Abstract—Both the communication limitation and the measurement properties based algorithm become the bottleneck of enhancing the traditional power system state estimation speed. The availability of synchro-phaser data has raised the possibility of a linear state estimator if the inputs are only complex currents and voltages and if there are enough such measurements to meet observability and redundancy requirements. The fiber optics communication network and advanced distributed computing and database technology provide the platform for fast state estimator. Moreover, the new digital substations can perform some of the computation at the substation itself resulting in a more accurate two-level state estimator. The main contribution of this paper is to propose a two-level fast linear state estimator based on the synchronized phasor measurements infrastructures.

We described the layered architecture of databases, communications, and the application programs that are required to support this two-level linear state estimator and the mathematical algorithms that are different from those in the existing literature. This paper also describes potential benefits of applying fast state estimator and how it can provide a pathway to the smart transmission grid of the future.

Index Terms—PMU, State Estimation, Energy control centers.

I. INTRODUCTION

Traditional power system steady state estimator is a software function in control center that connected to the back-end of the Supervisory Control and Data Acquisition (SCADA) system and provide a power system real-time model to other energy management software functions. The period of obtaining a system state varies from 10s seconds to even minutes. The reasons of slowness are mainly combined of both the communication system limitation and measurements properties. In one hand, the communication system that supports SCADA is a star connection between the control center and all the substation remote terminal units (RTU), which gather the substation data and are polled by the SCADA with a periodicity of a few seconds. The low bandwidth, usually microwave under 56Kb/s, communication links of the 70s could not support faster periodicities. The real-time measurement set used by the SE is a subset of the measurements gathered by SCADA and some care was taken to make sure that this subset was gathered (polled) within a small, typically 10s, time window. In another hand, the real-time measurements as inputs to state estimator are typically active and reactive power flows, injections, and current and voltage magnitudes, some of which make the measurement functions nonlinear. Thus iterations exist in the calculation process and the computation time cost will depend on iteration times and convergences.

With the development of advanced power system measurement infrastructures and information technologies, especially communication and database technologies, it is possible to enhance the state estimation performance by solving those two critical problems. Synchronized Phasor Measurements (PMUs) can be used in power system steady state estimation to change the measurement properties to eliminate iterations. Fiber optics network and distributed computation platform can eliminate both hardware and software bottlenecks of SCADA communications networks. With applying strict time alignment to measurements, the quasi-static condition can be fully satisfied to ensure the estimation period cut to milliseconds level.

We proposed a two-level, substation level and control center level, PMU based linear state estimator in this paper to carry out a fast power system state estimation scenario. In chapter II, the algorithms are described first followed by some experimental results. In chapter III, we present the architecture and information platform of the proposed state estimator. With implementing the two-level fast state estimation, wide-area monitoring systems (WAMS) and wide-area control systems (WACS) will benefit and so do the future smart grid applications.

II. TWO LEVEL LINEAR STATE ESTIMATOR

Theoretical fundamentals of the Synchronized Phasor Measurements based linear state estimator are introduced in [1], [2]. If all the analog measurements were synchronized currents and voltages, then the state estimation equations would be linear. In this research, we propose a two-level infrastructure of applying the linear state estimator into power system. The three main functions, topology processing (TP), state estimation solution (SE) and bad data detection-identification (BD), of the state estimator is divided into two levels: substation level and control center level. It should be mentioned here that most publications on two-level SE refer to the coordination of state estimation between hierarchies of control centers, such as between several balancing authorities and their reliability coordinator. Few papers [3], [4] consider substation based SE calculations and the considerations are
quite different.

A. Substation Level Linear State Estimator

At the substation level, we propose to use bus-section/circuit-breaker model introduced in [5], [6] instead of bus/branch model to handle each voltage level separately so that we only deal with zero-impedance circuits (the transformer branch impedances will be considered at the control center level).

In each kV system, as there is no impedance, 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 follows:

\[ \tilde{z}_j = A_{KCL} \tilde{x} + \tilde{r}_j \]  

where \( \tilde{z}_j \) 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 \( \tilde{r}_j \) is the corresponding residue vector.

The equations for the current measurements at each circuit breaker have the obvious relationship:

\[ \tilde{z}_{cb} = I \tilde{x} + \tilde{r}_{cb} \]  

where \( \tilde{z}_{cb} \) 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:

\[ \tilde{z} = \begin{pmatrix} \tilde{z}_j \\ \tilde{z}_{cb} \end{pmatrix} = \begin{pmatrix} A_{KCL} & I \\ I & \tilde{r}_{cb} \end{pmatrix} \begin{pmatrix} \tilde{x} \\ \tilde{r}_j \end{pmatrix} = H \tilde{x} + \tilde{r} \]  

This is a linear state estimation problem, so we can find the estimation solution [2] 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 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.

It should be mentioned again that the processing of analog data at the substation voltage levels assume that there are enough phasor measurements available to provide observability and redundancy. The fact that only voltage and current phasors are utilized leads to the linear formulation.

B. 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 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.

III. ARCHITECTURE AND INFORMATION PLATFORM

A. Communication System

The proposed communication infrastructure is shown in Fig 2. In each substation, we use a high bandwidth LAN for intra-substation communication and each substation server collects all the synchro-phasor 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.

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 [7]. 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 Fig. 3 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.

**B. Distributed Database**

The substation level static data and real-time data will all be needed for the substation level calculations in the proposed SE, hence these databases will need to reside at the substation. Then the control center will need a much smaller database. This distributed database is described below.

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 Fig 3.

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.

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] 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 [9] which is backed up locally and at the backup control center.

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.

**IV. CONCLUSION**

Synchro-phasor measurements 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 and the corresponding architecture include:

- Its ability to handle the volume of phasor data produced by every IED in the substation. Given that the SE will require enough phasor data in each substation for observability and each measurement is gathered at 30 or 60 samples per second, the volume of data gathered locally is several magnitudes more than in the typical RTU today.
- The two-level state estimator does a lot of the computing at the substation thus alleviating the need to transfer this large volume of data to the control center.
- The distributed database is designed so that the bulk of the data can be stored at the substation with only the data needed to solve the whole system has to be transferred to the control center.
- The publisher-subscriber communication system only moves the data where it is needed. Thus the SE calculations at the control center subscribes to only a small subset of the measurements as well as the calculated results from the substation level SE.

The main characteristic of this architecture is that it can be phased in one substation at a time. Thus the most recent and highest voltage substations which already have digital processing and LAN can be the first ones to conform to this architecture. We show how this can coexist with the present day SCADA architecture. As more substations are retrofitted, they can be brought into the linear state estimator.

The proposed two-level linear state estimator will also bring the grid a novel monitoring and control infrastructure as:

1. Fast state estimation can provide substation visualization which combine bus-section/circuit-breaker and bus/branch model together to provide detailed substation visualization.

2. Fast state estimation (fast modeling) extends the application of power system steady-state estimation to dynamic analysis, WAMS and WACS can benefit from the results. As long as the sampling time is also synchronized, quasi-static condition will be fully satisfied then the static state estimator can run in milliseconds level to provide a dynamic model.

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VI. REFERENCES


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