Real-World Synchrophasor Solutions

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***Abstract*—Synchrophasors are no longer an academic curiosity. Today, synchrophasors are providing solutions that otherwise would have been too expensive or too complicated to implement with traditional approaches. This paper examines ten synchrophasor applications being applied to monitor, visualize, and control electric power systems.**

1. **Voltage and current phasing verification**
2. **Substation voltage measurement refinement**
3. **SCADA verification and backup**
4. **Communications channel analysis**
5. **Wide-area frequency monitoring**
6. **Improved state estimation**
7. **Wide-area disturbance recording**
8. **Distributed generation control**
9. **Synchrophasor-assisted black start**
10. **Synchrophasor-based protection**

Included with each application is a description of the required equipment, communications channels, and data rates.

I. Introduction

Synchrophasors have left the laboratory, moved beyond demonstration projects, and are used around the world in diverse applications: testing, commissioning, automatic station-level self-checks, disturbance recording, and wide-area protection and control systems.

A decade ago, synchronous phasor measurement capabilities were available only in standalone instruments, called phasor measurement units (PMUs). Subsequently, SEL introduced synchrophasors into its protective relays, as a standard capability. Today, synchrophasors are available in protective relays, meters, and recorders as well as in PMUs. It is even possible to upgrade a wide range of protective relays to produce synchrophasor measurements and effect control.

IEEE Standard C37.118 has been widely accepted as the preferred method for exchanging synchrophasor measurements. Sixty measurements per second from dozens of channels can quickly produce tremendous amounts of information. Fast data rates are useful in observing the electrodynamic nature of the power system, such as power swings. Special-purpose computers, called phasor data concentrators (PDCs), combine the streaming data from multiple sources to communicate them to a central point for display, storage, or processing. Also available are local- and central-office disturbance recorders that handle synchrophasors [1].

The IEEE standard does not immediately support control. However, by using IEEE C37.118 data in conjunction with other control and protection protocols, we can build control systems. We developed the synchronous vector processor (SVP) for just this purpose. It handles data at a once-per-cycle processing rate, performs vector calculations, and controls other equipment [2] [3].

Communicating data once per cycle, and even faster, is practical inside a plant or substation but frequently difficult outside due to limited communications channel capacities (e.g., lack of Ethernet or other high-speed connectivity). Certainly, traditional supervisory control and data acquisition (SCADA) communications did not anticipate high speeds and high volumes of data.

Slower data rates, such as once per second or even less, are easier to communicate and process and are useful in directly measuring the state of the power system. It is practical today to move synchronously measured data through asynchronous SCADA channels every few seconds. Thus, we can directly measure the state of the power system every few seconds using today's communications systems. Direct state measurement is better than state estimation because it is simpler, costs less, requires less processing, has no convergence issues, is less dependent on system data, and is faster.

Even "snapshots" of synchrophasors are useful. The first example in Section II shows simplified commissioning using synchrophasor snapshots within a station. The "communications" and "processing" are so simple, they can be performed with a pencil and paper and a calculator.

Locally, all a system needs in order to synchronize all measurement devices is a common time source, such as a clock. When involving more than one location, GPS clocks are a solution because they can produce time signals accurate to a microsecond virtually anywhere in the world [4].

Given that synchrophasor measurements are now broadly available and the processing engines and software are available, it follows that applications are evolving daily.

II. Substation Analysis

The applications in this section require communications only within the substation, and most do not require an Ethernet communications infrastructure.

A. Verifying Voltage and Current Phasing

How do you quickly verify the connection and phasing of the voltages and currents of an entire panel lineup during commissioning or after performing work on panels?

Usually, relays and meters use the A-phase voltage as the reference for the other phases. If we issue a meter command to the relay and consider only the voltages, it would look similar to this:

VA = 67 kV ∠ 0°
VB = 67 kV ∠ –120°
VC = 67 kV ∠ 120°

If instead we roll the voltage phases during initial construction or modification such that we wire the VA source to the VB terminals, VB to VC terminals, and VC to VA terminals and issue a meter command with this wiring configuration, then we receive the same results. Simply issuing a meter command to all the relays and verifying that all the VA-VB-VC relationships are the same is not sufficient to ensure correct panel-to-panel wiring of all phases. The reason is that each relay normally uses whatever is on its A-phase voltage input as the reference.

Synchrophasors solve this issue. If the relays have synchrophasor technology and if we connect the relays to the same time source, then we can compare time-stamped measurements of each and every relay in the panel lineup. See Fig. 1.

Fig. 1. Relays With Synchrophasors in Protection Panels

The voltage magnitude and phase are now referenced to absolute time. A cosine wave with its peak exactly on the second, to the microsecond, is the zero-degree reference. Once synchronized, the relays are all measuring against this common and very accurate time source. Another way of looking at it is the angle reference for all voltages and currents is a 60.000 Hz cosine wave that has its peaks on the second, to the microsecond.

Issuing simple ASCII commands to relays triggers measurements (snapshot) at a specified instant. The relays then report the phasor information in an ASCII format. Engineers can record the data from each device or automate the process using a common spreadsheet program. Issuing a special meter command (Meter PM, where PM stands for phasor measurement) to the relays provides synchrophasor-based measurements. Fig. 2 and Fig. 3 show the results of issuing a MET PM command to two relays at time 13:22.

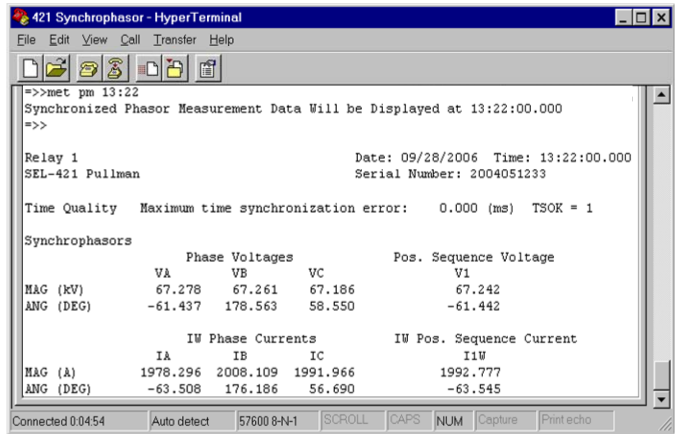

Fig. 2. Relay 1 Synchrophasor Snapshot Using the Meter PM Command at 13:22

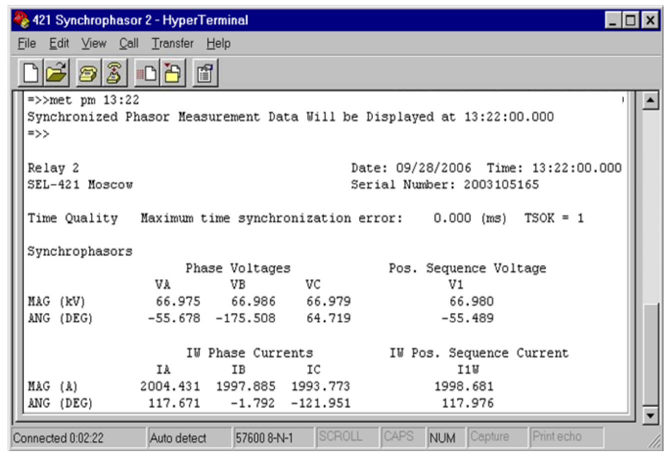

Fig. 3. Relay 2 Synchrophasor Snapshot Using the Meter PM Command at 13:22

The command instructs each relay to measure the phasor data at that predetermined and precise instant of time. We can see that the angles for the A-phase voltages are not zero. They would be zero only in the rare situation where VA actually was at zero degrees with respect to the reference cosine with its peaks on the second. The relays also measure the voltage magnitudes at precisely that instant, so we can accurately compare the magnitudes **and** angles without worrying about the usual movements in the voltages being measured.

The intriguing aspect of this application is that it does not require high-speed communications or even the IEEE protocol. The only tool required is a computer with a terminal program.

We can easily automate the Meter PM command process with a communications processor, as in the following example. At the substation serving a Honda plant, a communications processor communicates with 11 relays and a computer. See Fig. 4.

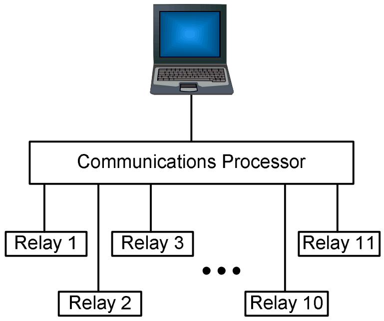

Fig. 4. Automated Meter PM Synchrophasor Polling System

We programmed the communications processor to automatically issue the Meter PM command to all 11 relays at advancing and identical instants of time. Fig. 5 shows an example of the communications processor scripting language that performs this command.

```
IF 17:003Ch:5
#79BF/L1 451 METER PM DATA
42,C;;451_PORT = 2
43;;MONTH = 02:FLEX:Month
44;;DAY = 02:FLEX:Day
45;;YEAR = 02:FLEX:Year
46;;HOUR = 02:FLEX:Hour
47;;MINUTE = 02:FLEX:Minute
48;;SECONDS = 02:FLEX:Second
49;;TSOK = 02:FLEX:TSOK
#PHASOR ANALOGS
50,F;;VAMAG = 02:D2:000Ch
52,F;;VAANG = 02:D2:0014h
54,F;;VBMAG = 02:D2:000Eh
56,F;;VBANG = 02:D2:0016h
58,F;;VCMAG = 02:D2:0010h
60,F;;VCANG = 02:D2:0018h
62,F;;V1MAG = 02:D2:0012h
64,F;;V1ANG = 02:D2:001Ah
#IW CURRENTS
66,F;;IAMAG = 02:D2:001Ch
68,F;;IAANG = 02:D2:0024h
70,F;;IBMAG = 02:D2:001Eh
72,F;;IBANG = 02:D2:0026h
74,F;;ICMAG = 02:D2:0020h
76,F;;ICANG = 02:D2:0028h
78,F;;I1MAG = 02:D2:0022h
80,F;;IANG  = 02:D2:002Ah
#IX CURRENTS
82,F;;IAMAG = 02:D2:002Ch
84,F;;IAANG = 02:D2:0034h
86,F;;IBMAG = 02:D2:002Eh
88,F;;IBANG = 02:D2:0036h
90,F;;ICMAG = 02:D2:0030h
92,F;;ICANG = 02:D2:0038h
94,F;;I1MAG = 02:D2:0032h
96,F;;IANG  = 02:D2:003Ah
#SUMMED CURRENTS
98,F;;IAMAG = 02:D2:003Ch
100,F;;IAANG = 02:D2:0044h
102,F;;IBMAG = 02:D2:003Eh
104,F;;IBANG = 02:D2:0046h
106,F;;ICMAG = 02:D2:0040h
108,F;;ICANG = 02:D2:0048h
110,F;;I1MAG = 02:D2:0042h
112,F;;IANG  = 02:D2:004Ah
#FREQUENCY
114,F;;FREQ = 02:D2:004Ch
```

Fig. 5. Portion of Scripting Lines to Send Automatic Meter PM Commands

We also programmed the communications processor to parse the responses from the relays and put the synchrophasor information into registers. See Fig. 6.

```
*acc
Password: ? *****
DECATUR PRIM SEL2030#1-S/N 2007079088       Date: 02/14/08
Time: 13:53:37
Level 1
*>vie 17 user
Port 17,  Data Region USER   Data

451_PORT = \002  MONTH = 2  DAY = 14
YEAR = 2008  HOUR = 13  MINUTE = 53  SECONDS = 10  TSOK = 1
VAMAG =     80.590  VAANG =     43.749  VBMAG =     81.059
VBANG =    -76.313  VCMAG =     81.033  VCANG =    163.451
V1MAG =     80.890  V1ANG =     43.620  IAMAG =     40.745
IAANG =    140.016  IBMAG =     37.615  IBANG =     21.842
ICMAG =     40.750  ICANG =    -96.636  I1MAG =     39.690
IANG =     141.730  IAMAG =     39.272  IAANG =    -35.388
IBMAG =     36.434  IBANG =   -152.674  ICMAG =     39.994
ICANG =     87.753  I1MAG =     38.550   IANG =    -33.440
IAMAG =      3.530  IAANG =     76.945  IBMAG =      3.734
IBANG =    -46.999  ICMAG =      3.183  ICANG =   -170.704
I1MAG =      3.470   IANG =     73.200   FREQ =     60.012
```

Fig. 6. Results of the Meter PM Command Stored in the Communications Processor User Region

The engineer then manually read the information out of the communications processor registers and entered the synchrophasor data into the spreadsheet in Fig. 7.

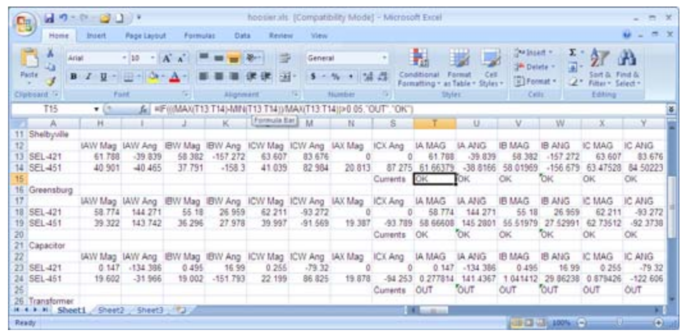

Fig. 7. Microsoft® Excel® Spreadsheet Showing Results of Magnitude and Phase Angle Measurement Checks

We could have set up the spreadsheet program to automatically retrieve the information from the communications processor, but this was not necessary, because the objective was a one-time commissioning check. An automated version of this example is available at www.synchrophasors.com.

This example shows a quick and efficient way of determining proper phasing within a substation breaker panel lineup. Because we used relays with synchrophasor capabilities, we did not need any extra equipment to determine the results on a station-wide basis.

B. *Real-Time Substation Voltage Measurement Refinements*

Fig. 8 shows four line relays and a bus relay, each connected to its own instrument transformer. When the four circuit breakers are closed, the five voltage measurements should be very nearly the same. The primary voltages E_1, E_2, E_3, E_4, and E_5 differ only by the ZI drops between the instrument transformers, and these differences should be small. The secondary voltages $V_1 \ldots V_5$ additionally differ by errors introduced by the instrument transformers and the measurement devices (e.g., relays or meters). Sufficiently large measurement differences may indicate problems with the primary equipment (e.g., high-resistance connection, bad switch, or breaker contact), the instrument transformer, or the measurement device.

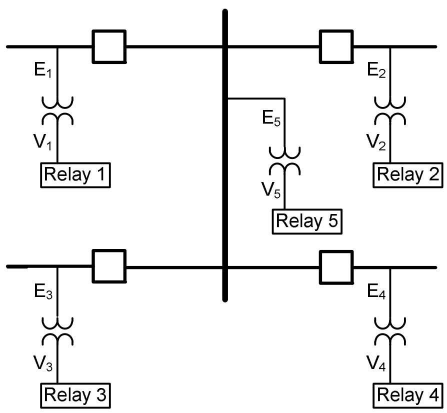

Fig. 8. Four-Breaker Configuration Used in Best Bus-Voltage Estimate

How might we best use these five measurements? a) We can locally check phasing and synchronism across any open breaker; b) when at least one breaker is closed, we can do three things: 1) detect and report on any large and unexpected differences, 2) average "good" measurements to gain accuracy, and 3) communicate measurements to adjacent stations for further comparisons. For now, we will focus on managing the measurement errors within the station for closed breakers.

We can write an equation for each measurement in terms of the primary voltage and the total error:

$$V_i = E_i + \varepsilon_i$$

where: V is the measured voltage
E is the true voltage
ε is the total error

First, we need to make sure that all voltage measurements are within a reasonable range (i.e., the maximum deviation between any two voltage measurements is less than a predefined value). We can do this by comparing the voltage measurements to one another using the SVP. For the bus configuration above, this would equate to the calculations in Table I.

TABLE I
DIFFERENCE VOLTAGE CALCULATIONS

Relay 1	Relay 2	Relay 3	Relay 4
v1 – v2	-	-	-
v1 – v3	v2 – v3	-	-
v1 – v4	v2 – v4	v3 – v4	-
v1 – v5	v2 – v5	v3 – v5	v4 – v5

We can write Table I as follows:

$$\Delta v_i = v_i - v_j$$

where: i = 1 to N – 1
j = i + 1 to N
N = number of nodes

After making each delta calculation, we compute a comparison between an absolute threshold and the delta voltages as shown in (1).

$$\text{Max\_Threshold} > |\Delta v_i| \quad (1)$$

If a measurement is above the maximum threshold, we flag it so it is not used in the voltage best estimation. We then calculate the best estimation of the bus voltage by calculating the average of the measured bus voltage using (2):

$$\hat{E} = \frac{\sum_{i=1}^{N} v_i}{N} \quad (2)$$

where: E is the best estimate bus voltage
v is the measured value
N is the number of measurements

The SVP then forwards the best estimate to SCADA or other similar systems that can benefit from refined analog measurements.

Equation (3) describes the number of delta voltage calculations required per number of measurement points within a particular zone.

$$\text{Num\_Calcs} = \frac{N \cdot (N-1)}{2} \quad (3)$$

As N becomes large, the number of comparison calculations becomes very large. For example, if N is 6, there are 15 calculations to perform. If N is 18, there are 153 calculations. Because we are trying to find a best estimate using an average, we can break the system into subcomponents and follow the same procedure. For example, if the system consists of 18 points, we can break the system into three sections. The resulting number of calculations would be 15 + 15 + 15 = 45 comparisons, which is much less than the 153 calculations that would be required if we did not break the system into subsections. We then average the subsections' best estimate voltages to produce the system's best estimate voltage.

C. SCADA Verification and Backup

Idaho Power Company (IPC) is evaluating synchrophasor data for use in their Energy Management System (EMS). IPC believes synchrophasor data are more accurate than traditional SCADA measurements. However, before IPC switches from their traditional SCADA/EMS system, they are verifying that synchrophasors provide information that is as reliable as the traditional SCADA system.

IPC is using two relays with synchrophasor capabilities at their 230 kV Caldwell and Locust Substations. Each relay reports the synchrophasor measurements (V1, VA, VB, VC, I1, IA, IB, IC, freq). The synchrophasor verification test involves comparing the load flow between the Caldwell and Locust Substations using traditional SCADA data and synchrophasor measurement data. IPC collects the traditional SCADA measurements every minute with an associated one-second time stamp. A PDC collects the synchrophasor data 30 times a second and performs the load flow calculations using (4) and (5).

$$P = VI\cos(\theta_v - \theta_i) \tag{4}$$

$$Q = VI\sin(\theta_v - \theta_i) \tag{5}$$

Due to the higher sampling rate of the synchrophasor system, the PDC decimates the synchrophasor data to match the one-second resolution of the SCADA system. Fig. 9 and Fig. 10 show a time-aligned comparison between the synchrophasor measurement and the traditional SCADA measurement.

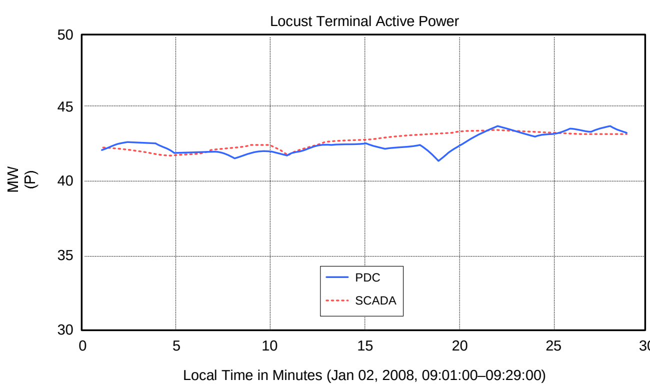

Fig. 9. Active Power (P) at Locust Terminal

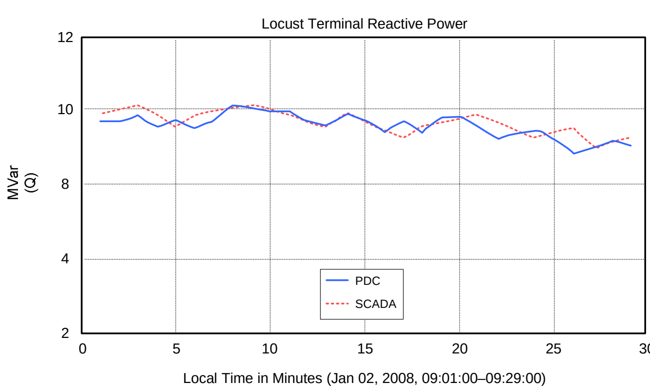

Fig. 10. Reactive Power (Q) at Locust Terminal

Fig. 9 and Fig. 10 show a high degree of correlation between the SCADA and synchrophasor active and reactive power plots. However, synchrophasors offer several improvements when performing visualization over a wide area.

- Unlike SCADA scans, all the synchrophasor data are time-aligned to the microsecond. This provides a coherent visualization of the power system.
- Synchrophasor data rates are scalable from once a cycle to once a second. For power flow visualization, twice a second would be more than adequate. SCADA scans, in contrast, are on the order of seconds or longer, resulting in slower visualization update rates.
- Many synchrophasor devices, such as relays, are already in power systems at critical measurement points that utilities can immediately use. This eliminates the need for installing additional equipment.
- Synchrophasor and SCADA data can coexist over existing communications channels.
- Synchrophasors can also be embedded into traditional SCADA protocols, such as DNP. This allows the SCADA system to use the synchrophasor data in the various SCADA calculations, instead of the time-indeterministic SCADA scans.

D. Communications Channel Analysis

In December of 2007, New Brunswick Power and Bangor Hydro began loading the new 345 kV international tie line from Point Lepreau nuclear plant in New Brunswick, Canada and Orrington Substation in Maine. See Fig. 11.

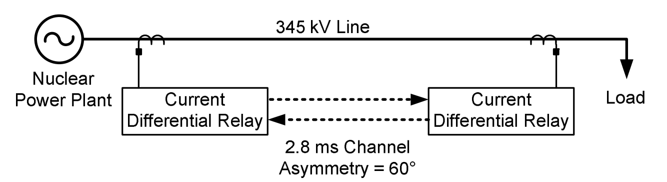

Fig. 11. Line Current Differential Communications Diagram

The transmission line protection included a line current differential relay with synchrophasor capabilities. When they energized and lightly loaded the line, the charging current was higher than expected, which caused the differential element to approach its tripping angle thresholds. However, the engineers believed that by adding load to the point where the current magnitude reached the current differential operational magnitude, the differential angle would retract into the restraint region. While monitoring the differential metering during a light-load test, they noted that as they increased load, the line current differential Alpha Plane values moved toward the trip threshold instead of away from it. The differential communications path on the New Brunswick side was via asynchronous transfer mode (ATM) over Internet protocol (IP). They expected it to have only a degree of asymmetry, resulting in a small rotation of the Alpha Plane angle toward the trip condition. However, they observed an Alpha Plane angle of nearly 60 degrees.

After compensating for the load and charging currents, the remaining angular difference was much higher than the utility communications group had predicted. By checking all measurements and calculations, they identified two possibilities for the increase of the differential element into the operate region. Either the communications asymmetry was much higher than specified or the system was incorrectly phased end to end and one set of CTs was connected in reverse polarity, which would result in a 60-degree error.

To isolate the problem, they used synchrophasors to verify each relay's metering quantities. With known measurement values, the engineers could determine whether there was a communications asymmetry issue or a more serious and costly phasing error.

Again, using a Meter PM command, they collected synchrophasor information from both terminal ends. Data analysis showed the relays were measuring approximately the same current values. This eliminated the phasing error. Further analysis showed the communications asymmetry was much higher than predicted and the line differential relay was connected and measuring power system quantities correctly.

III. Power System Analysis

Synchrophasors provide a new way to analyze both small and large disturbances in a power system. Examples of these wide-area disturbances include the 2003 Midwest blackout and the 2008 Florida blackout. Regarding the Florida blackout, North American Electric Reliability Corporation CEO Rick Sergel said that "while we can't predict the timetable of analysis, information collected by new monitoring technologies, called 'synchro-phasors,' will enable our teams to analyze yesterday's outages more quickly than in the past. This new technology is like the MRI of bulk power systems, giving operators and analysts more granulated data and helping them to dissect and piece together the events that occurred step by step, microsecond by microsecond [5]."

A. Wide-Area Frequency Monitoring

1) System Disturbance Monitoring in New Zealand

In New Zealand, engineers were concerned with how their power system would react to a major loss of generation. Huntly is a thermal generation site with an approximate capacity of 400 MW. Whakamaru is a substation near a small hydro generation station. A 220 kV double-circuit line connects the two stations. See Fig. 12. In order to confirm proper system operation, engineers installed a synchrophasor system with archiving capability at the Huntly and Whakamaru Substations.

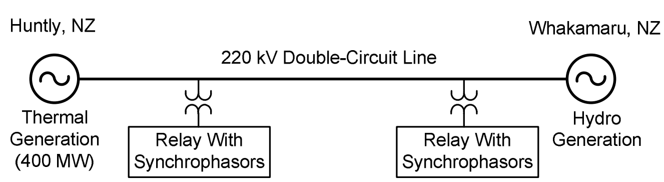

Fig. 12. New Zealand Wide-Area Monitoring System

By using synchrophasors to monitor the main network near the Huntly generation site and further away at Whakamaru, engineers gained a better understanding of how the system would respond if a generator the size of Huntly was removed.

Fig. 13 shows the drop in frequency as a result of removing 200 MW of generation from the system. Shortly afterwards, the governors of the generators still connected to the power system began to compensate and bring the frequency back to nominal.

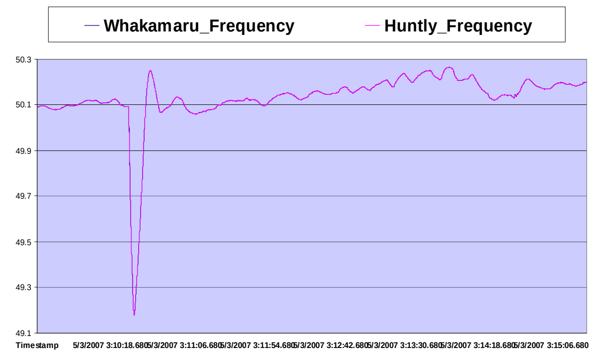

Fig. 13. Synchrophasor Graph Showing Frequency Disturbance

What may not be immediately obvious is that both the Huntly and Whakamaru frequency plots are identical. Synchrophasors allowed the engineers to accurately plot the frequency disturbance using an Excel spreadsheet without any special data manipulation. Synchrophasor relays provided distributed monitoring points throughout the system that allowed the engineers to measure and correlate data not available with traditional measuring devices. Because synchrophasor data are already time aligned to a common reference point, they did not need to perform post data processing. This is a tremendous time saver, especially if this had been a real event requiring immediate analysis.

2) System Monitoring in Washington State

The benefits of synchrophasors extend beyond high-voltage transmission system monitoring. At our factory, we continually have synchrophasor measurement devices monitoring our local power system. During an internal test, an engineer monitoring synchrophasor frequency at a 115 Vac wall plug and plotting the data in real time noticed the frequency excursion shown in Fig. 14. Checking the Bonneville Power Administration (BPA) website revealed that two 500 kV lines and one 230 kV line had tripped, resulting in a loss of 1300 MW. See Fig 15.

Fig. 14. Synchrophasor Data Plot Showing Frequency Excursion at Distribution Voltages

Fig. 15. BPA Synchrophasor Data Plot Frequency Excursion at Transmission Voltages

Synchrophasors used throughout a power system, from transmission through distribution, allow engineers to monitor and quickly analyze disturbances without the tedious correlation of various event reports.

B. Improved State Estimation

State estimators determine power system security. Schweppe introduced state estimation, which has developed into a highly refined science [6] [7] [8]. Engineers can determine the condition of the power system if they know the model of the network and the phasor voltages at all buses. To illustrate this, consider the matrix equation:

$$I = Y\,V$$

where: I is a vector of the branch current phasors

V is the vector of bus voltage phasors

Y is the bus admittance matrix

If we know Y and V, then we can calculate the currents. Once we know the currents, we can calculate watts, VARs, losses, etc.

Many factors affect state estimator accuracy.

- SCADA information reports magnitudes without time stamps. Each SCADA scan consists of various data points taken over a period of many seconds. These non-time-aligned data points lead to state estimation calculation inaccuracies.
- State estimators rely on the SCADA communications channel. Missing data affect the ability of the state estimators to produce an accurate result.

All these conditions (magnitudes only, missing data, non-time-aligned data) result in slow state estimator results or an inability for the state estimator to converge. Synchrophasors take us from state estimation to state measurement.

Salt River Project (SRP) is working to improve the accuracy and speed of their state estimator by using synchrophasor data. As a first step in building this new synchrophasor-based state estimator system, they installed PMUs where observability is poor or where the admittance matrix model may be inaccurate. Placing PMUs in these locations provides the best opportunity to increase state estimator accuracy. Adding additional PMUs creates a highly observable area and decreases the amount of the grid that requires the traditional state estimation process. Once the whole system is highly observable, determining the system state is done in a single step, rather than using iterative techniques. In addition, it is possible to accurately measure the Y matrix instead of calculating it. SRP can use these improved models for security analysis applications, operational planning, and system protection functions.

SRP has not installed PMUs on every bus in their system. This results in a mixture of traditional SCADA and synchrophasor data as inputs into the state estimator. To account for the data quality differences, SRP gives the synchrophasor data greater weight than the SCADA data. The more accurate synchrophasor data thus have a greater influence on the state estimation process.

SRP’s SCADA system collects synchrophasor data every 32 ms. The estimation process, including communications and calculation latency times, takes less than one second. That is fast enough to detect dynamic system problems. SRP is now exploring the possibility of detecting conditions where voltage stability is deteriorating and automatically imposing changes to operating conditions such as maximizing VAR support, disabling automatic voltage regulation, and invoking load reduction.

C. WECC Wide-Area Disturbance Recording

Having a precise record of wide-area power system events allows engineers to quickly analyze and explain those events. However, analyzing wide-area data from several utilities can be challenging. Wide-area synchrophasor communications links are uncommon between neighboring utilities, including members of the Western Electric Coordinating Council (WECC). To overcome the lack of intercommunications links, the WECC members implement local synchrophasor disturbance recorders (SDRs) to record disturbances within their operating territory. They then share the data with other WECC members. WECC implemented a procedure to inform members to enable, or trigger, their SDR systems at coordinated times. WECC uses the resulting data, gathered from the various measurement points within the system, to analyze outages, review system tests, and examine large switching events. Following are some WECC member SDR system descriptions.

1) Arizona Public Service (APS)

The Westwing Substation includes seven relays streaming synchrophasor data to a PDC, which then reports to a BPA PDC. The BPA PDC also receives data from other dedicated PMUs located in other areas of the power system. The BPA PDC then streams synchrophasor data to a desktop computer running the BPA StreamReader software. The StreamReader software archives the synchrophasor data in a .dst file format (disturbance file, which is a binary proprietary format).

2) Salt River Project (SRP)

This system consists of several relays, two PDCs, and archiving software. The PDCs and archiving software collect data from the relays, concentrate and convert all data to a common format, and then store the data. SRP uses a comma-delimited format (.cvs) as the storage file format.

3) Nevada Power (NP)

Six relays located at Harry Allen Substation, just northeast of Las Vegas, Nevada, connect to a PDC. The PDC streams data via BPA protocol to the StreamReader software located at NP's relay/operations office in Las Vegas. The StreamReader software archives the synchrophasor data in a .dst file.

4) Sierra Pacific (SP)

Five relays at East Tracy Substation, outside of Reno, Nevada, along with one relay at another nearby substation, send synchrophasor data to a PDC. The PDC collects and sends data to a desktop PC at East Tracy running the BPA StreamReader software, which archives the synchrophasor data in a .dst file.

5) Southern California Edison (SCE)

This system is a mixture of dedicated PMUs, relays, and a PDC. SCE has a communications link to BPA. In this case, SCE and BPA each archive data locally using the .dst file format.

6) San Diego Gas and Electric (SDG&E)

Five relays, spread throughout their system, report data to a centralized PDC. The PDC reports data to a PI historian, the StreamReader software, and synchrophasor visualization software. The StreamReader software archives the synchrophasor data in a .dst file.

7) Idaho Power Company (IPC)

Five relays, spread throughout their system, send data to a centralized PDC. The PDC sends data to synchrophasor visualization software and to the StreamReader software for local archiving of the synchrophasor data in a .dst file. IPC also has a direct communications link to BPA for archiving .dst files.

8) BC Hydro

Dedicated PMUs, along with relays, take synchrophasor measurements and send them to a PDC. The PDC streams data to BPA via a dedicated communications link. The StreamReader software archives the synchrophasor data in a .dst file.

9) Bonneville Power Administration (BPA)

A wide variety of PMUs along with a number of proprietary portable synchrophasor units report data to a BPA PDC. The PDC sends the data to the StreamReader software, which archives the synchrophasor data in a .dst file.

10) Western Area Power Administration (WAPA)

In this system, PMUs report data to a BPA PDC located in Loveland, Colorado. The PDC sends the data to the StreamReader software, which archives the synchrophasor data in a .dst file.

After an event or test, WECC collects data from the various members for analysis. Though this system is not fully automated, it does provide a precise, time-aligned, wide-area measurement system that allows WECC to easily analyze wide-area system events.

IV. Wide-Area Control

The ultimate application for synchrophasors is real-time, wide-area control.

A. Distributed Generation Control

Anti-islanding is an important requirement for distributed generation (DG). Anti-islanding is the ability of a scheme to detect when a generator is operating in an islanded system and to disconnect the generator from the system in a timely fashion. Failure to trip islanded generators can lead to a number of problems for the generator and the connected loads.

Fig. 16 shows a one-line diagram of a simple interconnection between a transmission system and the distribution network. The anti-islanding scheme detects loss of the transmission network and disconnects the generator. The DG disconnection time must be less than the reclosing time (0.4 seconds) of the transmission network.

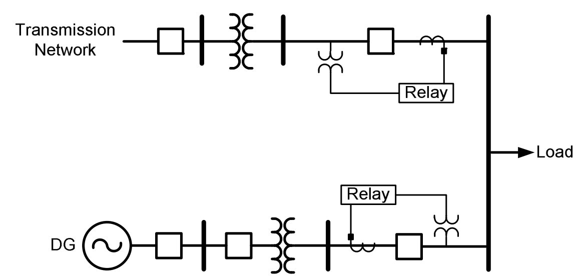

Fig. 16. Typical DG System

The following traditional schemes detect island conditions:

1) Breaker and Disconnect Status-Based Schemes

Relays, recloser controls, or remote terminal units (RTUs) send breaker and disconnect status information to a central logic processor. The processor trips the DG following an islanded condition. The scheme gets complicated if it consists of many breakers, reclosers, and disconnect switches; the network topology adds complexity as well.

2) Frequency-Based Schemes

Frequency-based schemes are the most widely used islanding-detection schemes. The DG trips if the frequency becomes too low. To improve the speed of this scheme, we can use a rate of change of frequency detection method. In this case, the DG trips if the frequency changes very quickly. The scheme is effective only if there is significant mismatch between the generation and the load.

3) *Voltage-Based Schemes*

Under- and overvoltage-based schemes can also detect some islanding conditions. Reactive power mismatch between the total generation and load determines the voltage mismatch. Voltage-based schemes are faster than frequency-based schemes because they do not depend on machine inertia.

Both frequency- and voltage-based schemes are sensitive to disturbances other than islanding conditions. It is challenging to define the thresholds to differentiate between the islanding conditions and system disturbances.

Synchrophasors offer a new method for detecting undesirable islands, which is simpler and more predictable. We use synchrophasors to determine the phase angle difference between the point of common coupling (PCC) and the DG system. When we detect an angle difference greater than a predetermined threshold, we declare an island condition. Measuring the angle difference is easy regardless of generation-to-load matches, system disturbances, or system configuration. And, if the island is stable, we might decide to let it be and not shut it down.

Florida Power and Light (FPL) is in the process of connecting a landfill generation site to their system. Fig. 17 shows the system one-line diagram. FPL designed their anti-islanding scheme to detect loss of transmission interconnection and trip the DG prior to reclosing at an angle that would be damaging to the generator. Referring to Fig. 17, FPL provides reclose supervision only at breaker FB-2. The scheme uses phasor measurements at the PCC and DG sites. Fig. 17 shows relays with synchrophasors at the PCC and the DG sites connected to an SVP. The SVP calculates the angle, frequency, and rate of change of frequency between the PCC and DG sites. Fig. 18 shows the logic running in the SVP that trips the DG. FPL uses a synchronism check with a dead-line permissive to supervise reclosing on FB-2. The permissive checks voltage on each side of FB-2.

In this scheme, the PMUs send synchrophasor measurements to the SVP at a rate of one per cycle. An Ethernet channel connects the PMUs to the SVP.

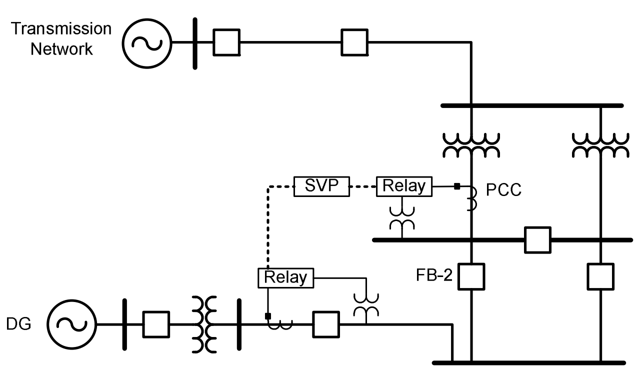

Fig. 17. DG One-Line Diagram for FPL

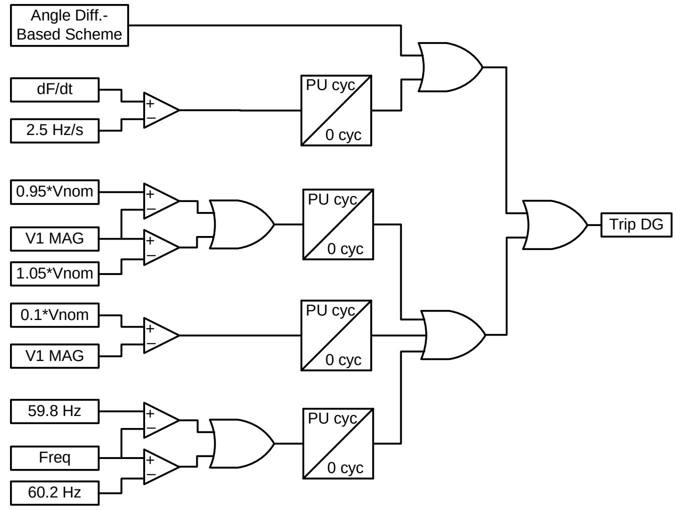

Fig. 18. DG Tripping Logic

B. *Generator Black Start Using Synchrophasors*

Starting generation units without using power from the bulk grid is called a black start. SRP used synchrophasors not only to provide system visualization over traditional SCADA during black-start testing, but also as a synchroscope to connect the SRP and WECC systems [9].

Fig. 19 shows SRP's black-start system. For the purposes of the black-start testing, SRP islanded from WECC at the 230 kV V2 bus via Breaker 678.

SRP had two black-start goals: synchronize the thermal and hydro units and synchronize the SRP and WECC systems.

SRP's synchrophasor system includes the following:

- Relays with synchrophasors installed at the SRP/WECC tie point (230 kV V2).
- High-precision GPS clocks that provide accurate time to the relays.
- Relays that communicate synchrophasor data at 10 messages per second.
- An OC-1 synchronous optical network (SONET) multiplexer that connects the substations to the power dispatch office.
- Synchrophasor visualization software that displays magnitudes, angles, frequency, and rate of change of frequency.

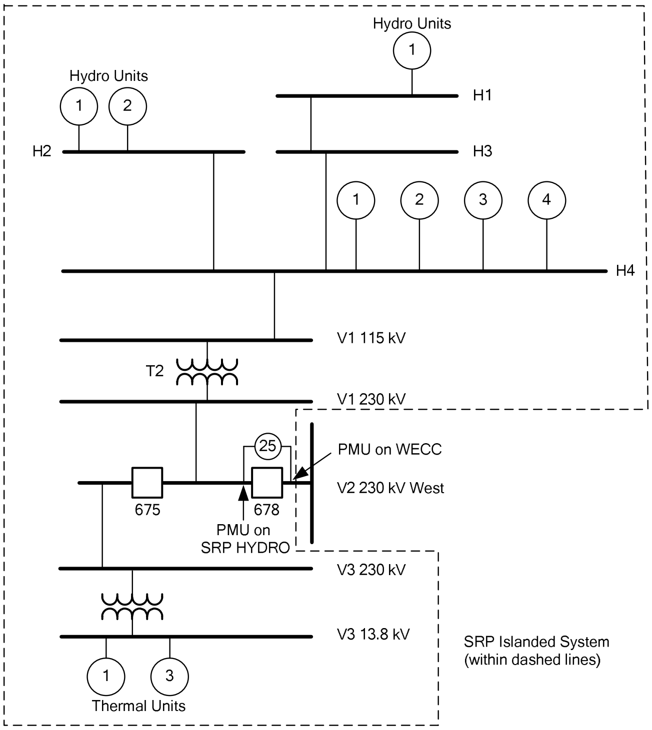

Fig. 19. SRP Black-Start Island Test System [9]

During synchronization of the thermal and hydro units, SRP used synchrophasors to monitor frequency and slip differences between the systems to verify when to connect them. With both the hydro and thermal units online, the synchrophasor visualization software monitored the phase angle difference. They used the synchrophasor data to verify that the systems were connected and within phase angle difference tolerances. With both systems connected, they observed improved frequency stability. Fig. 20 shows actual synchrophasor frequency plots of the SRP hydro and thermal units (in red) compared to the WECC frequency (in green and used only as a reference for this test). Before connecting the hydro and thermal units, SRP observed about 150 mHz of frequency deviation. After connecting the hydro and thermal units, they observed only about 50 mHz of deviation.

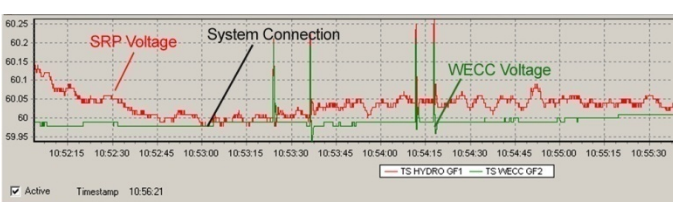

Fig. 20. SRP and WECC Pre- and Post-System Connection Frequency Deviation

The next test was to connect their system with the WECC system. During this test, the automatic synchronizer was not operational. The operator used synchrophasor visualization software to view the angle separation and slip between the two systems and manually close the tie breaker. Fig. 21 shows the synchrophasor synchroscope and the system connection at 11:28:37.

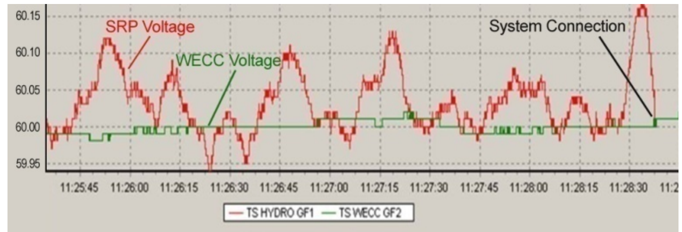

Fig. 21. SRP and WECC System Connection

SRP's synchrophasor relays provide two distinct advantages over their previous system.

- Multiple measurement sources
  Relays with synchrophasors installed throughout the power system provide multiple measurement sources that can be used as synchroscopes throughout the power system.
- Higher update rates
  Synchrophasors are available at higher update rates (up to 60 times per second) than traditional SCADA scans. In SRP's case, the SCADA scan was about 5 seconds. The faster update rate tolerates more slip.

By installing an SVP, they can completely automate the synchronization process. Further, relays with synchrophasor capabilities throughout the power system, coupled to the SVP, can allow synchronization at any point in the system without additional, standalone synchronization devices.

C. *Synchrophasor-Based Relaying in Mexico*

Comisión Federal de Electridad (CFE) has implemented an automatic generation-shedding scheme (AGSS) based on relays exchanging real-time synchrophasor information [10].

CFE has specific regional generation and transmission challenges due to large loads at the center of the country and large hydroelectric generation in the Southeast. Fig. 22 shows this portion of CFE's system.

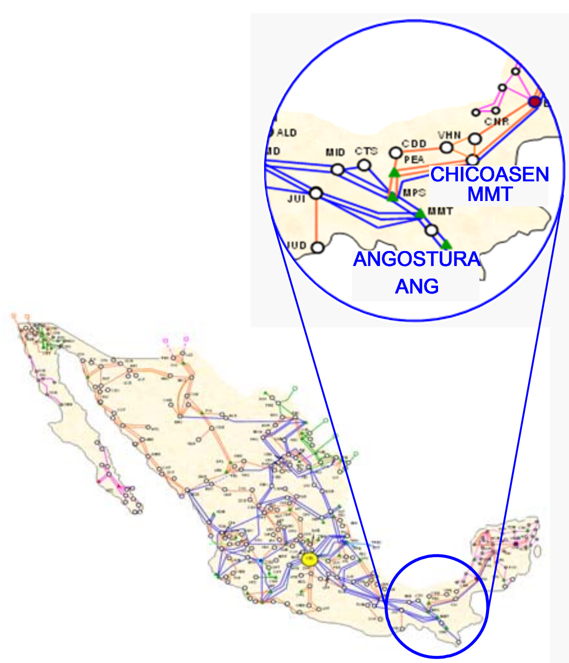

Fig. 22. Geographical Location of CFE's Synchrophasor System

During normal conditions, Angostura can generate as much as 900 MW, while the total load of Tapachula and the southern region does not exceed 100 MW. The excess power in the region flows from Angostura to Chicoasen and from there to the rest of the system. If two of the three 400 kV parallel lines are lost between Angostura, Sabino, and Chicoasen, all areas remain connected through the 115 kV network. During this condition, the Angostura generators may experience angular instability and the 115 kV network will overload. See Fig. 23.

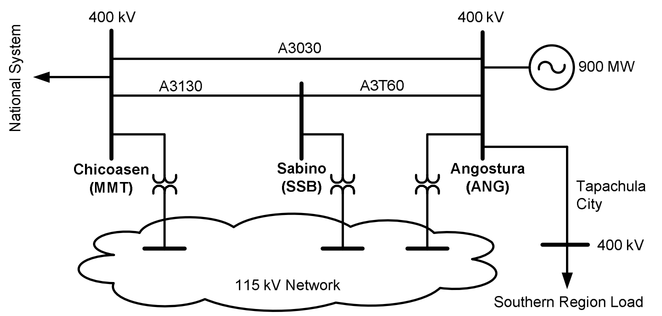

Fig. 23. Synchrophasor System One-Line Diagram

If the system loses two of the 400 kV lines, CFE must remove Angostura generation in order to maintain stability. CFE implemented a new method to detect loss of transmission capacity using relays with synchrophasor data processing capabilities. In this new AGSS, relays exchange synchrophasor data and calculate the angle difference between Chicoasen and Angostura in real time. If an angle difference between Angostura and Chicoasen is greater than a user-defined threshold, then the scheme sheds generation according to the logic in Fig. 24.

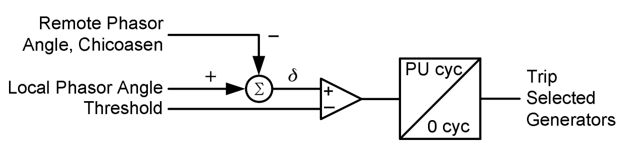

Fig. 24. Angle-Based AGSS Logic at Angostura

They modeled the power system and conducted simulations using PSEE™ software to develop settings. They determined that a double-line outage produced an angle difference of 14 degrees, resulting in instability. A single-line fault caused an angle difference of less than 7 degrees and did not cause instability. Based on these results, they chose an angle difference of 10 degrees to be the detection threshold for double-line outages.

CFE placed synchrophasor processing relays at Angostura, Sabino, and Chicoasen. Each relay measures the local bus voltage and line currents of the two lines. The relays also receive remote bus voltage and line currents from the remote relays. The relays, using the synchronized local and remote phasor data, calculate the angle difference, compare it to the angle difference setting, and issue a generator trip if the load exceeds the phase angle difference threshold.

The communications link connecting the substations is a fiber-optic multiplexer. Relays communicate with the multiplexer via EIA-232 (V.24) asynchronous interface at a data rate of 19,200 baud. See Fig. 25. Fast Message protocol exchanges synchrophasor data between the relays at a rate of 20 messages per second [11].

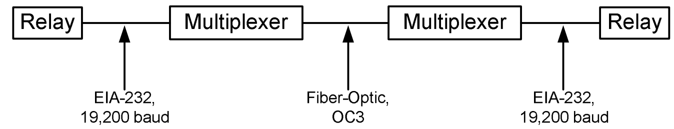

Fig. 25. Synchrophasor Control Communications Link

To validate the system operation, they programmed four angle difference logic elements into the relays at 3, 4, 5, and 10 degrees. They opened line MMT-A3030-ANG. Logic elements, set to 3 and 4 degrees, operated in 92 ms. After the initial angular change, the Angostura machines accelerated, the angle difference increased, and the 5-degree logic element asserted 292 ms later. Table II shows the testing results for additional single-line trip operations.

TABLE II
ANGLE DIFFERENCE ELEMENT OPERATING TIME

Line	Tripping Breaker	Operating Time (ms)
Chicoasen–Angostura	Chicoasen	92
Chicoasen–Angostura	Angostura	82
Angostura–Sabino	Angostura	75

The angle difference operating time includes the relay measurement processing, communications channel delay, and the message rate latency.

V. CONCLUSION

Utilities are taking advantage of the capabilities synchrophasors afford, from visualization to real-time situational awareness to wide-area control. In summary, we have shown practical real-world solutions in use today.

- Relays with synchrophasor capabilities provide a quick and efficient way of determining proper phasing within a substation breaker panel lineup without using additional test equipment.
- Synchrophasors can determine substation system topologies and data measurement refinements.
- Synchrophasors offer several improvements when performing visualization over a wide area because data are time-aligned to the microsecond with flexible data rates.
- Synchrophasors provide a simple, accurate, and efficient way to analyze both small and large disturbances in a power system.
- Synchrophasors used throughout a power system, from transmission through distribution, allow engineers to monitor and quickly analyze disturbances without the tedious correlation of various event reports.
- Synchrophasors take state estimation to state measurement.

- Synchrophasors, along with visualization software, eliminate the need for dedicated synchroscopes.
- Relays producing and processing synchrophasor data allow wide-area, real-time automation, protection, and control.

Taking advantage of synchrophasors that exist in the power system is easy and cost-effective, and it improves the operation and reliability of the grid.

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VII. Biographies

Dr. Edmund O. Schweitzer, III is recognized as a pioneer in digital protection and holds the grade of Fellow of the IEEE, a title bestowed on less than one percent of IEEE members. In 2002 he was elected a member of the National Academy of Engineering. He is the recipient of the Graduate Alumni Achievement Award from Washington State University and the Purdue University Outstanding Electrical and Computer Engineer Award. In September 2005, he was awarded an honorary doctorate from Universidad Autónoma de Nuevo León in Monterrey, Mexico, for his contribution to the development of electric power systems worldwide. He has written dozens of technical papers in the areas of digital relay design and reliability and holds more than 30 patents pertaining to electric power system protection, metering, monitoring, and control. Dr. Schweitzer received his Bachelor's and Master's degrees in electrical engineering from Purdue University, and his PhD from Washington State University. He served on the electrical engineering faculties of Ohio University and Washington State University, and in 1982 he founded Schweitzer Engineering Laboratories, Inc. to develop and manufacture digital protective relays and related products and services. Today SEL is an employee-owned company, which serves the electric power industry worldwide, and is certified to the international quality standard ISO-9001. SEL equipment is in service at voltages from 5 kV through 500 kV, to protect feeders, motors, transformers, capacitor banks, transmission lines, and other power apparatus.

David Whitehead, P.E. is the vice president of Research and Development at Schweitzer Engineering Laboratories, Inc. Prior to joining SEL, he worked for General Dynamics, Electric Boat Division as a combat systems engineer. He received his BSEE from Washington State University in 1989, his MSEE from Rensselaer Polytechnic Institute in 1994, and is pursuing his PhD at the University of Idaho. He is a registered professional engineer in Washington and Maryland and a Senior Member of the IEEE. Mr. Whitehead holds seven patents with several others pending. He has worked at SEL since 1994 as a hardware engineer, research engineer, and chief engineer/assistant director, and has been responsible for the design of advanced hardware, embedded firmware, and PC software.

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