

Uses of Precise Time and Frequency in Power Systems

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Invited Paper

Accurately measured time and frequency plays an important role in the operation of modern electric power systems. A modern power system is a complicated and widely dispersed structure often covering a multistate or multiprovince area. Large numbers of generators and customer loads are operated in parallel. On an interconnected system composed of many control areas, the reliable transfer of electrical power from the point of generation to the consumer depends on measuring power system frequency in many locations. Because of the large amounts of electrical energy consumed in modern society, power is transmitted at high voltages. An elaborate protection and control system guards the high voltage equipment from short and open circuits. For the highest reliability of electric service, all control system operations need to be analyzed. Precise timekeeping networks aid in the analysis of power system operations by synchronizing the clocks on recording instruments. For dependable electrical service, all generators and large motors must remain close to speed synchronism and the voltage levels must remain near nominal values. The stable response of a power system to small and large perturbations is critical to continuity of electrical service. Research shows that measurement of the power system state vector can aid in the monitoring and control of system stability and voltage collapse. State vector measurement requires clock synchronizations of 5 to 46 microseconds. Knowledge of the location of a short circuit fault can speed the automatic or manual reenergizing of a transmission line. One fault location technique requires clocks synchronized to one microsecond. Research is now in progress to see if one microsecond timekeeping can aid and improve power system control and operation.

I. INTRODUCTION

In 1981, I investigated why some protective relays deenergized an important power transmission line. The first task was to gather all relevant information. Clues were available from the daily logs maintained by the power system operators (also called dispatchers) or from the Supervisory Control And Data Acquisition (SCADA) system log. In addition, oscillographs located at major transmission

substations may have recorded useful current and voltage waveforms.

Examination of the documents revealed that the time-of-occurrence of an event recorded on one system was difficult to relate to an event recorded on another system. In other words, the clock on the oscillograph that recorded the time when a power circuit breaker opened ("tripped") was not time synchronized to any other clock. Without clock synchronization, the task of determining why the relays misoperated was more challenging and time consuming.

To solve this problem, a timekeeping network with 1 ms accuracy with respect to Coordinated Universal Time (UTC) was built. One millisecond was the design goal because a recording instrument called a sequential events recorder (SER) had a 1-ms resolution. Other utilities with similar analysis problems had built similar timekeeping networks [1], [2]. Moderately priced "range timing" equipment developed for missile tracking was used without extensive modification [3]. A disturbance recording system consisting of a light beam or digital oscillograph and an SER costs from \$80 000 to \$130 000. Time synchronizing equipment adds about \$5000 to the cost.

After building millisecond timekeeping networks, engineers within many utilities realized more accurate networks were possible. At the same time, researchers wanted to sample currents and voltages simultaneously at substations separated by hundreds or thousands of kilometers [4]. Another long-standing goal was to measure the key to rapid real-time control of power systems, the state vector [5].

Frequency plays an important role in power systems operations. Alternating current (ac) circuits transmit a majority of our electrical energy. There are two fundamental requirements for the successful operation of ac systems:

- 1) Large generators and (synchronous) motors must remain in close speed synchronism.
- 2) Voltages must be kept near their rated values [6].

A power system is a dynamic nonlinear structure that uses feedback control to maintain these requirements. For

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example, a feedback loop regulates generator voltage by varying the voltage on the field winding of the generator [7]. A feedback technique called "net interchange tie line bias control" controls the balance between generation and consumption (load) over a utilities service area. This is called "dynamic" system control.

A closely related concept is the idea of power system stability. A power system is stable if, after a disturbance, the response is dampened and the system settles to a new operating condition in finite time [8]. Instability is when some generators lose speed synchronism and go "out-of-step." The "transient" response is the power system response to a large perturbation. This idea will be discussed more in a later section.

Figure 1 is a simplified representation of a power system. Generators G1-G6 produce power and energy at a moderate voltage of between 12 and 22 kilovolts (kV). Transformers T1-T6 increase the generator voltages to a higher level for transmission (230 to 765 kV). The squares represent power circuit breakers and the vertical lines represent generation plant or substation busses, the nodes of the system. Major transmission lines TL1-TL3 connect the three areas. Within a region, shorter transmission lines connect local generators with each other and local load. Transformers T7 and T8 reduce the voltage levels for distribution to consumers.

The electric power system of the United States, Canada, and northern Baja California, Mexico is divided into nine regional reliability councils. Examples are the Electric Reliability Council of Texas (ERCOT) and the Western Systems Coordinating Council (WSCC). Through the North American Electric Reliability Council (NERC) these councils coordinate policy issues related to reliable operation of generation and transmission facilities and the adequacy and security of member electric systems [9].

A large interconnected power system is divided into many "control areas." A control area will manage the power produced from its generators and monitor and control voltage levels. Usually a control area is operated by one utility and serves a particular geographical region. Control areas negotiate agreements with neighboring control areas for the buying and selling of lower cost energy. During emergencies control areas share on-line standby generation (called "spinning reserve") [10]. Figure 1 shows three control areas. The larger structure is called an interconnection or grid. A disadvantage of an interconnection is that this larger system is harder to control. For example, it is harder to maintain system stability [11].

In North America there are four isolated electrical systems: the eastern United States, the province of Quebec, most of the state of Texas (ERCOT) and the western United States (WSCC). These electrical interconnections operate almost independently of one another. Power system frequencies can differ and the only electrical connections are through direct current (dc) links. AC power in one interconnection is transformed to dc power and then back to ac power in the other interconnection. See Arrillaga [12] for a good discussion of dc transmission and Yu [13] for information on electrical systems in other countries.

Power is a complex vector quantity: total power equals the complex algebraic sum of real or active power plus quadrature or reactive power. The units are volt-amperes for total power, watts for active power, and "vars" for volt-amperes reactive. Energy, the time integral of power, is measured in units like kilowatt-hours or megawatt-hours.

The word "synchronize" has different meanings in different parts of this paper. Synchronous generators produce most electrical power and energy. Here synchronous refers to a particular type of electrical machinery. When we say generators must remain in synchronism for successful operation, we mean speed synchronism. Many applications discussed in this paper require accurate clock synchronizations. In this instance, we mean time synchronism.

II. PROTECTION, LIGHTNING, AND ANALYSIS

Modern electric power systems use very high voltage to economically transmit large blocks of power and energy over long distances. Air, specially designed insulators, or dielectric fluids or gasses insulate energized conductors from ground potential or other conductors. A lightning strike to an energized conductor causes a voltage impulse that usually jumps across the insulation. When a high voltage circuit shorts to ground potential or to another phase conductor, the power delivered to this fault can approach 50 giga-volt-amperes [14]. Faulted pieces of equipment or transmission lines must be quickly isolated from all sources of power. Faults can seriously damage conductors, equipment, and disrupt the stable operation of the power system. Power transformers are costly system components that experience high levels of mechanical stress during a fault [15], [16].

One part of this "protection" system is the high power switches, the power circuit breakers (PCB's). These devices must interrupt a circuit operating at perhaps 500 kV and a current of 50 000 A in one or two electrical cycles (17 to 33 ms in a 60-Hz system) [17]. The other major component of the protection system is the protective relays. A relay may be inactive for several years before having to respond to a power system fault. A transmission line relay may also have to estimate the distance to a fault and decide if the fault is internal or external to the transmission line [18]. The time interval from fault inception to the opening of the PCB normally needs to be within two or three electrical cycles to maintain system stability.

The protection system may misoperate occasionally. These improper responses significantly affect system operations and can lead to power system instability. Years could pass before errors in relay application or settings are found. Records kept by NERC show that relay misoperations play a large role in the major power system disturbances and blackouts [19], [20].

The number of faults on a typical transmission line ranges from 1 every few years to 15 per year. With such a low number of PCB operations it is prudent to capture as much data as possible from every relay-caused PCB trip. Light beam or digital oscillographs record selected voltage and

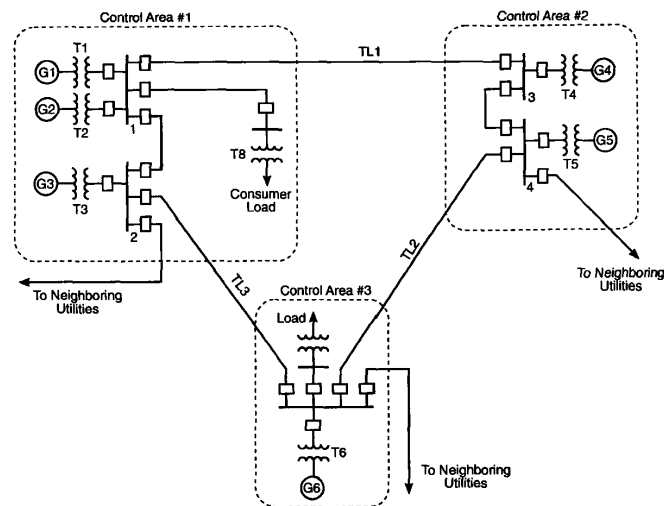


Fig. 1. A diagram of a simplified power system. Note that the generation and loads are grouped into three separate control areas connected by single transmission lines.

current waveshapes for later analysis [21]. Some protective relays can produce time synchronized event reports [22]. With a millisecond timekeeping network, isolated recorders and relays become a system-wide analysis tool. Many utilities have wisely synchronized to UTC so any recorded event can be conveniently related to any other time-tagged event.

Figure 2 is a simplified schematic of a PCB trip circuit. In a major substation, up to twenty different protection schemes may trip any one PCB. In analyzing disturbances it is important to know which scheme tripped the PCB. A sequential events recorder would be the best instrument to record this type of data.

Information from a digital oscillograph, an SER, and relays in some cases can be remotely retrieved through communications ports and processed in a "master station" [23], [24]. Many times the control center is the location of the master station. It is my experience that the master stations do not synchronize the recording instruments—a separate timekeeping network is needed.

Since lightning causes most transmission line and some substation faults, time-tagged information about lightning strike locations would aid power system operations. If a lightning strike was detected near a transmission line at about the same time the protection system deenergized the line, the control system or power system operator could quickly reenergize this line (see the section on fault location). Orville and Songster [25] discuss a lightning detection network while Whitehead and Driggins [26] discuss one utility's experience with the network. In the immediate future, GOES synchronized clocks will be added to this system and the number of detection stations will be increased [27]. (GOES is a meteorological satellite which also provides a time signal referenced to the time scale maintained by the National Institute of Standards and

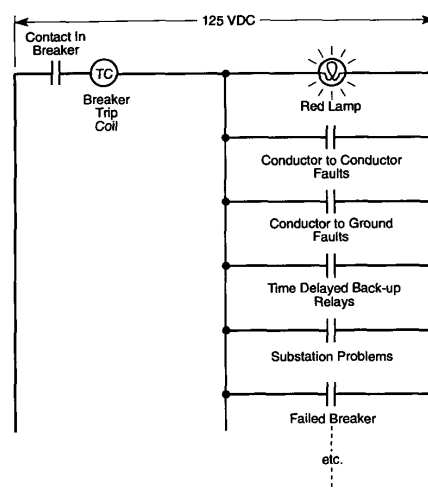


Fig. 2. A simplified electrical schematic of the trip (opening) circuit of a power circuit breaker.

Technology—see Sen Gupta *et al.* in this issue.)

III. POWER SYSTEMS OPERATIONS

The measurement of power system frequency plays an important role in the minute by minute operation of an interconnected power system. System frequency reflects the balance between real (active) power generation and consumption and serves as a sensitive indicator of the health of the system [28]. For efficient operation of an interconnected power system, frequency measurements between different control areas need to be accurate and standardized.

Since the early 1950's, power systems use a operating principle called "net interchange tie line bias control." From

historical data, a control area will predict the amount of energy needed in an upcoming hour. If internal generation is inadequate, energy is purchased and then "scheduled" from other control areas over the interconnecting "tie lines" (TL1-TL3 on Fig. 3). Figure 3 shows Control Area #3 importing power and energy from the other areas.

The basic operating equation is:

$$ACE = (T1 - T0) - 10 \cdot B(F1 - F0)$$

where

ACE= Area Control Error,

T1= actual net power from and to neighboring control areas,

T0= scheduled net power from and to neighboring control areas,

F1= actual system frequency,

F0= desired or "scheduled" frequency,

B= area frequency bias setting in MW/ 0.1 Hz[29].

A nonzero first term on the right hand side of the above equation shows that the actual power in and out of the control area does not equal the previously agreed upon amount of power. A nonzero second term indicates the frequency of the entire interconnection is not what is desired. The bias coefficient B is the amount of power each control area has agreed to contribute to the interconnection for maintenance of frequency. From another viewpoint, this coefficient is the system frequency response. The WSCC has added a third term that increases the bias coefficient if the first term and the time error have the same sign [30] while a Midwestern utility has implemented a variable nonlinear bias term [31].

Time and frequency measurements in each control area need to be accurate. If measurements of the same power system frequency produce different values, the ACE will increase. A false nonzero control error requires generation of additional and unnecessary energy. An instrument called a power system time and frequency standard measures and displays four quantities: standard frequency, standard time (UTC), power system frequency, and power system time. Time error is the difference between UTC and power system time. To standardize measurements the historical source of standard time and frequency synchronization has been low frequency radio station WWVB [29]. A utility can now purchase equipment that uses WWVB, the GOES weather satellite, or the GPS satellite navigation system for synchronization. (See the article by Lewandowski and Thomas in this issue for a complete discussion of GPS.)

Ideally, the area control error should be zero. Trying to control the ACE too tightly is expensive because of the enormous spinning masses of the generators. The operating practice required by NERC is to have every ACE cross zero at least once every ten minutes [32].

The frequency of the power grid is controlled to roughly ± 0.05 Hz of the nominal frequency. Beyond good operating practice there is no formal requirement on frequency deviation [32]. Time error, which is the integral of frequency

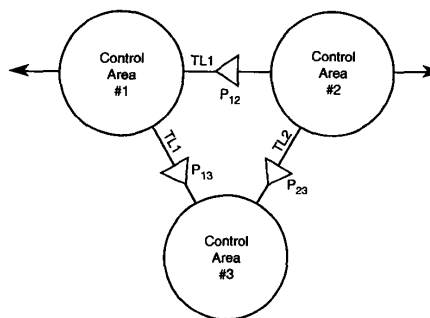


Fig. 3. A simplification of the power system of Fig. 1 designed to show area control concepts. This type of diagram is often called a balloon or circle diagram.

deviation, is monitored and corrected over a longer period. Table 1 lists acceptable time errors within three different North American interconnections [33].

Within an interconnection one control area is selected as timekeeper. Periodically, the timekeeper transmits its measured time error so that other control areas can reset their measurements. When the time error exceeds the predetermined amount, the timekeeper directs all members of the interconnection to raise or lower the "scheduled" system frequency. The entire interconnection is then operated at this higher or lower frequency. System frequency is returned to 60 Hz when the time error is reduced to the values shown on Table 1. The eastern interconnection time error limit of ± 8 s is under evaluation and was formally considered by NERC in June, 1991 [32].

IV. POWER SYSTEM CONTROL

Many power systems are operated in what could be called an "open loop" manner. As an example assume that lightning strikes a transmission line that is not automatically reclosed by the substation control circuits. The protective relays detect the fault and trip the power circuit breakers displaying these events at a centralized control center. If there is no indication of trouble, a power system operator remotely closes the power circuit breakers to return the line to service. The time interval is typically one-half to two minutes. This scenario has worked well for slowly changing system events.

The science of control theory is well developed. In the future an entire interconnection may have certain responses controlled by a large closed loop control scheme. Microsecond timekeeping and a reliable communications network would be key parts of this control system.

Large Area Synchronous Sampling: Present power system protection is organized into discrete and slightly overlapping domains of measurement and control called zones of protection. Examples would be the protection of a transmission line, a high voltage bus or a transformer. Equipment assigned to one zone of protection is mostly unaware of happenings outside that zone. The state of the power system can change, but preprogrammed settings fix

Table 1 Time Error Correction Practices within Three North American Interconnected Power Systems.

Time Correction	Time of Initiation	INITIATION Time Error-Seconds			TERMINATION Time Error-Seconds		
		East	WSCC	ERCOT	East	WSCC	ERCOT
SLOW	0000-0400	-4	-2	-3	0	± 0.5	± 0.5
	0400-2000	-8			-4		
	2000-2400	-4			0		
FAST	0000-0400	+8	+2	+3	+4	± 0.5	± 0.5
	0400-1200	+4			0		
	1200-1700	+8			+4		
	1700-2000	+4			0		
	2000-2400	+8			+4		

the response of most relays. Changing the settings on an electromechanical relay is a multihour task.

Modern microprocessor based relays offer new possibilities. Through communications ports, relays and other control equipment can have their settings changed in response to changes in the high voltage system. This is called "adaptive" relaying [34], [35]. Nested in the idea of adaptive relaying is the move toward a hierarchy of control and protection equipment. The digital relay communicates with computers that monitor and control the entire substation. In turn, the substation computer communicates with another computer at the dispatch or control center.

System quantities (currents and voltages) need to be sampled at approximately the same time throughout the utility's control area. Thus in large area synchronous sampling requires a multistate timekeeping network. One group of researchers uses a digital sampling rate of 12 times the 60-Hz fundamental frequency [4]. This implies clock synchronizations of 1.4 ms.

Stability: The amount of electric power that can be transmitted over a transmission line is often not limited by the thermal capacity of the conductors. Many times the limiting factor is power system stability. In our example system of Fig. 1, the power through TL1 can be slowly increased to a point called the steady state limit. Any additional transmitted power causes some generators to lose speed synchronism and go "out of step." Protective equipment would remove these generators from service, possibly causing an imbalance between generation and consumption. Loss of generation in one control area could cause an overload on a transmission line or transformer. Soon the protection might remove this equipment from service, possibly leading to a blackout [36], [37].

The prevention of instability is a critical operational concern. As mentioned in a previous section, two quasi-independent feedback loops control generator frequency and voltage. These control systems operate continuously and apply a control signal that is proportional to a locally generated frequency or voltage error. If these control

schemes can not guarantee stability, additional measures are necessary.

Specific stability problems can be solved with specific discrete supplementary controls. An IEEE Task Force [38] considered ten different schemes while a later IEEE Working Group [39] provides an updated bibliography. As an example of a supplementary control, consider the following. Lightning causes most transmission line faults. These faults are temporary, and involve only a single phase conductor and ground [40]. Hence for most faults it is not necessary to open all three "poles" of a power circuit breaker. With "single pole tripping," a portion of the "synchronizing power" can still flow on the other two phases. After a certain time interval, the open poles can be automatically reclosed. This helps to maintain speed synchronism, but there are disadvantages [41].

Protective relays can be viewed as discrete controls that respond to certain disturbances in a preprogrammed way [38]. There is a limit to the dynamic performance of an isolated protective relay. Hansen and Dalpiaz point out:

... it seemed that with each new line installation, the task of coordinating the OOS (out-of-step) relays grew more difficult. This difficulty was eventually found to stem from a fundamental problem: OOS relaying (or any other impedance based relaying) is not always the best tool for instability protection, but it is usually the most convenient. Often OOS relaying is adequate, but as a power system grows more complex, OOS relaying's weakness is revealed. This weakness is that, being impedance based, OOS relaying is "line oriented" rather than "system oriented." And instability problems in a power system are really system problems [42].

These researchers found that the fastest and most global indicators of imminent power system instability are: system voltage phase angles, power flow through key lines or units, voltage magnitude, network status, and time [43].

The voltage phase angles will be discussed shortly.

If a power system is unstable, local frequency-sensitive relays can help keep a portion of an electrical system intact. When an interconnected system becomes unstable, the tendency is to separate into disconnected "islands" of generation and load. In the ideal scenario, within an island there would be a reasonable balance between generation and load. If there is a substantial mismatch, the system frequency will decrease or increase. The desire is to maintain electrical service to a portion of the control area. This can be done by sacrificing less critical customer load. As the system frequency drops, under-frequency relays automatically disconnect predetermined percentages of load [44].

State Vectors and Estimators: A state vector shows the actual condition or state of a system. The complex voltages of all substation busses are the state vectors of the power system. Complex voltage means the magnitude and the relative phase angle of that voltage with respect to a system-wide reference. The present practice in many control centers is to calculate the voltage angles from other measurements. This is called state estimation. The purpose of state estimation is primarily to detect, identify, and correct gross measurement errors and to compute a good estimate of the voltage angles. Knowledge of the state vector helps in evaluating power system security [45], [46]. The disadvantage to state estimation is the time interval required to compute the phase angles: the state vector is not available in "real-time."

Measuring voltage magnitude is routine but measuring the voltage phase angle is more difficult [47]. The phase angle is measured by comparing the zero crossings of the voltage waveform with a system-wide reference time marker. Figure 4 presents a conceptual explanation. A better method is to measure the positive sequence voltage [48]. One electrical degree of the 60 Hertz waveform equals about 46 μ s. Across short transmission lines (less than 50 km), measurements may need to be made to 0.1 electrical degree [4] which translates to clock synchronization of roughly 5 μ s.

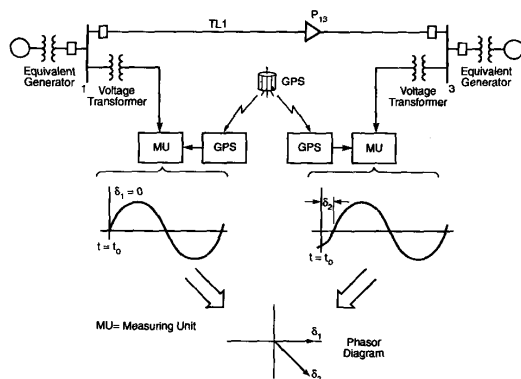


Fig. 4. A simplification of the power system of Fig. 1 designed to show a conceptual representation of how the power angle δ (delta) is measured. The GPS synchronized clock could be replaced with any future microsecond service.

There are many possible applications for power system state vectors such as: the detection of instability [34], improved system out-of-step response [49], dynamic stability enhancement of ac-dc systems [50], and possible use with interarea mode detection [19]. Direct measurement of system phase angles improves the performance of state estimators [51].

Interconnected systems can also suffer another form of instability, a rapid collapse of voltage [52]. Differences in voltages reflects the unbalance between generation and consumption of reactive power [7]. Possible solutions to voltage collapse are more generation, new transmission lines, shedding of load by undervoltage relays [53], local generation of reactive power by parallel connected (shunt) capacitor banks, or observation and control by the state vector [54].

Fault Location: Knowledge of the relative location of transmission line short circuit faults can be used to improve system control. As discussed earlier, most line faults are temporary and rapid circuit breaker reclosing can help maintain system (frequency) stability. However, rapid circuit breaker reclosing presents a risk to stability and fault location techniques can lower this risk.

Immediately after a fault, some generators may be oscillating relative to a 60 (or 50) Hz frame of reference. Reclosing a breaker into a nearby permanent fault may further perturb some generators and lead to instability. Generally the risk of instability decreases as the distance between generation and the fault increases. If the location of the fault is accurately known, the control system or the operator can make better reclosing decisions. If the fault is permanent, line maintenance crews can be sent to the exact location.

Either "time domain" or impedance techniques can be used to locate transmission line faults [55], [56]. Time domain techniques need microsecond clock synchronizations. Fault-induced waves travel at the speed of light, 300 m/ μ s. By time-tagging the arrival of fault-induced pulses at each end of the transmission line to within one microsecond, the fault can be located to within 300 m, the typical tower spacing on a high voltage transmission line [57]. Figure 5 illustrates the time domain concept. On the other hand, impedance techniques are accurate to about 1% or 2 % of the length of a line or roughly one kilometer, whichever is larger [55]. This is true for 90% of all faults.

Protective Relay Testing: It has long been the relay engineer's desire to test the protection system under conditions that are as close to actual conditions as possible. When a critical transmission line falsely trips, the reasons for this misoperation need to be discovered. A good method of analysis would be to retest the whole protection scheme (including communications circuits) with a recorded reenactment of the fault or disturbance that produced the problem. Field testing based on either a recording or a computer generated simulation requires a means to synchronize the signals applied to the widely separated relays. In this application, the needed synchronization may be 10 μ s [58]. Relay test sets can also be synchronized via a

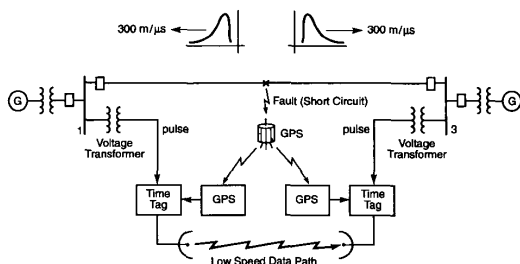


Fig. 5. Fig. 1 redrawn to show the basic idea of time domain fault location. For a short circuit fault at the center of the transmission line, the fault induced pulses would arrive at the substations at the same time.

communication channel [59].

V. UTILITY USAGE

Radio station WWVB has been a popular source of time and frequency information at the utility control center. Receiver specifications of 1 ms on equipment suggests that WWVB would be a good source for oscillograph and SER synchronization. Wright reported on one utility in Colorado successfully constructing a disturbance recorder synchronization system using WWVB [60]. Published field strengths were as large as $2500 \mu\text{V/s}$ for sites close to the WWVB transmitter. WWVB receivers were less expensive than other alternatives and worked well in substations and power plants.

Other utilities have experienced difficulties receiving WWVB. Burnett reported reception problems in the state of Georgia [1] where the signal was lost twice daily at local sunrise and sunset. Corona and other substation generated noise made reception difficult. Missout experienced similar difficulties in Quebec, Canada [61]. In some cases, United Kingdom station MSF, which also transmits on 60 kHz, produces interference.

Loran C is a low frequency radio navigational service that promises microsecond timekeeping. Burnett reported unsatisfactory reception by a portable automatic receiver in a 500-kV substation. On the other hand, Loran C was successfully used at the utility control center [1]. Missout temporarily used Loran C for manually synchronizing a phase angle measuring system [62]. An informal survey has produced no known Loran C substation usage.

In 1981, Missout experimented with using the GOES system in a phase angle measurement system. The requirement was for clock synchronization of $40 \mu\text{s}$ [63] but the GOES system proved unsatisfactory [64].

Burnett used a centralized approach to timekeeping for most of his timekeeping needs [1]. In this approach, UTC is received at the control center then a serial time code is broadcast over a utility voice-grade microwave radio channel. At the substations, time code generators correct for propagation delay. Where a utility microwave radio channel was not available, GOES clocks were installed. The difference between a GOES clock and a substation

time code generator recorder was at most $500 \mu\text{s}$ [65]. I constructed a similar system [66] as shown in Fig. 6.

For their work on stability assessment and global relaying, Hansen and Dalpiaz initially selected the GOES system for synchronization [67]. Here the required level of synchronization between clocks was one electrical degree of 60 Hz ($46 \mu\text{s}$). Clocks were synchronized via the "common view" mode (see Lewandowski and Thomas in this issue) where multiple timing receivers view the same satellite. The same level of synchronization to UTC was not needed in this application. GPS clocks will replace the GOES equipment on the remote phase angle encoders. For time tagging of disturbances, the centrally located master decoder was synchronized to UTC via GOES equipment [68].

Phadke at Virginia Polytechnic Institute (VPI) is using GPS clocks to synchronize digital sampling between different sites [69]. Two measurement systems under development were tested in a laboratory experiment [70]. The Bonneville Power Administration, U.S. Department of Energy, has installed several GPS clocks for phase angle measurement using the VPI encoding system. Data are telemetered back from several substations to the control center for project evaluation [71].

VI. DISCUSSION

Because of valid environmental, financial and biological concerns, new high voltage transmission lines are difficult to build. On the other hand, society is demanding more electrical energy. One possibility is that the advanced control techniques discussed here and in the literature will allow heavier usage of the existing transmission system. An issue is whether this can be done without any real loss of reliability. If there is an incremental loss in reliability, will the utility industry and society accept this loss of reliability in exchange for fewer new transmission lines?

The utility industry is interested in the highest degree of reliability and security. Within many utilities and federal power agencies the discussion of using earth satellites as part of power systems operations is guaranteed to start a spirited debate. There is misunderstanding on this point. A well designed satellite clock would have an internal oscillator or other circuitry to "flywheel" over losses in the synchronizing signal. Present proposals use satellite receivers to synchronize a measuring unit. The measuring unit and dedicated high-security control computers would make any critical power system decisions.

A major advantage to satellite based timekeeping is saving of limited bandwidth on the utility microwave radio communications network. The communications network will be needed for moving data to the centralized control computers and decisions back to the substations. If the timekeeping network or the communications fails, the control system must revert to a secure operating mode.

The futuristic concepts discussed here are for the high voltage transmission systems that are the "super highways" of our power systems. In early 1991, the cost of a synchronized clock ranges from about \$5000 for a GOES unit to

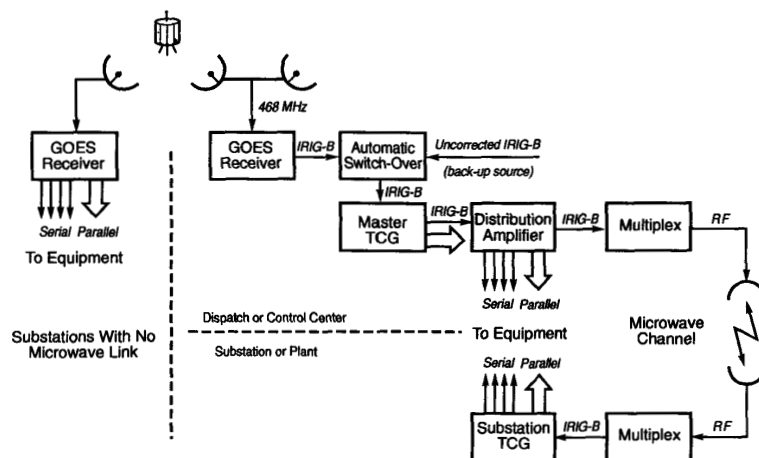


Fig. 6. A typical power system millisecond timekeeping network.

just under \$10 000 for a GPS unit. It is unlikely that GPS synchronized measuring units will be installed in lower voltage substations.

VII. CONCLUSIONS

The accuracy requirements of the power industry are relatively modest when compared with other applications. An important consideration is the continuity and availability of any time and frequency broadcast service. For power system operations, all components must be available at all times.

Standardized frequency measurements and millisecond timekeeping is a proven and accepted part of the operation of many electric utilities. Fault location is gaining acceptance as a valuable tool. At the present, the estimated distance to the fault is displayed but not programmed into automatic control schemes.

The control of electric power systems is a very challenging problem. Microsecond timekeeping networks may be part of an improvement in network response to large and small events. It is my experience that our power systems are operated on the basis of a worst case scenario. The operating philosophy is: will power system conditions be satisfactory upon loss of the most critical generator, transformer, or transmission line? Possibly in the future system-wide state vectors will aid in improved control. Any possible move in this direction will be slow and deliberate because an error in such a control system could put many people and state officials in the dark.

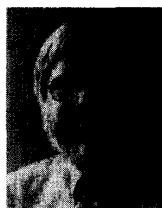
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