Precise Time and Time Interval Applications to Electric Power Systems

Robert E. Wilson
Department of Electrical Engineering University of Idaho Moscow, Idaho

Abstract

There are many applications of precise time and time interval (frequency) in operating modern electric power systems. Many generators and customer loads are operated in parallel. The reliable transfer of electrical power to the consumer partly depends on measuring power system frequency consistently in many locations. The internal oscillators in the widely dispersed frequency measuring units must be syntonized.

Elaborate protection and control systems guard the high voltage equipment from short and open circuits. For the highest reliability of electric service, engineers need to study all control system operations. Precise timekeeping networks aid in the analysis of power system operations by synchronizing the clocks on recording instruments. Utility engineers want to reproduce events that caused loss of service to customers. Precise timekeeping networks can synchronize protective relay test-sets.

For dependable electrical service, all generators and large motors must remain close to speed synchronism. The stable response of a power system to perturbations is critical to continuity of electrical service. Research shows that measure- ment of the power system state vector can aid in the monitoring and control of system stability.

If power system operators know that a lightning storm is approaching a critical transmission line or transformer, they can modify operating strategies. Knowledge of the location of a short circuit fault can speed the re-energizing of a transmission line. One fault location technique requires clocks synchronized to one microsecond (μs). Current research seeks to find out if one microsecond timekeeping can aid and improve power system control and operation.

I. INTRODUCTION

At previous meetings of this and other conferences, engineers and scientists have discussed precise time and time interval (PTTI) applications to electric power systems **[1,2,3,4]**. One application was the time synchronizing of recording instruments. The accuracy was 1 millisecond (ms) accuracy with respect to Coordinated Universal Time (UTC). One millisecond was the design goal because a recording instrument called a sequential events recorder (SER) had 1 ms resolution. Moderately priced "range timing" equipment developed for missile tracking was used without extensive changes **[1,3]**.

Frequency plays an important role in power systems operations. Alternating current (AC) circuits transmit most of our electrical energy. There are two basic 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 [5].

A power system is a dynamic non-linear structure that uses feedback control to maintain these requirements. For example, a feedback loop regulates generator voltage by varying the voltage on the field winding [6]. A feedback technique called "net interchange tie line bias control" controls the balance between generation and consumption (load) over a utilities service area.

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 [7]. Instability is when some generators lose speed synchronism and go "out-of-step." We will discuss this idea in a later section.

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. One issue is the reliable operation of generation and transmission facilities and the adequacy and security of member electric systems [8].

A large interconnected power system is divided into many "control areas." Usually one utility operates a control area that serves a particular geographical region. During emergencies control areas share on-line standby generation (called "spinning reserve") [9]. The larger structure is called an inter-connection or grid. A disadvantage of an inter-connection is stability is harder to maintain [10].

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. MORE INFORMATION FOR POWER SYSTEM OPERATORS

Modern electric power systems use very high voltage to send large blocks of power over long distances. A lightning strike to an energized conductor causes a voltage impulse that usually jumps across the electrical insulation. Faulted pieces of equipment or transmission lines must be quickly isolated from all sources of power.

A protective relay is specialized equipment designed to detect short-circuit faults. When a relay detects a fault, it sends a signal to a power circuit breaker. A relay may be inactive for several years before having to respond to a power system fault. A transmission line relay may have to estimate the distance to a fault and decide if the fault is internal or external to the transmission line [11]. The time interval from fault inception to the opening of the PCB may have to be one or two electrical cycles to maintain system stability.

The protection system may mis-operate occasionally. These improper responses significantly affect system operations and can lead to power system instability. Years could pass before engineers find errors in relay applications or settings. Records kept by NERC show that relay mis-operations play a large role in the major power system disturbances and blackouts [**12**].

The number of faults on a typical transmission line ranges from 1 every few years to 15 per year. Light beam or digital oscillographs record selected voltage and current waveshapes for later analysis [**13**]. Some protective relays can produce time synchronized event reports [14]. A millisecond timekeeping network can turn isolated recorders and relays into a system-wide analysis tool. Many utilities have wisely synchronized to UTC so any recorded event can be related to any other time-tagged event.

Information from a digital oscillograph, a SER, and relays in some cases can be remotely retrieved and processed in a "master station" [**15**]. It is my experience that the master stations do not synchronize the recording instruments. Recording systems need a separate timekeeping network.

Information about lightning activity can aid system operation. If a lightning storm is raging near a critical transmission line or substation, the system operators may start contingency measures. The amount of power transported along a key transmission line may be decreased. Say a lightning strike was detected near a transmission line at about the same time the protection system de-energized the line. With this information the control system or power system operator could quickly reenergize this line (see the section on fault location).

One commercial lightning detection network uses a time of arrival technique. Time synchronization is presently by LORAN-C. The network may use GPS in the future [**16**]. Orville and Songster [**17**] discuss a lightning detection network developed by the State University of New York at Buffalo.

III. POWER SYSTEMS OPERATIONS

The measurement of power system frequency plays an important role in the operation of an interconnected system. At the 1986 PTTI meeting Dr. Giles Missout pointed out that electric utilities operate the largest frequency dissemination system. As shown on Table 1 the accuracy of this frequency has been decreasing. The reason for this is economic. When the power system frequency can vary within wider bounds, the power output of large generators do not have to changed as often. Steady power output is the most efficient operating mode for thermal generation plants.

System frequency is a sensitive indicator of the health of the power system. Frequency reflects the balance between real (active) power generation and consumption [**6**]. Frequency measurements between different control areas need to be accurate and syntonized.

An instrument called a power system time and frequency monitor measures 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 [**18**]. A utility can now purchase equipment that uses WWVB, GOES, OMEGA or GPS for synchronization.

Operators control the frequency of the power grid to roughly ± 0.05 Hz of the nominal frequency. Beyond good operating practice, there is no formal requirement on frequency deviation. Operators monitor time error, the integral of frequency deviation and corrected over a longer period. Table 1 lists acceptable time errors within three different North American inter-connections [**19**].

TABLE 1. Time Error Correction Practices.

Time Error	Time of Day	Initiation			Termination		
SLOW	0000-0400	-4	-2	-3	0	±0.5	±0.5
	0400-2000	-8	-2	-3	-4	±0.5	±0.5
	2000-2400	-4	-2	-3	0	±0.5	±0.5
FAST	0000-0400	+8	+4	+3	+4	±0.5	±0.5
	0400-1200	+4	+2	+3	0	±0.5	±0.5
	1200-1700	+8	+2	+3	+4	±0.5	±0.5
	1700-2000	+4	+2	+3	0	±0.5	±0.5
	2000-2400	+8	+2	+3	+4	±0.5	±0.5

Note: The entries refer to Eastern US, Western US and Texas

Within an interconnection one control area acts as timekeeper. Periodically the timekeeper transmits its measured time error so other control areas can reset their measurements. When the time error exceeds the listed 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.

IV. POWER SYSTEM CONTROL

Many power systems are operated in an "open loop" manner. For an example, assume that lightning strikes a transmission line that is not automatically reclosed. The protective relays will detect the fault and trip the power circuit breakers. These events are displayed at a centralized control center. If there is no sign of trouble, a power system operator closes the power circuit breakers to return the line to service. The time interval is typically one-half to two minutes. This procedure has worked well for slowly changing system events.

Present power system protection is divided into discrete and slightly overlapping domains of measurement and control called zones of protection. Equipment assigned to one zone of protection is mostly unaware of events outside that zone. The state of the power system can change, but preprogrammed settings fix the response of most relays. Changing the settings on an electromechanical relay is a multi-hour task.

Modern microprocessor based relays offer new possibilities. Through communications ports, relays can have their settings changed in response to changes in the high voltage system. This is called "adaptive" relaying **[20,21]**. 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.

Stability The thermal capacity of the conductors is usually not the limiting factor for the power that can be sent over a transmission line. Often the limiting factor is power system stability. Above a certain level, any additional transmitted power causes some generators to loose 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 relays may remove this equipment from service possibly leading to a blackout **[22]**.

There is a limit to the dynamic performance of an isolated protective relay that uses local information only. 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. **[23]**

These researchers found that the fastest and most global indicators of imminent power system instability are: voltage phase angles, power flow through key lines or units, voltage magnitude, network status, and time **[24]**. We will discuss voltage phase angles shortly.

In addition to the work just discussed, other researchers are using PTTI techniques for stability enhancement. An out-of-step relaying system that uses the utility's digital communications system for synchronizing voltage sampling has recently been reported **[25]**. The level of synchronization is that of the digital communications system, 50 μs. At the recent Power Engineering Society Summer Power Meeting several engineers from France discussed a new loss of synchronism system. As with similar systems, the objective is to isolate the fault and prevent propagation of the disturbance. They built several "phasemeters" synchronized by a GPS receivers. The system is presently experimental with the first portion going into service in 1994 **[26]**. There are reports of similar work in mainland China and the island of Taiwan.

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. 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 **[27]**. The phase angle is measured by comparing the zero crossings of the voltage waveform with a system-wide reference time marker. See Figure 1 for a conceptual explanation. A better method is to measure the positive sequence voltage **[28]**. One electrical degree of the 60 Hertz waveform equals about 46 μs. Across short transmission lines (less than 50 km), measurements may need to be made to 0.1 electrical degree. This translates to a clock synchronization of roughly 5 μs **[29]**.

Fault Location Operators can use knowledge of the relative location of transmission line short circuit faults to improve system control. Most line faults are temporary and rapid circuit breaker reclosing usually can help maintain system 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 re-closing decisions. If the fault is permanent, line maintenance crews can go to the exact location.

Either "time domain" or impedance techniques can locate transmission line faults [**30,31**]. As discussed by M. Street at the 1990 PTTI meeting, time domain techniques need microsecond clock synchronizations [**32**]. Please see Figure 2. Fault-induced waves travel at the speed of light, 300 meters per microsecond. 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 meters. Three hundred meters is the typical tower spacing on a high voltage transmission line. Time domain techniques must be used on lines with series compensation. 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 [**30**]. 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, engineers need to find the reasons for this mis-operation. A good method of analysis would be to retest the whole protection scheme 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 test signals. In this application, the needed synchronization may be 10 μs [**33**].

V. WHAT T&F SERVICES DO UTILITIES USE?

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 at the substations. Wright reported on one utility in Colorado successfully constructing a disturbance recorder synchronization system using WWVB [**34**]. 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 receiver lost the signal twice daily at local sunrise and sunset. Corona and other substation generated noise made reception difficult. Missout experienced similar difficulties in Quebec, Canada [**35**]. In some cases United Kingdom station MSF, which also transmits on 60 kilohertz, produces interference.

LORAN-C promises microsecond timekeeping. Burnett reported unsatisfactory reception by a portable automatic receiver in a 500 kilo-volt substation. On the other hand, he used LORAN-C at the utility control center [**1**]. Missout temporarily used LORAN-C for manually synchronizing a phase angle measuring system [**36**]. 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 μs [37] but the GOES system proved unsatisfactory [**38**].

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 μs [39]. I constructed a similar system [3].

For their work on stability assessment and global relaying, Hansen and Dalpiaz initially selected the GOES system for synchronization [40]. Here the required level of synchronization between clocks was one electrical degree of 60 Hz (46 μs). Clocks were synchronized via the "common view" mode. GPS clocks will replace the GOES equipment for the substation encoders. For time tagging of disturbances, the centrally located master decoder was synchronized to UTC via GOES equipment.

Arun Phadke, who spoke at the 1990 PTTI meting, is using GPS clocks to synchronize digital sampling between different sites [41]. Two measurement systems under development were tested in a laboratory experiment [42]. The Bonneville Power Administration, U.S. Department of Energy, has installed several GPS clocks for phase angle measurement using a encoding system developed by Phadke. Data are telemetered back from several substations to the control center for project evaluation. Please refer to the paper by Ken Martin in these Proceedings.

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 always.

Table 2 Summary of Applications

Application	Accuracy	Source
Time & Frequency Monitor	1 ms & 1 E 5	WWVB, GOES, GPS
Recording Instruments SERs & Oscillographs	1 ms	GOES or utility system
Relay Test-Sets	10-20 μ	GPS
Phase Angles & Phasemeter	4.6-46 μs	GPS
Short-Circuit Fault Location	1.0 μs	GPS or custom

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 between the control centers and the substations. If the timekeeping network or the communications fails, the control system must revert to a secure operating mode. Some of the futuristic concepts discussed here are for the very high voltage transmission systems that are the "super highways" of our power systems. It is unlikely that you will see GPS synchronized measuring units in lower voltage substations.

Standardized frequency measurements and millisecond time-keeping is a proven and accepted part of operating 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.

Think Green! That was one message I took away from the IEEE Power Engineering Society (PES) Summer Meeting. The message was the health of our planet is becoming more important to the consuming public. At the Student-Faculty-Industry Luncheon Mr. Bernie Palk of the Los Angeles Department of Water and Power pointed out that:

> "The dominant mind-set of our industry for the previous three decades has been growth-oriented. How much new (generator and transmission line) capacity will we need, and when will we need it? Today the question is more likely to be, how can we stretch the capacity we've got?"

Valid environmental, financial and biological concerns, make new high voltage transmission lines difficult to build. On the other hand, society is demanding more electrical energy. One possibility is that the advanced control techniques discussed here 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?

REFERENCES

1. R.O. Burnett, Jr. *"Field Experience With Absolute Time Synchronization Between Remotely Located Fault Recorders and Sequence of Events Recorders,"* IEEE Trans. on Power Apparatus and Systems, vol. PAS-103, July 1984, pp. 1739-1742.

2. G. Missout, J. Bèland, G. Bèdard, P. Bussières, *"Study of Time Dissemination Methods Used on an Electric Power System With Particular Reference to Hydro-Quebec,"* IEEE Trans. on PAS, Vol. PAS-102, No. 4, April 1984, pp. 861-868.

3. R.E. Wilson, *"Uses of Precise Time and Frequency in Power Systems,"* IEEE Special Issue on Time and Frequency, Vol. 79, No. 7, July 1991, pp. 1009-1018.

4. P. Bonanomi, *"Phase Angle Measurements with Synchronized Clocks - Principle and Applications,"* IEEE Transactions on Power Apparatus and Systems, vol. PAS-100, No. 12, December 1981, pp. 5036-5043

5. T.J.E. Miller, *"The Theory of Steady State Reactive Power Control in Electric Transmission Systems,"* in Reactive Power Control in Electric Systems, T.J.E.Miller, Ed., New York, NY; Wiley-InterScience, 1982, pp. 52-54.

6. O.I. Elgerd, Electric Energy Systems Theory: An Introduction, New York, NY; McGraw-Hill, 1971, pp. 57-64.

7. P.M. Anderson, A.A. Fouad, Power System Control and Stability, Ames, IA; Iowa State University Press, 1977, pp.5-7.

8. North American Electric Reliability Council, 1989 System Disturbances, Princeton, NJ, August 1990.

9. N. Cohn, Control of Generation and Power Flow on Interconnected Power Systems, New York, NY; J. Wiley & Sons, 1961, p.3.

10. R.T. Byerly, E.W. Kimbark, Eds., Stability of Large Electric Power Systems, New York, NY; IEEE Press, p. 2.

11. J.L. Blackburn, Protective Relaying - Principle and Applications, New York, NY; Marcel Dekker, 1987.

12. North American Electric Reliability Council, 1983, 1984, 1985, 1989 System Disturbances, Princeton, NJ; 1984, 1985, 1986, 1990 (four reports).

13. E.A. Taylor, *"Fault Recorders and Power System Transients - Some Case Studies,"* Utility Fault and Disturbance Analysis Conference, Denver, CO, October 8-9, 1989.

14. J. Roberts, E.O. Schweitzer, III, *"Analysis of Event Reports,"* Western Protective Relay Conference, Spokane, WA, October 24-26, 1989.

15. L.E. Smith, *"The Remote Acquisition and Analyzation of Power System Disturbance Data,"* Utility Fault and Disturbance Analysis Conference, Denver, Colorado, October 30-31, 1986.

16. Atmospheric Research Systems, Inc., *"Accurate National Lightning Information,"* Palm Bay, FL, 1991.

17. R. Orville, H. Songster, *"The East Coast Lightning Detection Network,"* IEEE Trans. on Power Delivery, Vol. PWRD-2, No. 3, July 1987, pp. 899-907.

18. N. Cohn, *"Power Systems-Time and Frequency,"* Leeds and Northrup Technical Journal, No. 7, Fall 1969, pp. 3-11.

19. North American Electric Reliability Council, *"Appendix to Operating Guide 1.C.-Time Error Correction Procedures,"* Princeton, NJ, February 1, 1990.

20. A.G. Phadke, J.S. Thorp, S.H. Horowitz, *"Impact of Adaptive Protection on Power System Control,"* Proceedings of the Ninth Power System Computation Conference, Lisbon, Portugal, August 1987.

21. G.D. Rockefeller, C.L. Wagner, J.R. Linders, K.L. Hicks, D.T. Rizy, *"Adaptive Transmission Relaying Concepts for Improved Performance,"* IEEE Trans. on Power Delivery, vol. 3, no. 4, October 1988, pp. 1446-1458.

22. L.M. Olmstead, W.D. Brown, J. Bleiweis, *"The Blackout: It All Happened in 12 Minutes,"* Electrical World, January 24, 1966, pp.67-73.

23. D.J. Hansen, *"Real Time Digital Encoding and Telemetry of Key Power System Transient Quantities,"* Western Protective Relay Conference, Spokane, WA, October 23-25, 1984.

24. D.J. Hansen, *"Recent Progress on Stability Margin Measurement,"* Second Conference on Precise Time and Frequency in Power Systems, Fort Collins, Colorado, September 28-29, 1987.

25. Y. Ohura, et. al., *"A Predictive Out-Of-Step Protection System Based on Observation of the Phase Difference Between Substations,"* IEEE Trans. on Power Delivery, Vol. 5, No. 4, November 1990, pp. 1695-1704.

26. Ph. Denys, C. Counan, L. Hossenlopp, C. Holweck, *"Measurement of Voltage Phase for the French Future Defense Plan Against Loss of Synchronism,"* IEEE PES Summer Meeting, San Diego, CA, July 28-August 1, 1991, paper 91 SM 353-3 PWRD.

27. G. Missout, J. Bèland, G. Bèdard, Y. Lafleur, *"Dynamic Measurement of the Absolute Voltage Angle on Long Transmission Lines,"* IEEE Trans. on Power Apparatus and Systems, Vol. PAS-100, No. 11, November 1981, pp. 4428-4434.

28. J.S. Thorp, A.G. Phadke, S.H. Horowitz, M.M. Begovic, *"Some Applications of Phasor Measurements to Adaptive Protection"*, IEEE Trans. on Power Systems, vol. 3, No. 2, pp. 791-798, May 1988.

29. R.E. Wilson, *"Timing Within the Western Area Power Administration,"* Eighteenth Annual Precise Time and Time Interval (PTTI) Applications and Planning Meeting, Washington, DC, December 2-4, 1986.

30. E.O. Schweitzer, III, *"A Review of Impedance Based Fault Locating Experience,"* Western Protective Relay Conference, Spokane, WA, October 25-27, 1988.

31. T.W. Stringfield, D.J. Marihart, R.F. Stevens, *"Fault Location Methods for Overhead Lines,"* AIEE Trans. Paper No. 57- 160, August 1957.

32. M.A. Street, *"Delivery and Applications of Precise Timing for a Traveling Wave Powerline Fault Locator System,"* 22md Annual Precise Time and Time Interval (PTTI) Applications and Planning Meeting, Vienna, VA, December 4-6, 1990, pp. 355-360.

33. J.A. Jodice, *"Time Synchronous End-to End Relay Testing,"* Second Conference on Precise Time and Frequency in Power Systems, Fort Collins, CO, September 28-29, 1987.

34. K. Wright, *"Synchronization Work at Public Service Company of Colorado,"* Second Conference on Precise Time and Frequency in Power Systems, Fort Collins, CO, September 28-29, 1987.

35. G. Missout, *"PTTI Applications in Power Utilities,"* Eighteenth Annual Precise Time and Time Interval Applications and Planning Meeting, Washington, DC, December 2-4, 1986.

36. G. Missout, P. Girard, *"Measurement of Bus Voltage Angle Between Montreal and Sept-Iles,"* IEEE Trans. on PAS, Vol. PAS-99, No. 2, March/April 1980, pp. 536-539.

37. G. Missout, J. Bèland, G. Bèdard, Y. Lafleur, *"Dynamic Measurement of the Absolute Voltage Angle on Long Transmission Lines,"* IEEE Trans. on PAS, Vol. PAS-100, No. 11, November 1981, pp. 4428-4434.

38. G. Missout, J. Bèland, P. Lebel, G. Bèdard, P. Bussières, *"Time Transfer by IRIG-B Time Code Via Dedicated Telephone Link,"* Thirteenth Annual Precise Time and Time Interval (PTTI) Applica- tions and Planning Meeting, Greenbelt, MD, December 2-4, 1980.

39. R.O. Burnett, Jr. *"Additional Developments With the Georgia Power Time Synchronizing Project for Fault Recorders and Sequence of Events Recorders,"* Second Conference on Precise Time and Frequency in Power Systems, Fort Collins, CO, September 28-29, 1987.

40. C.P. Dalpiaz, D. J. Hansen, *"High Rate Telemetry of System Voltage Phase Angle and Other Stability Related Quantities,"* IEEE Trans. on Power Systems, Vol. PWRS-1, No. 3, August 1986, pp. 202-206.

41. A.G. Phadke, M.M. Begovic, V.A. Centemo, V. Phamiraj, *"Clock Synchronization For Improved Monitoring, Protection and Control,"* Proc. High Technology in the Power Industry International Symposium, Scottsdale, AZ, March 1-4, 1988, pp. 9-13.

42. A.G. Phadke, *"Precise Synchronization of Phasor Measurements in Electric Power Systems,"* Twenty-Second Annual Precise Time and Time Interval (PTTI) Applications and Planning Meeting, Washington, DC, December 5-7, 1990.

Figure 1. Voltage Phase Angles

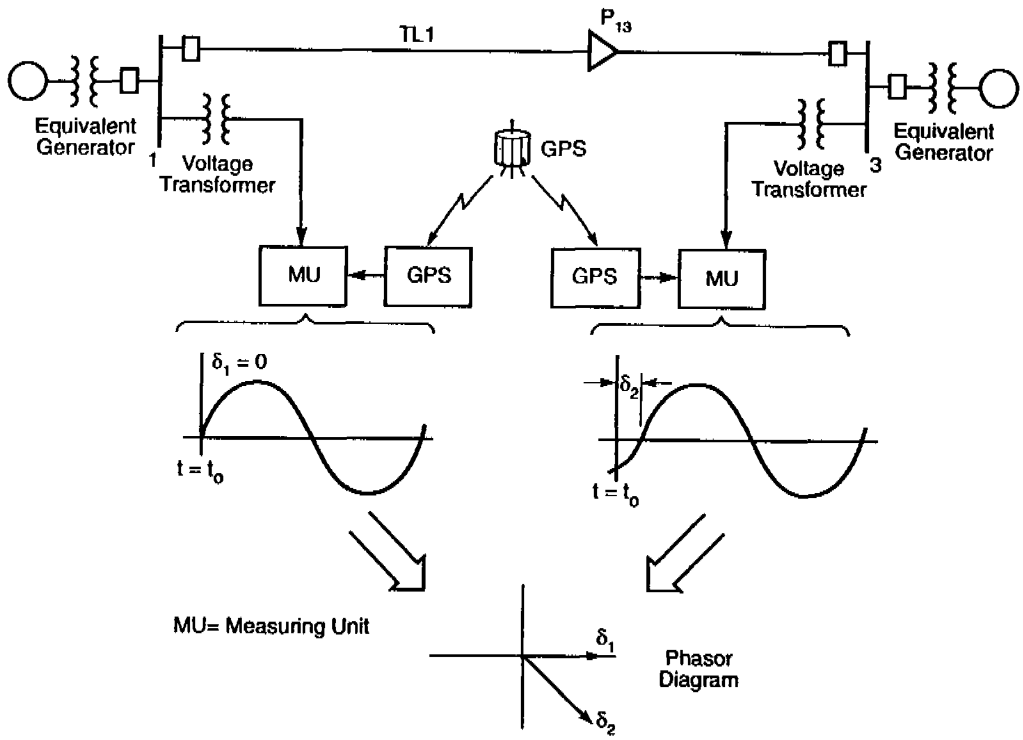
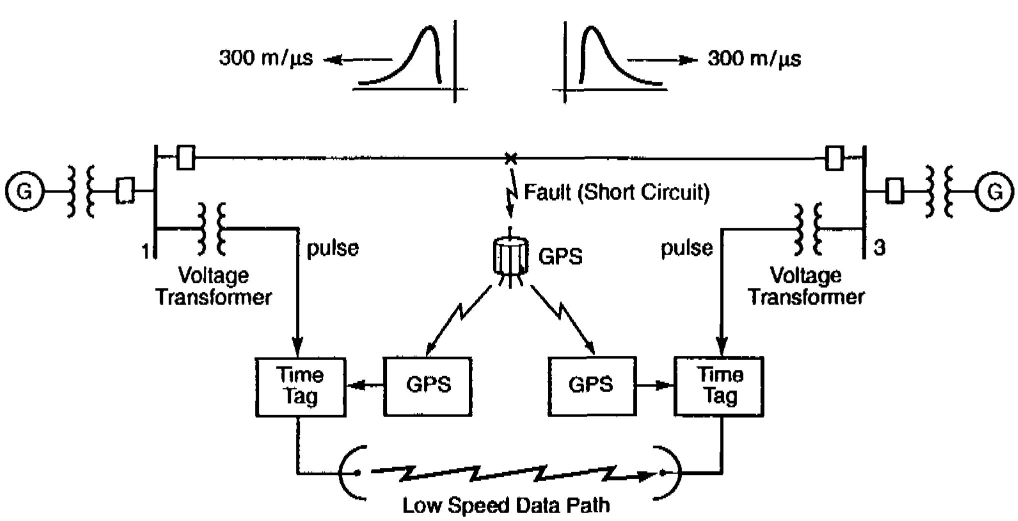


Figure 2. Fault Location



QUESTIONS AND ANSWERS

David Allan, NIST: If it would be of help, the Department of Transportation has a real time output of all lightning strikes across the United States.

Mr. Wilson: More and more utilities are seeing the usefulness of this data. It varies with region.