



KE

# EPING<sub>THE</sub>

Synchrophasor measurements have gradually gained acceptance since their invention in the 1980s. Major blackouts have given great emphasis to this technique due to the need for better disturbance analysis and more situational awareness. The main application for these measurements is disturbance analysis, and it is a well established practice in the WECC. Displays for situational awareness are quickly moving into practice, but are still not considered "essential". State estimation with phasor data is also moving into common use. Controls have been prototyped and demonstrated with success.

# LIGHTS

SYNCRPHASORS FOR WAMS

# ON

## This is a new type of measurements, and it takes a shift in perspective to recognize the advantages it opens

THE SALAZARS WERE JUST SITTING DOWN TO DINNER when the lights flickered, dimmed slightly, and then steadied to normal in a few seconds. Six-year old Ramon said "I'll bet the 'lectricity gremlins just got another wire!" Little did they realize lightning had caused a flashover that in turn caused a breaker failure at a 500 MW power plant. The plant tripped off line, and the loss in power was made up by generation up to 900 miles away. See Figure 1a, 1b.

Such is the nature of the huge modern power grids that span continents. Due to the size and distribution of current power grids, most power consumers have little idea of where their power comes from or what it takes to get it there. For that matter, many workers in the power industry have little idea either. Connecting and operating grids distributed over large geographic areas is a complex and exacting job. Grid growth is primarily driven by economics, but also serves reliability and environmental needs. However growth has increased operational problems. Unexpected system oscillations, line overloads, and generation deficiencies have increased with demand and the need for greater system utilization. These small events have been underscored by large scale problems such as the blackouts in 1996 and 2003. All these problems have shown the need for better modeling

### 1a,b A family enjoys dinner in the convenience of electric light



"Wires", a 5 year old's vision of 'lectricity (by Declan Moore, author's grandson)

of the dynamic power grid, better operational planning, more system controls, and increased operational grid awareness. A Wide Area Measurement System (WAMS) can significantly aid in implementing some of these needs.

#### Phasor measurements at BPA

The Bonneville Power Administration (BPA) has been involved in dynamic system measurements since the 1970s. Telemetered signals from MW, MVAR, & kV transducers were used for AGC as well as system monitoring. These signals were recorded when a disturbance was discovered and used to analyze power system dynamic response. WAMS was first used to describe a system of computers that recorded locally signals from transducers at substations. It included simple data file retrieval and merging. As phasor measurements evolved, the original system has been mostly replaced by the current real-time phasor measurement system described in the following sections.

BPA began its long involvement with phasor measurements with a research contract with Virginia Tech in 1986. Under this and a complimentary contract from American Electric Power, the first PMUs were developed under the direction of Professor Arun Phadke. BPA received 2 units for test on the real power system. As a specialist in measurements in the BPA laboratory, I was assigned the project of designing a suitable test, carrying it out, and analyzing the results. Little did I realize this would become a whole career. Installing anything on an operational power system, even for "test", is a challenge in itself. After many months of obtaining communications, producing design documents and configuring the test units, we were ready. We built a data concentrator that would receive and record the phasor data and in parallel the analog telemetry that we were already using for system measurement. The test was set up to see if PMUs could produce comparable measurements of voltage and power as well as reliable phase angle and frequency. The results showed a high accuracy measurement with very low noise compared with the telemetry. The dynamic response was sharper and quite comparable. We also learned a number of things about operation of a digital system, such as requiring a validity check for control commands, like a CRC. Otherwise one can expect odd operation caused by random noise.

However the test did not prove accuracy or response in any quantifiable way, so we initiated a series of tests using a digital model power line. Our 3-phase signal generators would only produce constant signals or changes with limited dynamic characteristics. With the digital power line we could produce any signal that we could represent mathematically. We found that the PMU was not only very accurate but would track any dynamic signal within the conversion

WIRE

Phasor

passband (we used the 720 sample/second calculation rate most of the dynamic tests). Pretty neat. All we needed were more PMUs, some improvements in the software, and of course, some money. It turned out we also needed an application that someone could use. We got a connection to SCADA where we input our one phase angle measurement. We also packaged up a portable unit that we used in dynamic voltage collapse and generator excitation boosting tests. So the project went on standby while we went on to other things, particularly developing a GPS receiver configuration for traveling wave fault location.

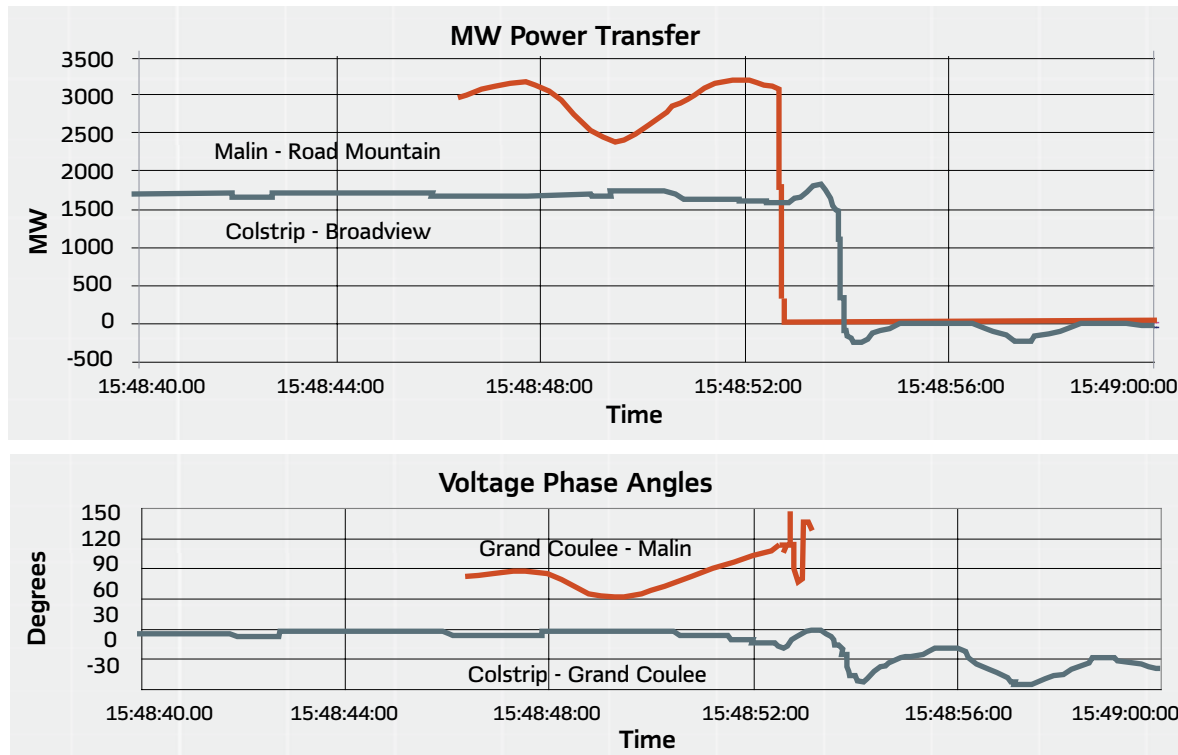
In 1993 EPRI initiated a project using PMUs installed at several utilities in the WECC (then called WSCC) for a wide area control action. Several of the participating utilities, including BPA, successfully installed these units by the summer of 1996. BPA recorded data during the August 10, 1996 blackout that showed the growing oscillation as the system became unstable. [FIGURE 2] The measurements from throughout the day also showed the increasing phase angle as the system weakened. In the aftermath of the event and subsequent analysis, BPA implemented many system improvements, one of which was improving the real-time phasor measurement system. The system at that time consisted of PMUs at 4 substations with modems to provide

real-time data communications to the control center. The data concentrator did not work reliably. It did not provide adequate data management or recording. There was no means for system management. There were no real-time applications. To rectify these shortcomings, we decided to build a new phasor data concentrator (PDC) with the following features:

- Expandability for a much larger PMU network
- Low latency (delay) throughput
- Error checking of input data
- Flexibility for accepting multiple protocols
- A function to detect event triggers and save files of data
- Recording of all PMU and PDC errors to facilitate management and maintenance
- Development of suitable protocols to accomplish the objectives

To simplify programming and facilitate expansion, we also decided on a distributed processing approach. The PDC would have multiple processors, each operating independently and delivering data to a table for output. As the system grew, more processors could be added as needed. Functions available in other units could be utilized. The PMUs included trigger functions for event detection, so the PDC did not need to detect system events. Displays and other

## 2 Oscillation and intertie trip on August 10, 1996 at Malin substation



BPA recorded data during the August 10, 1996 blackout showing the growing oscillation as the system became unstable

applications would be on separate machines doing their own data processing. Data is the unifying medium, and it is readily distributed using with modern data communications.

In addition to the PDC, we developed several applications to aid in system operations and data utilization. The StreamReader application which displays data in real time and records it continuously with automatic old file removal [FIGURE 3]. The PhasorFile application will read and display the file data for analysis [FIGURE 4]. The status monitor application displays system status and records performance statistics. [FIGURE 5]. The guiding philosophy was to make the system reliable so data was always available, and make the data as accessible as possible. These applications run on standard PCs with data distribution by network using the IP protocol. UDP was used rather than TCP in most cases to simplify distribution as well as minimize latency for control applications in the future. This approach also simplified application and data distribution to anyone who needed it.

#### WECC expansions

This new system was successfully operating by May 1997. It has undergone many improvements and further developments, but the basic system remains at the core. SCE began using the same PDC in 1997, WAPA followed suit in 1998, and BCH started a system in 2000. The first inter-utility data exchange was started between BPA and SCE in 1999, using communications through LADWP. In 2000 the WECC DMWG was founded to implement the new NERC disturbance monitoring requirements. They produced a guideline for the WECC that encouraged but did not require phasor measurements. As a result of these requirements and the need for better dynamic analysis, PNM, APS/SRP, & PG&E also started the same type of phasor system. All utilities used the same system architecture used by BPA, but each utility had to solve communication interface, data distribution, and cyber implementation issues. These problems have slowed system growth.

Interest in regional awareness has steadily increased. The 2003 blackouts accentuated the need for overall grid awareness, which is of critical importance to security monitors and ISOs. Data exchange between utilities extends the local WAMS to the whole grid. A link from BPA to the California ISO (CAISO) was established in 2002. This was different than the original BPA-SCE exchange: it used a high-bandwidth connection (T1 - 1.544 MBPS) that would carry Ethernet traffic. It uses UDP/IP over Ethernet for minimum bandwidth usage and delay. Setup and maintenance is simple. The system has operated very reliably with very little data loss. In 2004 similar data links from WAPA to BPA and SCE to CAISO were added. In 2005 PG&E began sending to CAISO and BPA. Figure 6 shows the approximate distribution of PMUs and PDCs in the WECC. More links between utilities are being explored, but administrative hurdles have slowed the process. Cost sharing for the high-speed data links needs to be resolved. More difficult issues are ownership of the data and cyber security. Links using the Internet need data

### 3 StreamReader application showing strip chart display



### 4 PhasorFile application showing strip chart display



### 5 StatusMonitor application with current PMU state, PDC status & station statistics



encryption and secure firewalls. Leased/private links are less vulnerable, but need firewalls at each utility. Data should only be exchanged between willing parties, but agreements are still required for how it will be handled and distributed. The problem quickly moves from engineer to lawyer work.

### Applications

Of course the real issue is: what good is all this? Engineers are fascinated with the measurement, particularly its high speed and accuracy. Administration and operations staff need to see a defined benefit to justify the cost and maintenance load for a new system. Several early test systems were implemented for demonstrating real-time control potential, and for recording data for analysis. These tests demonstrated potential and provided interesting observations of system behavior. But value did not exceed cost and widespread deployment did not follow. In these test systems, technical problems gave less than optimal performance which was not an incentive to proceed with deployment. There is also a reluctance to invest in something new and uncertain when the current solution satisfies existing regulations. Of course this has to be the case since regulations cannot require equipment that does not exist!

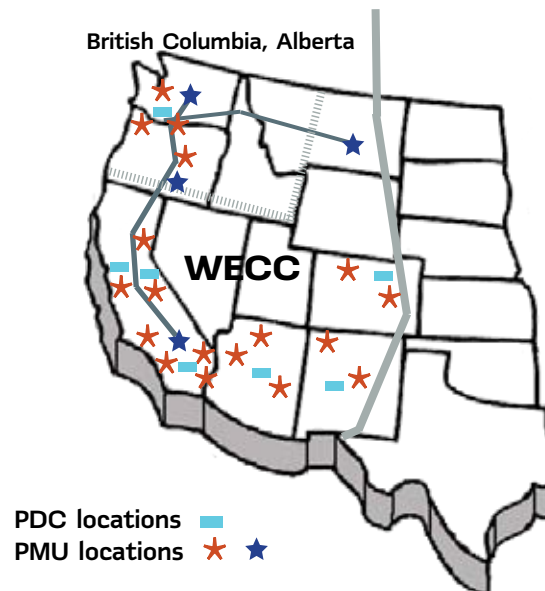
The current system at BPA (and other utilities) was implemented in response to a large blackout. The motivation was better situational awareness and dynamic analysis. Most of the value has come from event analysis. With centralized data access, determining a sequence of events and the likely causes can be done in minutes rather than hours and days. Deeper analysis such as studying modal response and load effects can also be done for better system understanding system model improvement. Several applications have been developed for comprehensive analysis, including the PSM utilities (DSI tools) and Power System Outlook (PSO). The DSI toolbox is a suite of tools that runs in the Matlab environment. PSO runs in the standard Windows and provides a number of windowed displays. However, the real-time system is tailored to meet the needs of operations including grid awareness and controls. The PDC correlates and distributes data in real time in a form that can be widely used. StreamReader provides a useful method of observing system performance, but does not interface into a standard EMS or have direct event recall. To present data to operations, we needed an interface to standard systems so they could use their usual systems, or a stand-alone system that would provide the same kinds of functions.

### Interface with EMS

The main problems interfacing phasor data with EMS systems are:

- The phase angle is an instantaneous value based on absolute time
- The measurement is a complex number which is unlike other measurements
- The data rate is much higher than other control center systems

## 6 Approximate distribution of PMUs & PDCs in the WECC



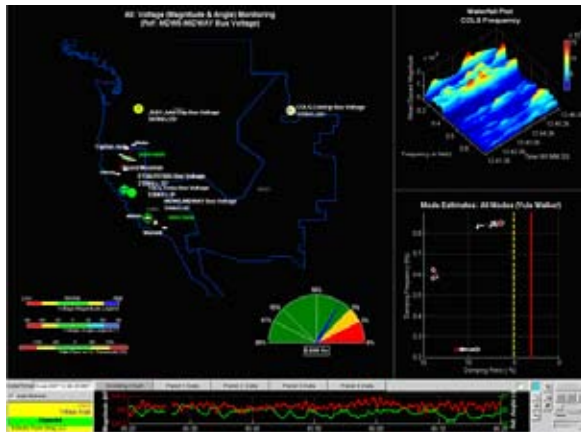
Phase angle measurement is a complicated issue. Phase angles in synchrophasors are relative to absolute time (UTC), not system time. Unless the system frequency is exactly at nominal—which it rarely is—the measured phase angle will rotate. Since all phasor values are referenced to the same time, they all rotate together. However that means angle comparisons between phasors requires measurements that are made at exactly the same time. Measurements from a single PMU are synchronized internally, so calculating power using a voltage and current from the same PMU is correct regardless of the external synchronization. However system phase angle between different stations requires aligning samples by timetag and assuring that the PMUs have an accurate external synchronization. All PMUs synchronize measurements to Universal Time-Coordinated (UTC). GPS is currently the only practical method of widely disseminating UTC time with the accuracy required by phasor measurement.

The easy way to deal with the complex number issue is to present the data to other systems as a magnitude and phase angle. Phase angles relative to the system are meaningful; absolute angles are not. Hence, absolute phase angles need to be related to a power system reference. The easiest way to do this is designate one bus as the “swing bus” and subtract it from every reading. That provides a common power system reference that “rotates” with the difference between system and absolute time. However if the “swing bus” measurement develops an error, then all of the other measurements may fail. Two other approaches are to report measurements as the angle between two busses (bus pairs), or use a “virtual bus” that won’t drop out. In 1998, BPA implemented an interface to the traditional SCADA system using the bus pair approach. This interface acted as a SCADA RTU and responded to data

## 7 RTDMS dashboard and main phase display of the WECC



## 8 RTDMS modemeter with historical "waterfall" plot modal estimates as well as flow-gates using selected WECC signals



Phasor  
measure-  
ments  
require  
development  
of  
supporting  
infra-  
structure,  
such as  
appropriate  
packaging  
and  
communi-  
cation  
protocols.

queries. It reported bus voltage magnitudes, frequencies, and angles between selected bus pairs. Each bus was represented in two bus pairs, so if one measurement failed, the picture could be obtained using different combinations. Filtering and holdovers were added to smooth outliers and short dropouts. Flags for synchronization and data errors were reported as digital status. As the system expanded, more angles were reported.

It was soon apparent that the pair approach was cumbersome and didn't scale well—every extra bus added two measurements. Our state estimator vendor also developed the ability to include measured voltage phase angle in the estimation process, so we wanted to report more angles. We developed a new interface which, like StreamReader, runs on a PC and uses the same real-time data feed from the PDC. Using the higher processing power of current PCs, we could improve the filtering and handle data impairments more easily. The new system simplifies setup, monitoring, and modification. This new interface also uses a virtual bus approach for phase angle. At each sample, the angle from a few PMUs that are electrically close are averaged and filtered to form a "virtual bus" angle for reference. This is subtracted from all angles to obtain relative angles for reporting to SCADA. Then each angle is only reported once. If an angle in the reference set is lost; there is only a small change in the reported angles. The virtual reference is only used for computing relative angles, so the state estimator can establish any swing bus and calculate bus angles from that; the system angles as used are thus always exact.

In addition to the phase angle issue, data measurement rate creates problems. Traditional SCADA uses low bandwidth transducers and samples at a low rate. Spikes due to switching, faults, and other transients do not appear. Phasor measurements are generally high speed with a wide bandwidth. Transients do appear, particularly in early PMU

models that did not use much filtering. Reporting phasor samples directly to SCADA caused false alarms when the sample happened to occur at a peak or valley of a transient. Simple filtering of the data removed most of this problem. The new system provides complete anti-alias filtering.

Another difference between SCADA and the phasor data system is the manner of reporting. SCADA is queried at slow speed with multiple attempts in each sequence. It uses lower speed communications which is usually more reliable. PMUs push out data with no retransmit and a higher speed which is often less reliable. There are more dropouts in phasors than SCADA. Due to the high reliability of SCADA, dropouts are quickly reported. The higher phasor dropout rate causes an unacceptable number of alarms in the SCADA system. Holdovers in the interface hold the last value for a few query cycles to minimize inconsequential alarms. Holdover has to be carefully balanced to be sure important events are reported promptly while nuisance alarms are eliminated.

### Stand-alone displays

The old saying "a picture is worth a thousand words" is worth heeding. The SCADA line-type displays are laid out somewhat geographically, but don't preserve scale with geography. We wanted to develop a display that would show system phase angle superimposed over the whole system map. After some investigation, we decided to use Power World with a colored contour overlay on the western states grid. Suitable labels and voltage magnitude "thermometers" were included to create comprehensive displays. The demonstration was successful, but interface problems and lack of actionable information did not warrant continued development.

Another visualization system called Real Time Dynamic Monitor System (RTDMS) has been developed by the Electric Power Group (EPG). This system includes a geographic

display of phase angle using colored arrows to show the direction of power flow. The colors illustrate preset alarm limits. It is easy to read and modify, and was designed to interface specifically with phasor data. It also includes a number of additional displays including strip charts, voltage profiles with alarms and system frequency. Recently a spectrum display of modal oscillation has been added. It also stores a block of data for immediate recall and has a data storage component using a standard data base. These features are much more adapted to standard control center operation and facilitate getting maximum value from the phasor measurement system. [FIGURE 7. RTDMS-DASHBOARD. FIGURE 8. FLOW GATE & MODAL DISPLAYS]

### Real time controls

In 2000 BPA initiated a program to develop a control system using the high speed, high quality measurement that phasors provided. One of the limiting conditions in the Western grid for north to south power transfer is the possibility of a large generation loss in the southwest. This would create a large N-S swing that could cause the regions to go out of step. The contingency limits the allowable power flow scheduling under certain conditions. A control that could detect this type of incident and take action quickly enough to prevent out of step could allow higher power flow at certain times. The basic detection plan was based on the fact that during a large swing, the intertie voltages will go way down and the nearby generation will increase VAR output to support intertie voltage depress. This proposed control, developed under the direction of Carson Taylor at BPA, included two detection schemes. One scheme used a weighted average of bus voltage measurements from PMUs along the intertie. When the average exceeded a threshold it issued a trip using an inverse time/magnitude accumulator. The other used the same weighted voltage average but combined that with another weighted average of VAR outputs from generation that supported the intertie. A fuzzy logic engine combined these two indicators to output control signals. Input from the controller was from the PMUs through the PDC at the control center. Output was through the existing RAS circuits. Control actions could include capacitor insertion, reactor trips, and generation trips. [FIGURE 9]

The system was fully prototyped and ran in monitor mode for 4 years. After the initial development stage, it only issued a trip one time, and this was the only incident that was significant enough that it should have issued a trip. The worst case contingency for generation loss in the SW used in most studies is the loss of two generators at Palo Verde. This is plausible based on WECC criteria, and is larger than other outages. In this unusual incident in 2004, not just two but all 3 Palo Verde units were lost in addition to several other generators in the area. The swing was large and very comparable with the model of such a swing [FIGURE 10], but the system stayed intact largely because the N-S power flow was well below the limit. It provided a good test of the control

## Ten Synchronphasor Application Tips

Edmund O. Schweitzer, III  
Schweitzer Engineering Laboratories, Inc.

Until recently, synchronized phasor measurements were available only from laboratory equipment or from expensive stand-alone phasor measurement units. The expense and need for separate equipment have limited the utility of synchronphasors. Today, when you buy many microprocessor relays or meters, you get synchronous phasor measurement capabilities for free! You can even get firmware upgrades to add synchronphasor capabilities for many existing relays, further extending the reach of synchronphasors.

Relay manufacturers and others have worked hard to make synchronphasors ubiquitous, because there are so many things you can do, now that voltage and current measurements are precisely time-aligned. Thanks to very low-cost microsecond-accurate GPS clocks, precise time is available everywhere today. One microsecond corresponds to only about 0.02 electrical degrees at 60 Hz, so phase errors in the measurements are mostly from instrument transformers.

Below, please find a list of ten tips for using synchronous phasor measurement information today. I believe that whether you test or commission protective

systems, manage assets, operate control centers, develop models, or analyze power system events, you will find these tips immediately useful.

### 1. Use synchronized phasor measurements from meters and relays to check your instrument transformers within your substation

When the breakers are closed, all line and bus voltage transformers should agree in magnitude and phase. Now you can find out! Use a meter or relay as a "vector voltmeter."

### 2. Check your CT polarities, phasing, and ratio

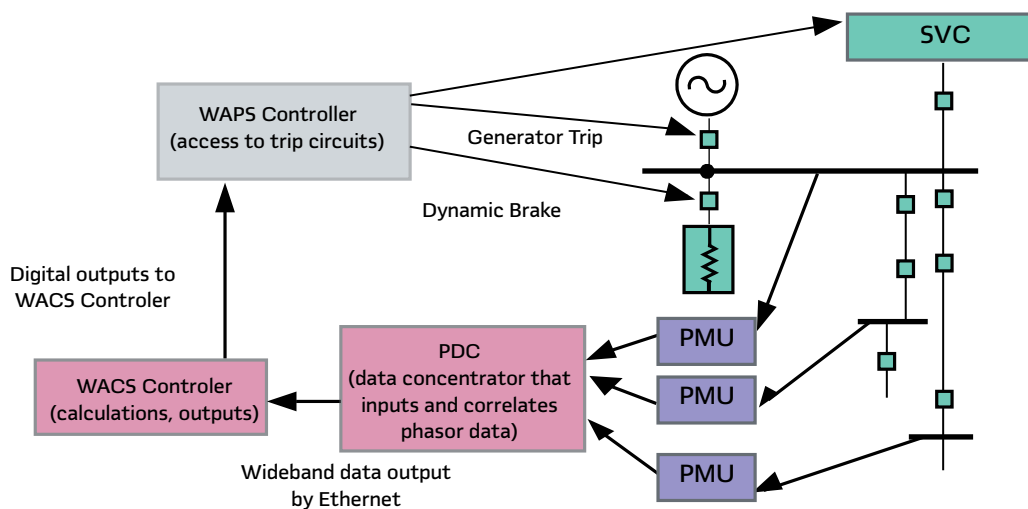
With a little load on the system, and all your relays synchronized, perform Kirchoff's Current Law around the bus, phase by phase. You will see any phasing, polarity, or ratio errors.

### 3. Check CT and VT polarities, phasing, and ratio, line end to line end

Take a phasor-measurement snapshot at each end of the line, with a manually initiated, time synchronized phasor record. For a quick sensibility check, in most cases, you don't even need to take into account line parameters.

by Kenneth Martin, Bonneville Power Administration, USA

## 9 WACS diagram of operations



Phasor  
measure-  
ments are  
a building  
block for  
new  
generations  
of applica-  
tions

and showed that both detection algorithms worked very well. Incidents of this type and magnitude are exceedingly rare—fortunately—so implementing and demonstrating reliable and secure controls with a high degree of confidence is difficult.

### Future of phasor measurement systems

Phasor measurement is an impressive technique of estimating the phasor equivalent of an AC waveform. Advances in computing using inexpensive microprocessors and microsecond time dissemination through the GPS system have made this breakthrough possible. Still, these are just measurements of power system quantities and not an end in themselves. They provide value through the analysis, monitoring, and controls that can be done with them. They are a building block for new generations of applications which need developers knowledgeable in the measurement and the advantages it provides.

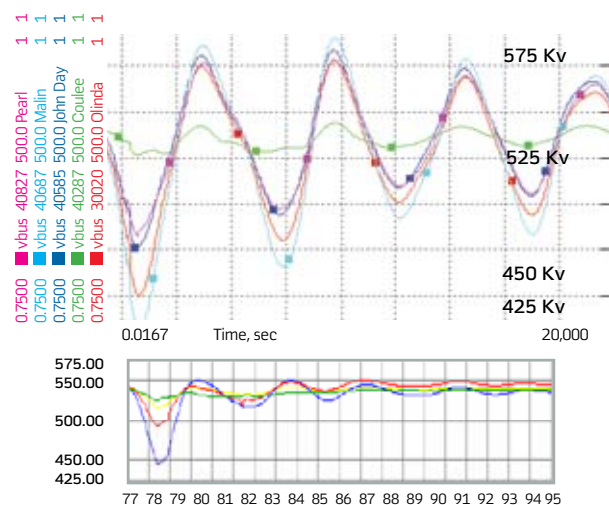
Most of the emphasis in phasor measurements has been the high bandwidth, low noise aspect that makes dynamic analysis and clear visualization possible. This is certainly where the technique shines in comparison with current methods. However this measurement can be used in many ways with different types of applications. Lower speed SCADA situational measurements for operator reporting and alarms can use phasor data. State estimation is an ideal application for phasor measurement, since phasors are the actual measurement of what could previously only be estimated. Phasor based controls take advantage of high speed, low latency as well as accuracy. We have demonstrated successful PMU deployments and have built high-speed, centralized systems and have proven that they work. We have shown some of the measurement capability and their

advantages. We now need more focus on the applications. We need to adapt and tailor the measurement system to meet those needs, rather than build one type of measurement system that applications must adapt to.

The high bandwidth systems being built today with relatively few measurements fill the need for many applications like disturbance monitoring and situational awareness. But SCADA reporting and state estimation needs many points, preferably every bus on the grid. Scaling a high speed data system to that size is very difficult and expensive to implement, and more difficult to maintain. In addition, the extensive communication systems and protocols used in an EMS do not adapt well to the high speed phasor systems. Eventually SCADA type reporting systems will speed up, so that high-speed phasor type systems may become the SCADA of tomorrow. In the meantime, lower speed reporting that includes precise measurement timing with anti-aliasing protection is needed. For example, if phasors were reported on the even second (ie, every 2 seconds) to the SCADA master, the measurements could be combined accurately for precise angle determination. The next generation PMUs (or PMU functions in other devices) should be able to report to several applications using different protocols and data rates.

There is no need to restrict phasor measurements to a single protocol system. The very successful IEEE standard C37.118-2005 prescribes a specific protocol for real-time data transfer, but doesn't prohibit the use of any others. This standard has been a big help to the industry by specifying a simple protocol that is easy to implement and makes a device interoperable among vendors. The basic methodology can be adapted to other protocols, such as ICCP, DNP-3 and IEC61850 to create compatible data transfer within those

## 10 Modeled and actual responses to similar events showing compatible responses



protocols. Wider adaptation will make these measurements available to more applications and spread the benefit.

Even in the area of high-speed data systems there are differing requirements. Precision modal analysis needs careful filtering to remove aliased artifacts. Filtering causes delay, and controls are very sensitive to delay. Continuous feedback controls need careful filtering and bandwidth limitation to prevent instability. Feed-forward (bang-bang) controls are usually insensitive to small signal events except when they become unstable, so only require minimal filtering. The end application is always the deciding factor in specifying the measurement requirements.

So do we need to abandon the measurement systems we have been building in favor of other approaches? Not a bit. Great strides are being made in PMU testing. This has shown that the current PMUs in production make very similar measurements that can be widely used. Most data systems currently being deployed are nowhere near hardware and software capacity. As shown above, adapters are being created to effectively convert data between applications. In the short term of 5-10 years, the systems being deployed will serve their intended functions, including many applications. However as new applications are developed, we should expect to encounter differences that will require broadening the measurement and data reporting systems.

The process has begun and will show increasing benefits as time goes on.

Verify that phase A is really phase A on both ends, for your currents and voltages. Since you have synchronized phasors at both ends of the line, you can use the transmission line equations to do a very exact calculation. Investigate any errors. They can come from wrong line constants, errors in the instrument transformers, or in their connections.

### 4. Analyze faults more thoroughly, and check your models

Calculate infeeds from all sources, calculate fault resistance, and check zero-sequence parameters for lines and sources.

### 5. Check your state estimator

The state estimator estimates the magnitudes and angles of bus voltages. Is it accurate? Trigger measurements at several buses at the same instant, and compare your measurements with the estimates and find out! Also helps find bad SCADA data, when they don't agree.

### 6. Don't have a state estimator? You now have something BETTER: direct measurement of the state!

Not only is it direct measurement, it is more frequent. You can get the measured state every second, versus an estimate every 1-10 minutes.

### 7. Build automatic system self-checking schemes

There are many examples. For instance, when two relays are on the same bus,

or same instrument transformers, they should be measuring the same voltages and currents. In addition to the manual checks mentioned earlier, you can build automatic checks in your communications processors, to check routinely and let you know when something goes wrong ... with a relay, a connection, a test switch, or with instrument transformers. Take the difference between phasors, and visualize magnitude AND phase errors right away.

### 8. Monitor angles across the transmission system

Bring a few critical bus voltages and angles together at the control center, and display them for the operator. Ask the planners to make a chart that maps angle relationships into critical operating scenarios, so operators can easily use the data.

### 9. Monitor angles between the transmission system and critical distribution buses

Ask the planners to make a chart that relates the angles to voltage stability limits. The operators will then have a tool to visualize impending voltage collapse.

### 10. Display oscillographic records collected by your synchronized intelligent devices, from anywhere on your system, in perfect time-alignment!

Your fault analysis oscillographic software probably already supports the perfect time alignment provided by synchrophasors!