Synchrophasors Redefining SCADA Systems

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***Abstract*—Modern power system grid monitoring tools use data from remote terminal units (RTUs), protective relays, and transducers to provide information to system operators. This information is vital for the operation of the power system on a daily basis and under system contingencies. However, the mechanism used to retrieve data from the devices is asynchronous and relatively slow. The asynchronous nature of the data does not provide accurate angle difference information from two nodes on the network. Additionally, the low data rate may be too slow to capture many short-duration disturbances on the grid. Alternatively, phasor measurement units (PMUs) sample voltage and current many times a second and accurately time-stamp each sample. This technology can be used to provide high-speed and coherent real-time information of the power system that is not available from legacy supervisory control and data acquisition (SCADA) systems.**

This paper discusses the existing SCADA system and the recently installed wide-area monitoring system (WAMS) at the Power Grid Corporation of India Limited (PGCIL) Northern Regional Load Despatch Centre (NRLDC). The paper discusses the communications infrastructure the WAMS uses and the tools to monitor and archive the time-synchronized data. The paper also discusses system events witnessed on the PGCIL network following the WAMS installation and how the WAMS provided critical information that is lacking in existing SCADA systems.

I. Introduction

State estimators are commonly used to estimate the state of the power system; power system operators use this information to make decisions about operating the power system under normal and contingency conditions. The front end of a state estimator is the supervisory control and data acquisition (SCADA) system that gathers system data, which include voltage magnitudes, active and reactive power values, and system topology via breaker status. The state estimator uses this information and system network impedances to estimate the state of the power system. The SCADA system periodically polls the devices that collect the information, which can include remote terminal units (RTUs), protective relays, and transducers, to obtain the data. One complete scan of the large number of devices could last from 2 to 10 seconds. During normal steady-state conditions, the long scan time is not a major concern. However, when the system state changes during the scan, the data retrieved no longer represent the system state accurately [1]. Fig. 1 shows a SCADA system performing an asynchronous scan of all the RTUs to retrieve the system data.

The asynchronous and slow nature of the SCADA system does not provide power system information at subsecond time frames to the state estimator. Therefore, a SCADA/EMS (energy management system) does not provide dynamic state measurement of the power system. The promising synchrophasor technology, available since the early 1980s, provides coherent and high-speed data. This technology became more attractive and economical with the availability of Global Positioning System (GPS) receivers. Some manufacturers provide synchrophasor capability in protective relays as a standard feature, which makes the technology more attractive and widespread. Synchrophasors provide phasor measurements of voltages and currents with a common time reference; the GPS time source is one such common time reference. With synchrophasors, the state of the power system can be measured, as compared with state estimation using a traditional SCADA/EMS. Fig. 2 shows a sinusoidal waveform in time and phasor domain representation, where A is the amplitude of the signal and ϕ is the phase angle.

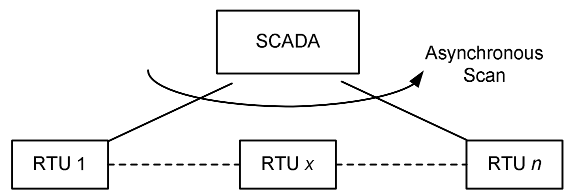

Fig. 1. SCADA system performing an asynchronous scan of RTUs

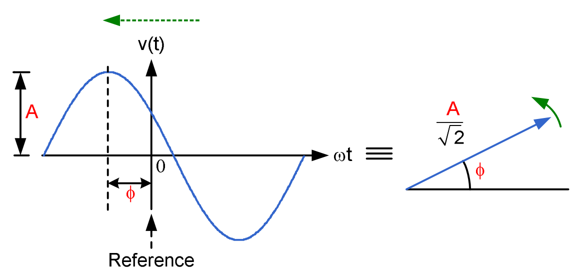

Fig. 2. Phasor representation of a sinusoidal waveform

Power Grid Corporation of India Limited (PGCIL) installed a synchrophasor-based wide-area monitoring system (WAMS) to provide visibility of critical nodes on their 400 kV system. The system provides phase angle difference, along with phase voltage magnitudes, power flow, frequency, and rate of change of frequency. The system also provides archiving and playback functionality for post-event analysis. We analyzed two major events with data provided by the WAMS and the SCADA system. The WAMS proved to be beneficial in the analysis of the events and provided details of the system dynamics that were previously hidden because of the asynchronous and slow data rate of the SCADA system.

II. SCADA IN THE INDIAN POWER SYSTEM

The Indian power system is divided into five regional grids for operational flexibility. Fig. 3 shows the regional grids: the northern, western, southern, eastern, and northeastern regions. The southern grid is asynchronously tied to the rest of the system through a dc transmission link.

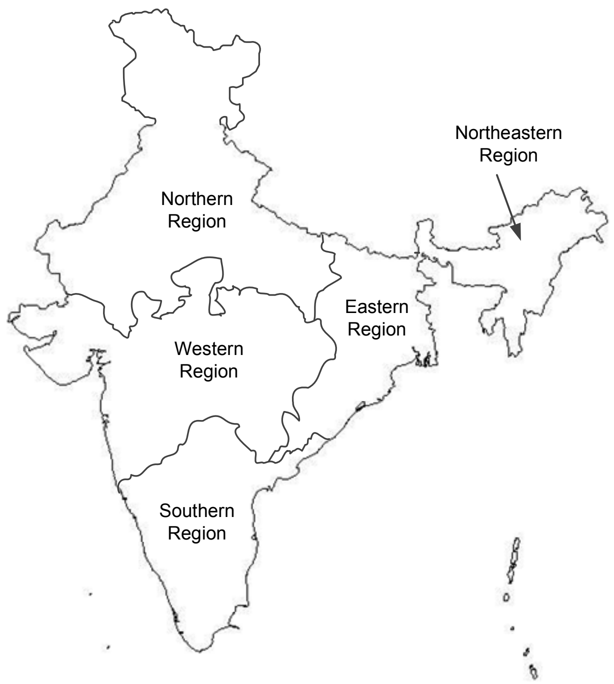

Fig. 3. The Indian power system has five regional grids

A SCADA/EMS supervises, controls, optimizes, and manages generation, transmission, and distribution assets. Typical functionality of a SCADA/EMS includes:

- Data acquisition from RTUs and protective relays.
- Postprocessing of data for sanity checks and scaling.
- Data archiving for postmortem analysis.
- Sequence-of-event recording.
- State estimation.
- Manual and automatic generation control.
- Load forecasting.
- Contingency analysis.
- Offline tools for power flow, contingency, and scheduling.
- Operator interface for visualization and additional programming for custom applications.

The SCADA/EMS in the Indian power system has a tiered architecture [2]. Fig. 4 shows the data transfer from the substation level to the National Load Despatch Centre (NLDC).

The data transmission from substations to control center(s) is through a combination of power line carrier, microwave, and optical fiber links. The use of dedicated wideband communication has immensely improved the reliability of data. Online monitoring of all these data enables the regional load dispatch operator to have wide-area awareness of the regional grid as well as interregional links. Similar data are available in all state load despatch centres (SLDCs), making it easy for operators to take the required measures for controlling the safety and security of their system in a most interactive and effective manner.

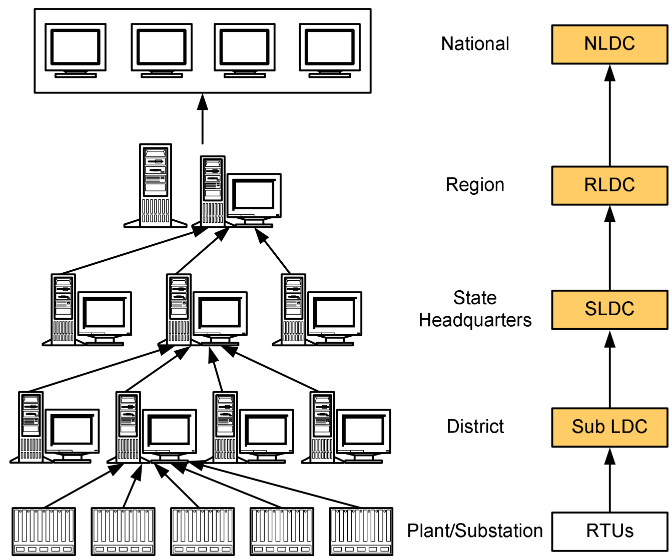

Fig. 4. Data flow from the substation to the NLDC

In addition to the monitoring and control tools provided by SCADA, tools were developed by PGCIL to monitor the phase angle difference between critical nodes on the system using SCADA measurements [3]. Equation (1) calculates the phase angle difference based on the traditional power transfer equation.

$$\delta = \sin^{-1}\left(\frac{P \bullet X}{|V1| \bullet |V2|}\right) \tag{1}$$

where:

P is the active power transfer between Nodes 1 and 2.

X is the reactance between Nodes 1 and 2.

V1 and V2 are the voltages at Nodes 1 and 2.

The phase angle difference provides a signature of the system stress. Using offline study results and operating experience, operators trigger remedial actions based on the angle difference between nodes on the system. One of the reported limitations is the slow measurement update provided by the SCADA system, which is in the order of 2 to 10 seconds. Additionally, the approach to calculate the angle difference depends on the system reactance, which depends on the system topology.

III. Synchrophasor Technology

Synchrophasor technology is used around the world for data visualization and postmortem analysis applications. IEEE C37.118, IEEE Standard for Synchrophasors for Power Systems, defines synchrophasors, provides the requirements for the quality of the measurements, and specifies the protocol for data transfer [4]. The standard defines synchronized phasors as phasors calculated from data samples using a standard time signal as the reference for the measurement. The commonly used time reference is GPS. The data frame of the IEEE C37.118 message includes time-quality information from GPS receivers and/or satellite clocks. It is critical to supervise synchrophasor-based applications using this information. The standard emphasizes that GPS clocks should support IRIG-B, with additional extensions to provide the time-quality information to the phasor measurement unit (PMU).

Synchrophasors are well suited for steady-state and quasi steady-state phenomena (not for transient conditions like faults) and for observing low-level oscillations. Fig. 5 shows the magnitude response of a synchrophasor filter for a 50 Hz power system. This filter processes 50 messages per second. Based on the magnitude response, the filter has a pass band from 43.0 to 57.0 Hz and has an attenuation of over –25 dB for all other frequencies.

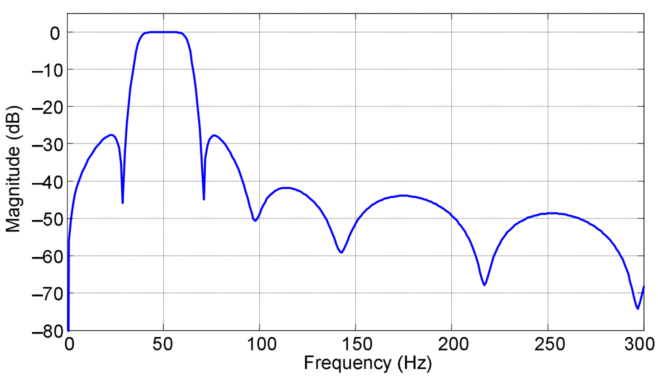

Fig. 5. Synchrophasor filter for 50 messages per second

Fig. 6 shows the building blocks of a synchrophasor-based system. PMUs connected to a GPS satellite clock send voltage and current phasor measurements to a phasor data concentrator (PDC) at a rate of 25 messages per second, for example. The PDC receives data from multiple PMUs, time-aligns the data, and provides the super packet to upstream applications. A super packet consists of phasor measurements from different PMUs with a common time stamp. Typical implementations of PDCs provide a message waiting period to allow time to receive data from all the PMUs; data arriving outside the message waiting period will be zero-filled and flagged for a PMU out of synchronism.

In recent years, synchrophasor applications have gone beyond visualization and postmortem analysis [5]. An automatic generation-shedding application using synchrophasor data is discussed in [6]. Reference [7] provides information about islanding detection and control. Controllers are available today that allow customers to implement remedial action schemes (RASs) and system integrity protection schemes that process coherent data (super packets) and send control commands back to the power system [8]. Synchrophasors are being used in SCADA/EMS by many utilities. Some of these utilities include Southern California Edison, Consolidated Edison, and San Diego Gas & Electric. The key objective of making synchrophasors available to SCADA/EMS is to enhance state estimation. Reference [9] states that an adequate PMU base significantly enhances state estimation results.

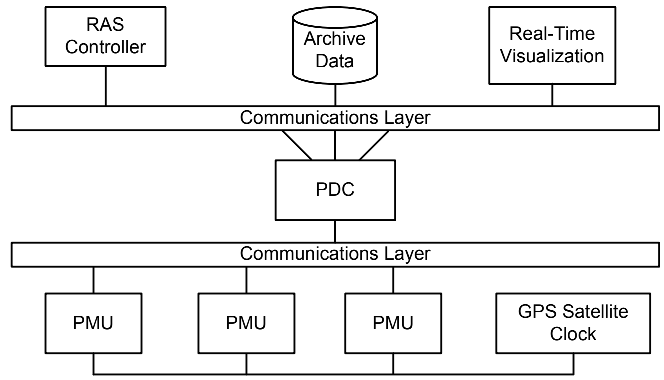

Fig. 6. Building blocks of a synchrophasor-based system

IV. PGCIL Synchrophasor System

The synchrophasor system implemented in northern India consists of PMUs, GPS satellite clocks, and a PDC, along with an application software package. Four monitoring sites were selected for the first phase of the project; at each site, a PMU and a satellite clock were installed. Each PMU was connected to measure three-phase voltages and currents, along with breaker status. The PMUs are IEEE C37.118 Level 1 compliant and are configured to stream the synchrophasor data via Transmission Control Protocol (TCP) at 25 messages per second using IEEE C37.118. Fig. 7 shows the locations of the four phasor measurement sites, along with the location of the Northern Regional Load Despatch Centre (NRLDC) where the PDC is installed.

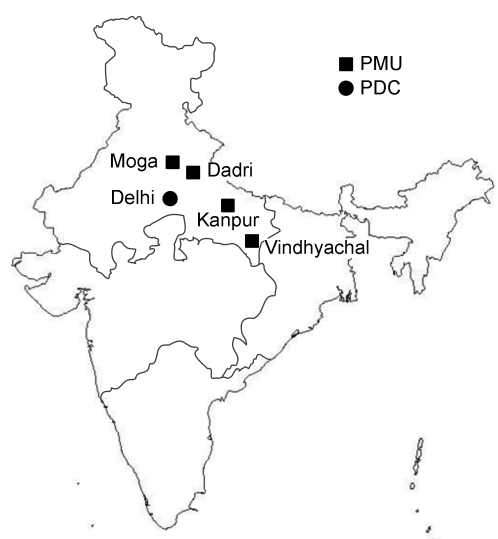

Fig. 7. PMU locations in the northern region of India

Two of the sites are 400 kV switching stations, and the remaining two are high-voltage dc stations. The PDC installed at the NRLDC performs time alignment, supports IEEE C37.118 clients, and provides the user interface to perform vector calculations on the time-aligned data. This PDC also has the ability to send control commands to the PMUs. A converter was installed to provide the conversion from the Ethernet interface to the G.703 interface of the multiplexer (MUX). A 64 kbps communications link is used to send the data from the PMUs to the PDC. The application software package includes the following:

- Visualization software for the operator to monitor both real-time data at 25 messages per second and archived data based on the time window specified by the user.
- Data historian to archive the synchrophasor data.
- Integration of the time-aligned synchrophasor data with existing SCADA via OPC protocol.

The real-time data provided to the operator include voltage magnitude, active and reactive power flow, frequency, rate of change of frequency with respect to time (df/dt), and phase angle difference between user-configured nodes. Fig. 8 shows the installation at one of the synchrophasor acquisition sites. Fig. 9 shows the PDC and historian server installed at the NRLDC.

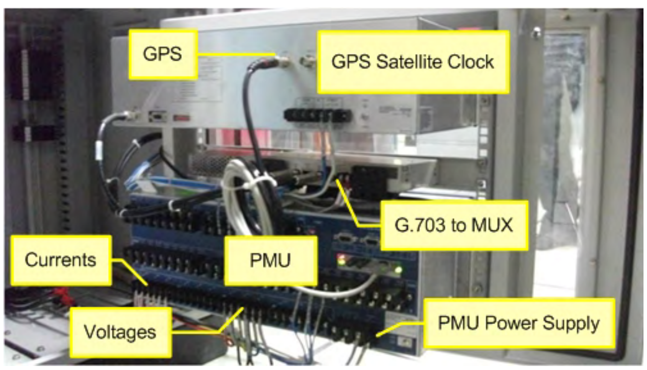

Fig. 8. Site installation

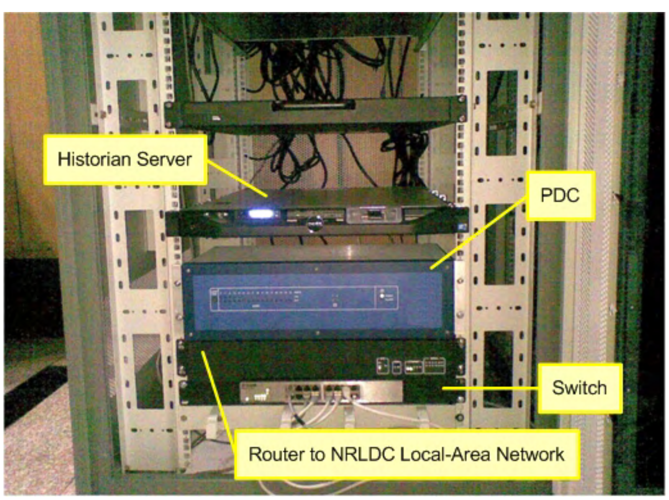

Fig. 9. Setup at the NRLDC

V. Case Studies

We analyzed two real-world events to compare the quality and relevance of the data available from the SCADA and synchrophasor measurements.

A. Loss of Generation

The first case is a loss of generation; PGCIL reported that tripping of transmission lines triggered the generation loss. We used data from this event to compare the accuracy of the frequency measurements.

Fig. 10 shows the frequency measurements from SCADA and PMUs. The frequency initially increased with the loss of load and then started to decrease following the generation loss. The frequency measurements from SCADA show a constant error of 70 mHz. We used a high-accuracy test source to validate the frequency measurements from the PMUs; their accuracy is better than 1 mHz. Frequency measurements from PMUs can be used as a reference to verify the proper operation of underfrequency relays. We cannot use SCADA measurements to make this validation because of the slow data transfer rate. With the present practice, utilities have to retrieve oscillography records from underfrequency relays or digital fault recorders (if available) to validate the relay operation. The typical frequency threshold for underfrequency relays on the PGCIL system is 48.8 Hz, and the typical time-delay setting for load shedding is 8 to 10 cycles. To maintain system stability, the PGCIL system also requires df/dt relays with a set point of 0.1 Hz per second. In addition to frequency, the synchrophasor message includes df/dt. As mentioned earlier for frequency, we can use the df/dt measurements included in the synchrophasor message to verify the proper operation of the df/dt relays.

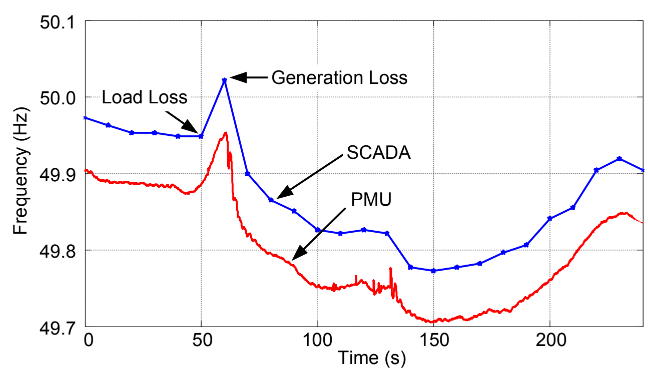

Fig. 10. Frequency measurements from SCADA have 70 mHz offset error

B. Major Loss of Generation Following a Fault

The second event is a major loss of generation following a fault on the system. Multiple transmission lines were tripped, and hundreds of megawatts of load were shed, which resulted in generator tripping. We used the data from this event to verify the coherency of the synchrophasor measurements and show the valuable information that synchrophasor measurements bring to power system monitoring and analysis.

Fig. 11 shows the comparison of the measurements from SCADA and synchrophasors from two different stations. Synchrophasor frequency measurements from Station A and Station B perfectly coincide. This is a logical result because Stations A and B are located close to each other when compared to the location of the disturbance. However, the SCADA measurements show an offset similar to that in Fig. 10 and a lack of alignment, which do not exist.

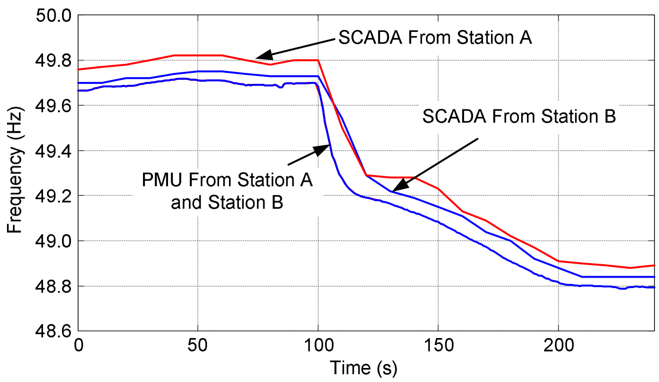

Fig. 11. Synchrophasors provide coherent frequency measurements

1) System Oscillation

During this event, we observed small signal oscillations on the voltage phasor magnitude at the four PMU installations. Fig. 12 shows the voltage magnitudes on Phase A at the four sites. In this particular event, the oscillation was damped within seconds. SCADA, with its slow data rate, cannot provide this detailed information.

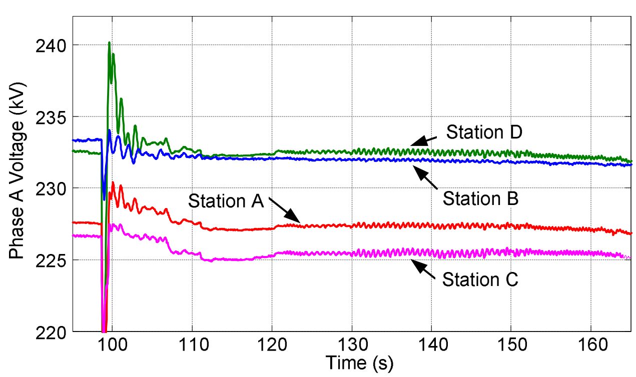

Fig. 12. Phase A voltage magnitude from synchrophasors

We performed Prony analysis [8] on the active power on one of the transmission lines leaving Station C to calculate the oscillation mode and the associated damping ratio. Typical oscillation modes for interarea oscillations are in the order of 0.2 to 0.7 Hz and for local-area oscillations are in the order of 0.7 to 2.0 Hz [10]. A negative damping ratio results in growing oscillations, leading to system collapse.

Fig. 13 shows active power oscillations of 10 MW and a damping ratio of 9 percent before the disturbance. The oscillation frequency is around 2.6 Hz before and after the event; however, the damping ratio percentage drops from 9 to 4.6 percent as a result of the event. These results should alert the system operators and engineers and make them investigate the cause. During the August 1996 Western North American blackout, the damping ratio associated with the interarea mode decreased from +8.9 to –3.22 percent when the system collapsed. Fig. 14 shows the power flow on the Malin-Round Mountain 500 kV transmission line connecting California and Oregon, along with the modal analysis results. Tools are available today to calculate oscillation modes and associated damping ratios in real time and provide early warning to system operators.

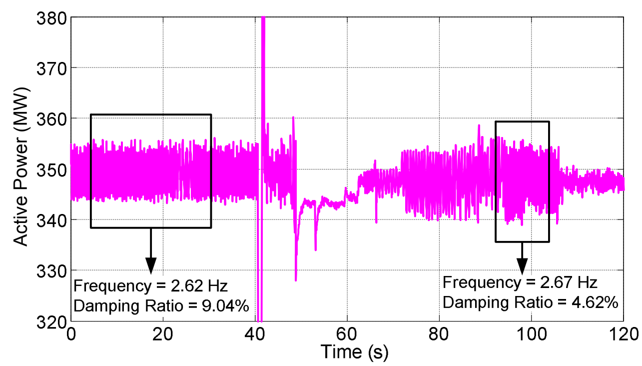

Fig. 13. Active power flow oscillations

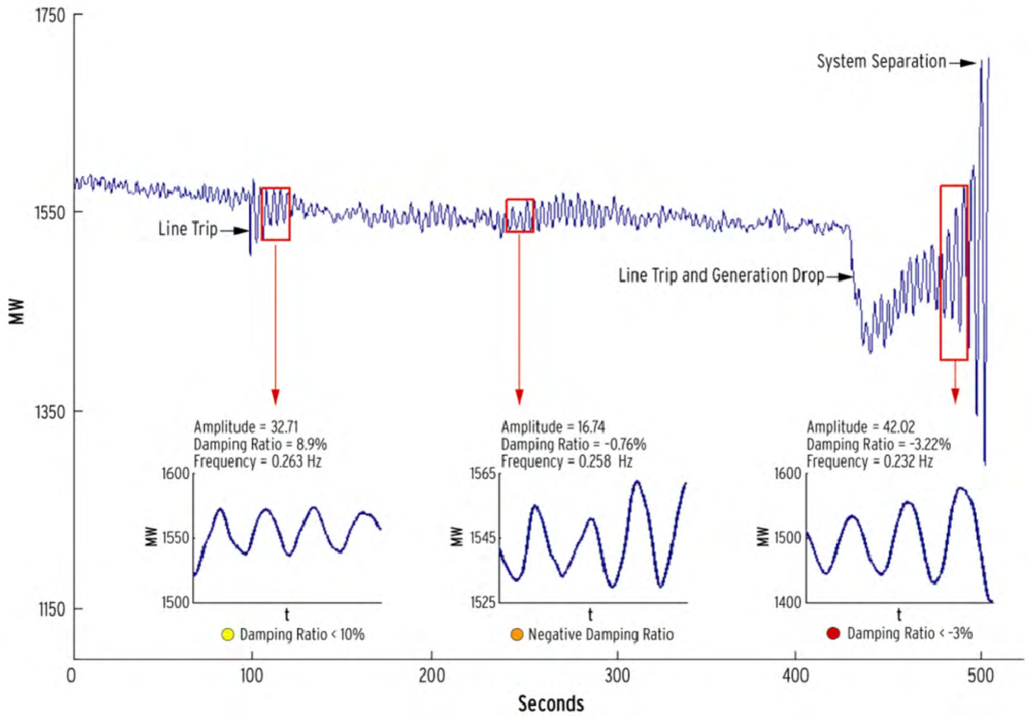

Fig. 14. Malin-Round Mountain power flow during the August 1996 blackout

2) *Phase Angle Difference*

One of the major advantages of using synchrophasors is the ability to provide coherent data from different parts of the network. System operators and engineers require knowing the trends of voltage phase angle differences among coherent groups of generators and major interconnections to monitor the stability of the system. The phase angle difference also provides knowledge to the system operators on the available power transfer margin. We cannot obtain precise high-resolution voltage phase angle differences using SCADA-based measurements. Fig. 15 shows the voltage phase angle difference during the disturbance between the sites where PMUs were installed.

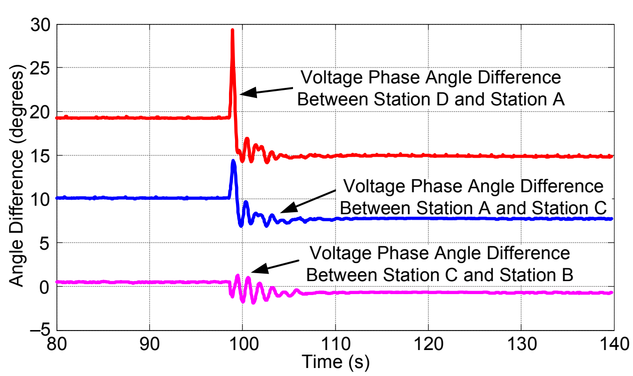

Fig. 15. Angle difference between Station D and Station A is greatest compared to the angle difference across other stations

VI. Conclusions

Synchrophasors provide high-speed (subsecond) coherent data that are not available with traditional SCADA measurements in order to monitor power system dynamics. The following items highlight the details and results of the PGCIL installation:

- PGCIL installed one of the first synchrophasor systems in India as a pilot project to explore the capabilities of synchrophasors. Four PMUs were installed at critical 400 kV nodes on the network; one PDC, along with visualization and analysis software, was installed at the NRLDC.
- Analysis of two major events to compare the relevance and quality of the data showed that one of the frequency measurements from SCADA was off by 70 mHz.
- Asynchronous polling of the SCADA measurements resulted in different frequency measurements. This difference does not exist in the power system, as demonstrated by the synchrophasor frequency measurements.
- Frequency and df/dt measurements in the synchrophasor message were used to validate the operation of underfrequency and df/dt relays.
- Synchrophasors provide information of low-level oscillations; tools are available to calculate oscillation frequency and damping ratio in real time. One test case showed a 2.6 Hz oscillation with a damping ratio of less than 5 percent.
- Synchrophasors provide voltage phase angle difference information that is critical for power system operators to monitor the stability of the power system.

VII. Acknowledgment

The authors gratefully acknowledge Mr. P. K. Agarwal from Power Grid Corporation of India Limited for his contribution to the case studies and his peer review.

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IX. Biographies

Mangapathirao (Venkat) Mynam received his MSEE from the University of Idaho in 2003 and his BE in electrical and electronics engineering from Andhra University College of Engineering, India, in 2000. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2003 as an associate protection engineer in the engineering services division. He is presently working as a lead research engineer in SEL research and development. He was selected to participate in the U.S. National Academy of Engineering (NAE) 15th Annual U.S. Frontiers of Engineering Symposium. He is a member of IEEE.

Ala Harikrishna received his BTech in electrical and electronics engineering from Jawaharlal Nehru Technological University, Hyderabad, India, in 2005. He has experience in process automation, substation automation, building management systems, and control systems. He worked for nearly five years as a field and design engineer in automation systems for several industries. After joining Schweitzer Engineering Laboratories, Inc. in 2008, he has been involved in design, testing, and commissioning of substation integration and automation projects, including synchrophasor and IEC 61850 applications in India.

Vivek Singh received his BE in electronics and telecommunication engineering from Mumbai University, Mumbai, India, in 2005. He has experience in automation, substation automation, and control systems. He worked for nearly five years as a field engineer in automation systems for several industries. Since joining Schweitzer Engineering Laboratories, Inc. in 2008, he has been involved in design, testing, and commissioning of substation integration and automation projects, including synchrophasor and IEC 61850 applications.