A SunCam online continuing education course

Introduction to Electrical Energy Management Systems

by

Robert Krug, P.E.

Electric Power Systems

To understand the role of Energy Management Systems in power systems control, a discussion of the electric system is required. Power systems are made up of components including generators at power plants, substations, transformers and transmission and distribution lines. See diagram below.

The first step is electrical energy production. Generators convert thermal, chemical, mechanical or nuclear energy to electrical energy. This energy must be efficiently transmitted to points of use. Transmission lines connect power plant energy to transmission substations at 115 to 765 kV. Alternating current (AC) is used because it can be transmitted at great distances with less losses than direct current. The AC frequency used in the United State is 60 cycles per second with the unit name of Hertz (Hz).

Finally the voltage is stepped down to distribution levels and routed to distribution feeders. These supply primary voltage to customer transformers.

Three phase power is produced at the power plants as the average power is constant and does not pulsate. Three phase motors used at industrial and commercial locations are more efficient than single phase motors. AC transmission lines have three conductors with a ground shield conductor to protect the lines from lightning strikes.

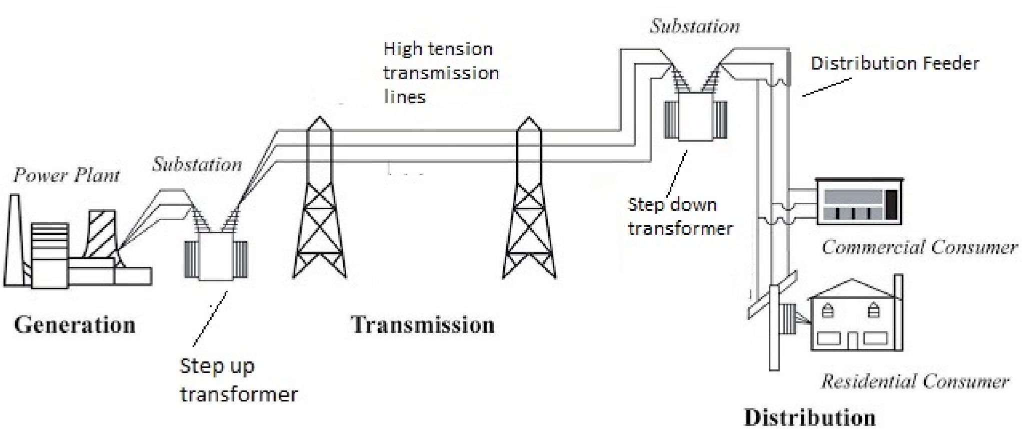

Figure 1 - AC Power System

AC power contains two components. Real power which does the useful work (rotation, heat, light) and reactive power which supplies the magnetic effect required by motors.

Real power flow is measured in watts and energy is measured by watts over a period of time. Energy is what is sold to electric utility customers in units of kilowatt hours or kWh.

Real power flow in power systems is measured in megawatts (MW) and reactive power is measured in mega volt-amps-reactive (MVAR). The latter is produced by generators and capacitors and is used to supply magnetic energy required by electric motors. Motor loads (ex: HVAC compressors, refrigerators, fans, pumps) dominate power system loads so MVAR control is critical to power systems. Reactive power does no useful work.

All power system components have current carrying capability ratings. There are normal ratings and emergency ratings. The emergency ratings are usually time based (ex: 4 hour, 10 hour or 24 hour). The difference is how much loss of equipment life is impacted by above normal rating operation. The total current has to also supply reactive needs of the system. Therefore the concept of apparent power was introduced and expressed as:

$$|S^2| = |P^2| + |Q^2|$$

Where:
S = Apparent power
P = Real Power
Q= Reactive Power

In other words, the magnitude of the apparent power in mega volt-amps (MVA) equals the square root of the sum of the squares of real power (MW) magnitude and reactive power (MVAR) magnitude. Equipment ratings are specified in MVA.

The output voltage of most generators is in the 4-24 kV range. A transformer can convert voltage levels but they also a produce a reciprocal change in output current. Since transmission conductors that make up the lines have resistance proportional to distance of the line, it is advantageous to lower the current. Loss in output power is calculated by the current squared in amps multiplied by the resistance. Therefore lowering the current by stepping up the voltage results in more efficient transmission.

The purpose of the substations is convert the voltages, provide switching and isolation of lines and enclose the equipment for security and safety. The switching of equipment is done by breakers and disconnect switches.

Distribution substations step the voltage down to safe voltage levels for connection with residential and commercial transformers.

Electric power delivery systems are unique compared to gas or oil delivery as electric energy is not easily or practically stored in large quantities. Electric energy must be produced and consumed at the same instant. This is called the generation/load balance. If the balance is perfect, the frequency is 60 Hz.

Frequency is controlled at the power plant by adjusting the rotational speed of each generator using a control scheme called the automatic load frequency (AVR) loop. Basically, machine speed is increased when load increases and vice versa.

Protective relays at the power plants will trip a generating unit on under frequency typically 58.5 Hz or over speed typically 62.0 Hz to prevent damage to the machine. Frequency control protects the generator and maintains the system load balance.

Monitoring and Control of Power Systems

To monitor and control power systems measurements called analogs, status and accumulators are required. These values are collected at each power plant and substation and concentrated at a central point called a Remote Terminal Unit (RTU) or data concentrator.

These values must be transmitted to a central control center by a data communications system called Supervisory Control and Data Acquisition (SCADA). The data communication system used is digital so the analogs and status indications must be converted to a digital format. Analog values are usually converted to a 16 or 32 bit value where statuses are 2 bits.

For the RTU and SCADA system to communicate correctly, a common communications protocol is used. The protocol establishes the message format exchanged over the communications media. On both ends a pre-established point address designates which values are from which device in the substation.

Basically RTU's are polled/scanned by a SCADA system at the central control center. The SCADA system also provides a computer display drawing of the substation with the values measured for system operators to monitor and control the substation equipment.

Analogs

Power flow, voltage, current, and system frequency need to be collected at various points in the system. Therefore the following time varying values must be measured:

- MW/MVAR (total three phase)
- kV (single phase line to ground converted to line to line)
- amperes (single phase)
- Frequency in Hz

The above measurements are called analog values. Since they are time varying they must be sampled at various rates. Typical scan rates are 2 seconds, 4 seconds and 10 seconds.

Another analog that is measured is transformer tap position. Some transformers have load tap changers (LTC) used to control voltage by varying the winding ratio of the transformer. The LTC can have tap position values of negative 16 to positive 16 or some other range in between these values. (ex: -8 to 8). Tap position zero is called the neutral tap.

The analogs are measured on generators, transformers, substation bus bars and lines.

Analogs measurements are not measured directly because it is not practical or safe to measure kilovolts or thousands of amperes. To circumvent these issues, devices called potential transformers and current transformers are used.

Potential transformers (PTs) step down high voltage to low voltages for use in measurement systems. Typically, a standard secondary measurement range used is 0-120 volts.

PT's are connected on the primary phase to ground (V_P). In power systems, voltage can be measured between 2 phase conductors know as line to line voltage (V_L) and relates to the phase to ground by the following equation.

$V_L = \sqrt{3} * V_P$

Current transformers (CTs) perform the same task but reduce high values of current to a standard measurement range usually 0-1 amp or 0-5 amps. Current is measured phase to ground.

To measure MW flow, current and voltage values are required since:

Real Power (single phase) = $P_{1\phi}$ = Current * Voltage * cos θ

Where the voltage and current are line to ground and θ is the phase angle between the current and voltage

Real Power (three phase) = $P_{3\phi} = 3 * P = \sqrt{3} * V_L * I_P$

The PT and CT outputs are wired to a transducer or smart relay in the substation that performs the above calculation based on the MW output range specified for the device.

To measure MVAR flow, a MW measurement system can be used with a 90 degree phase shift introduced since:

Reactive Power = Q = Current * Voltage * sin θ

And

sin θ = cos (90- θ).

Frequency is measured by a transducer or digital relay. Frequency is measured by narrow band and wide band ranges. Wide band frequency is measured in the range of 55-65 Hz. It is used for system restoration and monitoring long term frequency decay. Narrow band frequency is a tighter range and measures in hundredths of a Hz. The narrow band frequency detects large changes in frequency that can occur in system emergencies like loss of a large generator or blocks of load.

Analog measurements are usually specified by a range so they can be scaled back to MW/MVAR, ampere and kV levels. Another important specification of analog measurement systems is the accuracy. Accuracy usually is specified as plus or minus percent of full scale. For example, if an ampere measurement is specified with a range of 0-2000 amp and percent of full scale of 2%. Each reading is accurate to within +/- 40 amps = (0.02 * 2000).

Status and Control

To determine the electric system connectivity or state of the system, discrete values are collected. Breaker and switch status (OPEN/CLOSED) are measured by auxiliary contacts that mimic the operation of the breaker.

Status values are usually measured by 2 digital bits. One bit represents the current state with 1 or 0 meaning CLOSED or OPENED, and the other bit is used to indicate the state has changed since last RTU scan.

Breakers and disconnect switches can be controlled either manually by a local substation operator or remotely by a Master SCADA station called supervisory control. For the latter, the SCADA protocol provides a handshake check to verify the control address and the state change followed by a remote operator acknowledgement. This is called select before operate (SBO) control.

Breakers and disconnect status points need tagging capability. A tag colors the equipment symbol differently and alerts the operator that the device should not be operated due to safety concerns (ex: personnel working on device) or equipment malfunction. A tag allows the operator to describe the abnormal condition.

Accumulators

Accumulators measure energy use by storing MW flow values and mathematically integrate them over a standard time period usually 1 hour.

The master SCADA station sends an ACCUMULATOR freeze command before reading the accumulator value at the top of the hour.

Some accumulators reset to zero after their value is sent to the master. Other accumulators keep collecting data and do not reset. The master must save the previous value to calculate the difference which is the next actual value. This type will rollover to zero like a car odometer after its value exceeds its maximum reading.

Accumulators are located at power plants and power system interconnections (lines between different electric utilities) called tie lines. Utilities use tie lines to import or export power also known as interchange for economic or reliability reasons. Therefore two accumulators are used to track exported power and imported power for energy accounting purposes. The cost to produce electric power in one area may be cheaper than another so it is exported to the higher cost area to save generation costs in the higher cost area.

Master SCADA Station and Energy Management System

SCADA

After all the power system data is measured and transmitted to a Master SCADA station via communications protocol over fiber, microwave, radio, serial line or IP connection, it must be processed and displayed to power system operators and used as inputs for computer analysis.

The master SCADA station polls all the substation RTU's and performs the digital to analog conversion or digital processing and device association. Analog measurements must be scaled. At the master station, there is a database that has tables of point addressing, scaling, accuracy, protocol type and scan rate.

Status processing uses the change of status bit to see if the current status needs to be updated. This bit is reset after processing.

Figure 2 (next page) shows a typical computer SCADA display of a substation. This display shows 3 transformers supplying a distribution bus with distribution feeders. Each distribution feeder has its own breaker and 3 phase ampere measurements.

Display coloring is used to represent the state of breakers and switches (RED=CLOSED, GREEN=OPEN). If a breaker trips its symbol will blink on the display until its associated alarm is acknowledged by the operator.

Note that supervisory control is performed using the display. The operator selects a device on the display by mouse click and popup windows are used to send an OPEN or CLOSE command. A confirmation pop up window is used to verify the device and the control operation. This is called select before operate (SBO) control. SBO control helps prevent misoperation of a device by adding a confirmation step.

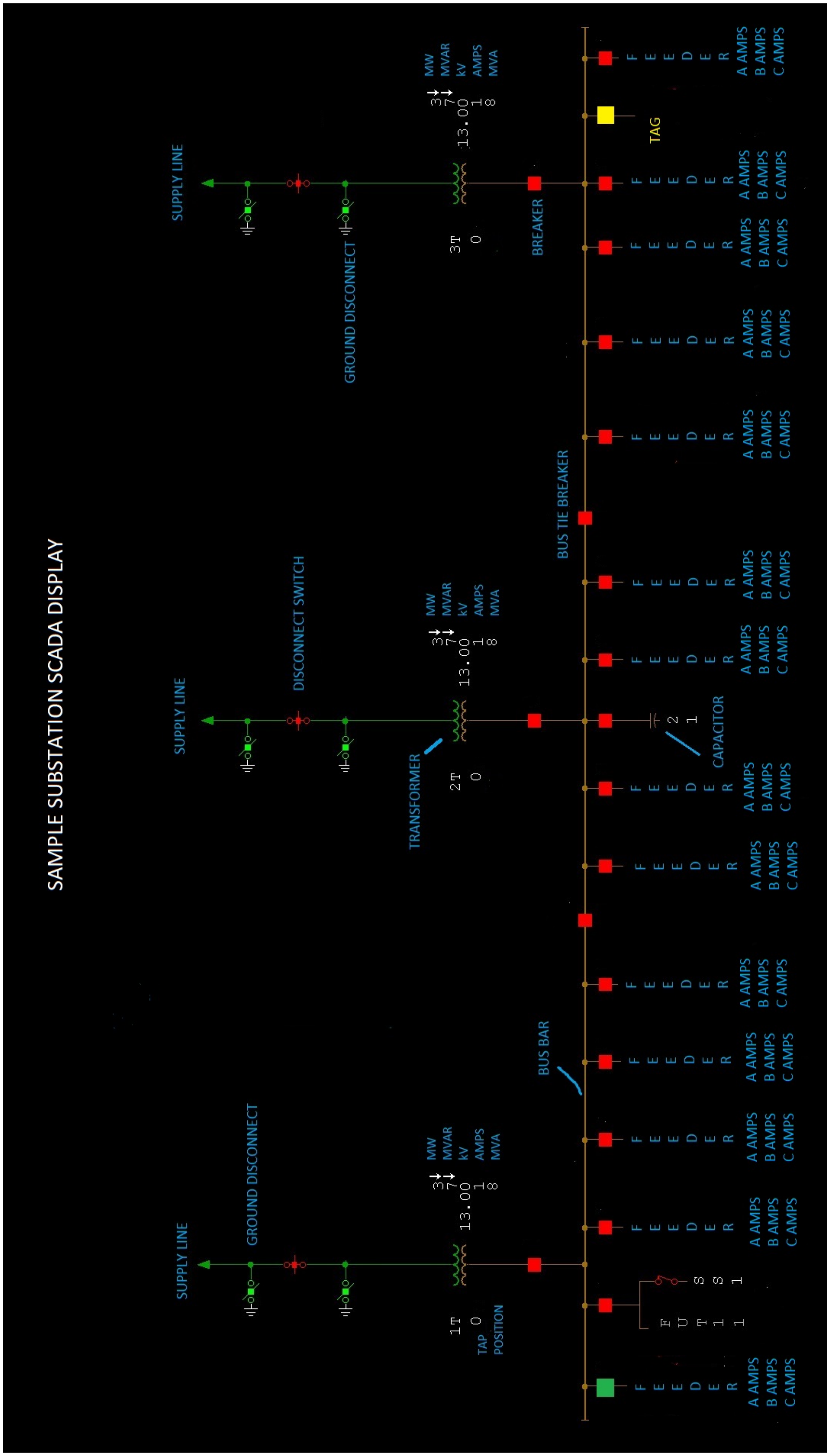

Figure 2 – Sample SCADA Display

A very important function of SCADA systems is the alarm subsystem. An operator may be responsible for monitoring and control of hundreds of substations. Monitoring all stations is impractical so each analog or status point is assigned an alarm. An alarm summary display shows the operator the time, station, point name and severity of the alarm. The operator can then access the station display with abnormal condition.

An alarm will blink on the summary display to show the alarm is new or has not been addressed. An operator must acknowledge the alarm to let the system and other operators know someone is addressing the issue.

Alarms are categorized and have a numerical severity index. Typically control centers have many operators on shift. Typically they are given roles as transmission or distribution operators. The operators can be further differentiated by geographic areas. By using alarm categories the operator log on the system and his role will only show him the alarms for which he is responsible.

Alarms can be sorted or filtered like spreadsheet columns (ex: area, severity, substation, etc.). Alarms are propagated to a database for historical analysis.

Typical high priority alarms are breaker tripping, equipment thermal limit violation and voltage or frequency out of limit.

Operator display consoles have 3 or 4 display monitors to minimize display navigation. One of the monitors is usually used for the alarm summary display.

Computer and communication system security is paramount with SCADA systems and achieved by many hardware and software methods.

ENERGY MANAGEMENT SYSTEM (EMS)

In the early days of power systems, substations were staffed by on site personnel. Data was phoned in to a central office. SCADA systems made this unnecessary. With the growth in computer speed and data storage, it became possible to use the power systems data for more than just monitoring and control.

New computer programs for analysis and the ability to predict the impact of equipment outages were developed. The goal was to create a method to determine a real time security assessment. A power system is secure if the following conditions exist:

- There are no existing equipment thermal or voltage violations
- The system can survive credible unscheduled outages (contingencies)

- Control actions can be implemented following a contingency to eliminate thermal or voltage violations.

For years, power system simulators were used to plan and construct the electric systems. They were also used offline to determine if equipment outages for maintenance and construction were feasible for the predicted loads at the time of the outage.

An Energy Management System is a SCADA system with advanced computer applications for simulation and analysis. The applications include the below and are discussed in the next sections:

- Power System Simulator
- State Estimation
- Contingency Analysis
- Load Forecast
- Real Time Voltage Control
- Load Shed
- Operator Training Simulator
- Economic Dispatch and Automatic Generation Control
- Data Historian

From a hardware and communications standpoint, an EMS has a primary and backup system that are identical. Switching primary/backup status allows scheduled hardware and software maintenance as well as primary system component system failures. The communication lines between the EMS and substation RTU's are also redundant.

There is usually another EMS system used for testing database changes and software upgrades so that they are not directly loaded on the primary and backup system without verification.

EMS systems are usually located in the same secure building with redundant utility supplies, battery backup and emergency generators. In case of fire or other emergency an emergency backup control center is located in another secure location (usually within 30-60 minutes travel time). The RTU's at the substation have dual ports that allow communication to the primary control center and the emergency back up control center.

POWER SYSTEM SIMULATOR

A power system simulator, also known as a power flow or load flow program, calculates the state of a power system at an instant in time. It uses a mathematical model of the electric system. The model uses electrical parameters for equipment (ex: resistance, reactance, and susceptance).The model is constructed from the connectivity (topology) of the equipment and the values for load, generation and equipment setting (ex: transformer tap position).

The data is taken from the SCADA analog and status data. For simulators to work, the data entered must obey laws of power systems. For example, all real and reactive power going to a substation bus must sum to zero. That is, all power coming in must equal what goes out.

If volts, amps, MW and MVAR are measured at the same point (ex: substation transformer or line) then the MVA value should be the same value (or close by a specified tolerance) by the below formulas.

MVA = √3 * V * I = $P^2 + Q^2 = S^2$

Where:

V = Line Voltage (in kV/1000)
I = Current (in amperes)
P = Real Power (in MW)
Q = Reactive Power (in MVAR)
S = Apparent Power (in MVA)

For the above relations to be true, the SCADA data would have to be very accurate. Recall that analogs are specified with an accuracy and it is possible to have a bad status measurement. Therefore real time data cannot be used for power systems simulation.

This hurdle was overcome by the advent of State Estimation.

STATE ESTIMATION (SE)

A state estimator uses statistical methods to adjust real time data so it can be used by the power system simulator. It does this by using values of analog accuracy, rejecting obvious bad data, and the above measurement relations used in power systems. The use of statistical methods is quite complicated and computer processing intensive. It is based on minimization of least squares of the weighted deviation between measured and true values.

State estimation also can fill in data if an RTU or communications channel fails. It does this by using the last known good values and adjusting them based on values of nearby connected equipment. For example, is a transmission line connects two substations and one of the RTU's fails SE uses the MW/MVAR flow values and direction and the impedance of the line to calculate the power flow on the other end. Similarly, if the line trips, SE will fill in an open status on the other end of the line and verify this by no current or power flow on the good measurement side.

State Estimators will alert the operator of gross measurement errors based on database values of detection criteria and accuracy. The operator can then remove the measurement from being scanned until it is repaired.

SE is so crucial to monitor power system security that auditing organizations (NERC) require reporting of SE down time of more than 15 minutes.

CONTINGENCY ANALYIS (CA)

The term power system security in the context of EMS systems means the power system can withstand the loss of a piece of equipment without thermal or voltage limits to prevent loss of load. The loss of a piece of equipment is called a contingency. Multiple devices can be part of a contingency definition. These definitions are input to the EMS database based on which circuit breakers would trip upon equipment failure or overload.

Each contingency is run through the current state of the system and analyzed for limit violations. A severity index is calculated for each and then ranked in order of severity and the results are presented to the operator. The operator can then attempt corrective actions (ex: generator output change, adjustment of power flows using phase shifting transformers or circuit switching.)

This gives the operator advanced warning of potential problem areas of the system.

Another important application of CA is in the equipment outage scheduling process. Power system equipment must be removed from service for maintenance, repair or replacement. Power companies study day ahead, week ahead and month ahead outages to ensure they can be accomplished without impacting system security.

This process involves studying the system topology and forecasted peak load for the day of the outage. The study case should reflect all scheduled outages for the date in question. Obviously, if the system is secure at peak load it will be secure for all other hours. The forecasted load is determined by the EMS Load Forecasting system discussed below.

The sequence of application programs is important. The State Estimator runs first to provide input data values for the power system simulator. The simulator calculates the current system state called the base case or snapshot. The base case is then passed on for contingency analysis. This sequence of application programs can be triggered manually by the operator, on a periodic timer (5-10 minutes) or by significant topology change (predetermined list of breakers or equipment trippings).

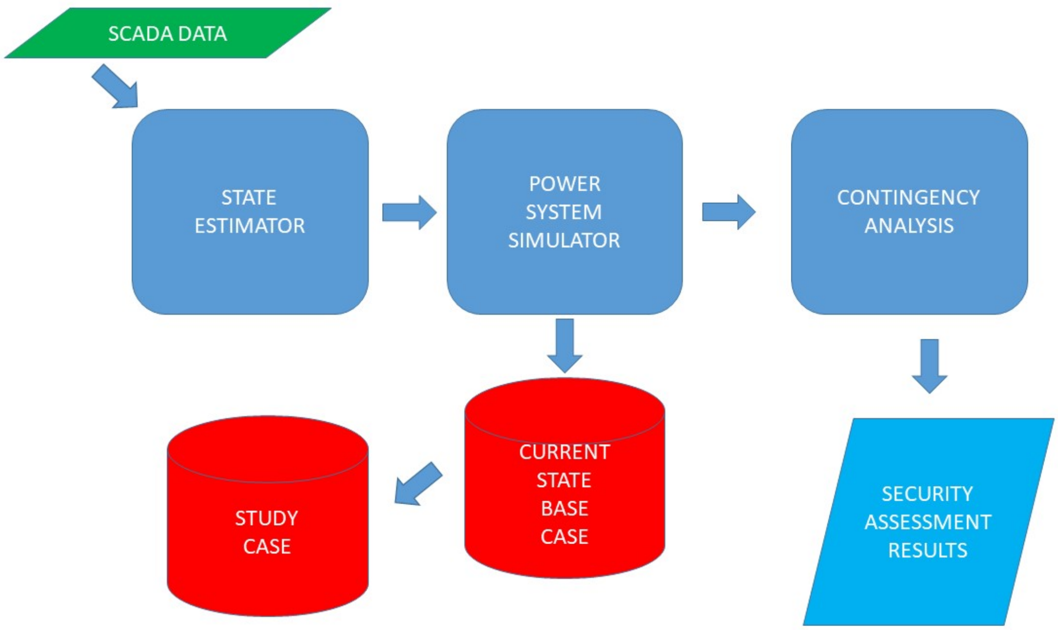

Figure 2 Sequence of EMS Security Analysis Applications

Typically the peak base case is saved and used for outage studies for the next day. The operator can then enter the topology and load values for the next day.

LOAD FORECAST (LF)

To plan the generation schedule for the next day the peak load must be estimated. To study upcoming scheduled outages the peak load for that day must also be estimated. The EMS Load Forecast (LF) subsystem performs this function.

Load forecast uses historical peak load data and weather forecasts to estimate the peak load. Of course since weather forecasts can be updated LF must adjust its estimates.

Other parameters such as day of the week, and holiday schedules are used. Weekend and holidays will result in lower loads than work weekdays. The four seasons are also considered for the variations in light and temperature.

Statistical regression and parameter weighting factors are used. The operator can also tune the forecast.

REAL TIME VOLTAGE CONTROL

All electrical loads must operate in a design voltage range. This is usually +/- 5 percent of a nominal voltage. In the United States the nominal is 120 volts for normal conditions. ANSI standard C84.1 specifies to ranges A and B. (See chart below). Range A is for normal conditions and range B is for emergency conditions and are for short duration.

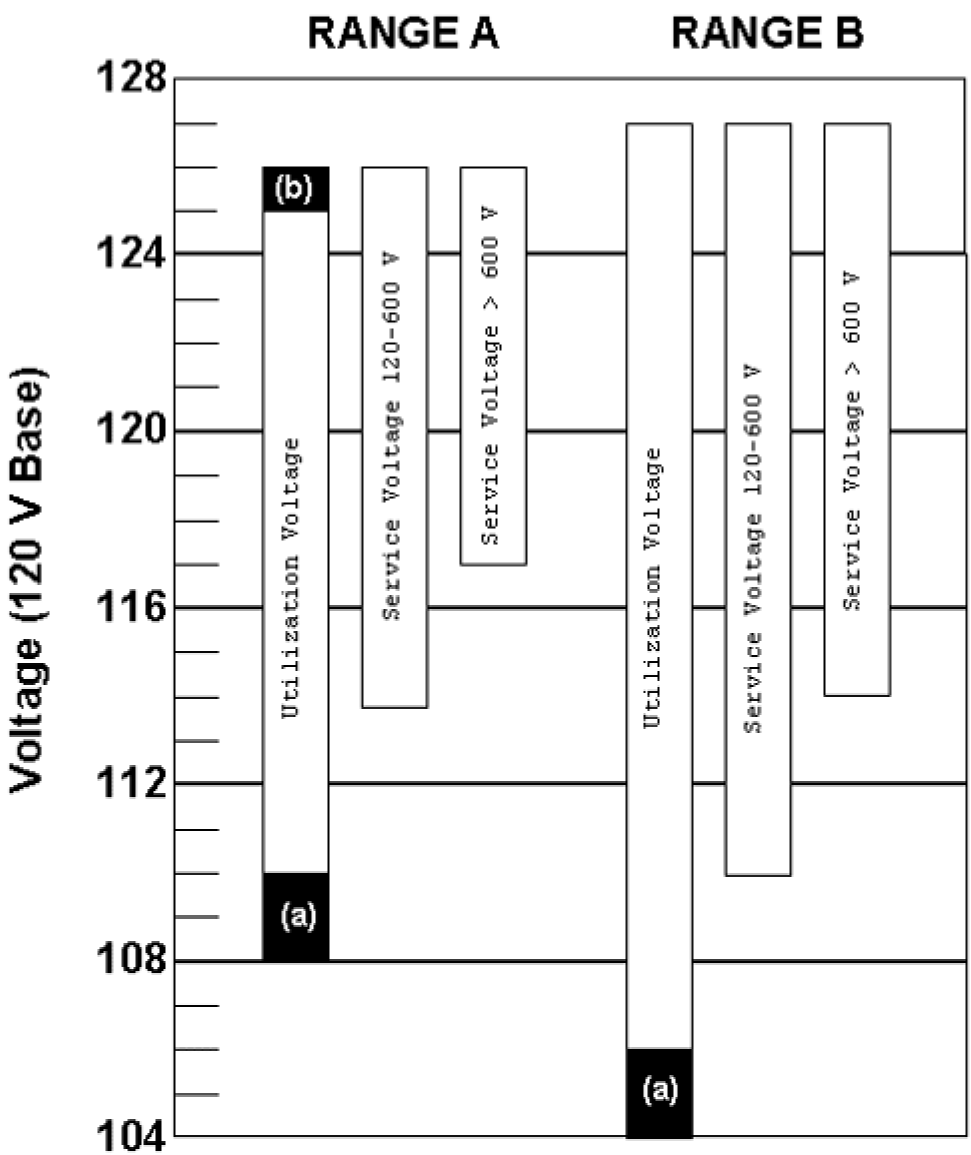

Figure 3 - ANSI C84.1 Utilization Voltage Standard

Electrical loads at a reference point will lower the voltage as the load increases and vice versa. Some means of regulation and adjustment is required to ensure voltages stay within the limits. Power companies use load tap changing (LTC) transformers and capacitor and reactor switching for this purpose.

A capacitor switched on will raise the voltage at the point of application and lower it when switched off. Power companies mount capacitor banks on distribution line poles. Large capacitor banks are also located in substations. Capacitors produce reactive power.

Reactors consume reactive power and lower voltage at their connected point when switched into the system. Large reactors are located at substations.

Transformers can increase or reduce input voltage based on the ratio of primary and secondary winding turns. LTC transformers adjust the ratio in fine increments. These adjustments can be automatic by local control, or manually by an operator via SCADA. An EMS voltage control application allows system wide voltage regulation.

The real time voltage control program scans voltage and transformer tap measurements and will send corrective controls if the voltage is not within a database schedule and bandwidth. Closed loop control is used where the control actions are simulated first to ensure they are appropriate. For example, is one or two tap changes acceptable and is three too much. Capacitor switching can be at the substation or on distribution lines by local control or by the EMS if SCADA is available.

Another use for a voltage control program is voltage reduction or a brown out. Power companies will reduce the voltage at substations by 5% to reduce load by about 1-2%. This may be necessary in times of short energy capacity or equipment unscheduled outages have caused a shortage of supply capacity. This is attempted to prevent loss of load.

Voltage control programs run periodically typically every 5-15 minutes or can be executed by the operator at any time.

LOAD SHED

As a last resort during system emergencies or capacity shortages, load must be disconnected to restore system frequency or prevent supply overloads. This is not practical on a large scale manually so it is handled by the EMS Load Shed application and under frequency relays.

If the system frequency decay is large, the under frequency relays will trip distribution feeder breakers at a high rate and in blocks to prevent over shedding of load. For example for one Regional Transmission Organization each area of the interconnection sheds a predetermined percentage of RTO load at 59.3 Hz, 58.9 Hz and 58.5 Hz.

If the frequency decay is not fast or there is a problem with supply capacity the EMS load shed program is used. The load shed program can be used for system wide, area, or local issues. A predetermined priority list of loads is created and entered in the EMS database. Critical loads (ex: hospitals, police and fire locations, national security sites) are excluded.

Load shed lists are created for areas and substations. For example if a transformer is overloaded due to an unscheduled outage of another transformer at the same station load is shed to protect the transformer still in service.

Of course it is not acceptable to shed the same customers every time it is necessary. Therefore once a block of customers are shed they are automatically assigned to the bottom of the list.

Another feature added to the load shed application is the concept of rotational load shedding. This means the burden is shared among many customers for shorter duration than one block of customers. Every 1-2 hours customers who were shed are restored following a trip/restore balance of load. For example, restoring one distribution line that has “x” amount of load is done after “x” amount of new load is shed.

The restore function can also put back the large amount of load in an under frequency event slowly to ease frequency control. The EMS database also has the list of which distribution feeders have under frequency protection enabled.

Using a load shed application greatly improves emergency response times and reduces outage time for the affected customers.

OPERATOR TRAINING SIMULATOR

System Operators require knowledge of many facets of power systems. This includes underground and overhead transmission and distribution lines, transformers, substations, generating plants, system protective relays and schemes. System Operators typically come from field experience in one of these areas. They are trained in distribution operations first. They then work up to transmission operations. They need to be trained on use of the EMS.

The Operator Training Simulator (OTS) mimics the SCADA system interface so basic EMS operation of displays and controls can be taught.

To test the operator's skills, a system scenario can be input to the simulator based on an actual system event or one developed by an instructor.

An OTS is used for required annual certification of system operators. The most important scenario is a system wide black out. Detailed restoration procedures are developed so the trainee can rehearse them. This is a complicated procedure that would take days to actually perform because some generating plants have 24 hour restart times. One switching error could black out the system again.

The OTS allows the operator to learn which control errors to avoid without actually committing the error.

Some fail-safes such as water marking displays, display headers and a different control operation interface, are used to make operators know they are not on the live or active EMS.

ECONOMIC DISPATCH and AUTOMATIC GENERATION CONTROL

Electric utilities with transmission assets and interconnections to other utilities are required to be a member of a Regional Transmission Organization (RTO). The RTO monitors the power plants, major transmission systems and interconnections. These interconnections allow power to be transferred between areas, provides economic power, enhances system security and improves generating unit stability.

If power companies operated as isolated areas, then the unscheduled outage of a large generator would have to be made up by the inertia of the other units or more likely result in some of the under frequency load shed relays operating. If large areas like the east coast are interconnected, the loss of a generator is made up by hundreds of units and no load is lost. The inertia of the generators is called spinning reserve.

Some generating units are more economical to operate than others. For example, a hydro unit is cheaper because it does not require fossil fuel or a nuclear reaction. Also fossil fuel prices dictate costs to operate diesel, natural gas or coal units. A cost curve is created for each generator and provided to the RTO.

Also the RTO must know which generators are available to run and schedules them for the next day. Other factors involve cost and time to start up. Generators can take hours to be available so start up times need to be coordinated. Some units (ex: combustion turbines) can be started quickly to ride through the peak hours or for capacity emergencies.

The Economic Dispatch application runs on the RTO EMS. The application determines which units to run and at what output for economics and to meet the current load. However if too much generation is imported or exported between areas it could overload the interconnection lines. Therefore contingency analysis is also part of this process called security constrained economic dispatch.

Another important computer application that runs on the RTO EMS is automatic generation control or AGC. This program dispatches generation MW set points to certain units responsible for area regulation. Area regulation ensures scheduled interchange levels are maintained between areas of an interconnection and frequency is corrected toward 60 Hz.

The RTO EMS also runs real time State Estimation and Contingency Analysis of critical area transmission systems. The RTO compares its security analysis results with each area to ensure they are accurate if there are differences in results.

DATA HISTORIAN

Data historians store SCADA data and alarm history. Analog data is archived based on a change rate to minimize storing many duplicate values. Status values are stored at time of state change. Historical values are used for load forecasting and electric system planning. The data is used in event analysis and root cause analysis. Alarm data storage is very important as equipment ratings can change with upgrades and alarm data also shows other key factors in an event like transformer oil temperature or underground cable oil pressure.

Historical data can be queried and plotted on graphs and charts. The system load is usually displayed in the control room and can be plotted against the forecast load. Narrow and wide band frequency are also plotted on graphs and displayed on large monitors for operator monitoring.

Data historians have a corporate interface for sharing real time and historical data without giving EMS access privileges. EMS data can also be exported to commercial spreadsheets for off line analysis.

State public service commissions also require retention of power systems data for at least 3 years. Data historians can archive data for as far back as data storage media have capacity.

COURSE SUMMARY

Electric power systems are monitored and controlled by an Energy Management System (EMS). An EMS provides a SCADA system that collects analogs, status and accumulator values from RTU's and can send remote control actions.

In addition to SCADA, an EMS has advanced computer application programs. These programs monitor system security and can control power plants and substation devices. Voltage control is also an important component of an EMS.

There is an EMS located in each control area in an interconnection and one at the Regional Transmission Organization (RTO). The RTO EMS is responsible for generation control, economic dispatch, interchange schedules and grid frequency.

The RTO has control area members that coordinate system operation and monitor and control distribution systems.