Applied Synchrophasor Solutions and Advanced Possibilities

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***Abstract*—Synchrophasors have been applied in numerous applications to improve power system operations. Today, they are providing solutions that otherwise would have been too expensive or too complicated to implement with traditional approaches. As applications have increased, additional possibilities are being studied and analyzed. This paper examines synchrophasor applications being applied to monitor, visualize, and control electric power systems and presents how these applications can be extrapolated to more advanced schemes. Present applications include station wiring checks, improving situational awareness, integration with EMS systems through SCADA, and real-time protection and control.**

Future applications move from these to advanced topics, such as:

- **Detecting out-of-step conditions.**
- **Identifying interarea power oscillations.**

As more electric utilities apply this technology, new applications are emerging. While synchrophasors are not a "cure all" for all capacity limitations existing on the power grid, they do provide a new tool to solve these problems.

***Index Terms*—Situational awareness, state measurement, synchrophasors, wide-area control**

I. Introduction

SYNCHRONIZED phasor measurements (synchrophasors) are no longer a laboratory project. They have 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. Today, synchrophasors are available in protective relays, meters, and recorders, as well as in stand-alone phasor measurement units (PMUs).

IEEE Standard C37.118 has become widely accepted as the preferred method for communicating synchrophasor measurements between devices. Data rates of one measurement per second to one measurement per cycle, 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. Local- and central-office disturbance recorders that handle synchrophasors are also available [1]. Relays are now able to directly exchange synchrophasor information, correlate the data, and make logic decisions based on combinations of local and remote values.

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 simple or complex control systems. A synchronous vector processor (SVP) handles data at a once-per-cycle processing rate, performs vector calculations, and controls other equipment [2] [3].

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

Locally, all a system needs in order to synchronize all the measurement devices is a common time source, such as a Global Positioning System (GPS) clock [4].

As synchrophasor technology becomes more widespread, more applications are being developed. Synchrophasors are a tool that is being used to solve more power system problems as more engineers give thought to how adding synchronized measurements could address problems that were difficult or expensive to solve before.

II. Substation Applications

Many synchrophasor applications require communications only within the substation. Serial or Ethernet communications between relays/PMUs and with a central processor can be used.

A. Verifying Voltage and Current Phasing

Relays and meters typically 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:

$$VA = 67\ \text{kV} \angle 0°$$

$$VB = 67\ \text{kV} \angle -120°$$

$$VC = 67\ \text{kV} \angle 120°$$

We receive the same results if we inadvertently roll the voltage phases during initial construction or modification so that the VA source is wired to the VB terminals, VB to VC,

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and VC to VA and issue a meter command with this wiring configuration. 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. This is because 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 the relays are connected to the same time source, 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. Based on IEEE C37.118, a cosine wave with its peak exactly on the second and at exactly nominal frequency is the zero-degree reference.

Issuing a command to the relay, with a time specified, triggers measurements (snapshots) at that specified instant. Engineers can record the data from each device or automate the process using a common spreadsheet program. Fig. 2 shows the results of issuing this command to a relay, at time 13:22.

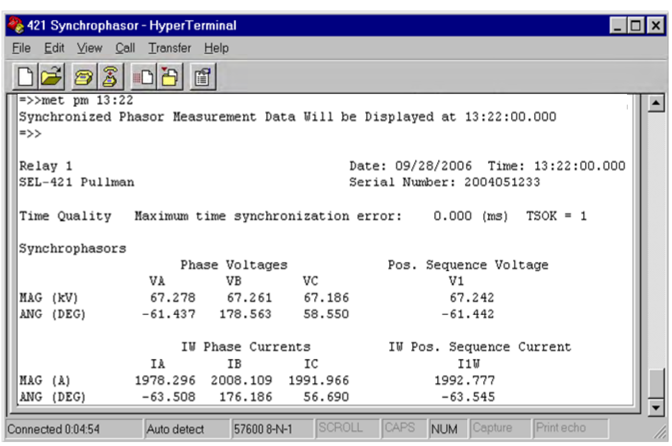

Fig. 2. Relay 1 Synchrophasor Snapshot Using the Meter PM Command at 13:22

We can see that the angles for the A-phase voltages are not zero. 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.

This application does not require high-speed communications. A communications processor can automate this command and use the response in calculations. For example, at the substation serving a large automotive factory, a communications processor communicates with eleven relays and a computer (Fig. 1).

The communications processor was programmed to automatically issue the Meter PM command to all eleven relays at advancing and identical instants of time. Fig. 3 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
#FREQUENCY
114,F;;FREQ = 02:D2:004Ch
```

Fig. 3. Portion of Scripting Lines to Send Automatic Meter PM Commands

The communications processor was also programmed to parse the responses from the relays and put the synchrophasor information into registers. The data were then entered into a spreadsheet. This was completed manually because the objective was a one-time commissioning check. An automated version of this example is available at www.synchrophasors.com.

No extra equipment was necessary to determine the results on a station-wide basis.

B. *SCADA Verification and Backup*

Idaho Power Company (IPC) is testing synchrophasor data for accuracy in energy management system (EMS) applications. IPC is using two relays with synchrophasor capabilities. The synchrophasor verification test involves comparing the load flow using traditional supervisory control and data acquisition (SCADA) data and synchrophasor measurement data. IPC collects the traditional SCADA measurements every minute with an associated 1-second time stamp. A PDC collects the synchrophasor data 30 times a second and performs the load flow calculations using (1) and (2).

$$P = VI\cos(\theta_v - \theta_i) \tag{1}$$

$$Q = VI\sin(\theta_v - \theta_i) \tag{2}$$

Because of the higher sampling rate of the synchrophasor system, the PDC decimates the synchrophasor data to match the 1-second resolution of the SCADA system. Fig. 4 shows a time-aligned power flow comparison between the synchrophasor measurement and the traditional SCADA measurement. Volt-ampere reactive (VAR) flow is similar.

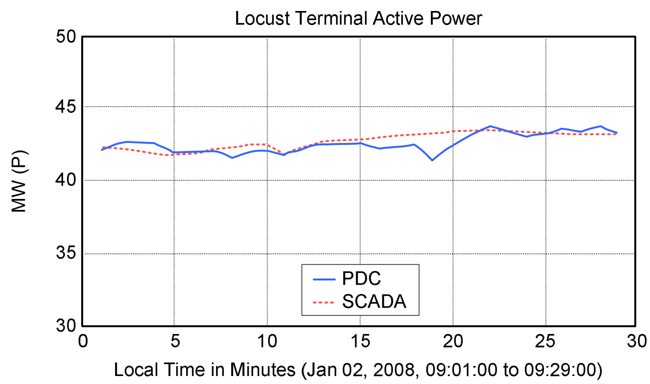

Fig. 4. Active Power (P) at Locust Terminal

Fig. 4 shows a high degree of correlation between the SCADA and synchrophasor active power plots. However, synchrophasors offer several improvements such as correlated scans (data from all devices are simultaneous), improved visualization, flexible output rates, and multiple data formats.

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 (NERC) CEO Rick Sergel said that "while we can't predict the timetable of analysis, information collected by new monitoring technologies, called 'synchrophasors,' 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 (shown in Fig. 5). Using standard transmission relays (with synchrophasors built in) at Huntly and Whakamaru Substations, the system response to a loss of generation was monitored.

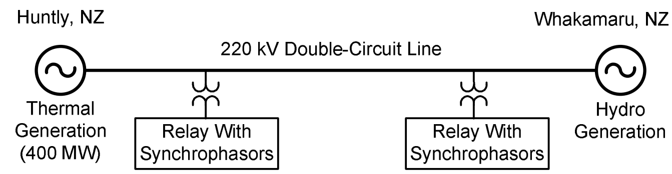

Fig. 5. New Zealand Wide-Area Monitoring System

Fig. 6 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.

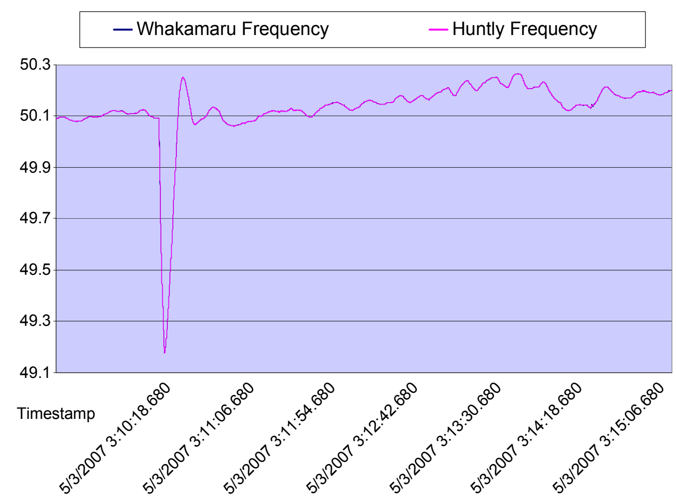

Fig. 6. Graph Showing Frequency Disturbance

2) System Monitoring in Washington State

The benefits of synchrophasors extend beyond high-voltage transmission system monitoring. At the authors' factory in Washington State, synchrophasor measurement devices are continually used to monitor the 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. 7. 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 1,300 MW.

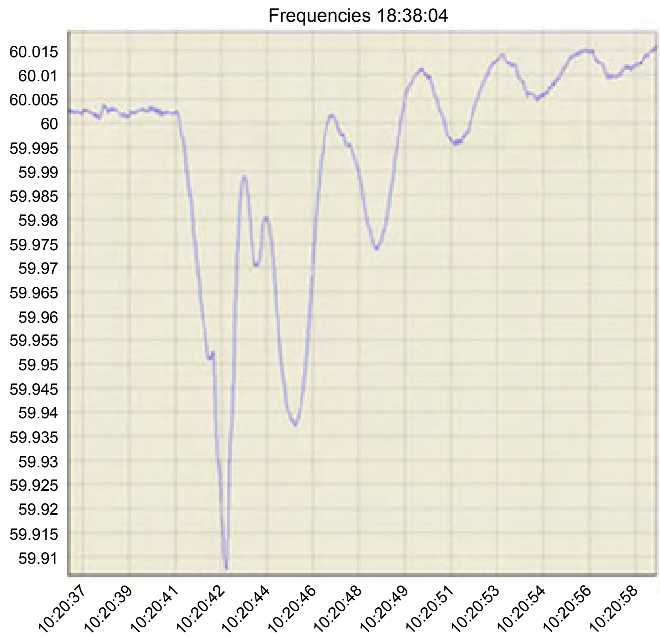

Fig. 7. Synchrophasor Data Plot Showing Frequency Excursion at Distribution Voltages

Note the periodic oscillation in Fig. 7 that would never be seen in a 5-second SCADA scan. This will be discussed later in Section V, Subsection B. 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. Fred C. Schweppe introduced state estimation, which has developed into a highly refined science [6] [7] [8]. Engineers can determine the condition of the power system and how it will respond to future events, 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, 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 nontime-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, and nontime-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.

Many electric utilities are 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, PMUs are installed, or existing relays with PMU capability are used for data collection, where observability is poor or where the admittance matrix model may be inaccurate. Connecting PMUs in these locations provides the best opportunity to increase state estimator accuracy.

It is not necessary to install PMUs on every bus in a system. This results in a mixture of traditional SCADA and synchrophasor data as inputs into the state estimator.

C. *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 Electricity 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. This system is being encouraged by NERC [9]. The 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.

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.

3) *Nevada Power (NP)*

Six relays located at Harry Allen Substation, just northeast of Las Vegas, Nevada, connect to a PDC.

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.

There are a number of other participating utilities.

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.

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.

Traditional voltage and frequency islanding-detection schemes cannot operate fast enough in most instances to meet these time requirements.

Florida Power and Light (FPL) is in the process of connecting a landfill generation site to their system. Fig. 8 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. 8, FPL provides reclose supervision only at Breaker FB-2. The scheme uses phasor measurements at the PCC and DG sites. Fig. 8 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. Logic using frequency, rate of change of frequency, voltage, and angles trips the DG on islanding. FPL uses a synchronism check with a dead-line permissive to supervise reclosing on Breaker FB-2. The permissive checks voltage on each side of Breaker 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.

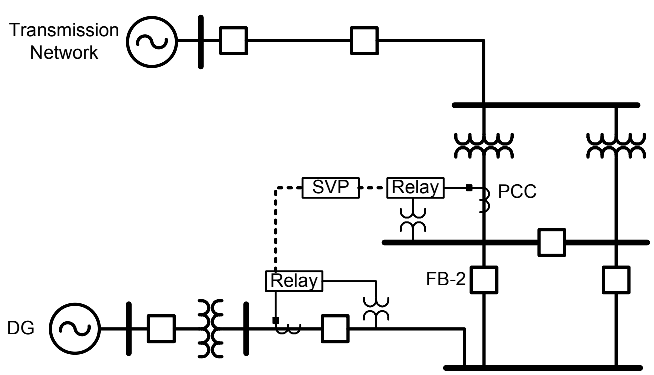

Fig. 8. DG One-Line Diagram for FPL

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 during black-start testing but also as a synchroscope to connect the SRP and WECC systems [10].

Fig. 9 shows the SRP 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.

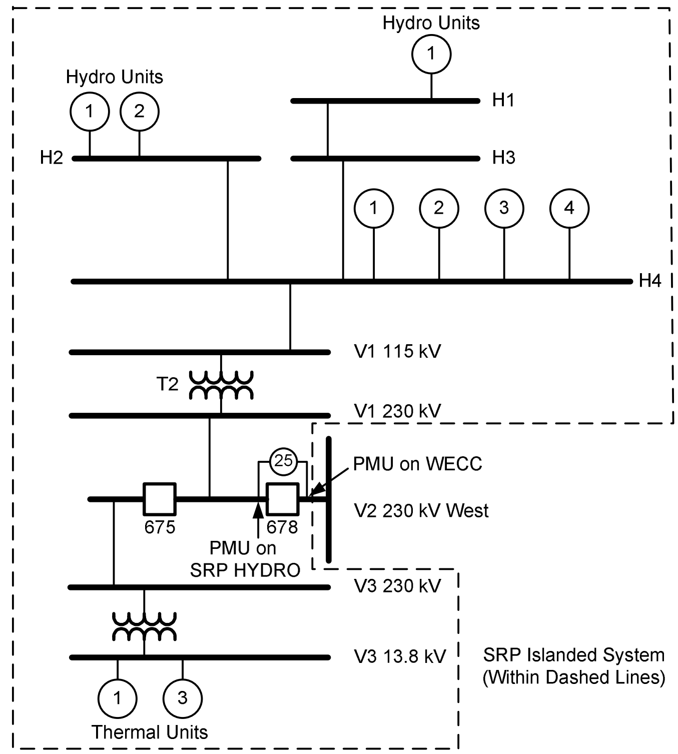

Fig. 9. SRP Black-Start Island Test System [10]

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. 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.

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. 10 shows the synchrophasor synchroscope and the system connection at 11:28:37.

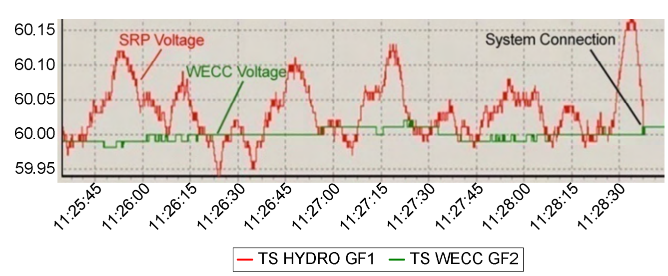

Fig. 10. SRP and WECC System Connection

The SRP synchrophasor relays provide the advantage of multiple sources and higher update rates compared to their previous system.

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 [11].

CFE has specific regional generation and transmission challenges because of large loads at the center of the country and large hydroelectric generation in the southeast.

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, as shown in Fig. 11. Loss of transmission will cause instability.

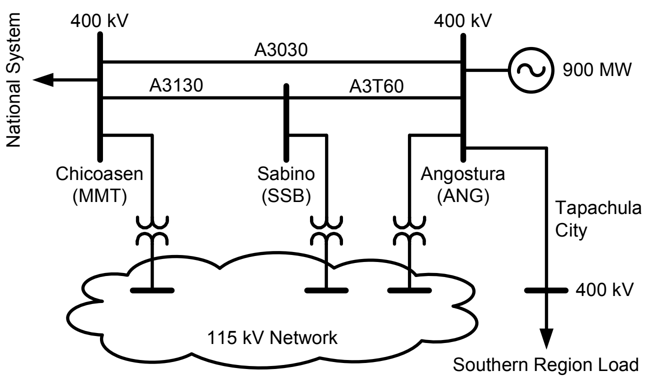

Fig. 11. Synchrophasor System One-Line Diagram

In this new AGSS, relays exchange synchrophasor data and calculate the angle difference between Chicoasen and Angostura in real time. If an angle difference δ between Angostura and Chicoasen is greater than a user-defined threshold, then the scheme sheds generation according to the logic in Fig. 12.

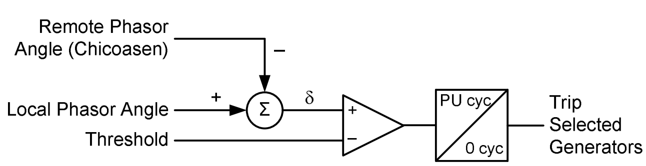

Fig. 12. Angle-Based AGSS Logic at Angostura

CFE modeled the power system and conducted simulations using Power System Simulator for Engineers (PSS/E™) 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, CFE chose an angle difference of 10 degrees to be the detection threshold for double-line outages.

CFE placed synchrophasor processing relays at Angostura 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.

To validate the system operation, CFE 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 milliseconds. After the initial angular change, the Angostura machines accelerated, the angle difference increased, and the 5-degree logic element asserted 292 milliseconds later. Table I shows the testing results for additional single-line trip operations.

TABLE I
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. FUTURE APPLICATIONS

The devices, communications, and technology presently exist to implement a number of advanced applications. While we only address two applications, there are certainly more that could be developed.

A. Out-of-Step Detection

Because of its system-wide nature and impact, it is both difficult and important to detect system out-of-step conditions as quickly as possible. Complicating this is that depending on the state of the power system, these swings could be slow, fast, or in between. An example system is shown in Fig. 13.

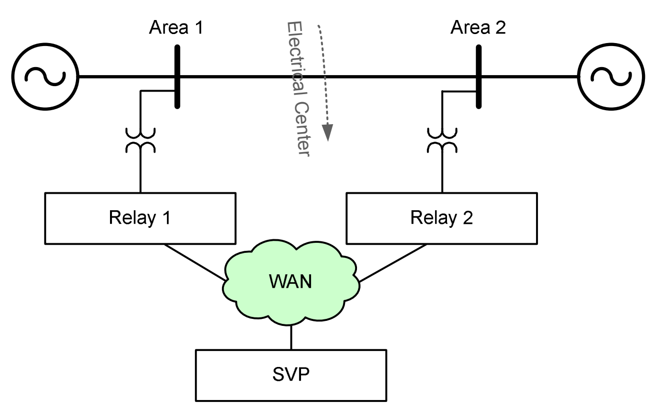

Fig. 13. Out-of-Step Detection System Configuration

Using wide-area information, we can create a system to detect swings, regardless of conditions. Consider the graph of Fig. 14. This shows the stable and unstable regions as a function of slip frequency and acceleration.

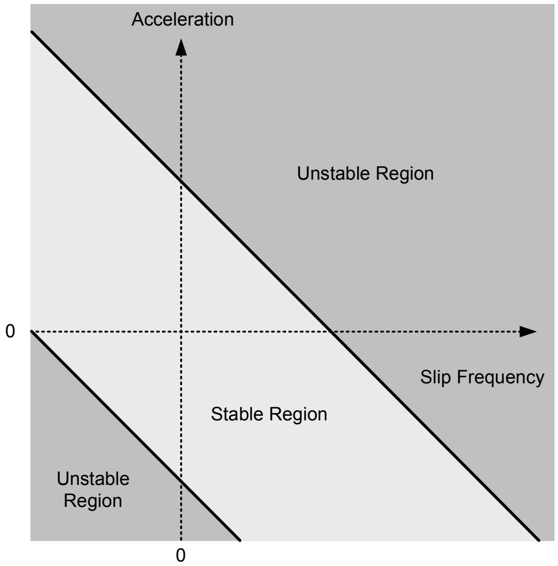

Fig. 14. Out-of-Step Detection

Using the data collection and calculation system of Fig. 13, we can use the simple functions based on slip frequency and acceleration to detect unstable out-of-step conditions. Tests showed the detection of unstable conditions that remain in the unstable region for more than 150 milliseconds [12]. High-speed control can use this same system to trip loads or generation to maintain stability.

B. Interarea Oscillation—Identification and Alarms

A device capable of receiving, concentrating, and performing calculations on synchrophasor quantities can be programmed to detect the presence and severity of system oscillations, as shown in Fig. 7. These can be frequency, phase angle, power flow, or other electrical quantities. An SVP performing this function can be connected as shown in Fig. 15.

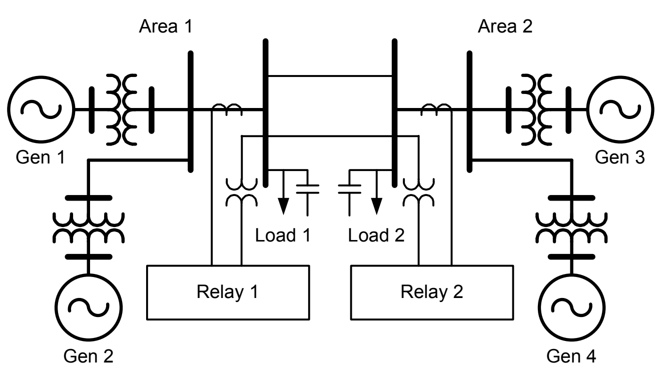

Fig. 15. Two-Area Power System Model With an Interarea Oscillation Problem

In order to use oscillations as a control or alarm quantity, the system needs to determine the frequency, amplitude, and damping ratio of the oscillation. Preprogrammed logic blocks within a vector processor can analyze a waveform and make alarm and trigger decisions based on the calculated quantities of oscillation frequency, damping, signal-to-noise ratio, and oscillation amplitude.

Studies can determine critical amplitude and damping factors to separate trivial from important events.

VI. 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 and potentially applied tomorrow.

- 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 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 practical and cost-effective, and it improves the operation and reliability of the grid.

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VIII. 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 Ph.D. 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. (SEL) 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. (SEL) 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 Ph.D. 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.

Armando Guzmán received his BS in electrical engineering with honors from Guadalajara Autonomous University (UAG), Mexico, in 1979. He received a diploma in fiber-optics engineering from Monterrey Institute of Technology and Advanced Studies (ITESM), Mexico, in 1990, and his MSEE from University of Idaho, USA, in 2002. He served as regional supervisor of the protection department in the Western Transmission Region of the Federal Electricity Commission (the electrical utility company of Mexico) in Guadalajara, Mexico, for 13 years. He lectured at UAG and University of Idaho in power system protection and power system stability. Since 1993, Mr. Guzmán has been with Schweitzer Engineering Laboratories, Inc. (SEL) in Pullman, Washington, where he is presently research engineering manager. He holds several patents in power system protection and metering. He is a senior member of IEEE and has authored and coauthored several technical papers.

Yanfeng Gong received his BSEE from Wuhan University, Wuhan, China in 1998, his MSEE from Michigan Technological University, Houghton, MI, in 2002, and his Ph.D. in electrical engineering from Mississippi State University in 2005. He is currently working with Schweitzer Engineering Laboratories, Inc. (SEL) as a research engineer in Pullman, Washington. He is a member of IEEE.

Marcos Donolo received his bachelor's degree in electrical engineering from Universidad Nacional de Rio Cuarto, Argentina in 2000, his master's degree in electrical engineering from the Virginia Polytechnic Institute and State University in 2002, his master's in mathematics from the Virginia Polytechnic Institute and State University in 2005, and his Ph.D. in electrical engineering from the Virginia Polytechnic Institute and State University in 2006. Since 2006, he has worked with Schweitzer Engineering Laboratories, Inc. (SEL), where he is presently a research engineer. He is a member of IEEE.

Roy Moxley has a BS in electrical engineering from the University of Colorado. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2000 and serves as marketing manager for protection products. Prior to joining SEL, he was with General Electric Company as a relay application engineer, transmission and distribution (T&D) field application engineer, and T&D account manager. He is a registered professional engineer in the State of Pennsylvania and has authored numerous technical papers presented at United States and international relay and automation conferences. He also has a patent for using time error differential measurement to determine system conditions.

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