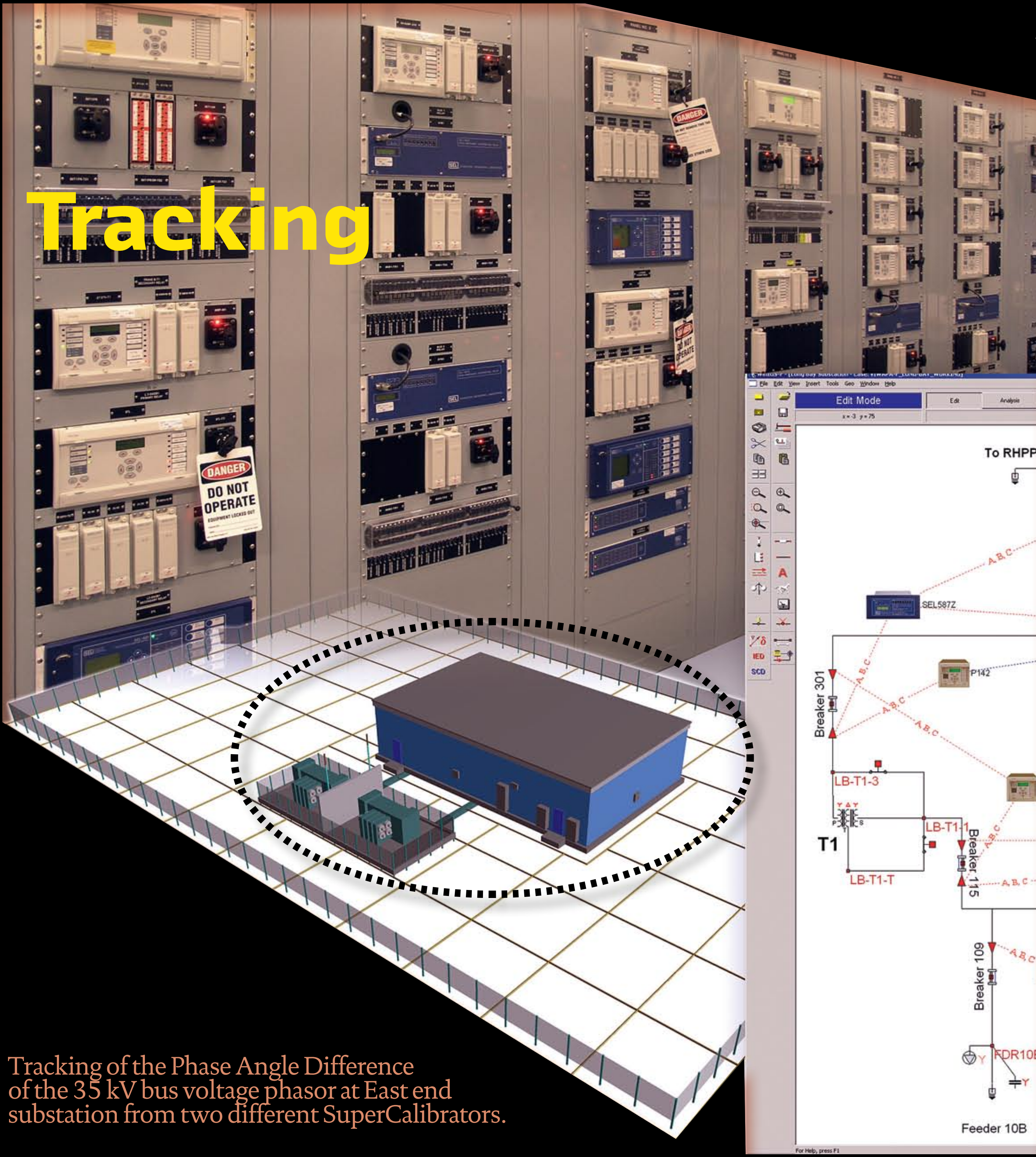
Tracking



Tracking of the Phase Angle Difference of the 35 kV bus voltage phasor at East end substation from two different SuperCalibrators.

by Sakis Meliopoulos, George Cokkinides, Georgia Institute of Technology, George Stefopoulos, NY Power Authority,
Terry L. Conrad, Concurrent Technologies Corporation and Clinton Hedrington, USVI-WAPA

Distributed State Estimator via the SuperCalibrator Approach

The primary purpose of a state estimator is to provide a reliable power system model and operating conditions in real time. The real time model and operating conditions are utilized in a variety of other applications, such as:

■ Load Forecasting; ■ Optimization; ■ VAR Control; ■ Available Transfer capability; ■ Security Assessment; ■ Congestion management; ■ Dynamic Line Rating; ■ Transient Stability; ■ EM Transients; ■ Day Ahead; ■ Power Balance; ■ Spot Pricing; ■ Transmission Pricing; ■ Ancillary Services, etc. It is critical that the state estimator provides a reliable real time model for all these applications.

FIGURE 1 PROVIDES A SCHEMATIC illustration of the traditional state estimation procedure. In the lower part of the figure the data acquisition systems at the substation level are illustrated. A communications system brings all data to a central location, the control center. At the control center the data are utilized to extract the system model in real time using state estimation techniques. This centralized approach has served the industry with reasonable success. However, the statistical performance of the centralized approach is not totally satisfactory. Surveys have shown that on average the reliability of the centralized state estimation is about 95% for the US utilities.

Another issue is the speed of the state estimators. The present centralized approach requires that all the data be brought into the control center and then be processed simultaneously using the overall model of the system. This approach results in relatively slow response time, in the order of minutes. There is a need for state estimators with faster response. Both of the stated issues associated with the traditional state estimation approach are addressed with the development of a SuperCalibrator based state estimator, which is described next.

Supercalibrator Description

The functional description of the distributed state estimator is illustrated in Figure 2. All locally available data (within each substation) are utilized by the substation level state estimator. These data include measurements generated by traditional SCADA equipment, PMUs, Digital Relays, and Digital Fault Recorders. These measurements are therefore a mix of both scalars and phasors.

It is important to recognize that present day modern substations have higher level of automation and employ standards such as the IEC 61850, which makes available all the data from relays, PMUs, SCADA, meters, etc. on a common bus accessible from any other device. In this case the SuperCalibrator is simply an application on a substation computer that simply accesses the IEC 61850 bus to retrieve the data and perform the state estimation.

The substation level state estimator uses these data along with a detailed substation model to generate the local state estimate. The substation model is a breaker oriented, instrumentation inclusive three phase model. This approach allows sharp bad data detection and identification, and alarm analysis and root cause identification. The advantage comes from the fact that at the substation level, there is greater redundancy of data than a typical centralized state estimator based on SCADA data alone. This redundancy facilitates the detection of bad data and system topology errors. In addition, the state estimator problem is much smaller in size and therefore powerful hypothesis testing methods are applied for both bad data and topology errors without substantial deterioration of the computational efficiency. Note that comprehensive hypothesis testing in centralized state estimators is a practical impossibility because of the large number of hypotheses associated with a large system. The use of the three-phase breaker-oriented model facilitates the identification of symmetric and asymmetric topology errors (one pole stuck, etc.). Traditional symmetric state estimators cannot identify asymmetric root cause events. The overall approach of the

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by Sakis Meliopoulos, George Cokkinides, Georgia Institute of Technology, George Stefopoulos, NY Power Authority,
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One only needs to validate the model.

SuperCalibrator is illustrated in Figure 3. The substation level State Estimation results are transmitted to the control center where the system wide state is synthesized. The substation state estimates and/or the system wide state is used for displays and other applications. Note that after the system has been successfully installed and tested, no further data processing is required at the control center. However, to verify the correct system installation, the state estimation coordinating algorithm is exercised. This algorithm is exercised only at the commissioning time and whenever GPS synchronization has been lost in one or more substations.

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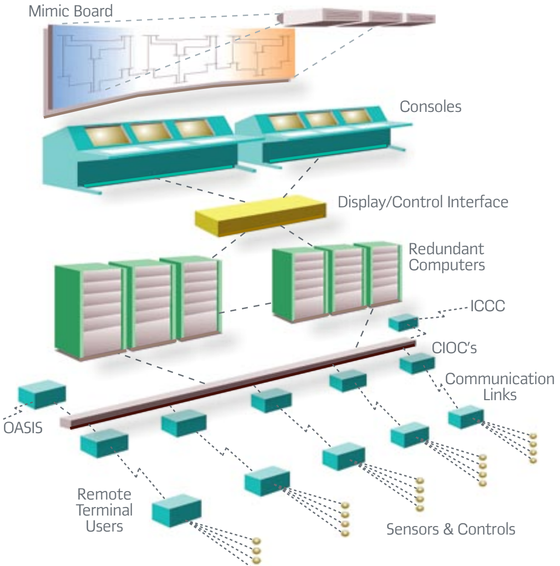
1 Conceptual View



The coordination algorithm checks the consistency of the estimated line flows obtained from the terminating substations. The estimates must be identical within the accuracy of the distributed state estimator.

In subsequent paragraphs brief descriptions of the algorithms involved are provided.

Distributed State Estimation Formulation

This section presents an overview of the basic building blocks of the distributed state estimator. Detailed description of all the blocks is given in subsequent sections. The basic building blocks are:

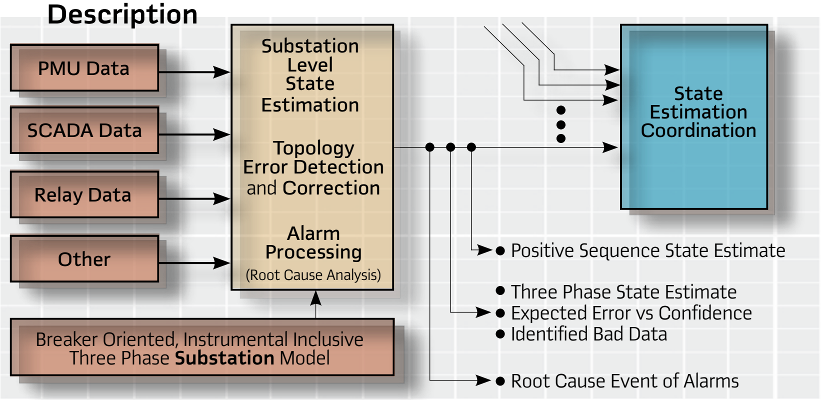
- The 3-phase breaker-oriented power system model
- The intelligent electronic device (RTU, relay, meter, disturbance recorder, PMU) with instrumentation model
- The substation level static state estimation method

A brief description of each of these blocks is given below.

Three-Phase Breaker-Oriented Model: Two sources of errors and biases for present-day state estimators are (a) system imbalances and (b) system asymmetries. These sources can be alleviated by using a three-phase breaker oriented model for the power system. And in particular, we use a physically based model from which the three-phase breaker-oriented model is extracted. 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.

IEDs/PMUs and Instrumentation Channel Model: An important issue is the accuracy of the available data. Specifically, GPS-synchronized equipment (PMUs) is in general higher precision equipment as compared to typical SCADA systems or relays. Conceptually, PMUs provide measurements that are time tagged with precision better than 1 microsecond and magnitude accuracy that is better than 0.1%. This potential performance is not achieved in an actual field installation because of two reasons: (a) different vendors use different design approaches that result in variable performance among vendors, for example use of multiplexing among channels or variable time latencies among manufacturers result in timing errors much greater than one microsecond, and (b) GPS-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 a typical PMU. For example,

2 Distributed State Estimator - Functional Description



A very important advantage of the SuperCalibrator is that it eliminates the need for tuning of the estimation process.

many utilities may use CCVTs for instrument transformers. We refer to the errors introduced by instrument transformers, control cables, attenuators, etc. as the instrumentation channel error. The end result is that "raw" phasor data from different vendors cannot be used as highly accurate data.

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 proposition. In the early 90's the authors directed a research project in which we developed calibration procedures for selected NYPA's high voltage instrument transformers. 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-synchronized pieces of equipment are known and the instrumentation feeding this equipment is also known.

We propose a viable and practical approach to correct for errors from instrumentation. Specifically, the models of the IEDs, PMUs and the associated instrumentation channel model is all integrated into a single model that provides the transfer function from the high voltage side to the output of the IEDs and PMUs. This model is also integrated with the three-phase breaker-oriented model that was described earlier. The end result is an accurate representation of the physical system by which the measurements are taken.

Substation Level Static State Estimation: The static state estimation algorithm utilizes the integrated model of the three-phase breaker-oriented instrumentation channel inclusive model and the set of measurements from meters, relays, PMUs, etc. (excluding frequency and rate of change of frequency) to perform a state estimation, bad data detection and identification, topology error detection and identification for the purpose of extracting the real time model of the system. The overall mathematical process is assisted with a number of pseudo-measurements. Additional details are provided next.

State and Measurement Set

The state is defined as the minimum information that completely describes the operating conditions of the substation. Consider for example a substation as it is illustrated in Figure 4. The substation is connected to four other substations via transmission lines. The state estimation problem is defined for the network that is included within the boundaries of the substation and the interconnecting lines. The state that needs to be evaluated is the state of the substation only. For reasons of developing the simplest possible implementation we also include the voltage variables at the other end of the transmission lines. However, the evaluation of these state variables is performed by utilizing measurements only at the local substation for the purpose of avoiding the requirement of obtaining and transmitting via communication channels measurements from other substations.

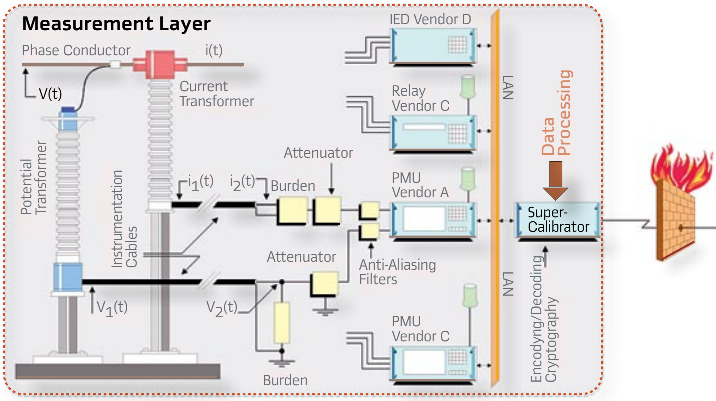
The substation level state is defined as the voltages everywhere in the substation and the other end of the transmission lines. It is important to recognize that at each bus of this system there may be four voltages, phase A, phase B, phase C and neutral voltage. Thus for the illustrated substation a total of 24 voltage phasors (states) are defined, eight inside the substation and 16 outside the substation.

Measurements: The measurements utilized in this approach are all available measurements in the substation mainly from SCADA, Relays, IEDs, fault disturbance recorders and PMUs. The measurements are categorized into GPS-synchronized and non-synchronized ones. Mathematically these two categories are treated differently.

The GPS-synchronized phasor measurement set consists of voltage and current measurements, both magnitude and phase in all three phases. Voltage measurements are direct state measurements. Current measurements can be expressed in terms of linear measurement equations with respect to the system state, provided that a rectangular coordinate formulation is used. Non-synchronized measurements consist of SCADA measurements of voltage and, possibly, current magnitude, active

The complexity of the model for the state estimation using the SuperCalibrator approach is higher compared to the traditional estimation, but there are significant advantages that fully justify the approach.

3 Illustration of the SuperCalibrator



by Sakis Meliopoulos, George Cokkinides, Georgia Institute of Technology, George Stefopoulos, NY Power Authority,
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and reactive power flows at each side of the substation transformer and on the substation end of the lines. Such measurements are typically obtained via analog measurement devices and are in general related to the system state via a set of non-linear equations. In our formulation such measurement equations are of degree at most quadratic. In addition to the actual measurements the approach is facilitated by a number of pseudo-measurements. These are defined below.

Pseudo-measurements of the voltages at the other end of the lines (*neighboring substations*): These pseudo measurements are illustrated in Figure 5. Given measurements of $\tilde{I}_S$ (all three phases) and $\tilde{V}_S$ (all three phases) of a line ***i*** at a substation ***k*** and a 3-phase model of the line allows the calculation of the voltage pseudo-measurement at the other end of the line (*neighboring substation*). Other pseudo-measurements are available and utilized.

Instrumentation Model

PMUs, SCADA, relaying, metering and disturbance recording use a system of instrument transformers to scale the power system voltages and currents into instrumentation level voltages and currents. Standard instrumentation level voltages and currents are 67 V or 115 V and 5 A respectively. These standards were established many years ago to accommodate the electromechanical relays. Today, the instrument transformers are still in use, but because modern relays, metering and disturbance recording operate at much lower voltages, it is necessary to apply another transformation 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. Figure 3 illustrates typical instrumentation channels.

Note that each component of the instrumentation channel will introduce an error. Of importance is the net error introduced by all the components of the instrumentation channel.

The instrumentation error can be computed by appropriate models of the entire instrumentation channel. It is important to note that some components may be subject to saturation (CTs and PTs), while other components may include resonant circuits with difficult to model behavior (CCVTs). The design should be such that during normal operating conditions these nonlinear phenomena do not occur, and indeed this is the case. Then, it is straightforward to model the instrumentation channel and compute the transfer function. The computed transfer function is integrated into the state estimation model.

Distributed State Estimator Algorithm

The formulation is presented with the following postulated model:

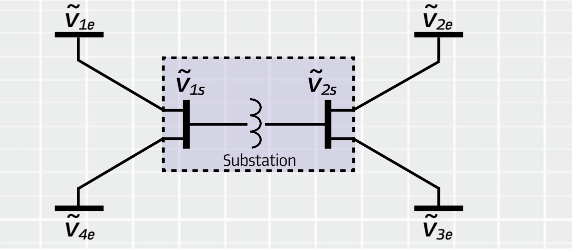
$$z = h(x) + \eta$$

where $\boldsymbol{z}$ is a vector of three phase measurements; $\boldsymbol{x}$ is a vector of the state (three-phase state); η is a vector of error; $\boldsymbol{h}$ is a vector function depending on the system modeling. The three-phase state estimator is formulated by selecting the three-phase state, the three-phase measurements and the three-phase system model. It is noted that if all measurements are synchronized, the state estimation problem becomes linear and the solution is obtained directly. In the presence of non-synchronized measurements and in terms of the above formulation, the problem can be made quadratic.

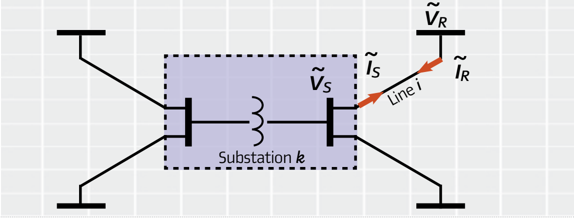
Quantification of SuperCalibrator Output Accuracy

The overall accuracy and performance of the SuperCalibrator can be evaluated using the concept of the confidence level (chi-square test) as in the case of the traditional state estimator. Again one has to identify the number of states, the number of measurements for the

4 State definition at: Substation level

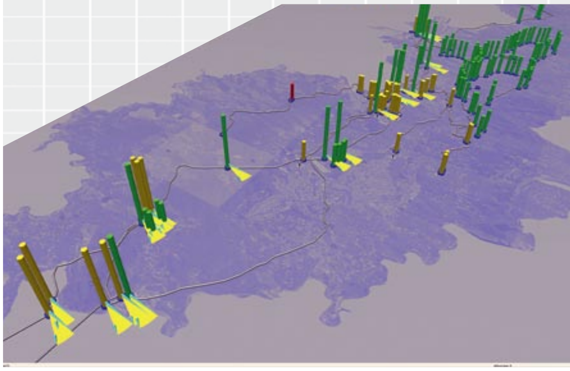


5 Pseudo-measurements of: Voltage at other end of lines



6 Visualization

A sample visualization of the VIWAPA system operating conditions using the results of the Distributed State Estimator



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purpose of computing the degrees of freedom. Then at the state estimate, the value of the objective function should be computed.

More specifically, with respect to the quality of state estimation, there are two related problems. The first one relates to the validity of the data (measurements). If the measurements are polluted with reasonable measurement error (within the specifications of the measuring instruments), and assuming there is enough redundancy, the state estimate will be reasonably accurate. However, if one or more data have large errors (due to a number of reasons), the state estimate will not be accurate. Thus, it is necessary to be able to detect and reject bad data. The second problem relates to the error transmitted to the state estimate from the measurement error. This error is measured with the standard deviation of the state estimate. It should be expected that in the presence of statistically reasonable measurement errors, the standard deviation of the state estimate should decrease as the redundancy increases.

Demonstration System Description

The SuperCalibrator based distributed state estimator has been implemented on the power system of the US Virgin Islands St. Thomas and St. John. The host utility is the USVI Water and Power Authority (VIWAPA). The St. Thomas and St. John electric power system is illustrated in Figure 7. It consists of a generating plant with eight units of total installed capacity near 190 MW, five substations and one under planning. The network is operated at 35 kV and 15 kV. The system is unique in having generating units connected directly to the 15 kV distribution network, and having unbalanced loads directly on circuits that are connected directly to the generators. The 35 kV transmission network consists of overhead circuits, underground cables, and submarine cables. This system has a very high R to X ratio and significant asymmetries. Furthermore, being an isolated system, it is profoundly affected by load changes, unlike typical US mainland interconnected power systems. As a consequence, blackouts are frequently occurring. In order to reduce blackout occurrence, VIWAPA has undertaken two initiatives: (a) review and coordinate the relaying scheme for the entire system, and (b) implement a system wide SCADA (using relays) with a fiber optic connection from each substation to the control center.

While these initiatives help to better operate and control the USVI power system, it is important to recognize that the system special characteristics (high R/X and unbalanced operation) impose special requirements on the operation control and protection tools. While traditional state estimators are not well suited for this system, the special requirements are well matched by a SuperCalibrator based state estimator.

The SuperCalibrator implementation uses a three phase system model including relaying, SCADA and fault recording instrumentation. All available measurements are utilized including measurements collected by the various relays and meters in the system, PMU's, and fault recording data. The distributed state estimator requires at least one PMU at each substation. Presently the VIWAPA's system has nine PMUs distributed at five subs.

Results

The results of the SuperCalibrator from each substation are transmitted to the control center where the state of the overall system is synthesized. There is no additional processing of the data at the control center other than tracking the performance of the system. The state of the overall system can be used to create a visualization of the operating conditions of the system. Several options for visualizations have been developed. Figure 6 illustrates such a visualization that shows the phase angles as pies and the voltage magnitude as cylinders. The cylinders change colors depending on their value and whether they are in specific user selected ranges, for example within plus or minus 4% of nominal value.

A limited capability of storing the results of the Distributed State Estimator has been also developed. The stored information can be displayed for further study of the history of the system. As an example, Figure 8 illustrates a zoom in view of the phase angles over a period of 26 seconds. The ability to store the data and play it back is very important. While this capability has not been fully developed presently, it is of high priority and it will enable to move from fault recording with individual relays and fault recorders to system disturbance recording and playback

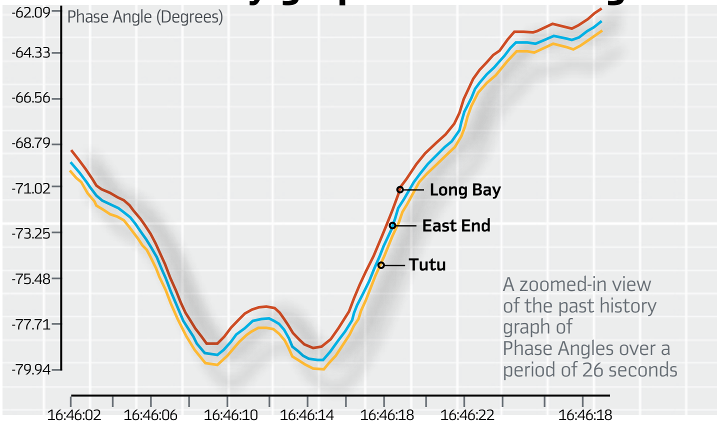
7 St. Thomas and St. John System

Single line diagram
of the St. Thomas and St. John Electric Power System

Additional advantages of the SuperCalibrator are:

- Utilization of full three-phase system models
- Inclusion of instrumentation channel modeling
- Utilization of all available data
- Distributed SE approach
- Data accuracy
- Minimization of transferred data accuracy

8 Past history graph of Phase Angles



A zoomed-in view of the past history graph of Phase Angles over a period of 26 seconds

by Sakis Meliopoulos, George Cokkinides, Georgia Institute of Technology, George Stefopoulos, NY Power Authority,
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capability. We expect that this capability will be completed soon.

Performance Evaluation

The performance evaluation of the distributed state estimator based on the SuperCalibrator is performed with three metrics. The first metric is based on the chi-square test utilized to provide the probability that the expected error of the estimated state values will be within a specific range. Because there are many data acquisition devices in any substation with different accuracy, we have introduced a normalization constant k defined as follows: if it is 1.0 then the standard deviation of each measurement is equal to the accuracy of the meter with which this measurement was obtained. If different than 1.0 then the standard deviation of the measurement error equals the accuracy of the meter times k. This allows us to characterize the accuracy of the estimated state with only one variable. Figure 9 shows the parameter k versus confidence level. This is equivalent to providing the expected error (variable k times the standard deviation of the measurement error) versus probability (confidence level).

The second metric relates to the overall response speed of the state estimator. The way that the system has been developed is as follows: the user selects how often he would like to execute the state estimator. If the system can support this speed, it will continue to work and provide the state estimation results at the user selected rate. If not, a diagnostic is issued and the speed is reduced by a factor of 2. Presently the system has been set to perform the state estimator four times per second and runs without any problems. This speed is a breakthrough for state estimators.

The communications between the different parts was a challenging task, but the great payoff was the ability to perform state estimation four times a second.

The third metric is transparent to the user. Its operation is as follows. The SuperCalibrator for substation A provides the estimated values of the voltages at substation A and all next substations. Assume that substation X is one of the next substations. The SuperCalibrator at substation X provides the estimated values of the voltages at substation X and at the next substations (substation A is one of them). Therefore, we have two estimated values for a voltage at substation A: the estimated value from the SuperCalibrator in substation A and from the SuperCalibrator at substation X. Both these values are available at the control center since the SuperCalibrator from each substation sends the estimated values to the control center. There, the two values are compared. If their difference is above the expected error with probability 99% (see second metric) then a flag is issued. In this case, the difference is resolved by setting up an estimation problem that includes the substation where the discrepancy occurred and all next substations. During the demonstration we monitored this function between the plant substation and the Longbay substation and the condition never triggered. The results of the comparison can be tracked to provide the "observed" performance of the SuperCalibrator. Figure 10 provides the difference between the estimated values of the same physical quantity over a period of time (*lower left graph*). The indicated quantity is the phase angle of phase A voltage phasor at the East End substation 35 kV bus. Note that the difference is within 0.08 degrees on an absolute base.

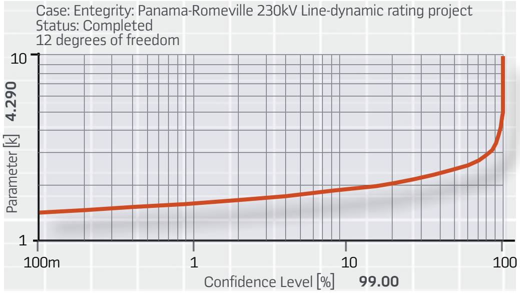
Scalability

The 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 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. Even for this and larger substations the response is sub-second. ■

This performance is scalable to any size system since the computations are fully distributed.

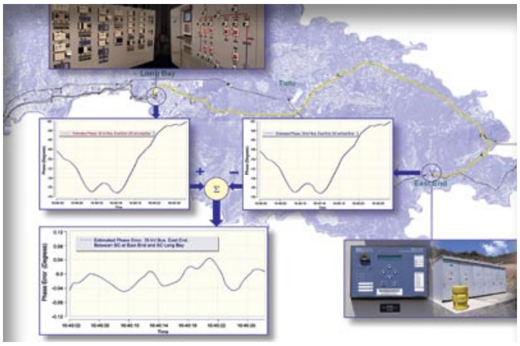
9 Value vs confidence level

Provides an actual curve for a sample result of the SuperCalibrator for the Longbay substation in St. Thomas



10 Tracking

Tracking of the Phase Angle Difference between the estimated phase a phasor at then 35 kV bus at east end substation from two different SuperCalibrators



Clinton Hedrington obtained his B.S. in Electrical Engineering from North Carolina Agricultural and Technical State University in 2000. He has been employed with the Virgin Islands Water and Power Authority in various capacities. From 2005-2006 he was promoted to Electrical Engineer III and in 2006 he entered the management role as Transmission and Distribution Manager. In 2008 Clinton became the Director of Transmission and Distribution and presently remains in that capacity.