Turning Synchrophasor Data Into Actionable Information

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***Abstract*—Changing load characteristics, limited transmission paths, and distributed generation have combined to complicate the task of controlling the electric power system. This complication has come at the same time that improved operator and automatic responses are needed to cope with increased stress on the power system.**

This paper demonstrates the use of synchrophasor data in displaying and analyzing system events in order to improve system response to load and transient events. Examples are given of actual events captured using wide-area and local synchrophasor measurements.

A comparison of the data analysis capabilities of streaming synchrophasors with traditional supervisory control and data acquisition (SCADA) is presented. The use of synchrophasors to evaluate the performance of new generator types, such as wind generation areas and photovoltaic sites, is presented and discussed.

Synchronized wide-area measurements of power system conditions show the best promise of improving manual and automatic response to system disturbances. By showing the capability of viewing real events and processing the data in real time, this paper advances the understanding of wide-area-based systems. To complete the paper, future capabilities, such as dynamic line loading and generator shaft measurements, are introduced with their implementations and applications evaluated.

I. Introduction

Since the 2003 North American Eastern Interconnection, Denmark, and Italy blackouts, synchronized phasor measurements (synchrophasors) have been recognized as having the ability to provide unique system insight [1]. This is due to the fact that they are time-synchronized measurements, provide fixed sample rates, and are continuously streaming measurement data. The graph in Fig. 1 shows (after the fact) how synchrophasors could have been used by operators to indicate that the North American Eastern Interconnection system was in trouble. In Fig. 1, the angle differences between two important buses are shown as they separate significantly prior to the actual blackout. Angle differences require time-synchronized measurements because angles change at a high rate and require a time stamp in order to align and perform the difference operation.

While Fig. 1 shows some of the potential value of synchrophasors, upon close examination, it also illustrates how far the technology needs to progress. Note the nonlinear scale on the bottom of the graph in Fig. 1. Most of the time, if viewed on a linear scale, the phase angle difference that indicated a potential problem was relatively unchanged. It was only during the last 3 minutes that the angle significantly separated (see Fig. 2).

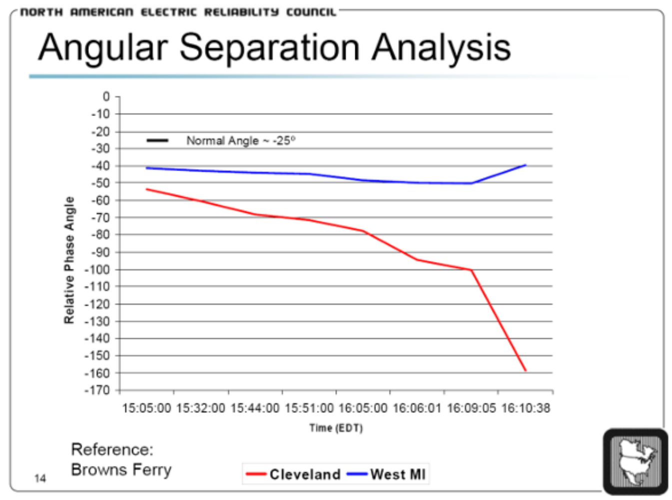

Fig. 1. System separation, August 2003 (figure courtesy of North American Electric Reliability Corporation [NERC]).

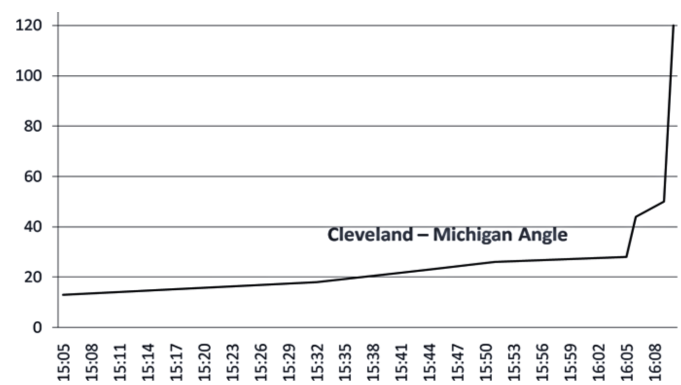

Fig. 2. Redrawn phase angle difference with linear scale.

Another issue with the raw data of Fig. 1 is the number of points the graph includes. Because this graph was created from event reports from around the system, not from direct measurement, there are only a few data points, which show only the general trend. While this is useful, examining synchrophasor data arriving at continuous message rates of one per cycle provides significantly more information.

One of the issues during the 2003 North American Eastern Interconnection blackout was inaccurate state estimation of power flows and angle measurements that occurred when the system was rapidly changing in the final minutes before the blackout. Operators had either no information or inaccurate system state information. Existing state estimation systems use system topology and magnitude measurements to calculate the system state. The algorithms used are nonlinear and computationally intensive, and they use nonsynchronous measurement data. This results in system state estimates being updated every few minutes or not at all, thus leaving the operators without the up-to-date and accurate system state information needed to take mitigating actions.

Streaming synchrophasor measurements would have provided improved situational awareness to the operators by directly measuring power flows and voltage angle measurements and providing operators with near real-time, accurate measurements of the system state.

II. Synchrophasor Measurement System

Since 2003, a system for collecting and displaying synchrophasor information from around the world has been in service using the Internet [2]. The phasor measurement units (PMUs) are located in offices, and the measurements are from the wall outlet level.

Fig. 3 shows the North American portion of the system architecture. Relays operate as PMUs and are directly connected to each wall outlet. The synchrophasor data are sent using the IEEE C37.118-2005 communications standard over a virtual private network (VPN) [3]. The connection type is Transmission Control Protocol (TCP), which provides robustness against dropped packets. At the data collection site, a phasor data concentrator (PDC) time-aligns the data. This compensates for communications and processing latencies in the network. Finally, data are archived and visualized with a software situational awareness package that is optimized for the unique characteristics of synchrophasor data. The data are then published for display over the Internet and are accessible with any standard web browser.

Wall outlet measurements include frequency, phase angle, and distribution voltage magnitude information but do not provide current measurements. Utilities use substation-connected PMU systems, which also include time-synchronized current values (magnitude and phase angle) along with voltages and power measurements. While the absolute phase angle values are uncertain due to unknown phase connections and intermediate transformer shifts, office-connected PMUs have been shown to provide accurate and useful information to evaluate system conditions through relative phase angle differences and frequency measurements [4].

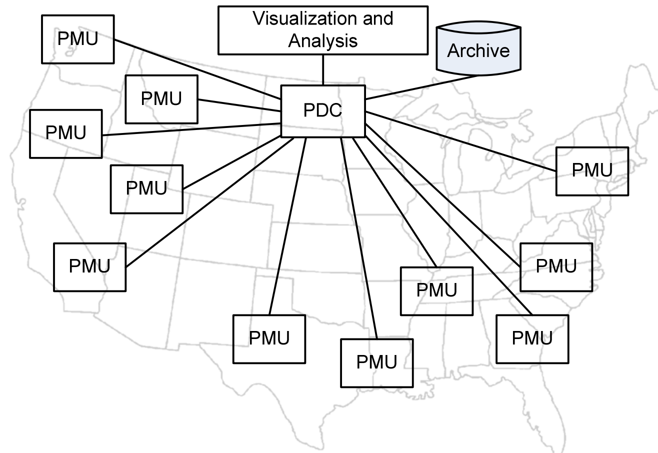

Fig. 3. PMU locations for the synchrophasor measurement system. The PDC, visualization, and analysis applications are located in Pullman, Washington.

III. System Response to Major Events

Any significant event on the power system that results in loss of load or generation will involve three elements: inertial response, governor response, and automatic generation control (AGC) response. To view and analyze these elements requires far more detail than that shown in Fig. 1 and Fig. 2.

A. Inertial Response

On February 2, 2011, the Texas electrical system experienced several generator outages due to unseasonably cold weather. The weather caused the loss of some capacity, which then reduced the ability for the available generation to meet the load requirements. Fig. 4 shows the real-time synchrophasor data (derived frequency at Boerne, Texas, and Houston, Texas) that were recorded by the system of Fig. 3.

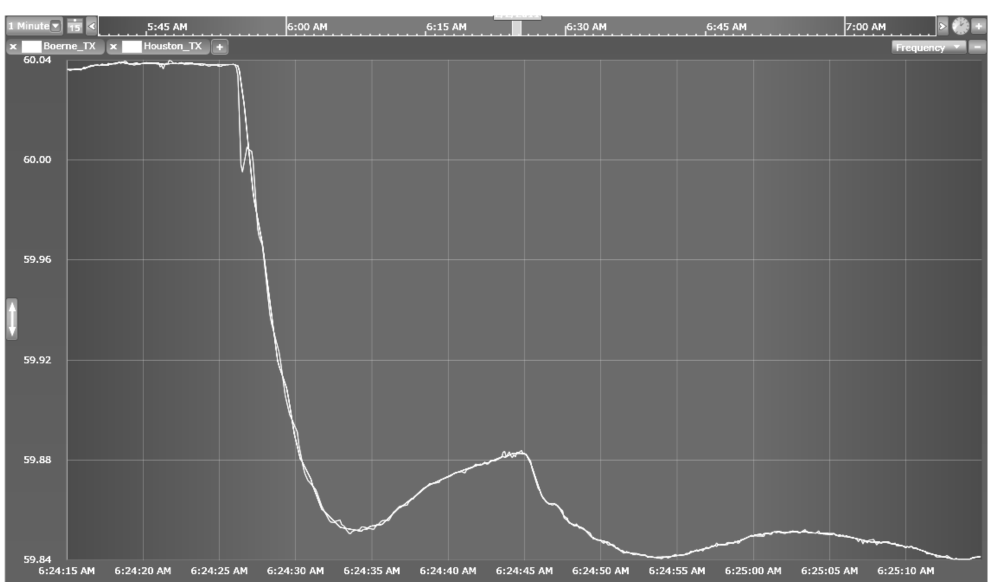

Fig. 4. Synchrophasor measurements from February 2, 2011.

By analyzing these synchrophasor data, information about system inertia, amount of generation lost, and other system parameters can be learned. First, consider system inertia. The equation of motion, (1), for a synchronous machine relates change in frequency to torque [5].

$$J\frac{dw}{dt} = Tm - Te \tag{1}$$

The rotational rate of change, dw/dt, of the machine is proportional to the difference between the mechanical input torque to the machine, *Tm*, and the electrical load on the machine, *Te*. The rotational rate of change is scaled by the moment of inertia, *J*, which has units of kg • m^2. A normalized inertial constant, *H*, with units of seconds, is often used in place of *J*. The inertial constant *H* is defined in (2).

$$H = \frac{1}{2}\left(\frac{Jw^2}{VA_{base}}\right) \tag{2}$$

Combining (1) and (2) and converting torque to power by multiplication with the rotational frequency give a relationship for the inertial constant.

$$H = \frac{(Pm - Pe) \bullet f}{\left(2\frac{df}{dt}VA_{base}\right)} \tag{3}$$

Consider (3) in light of the step response shown in Fig. 4. Because of the high sample rate, the rate df/dt is easy to measure. Notice that the high sample rate shows that the rate of change itself changes. Initially, the frequency decays with a high rate of change, and then the rate slows down and stops. The reason for this is the governor response of the generators, which arrests the changing frequency and brings it to a constant value. Therefore, the most accurate place to measure df/dt for estimating inertia is toward the decay initiation. Measuring df/dt at a specific instant on the slope is enabled by synchrophasors. Equation (4) provides the estimated df/dt.

$$\frac{df}{dt} = -\frac{1}{8}\ \text{Hz per second} \tag{4}$$

Several parameters of the Texas electrical system are not known to the authors, but when synchrophasors are applied in a specific utility, these parameters are known. Therefore, without loss of generality, this paper assumes some values with the understanding that in a utility application, the correct values are applied and the accuracy of the results improved accordingly. For example, a reasonable approximation of the VA_{base} of the system for Texas is 50 GW. Substituting df/dt and VA_{base} into (3) results in the following:

$$H = -(4.8\ \text{seconds per GW})(Pm - Pe) \tag{5}$$

During an event of this duration, the mechanical power does not change significantly. Therefore, the relationship in (5) shows how the electric load change is related to *H*. For a situation where the load power change is known, (5) provides an estimate of the system inertial constant. Conversely, if the system inertial constant is known but an operator is trying to determine how much generation was lost, (5) provides this information. Typical values for *H* are in the range of 3 to 12 seconds [6]. Assuming *H* = 8 seconds, then (5) indicates that 1.7 GW of generation was lost.

The inertial performances of renewable generation sources, such as wind turbines and solar arrays, are different than traditional generation sources. A nuclear power plant or coal-fired power plant is directly connected to the power system through a generator with a large turbine, whereas most renewable generation is electronically connected. Tracking the inertial response of the system as a function of time during the installation of renewables helps operators and planners prepare for new system dynamics. This can also provide data when working with renewable generation owners on interconnection requirements.

Compare the information learned from the synchrophasor measurements to what could be learned from a supervisory control and data acquisition (SCADA) system. The scan rate for SCADA is in multiples of seconds. Each horizontal division in Fig. 4 spans 5 seconds. Therefore, depending on where the samples fall within that 5-second window, the estimate of df/dt is different and an accurate measurement of the inertial constant or tripped generation power is not guaranteed.

B. Governor Response

The governor response of a particular unit is established by physical settings at the station itself. How these all combine to form a response of the entire system is the subject of system models. The general response of the governor is described in (6).

$$T\frac{dP_G}{dt} = -P_G + P_{AGC} + \frac{1}{R}(60\ \text{Hz} - f_s) \tag{6}$$

Consider the synchrophasor response to a system event in the southwestern United States on September 8, 2011. While the root cause of the event is still under investigation, publicly available information states that it involved a 500 kV line trip followed by the loss of approximately 4,000 MW of generation and a corresponding load [7]. Fig. 5 provides a view of the response after load shedding and then loss of generation. Note that the high-intermittent, high-frequency oscillations are probably related to secondary load interference at the PMU location. The drop in frequency from the 60.17 Hz peak to 60.04 Hz looks smooth and without oscillations. Now, look at the phase angle, along with the frequency, of the voltage as measured in California (see Fig. 6). The reference phase angle is in Pullman, Washington, near significant generation sources supplying power over ac and dc links.

Power in a system will flow according to (7).

$$P = \frac{|V_1| \bullet |V_2|}{X}\sin(\theta) \tag{7}$$

where:

V_1 and V_2 are the voltages on either end of a system.

θ is the phase angle difference between the two ends.

X is the impedance between the two ends.

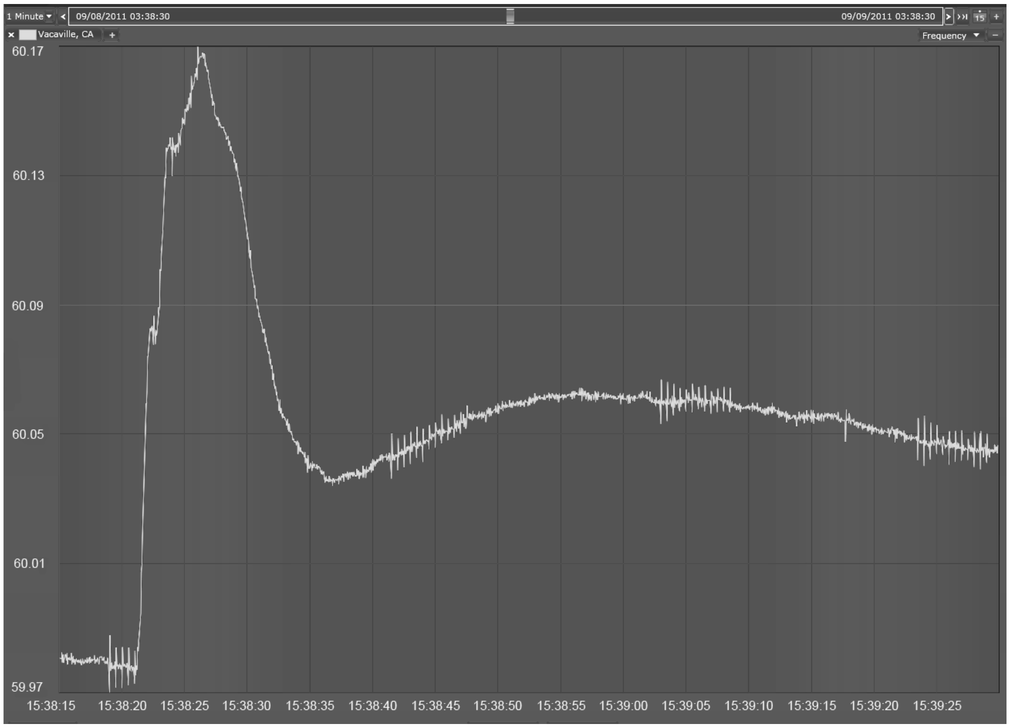

Fig. 5. System composite governor response.

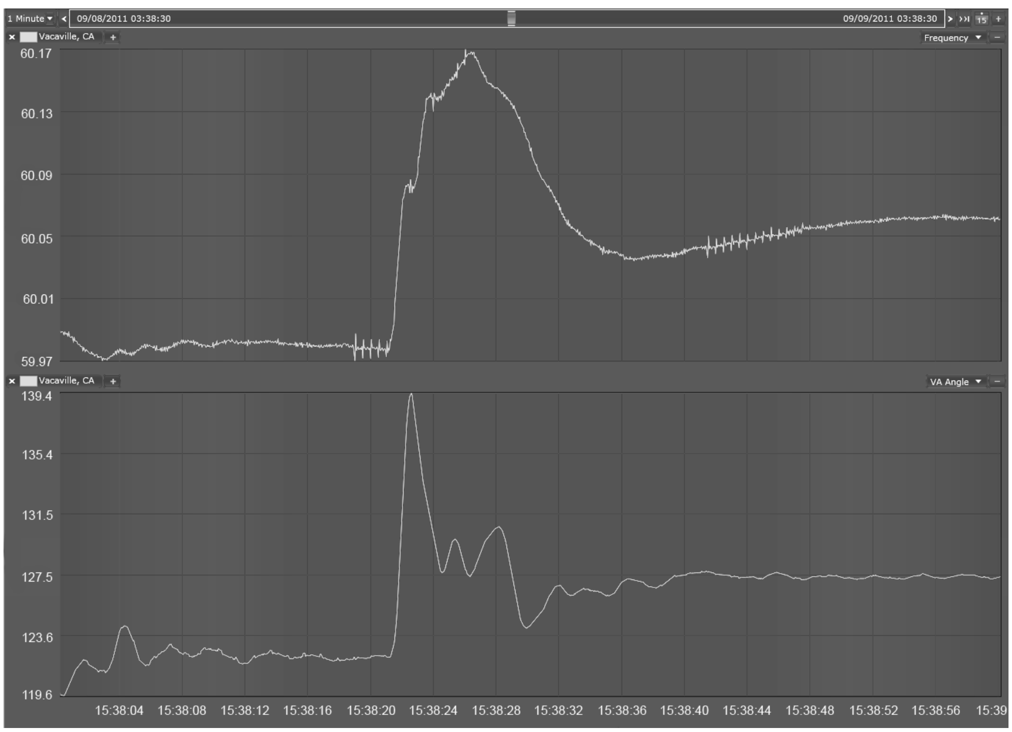

Fig. 6. Frequency and phase angle.

The oscillations in the phase angle that can be seen occurring at the time of the frequency peak are an indication of significant power oscillations. These oscillations are not indicated in the frequency chart. The angles shown are in respect to Pullman, which is somewhat to the east of significant generation sources on the Columbia River. Fig. 7 shows phase angles at another point on the other side of these generation sources (at Vancouver, British Columbia).

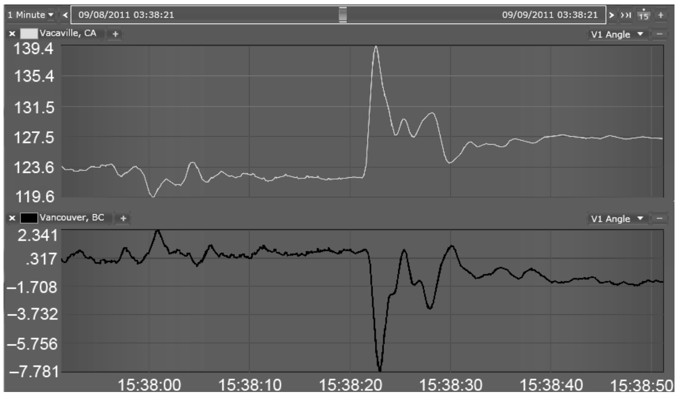

Fig. 7. Phase angles in California and British Columbia during the September 8, 2011, event in the southwestern United States.

Because these PMUs were connected in offices at the distribution level, the phase is not identified and no phase compensation is included. Given the phase angle difference shown between Vancouver and Vacaville, California, it is quite likely that the connections are on different phases, so the 123-degree shift shown at the beginning of the trace is probably a 3-degree phase shift. At the peak of the phase angle shift, with this assumption, the phase shift has increased to 27.1 [139.4 – 120 – (–7.7)] degrees. Putting these values into (7) and assuming that the generators cannot respond as fast as the phase angle has shifted, the power flow across the system has changed from 0.05 per unit [sin(3 degrees)] to 0.46 per unit [sin(27.1 degrees)], an increase by a factor of nine times in a matter of 1 second. Unless a SCADA scan was faster than once per second, this power swing would never have been seen.

Using synchrophasor visualization software that lets a user select the desired measurement points (PMUs) and the specific measurement quantities allows the user to quickly see oscillations such as these. Furthermore, including breaker status information in the synchrophasor message provides additional insight into which line trips started the oscillation or how subsequent actions impacted the oscillation.

C. AGC Response

The AGC response brings the frequency back to nominal and maintains scheduled power flow between regions. Instead of examining frequency (which is not interesting in this case), it may be of more value to examine the phase angle again (see Fig. 8).

With a time scale of 10 seconds per division, it is easy to see a low-frequency oscillation in power flow, as shown by a change in phase angle. The frequency of the oscillation appears to be 7 cycles in 30 seconds, or approximately 0.2 cycles per second. The angular difference change is only about 0.8 degrees, which is about the same as it was well before the start of the blackout event. The measured frequency of standing oscillation is low, but based on the Nyquist criterion, it would require a SCADA scan of faster than once every 5 seconds to be able to observe it.

The low-level oscillations seen in Fig. 8 are not impacting power system reliability. If they were exciting a natural mode of the system or if they were growing, they could be a concern.

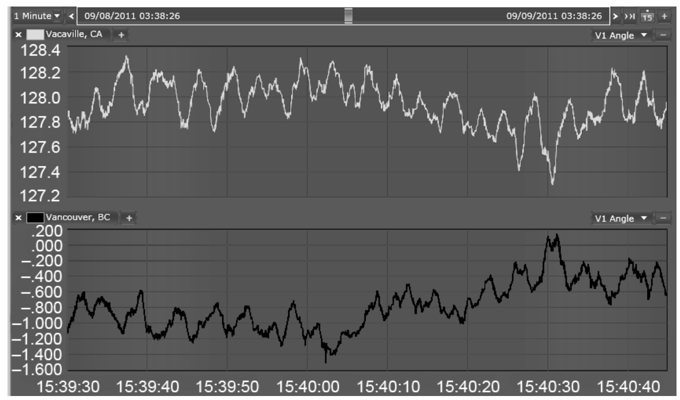

Fig. 8. AGC phase angle response following blackout.

IV. LINE SWITCHING EVENT

Because synchrophasors are a streaming protocol, it is not just serious blackouts that trigger event recording. Anything that occurs on the system can be viewed because the details of portions of the event can be analyzed in depth. The ever-decreasing cost of data storage has made it possible to keep a complete high-resolution system record for one year or more. Using the data from small events on the system can be a tool to reduce the chance of large events. Models can be improved by comparing modeled performance with measured performance to provide engineers with increased confidence in ensuring secure system operation. This section describes a dc line switching event, showing real-time synchrophasor waveforms along with event details provided by publicly available information about the event from the Bonneville Power Administration.

At 04:10 on July 30, 2011, scheduled maintenance was done on the ±500 kV north-to-south dc line. This involved switching taps on Poles 3 and 4. This dc tie carries significant power from the hydrogeneration in the northwest to the Los Angeles area in the southwest. It is paralleled by a 500 kV ac link. There are no taps along the dc line.

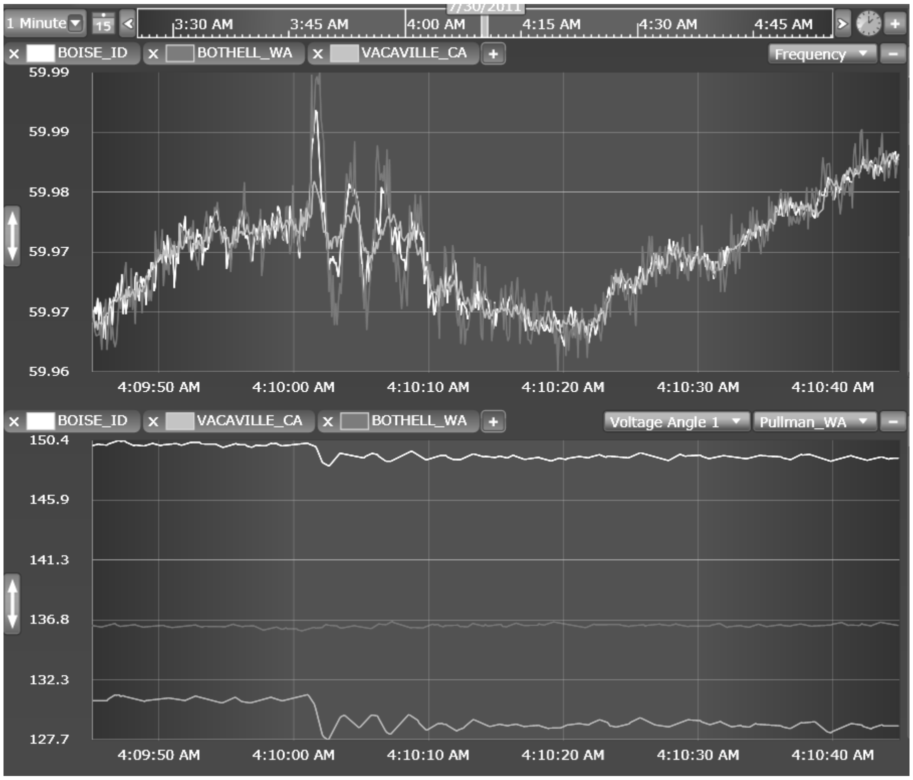

Fig. 9. ±500 kV operation event.

During this switching event (shown in Fig. 9), there was a significant frequency oscillation triggered, although it can be seen that there was virtually no change in load or net generation because the central frequency remains unchanged. The period of the oscillation is approximately 2 seconds, indicating a 0.5 Hz frequency. The decay time of the frequency and phase angle continues for about 10 seconds, indicating a slowly well-damped oscillation.

Not surprisingly, the frequency oscillation measured at the Vacaville PMU (in the middle of the dc line) is very small compared with that of the PMU located in Bothell, Washington. It is also interesting to note that the phase angle oscillation measured at Vacaville exhibits a larger oscillation than elsewhere on the system. The Bothell PMU is located relatively close to the dc terminal and exhibits almost no phase angle shift when Poles 3 and 4 are switched. The Vacaville PMU, about 600 kilometers from either terminal, shows about ten times larger phase angle oscillation. This illustrates the shift in load to the ac ties when the dc poles are switched. The generators in the north continue to generate, but now the power is transiently flowing over the ac ties, which pass near the Vacaville PMU. The frequency difference between the ac- and dc-caused oscillations gives operators an indicating factor of where to look for problems when an oscillation is observed.

V. Reliably Integrating Renewable Generation

Renewable generation is being added to the power system at an ever-increasing rate, both at the transmission and distribution levels. This new generation comes with new challenges. Specifically, renewable generation has high intermittency due to the wind not blowing continuously or clouds moving across solar panels, causing generation output to vary widely and rapidly. Another concern with renewable generation is that it often uses an inverter-based conversion process, which has little or no inertia. Reducing system inertia has raised concerns that it can potentially decrease the stability of the power system.

Synchrophasor measurements are well-suited for reliably integrating renewable generation because they provide high-resolution measurements of the power system, giving details of system operation as often as every cycle. Using synchrophasor measurements allows the system to be baselined before and after adding the generation. Furthermore, system stability can be analyzed by capturing events that occur with varying amounts of renewable generation in use and analyzing the system response. This has been an area of study at The University of Texas at Austin, where work has been done to understand the effect of large amounts of wind generation on the Electric Reliability Council of Texas (ERCOT) system [4].

An example of the system insight that synchrophasor measurements provide was recently demonstrated by identifying an unexpected issue with a new wind farm. The utility reported that it was receiving customer complaints because of flicker on a portion of the distribution network. The utility had begun to replace distribution transformers only to find out that the renewable generation was the source of the problem [8]. Having PMUs throughout its system and being able to visualize and analyze the data helped the utility find the source of the issue—an inadvertent frequency component that was being generated by the inverters. This phenomenon went undetected by the SCADA system, but it was quickly identified when the synchrophasor data were analyzed.

VI. Future Capabilities

The application of synchrophasors is still relatively new to the electric power industry. Using synchrophasors in examining system conditions is becoming widespread, with numerous events being quickly and efficiently described in ways not possible before. New applications, with improved accuracy, are under investigation.

A. Dynamic Line Loading Methodology Improvements

Synchrophasor measurements can be used for measurement of line parameters [9], including resistance, which could be used to dynamically measure line temperature. Accuracy concerns based on angle shifts of voltage, especially if the line has a high X/R ratio, lead to problems in implementing such a system.

We can solve the equations of a line model, as illustrated in Fig. 10.

$$Z = \frac{V_S^2 - V_R^2}{I_S V_R - I_R V_S}$$

$$Y = 2\frac{I_S + I_R}{V_R + V_S}$$

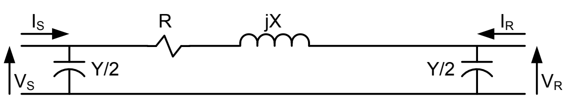

Fig. 10. Pi section model for a transmission line.

A single measurement is susceptible to unbiased noise and biased measurement errors, and regression techniques are available to improve the estimate [9]. It is also possible to use two methods to improve performance. Consider the measurements of Fig. 11.

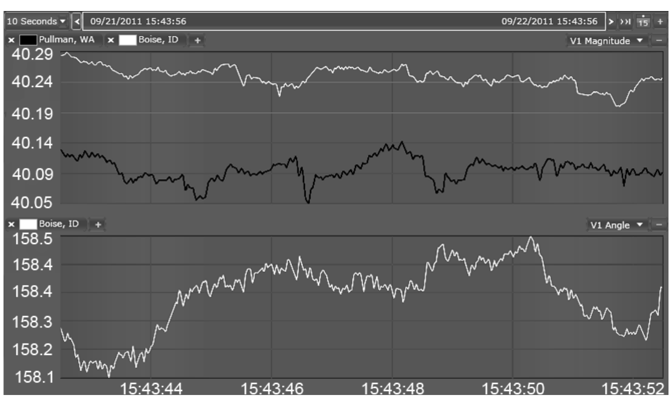

Fig. 11. Path monitoring of voltage magnitude and angle.

Fig. 11 shows the number of measurements over a very short time (10 seconds). This is only showing the voltage magnitude and angle. In a substation, current magnitude and angle are also captured on the selected line. With 60 messages per second (50 for 50 Hz applications), 600 measurements are available every 10 seconds for estimating the line parameters. If a line has a thermal time constant of 2 minutes, this increases to 7,200 (5,000 at 50 Hz) measurements. By performing repeated calculations, statistical and noise-related errors are greatly reduced by plotting a distribution of the results.

The second method of improving accuracy is to normalize the data using ambient temperature measurements for the calculated line temperature [10]. Comparing a synchrophasor-calculated value to an independent method can return an adjusted value with improved accuracy.

B. Generator Shaft Measurements

The idea of synchronous measurements does not apply only to electrical quantities. Mechanical measurements can be correlated with electrical measurements in real time. This is particularly valuable when evaluating generator operating characteristics and conditions. An input from the generator shaft (see Fig. 12) can be brought into the same relay (PMU) measuring electrical quantities on the output from the generator.

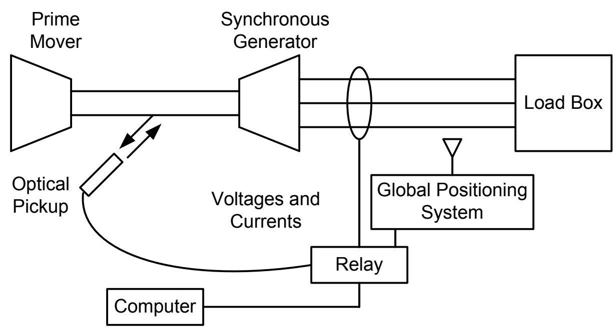

Fig. 12. Shaft displacement and electrical inputs to PMU.

Shaft measurements provide insights to mechanical and/or electrical interactions. These can include subsynchronous resonance caused by active devices (high-voltage dc stations and series capacitors) as well as new generation sources (wind farms and photovoltaic sources).

VII. Conclusion

Synchronized phasor measurements have been demonstrated to provide new tools for both real-time situational awareness and post-event analysis. These measurements provide significantly more system information than was previously available using SCADA systems. As the number of PMUs expands, new capabilities will be put into service, with even more detailed system views. New synchrophasor software that provides flexible, yet powerful visualization and analysis makes finding valuable information in large amounts of synchrophasor data fast and easy. Utilizing features of this software allows the user to identify and capture events of interest, save user-specific views, and quickly compare measurements points across the system. This paper, using synchrophasor visualization and analysis software and utilizing PMUs connected to wall outlets in offices throughout the United States, demonstrates how these measurements can be used for the following:

- Improving system dynamic response models during major loss of load using high-speed streaming data.
- Understanding system response to transmission line switching operations.
- Observing differences between different types of events and seeing how this can be used to identify event types.

Observing system response to different events is the first step to better understand the limitations and capabilities of the system. Using the high-speed, streaming, synchronized nature of these new measurements greatly adds to the tools available to maximize asset utilization. Transmission lines, generators, and other primary components can be loaded to true stability limits when operators fully understand how this loading impacts the system.

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IX. Biographies

Roy Moxley received his B.S. in electrical engineering from the University of Colorado. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2000 as a market manager for transmission system products. He is now a senior product manager. He has authored and presented numerous papers at protective relay and utility conferences. 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 a member of IEEE and CIGRE.

Greg Zweigle received his M.S. in electrical engineering and M.S. in chemistry from Washington State University. He also received a B.S. in physics from Northwest Nazarene University. He is presently a principal research engineer at Schweitzer Engineering Laboratories, Inc. Greg holds seven patents and is pursuing a Ph.D. in energy systems. He is a member of IEEE and the American Chemical Society.

Bill Flerchinger is a senior marketing engineer in research and development responsible for synchrophasor-based solutions at Schweitzer Engineering Laboratories, Inc. (SEL). Prior to joining SEL, he worked for Agilent Technologies, Mobile Broadband Division, as the product planning manager. He completed a master's certificate in transmission and distribution from Gonzaga University in 2010. Bill received his M.S. in engineering management and a B.S. in electrical engineering from Washington State University in 1993 and 1987, respectively. He is a member of IEEE.