy of the state results.

Furthermore, the use of the entire state of substation leads to root cause identification as opposed to having multiple relays observing the same events and performing identical calculations.

The ISP system consists of the following components:

- Universal GPS-synchronized meters (UGPSSMs)
- SuperProcess bus hardware
- SuperCalibrator hardware
- SuperRelay hardware

The UGPSSMs are fully described in Chapter 2 and provide all input data from which the SuperCalibrator utilizes to compute the state of the substation. The state of the substation is then utilized by the SuperRelay to compute a protective decision. The SuperProcess bus is a digital communication bus utilized to rout the data from all of the UGPSSMs in the substation to the SuperCalibrator and to rout the protective decision from the SuperRelay back to the required UGPSSMs. The components in the ISP system and the orientation of the information flow are graphically shown in Figure 4.1.

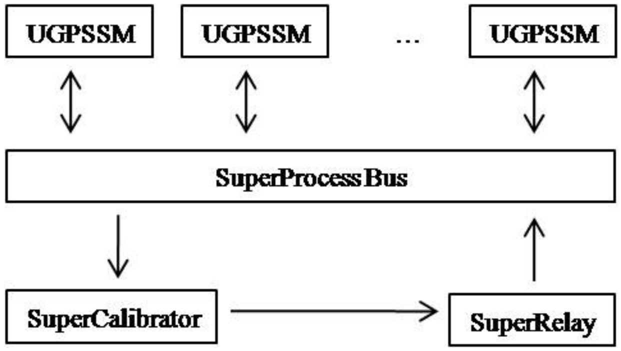


Figure 4.1: Integrated substation protection (ISP) components.

An illustration of the proposed scheme is provided in this chapter.

4.1 Impedance Relay

Impedance relays track the apparent impedance looking into a transmission line. The relay operates whenever the impedance "seen" is below a selected value. When a fault occurs on this line, assuming that the line construction is uniform, this impedance is proportional to the line length between the fault and the relay location. Thus, this information can be used to identify whether a fault is within the desired zone of protection, and consequently whether or not the line breaker should be tripped. The relay monitors the voltage and the current at a certain location of a line.

4.1.1 Background

An analog implementation of the impedance relay is a balancing beam type relay. Note that the beam pivots and it will move in one direction or another depending on the monitored voltage and current. The relay contains two coils one on each end of the balancing beam, the coils are excited with currents that are proportional to the monitoring voltage and current respectively.

In digital relays the impedance function can be easily implemented by computing the phasor of the voltage and current and taking the ratio of these phasors.

There are many modifications of the impedance relay. For example many times it is desirable to trip for a fault within a certain distance but in one direction only. A directional element in series with the impedance relay will achieve this objective. In addition, many times it is desirable to have an operating region shape that will better differentiate between faults at a certain location and other conditions such as transients and heavy load conditions.

Distance relays permit sophisticated protection schemes. When applied to transmission lines, depending on the fault type, the equivalent per unit length impedance may vary. For example, for a three phase fault the per unit length impedance of the line equals the positive sequence impedance of the line. For a single line to ground fault the equivalent per-unit impedance is approximately equal to the average of the positive, negative and zero sequence impedance of the line.

For the purpose of standardizing the distance relay design for three phase circuits, the relays should be so designed as to "see" an equivalent impedance that is approximately equal to the positive sequence impedance of the circuit per unit length times the distance to the fault. This is easily achieved with numerical relays by providing appropriate algorithms. For electromechanical relays, one can have multiple relays that will determine the distance to the fault for various fault types and then have logic to select the correct answer.

4.1.2 Experiment

To illustrate the impact of the accuracy of measurements a computer simulation program is utilized to simulate a phase-A to ground fault 55 miles into a uniformly constructed transmission lines which has total length of 80 miles. The three phase fault voltages and currents are computed at the hypothetical location of the impedance relay, shown in Table 4.1.

Table 4.1: Simulated phase-A to ground fault voltages and currents

Phase	Voltage		Current	
	Magnitude [V]	Phase Angle [˚]	Magnitude [A]	Phase Angle [˚]
A	30100.4	26.2	558.3	-39.97
B	38750.2	-86.55	150.1	-164.77
C	39442.9	141.05	289.4	119.86

The distance to the fault $|\tilde{l}|$ [mi] is the magnitude of the complex distance computed using Equation (4.1).

$$\tilde{l} = \frac{\tilde{V}_A}{\tilde{z}_1^* \cdot (\tilde{I}_A + \tilde{m} \cdot \tilde{I}_0)} \tag{4.1}$$

In Equation (4.1), $\tilde{V}_A$ is the phase-A voltage phasor, $\tilde{I}_A$ is the phase-A current phasor, $\tilde{I}_0$ is the zero sequence current phasor (computed using Equation (4.2)), $\tilde{z}_1^*$ is the normalized positive sequence transmission line impedance ($\tilde{z}_1^* = \tilde{z}_1/55, \tilde{z}_1 = 16.737 + j \cdot 36.999$), and $\tilde{m}$ scaling factor defined in Equation (4.3).

$$\tilde{I}_0 = \frac{1}{3} \cdot (\tilde{I}_A + \tilde{I}_B + \tilde{I}_C) \tag{4.2}$$

In Equation (4.2), $\tilde{I}_B$ is the phase-B current phasor and $\tilde{I}_C$ is the phase-C current phasor.

$$\tilde{m} = \frac{\tilde{z}_0 - \tilde{z}_1}{\tilde{z}_1} \tag{4.3}$$

In Equation (4.3), $\tilde{z}_0$ is the zero sequence transmission line impedance ($\tilde{z}_0 = 39.983 + j \cdot 147.023$).

Notice that, substituent the simulated values into Equation (4.1) results in the following value:

$$|\tilde{l}| = |54.7605 - j \cdot 0.8893| = 54.7677 \text{ [mi]}$$

Moreover, the percent error is as follows:

$$(55 - 54.7677)/55 \cdot 100\% = 0.4236\%.$$

To investigate the impact of measurement channel errors the simulated fault data will be converted into time series measurements, polluted with a assumed amount of measurement error, converted back to phasors, and then utilized to compute the distance to the fault using Equation (4.1). Each step of the experiment will be fully described.

This experiment will first be described using no measurement error. This represents a hypothetical case where all measurements are performed perfectly. First the simulated phasors are converted into discrete time series vectors representing the power system measurements. This conversion is performed using the discrete time equivalent of the basic sinusoidal phasor representation shown in Equation (4.4).

$$\vec{z}_i = \sqrt{2} \cdot Z \cdot \cos\left(2 \cdot \pi \cdot f_0 \cdot \vec{t}_i + \phi_Z\right) \tag{4.4}$$

In Equation (4.4) $\vec{z}_i$ represents the discrete time series vector of measurements of the general phasor $\tilde{Z}$ $(i = 1,2, \dots, N)$, $\tilde{Z} = Z \cdot \cos(\phi_z) + j \cdot \sin(\phi_z)$, f_0 is the base power system frequency ($f_0 = 60$ [Hz]), and $\vec{t}_i = (i-1)/(N-1) \cdot T_0, i = 1,2, \dots, N$ is the discrete time series vector. Here $\tilde{Z}$ is used as a general variable representing all simulated phasors V_A, V_B, V_C, I_A, I_B, and I_C. For this experiment N was set to 167 [samples per cycle], representing a sampling frequency of just over 10 kHz.

Next a series of calculations are performed to compute a phasor representation $\tilde{Z}_c$ of the discrete time series vector of measurements $\vec{z}_i$.

$$A = \sum_{i=1}^{N} \vec{z}_i \cdot \cos\left(2 \cdot \pi \cdot f_0 \cdot \vec{t}_i\right) \tag{4.5}$$

$$B = \sum_{i=1}^{N} \vec{z}_i \cdot \sin\left(2 \cdot \pi \cdot f_0 \cdot \vec{t}_i\right) \tag{4.6}$$

$$\tilde{Z}_c = \frac{\sqrt{2}}{N}(A - j \cdot B) \tag{4.7}$$

Using the described method to compute $\tilde{Z}_c$ (representing all a computed phasors for all the quantities $\tilde{V}_A$, $\tilde{V}_B$, $\tilde{V}_C$, $\tilde{I}_A$, $\tilde{I}_B$, and $\tilde{I}_C$) a distance to fault was computed using Equation (4.1) resulting in $|\tilde{l}| = |54.9094 - j \cdot 1.4747| = 54.9292$ [mi], with percent error $(55 - 54.9292)/55 \cdot 100\% = 0.1287\%$.

Next, the measurement errors will be described. Two types of errors are introduced to the measurements. The first is realized by modifying the time which the measurement samples are created. This represents variability in the time synchronization of the measurement channels. The second is realized by modifying the amplitude of the discrete measurements. This represents variability in the ability of measurement channels to reproduce an exactly scaled version of the power system quantity being measured.

Suppose that t^* is the exact instance for measurement z^*. We are assuming that the actual time of the measurement sampling is $t = t^* + t_e$. Where t_e is assumed to be an independent uniform random value within the range $[0, 1/360 \cdot 1/T_0]$, indicating that the maximum time variability of the actual measurements is delayed one degree of the fundamental period. A uniform distribution was chosen for simplicity and because it is assumed that time variability will only involve delays.

The amplitude variability is assumed to be Gaussian with variability in direct proportion to the amplitude of the measurement. Suppose that z_c is the measurement at time t, then the acual measurement will be $z = z_c + z_e$. z_e is assumed to be an independent normal random variable with zero mean and $(\sigma \cdot z_c)^2$ variance. σ is 5% for voltage measurements and 1% for current measurements.

As illustration of the developed method a histogram of the generated time skew error values is shown in Figure 4.2, a histogram of the generated amplitude error values is shown in Figure 4.3, and a comparison of the phase-A voltages with and without error is shown in Figure 4.4.

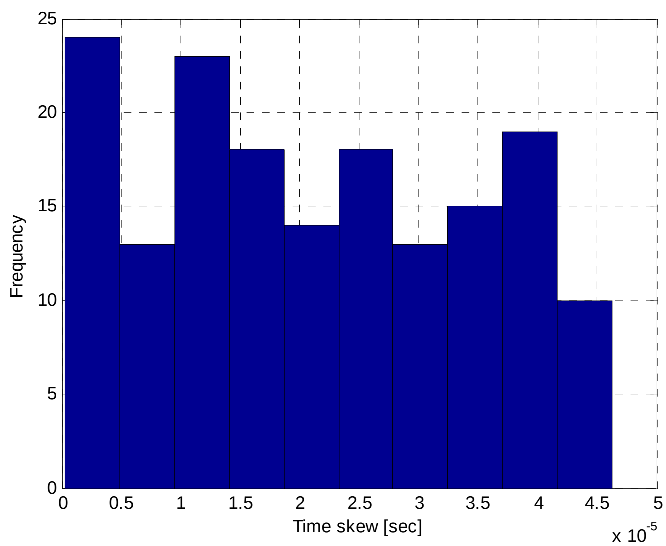


Figure 4.2: Time skew histogram for 167 generated time delays.

The distribution of times skew values in Figure 4.2 is characteristic of uniformly distributed random values. One degree of the base power period was chosen to resemble typical measurement error time skew.

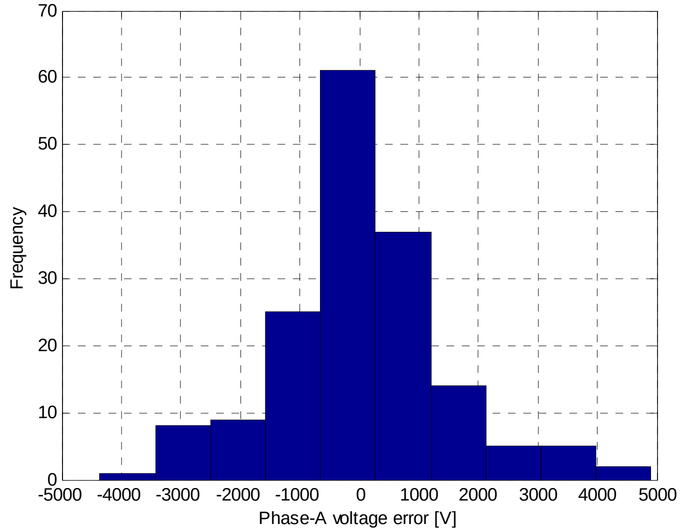


Figure 4.3: Phase-A voltage error histogram for 167 generated error values.

The distribution of phase-A voltage error values in Figure 4.3 is characteristic of normally distributed random values. The variance is scaled proportionally to the amplitude with relative size based on typical measurement accuracies.

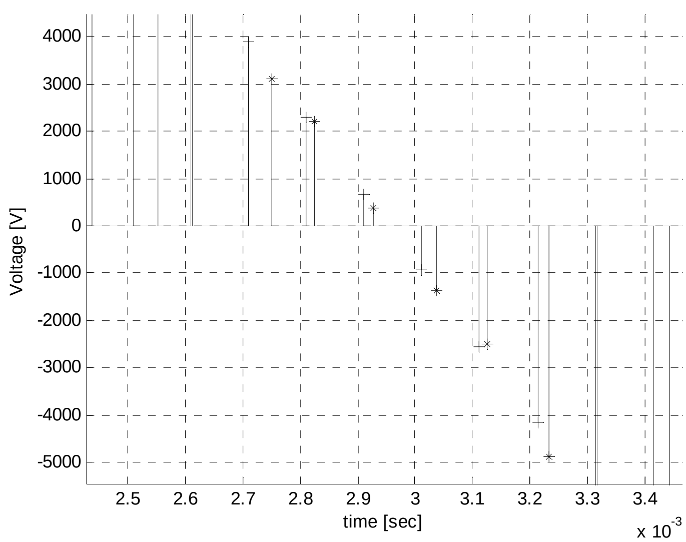


Figure 4.4: Phase-A voltage stem plot showing phase-A voltage with no error (+ markers) and phase-A voltage with generated error (* markers).

The time series data in Figure 4.4 shows both the phase-A voltage with error and without error. The voltages with no error are marked with '+' and the voltages with error are marked with '*'. Clearly, the time skew is relatively smaller then the magnitude error.

The error models used in this experiment are random. Thus, repeated simulations are utilized to compute an estimate of the expected results. Specifically, 50 repeated simulations are performed and a distance to the fault is computed using Equation (4.1). In each simulation the percent error is computed exactly the same way as has been described for the simulated distance to fault and no error phasor calculations. Suppose that e_i is the percent error from the ith iteration then an estimate of the average percent error $\bar{e}$ is defined in Equation (4.8), an estimate of the percent error variance σ_e^2 is defined in Equation (4.9), an indication of the spread of expected results around the sample mean a 90% confidence interval half width ($\mathrm{C.I.H.W}$)is defined in Equation (4.10).

$$\bar{e} = \frac{1}{n}\sum_{i=1}^{n} e_i \tag{4.8}$$

$$\sigma_e^2 = \frac{1}{n-1}\sum_{i=1}^{n}(e_i - \bar{e})^2 \tag{4.9}$$

$$\mathrm{C.I.H.W} = t_{1-\frac{\alpha}{2},n-1} \cdot \frac{\sigma_e}{\sqrt{n}} \tag{4.10}$$

In Equations (4.8)- (4.10)these equations $n = 50$ and in Equation (4.10) $t_{1-\frac{\alpha}{2},n-1}$ is 1.6766.

4.1.3 Results

Simulated phasors results in a distance to fault error of 0.4236%. The no error computed phasors results in a distance to fault error of 0.1287%.. A sample mean errors is 0.5102%, a sample variance is $1.4182 \cdot 10^{-5}$ computed using the random measurement errors. These results imply a 90% confidence interval half width of $8.9290 \cdot 10^{-4}$.

If we increase the error of any one of the measurements so that the variance is 100% of the measured value the distance error sample mean, variance and $\mathrm{C.I.H.W}$ are shown in Table 4.2.

Table 4.2: Simulated phase-A to ground fault voltages and currents

Additional Error	$\bar{e}$	σ_e^2	$\mathrm{C.I.H.W}$
$\tilde{V}_A$	8.06%	$3.68 \cdot 10^{-3}$	$1.44 \cdot 10^{-2}$
$\tilde{I}_A$	12.0%	$9.22 \cdot 10^{-3}$	$2.28 \cdot 10^{-2}$
$\tilde{I}_B$	0.95%	$5.57 \cdot 10^{-5}$	$1.77 \cdot 10^{-3}$
$\tilde{I}_C$	2.54%	$3.30 \cdot 10^{-4}$	$4.031 \cdot 10^{-3}$

The results in
Table 4.2 show the expected error in a phase A to ground fault if a single measurement channel required for the distance calculation is lost or becomes unreliable for any other reason. Clearly, the impact of the $\tilde{V}_A$ and $\tilde{I}_A$ measurements is critical for the phase-A to

ground fault distance calculation; these two phasors are explicitly utilized in Equation (4.1). The other components varied in this experiment $\tilde{I}_B$ and $\tilde{I}_C$ caused little change in the distance calculation. The other two phasor voltages $\tilde{I}_B$ and $\tilde{I}_C$ are independent of the distance calculation.

The remainder of this chapter will describe the proposed structure in terms of latency, accuracy, and reliability.

4.2 Latencies

Substation protection demands the highest speed decision making and the highest priority communications in a substation. Thus, the latency to compute a protective decision is critical. The goal of the substation of the future is to be able to provide a protective decision every 2 ms or at a rate of 500 Hz.

The required sequence of events that occur for each protective decision are shown in Table 4.3 along with the estimated latency for each event. Each event in Table 4.3 will be described next, along with a description of how the event latency is estimated.

Table 4.3: Integrated substation protection event sequence and latency.

Event:	**Latency [ms]:**
UGPSSMs condition all analog and digital data	0.01
SuperProcess bus routes **all** substation UGPSSM data to the SuperCalibrator	X/10
SuperCalibrator computes the SE	0.5
SuperRelay computes the protective decision	0.2
SuperProcess bus routes a trip signal to the proper UGPSSMs	Y/10
UGPSSMs communicate trip signals to switchgear	0.001

The event "UGPSSMs condition all analog and digital data" in Table 4.3 represents the occurrence of the following events in parallel within each substation UGPSSM.

- Analog electrical quantities are sampled and digitized.
- Any digital status data is collected.
- The digital data packet is time stamped with the available clock signal.

It is estimated that this event will require 10 cycles of calculations at a clock frequency of 1 MHz, thus requiring 0.01 ms to provide this data.

After each UGPSSM collects their data the data must be routed, via the SuperProcess bus, to the SuperCalibrator. This event is represented in Table 4.3 with the event "SuperProcess bus routes **all** substation UGPSSM data to the SuperCalibrator". All is emphasized because all the UGPSSMs in the substation must communicate to the SuperCalibrator for each protective decision because the SuperCalibrator utilizes all the available data in the substation to compute the state of the substation. It is estimated that one clock cycle of the SuperProcess bus will be required to rout the data from a single UGPSSM to the SuperCalibrator. The total latency to transmit all UGPSSM data to the SuperCalibrator is estimated to be X/10 ms, where X represents the number of UGPSSMs in the substation. It is assumed that the SuperProcess bus will utilize a clock frequency of 10 kHz.

Once all the data is collected at the SuperCalibrator the state of the substation can be computed. This event is represented in Table 4.3 with the event "SuperCalibrator computes the SE". This event requires 0.5 ms, this is the estimated latency for the SuperCalibrator hardware.

The next event in Table 4.3 is "SuperRelay computes the protective decision". This event represents the process of computing the required protective decision based on the state of the substation. This event requires 0.2 ms, this is the estimated latency for the SuperRelay hardware.

After a protective decision is computed the SuperProcess bus must rout the trip signals to the required UGPSSMs. This event is represented in Table 4.3 as "SuperProcess bus routes a trip signal to the proper UGPSSMs". It is assumed that the SuperProcess bus can rout a trip signal to a UGPSSM in one clock cycle. The total latency of this event is Y/10 ms, where Y is the required number of switchgear needed to operate.

Finally the trip signal must be communicated by the UGPSSM to the switchgear. This event is represented in Table 4.3 with the event "UGPSSMs communicate trip signals to switchgear". Due to the high priority of the trip signal it is assumed that this signal will be communicated in 0.001 ms, one cycle of the UGPSSM.

The ISP methodology relies on the SuperCalibrator state estimation (SE) from which a protective decision can be computed. The goal of the ISP is a protective decision every 2 ms. Additional considerations of the ISP are the accuracy and reliability; next, quantitative limits on the accuracy of the SuperCalibrator results will be described.

4.3 Accuracy

In [4.1] and [4.2] a discussion of the accuracy of power flow measurement is suggested to be 1%. Further, these papers identify corresponding levels of voltage magnitude and phase angle accuracy required to meet this level of power flow accuracy, the voltage magnitude and phase angle accuracy pairs are reproduced in Table 4.4.

Table 4.4: Required pairs of voltage magnitude and phase angle accuracy to achieve 1% power flow measurement accuracy.

Voltage Magnitude [%]	**Phase Angle [˚]**
0.5	0
0.4	0.03
0.3	0.05
0.2	0.09

Typical GPS time-synchronized devices, ignoring transducer and instrumentation communication errors, achieve voltage magnitude accuracy of 0.1% and phase angle accuracy of 0.02˚, which results in a 0.34% power flow accuracy [4.3]. An example instrumentation channel error is quantified in [4.2] as 1.46% voltage magnitude error and 0.41˚ phase error, which results in a 5.79% power flow accuracy. Thus, eliminating or correctly accounting for transducer and instrumentation communication error is critical to achieve the goal accuracy for state based protection.

The SuperCalibrator achieves a high level of accuracy because of the high level of redundant data points are estimated via a least square approximation. In [4.1] a simple example with 570% redundancy is presented. In [4.4] another simple example is provided with 870% redundancy is presented. The level of redundancy is also impacted by the use of pseudo-measurements; wherein, additional inputs can be computed using known physical rules such as Kirchoff's current law [4.5]. The higher the level of redundancy the more reliable the system becomes and the more accurate the results of the SuperCalibrator.

Table 4.4 provides a range of the required state accuracy SuperCalibrator state result. Provided results within these ranges will assure power flow accuracy of better than 1%.

4.4 Reliability

In [4.5] the reliability of industry wide state estimator utilization was stated to be 95% reliable; whereas, in [4.6] the reliability of protective relaying equipment was stated to be 99% reliable. Thus the goal of the substation of the future is to achieve better than 99% reliability state based reliability.

The SuperCalibrator and SuperRelay software will be housed within the substation control computer (SCC). To achieve high reliability two things must occur (1) the SCC and communication hardware, the SuperProcess bus, must be rugged and highly reliable and (2) the ability to provide parallel SCCs and communication paths. To achieve the first requirement the physical hardware of the SCC and Super Process bus must be modeled after proven substation equipment. This can be achieved by modeling the SCC after modern digital relays and intelligent electronic devices (IED) and using existing communication hardware in the SuperProcess bus. Significant differences in the SCC from modern digital relays and IEDs will be the software housed within the SCC. Secondly, the option to house multiple redundant SCCs on redundant SuperProcess buses must be available. These two requirements will allow the substation of the future to meet the highest reliability possible.

5. Power Quality Monitoring Based on Validated Data

The proposed scheme for calibrated power quality monitoring is an entirely new scheme for power quality monitoring in a substation. The basis of the proposed scheme is to periodically calibrate the measurement channels using a measurement channel calibration feedback signal. The signal is computed by the SuperCalibrator and feedback to the required universal global positioning satellite (GPS) time-synchronized meters (UGPSSMs).

The utilization of the calibration feedback signal provides increased accuracy measurements for all substation local processing of data. The local processing in the proposed substation automation (SA) structure includes phasor calculations, and power quality monitoring via the usual power quality indices, for example total harmonic distortion, voltage sags and swells, etc.

Disturbance analysis can be also performed at this level. Specifically the time waveform data are stored on devices attached to the process bus. User interfaces can be utilized to retrieve data for specific time intervals and use this data for disturbance analysis.

This chapter outlines how the power quality monitoring in the proposed system will function.

5.1 Power Quality Background

Electric power quality is loosely defined as the ability of the system to deliver electric power service of sufficiently high quality so that the end-use equipment will operate within their design specifications and of sufficient reliability so that the operation of end-use equipment will be continuous. The first requirement implies that the electric power service should be provided with near sinusoidal voltage waveforms at near rated magnitude and at near rated frequency. The second requirement refers to continuity of service. From this loose definition, it must be apparent that power quality is very much dependent upon the characteristics of end-use equipment and their design characteristics in terms of tolerances for voltage and frequency deviations.

The sources of disturbances are multiple and with varying parameters. For example in many places of the world, the most frequent disturbances originate from lightning activity near electrical installations. Lightning may result in flashover causing voltage sags to some portion of the distribution system, voltage swell to other areas, as well as interruption of power. The number of customers affected depends on the design of the system and placement of interruption devices, while the level of voltage sags or swells may depend on the grounding system, size of neutral, etc.

We have mentioned lightning as one of the causes of reduced power quality. Additional types of temporary disturbances include switching, power faults, feeder energization inrush currents, motor start transients, load imbalance, harmonics and resonance, electromagnetic interference (EMI), etc. The effects of these disturbances on the end user are voltage distortion, voltage sags, voltage swells, outages, voltage imbalance, etc. These effects may have different levels of impact, depending on the susceptibility of the end-user equipment. As end-user equipment becomes more sensitive, these effects are labeled as power quality problems. The impact of these temporary disturbances can be mitigated by modifications of circuit layout, grounding system design, overvoltage protection, filters, steel conduit, additional transformers, etc.

Another source of power quality problems can be end-use equipment or certain power system apparatus. Specifically, recent advances in power electronics resulted in a large number of switching devices, which are directly connected to the power system. These devices may be end-use equipment (electric motor drives, air-conditioning units, etc.) or power apparatus, which perform a specific control function (static VAR compensators, transformer tap controllers, etc.). A subclass of these devices controls the power quality and they affect system performance. These devices interact with the power system, may distort the voltage waveform (thus generating harmonics) and also are subjected to all transients, which are generated by the power system.

The two power quality issues introduced in this paper include harmonics and transients. Here harmonics are defined as, voltage and current deviations from the sinusoidal waveform with a specific pattern that is repeatable each cycle of the base frequency of the system. Here transients are defined as, oscillatory voltage or current deviations from the sinusoidal waveform of relatively high frequency.

This chapter will introduce the power quality processing functions harmonic spectrum monitoring and transient event monitoring.

5.2 Harmonic Spectrum Monitoring

The electric power system is comprises of devices that have the potential of generating harmonics, for example synchronous generators generate harmonics, transformers, if overexcited, will generate harmonics, etc. Recently we have witnessed the introduction of many grid connected power electronic devices. These devices operate by switching circuits at relatively high frequencies. The switching operation of these devices generates harmonics at level that can be potentially high and may affect the performance of the power system. Grid connected power electronic devices are proliferating and it is expected that eventually the majority of end use devices will include some type of power electronic circuitry.

As it has been mentioned, there are numerous sources of harmonics. Under normal operating conditions these devices produce a moderate level of harmonics; however, under abnormal conditions these devices have the potential of producing high levels of harmonics. For example, an overexcited transformer will saturate and depending on the saturation level it will generate a substantial level of harmonics that may damage the transformer itself.

The effects of the harmonics can be classified into the following categories insulation stress, thermal stress, and load disruption. Insulation stress occurs because of overvoltages that result from harmonics. Harmonic currents can increase the operating temperatures (thermal stress) of many devices because of one or more of the following phenomena: copper losses, iron core losses, and dielectric losses. Load disruption occurs whenever the harmonics interact with control and protection systems and disconnect the power apparatus. The control and protection systems are designed to operate in a certain way. Harmonics may interfere with this operation and may cause the disconnection of the apparatus.

Harmonic spectrum monitoring provides a continuous record of the harmonic spectrum content within the substation. We assume that the highest harmonic of interest is the 30th harmonic.

5.3 Transient Event Monitoring

Transient events are caused by internal and external events. Internal transients are all disturbances that originate from normal operations of electric power systems: switching of circuits, switching of capacitors, transformers, motors, etc. These operations cause temporary transients that may or may not lead to problems. Typical internal transients include power frequency overvoltages, ferroresonance, switching transients, inrush transients, motor start transients, and transient recovery voltages. External transients are caused by external causes: faults, lightning, and equipment failures.

Transient event monitoring provides a continuous record of any high frequency voltage events within the substation. We assume that the highest frequency transient event of interest is a 5,000 Hz signal, using this assumption and the Nyquist criterion results in a minimum sampling frequency of measurements is 10,000 Hz; this sampling rate accommodates monitoring of the 30^{th} harmonic.

5.4 Typical Results

Power quality monitoring with the proposed system may provide information about a number of issues that may develop in a substation. Examples of substation power quality events are overexcitation of transformers, DC current into the neutral of the transformer, imbalances, excessive harmonics from customers (from the feeders), excessive zero sequence current, stray voltages, etc. Future work involves illustrating the use of the proposed structure to identify the power quality concerns introduced in this paper.

An example of transformer overexcitation is shown in Figures 7.1 and 7.2. Figure 5.1 illustrates a set of waveforms captured at the low voltage side of a transformer. Figure 5.2 illustrates the harmonic analysis of the phase A voltage. This analysis indicates that the transformer is in an overexcitation state indicated by the harmonic signature of the voltage. Similar analysis of the data at the process bus can provide useful information about the power quality of the system.

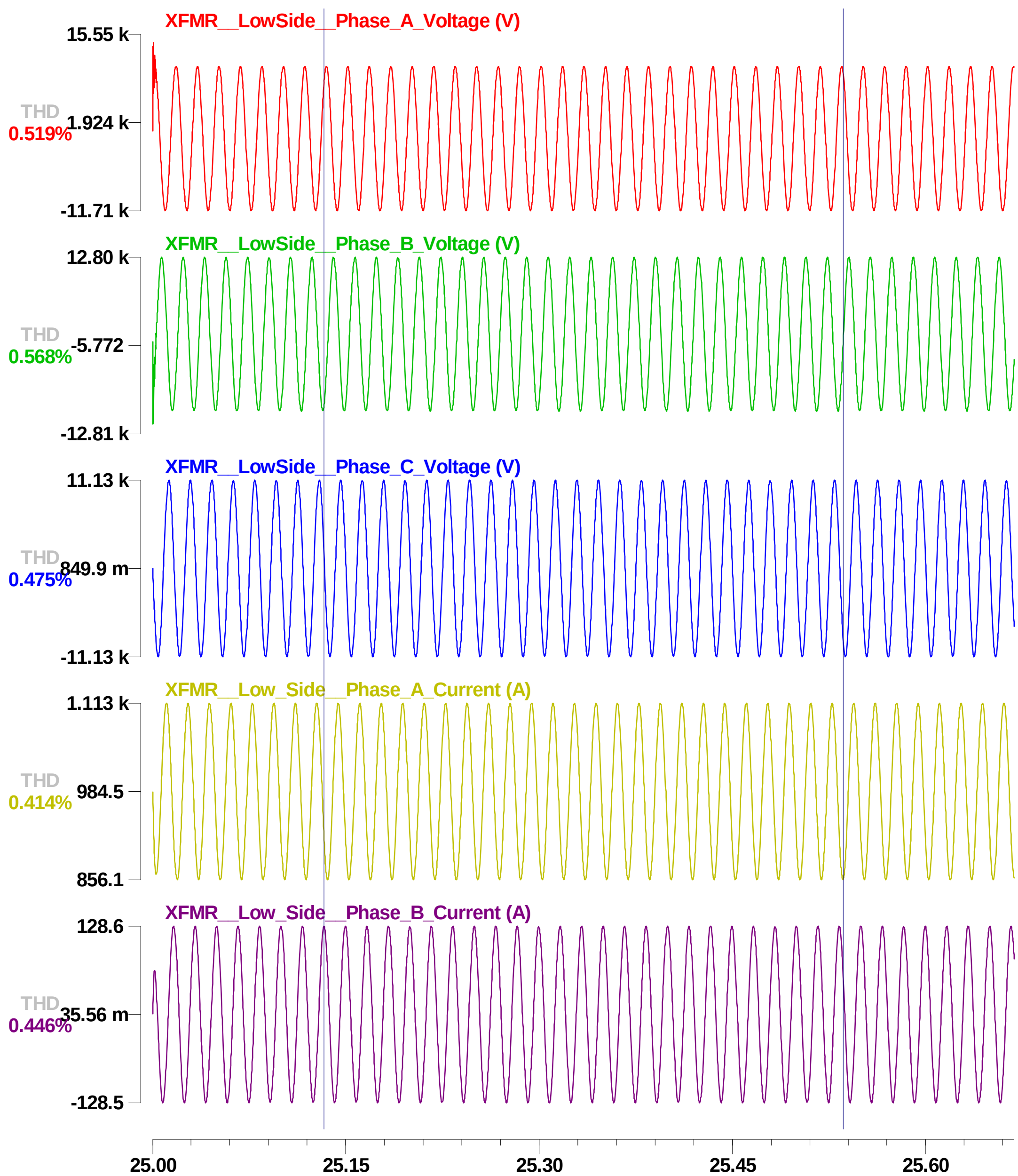


Figure 5.1: Captured data at the low voltage side of a transformer.

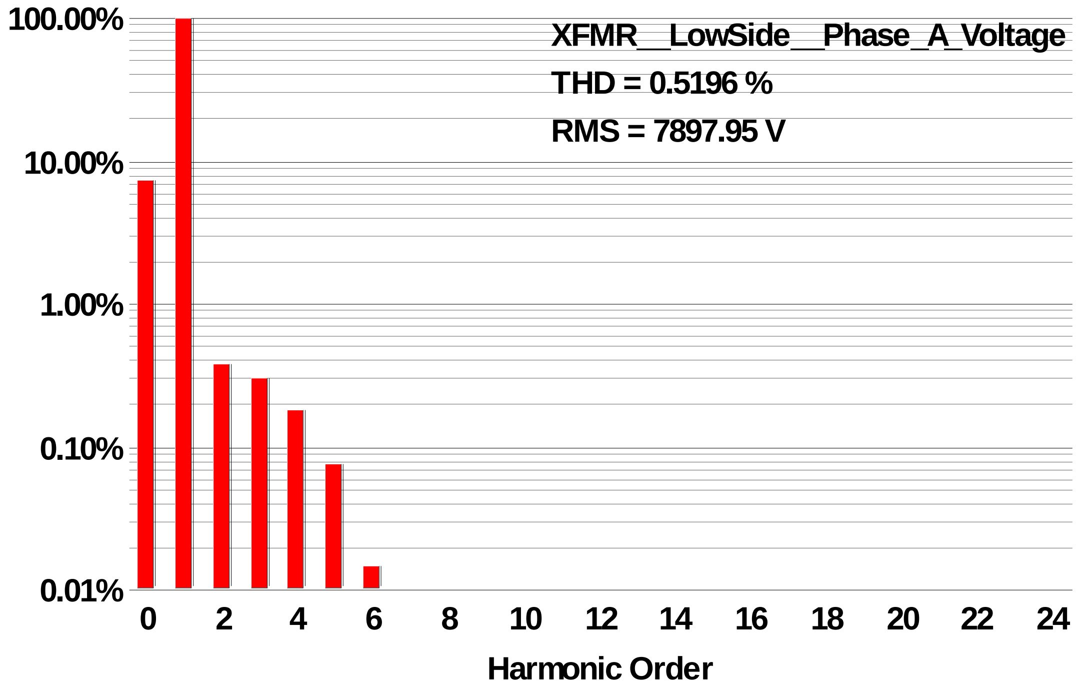


Figure 5.2: Harmonic analysis of the phase A voltage of Figure 5.1.

How alarm initiation, processing, and root cause analysis can be performed within the proposed scheme? What will be the computational requirements for alarm processing? What will be the required equipment?

Investigate the requirements for data archiving and retrieval of disturbance data, sequence of events, meeting, etc. Should data be stored at variable rates, for how long, retrieval tools, recreation of disturbances, etc. Hardware and software requirements. Develop metrics to assess performance.

6. Wide Area Monitoring and System Protection

The proposed structure of substation data is not different than a dedicated wide-area monitoring and control scheme - the only difference is that wide area monitoring requires dynamic data at relatively fast rates. Although we are used to thinking of a control-center as a particular location where many application functions have been centralized, the proposed scheme enables various applications to reside in various places (distributed approach). The difference between wide-area protection & control schemes and present day control-center functions is that the latter works at much slower speeds. In this section we describe the data flows for various wide-area control schemes and the feasibility of such schemes with emphasis of how these schemes are facilitated with the proposed structure of the substation of the future.

6.1 Background

The term wide area monitoring was introduced to facilitate the dynamic monitoring of a wide area of a power system with the specific applications of system protection. The first WAMS installation on the Eastern Interconnection was on the NYPA system (1993) for the purpose of monitoring dynamic disturbances and geomagnetic disturbances through harmonics. The western systems' WAMS installations were dedicated to event monitoring and disturbance analysis. The term monitoring implies that it is a system of data acquisition and a communications infrastructure that brings the data into a central location. Since the intended application is system protection, the data collection to a central location should be fast enough to facilitate system protection. This implies that time latencies must be at the sub-cycle region for electrical events, as opposed to latency in seconds for thermal events. Traditionally WAMS systems use data concentrators and fast dedicated communication links to achieve the necessary performance. No DLR technology to monitor thermal events in real time was employed at those first WAMS installations.

It is recognized that WAMS have other applications than system protection and control. One important target application is stability monitoring of the system. Another one is situational awareness. As a matter of fact, one of the leading drivers for grid modernization is the improvement of situational awareness capabilities for managing the bulk power transmission system electrically and thermally. Wide area time domain GPS time-synchronized sampling systems (WATSS) and Dynamic Line Ratings are both recognized by many electric utilities, government, and research entities as a key technology for situational awareness and the Smart Grid. WATSS has the potential to provide timely and reliable system information in phasor form which constitutes the cornerstone for control and protection of the electric power system (short time), and in conjunction with Dynamic Line Ratings to manage the system and facilitate markets (longer time). As a result any wide area monitoring system may serve many clients with different requirements in terms of frequency and time latencies in the data.

It is recognized that GPS time-synchronized data acquisition systems are the key technology to achieve the objectives of wide area monitoring. With the introduction of the GPS time-synchronized measurements, the WAMS technology has made some evolutionary steps. Presently we can use this advanced technology to achieve: (a) data validation at the local level and (b) data compactions to minimize communication latencies thus achieving the objectives of WAMS. These advanced technologies coupled with the knowledge of transmission line transfer capacity in real time, taking into account actual weather conditions between substations and across regions, enhance WASA as the thermal behavior of the line is complementary and synergistic to the PMU electrical outputs. These technologies will provide the infrastructure to perform grid control functions with precision and speed not possible with other technologies. A list of possible control applications and functions is:

- Control of renewable resources
- Dynamic line thermal monitoring (Dynamic line ratings)
- Frequency control
- Islanding monitoring / Controlled islanding / Restoration
- Load control
- Oscillation monitoring
- Parameter estimation / Model validation
- Predictive analysis / Look ahead
- Post mortem analysis / Play back capability
- State estimation
- System optimization
- System protection (electrical and thermal)
- System stability
- Visualization / Situational awareness / Alarming
- Voltage control
- Voltage security monitoring

In this section of the White Paper we will establish performance targets, identify needs in standards (gaps) and provide a roadmap towards achieving these goals for wide area monitoring systems (WAMS) in order to enhance WASA.

6.2 High-Level Requirements and Capabilities

A broad definition for any wide area monitoring system is: a system that is capable of providing accurate data (both numerical values and time tags) at a central location of a wide area and with a rate that is appropriate for the intended applications. A visual of the WAMS definition is shown in Figure 6.1. The figure shows the substation control computer (or data concentrator) that collects data and transports the data to a central location CC (control center or any other facility).

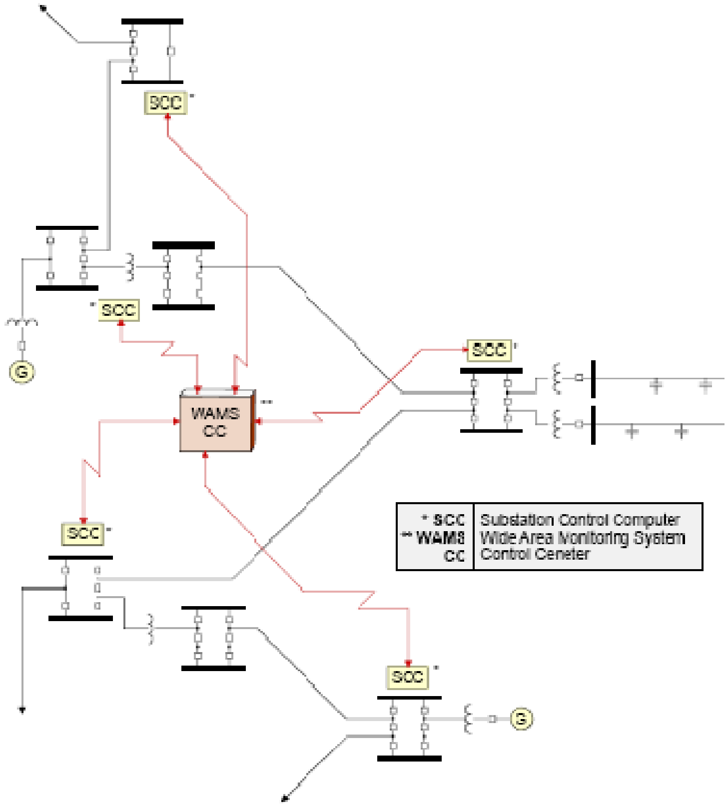


Figure 6.1: Pictorial of a wide area monitoring system.

The technology for the substation control computer or data concentrator and data collecting devices (IEDs and PMUs) has evolved. Figure 6.2 shows a modern mixed system. Note that merging units may be collecting data directly at the instrument transformers, where data is digitized, time tagged and then transmitted to the substation process bus. Older systems may have wire communications from the instrument transformers to various IEDs as shown on the right side of Figure 6.2. The IEDs are connected to the station bus. A data concentrator (substation control computer) is also connected to the substation bus as shown in the figure. Communications are enabled via gates connected to the station bus.

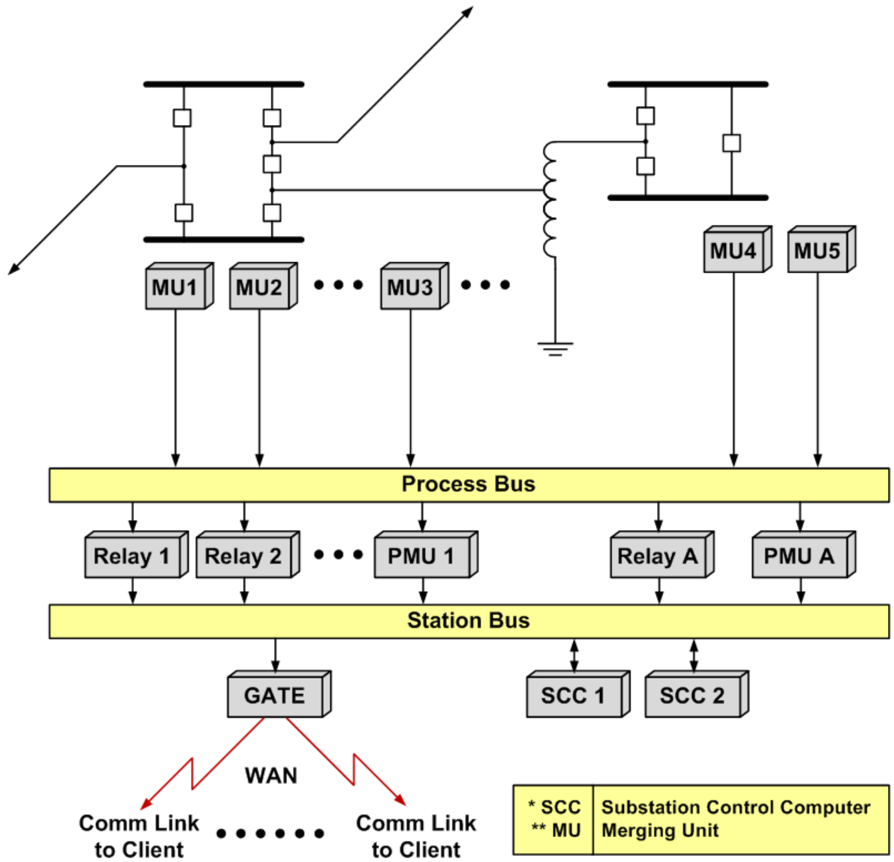


Figure 6.2: Data collection for WAMS at a substation.

While Figures 10.1 and 10.2 illustrate what is possible with today's technology and certainly some recently constructed stations do have the indicated capability, there are many older substations that are not as automated as Figures 10.1 and 10.2 suggest. In addition there are many gaps in the technology and challenges that need to be addressed. Some of the general issues in this space are described in greater detail in section 2.5.

6.3 Stakeholders in Wide Area Monitoring

The benefits of wide area monitoring distribution systems can be categorized for the following stakeholders: utility: protection and control (Table 6.1), operations (Table 6.2), enterprise (Table 6.3), and customers (Table 6.4).

Table 6.1: Protection and control applications and requirements.

Application	Rate Requirements	Latency Requirements	Data Accuracy (Time Tag and Value)
Control of System Oscillations	Moderately High (Tens of Milliseconds)	Tens of Milliseconds	Moderately High
System Integrity Protection Schemes (SIPS)	High (milliseconds)	Milliseconds	High
System Protection (Out of Step)	High (milliseconds)	Milliseconds	High
System Protection (Voltage Stability)	Moderately High (tens of milliseconds)	Tens of Milliseconds	Moderately High
Thermal Protection of Transmission Line	Moderate (minutes)	Low (Seconds)	High

Table 6.2: Operations applications and requirements.

Application	Rate Requirements	Latency Requirements	Data Accuracy (Time Tag and Value)
Dynamic Line Thermal Monitoring (Dynamic Line Rating)	Low (Minutes)	Low (Seconds)	High
Load Control	Low	Low	Low
Parameter Estimation / Model Validation	Off-Real-Time	Off-Real-Time	High
Post Mortem Analysis / Play Back Capability	Medium (Subsecond)	Low	High
Predictive Analysis / Look Ahead	Low	Low	Moderately High
State Estimation	Medium (Subsecond)	Subsecond	High
System Optimization	Low	Low	Moderately High
Visualization / Situational awareness / Alarming	Moderately Medium	Moderately Medium	High
Voltage Control	Lw	Low	Moderately High
Voltage Security Monitoring	Low	Low	High

Table 6.3: Enterprise applications and requirements.

Application	Rate Requirements	Latency Requirements	Data Accuracy (Time Tag and Value)
Metering	Medium (Subsecond)	Subsecond	High
Operational Costs	Low	Low	Moderately High
Play Back Capability	Medium (Subsecond)	Low	High
Visualization	Moderately Medium	Moderately Medium	High

Table 6.4: Customer applications and requirements.

Application	Rate Requirements	Latency Requirements	Data Accuracy (Time Tag and Value)
Rates	Low	Low	Moderately High

6.4 Relevant Standards in Use

The standards available today to address the systems depicted in Figures 10.1 and 10.2 determine (a) the interoperability of the merging units, IEDs, Process bus, and station bus, (b) the exchange of data – streaming data, and (c) storing and retrieving data. The list of these standards is provided below. It is important to note that the standards do not address all the needs of the system depicted in as Figures 10.1 and 10.2. For example synchronizing the data collected at the merging units is an area that is not well defined. These are addressed in the gap analysis.

- Distributed Network Protocol (DNP3)
- IEC 60870-6 Inter-Control Center Protocol (ICCP)
- IEC 61850 Protocols, Configuration, Information Models
- IEEE 1379 Data Communications between IED's & RTU's in a Substation
- IEEE 1525 Standard for Substation Integration Communications
- IEEE 1588 Precision Time Protocol
- IEEE 1613 Substation Hardening for Gateways
- IEEE 1686 Substation Intelligent electronic Devices (IEDs) Cyber Security Standards Key Interoperability Barriers
- IEEE 1711 Trial Use Standard for a Cryptographic Protocol for Cyber Security of substation Serial Links
- IEEE C37.111-1999 – COMTRADE
- IEEE C37.118 Synchrophasor Streaming Data

- IEEE C37.1 SCADA and Automation Systems
- IEEE C37.2 Device Function Numbers and Contact Designations
- Modbus

6.5 Key Technical Challenges of Wide Area Monitoring

The following key issues were identified in a working group report prepared for NIST (the author of this report participated in this working group but the work reported here includes the contribution of many working group members).

Key Issue 1: In a modern substation the amount of data collected is relatively large. Considering the number of substations in the power grid the overall amount of data is overwhelming. Transferring this amount of data through communication links at the speeds required by some applications is at best problematic even with the best communication technologies. Yet we need to recognize that the data represent redundant measurements by duplicate systems (relays, PMUs, fault recorders, meters, etc.). Extraction of the basic information included in this data will result in reduced amount of information points that need to be communicated.

Key Issue 2: The various IEDs connected to the process bus or the station bus must be interoperable in the sense that the substation control computers (data concentrators) should be able to collect the data from each IED with minimal latencies. Available standards and gap analysis of standards is provided elsewhere in this white paper.

Key Issue 3: Data Validation. It is important that the data be validated and characterized in terms of accuracy and timeliness before used by applications. Again because of the large amount of data, distributed validation and characterization of the data is very important.

Key Issue 4: Various applications require data at different rates, accuracy and timeliness. It is important to recognize the savings that can be accomplished by designing a WAMS to provide data to the most demanding applications (for example system protection or stability monitoring) and to be able to also provide data to other less demanding applications. A well designed WAMS can decimate data and provide data to any application at the rate, accuracy and timeliness required by the specific application.

Key Issue 5: Certain targeted applications for WAMS require data at fast rates, accurately synchronized and with very small time latency. Because the power grid is a geographically dispersed system spanning large distances, latencies cannot be reduced below travel times in the communication circuit (for example the travel time for a 150 mile long line using fiber optic communications is approximately 2 miliseconds one way). The challenge will be to develop distributed WAMS and applications that can use data in the vicinity of the application to avoid long latencies.

Key Issue 6: Presently WAMS requires highly skilled personnel and tools for monitoring the performance of these systems that are complex and difficult to use. The related issue of testing equipment to determine to what degree various requirements are met is also in its infancy. It is necessary to develop performance monitoring of these systems and testing procedures that can be utilized by technicians.

Key Issue 7: The accuracy of WAMS data is largely affected by the voltage and current sensors used to feed the power system signals to the phasor measurement units. Since WAMS applications are only as effective as the accuracies of the phasor and dynamic line rating data, there has to be a mapping of minimum sensor accuracy class with the intended WAMS applications.

Key Issue 8: It is sometimes not clear inside an electric utility where the responsibility lies in maintaining and operating a Wide Area Measurement System. The wide area infrastructure transcends all functional groups in utilities. For example, control center normally use the WAMS applications, the relaying department may have control of the phasor measurement units, and the communications department might have control of the communication infrastructure. Similar lack of ownership is also experienced with dynamic line ratings. It is necessary that the WAMS systems should have the support of the stakeholders inside a utility's organization.

6.6 Gap Analysis

The gap analysis of standards is similar to the other areas of the smart grid. The same gap analysis can be performed in reference to multiple classes of IEDs. Here we will discuss some additional requirements for WAMS.

The nature of WAMS is to provide accurate and timely data to a variety of technical applications, i.e. system protection and control, state estimation, etc. As such in order to meet the requirements of WAMS, the data accuracy must be addressed. Today's standards do not address the issue of accuracy. Accuracy applies to the time tagging of the data as well as the numerical accuracy of the data. As an example, there is no standard that defines the minimum required accuracy of a PMU and what metric to use to compare accuracies. Accuracy requirement should particularly apply during transient conditions when phasor data might be used for controlling the disturbance. The accuracy standard should also apply to the overall measurement chain which includes the voltage and current sensors. In a complex system as the one depicted in Figures 10.1 and 10.2, time synchronization is challenging if high accuracy is required. One of the reasons that standards do not address the issue of accuracy is the fact that technology has been a moving target and it is deemed appropriate to allow the process of continuous improvements to evolve the standard. To move beyond this, therefore, standards should be developed along the lines of assessing and monitoring the accuracy of WAMS and quantify the quality of the applications. A related issue is the recovery of WAMS in case the accuracy is compromised or one component fails. As an example loss of GPS clock synchronization in a WAMS subsystem should not deteriorate the performance of the overall system. Standards should be developed to address recovery from these failures and the level of redundancy to achieve certain reliability level for these systems. Again this requirement is influenced by the intended applications, that is, state estimation could accept temporary loss of phasor data while protection applications could not. In the latter case, an accurate IED clock could allow ride through a temporary loss of GPS signal. Overall, standards for WAMS are in their infancy and much more understanding and evolution of the technology is needed before standards should be adopted.

7. Control Center Operations

At present control-centers use a round-robin polling of all the RTUs at the substations at relatively slow rates via Supervisory Control And Data Acquisition (SCADA) system. If the RTU and SCADA are replaced with a new platform that has all the possible substation data available, the paradigm changes completely. Novel state estimation algorithms can be implemented in control-centers as new measurement infrastructure is implemented. And the data amount and frequency can be selected according to the application at the control-center or any other data accessing point. A systematical communication and database design for this new type of data acquisition has been developed and its feasibility will be tested by simulation.

7.1 State Estimator and Database Background

Power system state estimation which is the process carried out in the energy control centers in order to provide a best estimate of the system state based on the real-time system measurements and a pre-determined system model. It is also a software function that connected to the back-end of the Supervisory Control and Data Acquisition (SCADA) system. The real-time system measurement data used by the state estimator is an analog subset of the 'real-time' database in SCADA composed of Remote Terminal Units (RTUs) installed in substations while the pre-determined system model relies on both the digital subset of the 'real-time' database in SCADA and the system topology parameter data that is in the system static database.

In traditional power system state estimation, the RTUs will transfer the raw analog data which is consisted of active and reactive line power flows, active and reactive power injections, and sometimes line current magnitudes sampled in the substation to the control center at a slow rate. As those measurements are nonlinear to the bus voltage angles and magnitudes that are defined as the power system states, iterations exist in the process of state estimation which make the estimation time is very long. With the appearance of Phasor Measurement Units (PMUs), we can monitor the complex bus voltage at the substation and at the same time, we can also get the phasor current measurements in the same way. Those phasor voltage and current measurements are linear to the power system states to eliminate the iteration procedure in state estimation. The concept of linear state estimation and the corresponding observability analysis are introduced in many articles and publications [7.1], [7.2], while the PMU measurements are collected and transferred to the applications by Phasor Data Concentrators (PDCs) which are similar with the SCADA system but with higher transfer rate.

With the developing of the microprocessors applications in the substation many calculations can be done at the substation level and also many substation data processing algorithm and software are also introduced in [7.3]-[7.6]. Thus these redundant phasor measurements can play an important part in the wide area measurement systems (WAMS) and state estimations. Besides, RTUs also transfer the raw digital data such as the circuit breaker status to the control center which may be mixed with different kinds of bad data, and those bad data always create fatal topology errors in modeling the system networks. Some of the raw digital bad data can be eliminated at the substation with the help of the redundant substation analog measurements shown in [7.7]-[7.9]. Phasor measurements in the substation can also be used of that field.

In this chapter, we will design a systematical two-level, substation level and control center level, state estimator with the control center level state estimator will take advantage of the substation level state estimator to get a more efficient and accurate estimation of the whole system. As the transferred data are no longer from RTU and traditional SCADA system cannot handle the data amount and transfer rate, we will propose and build a distributed information system to be the platform of the state estimator. We also will analysis the synergy of them including algorithms performances, communication and database requirements, time alignment, and other critical issues which play a part in the whole procedure.

7.2 Two-Level Linear State Estimator

Phasor Measurement Unit (PMU) was introduced into power system at the end of last century [7.10] and more and more widely used in many applications like wide area monitoring, protection, control, and state estimation [7.11]-[7.13]. As introduced in [7.1], [7.2], if all the analog measurements were synchronized currents and voltages, then the state estimation equations would be linear. With the help of increasing installations of phasor measurements, we can implement a new measurement function of the state estimator which is linear in the complex plane. In this state estimator, both the states and the measurements are defined in the complex plane and the measurement functions are linear, making this a linear state estimator.

The linear state estimation in the complex plane is the following optimization problem:

$$\begin{aligned} &\text{Min } \tilde{\mathbf{r}}^T \tilde{\mathbf{W}} \tilde{\mathbf{r}} \\ &\text{s.t. } \tilde{\mathbf{z}} = \tilde{\mathbf{H}} \tilde{\mathbf{x}} + \tilde{\mathbf{r}} \end{aligned} \tag{7.1}$$

where $\tilde{\mathbf{r}}$ is the residuals vector, $\tilde{\mathbf{W}}$ is the weight matrix, $\tilde{\mathbf{z}}$ is the measurements vector, $\tilde{\mathbf{x}}$ is the vector of system states, and $\tilde{\mathbf{H}}$ is the measurement function matrix relating the measurement vector to the states.

For computational purposes, each measurement $\tilde{z}_i = z_{i,real} + jz_{i,imag}$, each state $\tilde{x}_i = x_{i,real} + jx_{i,imag}$, and each residual $\tilde{r}_i = r_{i,real} + jr_{i,imag}$ can be represented as the 2×1 vector $\mathbf{z}_i = \begin{bmatrix} z_{i,real} \\ z_{i,imag} \end{bmatrix}$, $\mathbf{x}_i = \begin{bmatrix} x_{i,real} \\ x_{i,imag} \end{bmatrix}$, and $\mathbf{r}_i = \begin{bmatrix} r_{i,real} \\ r_{i,imag} \end{bmatrix}$ in the real plane respectively. For each entry $\tilde{h}_{i,j} = h_{i,j,real} + jh_{i,j,imag}$ in the measurement function matrix $\tilde{\mathbf{H}}$, a 2×2 matrix $\mathbf{H}_{i,j} = \begin{pmatrix} h_{i,j,real} & -h_{i,j,imag} \\ h_{i,j,imag} & h_{i,j,real} \end{pmatrix}$ can represent it in the real plane. Then, if there are m measurements and n states in the system, (7.1) can be written as:

$$\text{Min } \mathbf{r}^T \mathbf{W}\mathbf{r}$$

$$\text{s.t. } \mathbf{z}=\begin{pmatrix} \mathbf{z}_1 \\ \vdots \\ \mathbf{z}_m \end{pmatrix}=\mathbf{Hx}+\mathbf{r}=\begin{pmatrix} \mathbf{H}_{1,1} & \cdots & \mathbf{H}_{1,n} \\ \vdots & \ddots & \vdots \\ \mathbf{H}_{m,1} & \cdots & \mathbf{H}_{m,n} \end{pmatrix}\begin{pmatrix} \mathbf{x}_1 \\ \vdots \\ \mathbf{x}_n \end{pmatrix}+\begin{pmatrix} \mathbf{r}_1 \\ \vdots \\ \mathbf{r}_m \end{pmatrix} \tag{7.2}$$

where $\mathbf{W}$ is the diagonal weight matrix in which all the entries are real numbers and $\mathbf{W}_i$ is the 2×2 weight block for each measurement: $\mathbf{W}_i = \begin{pmatrix} \sigma^2_{z_{1,real}} & 0 \\ 0 & \sigma^2_{z_{1,real}} \end{pmatrix}$. For the above linear state estimation problem, the solution is obtained [7.14] without iteration:

$$\mathbf{x} = (\mathbf{H}^T \mathbf{W}\mathbf{H})^{-1} \mathbf{H}^T \mathbf{W}\mathbf{z} \tag{7.3}$$

In the following two sections, we develop the state estimator formulations at both the substation and control center levels. All the formulations are linear and use (7.3) to obtain the solution.

(7.1) and (7.2) just described the generalized problem and solution of linear state estimation. In this research, as the state estimator is divided into two levels, different level will have different model to create different measurement function. And as in the traditional state estimator, this linear state estimator requires sufficient redundancy for the solution to provide good estimates. The detailed algorithm is in Appendix A.

Compared with traditional state estimator, our control center level state estimator has much less of a computational burden. The system topology build by merging all the substation topology together is much faster as most of the topology processing is done at the substations. The state estimation solution is much faster as most of the estimation is now done at the substation level and the linearity guarantees a solution with no divergence. At the same time, both the system topology and the input measurements are more reliable because they have already been estimated at the substation level. Any bad data detection or identification done at the control center should be less burdensome.

This two-level linear SE has many advantages over the traditional SE but it assumes the availability of enough phasor measurements that provides observability and redundancy at all substations. Although this is not the case today, the ability to utilize various substation IEDs as synchrophasor measurement sources suggests that many high voltage substations will have this capability.

7.3 Transitional Two-Level State Estimator Infrastructure

In this section, we describe a multi-area state estimation algorithm for a transitional state estimation in which portions of the grid takes advantage of advanced substation level state estimator while the rest of the grid is still solved in the traditional way. The assumption is that some of the ‘digital’ substations with local state estimators are connected together by branches, thus forming a contiguous linear network, while those substations without substation level state estimators are connected by branches to construct nonlinear areas, which will have to be solved by the traditional SE method. This assumption is reasonable because for example, we can assume that the substation level state estimators are implemented at the high voltage substations while the low voltage substations are not yet retrofitted. Then we can divide the whole system into several linear areas and nonlinear areas shown in Figure 7.1. The boundary buses connect these areas and the phasor based linear area calculations are weighted higher to influence the nonlinear area calculations.

Here we do not propose a new design of centralized SE leading to an optimal mathematical solution when only some substations are equipped with the substation level SE but the proposed method takes advantage of the substation level SEs without modifying existing centralized SEs. We estimate all the system states in the following order: first, use the linear state estimator to estimate the states in each linear area separately; second, use the estimated boundary states as pseudo measurements for each nonlinear area to estimate the states of each nonlinear area separately. For the convenience of using the traditional state estimator for each nonlinear area, we generate the power flows on each boundary transmission line by the corresponding estimated currents and bus voltages from the linear state estimator. So the pseudo-measurements for the boundary perform as highly accurate phasor measurements for the nonlinear SE areas. Besides, we use the boundary bus as the reference bus for each nonlinear area. Actually, the linear SE areas can be solved more often (at higher periodicities) and the boundary buses always provide an accurate reference and measurements for the nonlinear SE that can also help with bad data detection and identification.

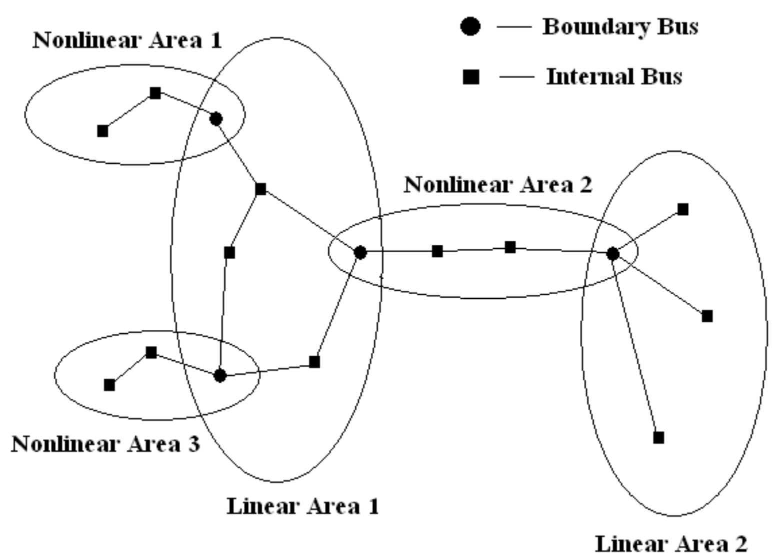


Figure 7.1: Multi-area network with boundary bus

Suppose there are p linear areas and q nonlinear areas in the system, then we will have a new state estimation problem:

$$\begin{aligned}
&\text{Min } (\sum_{i=1}^{p} \tilde{\mathbf{r}}_i^T \tilde{\mathbf{W}}_i \tilde{\mathbf{r}}_i + \sum_{j=1}^{q} \mathbf{r}_j \mathbf{W}_j \mathbf{r}_j) \\
&\text{s.t. } \tilde{\mathbf{z}}_i = \tilde{\mathbf{H}}_i \tilde{\mathbf{x}}_i + \tilde{\mathbf{r}}_i = \tilde{\mathbf{H}}_i [\tilde{\mathbf{x}}_{i,\text{int}}^T, \tilde{\mathbf{x}}_{i,\text{b}}^T]^T + \tilde{\mathbf{r}}_i \\
&\quad\ \mathbf{z}_j = \mathbf{h}_j(\mathbf{x}_j) + \mathbf{r}_j = \mathbf{h}_j([\mathbf{x}_{j,\text{int}}^T, \mathbf{x}_{j,\text{b}}^T]^T) + \mathbf{r}_j
\end{aligned} \tag{7.4}$$

where we divide the states in each area into internal states and boundary states.

Then the whole system state estimation problem will be divided into several subsystem state estimation problems. We can see from the flow chart shown in Figure 7.2, we divide the system and then use the linear state estimator to estimate the states in each linear area separately. For the ith linear area, we have the state estimation problem:

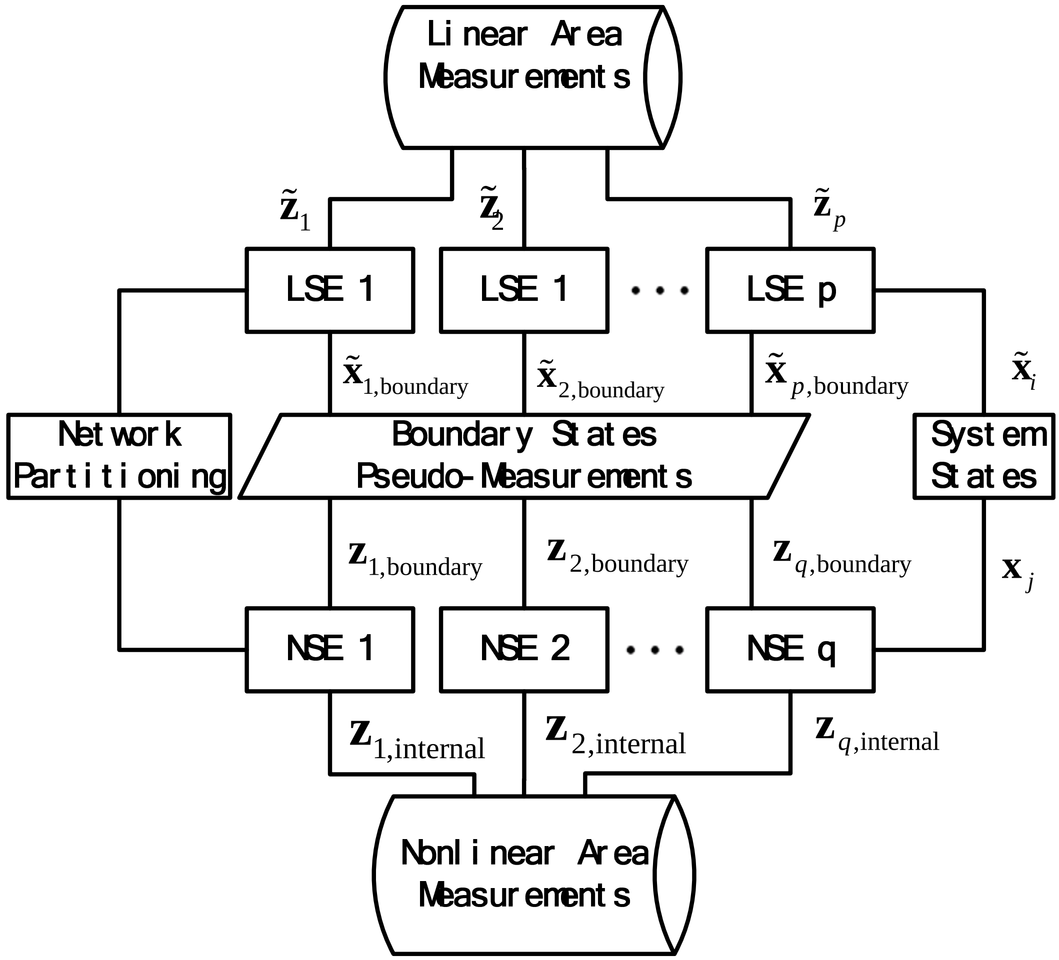
$$\begin{aligned}
&\text{Min } \tilde{\mathbf{r}}_i^T \tilde{\mathbf{W}}_i \tilde{\mathbf{r}}_i \\
&\text{s.t. } \tilde{\mathbf{z}}_i = \tilde{\mathbf{H}}_i \tilde{\mathbf{x}}_i + \tilde{\mathbf{r}}_i = \tilde{\mathbf{H}}_i [\tilde{\mathbf{x}}_{i,\text{int}}^T, \tilde{\mathbf{x}}_{i,\text{b}}^T]^T + \tilde{\mathbf{r}}_i
\end{aligned} \tag{7.5}$$

These linear areas only use phasor measurements as input, so can be run at higher periodicities, say 5 or 10 secs. Computation time is fast enough for this and the communication delays do not introduce significant time-skews. However, synchronizing the measurement data is very important but the time stamping of the phasor data by GPS can enable this with an accuracy of a few micro-seconds.

The multi-area state estimator, linear and non-linear areas combined, will be run at more traditional SE periodicities (in minutes) but synchronizing of the linear area solutions would be important here even though the nonlinear area measurements, which are not time stamped, cannot be as accurately synchronized. At the boundary buses we use the states estimated from the linear estimator as pseudo measurements with high accuracy for the nonlinear area estimate calculations. These pseudo measurements can be the estimated complex voltages and currents at the boundary buses as well as power and VAR injections which can be calculated from the linear state estimates. For the jth nonlinear area, we have the state estimation problem:

$$\begin{aligned}
&\text{Min } \mathbf{r}_j \mathbf{W}_j \mathbf{r}_j \\
&\text{s.t. } \mathbf{z}_j = \mathbf{h}_j(\mathbf{x}_j) + \mathbf{r}_j = \mathbf{h}_j([\mathbf{x}_{j,\text{int}}^T, \mathbf{x}_{j,\text{b}}^T]^T) + \mathbf{r}_j
\end{aligned} \tag{7.6}$$

For the convenience of using in the traditional state estimator for each nonlinear area, we also generate the power flows on each boundary transmission line by the corresponding estimated currents and bus voltages from the linear state estimator. So the pseudo-measurements for the boundary perform as high accuracy PMU measurements set on the boundary bus. Besides, as we can provide each nonlinear state estimator phasor boundary bus voltages, we use the boundary bus as the reference bus for each nonlinear area. The reason we use this estimation order is that we can use the highly accurate and reliable linear SE to provide high-weight pseudo-measurements at the boundary buses of the nonlinear state estimators. Moreover, the linear part of this hybrid SE may be solved more frequently as phasor data is sampled at much higher rates than SCADA data for the traditional SE.



(LSE-Linear State Estimator, NSE-Nonlinear State Estimator)

Figure 7.2: Flow chart of multi-area state estimation

8. Company Enterprise Needs

Although the need for this data in operation and control is very sensitive to latency, a much larger set of engineering and business functions need this data not as urgently. Thus, this data needs to be stored in a historical database that can be accessed by many functions and people inside and outside the enterprise. Besides, as lots of state estimation functions have been moved to substation level, the static database and real-time database also need to be distributed. In this task we will examine the storing of data in each substation and how this will be made available to all enterprise needs. It is not possible to think of and study all such functions but the generic needs of a multitude of functions will be studied. For example, some functions may only need a few pieces of data from many substations while another function may need all the data from only a handful of substations. A conceptual design of a networked historical data base will be developed and its feasibility determined.

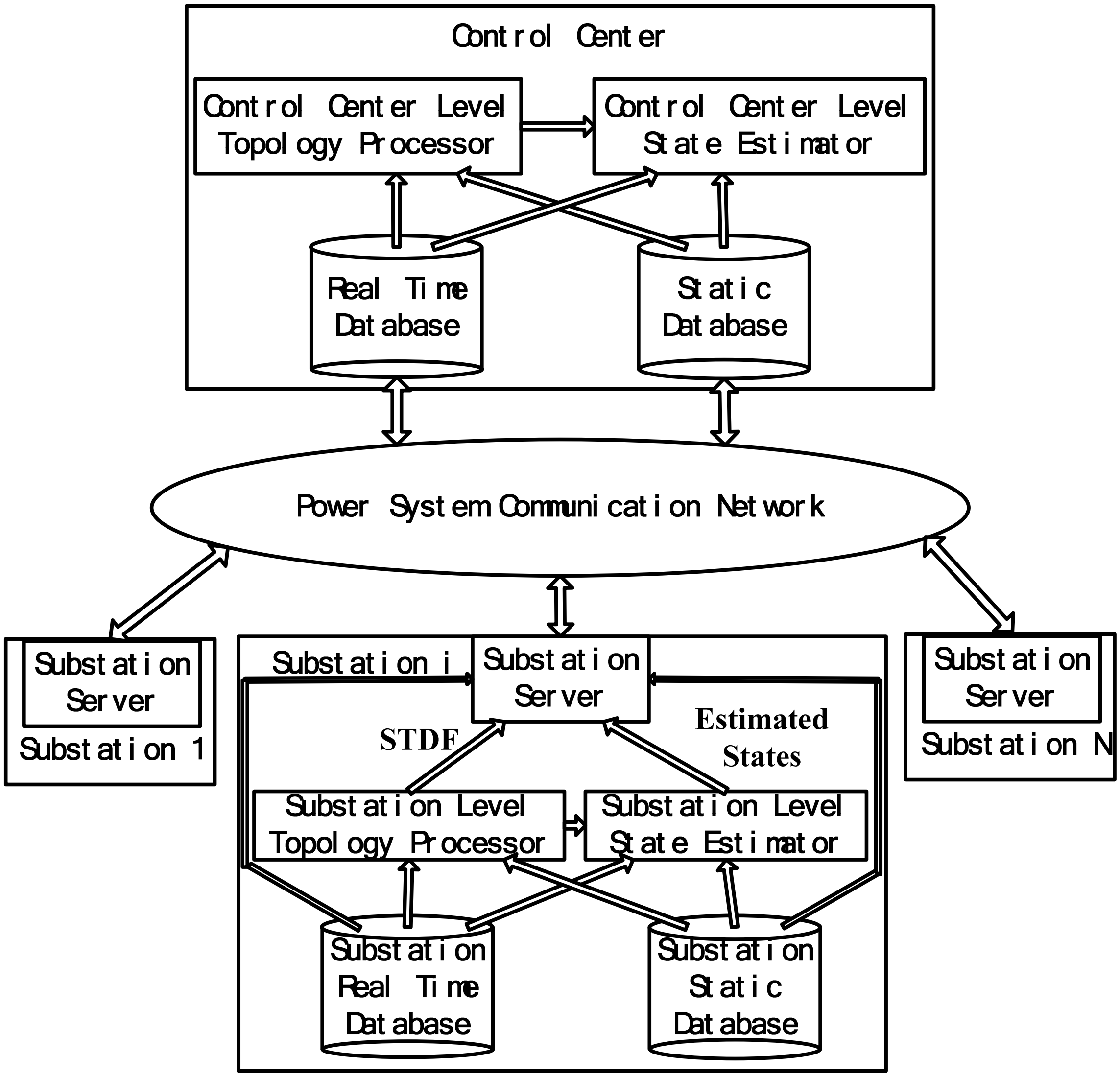
8.1 Distributed Communication and Database

In this two-level state estimator, the substation level state estimator needs to estimate the substation state and build the substation level topology. Thus it requires the substation connectivity data and real time measurements at the substation. Hence we can keep both the static and real time database pertaining to each substation at the substation itself which will be much more convenient for such a decentralized or distributed application.

At the same time, as the control center level state estimator calculations need to merge all the substation topology and substation calculations into a system state, a database is also needed at the control center to support this function. This distributed two-level database structure is shown in Figure 8.1. The substation level topology processor builds the substation topology while the substation level state estimator estimates the substation states. Thus much of the traditional centralized database can be distributed to the substations. Note that some historical data can be stored in the substation server.

The database storage at the control center is now much smaller because all the historian database, static and real time database storages are distributed in each substation. The static database at the center now consists mainly of branch parameters and connectivity. The real time database now handles only the calculated (estimated) data passed up from the substations. This distributed database architecture described here pertains to this proposed two-level state estimator only. The overall database that supports all the control center functions will certainly have other attributes. For example, the display functions at the control center will require access to the substation static and real-time data. Any applications can also access historical data in the substation server.

We can see that this distributed architecture for the state estimator function is similar to many other widely used distributed applications like those for telephones, ticket reservations, inventory, supply chain, etc. Such a distributed architecture for applications and databases has many advantages [8.1] especially for systems which are geographically dispersed, like the electric power grid. However, a distributed database requires different methods of backup (checkpoint) and failover in case of memory failures, than that of today's centralized database [8.2] which is backed up locally and at the backup control center.



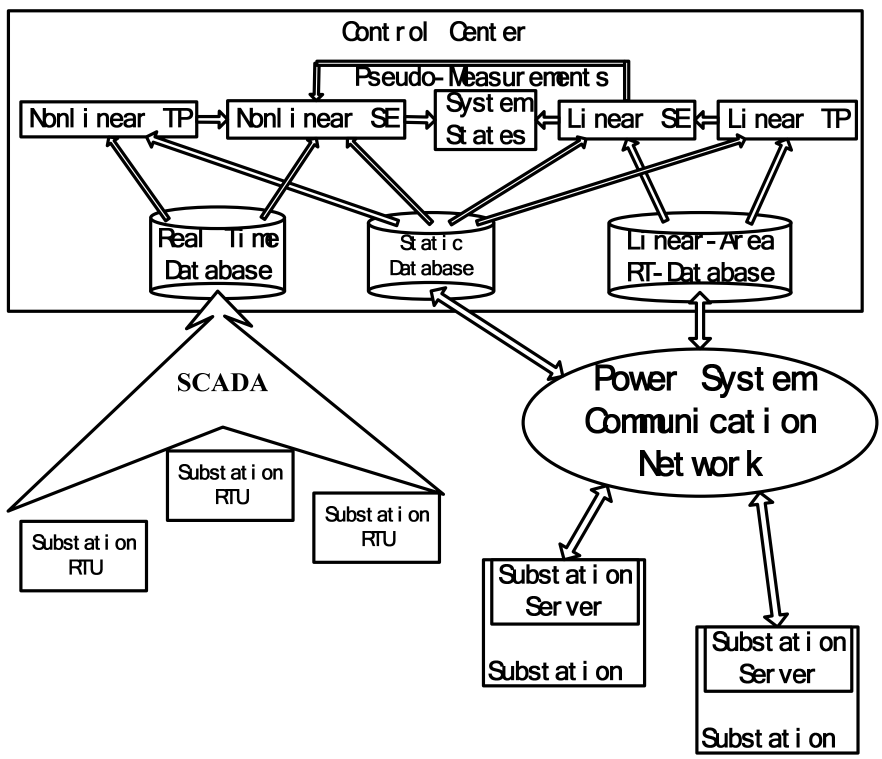
(STDF: Substation Topology Description File)

Figure 8.1: Decentralized real time modeling system and database

The proposed communication network is purely flat and different from the SCADA system which is centralized and hierarchical, so there can be direct communication between substations. This feature may be very useful for other applications, like Wide-Area Monitoring System (WAMS) and Wide-Area Control Schemes (WACS), which require such access. The control center and other units that make use of substation data can subscribe just to the data that they need. For example, the data needed to support the SE can be obtained only at the periodicity rate for the SE (say, once every 2 or 5 seconds, which is much faster than today's SE periodicities). For other applications like oscillation control, some data may be needed at much faster rates like 30 times a second. As is obvious from Figure 8.1 and this discussion, the centralizing of all data at the control center is not envisioned, as is further described in the next subsection on the database.

8.2 Transitional Two-Level State Estimator Infrastructure

The transitional two-level multi-area state estimator will require both real time measurements transferred by SCADA system and the new power system communication network. So we need transitional information architecture as shown in Figure 8.2. The old substations continue to use the existing SCADA-RTU communication to send real time data while the newer substations do the substation level SE calculations and use the new high-speed communication to transfer data. At the control center level the traditional SE is run side-by-side with the new linear SE. These two types of SE solutions are connected together seamlessly for operator displays.



(Nonlinear TP represents the topology processing in the "nonlinear area")

Figure 8.2: Transitional real time modeling system and database

9. Cyber Security

The security of the computation and communication system is a major concern these days. Thus, much larger data flow volumes within the substation and between substations have to be carefully designed to ensure data security. For example, the real-time data flows for operation and control may require a higher level of security with much more restricted access than the enterprise need for historical data. Actually, firewalls between real-time data and historical data would be part of the design. In this task we will look at the conceptual design of the data servers and data networks and study the level of security that can be ensured.

9.1 Communication System Infrastructure

The proposed communication infrastructure is shown in Figure 9.1. In each substation, we use a high bandwidth LAN for intra-substation communication and each substation server collects all the synchrophasor measurement data as well as other data collected or calculated within the substation. The synchro-phasor measurements are quite voluminous as they are sampled 30 or 60 times per second. In addition there can be much more data that may be calculated by the server or individual IEDs for local substation purposes.

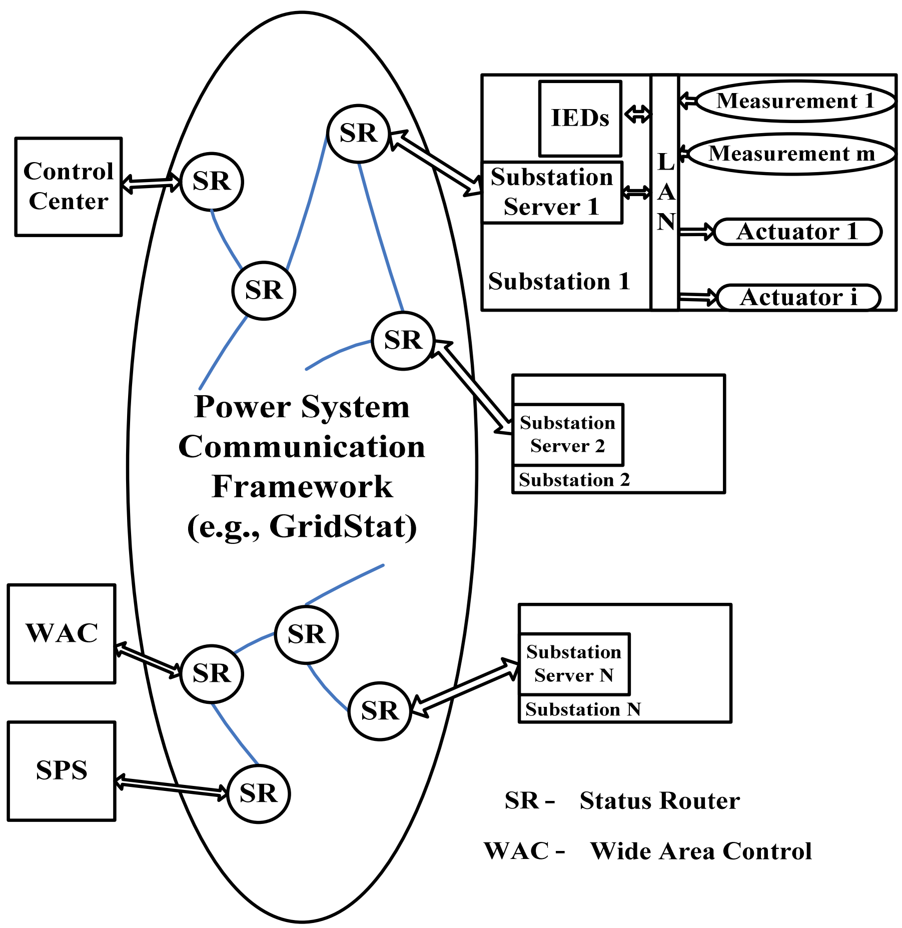


Figure 9.1: Proposed power system communication infrastructure

The communication system outside the substation is shown as a network of high-bandwidth communication links that connect all the substation servers and the control center and other centralized controllers like special protection schemes (SPS) or wide area controllers (WAC). We assume that this communication system uses a publisher-subscriber scheme that is managed by communication middleware such as GridStat shown in [9.1].

9.2 Cyber Security Issues

Assuming that the power system communication framework is stand alone without any third-party transmission service provider, the main security issues are: (1) Accessibility of Substation Server (Gateway) and substation IEDs; (2) Authority of retrieving data from substation and sending commands to IEDs via gateway. The first issue includes the firewall constructions at the substation server, network routing topology while the second one deals with security key assignment, access rights authentication, etc.

The basic philosophy of securing the cyber system has to be (and always has been) to isolate it from any connectivity from any computer/processor outside the system. This is difficult to do given the variety and number of processors that are connected within the system, especially those rapidly growing numbers of IED and PMU processors in the substations, which may require connectivity for various purposes like maintainability, setting changes, external information, etc. For example, the historical data base at the control center has connectivity to other parts of the enterprise system; thus the processors handling the historical data base must have layers of defense like unidirectionality of data, authentication, firewalls, etc.

These cyber security standards are now set by NERC (North American Electric Reliability Council) and are known as the CIP standards. The philosophy of these standards is as explained above but the implementation is not always simple. One part of these standards require that all processors be declared critical or non-critical depending on whether any intrusion into that processor can directly affect the operation of the power system. For example, all PMUs that measure data sent to the substation gateway servers and beyond must be critical processors and hence be under the CIP standards.

We can see from the state estimation algorithms and corresponding information platforms that, in this new infrastructure, the network security problem is more important because once one substation is attacked, the bad data, including static, real time, and historical data, will spread all over the network because of the consistency and coherency properties of distributed system.

10. Conclusions

In summary, we propose a conceptually new design of a substation with implications on the overall operation of the power system. The conceptual design of this system is driven by a comprehensive analysis of data requirements for all substation functions as well as control-center functions and company enterprise operations. A feasibility study of the proposed design has been performed and the conclusion is that this design can be achieved with existing technologies or incremental improvements of present day technology. The feasibility study determined the desirable properties of the collected data in terms of sampling rates, accuracy, and validation. Different applications need data in different forms and sampling rates. The applications range from data requirements for security assessment at the control-center to fault recordings for post mortem analysis.

The proposed scheme has several merits in designing the substation of future. First of all, the data acquisition system based on merging units guarantees a more reliable and accurate data collection since the new design uses digital data transmission as opposed to the traditional copper wiring that introduces errors, especially in large substations where the distances can be substantially long. Furthermore, the use of merging units has economic benefits because it avoids the needs for expensive copper cable installation. The merging units are connected to the process bus. The data at the process bus can be shared by multiple IEDs. The other advantage of the substation of future is its scalability for two basic applications: (a) system visibility (state estimation) and (b) wide area monitoring.

Overall the proposed structure of the substation of the future will have a beneficial impact on all aspects of the operation of the system. While present practice in substation design may not be close to the vision presented in this report, it certainly moves towards this direction. For example, the introduction of the GE Hard fiber provides the direction towards our vision of the substation of the future. Many other manufacturers developed and offer merging units with characteristics that will enable the approaches described in this report. It is also apparent that these technologies have the potential of reducing the cost of substation automation while they provide better applications. We are confident that these technologies will continue to evolve and our vision of the substation of the future will materialize in some form.

The digitized substation of future can be target of cyber attack. The proposed design of the substation of the future provides a secure environment within the substation and only one gateway point for digital communications with the rest of the system. Communications are based on validated information - this means that the amount of data is very small compared to the amount of raw data existing at the substation. It is manageable to use encryption on the communicated information to maximize cyber security. In general the fact that communications are based on information results in a flexible system for application of many cyber security approaches.

Project Publications

T. Yang, H. B. Sun, and A. Bose, "*Two*-level PMU-based Linear State Estimator," *Power System Conference and Exhibition (PSCE), Seattle*, *2009.*

T. Yang, H. B. Sun, and A. Bose, "Transition to a Two-Level Linear State Estimator part I: Architecture," *accepted by IEEE Transactions on Power Systems*.

T. Yang, H. B. Sun, and A. Bose, "Transition to a Two-Level Linear State Estimator part II: Algorithm," *accepted by IEEE Transactions on Power Systems*.

A.P. Meliopoulos, Curtis Roe and A. Bose, "Distributed dynamic state estimation power quality monitoring" Georgia Tech Fault and Disturbance Analysis Conference, May 2010.

A. P. Sakis Meliopoulos, George J. Cokkinides, Clinton Hedrington and Terry Conrad, "The SuperCalibrator – a Fully Distributed State Estimator", *Proceedings of the IEEE-PES 2010 General Meeting*, Minneapolis, MN, July 26-29, 2010.

Appendix A: Two-Level PMU-Based Linear State Estimator

The material in this appendix is based on work that was originally published at the IEEE/PES Power System Conference and Exposition in 2009. This work was supported in part through the Consortium for Electric Reliability Technology Solutions (CERTS), funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Distributed Energy and Electricity Reliability, Transmission Reliability Program of the U.S. Department of Energy under Interagency Agreement No. DE-AI-99EE35075 with the NSF. This work was also supported by the Power System Engineering Research Center (PSERC). This support is gratefully acknowledged.

A.1 Introduction

The traditional state estimator function in a control center is actually made up of three programs solved sequentially:

1. Topology Processor (TP) that uses the real-time circuit breaker status with the substation and system level topology to determine the connectivity of the whole network;
2. State Estimation (SE) that solves for the complex voltages at each bus from the real-time analog measurements;
3. Bad Data Detection-Identification (BD) which tests the solution to find bad measurements (and if found, reruns the SE solution without the bad data).

Topology errors are a major issue for the state estimators in use today [A.1]-[A.3]. First, they cause very large errors in the SE solution which in turn makes the downstream applications (contingency analysis, optimal power flow, nodal prices, billing reconciliation, etc.) erroneous. Second, topology errors are more difficult to detect and identify than analog measurement errors [A.4]. Third, topology processing is dependent on the circuit breaker status measurements which have no redundancy (unlike the analog measurements).

The state estimation equations are nonlinear because most of the analog measurements are real and reactive powers, so the solution requires iterating to convergence [A.5]. Convergence is hindered by bad data and particularly so if the error is in the topology. If all the analog measurements were synchronized currents and voltages, then the state estimation equations would be linear, thus eliminating the convergence issue. Accuracy will still be dependent on the measurement error distributions, thus redundancy will still be required. To have enough phasor measurements to meet observability and redundancy requirements would mean much higher penetrations of PMU technologies than is available today. However, some regions (like in China) are already aiming for this in the next few years while more will attain this if the very large numbers of intelligent electronic devices (IED) at high voltage substations are fitted with time synchronization signals.

In this paper, we propose a distributed two level state estimator function that uses a linear SE algorithm at the control center level but moves the local topology processing and the bad data detection-identification to the substation level. The local topology processing and bad data detection-identification at each substation is done with very different algorithms than is used today at the control center level. In fact, substation level topology processing and bad data detection-identification are no longer separate functions but analog measurement errors and circuit breaker status errors are identified together. The result is that both the topology results and the measurement data are filtered locally to provide a much more accurate set of data to the control center level state estimation calculation. Unlike the present state estimator and some other distributed state estimators [A.6]-[A.10], the bad data detection-identification and filtering is done prior to the state estimation solution rather than after. The linearity of the state estimator guarantees a solution and the substation level pre-filtering of topology and measurement errors guarantee the accuracy of the solution.

In Section A.2, the linear state estimation formulation is described. In Section A.3, we describe the new substation level calculations that pre-filter all the real-time data at that substation; we call this the substation level state estimator or zero impedance state estimator. In Section A.4, we briefly describe the communications and distributed database architecture that will be required to support such a two-level state estimator. Finally, we show some experimental results for the substation level calculations in Section A.5.

A.2 Control Center Level Linear State Estimator

If all the analog measurements were synchronized currents and voltages, then the state estimation equations would be linear. With the help of increasing installations of phasor measurements, we can implement a new measurement function of the state estimator which is linear in the complex plane. In this state estimator, both the states and the measurements are defined in the complex plane and as with the traditional state estimator, the power system states are the complex bus voltages.

In general, state estimation determines the most likely state of the system based on the quantities that are measured. Here we use the maximum likelihood estimation (MLE) method which is popularly used. So the linear state estimation is the optimization problem defined in Equation (A.1).

$$\begin{aligned} &\mathrm{Min}\ \tilde{r}^T \cdot \widetilde{W} \cdot \tilde{r} \\ &\mathrm{s.t.}\ \tilde{z} = \widetilde{H} \cdot \tilde{x} + \tilde{r} \end{aligned} \tag{A.1}$$

In Equation (A.1), $\tilde{r}$ is the residues vector, $\widetilde{W}$ is the weight matrix, $\tilde{z}$ is the measurements vector, $\tilde{x}$ is the vector of system states and $\widetilde{H}$ is the measurement function matrix relating the measurement vector to the states.

To the control center level state estimator, given a power system with n buses and m branches the measurement inputs are the bus voltages $\tilde{V}_{bus} = \left[\tilde{v}_{bus,1}, \dots, \tilde{v}_{bus,n}\right]^T$, branch currents at both ends $\tilde{I}_{b1} = \left[\tilde{\imath}_{b,1}, \dots, \tilde{\imath}_{b,m}\right]^T$, $\tilde{I}_{b2} = \left[\tilde{\imath}_{b,m+1}, \dots, \tilde{\imath}_{b,2\cdot m}\right]^T$, and the injection currents $\tilde{I}_{inj} = \left[\tilde{\imath}_{inj,1}, \dots, \tilde{\imath}_{inj,m}\right]^T$. The states of the system are the bus complex voltages $\tilde{x} = [\tilde{v}_1, \dots, \tilde{v}_n]^T$. Assuming the system admittance matrix is $\tilde{Y}$, the measurement function is defined in Equation (A.2).

$$\tilde{z} = \begin{bmatrix} \tilde{V}_{bus} \\ \tilde{I}_{b1} \\ \tilde{I}_{b2} \\ \tilde{I}_{inj} \end{bmatrix} = \widetilde{H} \cdot \tilde{x} + \tilde{r} = \begin{bmatrix} I \\ \tilde{Y}_1^b \\ \tilde{Y}_2^b \\ \tilde{Y} \end{bmatrix} \cdot \tilde{x} + \tilde{r} \tag{A.2}$$

In Equation (A.2), $\tilde{Y}_1^b$ and $\tilde{Y}_2^b$ can be derived from the branch admittances.

Then we can get the solution of the state estimation problem by the usual formulation, shown in (Equation A.3).

$$\tilde{x} = \left(\widetilde{H}^T \cdot \widetilde{W} \cdot \widetilde{H}\right)^{-1} \cdot \widetilde{H}^T \cdot \widetilde{W} \cdot \tilde{z} \tag{A.3}$$

In the linear state estimator, the cost function is still the weighted least squares (WLS) problem while the measurement function is linear. Compared to the traditional state estimator, our control center level state estimator does not require iterations during the process of state estimating, thus not suffering from divergence and needing much less calculation time. We can see from the algorithm that we need all the substations to provide synchronized voltage and current measurements to guarantee observability. This requirement is similar to that of the traditional state estimator and so is the requirement for redundancy.

A.3 Substation Level Linear State Estimator

With more and more sensors installed in substations, the substation measurements become more and more abundant to enable processing bad data of both analog measurements and circuit breaker statuses at the substation level. Previous papers have focused on the processing of substation measurements and the SuperCalibrator method [A.10] has also been tested in the field. But these methods all use the traditional topology processing, state estimation, and bad data processing within the substation as used at the control center level and suffer from some of the same difficulties.

The substation level state estimator we propose here uses all the current measurements including those through the circuit breakers to estimate both the substation current states as well as the substation topology without having to use the circuit breaker statuses first based on the circuit breaker oriented substation model shown in Figure A.1. Instead, the topology obtained from this processing is then compared to the breaker statuses to verify their accuracy.

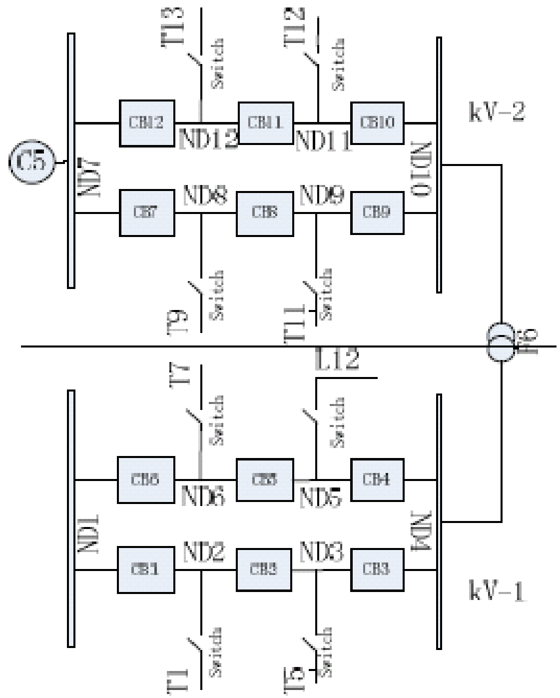


Figure A.1: Circuit breaker oriented substation model.

The main function of the substation level state estimator proposed here is to use all the digital and analog measurements in the substation to estimate the real time digital states and analog phasor data of bus voltages, branch currents, and injection currents. As before, the only analog measurements used are the synchronized voltage and current measurements, thus making all the equations linear. This filtered substation data together with the substation topology is provided to the control center as input to the state estimation at that level.

The substation level state estimator proposed here consists of two parts, one processing the current measurements and the other voltages. As there are no impedances at one voltage level within the substation, these two are called zero impedance current state estimator and zero impedance voltage state estimator, respectively. The brief flow chart of the substation level state estimator is shown in Figure A.2.

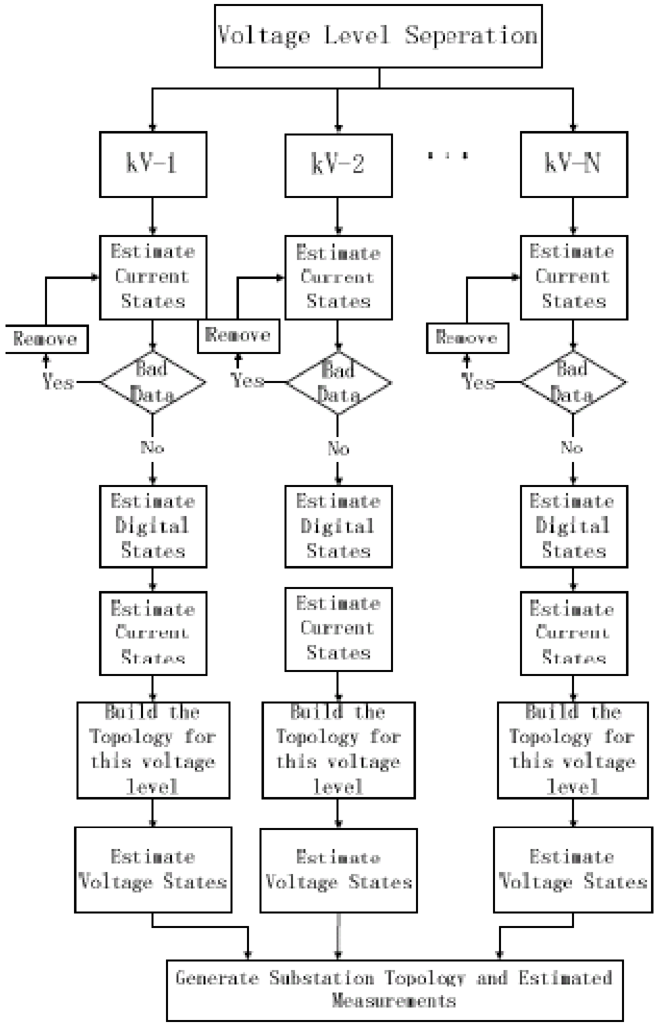


Figure A.2: Flow chart of the substation level state estimator.

Each substation is divided into several kV systems such that each kV system is one voltage level. For example, in the substation of Figure A.1, there are two kV systems named kV-1 and kV-2 respectively, which are connected by a transformer F6.

In each kV system, as there is no impedance, we cannot find the measurement function relating the voltages and the branch current measurements. Thus we calculate a new state estimator for each kV system to handle the current and voltage measurements separately. The zero impedance current state estimator defines the currents on circuit breakers as states and uses state estimation equations based on Kirchhoff's Current Law (KCL) to estimate the states. The equations for the current measurements at one voltage level, i.e. with no impedance connections, can be written as in Equation (A.4).

$$\tilde{z}_{inj} = A_{KCL} \cdot \tilde{x} + \tilde{r}_{inj} \tag{A.4}$$

In Equation (A.4), $\tilde{z}_{inj}$ is the injection current at each node, A_{KCL} is the adjacent matrix relating nodes to circuit breakers in the zero impedance power system, $\tilde{x}$ is the state vector of the circuit breaker currents, and $\tilde{r}_{inj}$ is the corresponding residue vector.

The equations for the current measurements at each circuit breaker have the obvious relationship, shown in Equation (A.5).

$$\tilde{z}_{cb} = I \cdot \tilde{x} + \tilde{r}_{cb} \tag{A.5}$$

In Equation (A.5), $\tilde{z}_{cb}$ is the vector of current measurements for each circuit breaker, I is the identity matrix, and $\tilde{r}_{cb}$ is the corresponding residue vector.

Then the measurements functions can be represented by Equation (A.6).

$$\tilde{z} = \begin{bmatrix} \tilde{z}_{inj} \\ \tilde{z}_{cb} \end{bmatrix} = \begin{bmatrix} A_{KCL} \\ I \end{bmatrix} \cdot \tilde{x} + \begin{bmatrix} \tilde{r}_{inj} \\ \tilde{r}_{cb} \end{bmatrix} = H \cdot \tilde{x} + \tilde{r} \tag{A.6}$$

This is also a linear state estimation problem, so we can find the estimation solution by Equation (A.3) with the difference that the entries in this H matrix are 1, 0, or -1 and the states are currents. The calculation is simple and fast.

Once the currents of all circuit breakers are estimated, the analog bad data can be identified and rejected by the traditional testing method based on maximum residue. The zero impedance current state estimation is repeatedly executed until no bad data remains.

The final estimated circuit breaker currents can then be directly utilized to verify the digital status of the corresponding circuit breakers to identify any topology errors. For example, if the estimated current for a circuit breaker is not close to zero but the digital measurement of this circuit breaker is open, we conclude that the status measurement is bad and the real state of the circuit breaker is closed. We call this verification process the digital state estimation.

After the bad status data are eliminated, we need to repeat this algorithm again because the new topology will give us a new adjacent matrix A_{KCL} to enable a more precise estimation of the currents.

We can see from this algorithm that the analog and the digital states are decoupled, i.e. the analog estimation can be done without knowing the digital status correctly as long as there is enough redundancy. The advantage of this is we can identify the bad data of analog and status directly instead of using the hypothesis testing method to find the topology error indirectly as done today.

After we get the estimated digital status of each circuit breaker, we can do topology analysis for this voltage level. The outputs will include how many buses this voltage level has and the relationship between buses and nodes, which can be sent to the control center.

Finally, the voltage at each bus needs to be calculated. In the zero impedance voltage state estimator, we define the state as the voltage of each bus, and the measurements are the voltage phasor measurements at the nodes belonging to the bus. Actually the solution is the weighted average value of all the voltage measurements on that bus.

Although the substation level state estimator proposed here has several steps, the calculations are very simple and fast. At the end, this calculation can output any analog values based on the estimated states to the control center together with the substation topology. At a minimum, we assume that branch currents, bus injection currents, and bus voltages for each voltage level will be transferred. The main advantages of this substation level state estimator are:

1. It utilizes all of the current and voltage measurements in the substation and provides a more accurate phasor measurement set to the upper level applications.
2. It provides a direct way to estimate the status of circuit breakers from analog measurements to avoid topology errors.

A.4 Architecture of the Decentralized Two-Level State Estimator

This two-level state estimator will require a new architecture for the power system state estimation system including a distributed database and communication system. In the present system, the static database of all substation connectivity information, at the node-circuit breaker level, resides at the control center. The real-time raw data from each substation is periodically transferred to the control center over the RTU to SCADA communication system.

In our proposed scheme, the substation level state estimator needs to estimate the substation state and build the substation level topology, thus requiring the substation connectivity data at the substation. In Figure A.3, we show a scheme of a distributed database that can support the two-level state estimator. Although networked communication is assumed in Figure A.3 because that is the expected communication scheme of the future [A.11], the two-level state estimator can be supported by the present star-connected communication as long as it is of high enough bandwidth to carry the extra data.

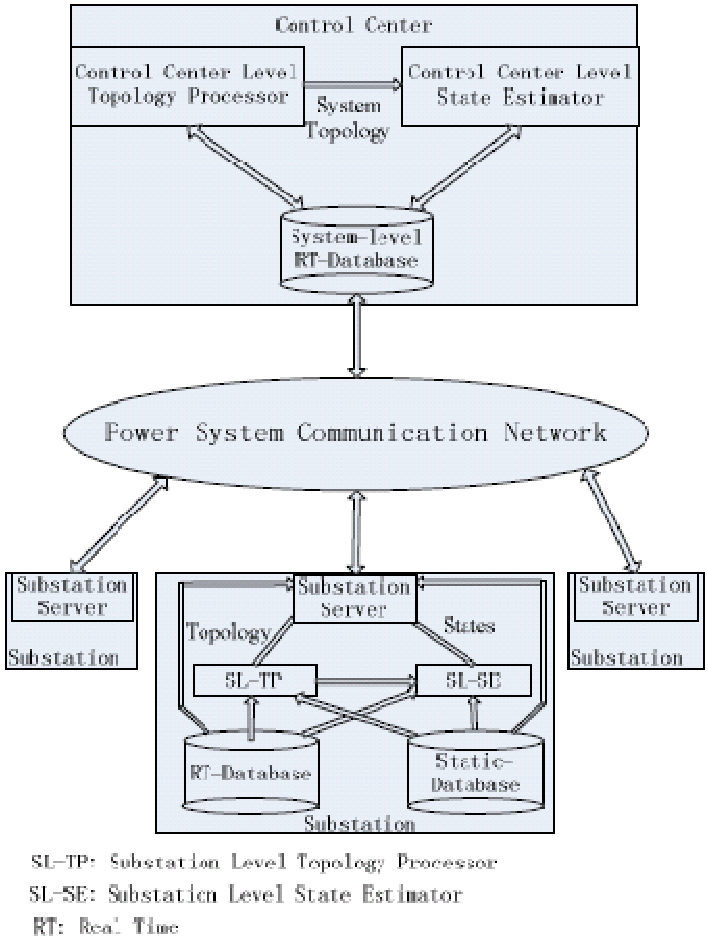


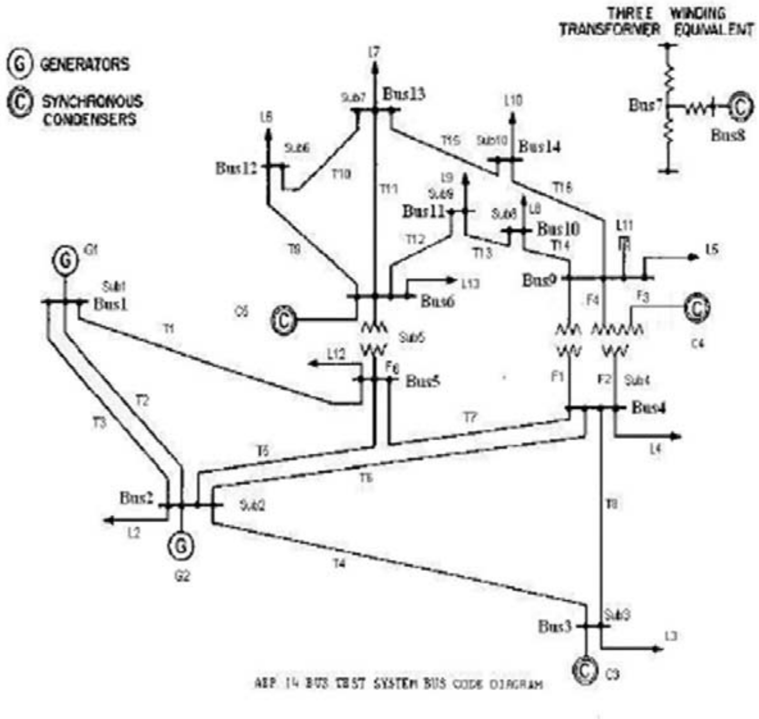
Figure A.3: Decentralized real-time modeling system and database.

At each substation, we assume a substation server which will manage all the data, communications and the processing of state estimation. (Obviously, this server will often be a cluster of distributed CPUs.) We can see from Figure A.3 that at each substation the static database of that substations connectivity must be stored and maintained. Keeping this database updated locally may be an easier task than keeping all substation data updated at the control center. The real-time database at the substation is expected to be larger than the present one in the RTU as the RTUs usually handle a much smaller subset of the available substation measurements.

Such a distributed database architecture, because redundancy can be built in, is more flexible and secure, and significantly improves the operating resilience of the control center functions against physical and cyber attack and natural disasters. Also, database maintenance, which is a major issue today, may become easier when updates are done locally.

A.5 Experiments

We use the IEEE-14 bus system in Figure A.4 as the test system. In this system, the buses connected by transformers are considered to be in one substation. For each substation, we created the circuit breaker oriented single phase model for each substation. For example, Figure A.2 is the node-circuit breaker architecture of substation 5 shown in Figure A.4.



T-Transmission Line
F-Transformer
G-Generator
C-compensator

Figure A.4: IEEE 14 bus system in the experiments.

We use a steady state power flow condition to generate the real-time measurement sets and consider these the true values. To make these measurements emulate real system measurements, Gaussian white noise is added to all measurements.

Using the kV-1 system in Figure A.2 as the example system, we generated a set of both the digital measurements (Table A.1) and analog measurements (Table A.2):

Table A.1: Digital measurement set for the substation level state estimator.

	True Value (p.u.)	**Measurement (p.u.)**
CB1 Current	0	0
CB2 Current	1	1
CB3 Current	0	1 (Bad Data)
CB4 Current	1	1
CB5 Current	1	1
CB6 Current	0	0

Table A.2: Analog measurement set for the substation level state estimator.

	True Value (p.u.)	**Measurement (p.u.)**
BS1 Injection	$-0.0317 - j \cdot 0.0051$	$-0.0317 - j \cdot 0.0051$
BS2 Injection	$-0.6040 + j \cdot 0.3811$	$-0.6040 + j \cdot 0.3811$
BS3 Injection	$0.5929 - j \cdot 0.3874$	$0.5929 - j \cdot 0.3874$
BS4 Injection	$0.4390 + j \cdot 0.1090$	$0.4390 + j \cdot 0.1090$
BS5 Injection	$-0.0826 - j \cdot 0.4821$	$-0.0826 - j \cdot 0.4821$
BS6 Injection	$-0.3342 + j \cdot 0.3442$	$-0.3342 + j \cdot 0.3442$
CB1 Current	$0.0053 + j \cdot 0.0177$	$0.0053 + j \cdot 0.0177$
CB2 Current	$-0.6095 + j \cdot 0.3609$	$-0.6095 + j \cdot 0.3609$
CB3 Current	$0.0025 + j \cdot 0.0003$	$0.0725 - j \cdot 0.1484$ (Bad Data)
CB4 Current	$0.4349 + j \cdot 0.1225$	$0.4349 + j \cdot 0.1225$
CB5 Current	$0.3583 - j \cdot 0.3566$	$0.3583 - j \cdot 0.3566$
CB6 Current	$0.0021 + j \cdot 0.0006$	$0.0021 + j \cdot 0.0006$

In addition to the Gaussian white noise, the measurements also include one status bad data and one analog bad data. Circuit breakers 1, 3, and 6 are open with bad data of current on circuit breaker 3 and bad data of digital measurements on circuit breaker 3.

This mixture of digital and analog bad data is difficult to identify by the traditional state estimator. In contrast, we used the zero impedance state estimation algorithm and formula in Equation (A.6) to estimate the branch current and bus voltage at the same voltage level (kV-1). We can see from the residues and standard error estimated shown in Table A.3, our zero impedance current state estimator can detect and identify the bad data on the circuit breaker 3 current measurement. After we removed this measurement and re-estimated the states, the results and residues become reasonable. We also see from Table

A.4 that the estimated digital status for CB3 is open whereas the measurement was closed thus flagging the bad status.

Table A.3: Residue analysis.

	Residue (p.u.)	**Standard Error Estimated (p.u.)**
BS1 Injection	0.0053	0.0072
BS 2 Injection	0.0164	0.0220
BS 3 Injection	0.0532	0.0717
BS 4 Injection	0.0442	0.0596
BS 5 Injection	0.0179	0.0242
BS 6 Injection	0.0154	0.0208
CB1 Current	0.0124	0.0185
CB2 Current	0.0384	0.0572
CB3 Current	0.0974	0.1452
CB4 Current	0.0270	0.0403
CB5 Current	0.0068	0.0101
CB6 Current	0.0192	0.0287

Table A.4: Estimated states of the zero impedance current state estimator.

	Analog	**Digital**
CB1	$-0.0044 + j \cdot 0.0028$	0
CB2	$-0.6069 + j \cdot 0.3776$	1
CB3	$-0.0099 + j0.0005$	0
CB4	$0.4332 + j \cdot 0.1199$	1
CB5	$0.3531 - j \cdot 0.3545$	1
CB6	$0.0161 - j \cdot 0.0006$	0

There are analog and digital bad data together on circuit breaker 3. If we transferred these data to the control center, the traditional state estimator would have both a topology error as well as an analog bad data. From the results in Tables A.3 and A.4, we can see that the substation level state estimator can detect and identify both errors and provide the control center with corrected inputs.

Table A.5 is the estimated states of the IEEE-14 bus system as calculated by the control center level linear state estimator. The results are very accurate because the substation level filtering has not only eliminated the bad data but has also made some correction to the random noise errors.

Table A.5: Results comparison with one analog bad data.

	Estimated States		**True States**	
	Voltage (p.u.)	Angle (Rad)	Voltage (p.u.)	Angle (Rad)
Bus 1	1.0597	0.0000	1.0600	0.0000
Bus 2	1.0447	-0.0869	1.0450	-0.0869
Bus 3	1.0100	-0.2220	1.0100	-0.2220
Bus 4	1.0186	-0.1803	1.0190	-0.1803
Bus 5	1.0196	-0.1533	1.0200	-0.1532
Bus 6	1.0694	-0.2486	1.0700	-0.2482
Bus 7	1.0613	-0.2335	1.0620	-0.2334
Bus 8	1.0892	-0.2333	1.0900	-0.2332
Bus 9	1.0552	-0.2610	1.0560	-0.2608
Bus 10	1.0502	-0.2638	1.0510	-0.2635
Bus 11	1.0562	-0.2585	1.0570	-0.2581
Bus 12	1.0544	-0.2635	1.0550	-0.2630
Bus 13	1.0494	-0.2651	1.0500	-0.2646
Bus 14	1.0354	-0.2804	1.0360	-0.2800

A.6 Conclusions

The new synchrophasor measurement units are expected to bring a revolution in power system applications. We propose in this paper, a decentralized two-level linear state estimator based on these phasor measurements. We first use the zero impedance state estimator to estimate the substation level analog states, digital states, and substation topologies. Then we transfer these filtered or estimated substation phasor measurement data with the topology of the substation to the control center instead of the raw data sent nowadays through the SCADA system. Thus we can use this phasor data and the substation topologies to build the system topology and estimate the power system states linearly.

The advantages of this two-level linear state estimator include

1. A linear solution to the system state that always guarantees a solution.

2. Pre-filtering of the substation real-time data at the substation to provide more accurate input to the system level state estimation calculations. Thus, the bad data detection, identification and elimination are done before the state estimation calculation rather than after, guaranteeing the accuracy of the calculated system state.
3. The substation level calculations are not only linear but also distributed over many substations, thus making this processing very fast. The topology processing and bad data detection at the substation level are also much simpler from a computational viewpoint.
4. As the calculations are distributed between the substations and the control center, the database for the static data used in the calculations is also distributed. Instead of one very large database at the control center, the substation information can be stored at each substation making the updating of these substation databases easier.

Appendix B: US Virgin Island SuperCalibrator Demonstration

A system wide three-phase distributed state estimator based on the SuperCalibrator approach was developed and installed in the US Virgin Islands Water and Power Administration (VIWAPA) system on the islands of St. Thomas and St. John. This project was completed and demonstrated in a workshop May 5th and 6th in 2008. The demonstrated system performance was excellent from several aspects; (a) a system wide state estimation (SE) was performed four times per second and (b) the accuracy of the state estimate was 0.05 degrees in phase and 0.1% in magnitude. Utilizing a distributed state estimator resulted in a scalable system wide three-phase state estimator.

The remainder of this appendix describes the VIWAPA power system, the demonstration objectives, an overview of the system modeling, and an analysis of the demonstrations results.

B.1 Power System Overview

The host utility, VIWAPA, is shown in Figure B.1

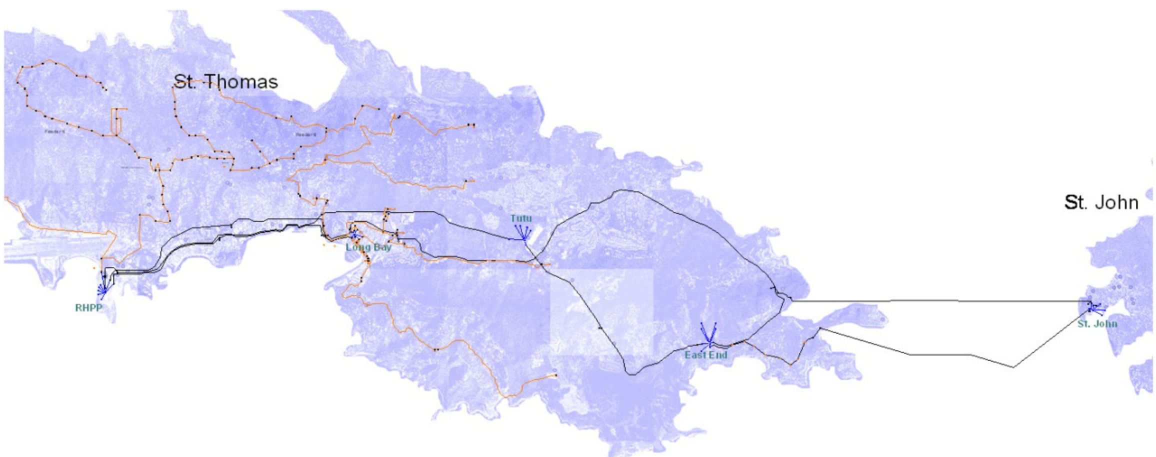


Figure B.1: VIWAPA system single line diagram.

The VIWAPA power system consists of an eight unit generating plant with total installed capacity of 190 MW and five substations. The transmission and distribution network consists of 35 kV transmission and 15 kV distribution systems. Historically the power system experienced multiple blackouts each year due to a transmission network with very high R to X ratios, significant asymmetries, and low system inertia. To minimize power system disruptions VIWAPA had undertaken two initiatives (a) review and coordinate the relaying scheme for the entire system and (b) implement a system wide SCADA system (utilizing relay data) with fiber optic connections from each substation to the control center.

B.2 Project Objectives

The main objective of this project was to demonstrate the use of the SuperCalibrator as a distributed SE algorithm. The benefits of this algorithm were critical for the VIWAPA system and for the industry as a whole in terms of demonstrating a new, robust, and high fidelity distributed state estimator.

For VIWAPA, the SuperCalibrator provided access to critical information about the status of the system, the imbalances, and the loading of each circuit with precision that allows the operators to assess the operational reliability of the system. The real-time information is provided via user selected visualization methods. Since the SuperCalibrator utilizes a three-phase model, the operators can select to display the three-phase state estimation results, or transform the three-phase results into positive, negative and zero sequence results.

The implemented SuperCalibrator system has performed well upon installation with practically no adjustments. The successful demonstration and proof of the SuperCalibrator technology on a system wide basis was very important and marked a milestone in the ability to continuously monitor an electric power system.

B.3 System Modeling

The complexity of the model for the SuperCalibrator approach appears to be higher compared to the traditional SE. However, there are advantages that fully justify the approach. One very important advantage of the SuperCalibrator is that no fine tuning of the SE process was required. By simply entering the physical power system parameters into the model, the state estimator worked without any further tuning.

The SuperCalibrator model included major electrical equipment including generators, power transformers, circuit breakers, and intelligent electronic devices (IEDs). Full three-phase models of these devices were created from nameplate data.

The IED models are utilized to represent monitoring, protection, and metering equipment present in the power system. The IED models require additional data to facilitate multi-vendor information exchange between the IEDs and the SuperCalibrator. Each IED model must be configured with the appropriate data including (a) parameters of the instrumentation channels through which the IED monitors system voltages and currents, and (b) communication parameters. The instrumentation channel parameters include description of the entire instrumentation channel (instrument transformers, instrumentation cables, various burdens attached to the instrument transformer secondary winding, and IED conversion electronics (filters and analog to digital converters)). The communication parameters include parameters required to establish communication with the IEDs (network address and communication protocol). The VIWAPA implementation utilized communication protocols including IEEE C37.118 [B.1], SEL Fast Message Protocol [B.2], DNP3 [B.3], and MODBUS [B.4].

The detailed modeling of the major electrical equipment, instrumentation channel, and communication parameters result in accurate measurement channel error correction and communication between all available substation equipment and the SuperCalibrator. This achievement at the VIWAPA power system was one of the major hurdles in implementing the SuperCalibrator for this project.

B.4 Analysis of Results

This demonstration has proved that it is possible to (a) perform SE with accuracy matching the accuracy of the modern day PMUs and relays and (b) the SE process can be fully distributed (on a substation basis) providing an unprecedented speed of response. Specifically, it was demonstrated that SE can be computed with phase accuracy of 0.05 degrees and magnitude accuracy of 0.1% every 250 ms including communication delays between the substations and the control center.

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