Energy Control Centers

1.0 Introduction

The energy control center (ECC) has traditionally been the decision-center for the electric transmission and generation interconnected system. The ECC provides the functions necessary for monitoring and coordinating the minute-by-minute physical and economic operation of the power system. In the continental U.S., there are only three interconnected regions: Eastern, Western, and Texas, but there are many *balancing areas* (also known as *control areas*), with each balancing area having its own ECC. Figure 1 illustrates the balancing areas within the US.

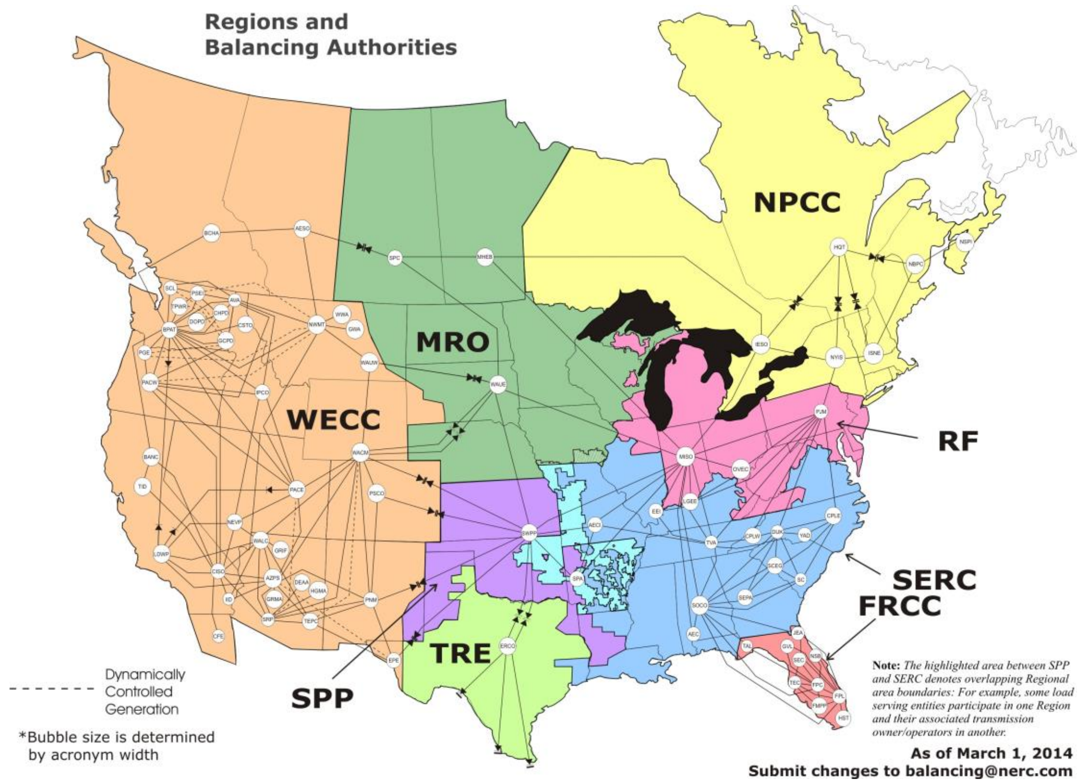

Fig. 1: U.S. Energy Control Centers [0]

Maintaining integrity and economy of an inter-connected power system requires significant coordinated decision-making. So one of the primary functions of the ECC is to monitor and regulate the physical operation of the interconnected grid.

Most areas today have a two-level hierarchy of ECCs with the Independent System Operator (ISO) performing the high-level decision-making and the transmission owner ECC performing the lower-level decision-making.

A high-level view of the ECC is illustrated in Fig. 2 where we can identify the substation, the remote terminal unit (RTU), a communication link, and the ECC which contains the energy management system (EMS). The EMS provides the capability of converting the data received from the substations to the types of screens observed in Fig. 2.

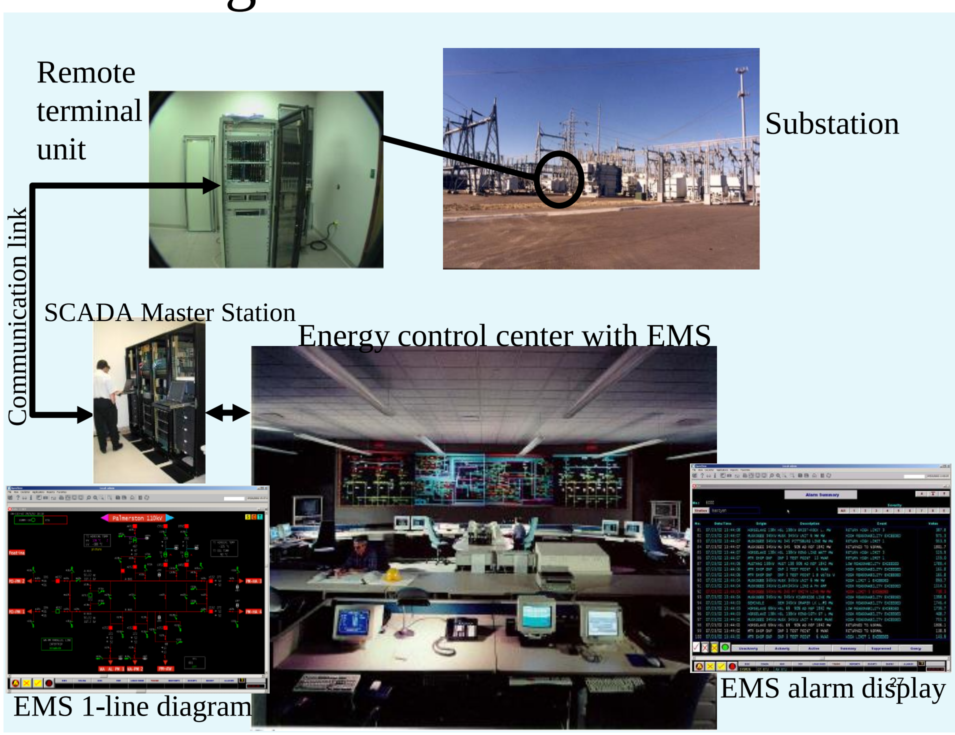

Fig. 2: Basic Components of Energy Control Centers

In these notes we will introduce the basic components and functionalities of the ECC. Note that there is no chapter in your text which provides this information.

2.0 ECC Components

The system control function traditionally used in electric utility operation consists of three main integrated subsystems: the energy management system (EMS), the supervisory control and data acquisition (SCADA), and the communications interconnecting the EMS and the SCADA (which is often thought of as part of the SCADA itself). Figure 3a [1] provides a block diagram illustration of these three integrated subsystems and Fig. 3b provides a closer view. The SCADA and communications subsystems are indicated in the dotted ovals at the top left hand corner of the figure. The rest of the figure indicates the EMS. We will describe each one in the following subsections.

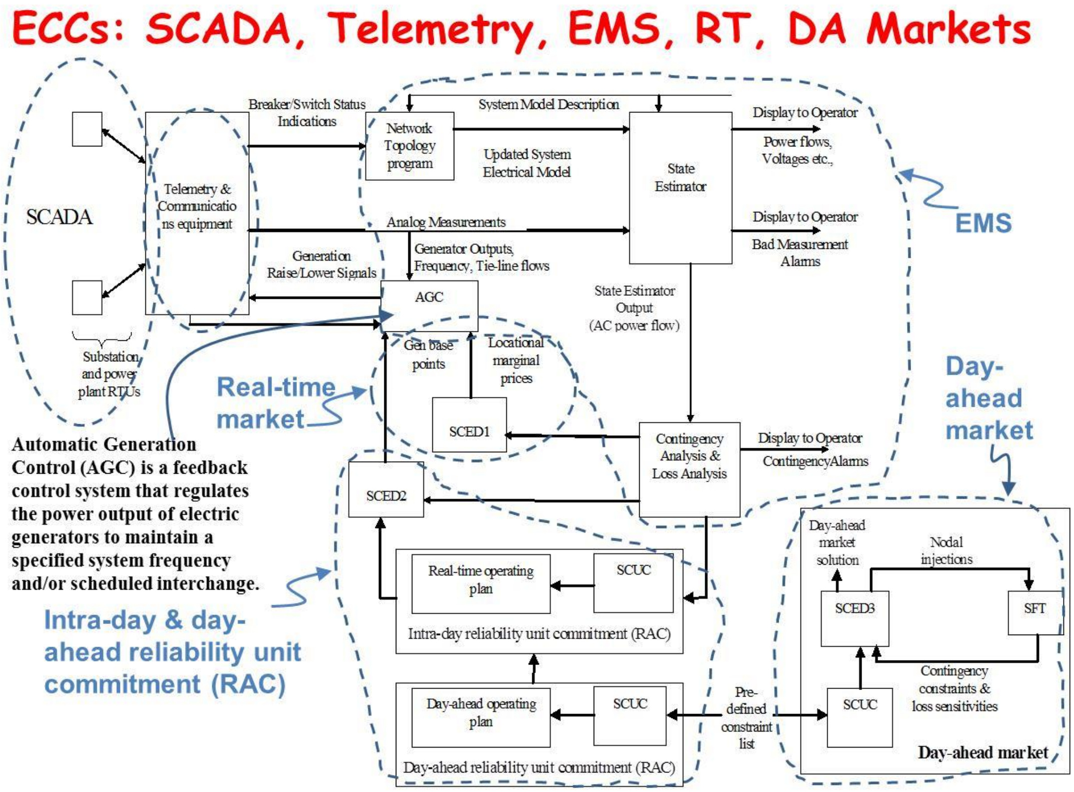

Figure 3a: System control subsystems - EMS, SCADA, and Communications [1]

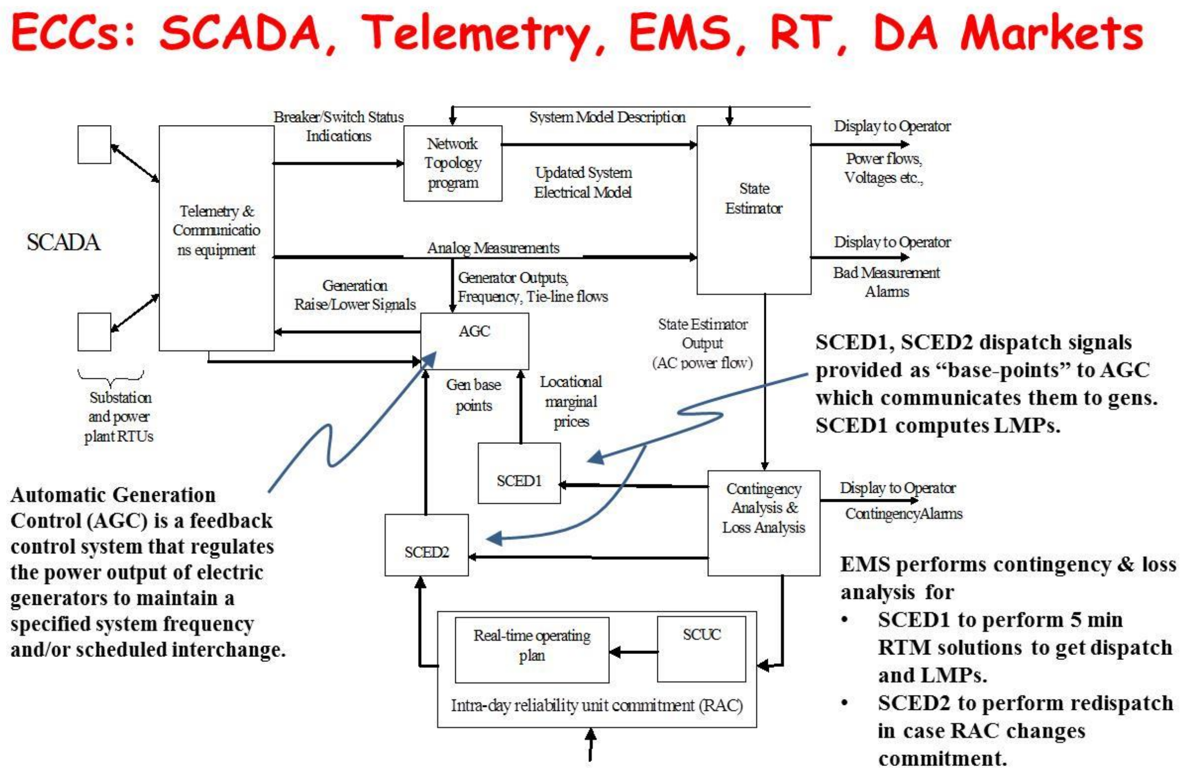

Fig. 3b: Figure 3a: System control subsystems - EMS, SCADA, and Communications [1]

We distinguish EMS from distribution management systems (DMS). Both utilize their own SCADA, but for different functions. Whereas EMS/SCADA serves the high voltage bulk transmission system from the ECC, the DMS/SCADA serves the low voltage, distribution system from a distribution dispatch center. We are addressing in these notes the EMS/SCADA.

2.1 SCADA

There are two parts to the term SCADA [2-5]. *Supervisory control* indicates that the operator, residing in the energy control center (ECC), has the ability to control remote equipment. *Data acquisition* indicates that information is gathered characterizing the state of the remote equipment and sent to the ECC for monitoring purposes.

The monitoring equipment is normally located in the substations and is consolidated in what is known as the remote terminal unit (RTU). Generally, the RTUs are equipped with microprocessors having memory and logic capability, together with some form of telemetry to provide the communication link to the ECC.

Relays located within the RTU, on command from the ECC, open or close selected control circuits to perform a supervisory action. Such actions may include, for example, opening or closing of a circuit breaker or switch, modifying a transformer tap setting, raising or lowering generator MW output or terminal voltage, switching in or out a shunt capacitor or inductor, and the starting or stopping of a synchronous condenser.

Information gathered by the RTU and communicated to the ECC includes both analog information and status indicators. Analog information includes, for example, frequency, voltages, currents, and real and reactive power flows. Status indicators include alarm signals (over-temperature, low relay battery voltage, illegal entry) and whether switches and circuit breakers are open or closed. Such information is provided to the ECC through a periodic scan of all RTUs. A 2 second scan cycle is typical.

2.2 Communication technologies

The form of communication required for SCADA is *telemetry*. Telemetry is [6] the measurement of a quantity in such a way so as to allow interpretation of that measurement at a distance from the primary detector. The distinctive feature of telemetry is the nature of the translating means, which includes provision for converting the measure into a representative quantity of another kind that can be transmitted conveniently for measurement at a distance. The actual distance is irrelevant.

Telemetry may be analog or digital. In analog telemetry, a voltage, current, or frequency proportional to the quantity being measured is developed and transmitted on a communication channel to the receiving location, where the received signal is applied to a meter calibrated to indicate the quantity being measured, or it is applied directly to a control device such as a ECC computer [2].

Forms of analog telemetry include variable current, pulse-amplitude, pulse-length, and pulse-rate, with the latter two being the most common. In digital telemetry, the quantity being measured is converted to a code in which the sequence of pulses transmitted indicates the quantity. One of the advantages to digital telemetering is the fact that accuracy of data is not lost in transmitting the data from one location to another [2]. Digital telemetry requires analog to digital (A/D) and possible digital to analog (D/A) converters, as illustrated in Fig. 4 [2].

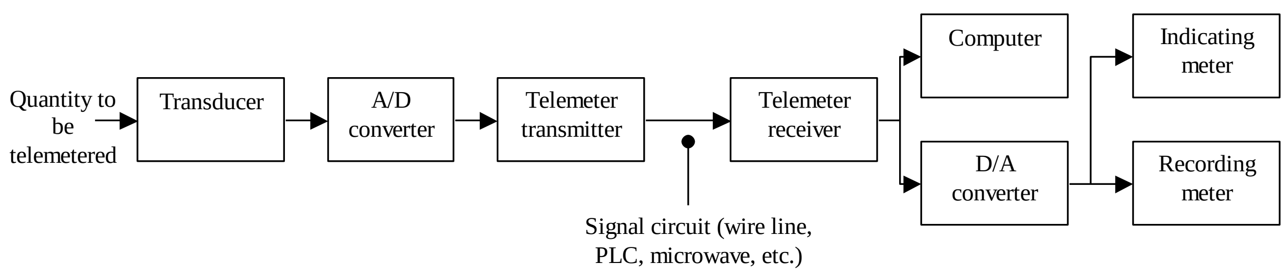

Fig 4: Block Diagram of Telemetering System [2]

The earliest form of signal circuit used for SCADA telemetry consisted of twisted pair wires; although simple and economic for short distances, it suffers from reliability problems due to breakage, water ingress, and ground potential risk during faults.

Improvements over twisted pair wires came in the form of what is now the most common, traditional type of telemetry mediums based on leased-wire, power-line carrier, or microwave [7]. These are *voice grade* forms of telemetry, meaning they represent communication channels suitable for the transmission of speech, either digital or analog, generally with a frequency range of about 300 to 3000 Hz [6].

<u>Leased-wire</u> means use of a standard telephone circuit; this is a convenient and straightforward means of telemetry when it is available, although it can be unreliable, and it requires a continual outlay of leasing expenditures. In addition, it is not under user control and requires careful coordination between the user and the telephone company. <u>Power-line carrier (PLC)</u> offers an inexpensive and typically more

reliable alternative to leased-wire. Here, the transmission circuit itself is used to modulate a communication signal at a frequency much greater than the 60 Hz power frequency. Most PLC occurs at frequencies in the range of 30-500 kHz. The security of PLC is very high since the communication equipment is located inside the substations. One disadvantage of PLC is that the communication cannot be made through open disconnects, i.e., when the transmission line is outaged. Often, this is precisely the time when the communication signal is needed most. In addition, PLC is susceptible to line noise and requires careful signal-to-noise ratio analysis. Most PLC is strictly analog although digital PLC has become available from a few suppliers during the last few years.

Microwave radio refers to ultra-high-frequency (UHF) radio systems operating above 1 GHz. The earliest microwave telemetry was strictly analog, but digital microwave communication is now quite common for EMS/SCADA applications. This form of communication has obvious advantages over PLC and leased wire since it requires no physical conducting medium and therefore no right-of-way. However, line of sight clearance is required in order to ensure reliable communication, and therefore it is not applicable in some cases.

A more recent development has concerned the use of fiber optic cable, a technology capable of extremely fast communication speeds. Although cost was originally prohibitive, it has now decreased to the point where it is viable. Fiber optics may be either run inside underground power cables or they may be fastened to overhead transmission line towers just below the lines. They may also be run within the shield wire suspended above the transmission lines.

Additional communication technologies include use of satellites, VHF and UHF radio, spread spectrum radio, and internet/intranet systems.

One easily sees that communication engineering is very important to power system control. Students specializing in power and energy systems should strongly consider taking communications courses to have this background. Students specializing in communication should consider taking power systems courses as an application area.

2.3 Energy Management System (EMS)

The EMS is a software system. Most utility companies purchase their EMS from one or more EMS vendors. These EMS vendors are companies specializing in design, development, installation, and maintenance of EMS within ECCs. There are a number of EMS vendors in the U.S., and they hire many power system engineers with good software development capabilities.

During the time period of the 1970s through about 2000, almost all EMS software applications were developed for installation on the control centers computers. An attractive alternative today is, however, the application service provider, where the software resides on the vendor's computer and control center personnel access it from the Internet. Benefits from this arrangement [10] include application flexibility and reliability in the software system and reduced installation cost.

One can observe from Figure 3 that the EMS consists of 4 major functions: network model building (including topology processing and state estimation), security assessment, automatic generation control, and dispatch. These functions are described in more detail in the following subsections.

2.3.1 Network Model Building

A network model is necessary in order to determine whether operating conditions are safe under the existing topology and also under the event that one or more components fail and are outaged. The network model must reflect the correct topology and the correct operating conditions relative to the actual network conditions. The information available to construct the network model includes the status indicators and the analog measurements available from the SCADA. The result of the network model builder is a power flow model. Network model building takes place in two steps, topology processing and state estimation.

Topology Processing: The topology of the network characterizes the connectivity between buses (nodes), the shunt elements at each bus, and which generators are connected to each bus. This information comes to the EMS from the SCADA in the form of status indicators for each circuit breaker and switch at all buses. This information is referred to as the *bus section-breaker-switch data* and provides a mapping of individual *bus sections* at each substation and how they are connected. Different bus sections connected by closed breakers or switches are electrically a single node. A key step in topology processing is to recognize these situations in order to minimize the number of nodes in the resulting network model.

Effectively, then, topology processing converts bus section-breaker-switch data into so-called *bus-branch data*. The bus-branch data is appropriate for modeling the transmission line and transformer connections between substations, rather than the precise bus-section connections at each substation [8], as illustrated in Fig. 5.

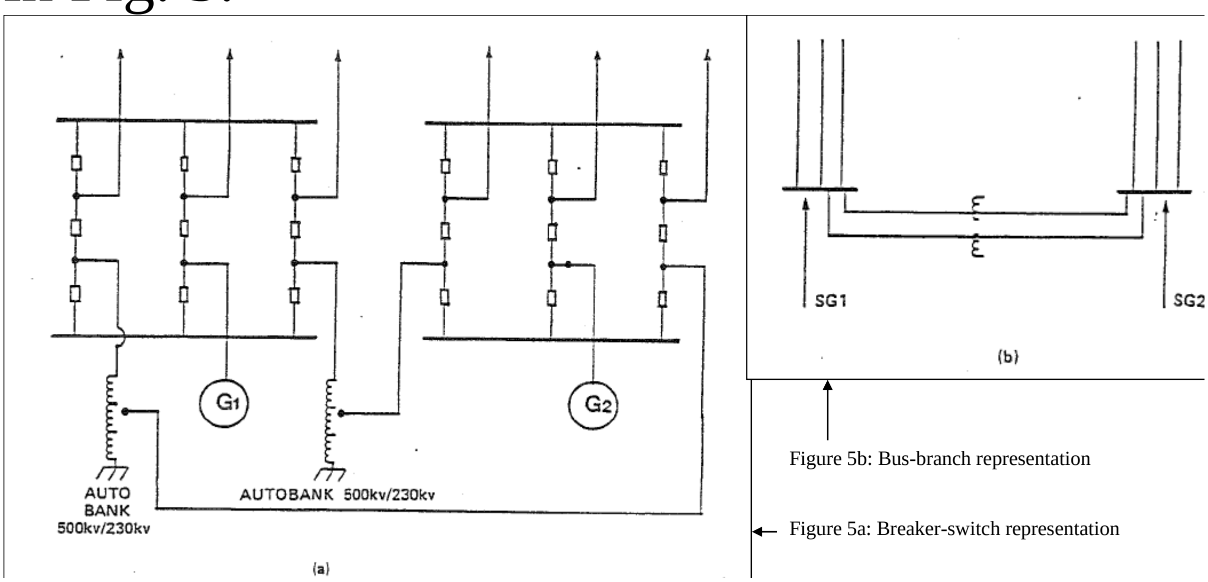

Figure 5b: Bus-branch representation

Figure 5a: Breaker-switch representation

Fig 5

The impedances of all network elements are stored in an EMS database, and this information, when combined with the output of the topology processor, is enough to establish the system topology.

State Estimation: Given the topology of the system, it still remains to determine the operating conditions, i.e., the bus voltages, load levels, and generation levels. At first glance, this appears to be an easy problem – just take the corresponding information from the SCADA. However, one must recognize the reality of data unavailability and of data error.

Data unavailability comes from two sources. First, there may be some substations that have no SCADA. Second, there may be some substation RTUs or telemetry systems that are unavailable due to maintenance or unexpected trouble.

Data error comes from the fact that all analog measurement devices contain some measurement error. Typically this error is small for any single device, but the use of many thousands of devices, each having small error, can result in significant inaccuracy in regards to the overall system analysis. The state estimator is a program that receives the SCADA measurement information and then uses statistical procedures to obtain the very best *estimate* of the actual state of the system. The result of state estimation is a power flow model that can be used for security assessment.

2.3.2 Security Assessment

Security assessment determines first, whether the system is currently residing in an acceptable state and second, whether the system would respond in an acceptable manner and reach an acceptable state following any one of a pre-defined contingency set. A *contingency* is the unexpected failure of a transmission line, transformer, or generator. Usually, contingencies result from occurrence of a *fault*, or short-circuit, to one of these components. When such a fault occurs, the protection systems sense the fault and remove the component, and therefore also the fault, from the system.

Of course, with one less component, the overall system is weaker, and undesirable effects may occur. For example, some remaining circuit may overload, or some bus may experience an undervoltage condition. These are called *static* security problems.

Dynamic security problems may also occur, including uncontrollable voltage decline, generator overspeed (loss of synchronism), or undamped oscillatory behavior.

Almost all EMS today are capable of performing static security assessment, because it only requires a power flow program to do so. Very few EMS are capable of performing dynamic security assessment, however, because the assessment tools are more complex and computationally intense. However, dynamic security assessment tools are rapidly becoming more prevalent in EMS with the continued growth in computational and algorithmic efficiency.

2.3.3 Automatic Generation Control

As we have seen already in this course, the purpose of AGC is to regulate the system frequency and power interchange between control areas.

There are two SCADA measurement used by AGC: total net tie line flow and frequency. There also exist *scheduled* values for these two parameters. The scheduled net tie line flow depends on the total sales less purchases to other control areas. The scheduled frequency is always 60 Hz. The differences between actual and scheduled tie line flow and frequency can be denoted as ΔP_{tie} and Δf, respectively. These two values are combined in a weighted sum $\Delta P_{tie}+B\Delta f$ and provided as the AGC control actuation signal. If this signal is positive, it means that either our control area is selling too much power or the frequency is too high. In either case, the solution is to reduce generation within our control area, and “lower” command pulses are consequently sent to all generators. If the control actuation signal is negative, it means that either our control area is buying too much power or the frequency is too low. In either case, the solution is to increase generation within our control area, and “raise” command pulses are consequently sent to all generators. AGC typically sends the appropriate command pulses to the generators every 1-5 minutes.

It is important to recognize that the command pulses sent to each generator represent incremental changes only. This leaves the question: What should be the set point power levels at the generators?

2.3.4 Economic Dispatch

Previous to the power industry restructuring, all ECCs used economic dispatch calculation

(EDC) to determine the set point power levels of all generators in order to supply the demand. Such a system still exists in some parts of the country. But in other parts, a market dispatch is done based on an auction system whereby the optimization algorithm is similar to EDC except generator cost-rate curves are replaced by generator owner bids. We have already studied the EDC problem and solution procedure.

One also observes in Figure 3 the acronym "SCED," which stands for *security-constrained economic dispatch*. The SCED is also an optimization problem. It is similar to EDC in that it typically has the same objective of minimizing the total cost of generation in order to supply the demand. Yet it extends the EDC to account for the equality constraints governing the real and reactive power flowing out of each bus and therefore, its optimal solutions are more realistic. More important, it offers the capability to determine the effects of different electrical constraints on the system economic operation.

The security constrained aspect of the SCED accounts for flow constraints imposed by security considerations identified through contingency analysis.

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