

BONNEVILLE POWER ADMINISTRATION TIMING SYSTEM

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INTRODUCTION

The Bonneville Power Administration (BPA) is a power marketing agency for the U.S. Federal government. It was established to market power from the federal dams being constructed on the Columbia River and has evolved into the major bulk power supplier in the Pacific Northwest. BPA sells power produced at Federal generating facilities, coordinates the Columbia river hydro system, and transmits power for other utilities.

Time is an integral part of BPA's operational systems. Generation and power transfers are planned in advance. Utilities coordinate with each other by making these adjustments on a timed schedule. Price varies with demand, so billing is based on time. Outages for maintenance are scheduled to assure they do not interrupt reliable power delivery. Disturbance records are aligned with recorded timetags for analysis and comparison with related information. Advanced applications like traveling wave fault location and real-time phase measurement require continuous timing with high precision.

Most of BPA is served by a Central Time System (CTS) at the Dittmer Control Center near Portland, OR. This system keeps time locally and supplies time to both the control center systems and field locations via a microwave system. It is kept synchronized to national standard time and coordinated with interconnected utilities. It is the official BPA time.

There are a few BPA applications which are not served by the CTS. BPA's traveling wave fault locator requires microsecond accuracy which is higher precision than IRIG-B can provide. This system, called FLAR for "Fault Location Acquisition Reporter," only has to be synchronized within the system and primarily uses a high frequency pulse over microwave. Some substations remote from the control center do not receive reliable time from the CTS. In some cases they used a free-running source manually reset on an occasional basis. In other cases a WWV or GOES timing receiver was used.

Power system control and operation is described in the next section of this paper. After that BPA timing systems including CTS, FLAR, time dissemination, and phasor measurements are described. References are provided for further reading.

POWER SYSTEM PRINCIPLES

Electric power is transmitted from generator to load primarily by alternating current (AC) systems. For reliability and economy, transmission systems are connected into grids that have many generators and load areas. Power systems in North America are interconnected into four grids.^[1] The Western Systems Coordinating Council (WSCC) grid covers the largest area, including the western US and Canada from the Rocky Mountains to the Pacific Ocean. By being part of a grid, each utility gains access to more generators and more transmission paths, which reduces the risk of outage due to failure. Also, sharing generating resources 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 in another.

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 (in North America) alternating current (AC). Synchronous devices such as generators and motors must be kept in phase with each other, tracking through frequency changes and disturbances. A primary utility task is keeping load balanced with generation and keeping synchronized with its neighbors.

Every utility is a member of a control area. An area controller, usually a large utility, is responsible for maintaining generation-load balance within that area. If there is insufficient generation for the load, an import from another area will be scheduled, and vice versa. However, power transfer won't just occur just because it is scheduled. It is a result of the phase relationship between areas. Power transfer between two points in an AC system is defined by

$$\frac{P = V_1 V_2 \sin \phi}{Z}$$

where V_1 and V_2 are the voltages at each point, Z is the line impedance between them, and ϕ is the included voltage phase angle. Since substation voltages are controlled at a constant level and line impedances are fixed, the power transfer is determined primarily by the phase angle between stations^[2].

So how is the phase angle set? Phase angle is the integral of frequency. Deviation of frequency from the nominal 60 Hz will either advance or retard the phase angle relative to other areas. Frequency in turn follows the generation-load balance. Despite advances in alternative energy sources, electric power is produced primarily by turning an alternator with a turbine. Power P produced in the turbine is expressed by $P = T\omega$ where T is the torque and ω is the angular velocity. A decrease of electric load on the alternator reduces the resisting torque, so the speed of rotation increases to absorb the power applied to the turbine. Conversely, an increase in electric load will cause the machine to slow down. The alternator speed determines the AC frequency. Consequently, the area phase angle is controlled by adjusting the generator-load balance within the area.

Interconnected utilities cooperate to keep the system operating on schedule. Individual genera-

tors and even small areas tend to be self-regulating. If a generator gets a little ahead, the power transfer increases which loads the generator and pulls it back into synchronism. Stabilizers are used to prevent local oscillation within the system. Beyond that, the area controller monitors area frequency and inter-area power transfer, minimizing error through generation control. A system timekeeper records accumulated system time error that results from sustained frequency errors. Coordinated system frequency adjustments continually drive the system time error to zero. Measurements for these controls are made by a CTS at the area control center. Each CTS maintains reference to a national standard so that measurements throughout the grid agree.^[3]

CTS SYSTEM DIAGRAM

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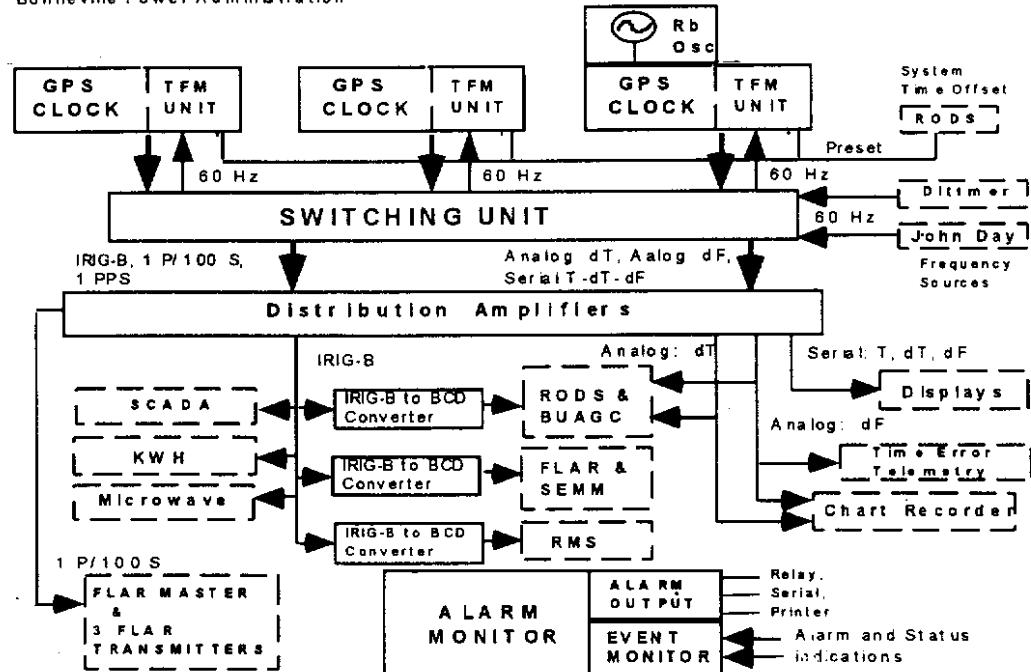


Figure 1. BPA Central Time System

CTS

In 1994 BPA installed a new CTS based on GPS. It replaced the original single redundant unit installed in 1974 based on WWVB. This new system has triply redundant primary sources, a voting switchover unit, and extensive monitoring. It provides all the time functions previously supplied by the CTS, including time and frequency error and IRIG-B. It also provides the synchronizing reference for the FLAR system (Figure 1). A framed T1 signal output will be added for the new fiber optic communication link.

The primary sources are fully equipped GPS receivers. Each has its own antenna and separate AC power circuit. The two primary units have a battery back up as well. The third, the reference

unit, has a rubidium oscillator with either manual or automatic GPS tuning, selectable by the user. Each receiver generates an IRIG-B, a 1 PPS, and a 1P/100S signal. Each is also equipped with a frequency and time monitor unit which computes power system frequency and accumulated time error. These quantities are output in both analog and a serial format.

Outputs from all three receivers are fed into a switching unit. In normal operation the switching unit compares the three outputs of each quantity against a user set tolerance. If any one of the three exceeds the tolerance, the unit is selected out. If the primary unit is selected out, all outputs are switched to the secondary unit. Once a unit is selected out, the switch drops into a primary-standby mode with the remaining two units. If any of the outputs from the now primary unit fails, the switch will select the last unit. Manual restoration is required to restore the voting mode to prevent multiple switching that could disrupt outputs. Manual mode selection includes three unit voting, two input normal/standby, or any single unit.

The outputs from the switch pass to distribution amplifiers. These are also fully alarmed for output failure. They are also designed for high isolation to prevent failure of one load from affecting other equipment. Separate outputs are provided for different systems to minimize the effects of a failure.

The whole system is fully alarmed with a PC that both records all alarms and groups them for output to other equipment. Selected alarms are sent to a printer. Grouped outputs can be sent out a serial link or routed to a relay. The PC records both failure and restoration times, whether they result in a change in the output or not. This complete monitoring is a great help in analyzing the "mystery event" that so often plagues high-tech automated systems.

A second identical system was purchased for the new control center in eastern Washington. Both systems have been in service about a year. They have been operated with a $1 \mu\text{s}$ tolerance on time, 20 ms in time deviation, and 5 mHz in frequency error measurements. There have been only a few disturbances which caused the three receivers in each system to deviate enough to exceed these limits. Two of these we investigated at length seem to be due to the GPS system itself. Those cases seemed to affect all three receivers at both the Dittmer and Eastern control centers, which are 300 miles apart. Ironically, without the extensive alarming capabilities of the new CTS, those disturbances would have not been noticed, as they did not result in observable system output changes. If GPS is going to play a central role in power system operation, we need better access to timely information for resolving anomalies.

FLAR

A short circuit on a high-voltage transmission line will create an ionized path that will sustain the short, even if the original cause is removed. Usually momentarily disconnecting the line will allow the ionized path to dissipate enough that the line can be returned to service. Occasionally, equipment is damaged and repair is required before restoration. In this latter case, locating the fault quickly is important and sometimes difficult. A tree in a line is easy to spot if you know where to look; an shorted insulator may be quite difficult to pinpoint.

When a fault occurs on a transmission line, the current increases, voltage decreases, phase angle increases, and a high-frequency wave propagates in both directions from the fault at nearly

the speed of light. The distance from a terminal to the fault can be computed by comparing the line impedance per unit distance with the apparent impedance produced by the fault. This technique does not work well with series compensation (capacitors) and can be thrown off by load current and magnetic coupling with adjacent power lines. Other methods involve measuring characteristics of the high-frequency traveling wave. In the FLAR system, BPA has pioneered a technique that compares the arrival times of the traveling wave at substations on either side of the fault (Figure 2)^[4, 5]. The traveling waves cover about 1 ft/ns, so 1 μ s timing accuracy allows fault location within 1000 ft. This is about the spacing between high voltage transmission line towers, where faults are most likely to occur.

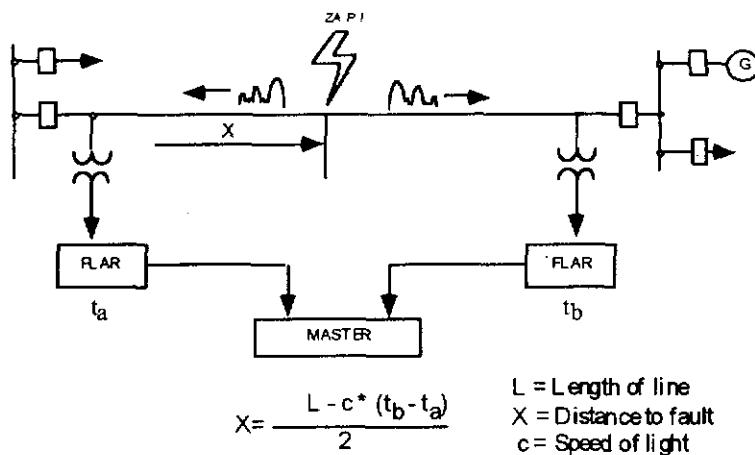


Figure 2. FLAR traveling wave fault locator diagram.

The FLAR system has microcomputer-based remote units installed at 24 key substations. Each has a clock synchronized by a high-frequency pulse sent every 100 seconds 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 the synchronization pulse, which uses 60 kHz of high frequency bandwidth on an analog microwave system. It is only available to major stations within BPA's service area. In 1989 we began extending it by synchronizing the microwave pulse to UTC time using a GPS receiver. Then we could use another GPS receiver to supply the same pulse to a FLAR remote unit that was off the microwave system^[6]. Finally, in 1992 we defined a data protocol and hardware configuration that allowed using a GPS receiver for a FLAR remote unit. Since then we used these GPS-FLAR receivers to extend our FLAR system to include tie lines with other utilities and several stations without microwave. We are making most new additions with this technology. Eventually, the analog microwave will be replaced with digital systems and the system will all be replaced with GPS.

STANDARD TIME DISSEMINATION

CTS still distributes standard time over microwave voice channels in IRIG-B format. In some locations this works well; in others it has always been a problem. It looks like a modulated 1 kHz signal should transmit easily over a 300-3000 Hz voice channel, but it isn't that simple. IRIG-B modulation produces signal energy at 10 Hz, 100 Hz, and harmonics of 1 kHz which are outside of the passband. Phase slips on a frequency division multiplex misalign the IRIG-B harmonics. These effects distort the decoded signal, making it difficult to read, especially for automatic recording equipment. Local time generation can overcome that problem.

In addition to problems with centralized time distribution itself, there are still locations without access to central distribution. In the past there was little in these smaller substations that needed a precise time source. Now almost all protection and monitoring equipment is microprocessor-based and records information with a time stamp. These systems also have capability for remote access, which makes having an accurate time reference even more important.

In response to both of these problems, we are now using GPS receivers more commonly for time dissemination. We have found they are easy to install and operate reliably. They are cost-competitive with any other time system with the same level of reliability and accuracy. The GPS-FLAR receivers also output IRIG-B, giving us two functions for the price of one box. However, the issue of centralized time and verification remain. How do we know if a GPS receiver is operating and is providing the same time as the CTS?

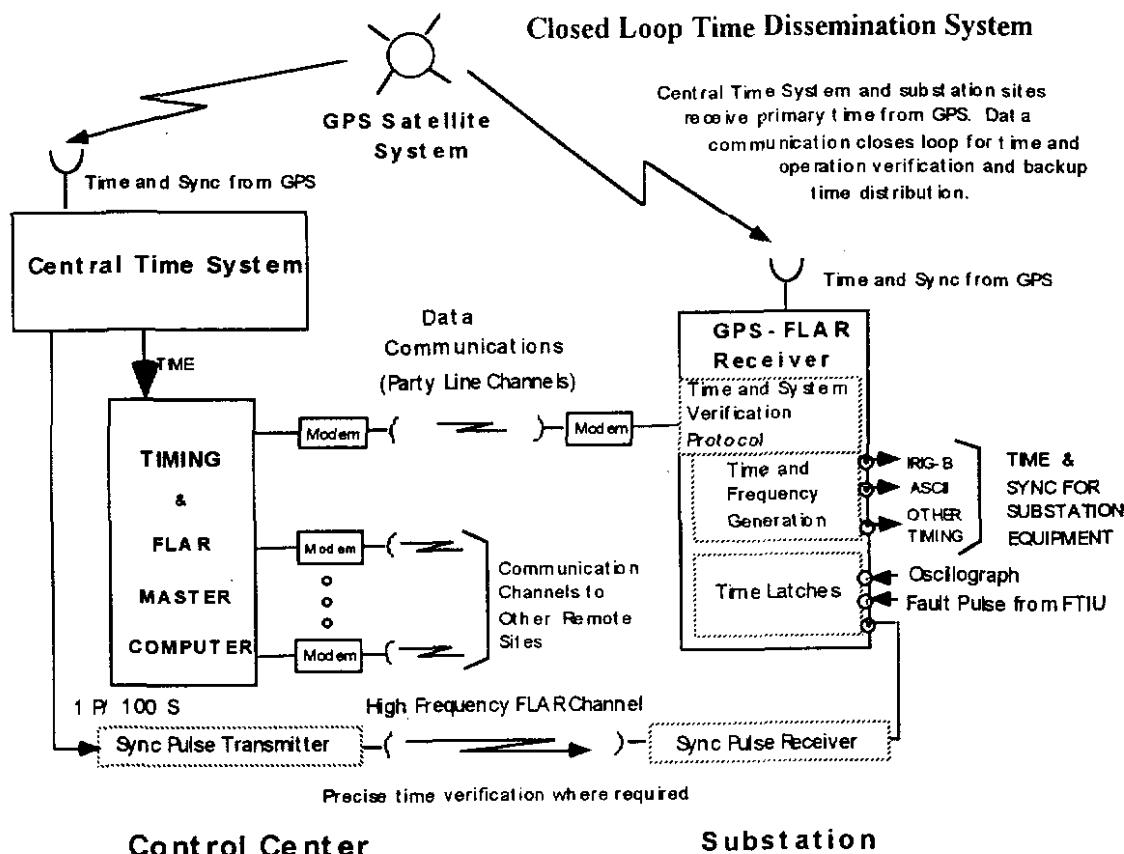


Figure 3. GPS based closed loop timing system.

In designing the new GPS-FLAR receiver, we included commands for time verification and error flags. All the FLAR remote units are polled by a master. The query for GPS-FLAR receivers includes asking the remote time, which is compared with the master time. If they differ by more than a fixed delay, the receiver is reported as having a failure. Flags for things like oscillator error and loss of lock are also checked and flagged. While this technique cannot verify GPS time with precision, it closes the time dissemination loop with the CTS and assures time coordination system-wide (Figure 3).

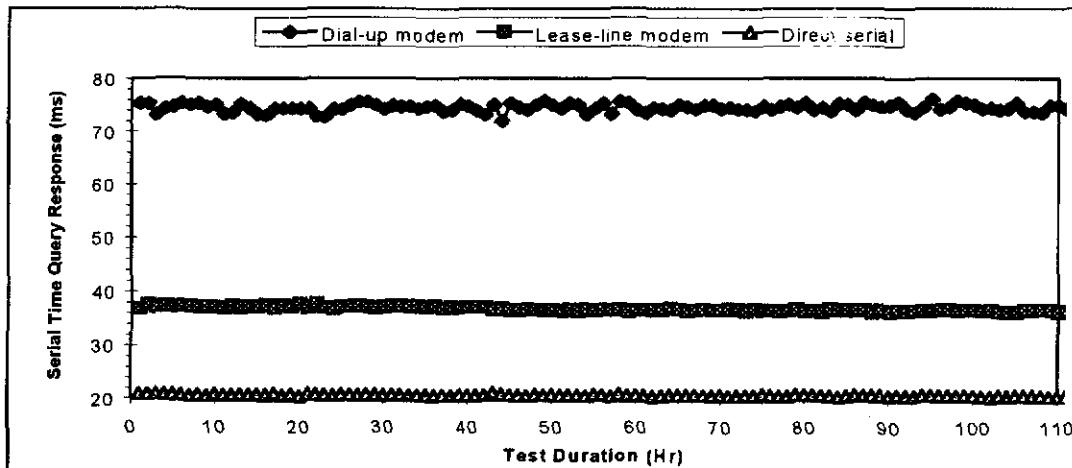


Figure 4. Time delay through serial communications--includes computer latency and delays in data switches.

We tested this technique of time verification through serial communications to be sure it was reliable. The GPS receivers we used time-stamped the time query message to the nearest millisecond (Figure 4). We used a PC to do the polling and timed the query using an internal timing board. We found the delay using a directly connected, 4800 BPS 4-wire modem was 37 ms, with a time variation of ± 1 ms. Using a dial-up, 4800 BPS 2-wire modem, the overall delay increased to 75 ms, with a range of ± 5 ms. A local, directly connected receiver provided a reference for the computer timing latency and delays through the local data switch.

PHASOR MEASUREMENT

A phasor is a vector representation of a sinusoidal quantity which includes both magnitude and phase angle. A power signal is a 60 Hz (or 50 Hz) sinusoid and is commonly analyzed in phasor format. Measurement of power signals in phasor format in real time presents unique opportunities for power system controls. A Phasor Measurement Unit (PMU) is a microcomputer-based system that digitizes the three phase waveforms and derives phasors in real time using FFT techniques^[7] (Figure 5). These devices are still in the research and testing stages, though there is already a standard for their implementation (IEEE 1344).

BPA has been involved in test systems with two different PMUs. The first one, a prototype unit, samples waveforms at 720 samples/second and derives phasors at the same rate. The second one takes 2880 samples/second, but decimates to 720/second for deriving phasors. Both use 12 samples for the Fourier transform, which is one cycle at 60 Hz. The three phasors combine into a single positive sequence phasor representing 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^[8]. As noted in [1], power transfer is directly related to the phase angle between stations. At 60 Hz, one electrical degree is equivalent to 46 μ s. A desirable accuracy of 0.1 electrical degree requires 5 μ s synchronization between PMUs.

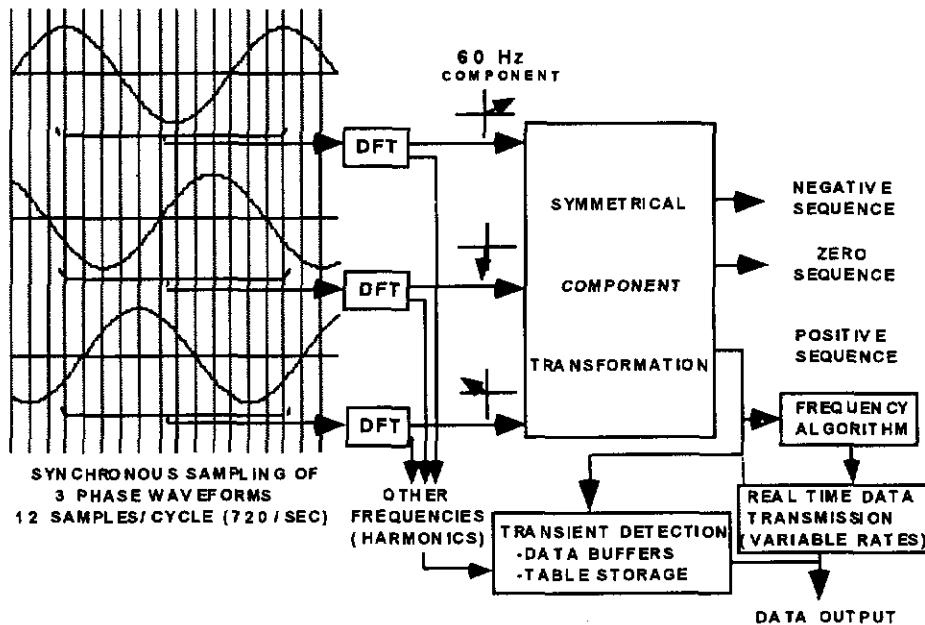


Figure 5. Phasor Measurement Unit signal processing diagram.

BPA tested two prototype PMU's on the main transmission link between the Pacific Northwest and Southwest (Washington to southern California). The two PMU's were synchronized with GPS receivers. A master terminal at the BPA Laboratories in Vancouver, Washington, recorded the data. 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^[8]. Phasor data responded with greater accuracy and less noise than comparable analog telemetered data.

The newer PMUs are production units currently being deployed in a wide area system control

test. BPA is installing four units in Montana, Washington, and Oregon. Other utilities in the western system are installing units in their service areas in Arizona, Utah, and California. The data from the total of 20 units will be transmitted in real time to a major substation near Los Angeles for control of a DC transmission link to Oregon.

CONCLUSIONS

We are continually trying to coordinate timing systems. Most events impact more than one system, so relating data from several systems is crucial. The problem is new applications occasionally have timing requirements that cannot be met with existing systems. It is usually cheaper and more expedient to build a separate timing system, even though it does not coordinate with the others. We are continually trying to update old systems to newer technology and to provide reference for newer applications.

Through GPS we have a common time base that is accurate enough for all current power system applications. BPA is working toward a comprehensive time system using GPS for the universal source, but with enough internal system transfer to assure internal coordination. It is somewhat risky building an infrastructure around an external system over which we have no control. We like many others, will be lending our influence to assure GPS remains an open and reliable system into the foreseeable future.

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Questions and Answers

ED URR (WORLD CLASS): In the flare test that you've been utilizing for the last year, what is the accuracy with respect to fault location you've been able to obtain?

KENNETH E. MARTIN (BONNEVILLE POWER ADMINISTRATION): You mean what percentage of them we actually locate?

ED URR (WORLD CLASS): How close can you get?

KENNETH E. MARTIN (BONNEVILLE POWER ADMINISTRATION): This technique allows locating within about 300 meters. Typically, the failures happen at transmission towers, because it's the shortest distance to short-to-ground or short to phase-to-phase, although not always; and so, we try to maintain a one-microsecond resolution which allows us to pinpoint it to a tower.

Generally, I would say that if we get plus and minus a tower, we're doing quite well; and it's quite accepted by most people.

ED ERR (WORLD CLASS): Secondly, are you involved in the phase or test measurements that are being done in conjunction with EPRI, BPA, PG&E, LADWP, APS in Salt River? If so, can you comment on them?

KENNETH E. MARTIN (BONNEVILLE POWER ADMINISTRATION): Yeah, we are involved in that. That particular system is a very large-scale system; as you just mentioned, they're all over the place. I'll refer you to this slide right here: Each one of the utilities that you mentioned has several phase or measurement units in its service area; we have one in Eastern Montana, one at Grand Coulee, one near John Day, one at Molin; there are some over here in Northern Arizona, Northern New Mexico; there's actually one — I think it's going to go in in Western Colorado. And then the rest of them are all in Southern California, Central California and Arizona.

All the signals from these are supposed to be fed in in real time, to the controllers on the south end of the DC transmission line from here up to Salilo, which is on the Columbia River. The idea is to, by controlling the power that's transferred over the DC transmission line, we should be able to stabilize the swing between the Northwest and the Southwest, which regularly occurs.