Abstract

Electric power systems in North America are interconnected into several massive grids that span the continent. AC synchronism within the grids and 60 Hz frequency is maintained by matching power generation levels to transmission capability and load patterns. Controls are primarily protection relays and set point stability monitors.

Cost and environmental concerns discourage building new facilities. This requires using existing facilities more efficiently including heavier power transfer over existing lines, better scheduling of both generation and load, and integration of diverse power sources into the network. A new generation of controls is needed to maintain stability as these systems become more highly stressed.

Precise timing offers a new approach to system wide controls. It enables measuring the system wide AC phase as well as timing events and synchronizing controls. The Global Position System (GPS) is the first system to provide timing with enough precision to make this approach practical. GPS also provides the wide area of coverage, continuous availability, and high reliability required for power system control.

A number of utilities, including the Bonneville Power Administration, have R & D programs for GPS timing systems or advanced protection and control systems based on precise timing. Several utilities have operational phase angle measuring systems and more will go into service in 1993. At least two utilities will start using GPS based fault location in 1993. The use of precise time will continue to grow as more equipment becomes available, applications are developed, and confidence in time based control develops.

Introduction

Time and frequency systems are an integral part of operations and maintenance of electric power systems. They are used for scheduling, billing, coordination, and analysis. They are used to control power system frequency, timetag disturbances, and locate power line faults. In this paper I will survey power system operations that require time and frequency, discuss some of the related research projects at the Bonneville Power Administration (BPA), and finally indicate some potential directions of future developments.

BPA is a Federal power marketing agency whose service area includes Washington, Oregon, Idaho, and Western Montana. It operates the largest Northwest (NW) power grid and controls 23,000 megawatts (MW) of generation. It is a member of the Western States Coordinating Council (WSCC), the western U.S. power grid. Examples in the paper will be drawn from this system.

Power System Basics

The simplest power system is a generator connected to a resistive load. There is no need for reactive compensation, no need for synchronization with other generators, and no concern for power signal frequency. Indeed, the first power systems were used primarily for lighting and were that simple. When motors and transformers are introduced, some frequency control is required. Long transmission lines introduce reactance so voltage control can become a problem. Increasing power demand is satisfied with more generators which require additional synchronization.

Today electric power systems are interconnected into four massive grids that span North America. WSCC is the largest of those grids, covering the US and Canada from the West coast to just east of the Rocky Mountains. There are many benefits to interconnecting the individual systems. System reliability is enhanced by multiple sources and many transmission paths. Sharing generation can result in significant savings in meeting peak loads, staggering maintenance, and using the most economical sources. However interconnection also requires
synchronization and controls to prevent a problem in one part of the system from causing problems elsewhere.

There are two distinct synchronizing issues found in power systems. First, electric energy must be used as it is generated. No one has created a successful electricity reservoir or battery suitable for power system use. Load must be constantly in balance with generation. Second, power is produced and transmitted primarily as a 60 Hz (50 Hz in Europe) alternating current. Synchronous devices such as generators and motors must be kept in phase with each other; they must constantly track through frequency changes and disturbances.

Electric power is produced primarily by turning an alternator with a steam or water turbine. Power P transferred from the turbine is expressed by

\[ P = T \omega \]

where \( T \) is the torque and \( \omega \) is the angular velocity. A decrease of electric load on the generator reduces the resisting torque so the speed of rotation will increase to absorb the turbine power. Conversely, an increase in electric load will cause the machine to slow down. This characteristic inherently stabilizes and synchronizes a group of generators. Each generator will find an operating point and the constant small load changes will automatically redistribute among the group. Similarly, if mechanical power input to one of a group increases, it will accelerate and take more load. The increased load will control its acceleration and the decreased load on the other units will allow them to speed up, keeping the whole group synchronized.

Power transfer between two substations in an AC system is defined by

\[ P = \frac{V_1 V_2 \sin \Theta}{Z} \]  \[ (1) \]

where \( V_1 \) and \( V_2 \) are the terminal voltages, \( Z \) is the line impedance between them, and \( \Theta \) is the included voltage phase angle. Terminal voltages are controlled to be nearly constant with inductors and capacitors. Since the line impedance is fixed, the power transfer is determined primarily by the phase angle between stations.\(^2\)

**Present Systems**

**Generation Controls**

Each power grid is divided into a number of interconnected control areas (usually individual utility service areas). Each area controller is responsible for maintaining generation-load balance and consequently frequency within that area. The control areas are connected with tie lines (Figure 1). Power is scheduled over the lines to maintain load balance within each area, and errors show up as inadvertent interchange over those lines. An error in one area will cause an error in another area. The control error (E) is computed by

\[ E = (T_1 - T_0) - 10B(F_1 - F_0) \]  \[ (2) \]

where
- \( T_1 \) = area interchange (MW)
- \( T_0 \) = interchange schedule (MW)
- \( F_1 \) = actual system frequency (Hz)
- \( F_0 \) = scheduled frequency (Hz)
- \( B \) = area frequency bias (MW/0.1 Hz).

The area controller measures power interchange and frequency and computes interchange error. An Automatic Generation Control (AGC) is usually employed to minimize the control error by continuously adjusting generation. Errors in frequency or power measurement will show up as inadvertent interchange or a system frequency offset. For example, BPA with \( B = 250 \text{ MW} \) would compute 25 MW in error if the frequency measurement were off by 0.01 Hz. AGC would minimize E and consequently cause a 25 MW inadvertent interchange. This is less than 1 % of a typical 3000 MW area interchange schedule, but illustrates the need for accurate frequency measurements.

As a further complication, each utility must estimate and schedule generation to serve its load. They may generate their own power, but most buy some from other producers. Load may vary by 300% throughout the day so generation is scheduled in hourly increments. A generation dispatcher can make schedule adjustments throughout the day to maintain balance, although a gross imbalance such as a generator failure may require power purchase on the spot market, possibly at great expense. Advance scheduling is essential since startup can take a whole day for a large thermal plant. That also means some generation must be kept on line and running well below capacity for emergency backup. If generation is lost this "spinning
reserve" replaces the power and prevents system collapse. Since spinning reserve is expensive, only a minimal amount is kept running to serve the entire grid.

Close operational coordination throughout a grid is essential to maintain proper power flows. A major utility is designated the system timekeeper. They integrate the 60 Hz power signal and compare it with an accurate clock to compute accumulated time error \( \Delta T \). If the accumulated time error exceeds the allowable limit, a new frequency is scheduled to bring the \( \Delta T \) back to zero. WSCC allows up to a 2 second error before rescheduling.\(^1\)

**System Protection**

A catastrophic event such as generator failure or transmission line outage requires instantaneous response. Protective devices called relays (which originally were electromechanical relays) detect power line faults and loss of synchronism. They operate circuit breakers and send control signals for remedial action schemes. Their purpose is to take appropriate action fast enough to protect equipment and minimize system disturbances. Relaying is predicated upon analysis of what will happen in various scenarios under various operating conditions. Power systems have become increasingly complex making traditional relaying more difficult to do successfully. New concepts of adaptive relaying where the relay adapts to current operating conditions are being developed. Advanced measurement methods discussed later in this paper are essential for adaptive relaying.

Some protection equipment may never be required to operate during its lifetime of 10-20 years; others will operate constantly. It must reliably sit for long periods of time in a ready mode. Each operation is a test of the system that no one wants to repeat, but every engineer wants to thoroughly analyze. Consequently power systems are monitored extensively with automatic recording equipment. Two of the most common are the Digital Fault Recorder (DFR) and the Sequence of Events Recorder (SER). The DFR records the actual power line voltage and current waveforms that occur during a disturbance. With this the protection engineer can determine the actual conditions to which the control system responded. The SER records the relay and switch responses. From this the engineer can determine how the control system responded. Sometimes the DFR and the SER are combined into one instrument which makes correlation of the data easy. When they are separate, timetags are required for data correlation. Recordings made on separate instruments in the same station can be hard wired to a common source so it does not matter particularly if the device is "on time." But if we wish to compare recordings between distant stations, "on time" is essential. Utility wide synchronization at the millisecond level is required to adequately timetag DFR and SER records. The WSCC coordination goal is a minimal 8 ms across the system and 1 ms within each station.

**Fault Location**

Another important monitoring device is a fault locator. A short circuit or fault usually can be cleared by momentarily disconnecting the line. Occasionally equipment is damaged and repair is required. Automatic fault location is much faster and cheaper than patrolling the entire line.

When a fault occurs on a transmission line, the current increases, voltage decreases, and a high frequency wave propagates in both directions from the point of incidence at nearly the speed of light. Fault location has relied on computing the distance from the apparent line impedance based on voltage and current. This technique does not work well with series compensation (capacitors) and can be thrown off by load current and mutual coupling. However, location can also be computed by comparing the arrival times of the traveling wave at substations on either side of the fault (Figure 2). BPA designed and built the Fault Location Acquisition Reporter (FLAR) based on this principle.\(^4,5\)

![FLAR traveling wave fault locator diagram.](image)

Figure 2. FLAR traveling wave fault locator diagram.

The FLAR system has microcomputer units installed at 24 key substations. Each has a precision clock synchronized by a high frequency pulse sent over the microwave system. The traveling waves are timetagged and reported to a master computer at the control center. The master correlates the timetags, computes the fault location and reports it to system dispatching.

The system has proven to be accurate and reliable. The drawback is that the synchronization pulse sent over the microwave system uses 60 Khz of bandwidth, requires an analog microwave, and is only available to major stations within BPA's service area. The system is currently being synchronized and extended with GPS.\(^6\)
Power Industry Requirements

Industrialized nations are increasingly dependent on continuous, reliable electric power. Outages are costly for both power producers and power users. Power systems are heavily capitalized and must operate near capacity to remain economical. The equipment is expensive; mistakes and failures can cause millions of dollars of damage in seconds. Consequently protection and control systems must be highly reliable and always available.

Likewise, time and frequency systems for power system controls must be reliable, available, and accurate. They must operate continuously over large geographical areas through all weather and seasonal conditions. They must operate unattended but reliably for long periods of time. They need to have low periodic maintenance requirements and alarm for failures. They have to be economical enough to be paid for by the benefit they bring over the life of the system (which can be 15-20 years). Above all they must be reliable.

<table>
<thead>
<tr>
<th>System Function</th>
<th>Measurement</th>
<th>Optimum Accuracy</th>
</tr>
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<tbody>
<tr>
<td>Fault Locator</td>
<td>300 meters*</td>
<td>1 microsecond</td>
</tr>
<tr>
<td>Relaying</td>
<td>1000 meters</td>
<td>3 microseconds</td>
</tr>
<tr>
<td>Stability Control</td>
<td>+1 degree</td>
<td>46 microseconds</td>
</tr>
<tr>
<td>State Estimator</td>
<td>+1 degree</td>
<td>46 microseconds</td>
</tr>
<tr>
<td>Oscillograph</td>
<td></td>
<td>1 millisecond</td>
</tr>
<tr>
<td>Event Recorder</td>
<td></td>
<td>1 millisecond</td>
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</tbody>
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*300 meters is the distance between two HV towers.

Figure 3. Power System Timing Requirements Summary.

Present timing accuracy requirements are summarized in Figure 3. A system that can deliver microsecond accuracy and meet the other industry requirements would be an ideal source. GPS now meets those requirements. It provides a highly redundant, multiple access time service. With multiple satellites there is little problem with signal blocking. Power system noise does not interfere with GPS's L-Band spread spectrum signal. The basic 200 ns accuracy meets accuracy requirements very well. Even the ±1 μs maximum S/A error is within requirements. The antennas are simple, easy to install and don't need adjustments. Finally, the receivers themselves are mostly digital, requiring little tuning or adjustment. Eventually receivers will be made on a single chip or two increasing reliability and reducing cost. Although other timing systems have been proposed and may be developed in the future, GPS with its present quality of service will satisfy power system needs for the foreseeable future.

Applications R & D

Electric power utilities have historically been involved in Research and Development of power system controls. Many system developments are new advances in the state of the art and there are no off the shelf solutions. Two areas of research BPA has been involved with, precise timing and phase angle measurement, will be discussed.

Time Dissemination and FLAR Extension

BPA requirements called for fault location on a line that extended outside of its service area. The synchronizing pulse could not be reliably sent over a digital microwave. The FLAR remote was finally synchronized with GPS receivers. Following that the FLAR functions were built into a GPS receiver. GPS-FLAR receivers could be the basis for a complete closed loop time system (Figure 4).

With this proposed system GPS-FLAR receivers could be installed at all substations requiring time or fault location. Data communications closes the loop with time verification and alarm reporting as well as timetag reporting for fault location, where required. For applications where precise time verification is required, an additional timetag input channel can verify time from an external source (such as the sync pulse) to within 100 ns.

Presently the FLAR system does not disseminate time of day, only precise synchronization. Time for all other applications is primarily broadcast as an IRIG-B signal over the microwave. A few stations that do not have microwave use GOES receivers with moderate success. IRIG-B over the microwave has never worked very well and is marginal with the automatic decoding equipment presently used. BPA is considering replacement of its
present time dissemination system with this GPS based alternative. Cost is still high compared with the present system. Simpler, independent GPS receivers are also being considered. In the mean time more GPS-FLAR remotes are being installed for tie line fault location. Laboratory receiver testing is continuing, particularly to find better ways to diagnose receiver degradation before failure. The new central time system at the power system control center will have GPS synchronization.

**Synchronous Phase Angle Measurement**

A phasor is a vector representation of a sinusoidal quantity which shows both magnitude and relative phase angle. A power signal is a 60 Hz sinusoid and is commonly analyzed in phasor format. Dr. Arun Phadke at Virginia Polytechnic Institute and State University developed a microcomputer system that will accurately compute power system phasors in real time. The Phasor Measurement Unit (PMU) digitizes the three phase waveforms at a 720 sample/second rate. After each sample the 60 Hz component is derived by a Fourier transform using the last 12 samples. The three 60 Hz components are combined into a single positive sequence phasor which represents the magnitude and phase of a balanced three phase system. It is a good representation of the state of a real power system in all but extreme fault conditions. By precisely timing the sampling clock with a GPS receiver, phase angle can be accurately computed between any two measurement points.

BPA tested two prototype PMU's on BPA's 500 kVAC Pacific Northwest-Southwest Intertie, the main transmission link between the two regions. PMU's were installed about 250 miles apart at John Day Substation along the Columbia River and Malin Substation at the California border. A master terminal at the BPA Laboratories in Vancouver, Washington recorded the data. The two PMU's were synchronized by GPS receivers (Figure 5).

Figures 6 and 7 are phasor data recordings of a disturbance caused by a bus fault which tripped off an 1100 MW nuclear power plant near Richland, Washington. A sharp voltage dip is seen at both John Day and Malin during the fault (about 30 milliseconds duration). It is followed by a voltage rise and decrease in phase angle between John Day and Malin as the power flow into California drops off. The system gradually approaches its old operating point during the 2 minutes following the fault.

![Figure 6. Voltage Magnitude at John Day and Malin Substations after loss of 1094 MW of generation.](image)

![Figure 7. Voltage Phase Angle between John Day and Malin Substations for same disturbance as Figure 6.](image)
The purpose of the test program was both to evaluate the phasor measurement system and to provide operational information on the GPS receivers used for the precise time source. The overall results were excellent. In 4 years of field deployment the only hardware failure was a chip in a GPS receiver. Phasor data responded with greater accuracy and less noise than comparable analog telemetered data. Proposals for expansion of the system into an operational data network are now being considered.

Future Applications

The future will see more power system development and integration. Lines will be loaded more heavily and generation will be used more at capacity. Power will be supplied by more diverse sources from more units. New systems will be invented for generation, transmission, and energy storage. All these advances will require controls. Precise timing is one of the key technologies that will enable the development of new control systems and the monitoring required to maintain them. Some of these areas of potential development are described in the following paragraphs.

System Timing

GPS is the key to making time domain fault location practical. The dedicated resource required for the system BPA has used is too expensive for common use and not available for all utilities. Two utilities, BC Hydro and Hydro Quebec, are deploying time domain fault locators of their own using GPS synchronization. BC Hydro is additionally considering low cost GPS receivers at all substations for system timing.

Most utilities use some kind of time reception at their control centers. Centers with AGC require a steady input which is usually WWVB. These centers must coordinate frequency and time error estimation. Better time and frequency reference will improve control. A common source for all utilities would also improve coordination. GPS covers all areas in North America with a more accurate and reliable signal than any other time service. BPA is replacing its central time system with a GPS based system which will also have a rubidium local reference in the event time signals are lost for any period of time.

The larger utilities have proprietary communication systems. Both microwave and fiber optic systems are digital and require precise frequency sources to prevent frame slips. Fiber has been found to be particularly compatible with power systems. It can be used in the same right of way and is unaffected by electric fields. Consequently several utilities have considered entering the data communication business. Optics are also being used to measure power system voltage and current using special glass that will distort in electric and magnetic fields. Precise frequency sources will be required to maintain the accuracy of these systems.

Stability Controls

Stability control schemes are designed to prevent unnecessary generator shutdown, loss of load, and separation of the power grid. Most equipment is protected by local controls and relays that detect overload conditions and remove the equipment from service. Stability control schemes extend over larger areas to maintain system integrity. When a disturbance is great enough to threaten the system, stability controls respond with system control actions including dynamic braking, generator dropping, load shedding, DC or static var ramping, or controlled islanding (See Appendix for brief description).

Existing control schemes are developed and tested on a computer model. They are based largely on switch position and set point arming. They are tested under every power system condition that is anticipated. They are biased toward security to be sure they will operate for any condition where action is necessary.

Generally they work very well. Most customers experience little loss of service. However they tend to overreact causing more equipment outage and loss of revenue than is necessary. Equipment cannot be fully loaded because a large safety margin is required to allow for unplanned conditions and inexact measurements.

Controls based on real time phasor measurements could improve operation. The controls could be programmed to respond to unstable conditions rather than certain switch positions and set points. The system would adapt to current conditions. The limitation of having to simulate every scenario would be eliminated. Safety margins could be set more consistently. Control actions could be fine tuned eliminate unnecessary operation.

Phase angle measurements have been explored by several utilities. Hydro Quebec used a proprietary microwave time dissemination to achieve a 10 μs sync. Pacific Power tried GOES receivers for their system but have turned to GPS. Electricité de France, Georgia Power, Florida Power, New York Power Authority, and the Tennessee Valley Authority are installing systems that measure phase angle.

System State Estimation

System state estimation is a mathematical technique that has evolved for determining stability of a power system based on its characteristic equations. It is used not only for assessing operating point, but for estimating the effect of taking system components out of service for maintenance. The major input requirement is the complex voltages at the power system buses throughout the system. Present
estimators use a least squares algorithm to compute these complex values from power and voltage magnitude measurements. The slow response time (seconds to minutes) renders the system usable only for static analysis. In addition, if data is inconsistent or missing, or the system is in an abnormal condition the solutions may not converge.

A state estimator based on phasor measurements could avoid most of these problems. The system could operate in real time since the complex voltages used in the algorithm would be measured rather than computed. Abnormal phase angles and system oscillations would not affect the process. State estimation could be incorporated into dynamic control schemes.

System Enhancements

Phasor measurements can also be useful in a number of other supplemental controls. Certainly its direct measurement of phase angle between buses as related to equation [1] is a good measure of power flow. Lines that are only lightly loaded and are not required for system stability could be taken out of service to reduce reactive losses. Too much load and line reactance without enough capacitive support can cause voltage collapse and subsequent black out. The high speed measurement and high accuracy of the phasor process could enhance schemes that monitor reactive support for long transmission lines. It is also ideal for measuring subsynchronous resonance, where a large machine has underdamped response to system perturbations. After a system has been separated into islands following a major disturbance, phase angle measurements would be critical to re-synchronizing and connecting the system. Since most power systems are now controlled by remote control from dispatch centers, accidental islanding is not always apparent. Real time voltage phase angle shown on dispatching displays could prevent accidental connection of systems that are out of phase, an action that usually has disastrous consequences.

Conclusions

Planning, operation, and maintenance of electric power systems is such a broad subject it is difficult to do it justice in one paper. I have tried to focus on the big picture of how present systems work with emphasis on aspects that involve time and frequency. Power systems are undergoing revolutionary changes with the acceptance of electronic and computer controls. In one decade relays have changed from the electromechanical devices they had been for nearly a century to sophisticated microprocessor instruments. The trend is not over yet. New concepts and ideas are being implemented and tested constantly.

Several predictions for the power system future can be made with some certainty. Power use will grow. For economic and environmental reasons, more use will be squeezed out of existing facilities. Power will be produced from more diverse sources. Power grids will become more tightly coupled.

Dealing with these changes will require more sophisticated and reliable measurements and controls, some of which will depend on timing with ever greater precision. GPS is today the quantum leap forward; tomorrow it may be Lasers or Fiber Optic systems or better atomic clocks.

Appendix

Power System Control Techniques

Control actions include dynamic braking, generator dropping, load shedding, DC or Static Var ramping, or controlled islanding. These terms are briefly described in the following paragraphs.

A dynamic brake is a large resistor. When load is momentarily lost, the brake is switched on line briefly to absorb the output of a generator to keep it in phase with the rest of the system. Sudden generator shutdown stresses equipment and restart can take time. A dynamic brake allows a generator to remain on line during a momentary outage. With phasor measurements, brake application could be precisely controlled by phase angle rather than triggered for a fixed time as it is now.

Load shedding is simply switching off load when it becomes too great for the generation or transmission. It is usually done as a last resort when power transfer overloads key transmission lines. Generator dropping is a fast action done in response to a sudden loss of load when there is not enough dynamic braking to maintain synchronism or the loss of load persists. This is also a last resort, especially with thermal units which restart slowly. Controlled islanding is the separation of the system into smaller independent but disconnected areas. Synchronism between areas is not required. Without inter-area power transfer, some load and generation will usually be lost. However, most service will be continued which is better than overloading successive areas until the whole system blacks out. In all these cases, a key stability indicator like system phase angle could improve the reliability and security of these schemes.

DC interties are used between the AC power grids and for several long distance transmission projects. DC ties do not require synchronization and the lines are cheaper to build, but require very expensive converter stations. Since the power transfer depends only on terminal voltage and line resistance, DC ties can be controlled independently from
the AC system to enhance stability. Fast ramping or modulation can damp out AC system instabilities.

A Static Var system uses solid state devices to control current to an inductor-capacitor combination to control AC system reactance. System reactance controls power flow in an AC system. Like DC controls, static var systems can be operated quickly and independently of the rest of the AC system. They don't offer the range of control that a DC link does, but offer the benefit of AC voltage support and lower overall cost. Both systems are solid state - static - and can be operated at high speed for system stability schemes. Phasor measurements provide the high speed and accuracy needed to get the most out of these systems.

References


