Transition to a Two-Level Linear State Estimator, part I: Architecture

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Abstract-- **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 main contribution in this paper is that this two-level processing removes the bad data and topology errors, which are major problems today, at the substation level.**

In Part I of the paper, we describe the layered architecture of databases, communications, and the application programs that are required to support this two-level linear state estimator. In Part II, we describe the mathematical algorithms that are different from those in the existing literature.

As the availability of phasor measurements at substations will increase gradually, this paper 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.

Index Terms-- **PMU, State Estimation, Energy control centers.**

I. Introduction

The traditional state estimator (SE) function in a control center was initially developed and implemented in the 70s. Conceptually, it was a software function that connected to the back-end of the Supervisory Control and Data Acquisition (SCADA) system. Thus the information architecture that supports the SE is highly dependent on the SCADA architecture. The measurement data used by the SE is a subset of the 'real-time' database in SCADA. The SE also needs connectivity and system parameter data that is not usually available in the SCADA 'static' database.

In addition to the information architecture of communications and data management, the SE software function itself is actually made up of three programs solved sequentially:

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

In the last two decades the substation measurement systems have changed to microprocessor based digital technology (intelligent electronic devices or IED) connected by local area networks (LAN) that can sample measurements at many times a second. Furthermore, these IEDs can time-stamp the measured data to a GPS time signal thus being able to measure current and voltage phasors directly. These developments have raised the following possibilities:

- If enough voltage and current phasors are measured to meet observability, the SE equations can be linear like in [1].
- With more computation available at the substations, some of the SE calculations can be done at the substation like [2]-[4].
- If higher bandwidth communications are available, the SE periodicity can be shortened to today's SCADA rates.
- The high accuracy time-stamping of the measurement data removes time-skewing as a limiting factor in SE periodicity.

In this two-part paper we develop both the architecture and the algorithms required for such a two-level, high periodicity, linear SE. Most papers on SE do not mention the supporting architecture, so we develop this novel, layered architecture in this first part in some detail as it is critical for such an SE to work. (We present the algorithms in the second part but as the linear SE [1] is not a new concept, only the additional new algorithms for the two-level implementation are presented.)

It has been generally assumed that implementing such an SE (and hence moving to the 'smart' grid) will only follow after a huge investment in infrastructure (substation retrofits, communication upgrades, etc.). In this paper, we show a pathway in which partial upgrades can be utilized immediately. This is different from incorporating individual phase angle measurements into the existing SE which doesn't improve the SE much until the percentage of phasor measurements exceeds a certain threshold [5]. We show how partial

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upgrades by making substations observable one at a time can produce SE solutions for the whole in which the upgraded portions can enjoy better SE results.

In this Part I of the paper, we present the architecture of the proposed SE. In section II, we present the information architecture: the communications needed within the substation and between substations and control center; and the distributed database configuration needed. In section III, we present the structure of this distributed two-level SE. We then describe how this architecture can be gradually implemented substation by substation in section IV. Finally, in the Appendix we provide a simple example of how the communication system can be simulated to determine time-skews that become increasingly important in phasor-based SE.

II. Information System 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 SE is a subset of the measurements gathered by SCADA and some care was taken to make sure that this subset was gathered (polled) within a small, typically 10s, time window.

The database that supports SE 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 will require 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.

A. Communication System

The proposed communication infrastructure is shown in Fig 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 [6]. 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.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.

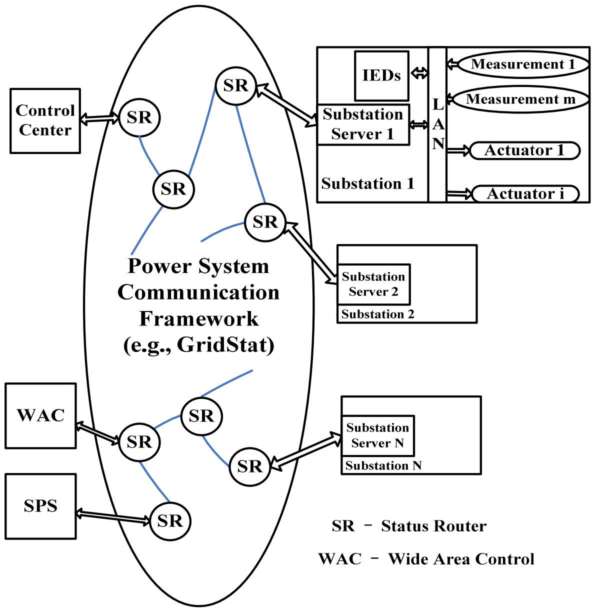


Fig 1. Power System Communication Infrastructure

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 [7]:

$$t_{comm} = t_{trans} + t_{prop} + t_q \tag{1}$$

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 will 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 [8]. Although communication delays have not been particularly relevant to the traditional SE using non-time-stamped data, these delays will have to be tightly controlled when using synchronized phasor data. Thus an example of how these can be calculated is shown in the Appendix for a small real system.

B. 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.

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

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 2. As the power system changes, such as the incorporation of new substations, both the static database and the real time database will change. Maintenance of the database remains a difficult and error-prone manual task as shown in [9].

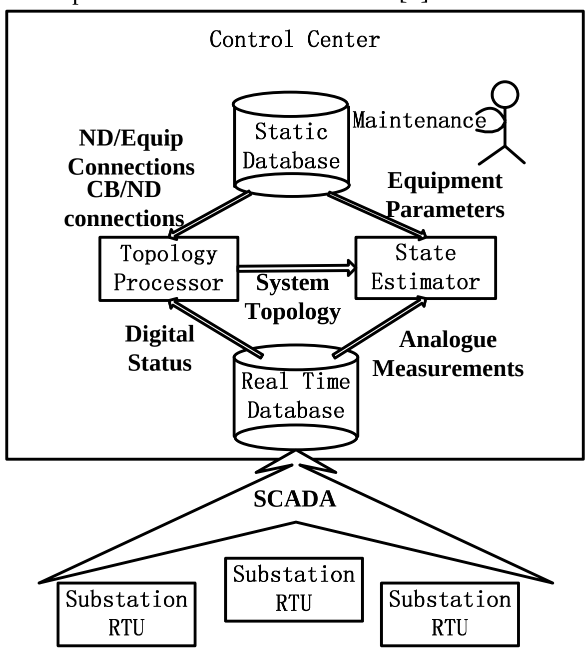
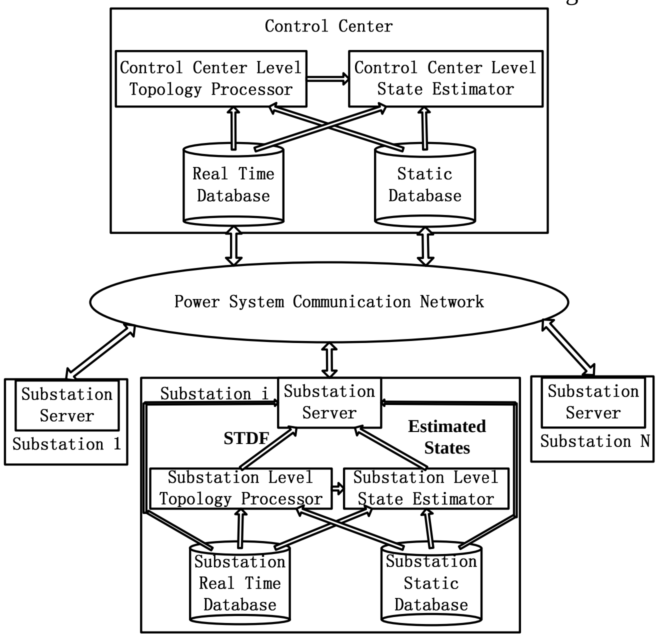


Fig 2. Traditional Real Time Modeling System and Database

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 will be much more convenient for such a decentralized or distributed application.

At the same time, as the control center level state estimator calculations need to merge all the substation topology and substation calculations into a system state, a database is also needed at the control center to support this function. This distributed two-level database structure is shown in Fig 3.



(STDF: Substation Topology Description File)

Fig 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 will certainly have other attributes. For example, the display functions at the control center will require access to the substation static and real-time data.

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 [10] 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 [11] 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.

III. Two-Level State Estimator Function Division

The three main functions, topology processing (TP), state estimation solution (SE) and bad data detection-identification (BD), of the state estimator is divided into two levels: substation level and control center level. It should be mentioned here that most publications on two-level SE refer to the coordination of state estimation between hierarchies of control centers, such as between several balancing authorities and their reliability coordinator. Few papers [3], [4] consider substation based SE calculations and the considerations are quite different. We describe our proposed scheme below, but only the software module structure is explained here whereas the algorithms are in Part II.

A. Substation Level State Estimator

At the substation level, we propose to handle each voltage level separately so that we only deal with zero-impedance circuits (the transformer branch impedances will be considered at the control center level). Thus the example substation shown in Fig 4 has two separate voltage circuits separated by a transformer F6. The program flow-chart is shown in Fig 5.

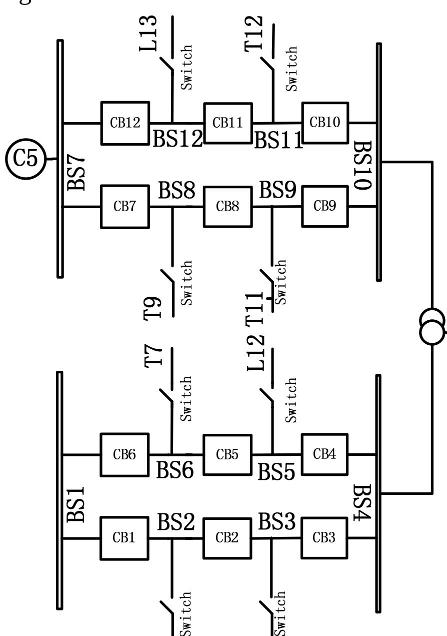


Fig 4. Circuit Breaker Oriented Substation Model

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 algorithm is presented in Part II of the paper. 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 [12]-[18].

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.

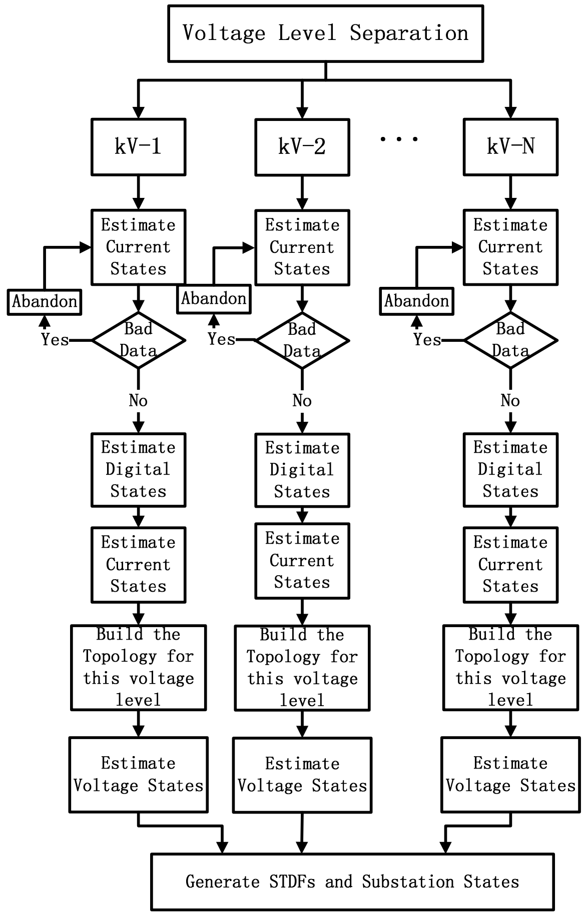


Fig 5. Flow Chart of the Substation Level State Estimator

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 Part II). 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.

As can be seen from the structure in Fig 5, 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.

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

We need to point out that other substation level state estimation formulation like those in [2]-[4] can also be used or integrated with our algorithm to obtain different advantages of local versus central handling of computation. Here we use a simple formulation where the local calculations only handle the simple Kirchhoff's Law equations while the network (Ohm's Law) equations are solved at the center. If the full substation solution is needed locally then the transformer equations will have to be handled in the substation.

B. Control Center Level Linear State Estimator

As we distributed many parts of the state estimation function to the substations, the control center level linear state estimator is much simpler than the traditional SE at the control center. The control center level linear state estimator receives all the analog estimated phasor measurements (bus voltages, branch currents, injection currents) and the substation topology from the substations.

The structure of this function, however, remains the same as the traditional SE, i.e. topology processing first, followed by the linear SE solution and bad data processing. The topology processor connects the substation topologies with the branch data. This algorithm is presented in Part II.

The analog phasor data from the substations are then used to solve the linear SE to obtain all node voltages. The bad data detection and identification is run on the results but it is expected that most bad data – digital and analog – would be filtered out at the substations.

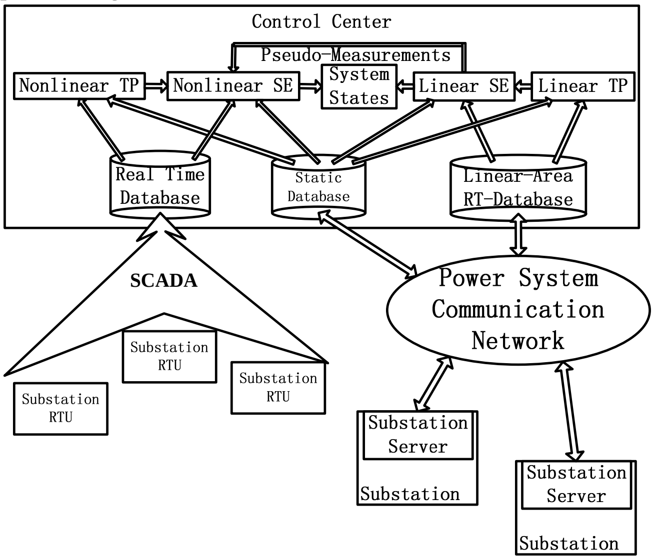
IV. Transitional State Estimator and System Architecture

In this paper we assume that in the future, all substations will be digital with many phasor measurements. Moreover, we assume that these substations will be connected through high bandwidth communication systems. As the technologies are already available the timing is only dependent on the investment needed for implementation.

We point out in this section that the state estimator can take advantage of partial implementation of such technologies. The assumption here is that enough phasor measurements are implemented in each substation thus making it locally observable and redundant, and that it is connected to the control center with high-speed communication. As more substations of this type are added or retrofitted, they can be incorporated to improve the SE in those areas.

The transitional two-level multi-area state estimator will require both real time measurements transferred by SCADA system and the new power system communication network. So we need a transitional information architecture as shown in Fig 6. 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.

Many distributed multi-area state estimation methods are introduced in [19]-[25]. We use this idea to solve the transitional multi-area state estimation but our network partitioning is somewhat different.



(Nonlinear TP represents the topology processing in the "nonlinear area")
Fig 6. Transitional Real Time Modeling System and Database

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 will have to be solved by the traditional SE method. This assumption is reasonable because for example, we can assume that the substation level state estimators are implemented at the high voltage substations while the low voltage substations are not yet retrofitted. Then we can divide the whole system into several linear areas and nonlinear areas shown in Fig 7. The boundary buses connect these areas and the phasor based linear area calculations are weighted higher to influence the nonlinear area calculations.

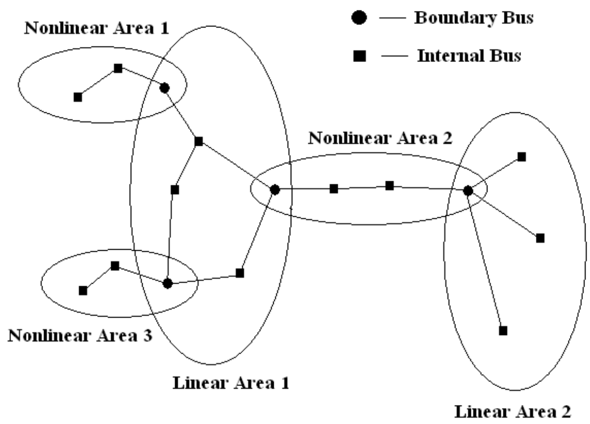


Fig 7. Multi-area network with boundary bus

Here we do not propose a new design of centralized SE leading to an optimal mathematical solution when only some substations are equipped with the substation level SE but the proposed method takes advantage of the substation level SEs without modifying existing centralized SEs. We estimate all the system states in the following order: first, 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 will be available to the operator and the contingency analysis functions.

V. Conclusion

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 will not be able to support the volume and transfer of the synchrophasor database needed to support such a SE, the Part I of this paper presents an architecture that will be able to do so. The main advantages of such an architecture are:

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

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

In Part II of this paper, we develop the algorithms for the two levels of calculations, and we also show how the new linear and existing non-linear state estimators can be solved together to provide seamless SE solutions.

VI. Appendix

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 will 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 will not introduce time skews of any significance. The time delays in communications will also have to be tightly controlled to get proper SE solutions. We show here how to calculate the time delays mentioned in section II by using a simulation program on a small communication network that would be appropriate for the IEEE-14 bus system shown in Fig 8.

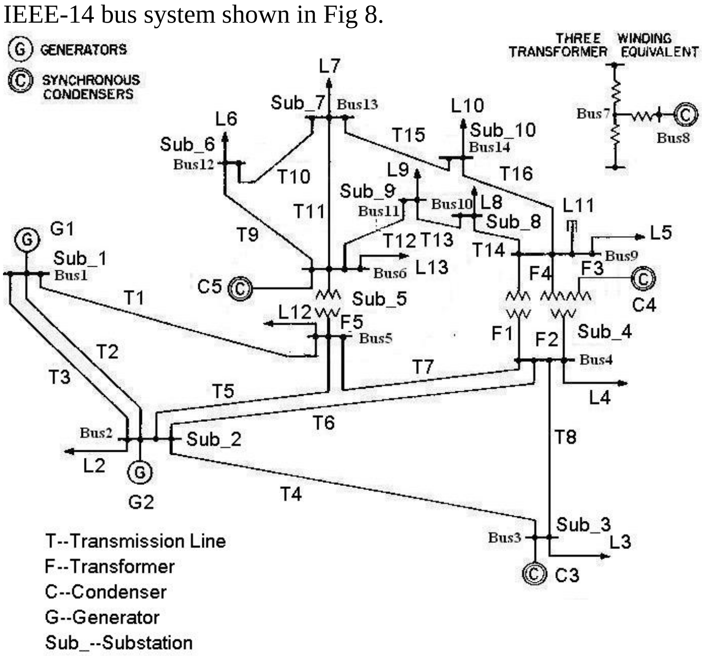


Fig 8. IEEE 14-bus system with named equipment

As introduced in (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 [8].

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 I.

TABLE I
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

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 will be somewhat larger.

More study results, using both more detailed simulation and experimental methods, about the time performance of an information system can be found in [26], [27], and some technical reports from GridStat Webpage (www.gridstat.net).

VII. Acknowledgment

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