Chapter 2
State Estimation and Visualization

One obvious application of GPS-synchronized measurements is the dynamic monitoring of the operating conditions of the system or the dynamic state estimation of the system. Since GPS-synchronized measurements can directly measure magnitude and phase of an electrical quantity (voltage and current) and since the state of the system often is defined as the voltage phasors at all buses of the system, some researchers have declared that GPS-synchronized measurements provide for the direct measurement of the system state and therefore there is no need for state estimation. This is not quite right since GPS-synchronized measurements are always tainted with measurement errors, and procedures for filtering the errors are necessary. These procedures are enabled by state estimators. Another important reason for using state estimators is that they provide the mathematical framework for validating the measurements against the model of the components of the system. This is the only practical approach to validate measurements. GPS-synchronized measurements enable new, better, accurate, and faster procedures for state estimation. In other words, GPS-synchronized measurements are the enabling technology to achieve system visibility and awareness at speeds not imagined before.

Most control and operation functions in a control center are model based. A model of the system is used to determine the best control action, or the model is used to determine the effects of specific actions (using a "what if analysis"). Since state estimation utilizing GPS-synchronized measurements provides a more accurate and reliable model of the system at faster speeds than before, more accurate applications and potentially dramatic improvements in the reliability and effectiveness of the controls are enabled.

In this chapter, the overall energy management infrastructure of a power system is reviewed, the role of the state estimator and the impact of GPS-synchronized measurements on the state estimator are discussed.

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2.1 The Energy Management System

The electric power system is a complex geographically dispersed system that delivers energy to most vital parts of the modern infrastructure of residential, commercial, and industrial facilities. It plays a very important role in the economic activities of any country and is responsible for generating, transmitting, and delivering energy to all vital economic activities of the society. The electric infrastructure system is evolving as more and more economic activities are "electrified" such as the recent trend of electrifying the transportation sector via electric vehicles and plug-in hybrid vehicles. Over time, the complexity of the system has grown. To manage this complex system, monitoring, control, and operation functions are computer assisted. Computer control systems of electric power systems have evolved as computer and monitoring technology evolved. Throughout the years, these systems have been named "control centers," "energy management systems (EMSs)," and "independent system operations." The names reflect the changing emphasis in the functions of these control centers. For simplicity, the term EMS will be used.

The EMS concept comprises hardware and software for the purpose of monitoring and controlling the power system. Typically, the function of monitoring is fully automated and comprises many sensors and meters that are typically integrated into a digital system. The introduction of GPS-synchronized measurements created devices that take measurements synchronized in time with microsecond precision. These measurements are very valuable to the overall monitoring system of a power system. As will be seen later, they provide new and better ways to identify the system model in real time at much faster computational speeds than previous technologies. In this chapter, an examination of how this technology has changed the process of state estimation and the process of extraction of the real time model of the system will be presented. The monitoring function and the subsequent extraction of the real time model of the system is fundamental to the control of the power system because the control methodology of power systems is model based. In general, control functions are either automated or manual, but they are both (automatic or manual) model based, i.e., the model is utilized to determine the best control option and to determine the effect of the control action on the system before the control is exercised.

Historically, EMSs have evolved from the offices of traditional dispatchers, who have in their reach supervisory equipment. Based on their experience, they would monitor the supervisory equipment and control the system appropriately. The control was manually executed upon communication between the dispatcher and local operator (e.g., plant operator). As the size and complexity of the system grew, this approach was not adequate. A number of incidents indicated that the security of the system, defined as the ability to operate in synchronism under possible random disturbances, could not be guaranteed with this simple approach. Out of this need, a comprehensive and integrated approach to monitor and control a power system has emerged.

Advances in computers and power system hardware have opened up new possibilities. As the technology has evolved, so has the EMS. A modern EMS is characterized by:

1. Monitoring system—which evolved from the basic supervisory control and data acquisition (SCADA) system to a digital monitoring system with state estimation, bad data detection, identification and rejection, validation of the real time model of the system, and sophisticated visualization methods of the system operating conditions.
2. Dispatch operation—which has been replaced with the fully digital automatic generation control (AGC). The AGC integrates the dispatch function with the load frequency control, power interchange control problem, and various power system optimization functions.
3. System security functions (monitoring and control)—which have been integrated into a hierarchical control scheme.
4. Advanced economy scheduling functions—which are an integral part of the system, including access to the power markets.

The hardware required for the new approach is illustrated in Fig. 2.1. The sensors and controls, located in the field, collect data. For example, a sensor can be a wattmeter, a voltmeter, a current meter, or a breaker status device. These data are collected at the remote terminal units (RTUs), which are normally hardwired to the sensors and controls. Then, the data are transferred through communication channels to communication input/output controllers (CIOCs) located normally in a central location. There the data are transferred to the computers. Computer programs evaluate the data, use them for state estimation, detect and reject bad data, provide the real time model of the system, and display the information on computer screens, dynamic mimic boards, or computer-generated projections of system displays using sophisticated visualization tools. The operator can visualize the operation of the system by examining the displays.

In a modern EMS, a computer (automatically or on dispatcher command) can issue commands, which are then transferred through the CIOCs, communication links, and RTUs to the field equipment for execution (e.g., a trip command for a breaker).

The hardware configuration of Fig. 2.1 provides the possibility of controlling and operating the system in a rather sophisticated manner. The number of functions and controls is relatively large. Table 2.1 provides a partial list of the computational and control functions. As mentioned, these control functions are model based. The state estimation provides the real time model that is needed by these functions. This is the reason state estimation stands out from the other functions. In this chapter, the focus is on state estimation and in particular the utilization of phasor measurement unit (PMU) data in the state estimation function.

2.2 Real Time Operational Requirements

Effective control and operation of electric power systems requires accurate and reliable knowledge of the system model and the operating state of the system in real time. For this purpose, modern power systems are equipped with an extensive data

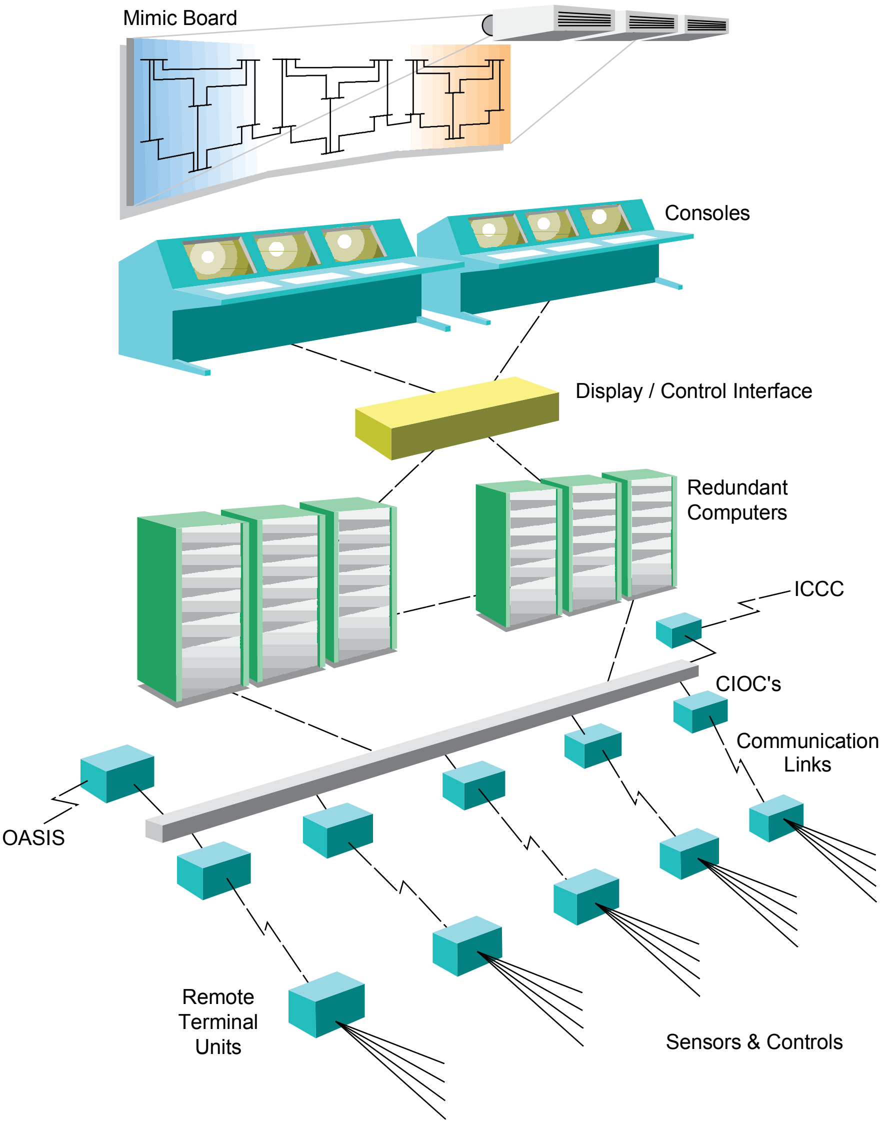


Fig. 2.1 Typical configuration of energy management system hardware

acquisition system. Local analog and status quantities, such as voltage magnitude, real and reactive power flows, loads, and status of breakers (open/close) are measured and transmitted to a central location. The measurements are simple, requiring simple instrumentation. Typical analog measurements are: (a) voltage magnitudes, (b) real and reactive power flows, and (c) current magnitude measurements. Recent technology based on GPS has made it possible to measure voltage and current phase

Table 2.1 Partial list of computational and control functions

Data acquisition and processing	Energy management (AGC)	Security monitoring and control
SCADA	Automatic generation control	Contingency selection
Network topology	Economic dispatch	Contingency analysis
State estimation	Optimal power flow	Voltage stability assessment
Visualization	Unit commitment	Dynamic stability assessment
	Load forecast	Security controls
	Wind/PV forecast	
	Interchange evaluation	
	Locational marginal prices	

PV photovoltaic, *SCADA* supervisory control and data acquisition, *AGC* automatic generation control

angles as well. Typical status measurements are: (a) breaker status and (b) disconnect switch status. The traditional measurements are taken every one to several seconds. The PMU measurements are recorded several times per second and most typically 30 or 60 times per second as discussed in the previous chapter. Measurements are transmitted to a central location (the EMS or the energy control center) where they are processed to yield the operating state of the system. The process consists of two analysis problems: (a) determination of network topology and (b) determination of operating state. The network topology is constructed from the status of breakers and disconnect switches. The operating state of the system is constructed from analog measurements by means of state estimation. The state estimator addresses two issues. First, measurements are usually corrupted with error (resulting from potential transformer or current transformer inaccuracies, instrument error, transmission error, calibration, and human error in setting instrument parameters.). These errors are directly transmitted to the computed operating state. State estimation enables the filtering of the measurement errors and the extraction of the best estimate of the system model. Second, it is possible that one of the measurements may include a large error (gross error—due to meter malfunction or communication errors) resulting in a large discrepancy between the computed operating state and the actual operating state of the system. The state estimator enables the detection and identification of wrong measurements or errors in measurements (bad data).

The state estimator provides an ideal approach for the solution of the above-mentioned problems by taking advantage of redundant measurements. The redundant measurements are utilized to compute the best estimate of the operating state of the system based on statistical methods. As discussed in subsequent sections of this chapter, state estimation provides the mechanism to: (a) determine whether the system state can be computed from existing data (observability); (b) filter out usual measurement errors and, therefore, compute the system state with minimum error; (c) identify and reject bad data; and (d) determine the degree of confidence on the estimated state of the system. The conceptual view of the process is illustrated in Fig. 2.2. The figure illustrates two sets of input data to the state estimator: (a) status data and (b) analog data. The status data are used by the topology processor to construct the system topology. The analog data are subjected to consistency checks, limit checks, and detection of data with large errors. The filtered data and

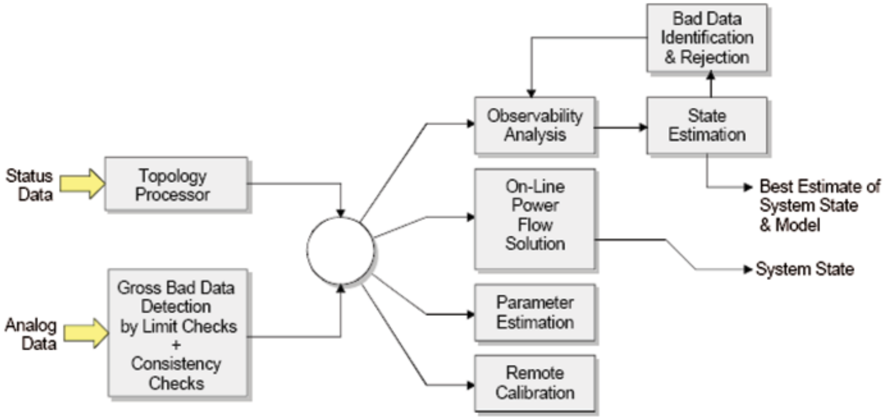


Fig. 2.2 Conceptual view of real time power system modeling and state estimation

the topology are used in the observability analysis to determine whether the state of the system can be computed from this data. Subsequently the state estimation is performed followed by bad data detection and identification. The end result is a validated real time model of the system.

In addition, other applications are possible using the collected data. These applications are parameter estimation and remote calibration of the meters as indicated in Fig. 2.2. The figure also indicates the on-line power flow option. The on-line power flow uses a subset of the available data to define and solve a power flow problem. The constituent parts of the state estimation process will be discussed next.

2.3 SCADA System

The necessary hardware to enable real time modeling of a power system is collectively referred to as the SCADA system. The supervisory control subsystem consists of hardware and software, which (a) collect status data (e.g., breaker status open/close) and analog data (e.g., measurements of voltage magnitude, current, real power, and reactive power) and transmit these data to a central location for processing and display and (b) allow remote tripping of breakers or changes of transformer tap. In most cases, supervisory control is a manual function, e.g., the dispatcher at the control center will initiate a command to open/close a breaker. The data-acquisition subsystem consists of remote terminal equipment for interfacing with power system instrumentation and control devices; interfaces with communication channels; and equipment for interfacing with the system control center. Since the SCADA system transmits data from the field to a central location and vice versa, communication media, protocols, and communication speeds are very important. In the past, it was customary to have separate communication channels for the SCADA. Today, however, it is a unified system, sharing common two-way communication channels that may consist of several physical layers. Communications are integrated into the RTU, which manages data collection, control functions, and communication with a master station. The master station (which is typically located in the control center) has multiple communication channels to RTUs. Many times a dedicated channel is assigned to each RTU. In other cases, there are fewer channels than RTUs, requiring more than one RTU to share a channel. Analog data is scanned periodically, typically every one second to a few seconds. Each scan is triggered by the system control center at the prescribed interval by using a request to all remote stations to send in data. The amount of data collected and transmitted is very large for typical power systems. These data are transported via communication channels. In order to minimize communication traffic some form of data compression is utilized. For example, for status data one can send only changes of status data. This approach minimizes the amount of data transfer and the amount of processing needed at the master station. Analog data can be also compressed with a number of methods. Independent of system configuration, SCADA system manufacturer, communication software, and computer configuration, the end result of the SCADA system function will be a collection of a set of system data for every sampling period. The data typically consists of:

- Breaker status
- Disconnect switch status
- Transformer tap setting
- MW flow measurements
- MVAr flow measurements
- Voltage magnitude (kV) measurements
- Current magnitude (kA) measurements
- Phase angle difference measurements

A simplified view of a SCADA system is illustrated in Figs. 2.3 and 2.4.

At the central location (EMS or control center), the data are managed using the data acquisition software, which performs the following tasks:

1. Data collection initiation and placement in the computer memory
2. Gross error checking
3. Conversion to engineering units
4. Limit checking
5. Generation of a data base interfaced with application programs

With the introduction of numerical relays and GPS-synchronized measurements (PMUs) the architecture of the RTU has changed. For example, the RTU may be a single intelligent electronic device (IED) connected to a "station bus," which is connected to a number of devices, e.g., relays and PMUs, or it can be a PDC that collects data from a number of PMUs and transmits this data to the master station. In fact, recently, merging units were introduced that allow for an additional flexibility in the configuration. Figure 2.5 illustrates some of these possibilities. In a typical

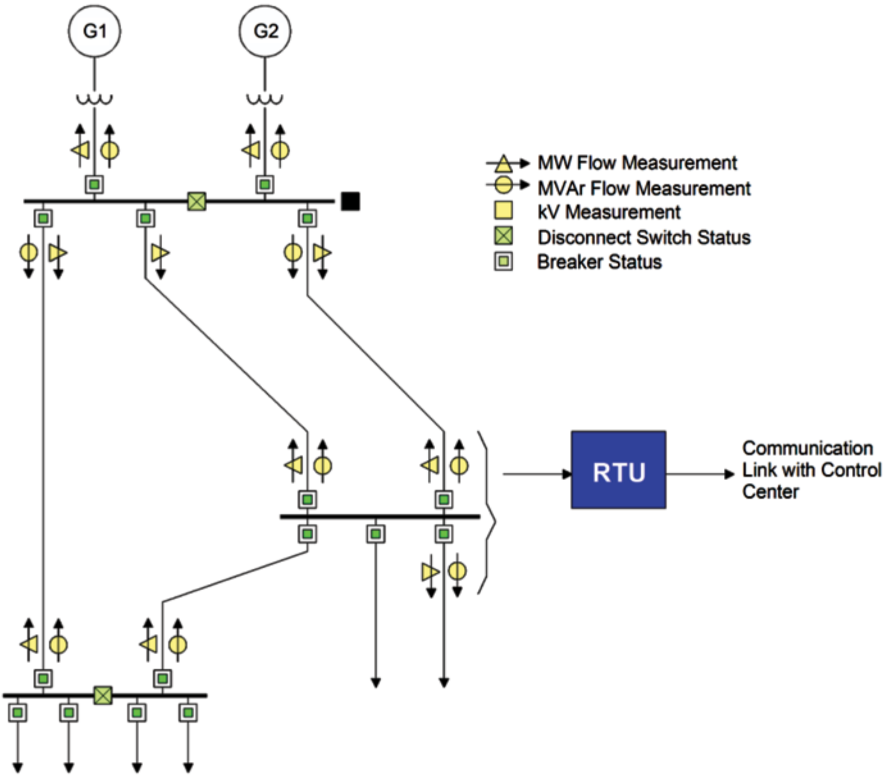


Fig. 2.3 Simplified view of a SCADA system—survey points

Fig. 2.4 Simplified view of a SCADA system—configuration

substation, one may observe subsystems of different eras integrated into the overall SCADA system. This reality is partially illustrated in Fig. 2.5.

The communication protocols used for PMU data and traditional SCADA data are different. Specifically, PMU data are streaming data in a format defined in the synchrophasor standard C37.118 [1]. The traditional SCADA data may use a number of legacy protocols or any of the new standards such as IEC 61850. In any case, the mixing of the data requires that the communications architecture should support

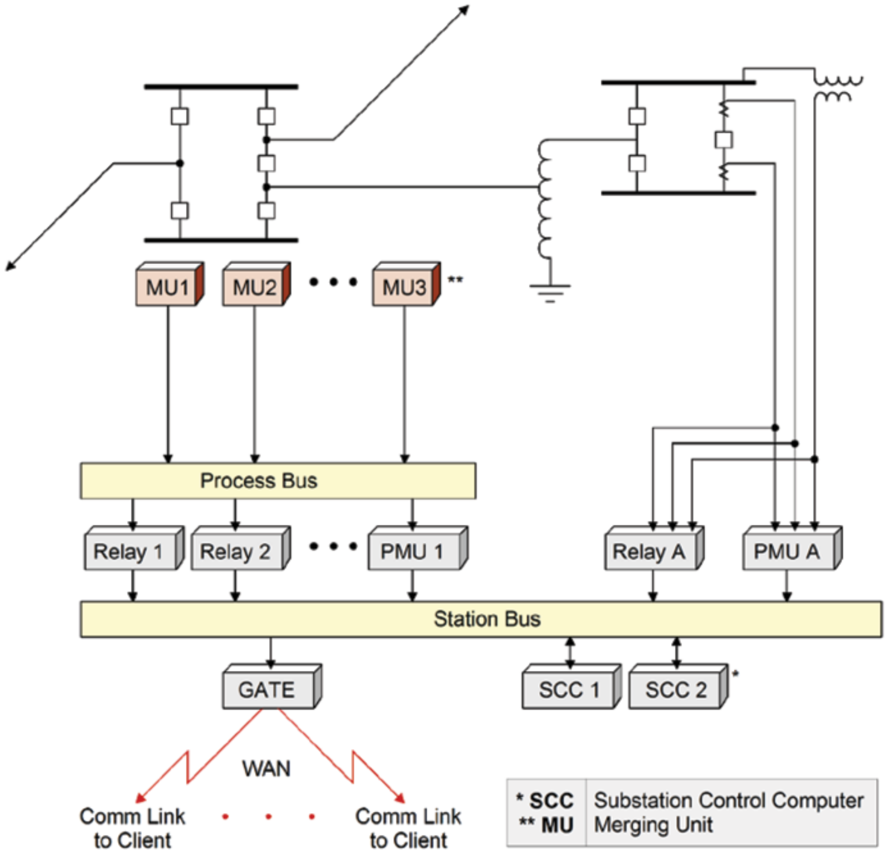


Fig. 2.5 Data collection, controls, and communications at a substation (Merging units/process bus/station bus architecture and numerical relays/station bus architecture)

the various standards or the entire substation should be designed in an integrated manner. This topic is beyond the scope of this book.

The data are utilized to form the system model (network configurator) and to estimate the system operating state (state estimation). The following sections describe these applications.

2.4 System Network Configurator

Data collected with the SCADA system are utilized in two ways. Status data (e.g., circuit breaker status, interrupt switch status, and transformer tap setting) are utilized to form the system network configuration and model. The software that takes

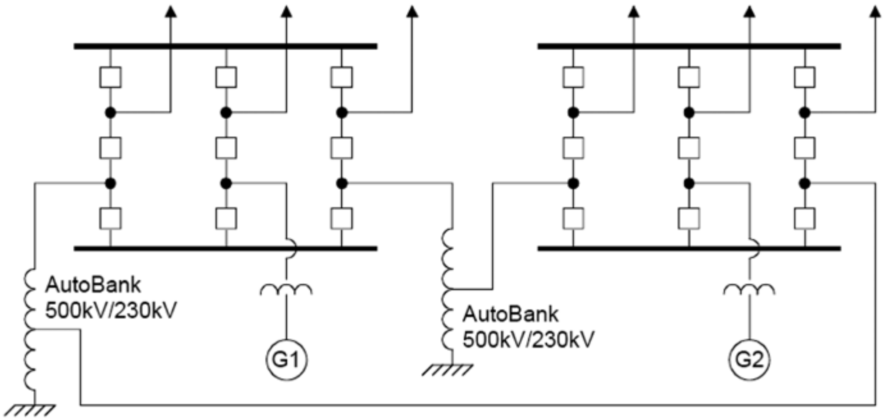
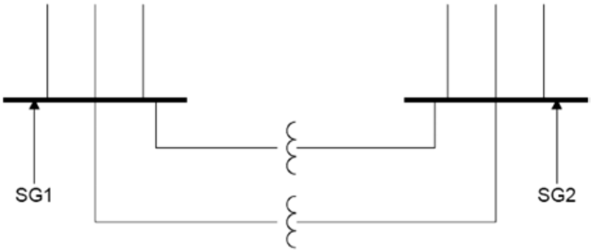


Fig. 2.6 Breaker-oriented model—pre-stored network data

Fig. 2.7 Bus-oriented network model of the system of Fig. 2.6



the status data and computes the system network configuration and model is known as the system network configurator. The information received with the SCADA system determines the status of the breakers. The system network configurator uses pre-stored information (physical arrangement of breakers, switches, and other substation equipment) and the breaker/switch status to determine a "bus oriented" model, i.e., which circuits are connected to which bus and what is the model of each circuit. A simple example is illustrated in Figs. 2.6 and 2.7. Figure 2.6 illustrates the breaker-oriented model at a substation. This model is invariant over time and it can be referred to as pre-stored network data. It changes only when new additions are implemented, such as addition of new breakers, construction of new lines, and other additions. Assuming all breakers are in the close position, Fig. 2.7 illustrates the bus-oriented model of the system. Typically, this procedure is executed only when a change in status data occurs.

The system network configuration and model is next combined with the analog data for the purpose of determining the operating conditions of the system. Typically, there are redundant measurements, which are used to obtain the best (in some

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