DESIGN OF A TWO-LEVEL POWER SYSTEM LINEAR STATE ESTIMATOR

By

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Abstract

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The availability of synchro-phasor 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. 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 objective of this research is to develop a two-level linear state estimator processing synchro-phasor data and estimating the states at both the substation level and the control center level.

Both the mathematical algorithms that are different from those in the present state estimation procedure and the layered architecture of databases, communications and application programs that are required to support this two-level linear state estimator are described in this dissertation. Besides, as the availability of phasor measurements at substations will increase gradually, this research also describes how the state estimator can be enhanced to handle both the traditional state estimator and the proposed linear state estimator simultaneously. This provides a way to immediately utilize the benefits in those parts of the system where such phasor measurements become available and provides a pathway to transition to the smart grid of the future.

The design procedure of the two-level state estimator is applied to two study systems. The first study system is the IEEE-14 bus system. The second one is the 179 bus Western Electricity Coordinating Council (WECC) system. The static database for the substations is constructed from the power flow data of these systems and the real-time measurement database is produced by a power system dynamic simulating tool (TSAT). Time-skew problems that may be caused by communication delays are also considered and simulated. We used the Network Simulator (NS) tool to simulate a simple communication system and analyse its time delay performance. These time delays were too small to affect the results especially since the measurement data is time-stamped and the state estimator for these small systems could be run with subseconf frequency.

Keywords: State Estimation, Synchro-Phasor Measurement, Distributed System, Energy Control Center, Substation, Time-skew

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Chapter 1. Introduction

1.1 Motivation

Power system state estimation which was introduced in 1969 by Fred Schweppe in [1] 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 power flow type system model. It plays an important role in modern Energy Management Systems (EMS) by providing a complete, consistent, accurate and reliable database as an input to other key functions of the EMS system, such as Contingency Analysis, Optimal Power Flow, Security Monitoring, Automatic Voltage Control and Economic Dispatch Control. It is also a software function that is 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 gathered from the Remote Terminal Units (RTUs) installed in substations while the 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 usually consists of active and reactive line power flows, active and reactive power injections, bus voltage magnitudes and (sometimes) line current magnitudes, from the substation to the control center sampled at a slow rate. As these measurements are nonlinear with respect to the bus voltage angles and magnitudes that are defined as the power system states, iterations are needed in the process of state estimation which make the estimation time 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. These phasor voltage and current measurements are linear with respect to the power system states and could eliminate the iterative procedure in state estimation. The concept of linear state estimation and the corresponding observability analysis are introduced in many articles and publications [2], [3]. The PMU measurements are collected and transferred to the applications by Phasor Data Concentrators (PDCs) which are similar to the RTU based SCADA system but can handle higher transfer rates.

Phasor measurements are increasingly being installed in substations, and for the state estimator, synchronized phasor measurements can be especially useful in the system level. Unfortunately, most phasor measurements are only used locally in the substations for protection and other control functions, and their usefulness to the state estimator is only being realized lately. With the development of microprocessor applications in the substation many calculations can be done at the substation level and many such substation data processing algorithm and software are also introduced in [4]-[7]. Thus these redundant phasor measurements can play an important part in the wide area measurement systems (WAMS) and state estimators.

Besides, a major problem with the present SCADA is that the raw digital data such as the circuit breaker statuses do not have any redundancy and errors in status data cannot be detected, and these bad data always create fatal topology errors in modeling the system networks for state estimation. Some of the raw digital bad data can be eliminated at the substation with the help of the redundant substation analog measurements shown in [8]-[10]. Phasor measurements in the substation can be particularly helpful in doing this.

In this dissertation, we create a systematic two-level, substation level and control center level, state estimator. We use the phasor measurements in the substation as inputs to the substation level state estimator to estimate both the analog and digital states of the substation. The control center level state estimator takes advantage of the substation level state estimator results to get a more efficient and accurate estimation of the whole system. As the transferred data are no longer from RTUs and the traditional SCADA system cannot handle the data volume and transfer rate needed by the PMU data, we propose and build a distributed information system to be the platform of the state estimator. We also analyse the different aspects of this state estimator including algorithm performance, communication and database requirements, time alignment, and other critical issues which play a part in the whole procedure.

1.2 Objectives and Contributions

The dissertation is mainly focused on designing a synchronized phasor measurements based two-level state estimator and the corresponding information architecture. With the redundant phasor measurements in the substation, we can design the substation level state estimator to estimate both the digital states like circuit breaker statuses and the analog states like bus voltages, circuit breaker currents. After estimating the phasor states locally, GPS time signals are used to print the time stamp on the estimated states to also make them synchronized phasor measurements. Then the control center or other wide area monitoring and controlling systems can receive a set of estimated digital and analog synchronized phasor states instead of the raw data from the substation. With the substation level state estimators implemented in most substations of the system, we can use the synchronized phasor measurements to construct a linear state estimator to estimate the whole system states. A lot of calculations are done at the substation level to eliminate digital and analog bad data being transferred to the control center.

To achieve that, a novel communication and database platform will be used instead of the SCADA system as the transferred data amount and refreshing rate requirements of such a state estimation system are beyond the capacity of the traditional one. So GridStat [11], [12] will be used as a communication middleware for the state estimation application. A distributed database, both static and real-time, to support the two-level state estimator and a Publisher-Subscriber scheme as the communication mode were designed and implemented on GridStat.

In conclusion, the following contributions are achieved in this study:

- Architectures and respective algorithms of a synchronized phasor measurement based two-level linear state estimator are designed. The lower level is the substation level state estimator while the higher level is the control center level state estimator.
- Functional programs of each level state estimator are proposed. Some of the computational tasks of the traditional state estimator are moved to the substation level to provide a faster and more reliable result.

- A transitional hybrid two-level state estimator is proposed where the linear state estimator can co-exist with the traditional algorithm as existing substations are transitioned to the new architecture
- A distributed system including a distributed data base and a middleware communication system which can be applied for not only state estimation but also other smart-grid applications is proposed.

1.3 Organization of This Dissertation

The dissertation includes seven chapters. Chapter I introduces the motivations, objectives, and contributions of the completed work. As the state estimator is constructed by four functional programs, we will discuss each one of them sequentially while introducing every state estimator. Chapter II reviews the traditional state estimation problem—its definition, formulation, and corresponding functional programs. With more and more Phasor Measurement Units (PMUs) installed in the system, we need to propose both new information architectures and state estimation algorithms to make full use of them. Chapter III then demonstrates a two-level linear state estimator which uses the PMU measurements to estimate power system states linearly. This chapter specifies the two levels: substation level and control center level separately and in each level, the topology processer, observability check, and state estimation are described sequentially. At either estimation level we use the same process to do bad data detection and identification as in the traditional state estimator, although the detection of bad status data is new. The installation of PMUs at every substation to achieve this two-level linear state estimator is a long process, so in Chapter IV, a transitional two-level state estimator is introduced which can deal with the combined PMU measurements and traditional RTU measurements for state estimator. The assumption in the transitional state estimator is that the PMU measured substations are connected together and construct a linear area while the rest are nonlinear areas. Linear state estimator is used for the linear area and the estimated states can be used to generate high weight pseudo-measurements for the nonlinear area. This algorithm can be viewed as using the more accurate measurements to verify the less accurate ones and the corresponding observability analysis program can also take advantage of the linear area. Chapter V provides a novel information architecture which is more efficient and reliable than the SCADA system including communication and distributed database systems. The transitional ones are also provided. Beside those, in Chapter VI, we provide a systematic simulation process to analyze the performance of the state estimator and the corresponding information platform. Given an EMS power flow file, this simulator can generate both the static database and the real-time database and analyze the real-time performance of the state estimator and communication time-skew problems which is very important to the applications of PMUs. Following a summary of the contributions of the completed work, Chapter VII offers suggestions for future research and programs whose performances can be enhanced by using this state estimator.

Chapter 2 Power System Linear State Estimator

In this chapter, both the traditional state estimator and synchronized phasor measurement based linear state estimator are introduced, such as problem definition, formulation, solution, and the corresponding functional programs. We first review the traditional power system state estimation including topology processing, observability analysis, state estimation, and bad data detection. Then we introduce Phasor Measurement Units (PMUs) and the linear state estimator based on it. The linear state estimator in this chapter is a general formulation of state estimation in complex plane which can be used to both bus-branch system model and circuit-breaker based substation model.

2.1 Traditional Power System State Estimator

Traditional State Estimator function in a control center is a software function that connects to the back-end of the Supervisory Control and Data Acquisition (SCADA) system. It receives the data transferred from RTUs by SCADA system and provides all other application, like the on-line contingency analysis [13], with reliable data for the system steady-states (complex bus voltages). The measurement data used by the State Estimator is a subset of the 'real-time' database in SCADA commonly includes:

- Power Flows: real and reactive power flows measured at the terminal buses of a transmission line or transformer.
- Power injections: real and reactive power injected at the system buses.
- Voltage magnitude: voltage magnitude measurements at system buses.

- Current magnitude: current magnitude measurements on the transmission lines or transformers.
- Circuit breaker status: open/close status of a circuit breaker.

The State Estimator also needs connectivity and system parameter data that are so called as “static” database and always stored in the control center including:

- Circuit breakers connectivity database: describes the connectivity between bus sections.
- Bus section connectivity database: describes the equipment connected to this bus section.

With both the real-time database and static database, State Estimation process can solve the system state by the executing the following functions [13] with the order shown in Fig. 2.1:

- Topology processing: uses the real-time circuit breaker status with the substation and system level topology to determine the connectivity of the whole network [14];
- Observability analysis: Given a set of measurements, determines if there exists a state estimation solution for the entire system or part of the system, and identifies the unobservable branches and the observable islands in the system if exist [15]-[19].
- State estimation: solves for the complex voltages at each bus from the real-time analog measurements;
- Bad data processing: tests the solution to find bad measurements (and if found, reruns the SE solution without the bad data) [20].

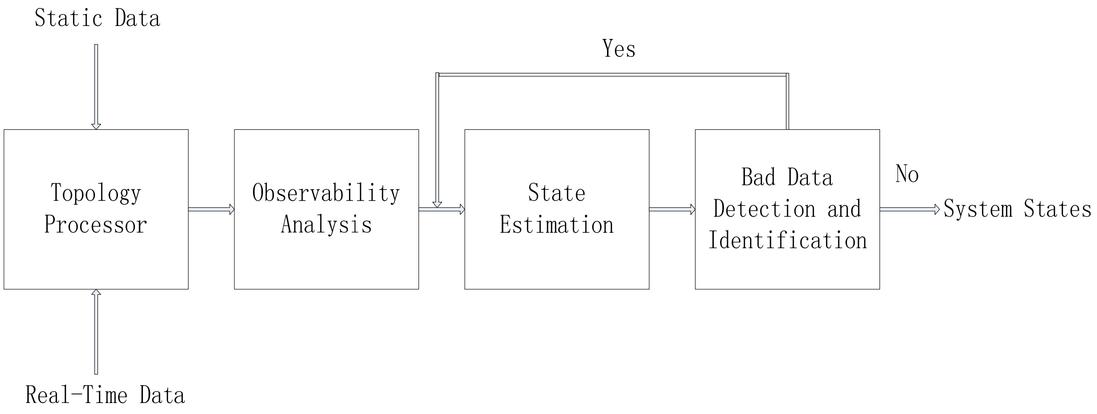


Fig. 2.1 Traditional State Estimator Flow Chart

2.1.1 Topology Processing

The topology processing function program is to use the status of the circuit breakers and the network connectivity in terms of bus-sections and circuit breakers to determine the present topology of the network. In another word, the network topology processing uses the status of the circuit breakers to retrieve the system bus-branch model from the circuit breaker oriented model which is in the static database. In the static database, all equipment, such as generators, load feeders, shunt capacitors, transformers, transmission lines, etc., are connected to bus-sections while the bus-sections in the same voltage level at a substation may be connected together by circuit breakers. Then in the output of the topology processor, all the equipments should connect to buses and some of them like generators, load feeders, shunt capacitors are injections while some of them like transformers and transmission lines are branches. Besides, the topology processor should identify network islands and discard non-energized islands out of the system. The method in [14] is widely used in practice and the substation level topology processor and control center level topology processor in this dissertation will be based on this tree search algorithm.

This algorithm is consisted of three steps. The first step is to use the circuit breaker status and circuit breaker oriented model in substation to determine the topology of each substation. At the beginning, each bus-section is considered a potential separate bus. Then the circuit breaker statuses are processed one by one. Once a circuit breaker is closed, then the two buses connected to it will be merged into one bus. At the end of this tree search process, all bus-sections connected by closed circuit breakers become part of one bus. In the tracking mode, however, only those substations in which circuit breaker status changes have taken place need to be processed. This step is usually very fast as the number of status changed during each cycle is normally quite small.

The second step is to use the substation topology gotten in the first step to determine the topology of the whole network and identify all the energized network islands. The tree search process used here is identical to that in the first step. Instead of bus-sections being combined by closed circuit breakers into buses, the buses are combined by branches into islands. After the tree searching, all the islands without generators are identified as non-energized islands and ignored for the next step.

The third step is to tabulate all the equipment connected to the buses. Since the equipment connected to each bus section is known and the bus-sections constituting a bus are known from the first step, the connectivity of the equipment to the buses can be established. The tables produced should be structured for easy use by subsequent programs. For example, each equipment type can be processed into separate tables to accommodate generator control, transformer control, or shunt switching algorithms in later programs. Generator and load buses are identified in this step and slack buses may be identified for each island.

We can see from the topology processor algorithm that, all the works can be divided into substation level and system level. The first and the part of the third step, which is tabulating the connectivity of the equipment to buses, can be done at each substation. The second step and another part of the third step, which is identifying bus properties, can be done at the control center. So with the help of many substation computation technologies the needs of substation level state estimator, we can move some of the work load into substation to reduce the burden of computation and storage of control center. We specify those functional programs and architectures in the following contents.

2.1.2 Observability Analysis

Given a set of measurements, determining if the entire state vector of bus voltage magnitudes and angles throughout the network can be estimated or parts of them can be estimated is so called as power system observability analysis. Once all the state can be estimated, the network is said to be observable. Otherwise the observable parts are names as observable islands. The observability algorithms can be mainly classified into two categories: numerical observability and topological observability.

2.1.2.1 Numerical Observability

Numerically, as introduced in [16], when the rank of the Jacobian matrix of $h(x)$ equals the number of states, the network is observable. When the DC power flow model is used, if the network is numerical observable, the rank of the matrix $\overline{\mathbf{H}}$ which is obtained from the linearized measurement function Jacobian $\mathbf{H}$ by deleting any column is of full rank. In another word, the rank of the matrix $\mathbf{H}$ needs to be the dimension of the state vector minus one. Otherwise unobservable islands exist in the network. A numerical test for observability based on triangular decomposition of the gain matrix $\mathbf{G}_{\theta}$ is proposed in [17]. If the system is observable is equivalent to if $\mathbf{G}_{\theta}$ can be successfully factored without encountering any zeros in the diagonal. Otherwise we can either add pseudo-measurements of bus voltage angles or power injections on the unobservable buss which correspond to the zero diagonal elements or just leave them as unobservable island and identify the other observable islands.

This numerical observability analysis is conceptually simple and the numerical routines are already needed for the state estimation. But as a numerical algorithm, the round-off errors (rounding errors) always make the process of determining if the diagonal entry is zeros difficult.

2.1.2.2 Topological Observability

Without using the actual numerical value of measurement, topological observability algorithms only use information about the network and measurement topology to determine if the whole network is observable or identify the observable islands. The necessary and sufficient condition for a network to be observable is that it contains at least one observable spanning tree. If not, then the topological observability analysis program tries to find a maximal forest of full rank for the network and each tree in the forest is an observable island, or use some pseudo-measurements to create such a spanning tree of the network to ensure the observability. The theoretical fundamentals of the topological observability are introduced in [15] and some related algorithms are introduced in [15], [18], [19].

The main procedure of determine the maximal forest of full rank is divided into two steps. The first step in each topological observability analysis algorithm is the same: assigning all the line flow measurements to the corresponding branches to construct a fundamental spanning forest and identify the boundary buses which connect these trees and unmeasured nodes. The second step is to assign injection measurements to one branch connected to it. As the injection measurement can be assigned to any of the branches incident to the measured bus. Different algorithms may use different ways to solve this problem. The algorithm in [15] uses an algorithm similar to the network flow algorithm to enlarge the spanning forest to an observable spanning tree, while in [19] augment sequences based algorithm was used to solve the same problem. There also exist other methods like [21], [22] to solve the observability problem without numerical computation.

2.1.3 State Estimation

The state estimation functional program is to estimate the bus voltage phasors by using measurements and the corresponding measurement functions obtained from the network model. The most widely used way is the maximum likelihood estimation (MLE). In power system, the measurements errors are always assumed to have the independent Gaussian distribution with zero mean. So the MLE problem can be obtained by solving the following optimization problem:

$$\begin{aligned} &\text{Min } \sum_{i=1}^{m} W_{ii} e_i^2 \\ &\text{s.t. } z_i = h_i(\mathbf{x}) + e_i, \quad i = 1, \dots, m \end{aligned} \tag{2.1}$$

where z_i is the i^{th} measurement, $h_i()$ is the i^{th} measurement function, $\mathbf{x}$ is the state vector, e_i is the error of z_i, and W_{ii} is the weight of z_i. m is the total number of measurements.

The solution of this optimization problem is called the weighted least squares (WLS) estimator for $\mathbf{x}$. As the assumptions of error distribution, we have:

- $E(e_i) = 0$
- $Cov(\mathbf{e}) = E[\mathbf{e} \bullet \mathbf{e}^T] = \mathbf{R} = diag\{\sigma_1^2, \sigma_2^2, \dots, \sigma_m^2\}$

where σ_i^2 is the standard deviation of the measurement error.

Hence the WSL problem can be transformed to the following form:

$$\text{Min } J(\mathbf{x}) = \sum_{i=1}^{m} (z_i - h_i(\mathbf{x}))^2 / R_{ii} \tag{2.2}$$

where R_{ii} is the i^{th} diagonal entry of the covariance matrix $\mathbf{R}$ and $W_{ii} = 1/R_{ii}$.

To solve an optimized point of such a convex function, we need to satisfy the following condition:

$$g(\mathbf{x}) = \frac{\partial J(\mathbf{x})}{\partial \mathbf{x}} = -\mathbf{H}^T(\mathbf{x})\mathbf{R}^{-1}[\mathbf{z} - \mathbf{h}(\mathbf{x})] = 0 \tag{2.3}$$

where $\mathbf{z} = [z_1, z_2, ..., z_m]^T$ is the measurement vector, $\mathbf{h}() = [h_1(), h_2(), ..., h_m()]^T$ is the measurement function vector, and $\mathbf{H}(\mathbf{x}) = [\frac{\partial h(\mathbf{x})}{\mathbf{x}}]$ is the measurement Jacobian matrix.

By Newton's method, we can solve (2.3) by expanding the nonlinear function $g(\mathbf{x})$ into its Taylor series:

$$g(\mathbf{x}) = g(\mathbf{x}^k) + G(\mathbf{x}^k)(\mathbf{x} - \mathbf{x}^k) + o(x^2) = 0 \tag{2.4}$$

where $G(\mathbf{x}^k) = \frac{\partial g(\mathbf{x}^k)}{\partial \mathbf{x}} = \mathbf{H}^T(\mathbf{x}^k)\mathbf{R}^{-1}\mathbf{H}(\mathbf{x}^k)$ is called as the gain matrix.

With neglecting the high order terms, we have the iterative solution:

$$\mathbf{x}^{k+1} = \mathbf{x}^{k} - G^{-1}(\mathbf{x}^{k})g(\mathbf{x}^{k}) \tag{2.5}$$

where k is the iteration index, $\mathbf{x}^{k}$ is the solution vector at iteration k.

As we discussed in 2.1.2, the system if observable is equivalent to the gain matrix is invertible. So without considering if the system is so, the following formula is more useful in computation:

$$G(\mathbf{x}^{k})(\mathbf{x}^{k+1} - \mathbf{x}^{k}) = \mathbf{H}^{T}(\mathbf{x}^{k})\mathbf{R}^{-1}[\mathbf{z} - \mathbf{h}(\mathbf{x}^{k})] \tag{2.6}$$

2.1.4 Bad Data Detection and Identification

Bad data due to various reasons such as random errors and telecommunication medium errors always exists in the measurements set. These bad data can affect the estimation result heavily so bad data detection and identification is an essential function of the state estimator. When using WLS estimation method, this function program can be done by processing the measurement residuals. The performance of this function program also depends on the redundancy of the measurement set and the number of bad data. If the measurements are not redundant enough, there may be critical measurements, critical pair of measurements, and critical k-tuple of measurements [23]. Besides, bad data also appear in several different ways depending upon the type, location and number of them. They can be classified as: (1) single bad data which means only one of the measurements in the entire system has a large error; (2) multiple bad data which means more than one measurement have errors. The multiple bad data can again be further classified into: Multiple non-interaction bad data, multiple interacting but non-conforming bad data, and multiple interacting and conforming bad data [24]. In this section, the commonly used method to detect bad data, the Chi-squares test, and the method to identify bad data, the Largest Normalized Residual (LRN) test is introduced.

From random theory, we know that if a set of N independent random variables X_1, X_2, …, X_N, where each X_i has the Standard Normal distribution $X_i \sim N(0,1)$, then the random variable $Y = \sum_{i=1}^{N} X_i^2$ has a χ_N^2 distribution with N degrees of freedom. For power system state estimation, the object function in (3.2) can be written as:

$$J(\mathbf{x}) = \sum_{i=1}^{m} e_i^2 / R_{ii} = \sum_{i=1}^{m} (e_i / \sqrt{R_{ii}})^2 = \sum_{i=1}^{m} (e_i^N)^2 \tag{2.7}$$

where $e_i^N \sim N(0,1)$.

Then $J(\mathbf{x})$ has a Chi-squares distribution with $m-n$ degrees of freedom. $m-n$ is the number of redundant measurements in the power system, m,n being the number of measurements and states respectively.

So the WLS state estimation function can be used the test for bad data. The steps are as follows:

- Solve the WLS estimation problem and compute the objective function:

$$J(\mathbf{x}) = \sum_{i=1}^{m} \frac{(z_i - h_i(\overline{\mathbf{x}}))^2}{\sigma_i^2} \tag{2.8}$$

where $\bar{\mathbf{x}}$ is the estimated state vector with dimension n

- Look up the value from the Chi-squares distribution table corresponding to a detection confidence with probability p (e.g. 0.95) and $m-n$ degrees of freedom. Say this value is $\chi^2_{m-n,p}$.
- Test if $J(\mathbf{x}) \geq \chi^2_{m-n,p}$. If so, then bad data is detected, otherwise there is no bad data in the measurement set.

Once the bad data is detected in the measurement set, it should be identified and eliminated from the measurement set. Largest Normalized Residue (LNR) method which uses the properties of the residue is widely used today's single bad data identification program. (At the same time, LNR can also be used as bad data detection.) Consider the linearized measurement equation:

$$\Delta\mathbf{z} = \mathbf{H}\Delta\mathbf{x} + \mathbf{e} \tag{2.9}$$

Then the WLS estimated result is given by:

$$\Delta\bar{\mathbf{x}} = (\mathbf{H}^T\mathbf{R}^{-1}\mathbf{H})^{-1}\mathbf{H}^T\mathbf{R}^{-1}\Delta\mathbf{z} = \mathbf{G}^{-1}\mathbf{H}^T\mathbf{R}^{-1}\Delta\mathbf{z} \tag{2.10}$$

and the estimated value of measurement:

$$\Delta\bar{\mathbf{z}} = \mathbf{H}\Delta\bar{\mathbf{x}} = \mathbf{K}\Delta\mathbf{z} \tag{2.11}$$

where $\mathbf{K} = \mathbf{H}\mathbf{G}^{-1}\mathbf{H}^T\mathbf{R}^{-1}$ is called hat matrix. And note that:

$$\mathbf{K}\mathbf{H} = \mathbf{H}\mathbf{G}^{-1}\mathbf{H}^T\mathbf{R}^{-1}\mathbf{H} = \mathbf{H} \tag{2.12}$$

Then the measurement residue can be written as:

$$
\begin{aligned}
\mathbf{r} &= \Delta\mathbf{z} - \Delta\bar{\mathbf{z}} \\
&= (\mathbf{I} - \mathbf{K})\Delta\mathbf{z} \\
&= (\mathbf{I} - \mathbf{K})(\mathbf{H}\Delta\mathbf{x} + \mathbf{e}) \\
&= (\mathbf{I} - \mathbf{K})\mathbf{e} \\
&= \mathbf{S}\mathbf{e}
\end{aligned} \tag{2.13}
$$

where $\mathbf{S}$ is called as the residual sensitivity matrix which represents the sensitivity of the measurement residuals to the measurement errors. Also note that $\mathbf{S}$ has the properties:

$$\mathbf{S} \cdot \mathbf{S} \cdot \ldots \cdot \mathbf{S} = \mathbf{S} \tag{2.14}$$

$$\mathbf{S} \cdot \mathbf{R} \cdot \mathbf{S}^T = \mathbf{S} \cdot \mathbf{R} \tag{2.15}$$

Then the covariance matrix $\mathbf{\Omega}$ of the error term can be calculated as:

$$
\begin{aligned}
\mathbf{\Omega} &= Cov(\mathbf{r}) = E[\mathbf{r}\mathbf{r}^T] \\
&= \mathbf{S}E[\mathbf{e}\mathbf{e}^T]\mathbf{S}^T \\
&= \mathbf{S}\mathbf{R}\mathbf{S}^T \\
&= \mathbf{S}\mathbf{R}
\end{aligned} \tag{2.16}
$$

Therefore the residue has the distribution $\mathbf{r} \sim N(0, \mathbf{\Omega})$ and the normalized residual for the measurement i is: $r_i^N = \dfrac{|r_i|}{\sqrt{\mathbf{\Omega}_{ii}}} = \dfrac{|r_i|}{\sqrt{\mathbf{R}_{ii}\mathbf{S}_{ii}}}$ which means $r_i^N \sim N(0,1)$. Thus the largest normalized residue can be compared against a statistical threshold (e.g. 3) to decide if it is a bad data.

The steps of LNR method is as follows:

- Solve the WLS state estimation problem and obtain the measurement residual vector:

$$r_i = z_i - h_i(\bar{\mathbf{x}}), \qquad i = 1, 2, ..., m$$

- Calculate the normalized residues:

$$r_i^N = \frac{|r_i|}{\sqrt{\Omega_{ii}}}, \qquad i = 1, 2, ..., m$$

- Find k such that r_k^N is the largest among all $r_i^N, i = 1, 2, ..., m$

- If r_k^N > threshold, then the k^{th} measurement is treat as bad data. Else stop, there is no bad data in the measurement set.

- Eliminate the k^{th} measurement and go to the first step.

The main shortage of the LNR method is that it is based on the residuals which may be strongly correlated. Hence, in case of multiple bad data, this correlation may lead to comparable size residuals for good as well as bad data. Thus another way to distinguish good and bad data is by estimating the measurement errors directly. Hypothesis testing method [25], [26] is one of such approach. Although we did not implement this algorithm in this research, applying this approach can also be part of our future work.

2.2 PMU Measurements Based Linear State Estimator

Phasor Measurement Unit (PMU) was introduced into power system at the end of last century [27] and more and more widely used in many applications like wide area monitoring [28], [29], protection [30]-[32], control [33]-[35], and state estimation [36]-[38]. As introduced in [2], [3], 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:

$$\begin{aligned}&\text{Min } \tilde{\mathbf{r}}^T \tilde{\mathbf{W}} \tilde{\mathbf{r}} \\ &\text{s.t. } \tilde{\mathbf{z}} = \tilde{\mathbf{H}} \tilde{\mathbf{x}} + \tilde{\mathbf{r}}\end{aligned} \tag{2.17}$$

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, (2.17) can be written as:

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

$$\text{s.t. } \mathbf{z} = \begin{pmatrix} \mathbf{z}_1 \\ \vdots \\ \mathbf{z}_m \end{pmatrix} = \mathbf{H}\mathbf{x} + \mathbf{r} = \begin{pmatrix} \mathbf{H}_{1,1} & \cdots & \mathbf{H}_{1,n} \\ \vdots & \ddots & \vdots \\ \mathbf{H}_{m,1} & \cdots & \mathbf{H}_{m,n} \end{pmatrix} \begin{pmatrix} \mathbf{x}_1 \\ \vdots \\ \mathbf{x}_n \end{pmatrix} + \begin{pmatrix} \mathbf{r}_1 \\ \vdots \\ \mathbf{r}_m \end{pmatrix} \tag{2.18}$$

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 [39] without iteration:

$$\mathbf{x} = (\mathbf{H}^T \mathbf{W} \mathbf{H})^{-1} \mathbf{H}^T \mathbf{W} \mathbf{z} \tag{2.19}$$

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 (2.19) to obtain the solution.

(2.17) and (2.18) 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 has 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. Also, observability is required to obtain a solution and thus on-line observability checking before every execution of the state estimator has to be part of the calculation cycle. We specify each functional program in each level respectively in the next chapter.

Chapter 3 Two-Level Linear State Estimator

In this chapter, a two-level linear state estimator is introduced and every functional program is specified respectively. With the developing of substation computation technologies, some state estimation procedure can be done at the substation level [4]-[6]. Thus we divided the linear state estimator into substation level and control center level. The substation level uses the circuit breaker oriented model, which is the bus-section/switching-device network model in [40], to estimate both the digital statuses and analog phasor currents and voltages in the substation. The control center level uses those estimated currents and voltages from the substation to estimate the state of the entire network. Different algorithms and even different state definitions are used in the two state estimators.

3.1 Substation Level State Estimator

At the substation level, many state estimation or data processing methods and algorithms have been proposed like the works in [4]-[7]. Here we propose to handle each voltage level separately so that we only deal with zero-impedance circuits (the transformer branch impedances is only considered at the control center level). The substation level state estimator is solved in several parts. First, each voltage level in the substation is solved separately. The advantage is that the substation circuit at one voltage level has no impedances, thus simplifying the SE equations. Second, the current phasor measurements and the voltage phasor measurements are handled separately. This further simplifies the equations, but more than that the SE based on current phasor measurements is used to determine the circuit breaker statuses. Of course, the results are finally combined at the control center level.

Unlike the traditional SE, the topology is not determined first. Instead the current phasor measurements are used to solve a local SE for each voltage level. The resulting circuit breaker currents are then used to check whether the breaker/switch statuses are bad. This method is an extension of the generalized state estimator based on bus-section/switching-device network model introduced in [40]-[42]. In the present day SE, the breaker/switch status measurements are usually non-redundant and cannot be checked for errors. Such topology errors can produce significant errors in the SE results shown in [43]-[49].

Once the breaker/switch statuses are checked for bad data, the topology processor can be used to define the circuit topology at each voltage level. The resulting nodal topology is then ready to be sent to the control center.

In addition to estimating the current states at each voltage level, the voltage phasor measurements are also processed through a state estimator calculation at the substation (also presented in 3.1.2). Finally the set of injection current phasors and nodal voltage phasors from the substation form the analog measurement data that is sent to the control center. The flow chart of the substation level linear state estimator is in Fig. 3.1.

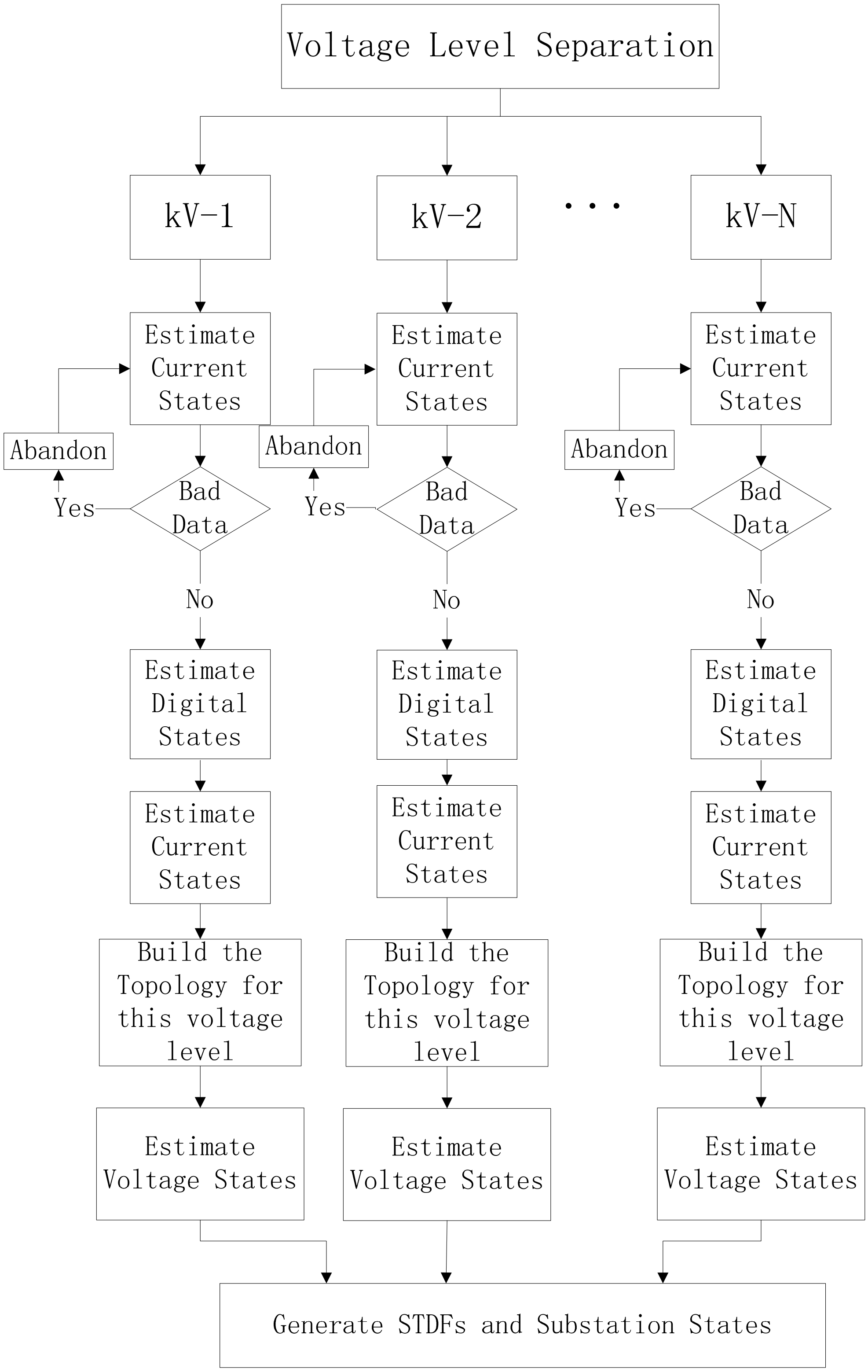


Fig. 3.1 Flow Chart of the Substation Level State Estimator

As can be seen from the structure in Fig. 3.1, at the substation the topology processing, SE solution and bad data detection/identification are not done sequentially as in the traditional SE. All of these functions are accomplished with a different sequence of programs. Besides, as the processing of current measurements and voltage measurements are separated in the flow chart, we define the processing of current measurements as Zero Impedance Current State Estimator and the processing of voltage measurements as Zero Impedance Voltage State Estimator.

3.1.1 Zero Impedance Current State Estimator

In this part, we use all the current phasor measurements to estimate the circuit breaker currents, which are the states of this SE formulation. These circuit breaker currents can then also be used to determine the circuit breaker statuses. In this model, all the bus sections and circuit breakers at the same voltage level inside the substation construct a zero impedance power system.

Follow the flow chart of state estimation introduced in Fig. 2.1 and Fig. 3.1, the substation level state estimator should also be consisted of four steps in order:

- Observability analysis: tests if there are enough current measurements available to estimate the circuit breaker flow currents. Or identify the observable island of the substation whose states can be estimated

- State estimation: finds out the estimated state of this voltage level by solving a nonlinear optimization problem
- Bad data detection and identification: tests the solution to find bad measurements out and if any bad data are detected, they are removed from measurement set and state estimation is repeated.
- Topology processing: uses the real-time circuit breaker status with the substation topology to determine the connectivity of the network in substation;

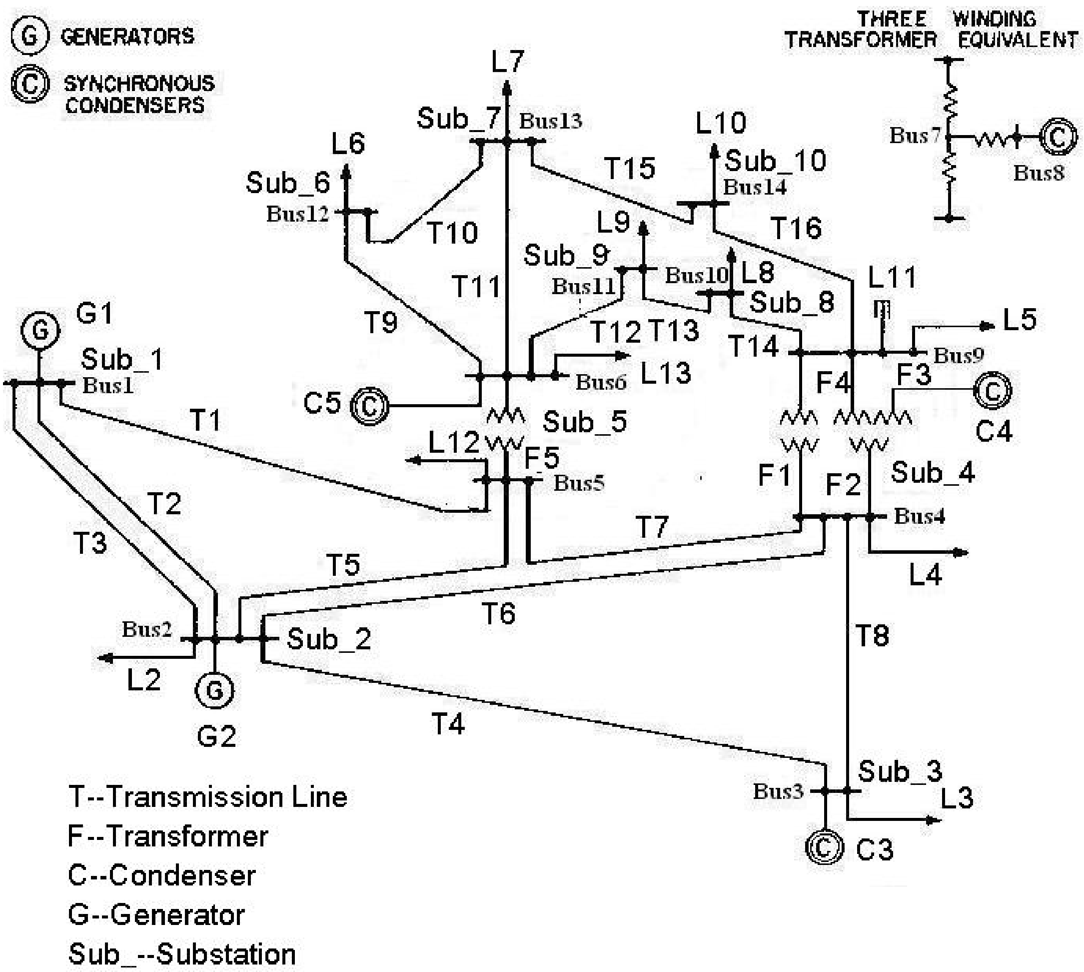


Fig. 3.2 IEEE 14-bus System with Named Device and Substations

We take the IEEE-14 bus system in Fig 3.2 as our example system. For the substation level state estimator, we use a breaker-and-a-half substation system in Fig 3.3 which is generated from Bus 5 and Bus 6 in the IEEE-14 bus system as an example to specify how each functional program works to get an estimated state and substation description to control center. In this substation, there are two voltage levels and two buses connected by a transformer.

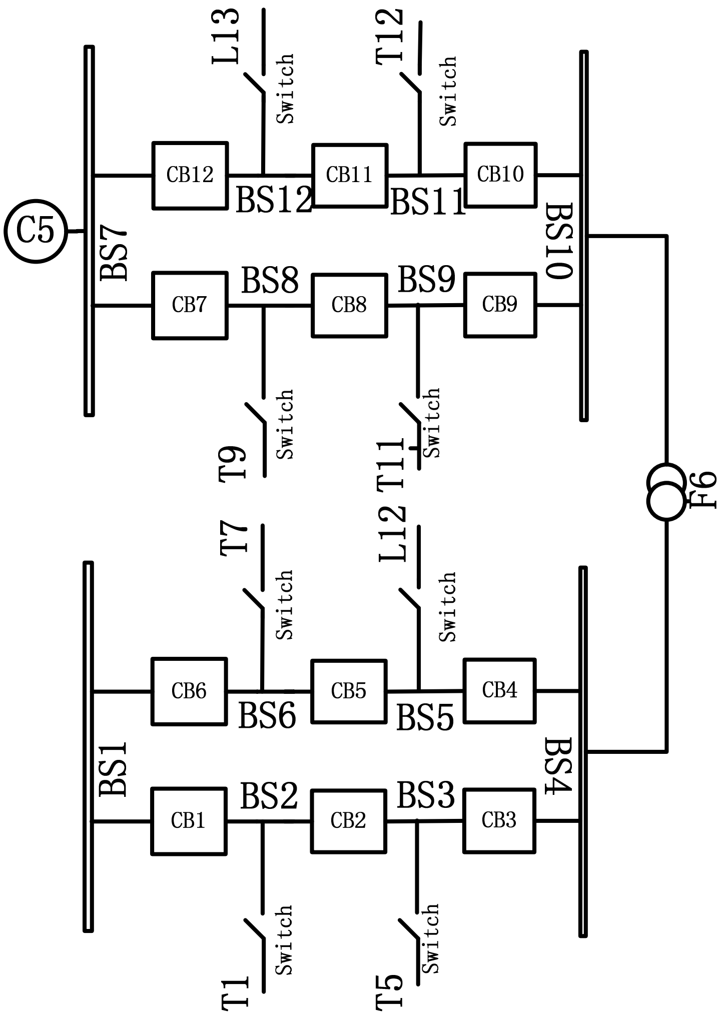


Fig. 3.3 Circuit Breaker Oriented Substation Model (Bus-Section/Switching-Device)

For example, Fig. 3.3 shows the bus-section/switching-device model of substation 5 of the IEEE 14 bus system. Fig 3.4 shows the substation 5 topology with using bus/branch model (if all circuit breakers are closed) that is calculated by the zero impedance current state estimator and sent to the control center.

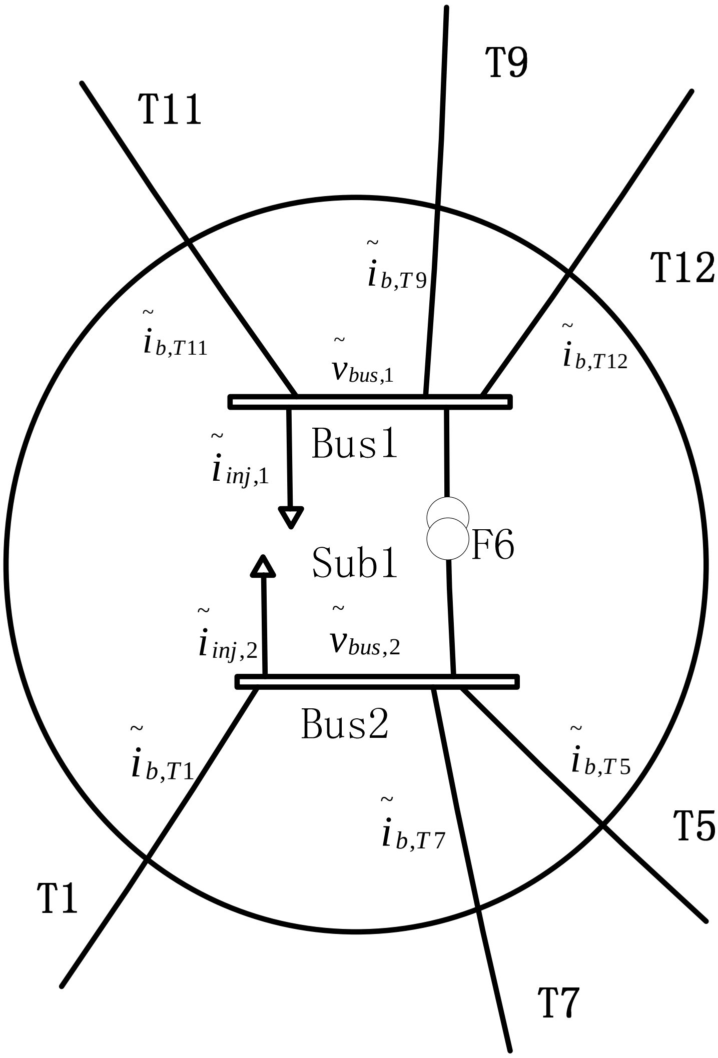


Fig. 3.4 Substation Bus-Branch Model When All Circuit Breakers Closed

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.

3.1.1.1 Observability Analysis

The observability analysis in the substation level is to check if there are enough measurements to estimate the circuit breaker flow currents or find out all the observable islands in which the state can be estimated. In the bus branch mode, bus voltage phasors are defined as states and measurements are mainly active and reactive power flows. Different from the bus-branch model, in the substation, we use the bus-section/switching model in [40] and define the current on circuit breaker as state. The same with the traditional state estimator, there could be two different ways to check that. The first way is to use the numerical way introduced in [16]. There are two main reasons for that: (1) in the substation level state estimation, there is no floating point in the measurement function matrix which creates the round-off errors; (2) the size of the measurement function matrix is fairly small so the calculation time is not unacceptable.

The Fig. 3.5 is the breaker and a half connectivity of one voltage level of the substation in Fig 3.4, we create the measurement set on this voltage level subsystem, and the triangle means current measurement. We also defined the direction of the state variable as the arrows on circuit breakers.

Follow the definition before, the state vector is $\mathbf{x} = [\overline{I}_7, \overline{I}_8, \overline{I}_9, \overline{I}_{10}, \overline{I}_{11}, \overline{I}_{12}]^T$ and the measurement vector is $\mathbf{z} = [\overline{I}_7, \overline{I}_{12}, \overline{I}_{inj7}, \overline{I}_{inj10}, \overline{I}_{inj11}, \overline{I}_{inj12}]^T$, where $\overline{I}_i$ represents the phasor current on circuit breaker i and $\overline{I}_{inji}$ represents the injection phasor current of bus section i. Zeros injection bus sections are assumed to have current measurements equal to zero. So the measurement function is $\mathbf{z} = \mathbf{Hx}$ where:

$$\mathbf{H} = \begin{bmatrix} 1 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & -1 \\ 1 & 0 & 0 & 0 & 0 & -1 \\ 0 & 0 & -1 & 1 & 0 & 0 \\ 0 & 0 & 0 & -1 & 1 & 0 \\ 0 & 0 & 0 & 0 & -1 & 1 \end{bmatrix}$$

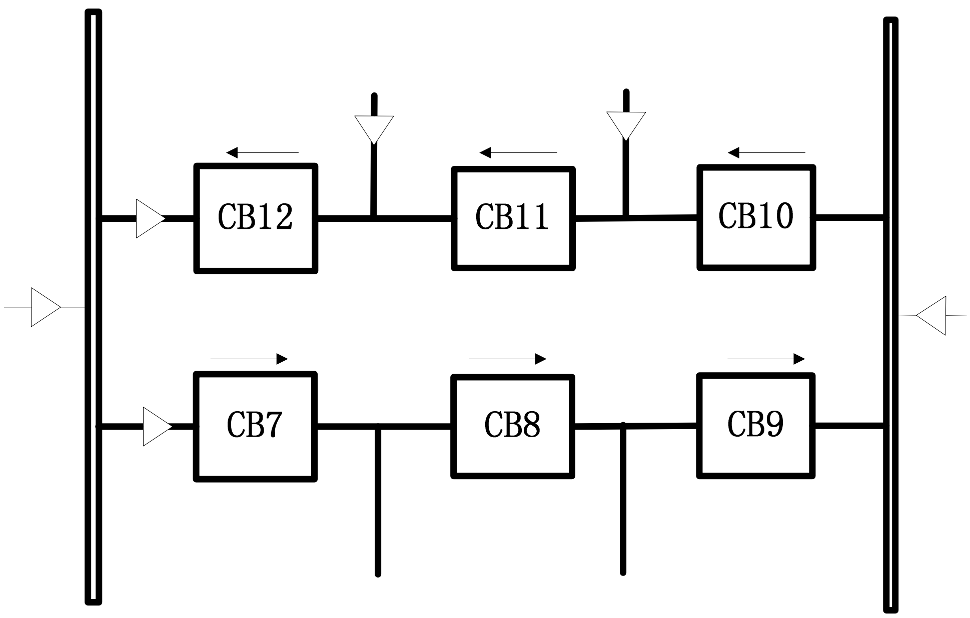


Fig. 3.5 Measured Substation Model in One Voltage Level

So the WLS estimate of $\mathbf{x}$ is $\mathbf{x} = (\mathbf{H}^T\mathbf{H})^{-1}\mathbf{H}^T\mathbf{z}$ with considering the weight matrix is identity matrix in observability analysis because the actual value of weight does not affect the result. Then the gain matrix $\mathbf{G} = \mathbf{H}^T\mathbf{H}$ is:

$$\mathbf{G} = \begin{bmatrix} 2 & 0 & 0 & 0 & 0 & -1 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 1 & -1 & 0 & 0 \\ 0 & 0 & -1 & 2 & -1 & 0 \\ 0 & 0 & 0 & -1 & 2 & -1 \\ -1 & 0 & 0 & 0 & -1 & 3 \end{bmatrix}$$

By LDL Cholesky factorization, we have $\mathbf{U}\mathbf{x} = \mathbf{L}^{-1}\mathbf{H}^T\mathbf{z}$,

where $\mathbf{U} = \mathbf{D}\mathbf{L}^T = \begin{bmatrix} 2 & 0 & 0 & 0 & 0 & -1 \\ 0 & 1.0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 1 & -1 & 0 & 0 \\ 0 & 0 & 0 & 1 & -1 & 0 \\ 0 & 0 & 0 & 0 & 1 & -1 \\ 0 & 0 & 0 & 0 & 0 & 1.5 \end{bmatrix}$ with the zero pivot at row/column 2 which is changed to 1.0. So the unobservable island is CB8.

The second way is to modify and implement the topological method introduced in [15] in the substation. In [15], the bus/branch model is used and state is defined as the bus voltage angle while here the bus-section/switching model is used and we define the circuit breaker phasor current as state. So to implement the topological method, we need to assume that the circuit breaker measurement is equivalent to branch measurement in bus/branch model and the equipment measurement, which is the bus-section injection measurement, are equivalent to the bus injection measurement. At the same time, we are not constructing a critical tree of full rank in the substation as we needed in the bus-branch model. Instead, we need to assign each equipment measurement to a circuit breaker measurement reasonably of the substation and then every circuit breaker with an assigned measurement becomes observable.

So the algorithm is constructed by two steps:

(1) Assign all the circuit breaker current measurements to the corresponding circuit breaker to construct a basic graph. In this graph, the bus section may be divided into three categories: inner bus section with which all the circuit breakers connected have measurement assignment, outer bus section with which all the circuit breakers connected have no measurement assignment, and boundary bus section with which some circuit breakers connected have measurements while some have not. At the same time, following the definition in [50], bus sections with injection measurements are called as measured bus sections, otherwise called unmeasured bus sections. The injection measurements on inner bus sections are noted as redundant measurements.

(2) Assign the measured boundary bus section measurements to a proper circuit breaker to decide the observable islands. For simplicity, we use a more conservative method to assign the boundary injections instead of the sufficient and necessary way. In this simple and conservative algorithm, only the boundary bus sections to which only one unassigned circuit breaker connected are chosen and assign its measurement to the unassigned circuit breaker. Then these boundary bus sections become inner bus sections. After that refresh the graph to see if there are new boundary bus sections satisfy the measurement assigning condition. If there is no such boundary bus section

in the graph, all the measurement assigned circuit breakers constitute the observable islands.

Given a set of flow measurements, the algorithm satisfies the necessary and sufficient condition of obtaining our desired observable island. The sufficiency is easy to show as we can see that once the observable islands care identified by this algorithm, it is observable. The necessarily is also easy to guarantee but somewhat tricky. After the first step and each injection assignment, we can obtain a subset of the original graph by subtract all the assigned branches and inner bus sections away. Then this subset only contains node injections and unassigned branches. At the end of the step 2, assume there are n injection measurements with m unassigned branches, from the algorithm we can see that each measured boundary node (bus section) should connect to at least 2 branches, otherwise its injection measurement is assigned to the branch it connect. Thus from the graph theory, the total number of branches, which is m, should be satisfy $m \geq n$. So the number of state m is larger than the number of measurement n, which makes the network unobservable.

By applying this topological observability analysis algorithm to the system in Fig. 3.5, we get the assignment result shown in Fig. 3.6. The observable island is constructed by CB7, CB9, CB10, CB11, and CB12. CB8 is unobservable which the same with the numerical observability analysis result is.

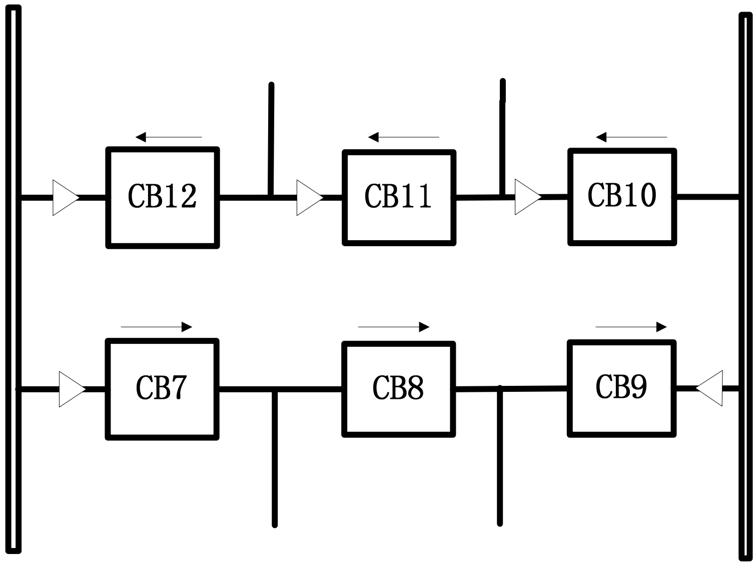


Fig. 3.6 Substation Model After Measurement Assignment

For some reason, maybe not every circuit breaker is observable. There are two ways to solve this problem. The more conservative way is to not provide the control center the estimated measurement on related branches to control center which means leave it as a non-measured branch. Another way is transfer the measurement, if exists, directly to the control center and give it a comparatively low weight. In our program we used the more conservative ways and leave this problem the control center level.

The advantages of the numerical observability are: (1) it is the sufficient and necessary condition of the network is observable; (2) it makes use of the numerical calculation routine which is already existed in the state estimation procedure. Numerical observability in the substation level also avoid annoying round off errors because the size of the gain matrix is small and no branch parameters exist in gain matrix. So in the substation level we prefer to use the numerical observability analysis.

3.1.1.2 State Estimation

In this part, we use all the current phasor measurements to estimate the circuit breaker currents, which are the states of this SE formulation. These circuit breaker currents can then also be used to determine the circuit breaker statuses. In this model, all the bus sections and circuit breakers at the same voltage level inside the substation construct a zero impedance power system.

After the observability analysis, we use the availability of current phasor measurements on each circuit breaker and branch to get the measurements sets $\mathbf{z}_{cb}$ and $\mathbf{z}_{inj}$ respectively. We assume that all the circuit breakers are closed to start with (the solution identifies the correct circuit breaker statuses). The equations for the branch current measurements can then be written as follows:

$$\mathbf{z}_{inj} = \mathbf{A}_{KCL}\mathbf{x} + \mathbf{r}_{inj} \tag{3.1}$$

where $\mathbf{z}_{inj}$ is the injection current at each node, $\mathbf{A}_{KCL}$ is the incidence matrix connecting bus sections to circuit breakers in the zero impedance power system, $\mathbf{x}$ is the state vector of the circuit breaker currents, and $\mathbf{r}_{inj}$ is the corresponding residual vector.

The equations for the current measurements $\mathbf{z}_{cb}$ at each circuit breaker have the obvious relationship:

$$\mathbf{z}_{cb} = \mathbf{I}\mathbf{x} + \mathbf{r}_{cb} \tag{3.2}$$

where $\mathbf{I}$ is the identity matrix, and $\mathbf{r}_{cb}$ is the corresponding residual vector.

Then the measurements functions can be represented by:

$$\mathbf{z} = \begin{pmatrix} \mathbf{z}_{inj} \\ \mathbf{z}_{cb} \end{pmatrix} = \begin{pmatrix} \mathbf{A}_{KCL} \\ \mathbf{I} \end{pmatrix} \mathbf{x} + \begin{pmatrix} \mathbf{r}_{inj} \\ \mathbf{r}_{cb} \end{pmatrix} = \mathbf{Hx} + \mathbf{r} \tag{3.3}$$

This is a simple linear state estimation problem (the entries in H matrix are 1, 0, or -1) of (2.16), so we can find the estimation solution by (2.18).

3.1.1.3 Bad Data Detection and Identification

It should be pointed out that one of the major advantages of this two-level state estimator is that the error detection and identification is done at the substation level. This is many times more efficient than the present method because each calculation at a substation is small and moreover, is done in parallel. Of course, the ability to detect status errors is another major advantage.

Once the circuit breakers currents are estimated, the analog bad data can be identified and rejected by the traditional testing method based on largest normalized residual. 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 with high probability that the status measurement is bad and the real state of the circuit breaker is closed. A special case is when the estimated breaker current is close to zero and the status measurement indicates a closed breaker; in such a case one cannot conclude with high probability the status of the breaker. Fortunately, this status does not affect our estimate calculations but may impact other operator decisions.

After the bad status data are eliminated, we need to repeat this algorithm again because the new topology gives us a new incidence matrix $\mathbf{A}_{KCL}$ 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 which means such analysis is possible only if there are redundant current phasor-measurements in the substation. The advantage of this is we can identify the bad data for not only the analog data but also for the circuit breaker and switch statuses directly. In the traditional SE there is no effective method for identifying status errors, which have become a major source of errors in the state estimators today.

3.1.1.4 Topology Processing

The topology processing function program in the substation level is to use the status of the circuit breakers and the substation bus-section/switching model to determine the bus/branch model of the substation and the connection with the equipments such as generators, load feeders, shunt capacitors, transformers, transmission lines, etc..

Substation level topology processor is actually the combination of first and the third step in traditional state estimator. The bus/branch model of the substation in Fig. 3.3 is shown in Fig. 3.4. The model in Fig. 3.4 is called as substation topology description file (STDF).

3.1.2 Zero Impedance Voltage State Estimator

After we get the estimated digital status of each circuit breaker, we can construct the topology for this voltage level. The outputs include the number of buses at this voltage level and all its connected elements and branches. We can then estimate the bus voltage from the voltage measurements at all the bus sections comprising this bus. This is essentially a weighted average and is formulated here as a zero impedance voltage state estimator. The states are the voltage of each bus, and the measurements are the voltage phasor measurements at the bus sections belonging to the bus. The measurement function then is:

$$\tilde{\mathbf{z}} = \tilde{\mathbf{H}}\,\tilde{\mathbf{x}} + \tilde{\mathbf{r}} = \begin{pmatrix} 1 \\ 1 \\ \vdots \\ 1 \end{pmatrix} \tilde{\mathbf{x}} + \tilde{\mathbf{r}} \qquad (3.4)$$

Because $\mathbf{H}$ is actually a vector with all 1s, the actual solution is the diagonal weighted average value of all the measurements:

$$x_{real} = \frac{\sum_{i=1}^{m} w_{2i-1,2i-1} z_{i,real}}{\sum_{i=1}^{m} w_{2i-1,2i-1}} \tag{3.5}$$

$$x_{imag} = \frac{\sum_{i=1}^{m} w_{2i,2i} z_{i,imag}}{\sum_{i=1}^{m} w_{2i,2i}} \tag{3.6}$$

where $w_{i,i}$ is the i th diagonal entry of $\mathbf{W}$.

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 at each substation together with the substation topology. At a minimum, we assume that branch currents, bus injection currents, and bus voltages for each voltage level are transferred to the control center. 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.

3.2 Control Center Level State Estimator

The control center level state estimator receives all the analog estimated measurements - bus voltages, branch currents, and injection currents - and the substation topology from the substation level state estimators to determine the state of the whole network. It is also constructed by the four functional programs. The control center level topology processor connects all the substation topologies with the branch data to get the whole system topology. It is actually the second step of the traditional topology processor program which merges all the STDFs together. Also in the observability analysis functional program, traditional numerical and topological algorithms can be used for the linear state estimator. The difference is that, the measurements sets are phasor bus voltages and phasor branch currents. Besides, in [51]-[57], the algorithms of optimal placement of PMU measurements to obtain the system observability based on the linear state estimator are introduced. In this section, the emphasis is the state estimation program, which builds the system linear measurement function model and solves the system states.

Based on the idea introduced in [2], given a power system with n buses and m branches, the measurement inputs are the bus voltages $\tilde{\mathbf{V}}_{bus} = [\tilde{v}_{bus,1},...,\tilde{v}_{bus,n}]^T$, branch currents at both ends $\tilde{\mathbf{I}}_{b1} = [\tilde{i}_{b,1},...,\tilde{i}_{b,m}]^T$, $\tilde{\mathbf{I}}_{b2} = [\tilde{i}_{b,m+1},...,\tilde{i}_{b,2m}]^T$, and the injection currents $\tilde{\mathbf{I}}_{inj} = [\tilde{i}_{inj,1},...,\tilde{i}_{inj,m}]^T$. The states of the system are the bus complex voltages $\tilde{\mathbf{x}} = [\tilde{v}_1,...,\tilde{v}_n]^T$. Assuming the system admittance matrix is:

$$\tilde{\mathbf{Y}} = \begin{pmatrix} \tilde{y}_{11} & \cdots & \tilde{y}_{1n} \\ \vdots & \ddots & \vdots \\ \tilde{y}_{n1} & \cdots & \tilde{y}_{nn} \end{pmatrix} = \begin{pmatrix} g_{11} + jb_{11} & \cdots & g_{1n} + jb_{1n} \\ \vdots & \ddots & \vdots \\ g_{n1} + jb_{n1} & \cdots & g_{nn} + jb_{nn} \end{pmatrix}. \tag{3.7}$$

The measurement function can then be written as:

$$\tilde{\mathbf{z}} = \begin{pmatrix} \tilde{\mathbf{V}}_{bus} \\ \tilde{\mathbf{I}}_{b1} \\ \tilde{\mathbf{I}}_{b2} \\ \tilde{\mathbf{I}}_{inj} \end{pmatrix} = \tilde{\mathbf{H}}\tilde{\mathbf{x}} + \tilde{\mathbf{r}} = \begin{pmatrix} \mathbf{I} \\ \tilde{\mathbf{Y}}_1^b \\ \tilde{\mathbf{Y}}_2^b \\ \tilde{\mathbf{Y}} \end{pmatrix} \tilde{\mathbf{x}} + \tilde{\mathbf{r}} \tag{3.8}$$

where $\tilde{\mathbf{Y}}_1^b$, $\tilde{\mathbf{Y}}_2^b$ can be derived from the branch admittances.

Using real number vectors and blocks to represent each complex number, the measurement function should have the form:

$$\mathbf{z} = \begin{pmatrix} \mathbf{V_{bus}} \\ \mathbf{I_{b1}} \\ \mathbf{I_{b2}} \\ \mathbf{I_{inj}} \end{pmatrix} = \mathbf{Hx} + \mathbf{r} = \begin{pmatrix} \mathbf{I} \\ \mathbf{Y_1^b} \\ \mathbf{Y_2^b} \\ \mathbf{Y} \end{pmatrix} \mathbf{x} + \mathbf{r} \tag{3.9}$$

The control center level state estimator formulation then is still another linear state estimator problem of (2.16) and can be solved by (2.18).

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 have this capability.

Chapter 4 Transitional Two-Level State Estimator

It is unlikely that large areas of the grid are equipped with redundant phasor measurements that guarantee observability any time soon [51]. On the other hand, many high voltage substations gain this capability and certain sections of the higher voltage grid could be estimated with the above formulation. Thus integrating the classical and proposed state estimator together is a very important step for transition. In this section, we describe a transitional state estimator with corresponding functional programs dealing with the combination of PMU measurements and traditional RTU and SCADA measurements.

4.1 Topology Processing

The transitional topology processor needs to deal with both the substation topology description file (STDF) transferred from the substation which installed the substation level state estimator and the traditional on/off status signal of circuit breaker from the RTUs by SCADA system. Thus we first need to use the digital statuses from SCADA and the static database in the control center to build the STDFs for the substations without implementing substation level state estimators and merge all the STDFs together to gain the topology of the whole system.

4.2 Observability Analysis

In the transitional two-level state estimator, the measurement set includes both the traditional measurements set like power line flow, power injection and the PMU measurements set like the bus voltage phasor measurements. In fact, it is easy to understand that there is not much difference between PMU measurements and traditional power flow measurements in using the numerical way to solve this problem. So we proposed a transitional way to combine the PMU measurements with traditional power flow measurements in topological observability analysis. In another word, when PMU measurements are used in state estimation, we model it as an equivalent line flow which can be used by topological algorithm to determine the system observability. For simplicity and non loss of generality, only active power flow, active power injections, and bus voltage angles measured by PMUs are considered as the measurement and only the angles of bus voltages are viewed as system states.

4.2.1 Theoretical Fundamentals

Different from the active power measurements which are linear combinations of two or several bus voltages, PMU measurements gives only the bus voltage angle independently. Follow the description in [16], $\boldsymbol{\theta}$ is the state vector of the system, then in the network Jacobian matrix $\mathbf{H}$, the line flow from bus k to bus l is represented as:

$$\boldsymbol{\zeta}_i = \left[\ldots, h_{i,k}, \ldots, h_{i,l}, \ldots\right]\boldsymbol{\theta} \tag{4.1}$$

The injection at bus k where there are branches connecting bus k to buses a, b, l are represented as:

$$\zeta_i = [\ldots, -h_{i,l}, \ldots, \Sigma, \ldots, -h_{i,a}, \ldots, -h_{i,b}, \ldots]\boldsymbol{\theta} \tag{4.2}$$

where $\Sigma = h_{i,l} + h_{i,a} + h_{i,b}$.

And the bus voltage phasor measurement at bus k is:

$$\zeta_i = [\ldots, h_{i,k}, \ldots]\boldsymbol{\theta} \tag{4.3}$$

where $h_{i,k} = 1$

We can see from the three expressions that if we assume the dimension of $\boldsymbol{\theta}$ is n including the reference bus, then the dimension of $\mathbf{H}$ should be $n-1$. In another word, the combination of measurements may vary from line flow, injections, and bus voltage phasor measurements, but at least, while at the same time at most, there should exist $n-1$ linear independent measurements. This indicates that we can find a way to change bus voltage phasor measurements to an equivalent line flow measurements by linear transformation without changing the linear independency of all the measurements.

Take a three bus system in Fig. 4.1 as an example:

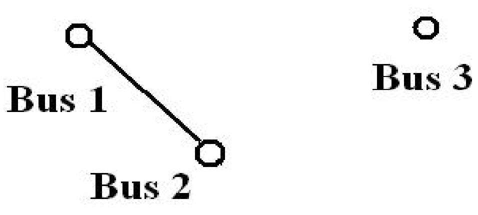


Fig. 4.1 Three Bus Example System

There is only one branch in system connects Bus 1 and Bus 2 while Bus 3 is isolated. If we assume there is the active power measurement on the branch and Bus 1 is a reference bus, then Bus 1, 2 construct an observable island and Bus 3 is an unobservable island. If we add a bus voltage phasor measurement on Bus 3 with respect to reference Bus 1, then the whole system becomes observable. Without considering the branch impedance, the adjacent matrix A of this system becomes:

$$\mathbf{A} = \begin{bmatrix} 1 & -1 & 0 \\ 0 & 0 & 1 \end{bmatrix} \tag{4.4}$$

By a linear transformation, A can be transformed to:

$$\overline{\mathbf{A}} = \begin{bmatrix} 1 & -1 & 0 \\ 1 & 0 & -1 \end{bmatrix} \tag{4.5}$$

Then the new adjacent matrix $\overline{\mathbf{A}}$ can be viewed as that there are two branches in the system, one of which connects Bus 1 and Bus 2 while another connects Bus 1 and Bus 3. So by a linear transformation without affecting the measurements linear independency, we can model the bus voltage phasor measurements as line flow measurements in observability analysis. In general, the statement that a network with n buses is observable is equal to that there exist $n-1$ linear independent measurements. This is also true in topological observability analysis because if the network with n buses is observable, then spanning tree of full rank has $n-1$ branches.

Thus if there are k bus voltage phasor measurements in the network including the reference bus, there are $k-1$ linear independent measurements. Only another set of $n-k$

linear independent measurements is needed to construct a whole set of measurements to keep the system observable. This set of $n-k$ linear independent measurements may include power injections, line power flows, or line current flows measured by PMUs at the same time as PMU can provide not only bus phasor voltage measurements but also some branch phasor current measurements. In topological observability analysis, those measurements are all assigned as line flow measurements properly. Hence the key point of including PMU measurements in topological observability analysis is how to assign bus phasor voltage measurements to line flow measurements.

4.2.2 PMU Measurements Modeling

Given a set of measurements, the assumption here is that both PMU measurements and RTU measurements exist in the measurement set. If we use DC power flow model to represent the system and measurements, then the synchronized phasor line flow current measurements are equivalent to line flow active power measurements. So only the bus voltage angle, line flow, and injections are in the measurements set and the bus voltage angles need to be modeled in topological observability analysis.

- Step 1: Assigning bus voltage angle measurements to line flows.

In the first step, we only consider the bus voltage angle measurements. Assume we have k bus voltage angle measurements in the given measurements set including the reference bus, and then it is easy to understand that those k buses are observable. So there exists a virtual tree with full rank whose nodes are those buses and edges are virtual branches (Here virtual branches mean they do not exist in the real system but exist in observability analysis program). Actually all the nodes and the possible edges construct a complete graph, so each edge can be assigned arbitrarily between those nodes as long as they can construct a tree. Then for any virtual branch connected two nodes in the tree, there exists a line flow on the virtual branch which is assigned by one of the bus voltage angle. In another word, bus voltage angles are assigned as line flows on those virtual branches. Different from injection assignment, we do not need to worry about which line flow is assigned by which bus voltage angle because there are only $k-1$ voltage measurements and $k-1$ branch line flows in the network. So as long as there is no loop in the network, the linear independency of the measurements never changes.

- Step 2: Reconstruct the network connectivity.

As the virtual branches are introduced into the network, the number of branches may change and so does the network connectivity. Specifically, if there is a physical branch between two buses which are measured by PMU, then the line flow on the branch is linear dependent with the bus voltage angle measurement. So after Step 1, we need to reconstruct the network connectivity to ensure the linear independency of the line flow measurements and the bus voltage angle measurements. All the physical branches connect two PMU measured buses are eliminated from the connectivity data. This step is not mandatory but can reduce the work load of the latter measurement assignment work.

Although the network connectivity has been change here, the observability of the system is not affected because no matter what topology of the full rank tree is, the nodes of the tree are still observable.

4.2.3 IEEE-14 Bus System Example

We use the IEEE-14 bus system in Fig. 4.2 as an example to describe the whole procedure of topological observability analysis with bus angle measurements (for simplicity, we use circles to represent buses and lines to represent branches). The black triangle on the branch means there is a line flow on this branch while the arrow on the circle means there is an injection measurement on this bus (zero injection is equivalent to an injection measurement). The θ in the circle means this bus has angle measurement. Illustrating how to assign injection measurements to branches is not the key point in this paper. So we used the injection measurements set used in [50]. Then after we assigned the bus voltage angle and reconstruct the system connectivity, the line flow measurements and injection measurements assignment followes the rules in [50]. From Fig. 4.2, we can see that beside the measurements set originally from that in [50], there are bus voltage angle measurements on bus 1, 4, 8, and 9.

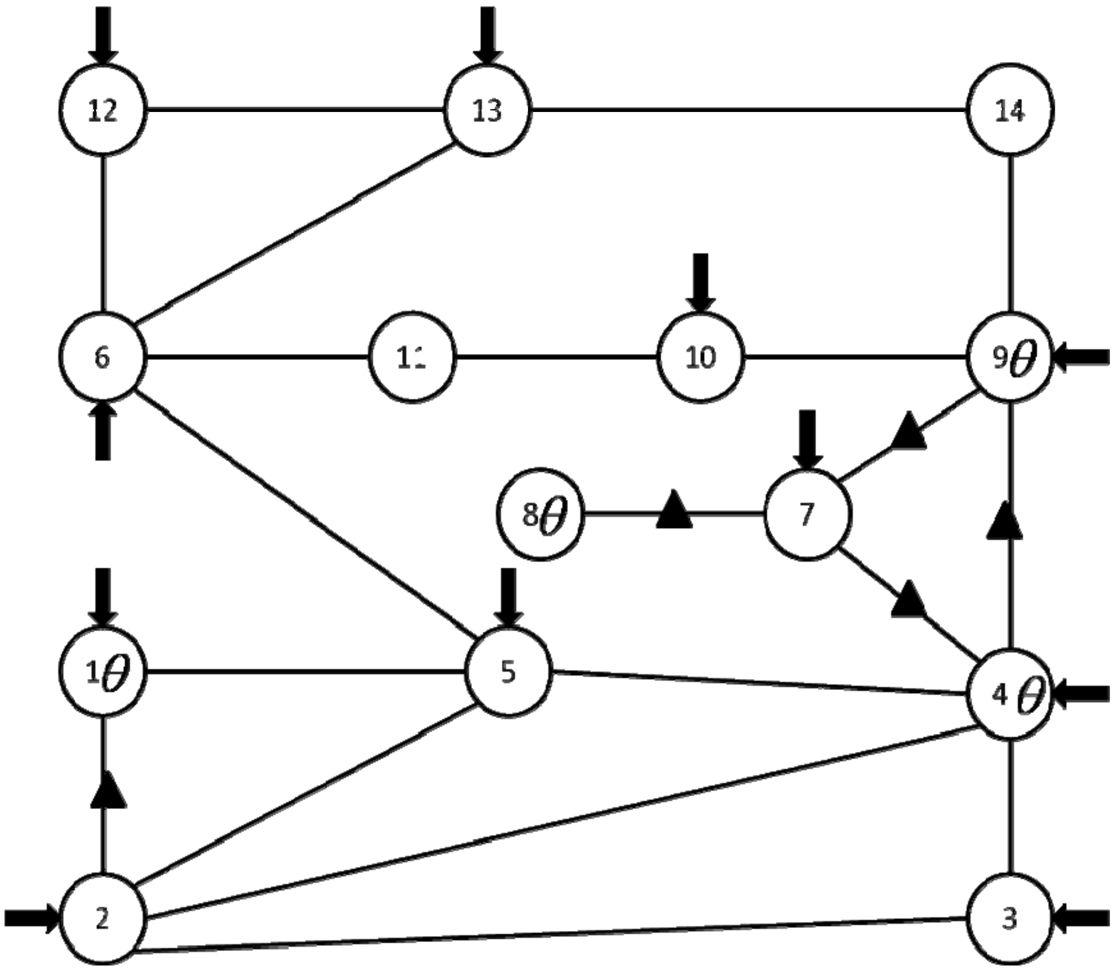


Fig. 4.2 Original IEEE 14-bus System with Measurements Set

Implementing the modeling method of bus voltage angle measurements to the system, we get a reconstructed network connectivity with assigned line flow measurements shown in Fig. 4.3. As we described before, the 4 nodes can construct a complete graph and any physical branch conflicted with virtual branch should be eliminated here to reduce the later work of measurement assignment. Then we can choose any possible tree topology to assign the 3 bus voltage angles to 3 virtual branches.

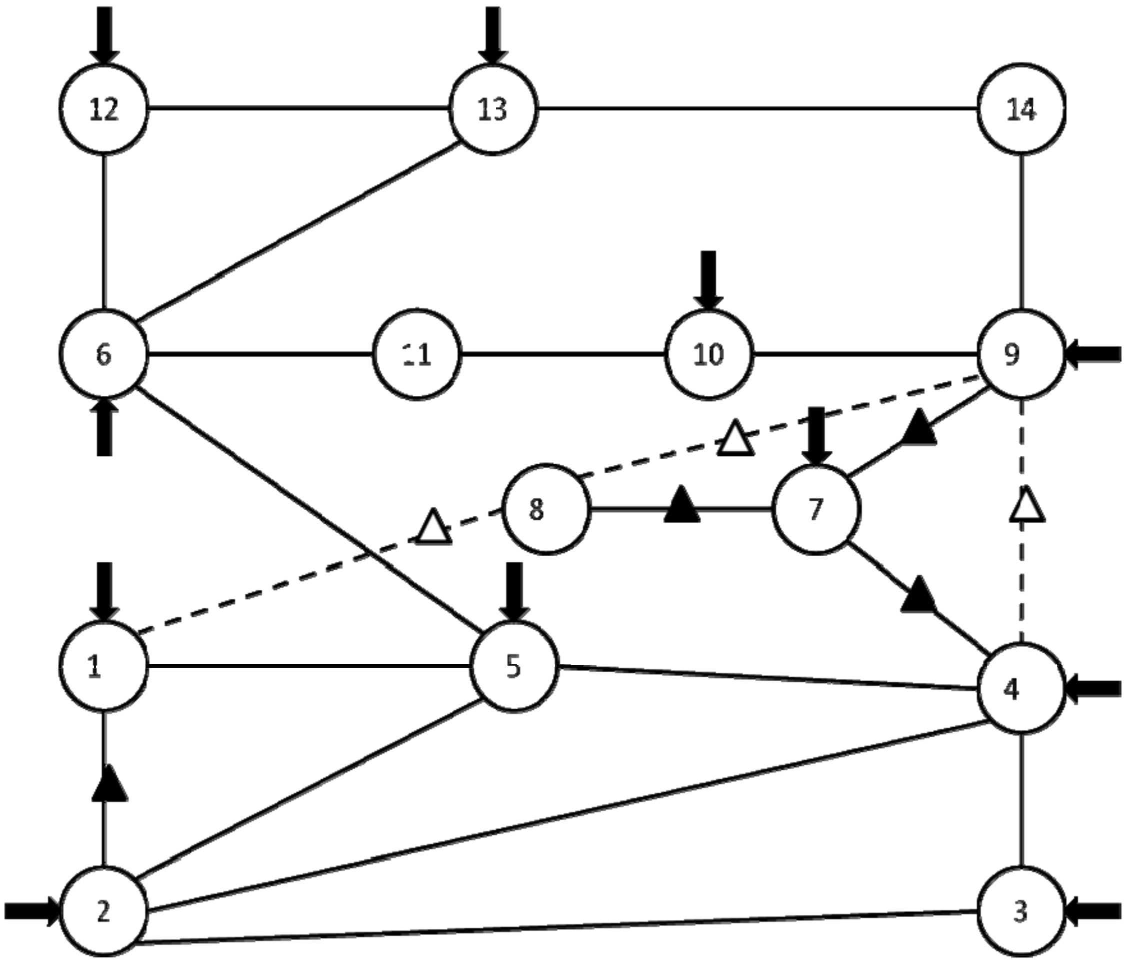


Fig. 4.3 Reconstructed IEEE 14-bus System with Measurements Set

After virtual measured branches are added into the network, we can use any network topological algorithm to analyze the observability.

4.3 State Estimation

In this section, we describe a multi-area state estimation algorithm for a transitional state estimation in which portions of the formulation takes advantage of this advanced formulation while the rest of the grid is still solved in the traditional way. This multi-area state estimation method is similar with the previous algorithms introduced in [58]-[64] but with some novel ideas.

We assume 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 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 because the high voltage level substations are more critical. Then we can divide the whole system into several linear areas and nonlinear areas shown in Fig. 4.4.

We can estimate all the system states in the following order: first, we use the linear state estimator to estimate the states in each linear area separately; second, we 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. Although we use a combination of nonlinear and linear state estimators in this Transitional phase, the performance of this architecture is still better than the traditional one because for those areas where the substations have been upgraded all the benefits of the higher accuracy and periodicities of the state estimator are available to the operator and the contingency analysis functions.

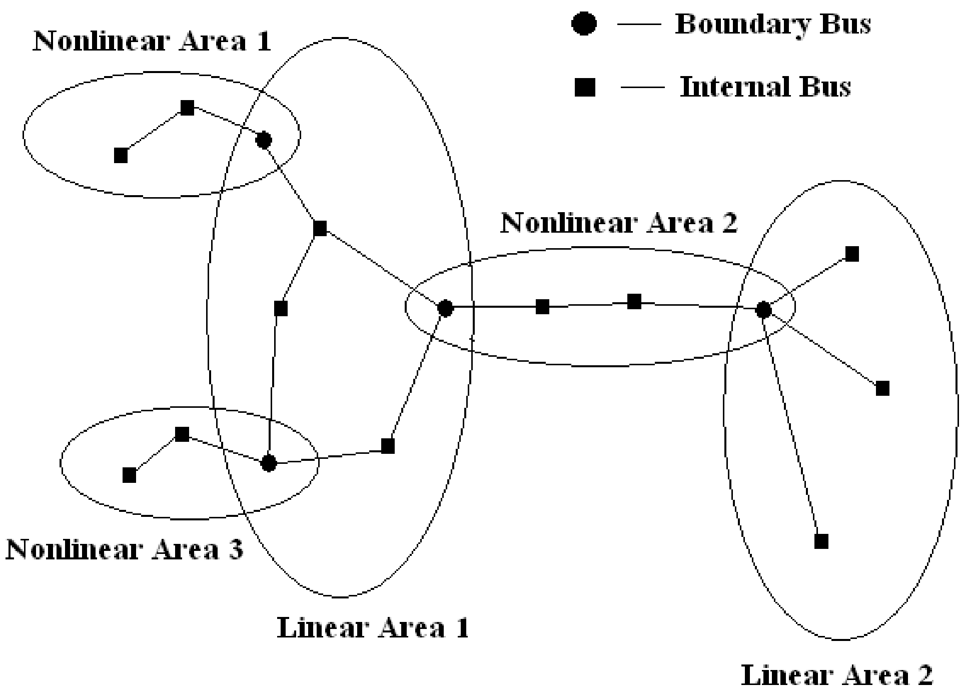


Fig. 4.4 Multi-area Network with Boundary Buses

As introduced in Fig 4.4, we partition the whole system into several linear and nonlinear areas. For each linear area, we can use the two-level linear state estimator to estimate subsystem states while for each nonlinear area, we can just use the traditional state estimator to do that. Suppose there are p linear areas and q nonlinear areas in the system, then we have a new state estimation problem:

$$\begin{aligned}
&\text{Min } \left(\sum_{i=1}^{p} \tilde{\mathbf{r}}_i^T \tilde{\mathbf{W}}_i \tilde{\mathbf{r}}_i + \sum_{j=1}^{q} \mathbf{r}_j \mathbf{W}_j \mathbf{r}_j\right) \\
&\text{s.t. } \tilde{\mathbf{z}}_i = \tilde{\mathbf{H}}_i \tilde{\mathbf{x}}_i + \tilde{\mathbf{r}}_i = \tilde{\mathbf{H}}_i [\tilde{\mathbf{x}}_{i,\text{int}}^T, \tilde{\mathbf{x}}_{i,\text{b}}^T]^T + \tilde{\mathbf{r}}_i \\
&\qquad \mathbf{z}_j = \mathbf{h}_j(\mathbf{x}_j) + \mathbf{r}_j = \mathbf{h}_j([\mathbf{x}_{j,\text{int}}^T, \mathbf{x}_{j,\text{b}}^T]^T) + \mathbf{r}_j
\end{aligned} \tag{4.6}$$

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

Then the whole system state estimation problem is divided into several subsystem state estimation problems. We can see from the flow chart shown in Fig. 4.5, 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:

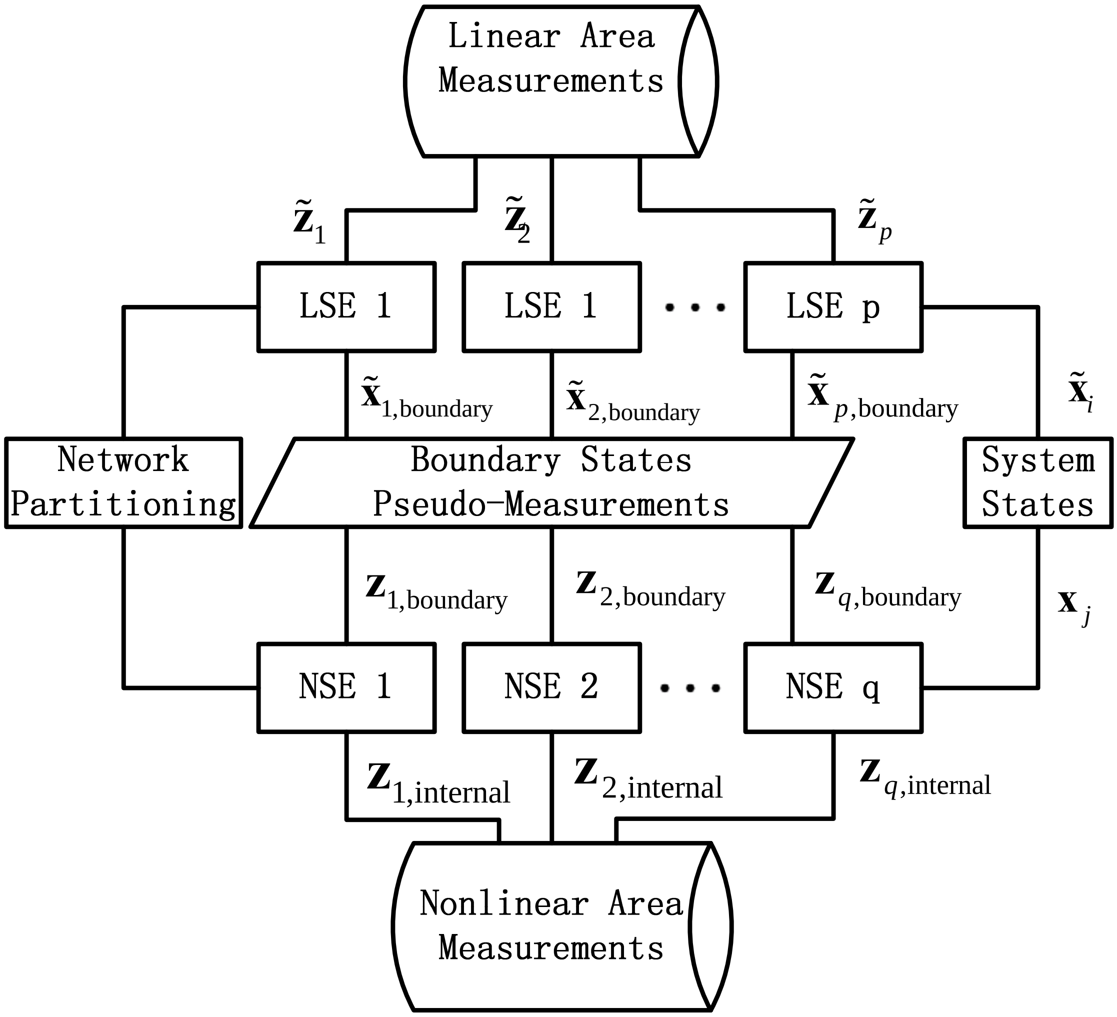
$$\begin{aligned}
&\text{Min } \tilde{\mathbf{r}}_i^T \tilde{\mathbf{W}}_i \tilde{\mathbf{r}}_i \\
&\text{s.t. } \tilde{\mathbf{z}}_i = \tilde{\mathbf{H}}_i \tilde{\mathbf{x}}_i + \tilde{\mathbf{r}}_i = \tilde{\mathbf{H}}_i [\tilde{\mathbf{x}}_{i,\text{int}}^T, \tilde{\mathbf{x}}_{i,\text{b}}^T]^T + \tilde{\mathbf{r}}_i
\end{aligned} \tag{4.7}$$

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 (discussed in 5.1.1) 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, runs 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:

$$\begin{aligned}&\text{Min } \mathbf{r}_j \mathbf{W}_j \mathbf{r}_j \\ &\text{s.t. } \mathbf{z}_j = \mathbf{h}_j(\mathbf{x}_j) + \mathbf{r}_j = \mathbf{h}_j([\mathbf{x}_{j,\text{int}}^T, \mathbf{x}_{j,\text{b}}^T]^T) + \mathbf{r}_j\end{aligned} \tag{4.8}$$

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)

Fig. 4.5 Flow Chart of Multi-Area State Estimation

Although we used nonlinear state estimator in this case, the performance of this architecture is still better than the traditional one because estimating the states of each small subsystem will be much faster and for each linear part, substation level linear state estimator provides the reliable measurements.

Chapter 5 Information Architecture

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 state estimator 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. The database that supports state estimator then consists of the ‘real-time’ database made up of these measurements and a ‘static’ database made up of power system parameters (e.g. impedances, connectivity, etc.). This information architecture consisting of the communications and databases that support the SE has not changed much over time. However, the periodicity of the SE computation has been often reduced from 15 minutes to even below a minute as higher computation power has become available. The lower limit for SE periodicity now is the periodicity of the SCADA data acquisition and the related time skew.

In this proposed SE, we assume the availability of many synchrophasor measurements in each substation instead of the traditional RTU data. This new SE requires a more flexible, robust, timely, and secure information system including a high bandwidth networked communication system and a distributed database structure. In this section we introduce the information system architecture.

5.1 Communication System

The proposed communication infrastructure is shown in Fig. 5.1. 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.

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 [65]. 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. 5.1 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.

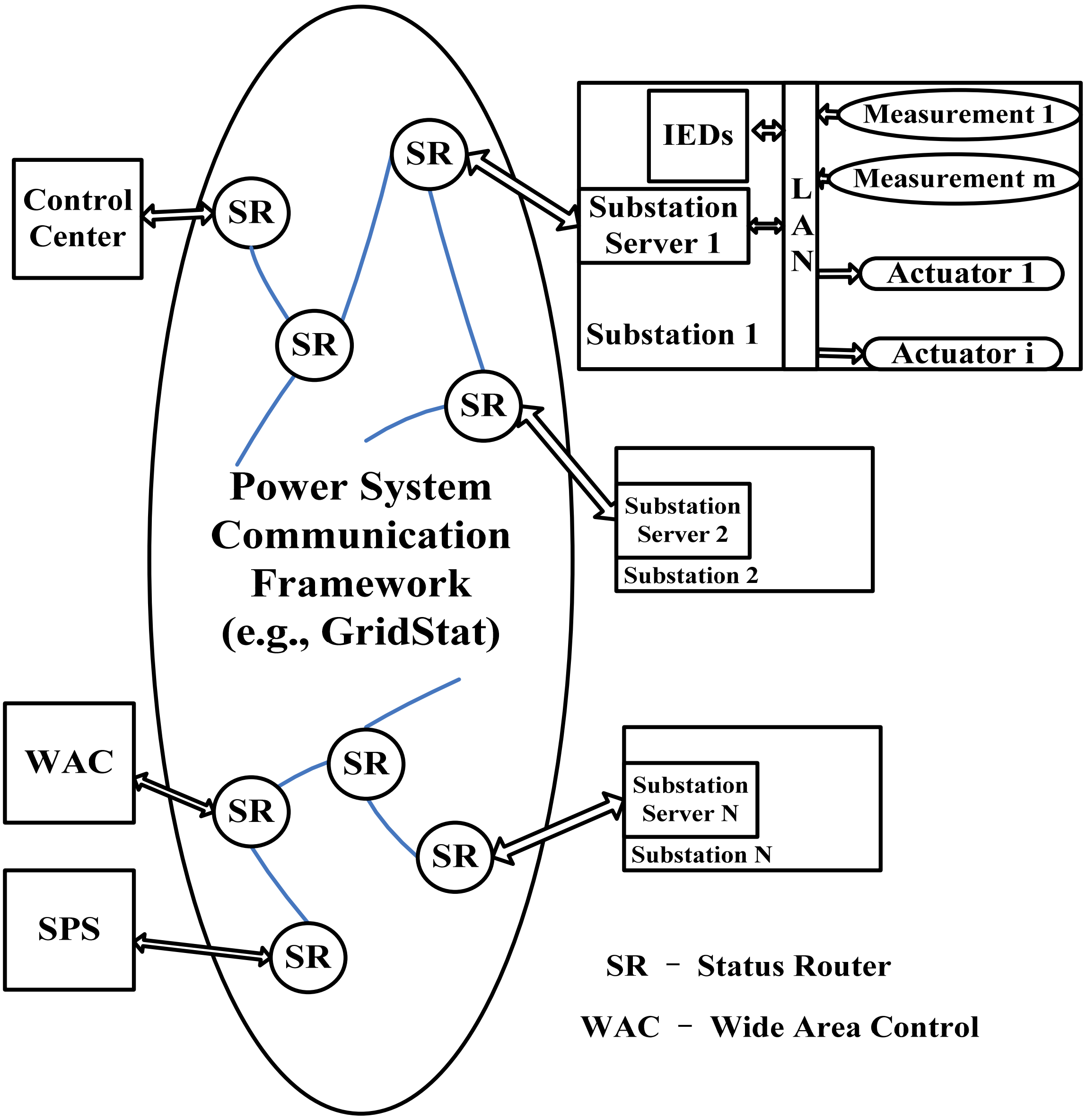


Fig. 5.1 Power System Communication Infrastructure

The traditional SE uses measurement data that is not time-stamped and this can introduce significant error in the solution. The synchrophasor based SE as proposed here is inherently free of this error as long as the time-skews introduced by communication delays are small. The communication delay t_{comm} consists of the transmission delay t_{trans}, propagation delay t_{prop}, and queuing delay t_q [66]:

$$t_{comm} = t_{trans} + t_{prop} + t_q \tag{5.1}$$

The propagation delay t_{prop} is proportional to the distance between each substation to the control center. The transmission delay t_{trans} and queuing delay t_q depend on the bandwidth and traffic of the network respectively. For a particular communication network these delay times can be estimated by simulating the traffic by using a network simulator tool like NS-2 [67]. Although communication delays have not been particularly relevant to the traditional SE using non-time-stamped data, these delays have to be tightly controlled when using synchronized phasor data. Thus an example of how these can be calculated is shown in the 5.1.1 for a small real system.

5.1.1 Network Simulator Simulation Results

As state estimators today do not use time-stamped measurements (except for the occasional PMU data), time delays in communications have not been a concern. However, the use of synchrophasors as the bulk of the measurements as well as higher periodicities for the SE require tight tolerances on the time skew between measurements. Synchronization of the measurement data can be achieved by using the GPS time stamping which is accurate to a few micro-seconds; this does not introduce time skews of any significance. The time delays in communications also have to be tightly controlled to get proper SE solutions. We show here how to calculate the time delays by using a simulation program on a small communication network that would be appropriate for the IEEE-14 bus system shown in Fig 3.2.

As introduced in (5.1), the propagation delay t_{prop} is proportional to the distance between each substation to the control center. We assume that these distances are similar to the transmission line distances which can be determined from the impedance of the transmission lines. Such an assumption is very reasonable as communication lines are often strung on the same towers as transmission lines. But the transmission delay t_{trans} and queuing delay t_q can only be estimated by the network simulators such as NS-2 [67]. To generate the other communication network parameters (inputs to the NS-2), we assume that the system uses fiber optic lines with the high voltage power transmission lines, which means the bandwidth of the link between high voltage substations is 1000Mbits/s. At the same time, the system uses twisted-pair communication lines with the low voltage power transmission lines, which means the bandwidth of the link is 100Mbits/s. In this test system, the high voltage substations are those shown below the transformers.

We consider our communication model at two levels. The lower level, intra-substation communication system, which connects all the IEDs including the PMUs to the substation server, can be modeled as a LAN on NS-2. The second level is the wide-area level which connects the substations, wide area controllers or special protection schemes (WAC/SPS) and the control center. The wide-area level can be modeled as a network whose nodes are the gateways and routers placed in each substation and the links go with the transmission lines.

For convenience, we assume that a reasonable length of the packet sent from the measurement to the substation server is 40 bytes and the packet rate is 60 packets per second. On the other hand, if needed, we also assume that the length of the packet from the substation server or measurements to the actuators is 40 bytes. The reason for that is that in a substation the data packet which may contain triggering or fault information is small but time critical. Our experiments mostly focus on whether the network can perform well in transmitting time critical data.

We also make assumptions about the data traffic needed for the various applications. For example, the data traffic between substations and the control center is very large in the amount of data but at slow rates compared to the traffic for WAC/SPS where the number of data packets are small but at very high rates. The intra-substation data traffic is at much higher rates as well as amounts.

Based on those requirements and assumptions, we build the simulation scheme of the IEEE 14-bus system on NS-2 and get the packet time delay from substations to control center shown in Table 5.1.

This method is just a heuristic way to estimate the latency of real time measurements. We can see from our experiment, in the 14 bus power system, as the data amount is little and system size is small, the real time measurements latency is in the ms level. It should be pointed out that the processing times through the communication switches are neglected here, and the actual time delays are somewhat larger.

Table 5.1: Signal Time Delay From Substation To Control Center

From Substation	t_{comm} (ms)
Sub1	1.1170
Sub2	1.3400
Sub3	1.8760
Sub4	2.0020
Sub5	1.7330
Sub6	1.8520
Sub7	1.8120
Sub8	1.9230
Sub9	1.8320
Sub10	1.9650

More study results, using both more detailed simulation and experimental methods, about the time performance of an information system can be found in [68], [69], and some technical reports from GridStat Webpage (www.gridstat.net).

5.2 Distributed Database

As the two-level state estimator does some of the calculations at the substation level and some at the control center, we need to specify what data we need and how to store those data for the convenience of application. In the present system, the whole database is at the control center. The static database of all system parameter and substation connectivity information resides at the control center. The real-time database consisting of the measurements from each substation is periodically transferred to the control center from the RTUs over the SCADA communication system.

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

5.2.1 Traditional Database Architecture

Traditional control centers build and maintain the real time database and the static database which are needed for all the displays and all the EMS applications. The architecture for the traditional state estimator system is shown in Fig 5.2. As the power system changes, such as the incorporation of new substations, both the static database and the real time database change. Maintenance of the database remains a difficult and error-prone manual task as shown in [70].

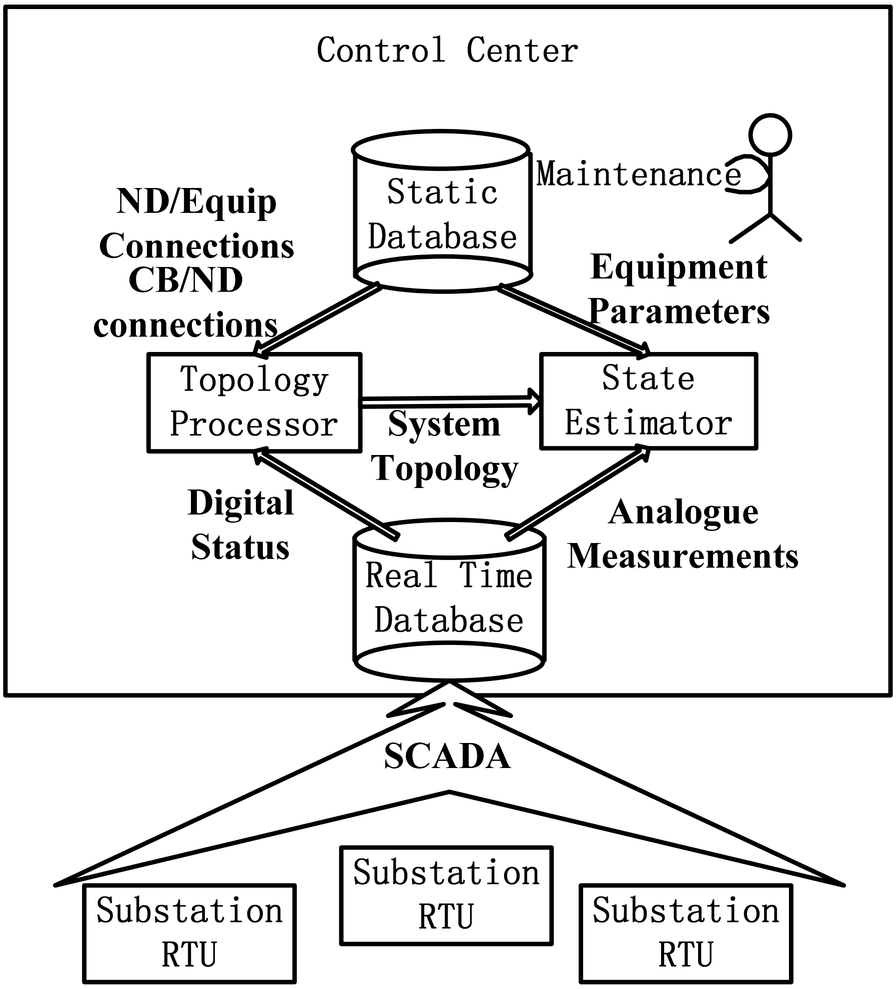
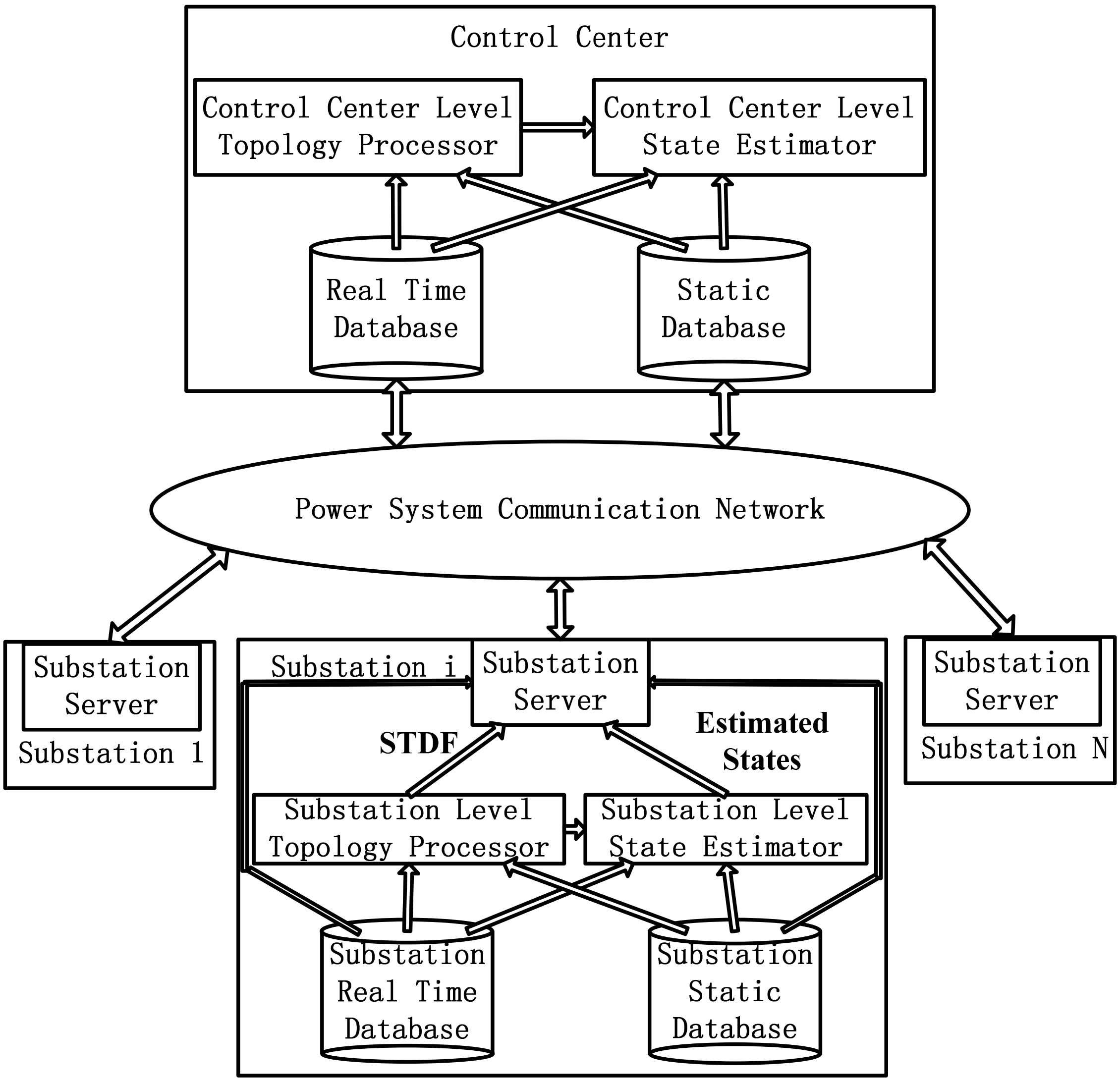


Fig. 5.2 Traditional Real Time Modeling System and Database

5.2.2 Distributed Database for Two-Level State Estimator

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 are 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 5.3.



(STDF: Substation Topology Description File)

Fig. 5.3 Decentralized Real Time Modeling System and Database

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.

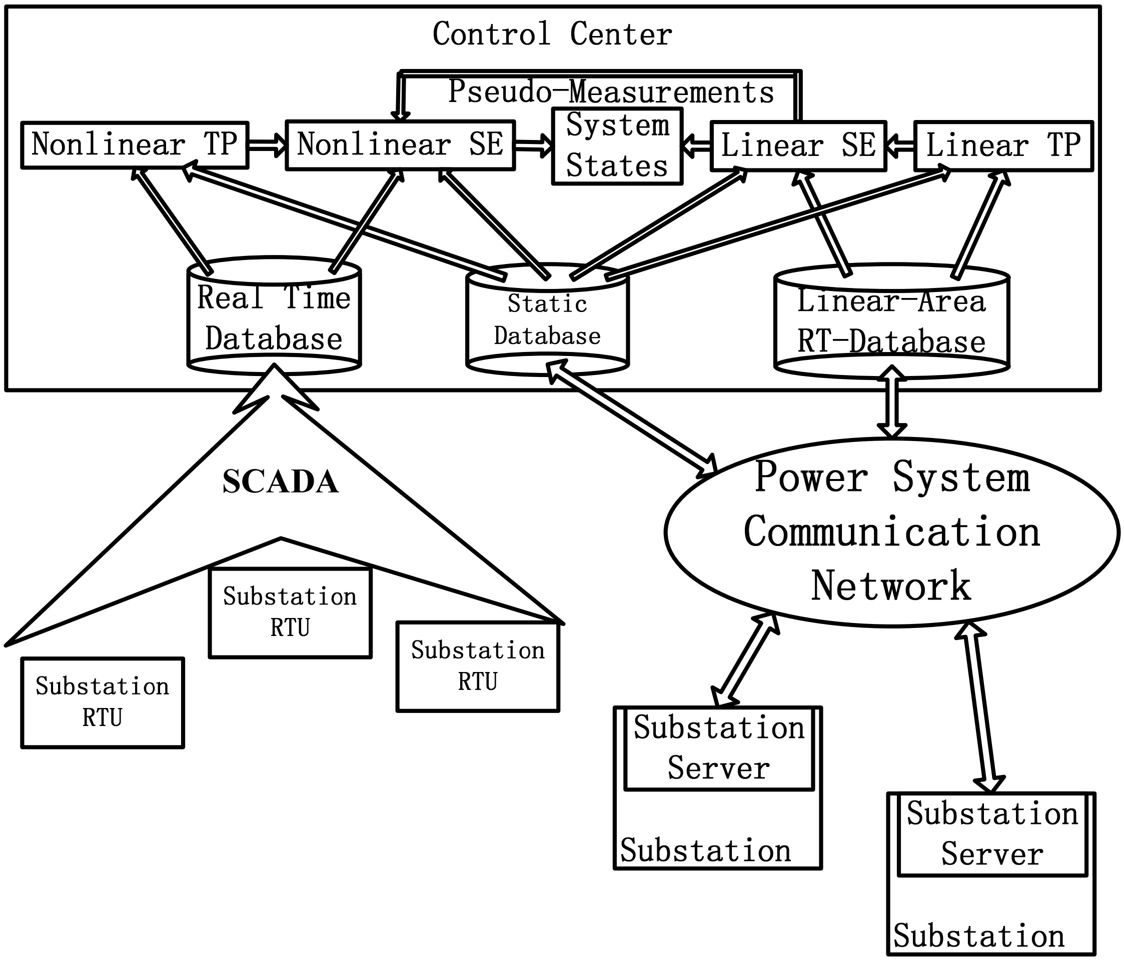
The database storage at the control center is now much smaller because both the static and real time database storages are distributed in each substation. The static database at the center now consists mainly of branch parameters and connectivity. The real time database now handles only the calculated (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 certainly has other attributes. For example, the display functions at the control center require access to the substation static and real-time data.

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 [71] 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 [72] 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.

5.2.3 Transitional Information Infrastructure

In the previous section we assume that in the future, all substations are digital with many phasor measurements. Moreover, we assume that these substations are connected through high bandwidth communication systems. As the technologies are already available the timing is only dependent on the investment needed for implementation. The transitional state estimator can take advantage of partial implementation of such technologies with the transitional two-level multi-area state estimator requires both real time measurements transferred by SCADA system and the new power system communication network. So we need a transitional information architecture as shown in Fig 5.4. 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”)

Fig. 5.4 Transitional Real Time Modeling System and Database

Chapter 6 Implementing Two-Level Linear State Estimator on GridSim Test Bed

In this chapter, we introduce a real-time simulation platform: GridSim and specify the implementation steps of the two-level linear state estimator on such a simulating test bed. Traditional power system simulation and study software, such as DSATools by PowerTech and PSS/E by Siemens, are well developed for off-line studies with ignoring the communications and database issues. Therefore, many critical implementation parameters such as the communication delays, database scalabilities, and real-time synergy performance can not be estimated before implementing in real system. With the developing of fast and time-critical wide-area monitoring and control schemes technologies, those real-time performance parameters become more and more important and mandatory in the designing process.

GridSim is a systematical real-time power system simulation platform which includes power system steady-state and dynamic simulations, real-time measurement streams infrastructure, data communications, and databases. For a given wide-area monitoring or control scheme, it can be as a full test bed for a “from measurements to system responses” performance evaluation. The building of the simulation environment, generating of the static and real-time databases are also included with state estimation experiments and performance analysis because the implementation of two-level linear state estimator requires the corresponding database and communication infrastructure which is based on GridStat [11], [12]. The flow chart of the GridSim platform integrated with the two-level state estimator and another wide-area monitoring scheme: Oscillation Monitoring System [28] is shown in Fig. 6.1.

6.1 Overview of GridSim Simulation Platform

The GridSim Simulation Platform is consisted of the following four parts:

- Virtual Power System by Simulation Tools (DSATools)

  TSAT [73] is a software tool developed by Powertech Labs Inc., for transient security assessment of power systems. Its extensive computational capabilities offer a “one-stop” solution to the transient security problem. Complemented by other tools in Powertech’s DSATools suite, namely PSAT (Power flow & Short circuit Analysis Tool), VSAT (Voltage Security Assessment Tool), and SSAT (Small Signal Analysis Tool), TSAT helps give accurate and complete assessment of transient security of a power system. As an off-line analysis and study software, traditional outputs of TSAT would provide some assessments and a full trajectory for a given time period. In the GridSim platform, this simulation tool acts as a real-time virtual power system as a test bed. It simulates an operating power system and provide the real-time system snapshot states data streams at any operating time.

- Real-time and Static Data Generating System

  The input of the TSAT is consist of power flow file which describes the bus-branch model of a power system, a dynamic parameter data file which describes the machine inertia and load parameters, and an event file which describes the disturbances of the system. So both the TSAT and the GridSim platform can use the power flow file and dynamic file to construct a static database of this power system. The fundamental real-time output streams from TSAT are the system states, which are bus phasor voltages. Other real-time measurements, such as line flows, injections, and phasor currents can be calculated out with the system model and static parameters. Then any combination of the real-time measurements set can be generated and acts as the input of corresponding power system applications.

- Communication and Database Platform

  GridStat and another open source communication software for phasor data concentration, openPDC [74], are used as communication middleware of the GridSim platform. They can provide the application-free transparent data communications for power system measurements including synchronized phasor measurements. The communication software provides a way of evaluating the real-time data communication performances and requirements of any monitoring and control schemes. Besides, security issues, quality of services, and database scalabilities can also be test and evaluated in this platform.

- Disturbance Simulation and Real-time Control Implementation (Future Work)

  As introduced in the first feature, the virtual power system generated by simulation tools can simulate disturbances and also receive the control signals from wide-area control schemes. GridSim provides a seamless interface between the virtual power system and user designed wide-area control schemes. This feature provides a full simulation test bed for wide-area control schemes “from meters to actuators ” including sampling rates and accuracies analysis, communication delay affects analysis, communication and database qualities and scalability analysis, and so on. These characteristics become more and more critical in designing wide-area control schemes and smart grid applications.

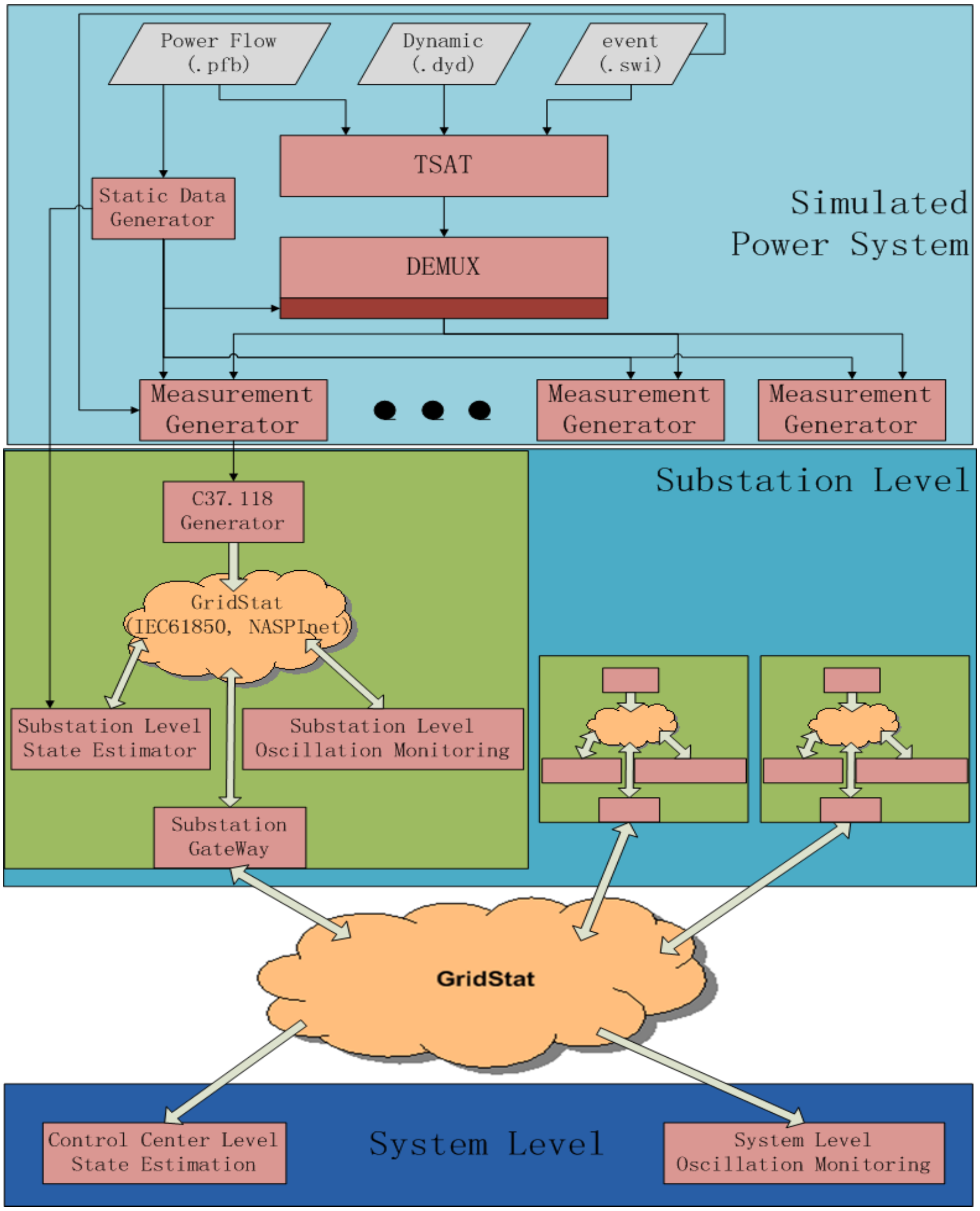


Fig. 6.1 Simulation Test Bed Infrastructure

6.2 Database Generating

In [13], the architecture of the static database is described in detail. As in some experiment cases, both the static and real time database may not be available, we need to find out a way to generate those databases automatically from some easily retrieved data like power flows files. Taken the IEEE-14 bus system as an example, we follow the rule to create the static and corresponding real time database. (This part is not the main contribution of our work, so there might be many assumptions which are probably not so reasonable in the process of generating database.)

6.2.1 Static Database Generating

- Step 1: Name all devices in the system.

As sometimes power flow file may be lack of device descriptions, here we need to name all the devices appeared in the IEEE-14 bus system. Each device, like generator, transmission line, load, compensator, transformer, needs to have a unique name in the system. The named IEEE-14 bus system is in Fig. 3.2.

- Step 2: Identify substations in the system

Sometimes the power flow file can tell how the substations are constructed in the system by the name of buses and branches. But sometimes we still need to identify the substation and the corresponding constructions in the system. Given a power flow file, first of all, we need to check how many buses are there and what branches connected to it. Secondly, for each bus, if all the branches connected to it are transmission lines, then this bus construct a substation. Otherwise all the buses connect together with it by transformers construct a substation. At last, name the substations and corresponding buses one by one. For example, Fig. 3.2 is substations identified.

- Step 3: Create the substation model and static database

After we classified the substations and the corresponding devices inside the substation, we need to determine the connectivity of the circuit breakers, bus sections, and devices in the substation. Actually there are many kinds of connectivity, so here we just choose the most popular ones like one and a half connectivity shown in Fig 6.2. To solve this problem more practically, maybe we can build several kinds of popular connectivity used in the industry and choose the connectivity randomly from them.

In Step 2, we know how many buses are there in the substation and which voltage level each bus is in. Here we assume that all the buses in the same voltage level are connected by circuit breakers, which means all the devices connected to these buses are in one zero impedance power system introduced in 3.1.1. In more detail, if there are multiple buses in the same voltage level, then each bus is constructed by a bay of a breaker-and-a-half and each bay is connected by a circuit breaker. Take the substation 5 in Fig. 3.2 as an example. We can see that there are two voltage levels in the substation, and there is only one bus in each voltage level. So the circuit breaker oriented substation model should be in Fig. 6.2.

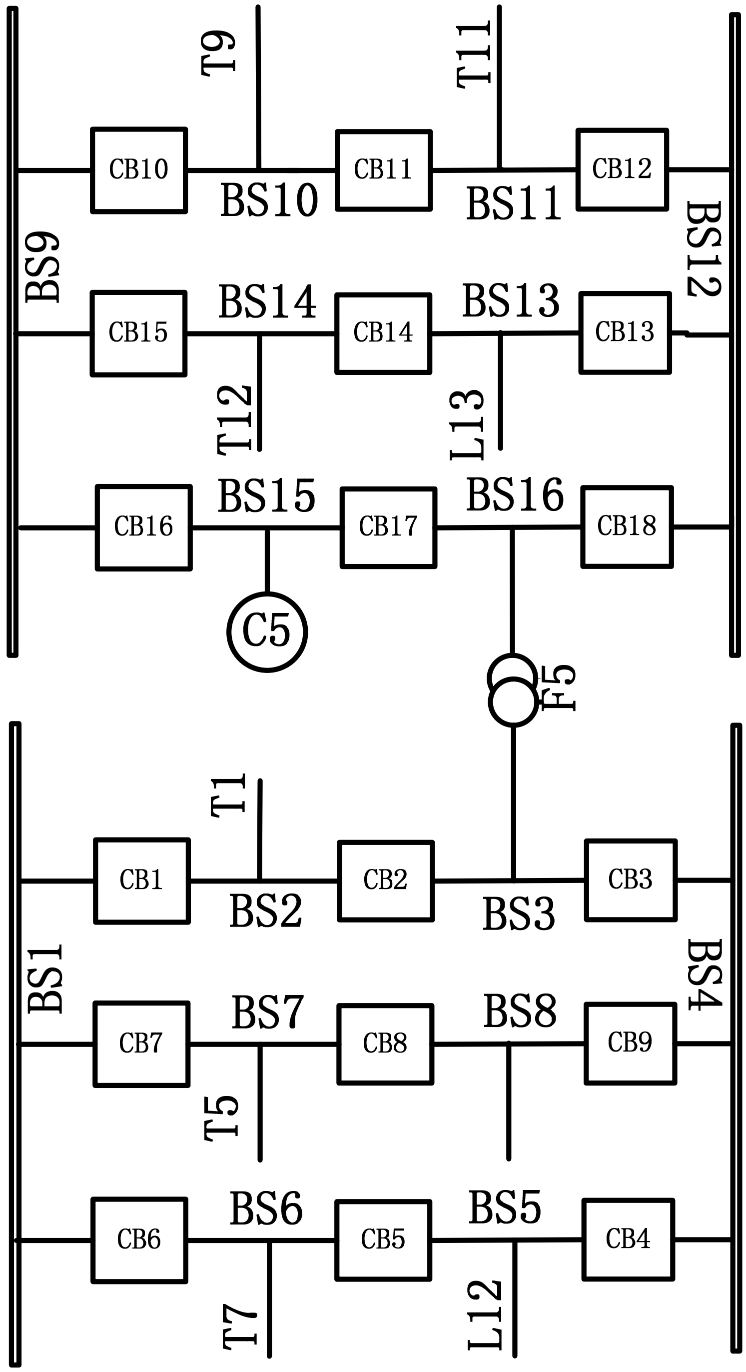


Fig. 6.2 Circuit Breaker Oriented Substation Model

The corresponding static database is shown in Table 6.1:

Table 6.1: Network topology input arrays (Static database)

Substation Number	Bus Section			Circuit Breaker		
5	No.	Type	Equipment Ident.	No.	From B. sec	To B. sec
	1	connection		1	1	2
	2	line	LT1	2	2	3
	3	transformer	TR5	3	3	4
	4	connection		4	4	5
	5	load	LD12	5	5	6
	6	line	LT7	6	6	1
	7	line	LT5	7	7	1
	8	connection		8	8	7
	9	connection		9	4	8
	10	line	LT9	10	10	9
	11	line	LT11	11	11	10
	12	connection		12	12	11
	13	load	LD13	13	12	13
	14	line	LT12	14	13	14
	15	gen.unit	CU5	15	9	14
	16	transformer	TR5	16	9	15
				17	15	16
				18	16	12

6.2.2 Real-Time Database Generating

6.2.2.1 Digital real time database

The digital real time database determines the system topology with the circuit breaker and bus section connectivity. So once the static database is created, we can only change circuit breaker status to change the system topology. To satisfy the topology described in the power flow file, we make all the statuses of circuit breakers in each bay as closed and make the status of the circuit breaker which connects two bays open if the two bays belong to different buses. So the corresponding digital real time database of the substation in Fig. 6.2 is in Table 6.2:

Table 6.2 Circuit breaker status (Digital real time database)

CB No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Status	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

(1-closed, 0-open)

6.2.2.2 Analog Real-Time Database

The analog real time database includes current measurements and voltage measurements. The current measurements database is constructed by circuit breakers measurements and equipment measurements. The process of creating current measurements database is actually a state estimation. From the power flow we can calculate out the branch flows and bus injections which represent the equipment measurements part. Unfortunately, there is no way to calculate out a unique circuit breaker current measurement set because there may be many possibilities of the current distribution in the bay. So different from the circuit breaker currents in the real system, we assigned a standard value to the current of each circuit breaker whose digital status is closed while assign a zero value to the current of each circuit breaker whose digital status is open as their pseudo-measurements. It is easy to see that some of the pseudo-measurement may be conflicts with nearby equipment measurements, so those conflicted pseudo-measurements should be filter out. Mathematically, those conflicted measurements are linear combinations of the equipment measurements and other proper assigned pseudo-measurements, so after filtered out those conflicted pseudo-measurements, the left pseudo-measurements and the equipment measurements construct a minimum set of measurements which can represent the state of this zero impedance power system, in another word, they are a linear transformation of the state.

Then we can give the equipment measurements with very high weight while the pseudo-measurements with very low weight and do the zero impedance current state estimation with this measurement set. The zeros impedance state estimator can detect and identify the bad data, in this case the improper assigned pseudo-measurements of circuit breakers, and filter them out from the measurement set. Finally, we can get a set of circuit breaker currents.

So in this substation, by calculating from power flow, the equipment measurements are in Table III. And we assume that the standard value is 0.01 p.u. for each circuit breaker current pseudo-measurement. After the state estimation, the minimum set of measurements is in Table 6.3 and the corresponding analog real time database of this substation is in Table 6.4.

Table 6.3: Equipment measurements and initial circuit breaker currents pseudo-measurements

Equipment	Measurement		Weight	
	real part	imaginary part	real part	imaginary part
CU5	-0.05832	-0.22362	1	1
LD12	-0.07064	0.026767	1	1
LD13	-0.08613	0.097097	1	1
LT1	0.712299	-0.04957	1	1
LT5	0.392968	-0.03319	1	1
LT7	-0.62337	0.013321	1	1
LT9	-0.06533	0.039395	1	1
LT11	-0.14549	0.099638	1	1
LT12	-0.05595	0.030141	1	1
TR5_1	-0.41128	0.043377	1	1
TR5_2	0.411281	-0.04338	1	1
Circuit Breaker	Measurement		Weight	
	real part	imaginary part	real part	imaginary part
1	0.01	0.01	0.05	0.05
2	0.01	0.01	0.05	0.05
3	0.01	0.01	0.05	0.05
4	0.01	0.01	0.05	0.05

5	0.01	0.01	0.05	0.05
6	0.01	0.01	0.05	0.05
7	0.01	0.01	0.05	0.05
8	0.01	0.01	0.05	0.05
9	0.01	0.01	0.05	0.05
10	0.01	0.01	0.05	0.05
11	0.01	0.01	0.05	0.05
12	0.01	0.01	0.05	0.05
13	0.01	0.01	0.05	0.05
14	0.01	0.01	0.05	0.05
15	0.01	0.01	0.05	0.05
16	0.01	0.01	0.05	0.05
17	0.01	0.01	0.05	0.05
18	0.01	0.01	0.05	0.05

Table 6.4: Equipment measurements and filtered circuit breaker currents pseudo-measurements

Equipment	Measurement		Weight	
	real part	imaginary part	real part	imaginary part
CU5	-0.05832	-0.22362	1	1
LD12	-0.07064	0.026767	1	1
LD13	-0.08613	0.097097	1	1
LT1	0.712299	-0.04957	1	1
LT5	0.392968	-0.03319	1	1
LT7	-0.62337	0.013321	1	1

LT9	-0.06533	0.039395	1	1
LT11	-0.14549	0.099638	1	1
LT12	-0.05595	0.030141	1	1
TR5_1	-0.41128	0.043377	1	1
TR5_2	0.411281	-0.04338	1	1
Circuit Breaker	Measurement		Weight	
	real part	imaginary part	real part	imaginary part
4	0.01	0.01	0.05	0.05
8	0.01	0.01	0.05	0.05
9	0.01	0.01	0.05	0.05

Explanation about the results: Theoretically, as there are 18 circuit breakers exist in the system, so the linear independent measurement number should be 18 while the number of equipment is 11 and the number of proper assigned measurement is 3. But when we do the state estimation, we use the injection of bus section as the measurement which means for the connection type bus section, there is also a pseudo-measurement zero. So the linear independent bus section injection measurement number is 5+11=16. And as bus section 8 is connection type, circuit breaker 8 and 9 should have the value and linearly dependent. So the total number of linearly independent measurements is 16+3-1=18 which is equal to the state number.

The real time voltage measurements database is much easier to generate. We just need to choose some random bus sections with phasor measurements in the bay which are similar within the real system.

6.3 Two-Level Linear State Estimator Case Study

6.3.1 Substation level state estimator case study

Two cases have been studied in the experiment, one of which is the IEEE-14 bus system while another one of which is the reduced WECC 179 bus system. As the substation level linear state estimator is the same for both systems, we just show the substation level state estimation results shown in Table 6.5 of the substation in Fig. 6.2 as an example.

Table 6.5: Estimated circuit breaker current states in Fig. 6.2

Circuit Breaker	Measurement	
	real part	imaginary part
1	-0.28103	0.026471
6	-0.684	0.049808
7	0.402973	-0.02334
5	-0.06064	0.036627
8	0.01	0.009999
2	0.431276	-0.02323
3	0.02	0.020002
4	0.01	0.01
9	0.01	0.010001
10	0.013333	0.013332
11	0.078674	-0.02618
12	0.224176	-0.12594
15	0.006667	0.006668
16	0.006667	0.006668

13	0.135432	-0.13415
18	0.359609	-0.26009
17	-0.05166	-0.21683
14	0.049289	-0.03693

6.3.2 Control center level linear state estimator case study

To analyze if the linear state estimator can totally trace the system trajectory, two test contingency cases are created based on the IEEE 14 bus system and the WECC 179 bus system, respectively.

6.3.2.1 IEEE-14 bus system

For the IEEE 14 bus system, a three phase fault has been introduced on bus 6 at 2 seconds in simulation time and cleared out 2 cycles later. The system voltage curve is shown in Fig. 6.3. If we assume the generated synchrophasor measurement streams rate is at 30 frames/second, and the control center can pick up each frame and process them in time, then the output of the two level linear state estimator is shown in Fig. 6.4. We can see that the curve in Fig. 6.4 is exactly the same with the one in Fig. 6.3. Besides, if we assume the control center does not pick up all the real time stream frames while can only pick up the newest set of stream after the previous computation, the estimated states results are shown in Fig. 6.5.

From the results, we can see (1) the linear state estimate can fully trace the trajectory of the system contingencies if all the data stream packets are processed. (2) As the communication delay and computation delay affect, sometimes the control center level state estimator can only capture some of the system dynamics which is the same with what the traditional control center state estimator can do while the substation level state estimator can capture almost all the dynamics and provide the estimated results to possible subscribers.

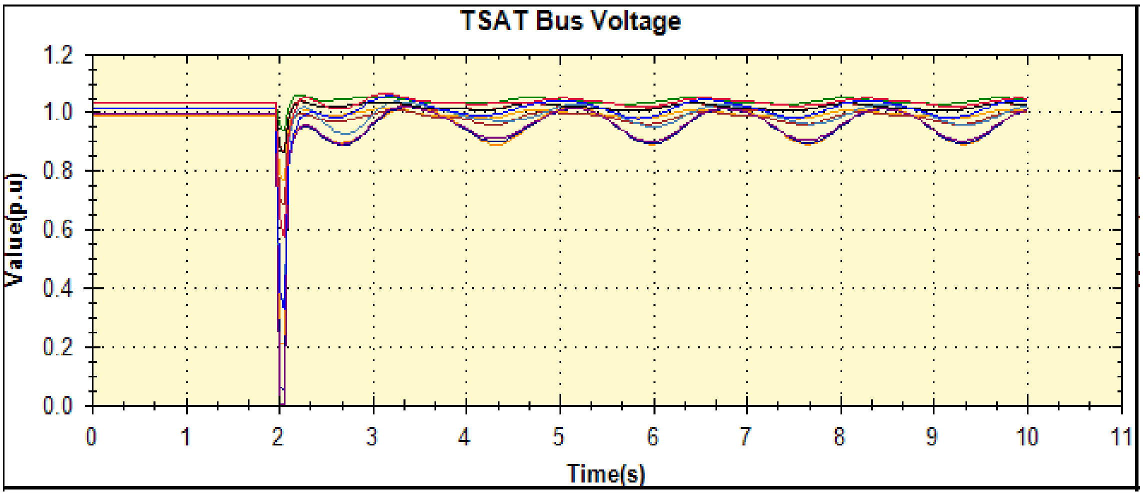


Fig. 6.3 IEEE 14-bus System Contingency Example

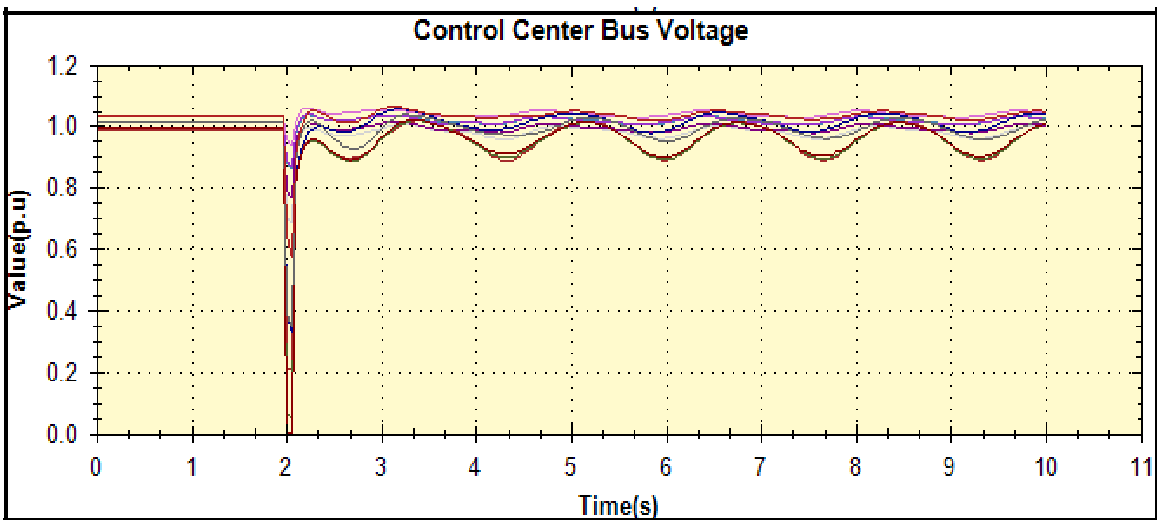


Fig. 6.4 IEEE 14-bus System Control Center Level LSE Full Result

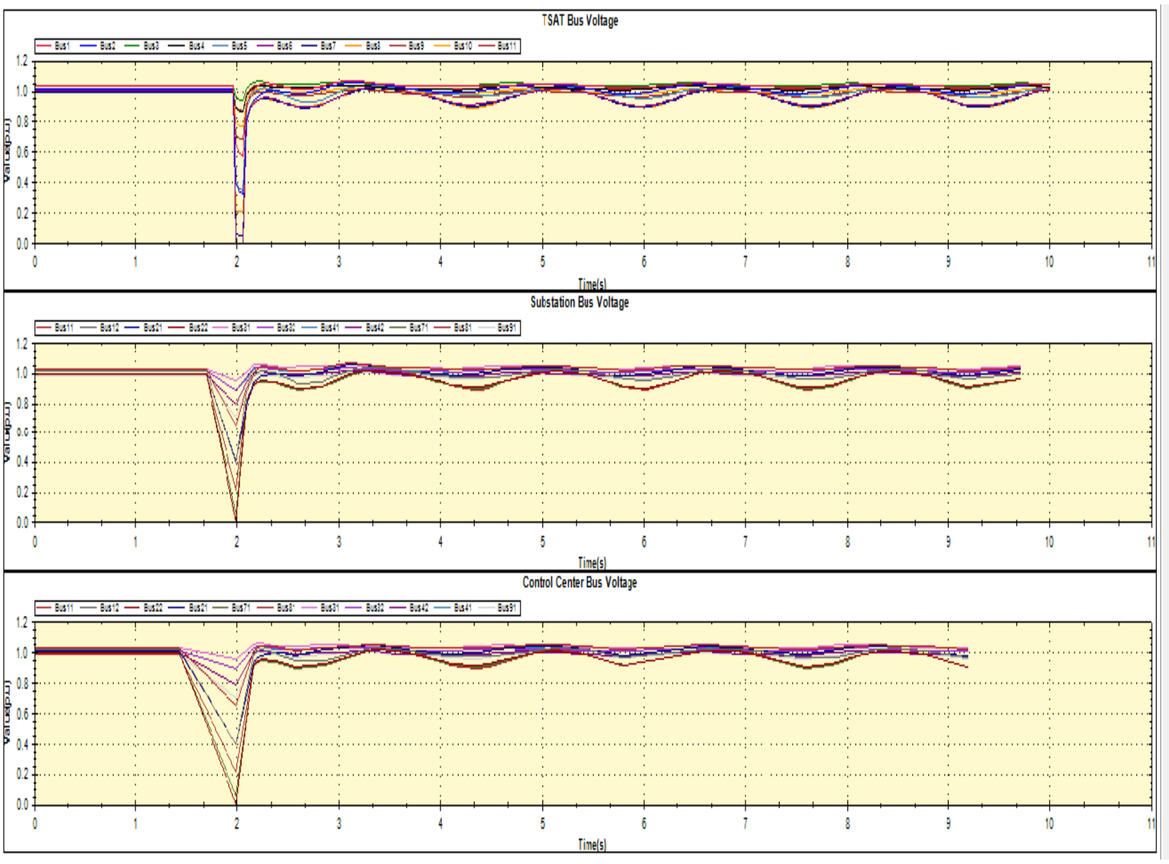


Fig. 6.5 IEEE 14-bus System Two Level Linear State Estimation Result

6.3.2.2 WECC-179 bus system

For the WECC 179 bus system, a three phase fault has been introduced on bus 14 at 2 seconds in simulation time and cleared out 1 cycle later, the system trajectory curve is shown in Fig. 6.6 and here we only assume the control center pick ups every data stream packet generated by the measurement generator. The control center level linear state estimator results are shown in Fig. 6.7.

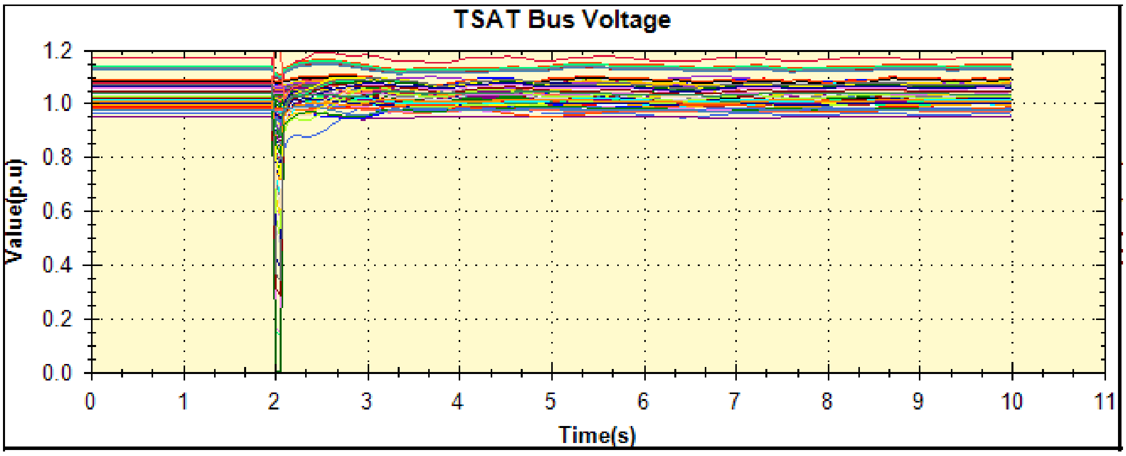


Fig. 6.6 WECC 179-bus System Contingency Example

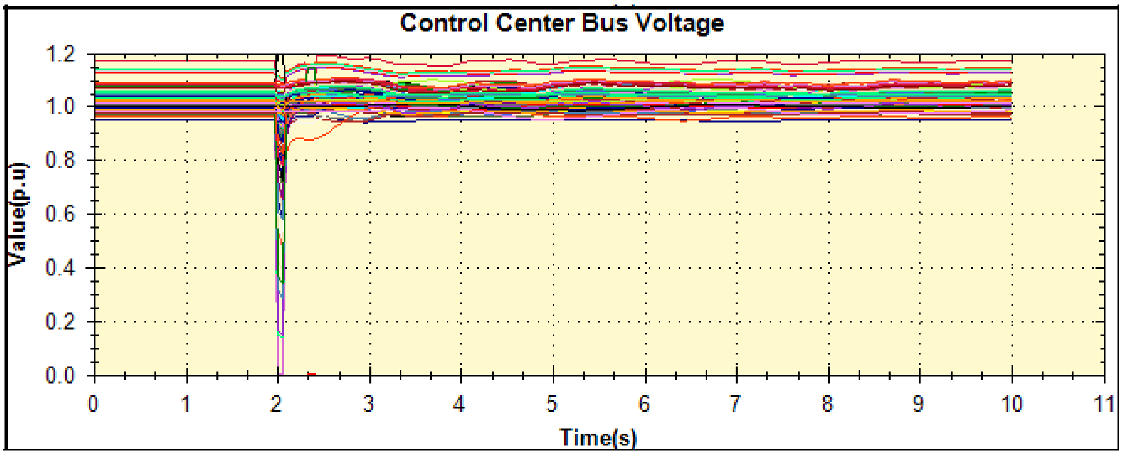


Fig. 6.7 WECC 179-bus System Control Center LSE Full Result

We can also see that the algorithm works well for a larger system without considering the communication and computation delays. As the computation performance is not the key factor in this research, we do not show the simulation results with considering its affects.

Chapter 7 Conclusions and Future Work

7.1 Conclusions

The new synchrophasor measurement units are expected to bring a revolution in power system applications. One such application is the linear state estimator, which if solved at higher periodicities, could be the basis for many other 'smart' grid applications. We propose in this paper, a pathway to the implementation of such a decentralized two-level linear state estimator. As the present day communication and information architecture are not able to support the volume and transfer of the synchrophasor database needed to support such a SE, this research presents an architecture that is able to do so. The main advantages of such an architecture are:

1. Its ability to handle the volume of phasor data produced by every IED in the substation. Given that the SE requires 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.
2. 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.
3. 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 to be transferred to the control center.
4. 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 algorithms for the two levels of calculations are developed, and we also show how the new linear and existing non-linear state estimators can be solved together to provide seamless SE solutions. First we 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 is 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 are 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.

We also have described the transitional two level linear state estimator which can be used before all the substations are synchronized. We believe that as synchronized phasor measurements proliferate in the power grid, this state estimation system eliminates many of the problems plaguing today's state estimators guaranteeing solutions that are more accurate.

7.2 Future Work

Although this research proposed both the architecture and algorithms of a two-level synchronized measurements based state estimator, the work doesn't end here. The following aspects should be studied further:

1. More accurate measurements are needed but this is not enough; in order to have a reliable SE, the consistency between the accuracy of measurements and the accuracy of models, must be ensured.

2. A precise review of standard approximate models must be done. Especially at the substation level, interoperability becomes a very important issue for all the “smart” applications and the substation level state estimator must merge into the substation computation systems to both take advantages of all kinds of IEDs and contributes to the substation information integration.

3. A sufficient and necessary condition of topological observability analysis at the substation level (Bus-Section/Switching-Device model) should be proposed. In this research, we just propose the necessary condition of the topological observability. With the condition in this paper, once the state is in the observable island, it is observable, but there might be observable states in the system while we identified them as unobservable. So more detailed research should focus on developing the Bus-Section/Switching-Device model based topological observability analysis.

The interface between the GridSim disturbance simulation and real-time control schemes need further development. As introduced in section 6.1, disturbance and user defined real time control scheme interface to the virtual power system generated by simulation tools needs to be developed to simulate disturbances and receive control signals from wide-area control schemes. This provides a “From Meters to Actuators” simulation test bed for wide-area control schemes and smart grid applications.

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