Public Interest Energy Research (PIER) Program
FINAL PROJECT REPORT

IMPLEMENTATION OF PHASOR MEASUREMENTS IN SAN DIEGO GAS & ELECTRIC STATE ESTIMATOR

Prepared for: California Energy Commission
Prepared by: Electric Power Group, LLC for
San Diego Gas & Electric

Electric Power Group

MAY 2012
CEC-500-2012-044

Prepared by:

Primary Author(s):
Manu Parashar (Electric Power Group)
Nand Tripathi (Electric Power Group)
Lu Kondragunta (San Diego Gas & Electric)

Electric Power Group, LLC
Pasadena, California 91101

San Diego Gas & Electric Company
San Diego, CA 92112-9831

Contract Number: 500-02-004, MR-053

Prepared for:

California Energy Commission

Jamie Patterson
Project Manager

Mike Gravely
Office Manager
Energy Systems Research Office

Laurie ten Hope
Deputy Director
RESEARCH AND DEVELOPMENT DIVISION

Robert P. Oglesby
Executive Director

Acknowledgements

The Project team would like to thank the Energy Commission's Public Interest Energy Research Program staff and the Energy Systems Integration Office for providing the funding and for their support in conducting this research and implementing phasor measurements into the San Diego Gas & Electric (SDG&E) state estimator. This project was implemented and demonstrated on the SDG&E transmission system under the project leadership of Dr. Lu Kondragunta. Special thanks to SDG&E staff Ms. Anita Hoyos, Mr. Parviz Ebrahimzadeh, Mr. Dan Eklund, Mr. Randy Schimka, and Mr. Charlie Mogannam for their role in facilitating the integration of phasor measurements into their GE State Estimator.

Please cite this report as follows:

Parashar, Manu, et al 2008. *Implementation of Phasor Measurements in SDG&E State Estimator,* California Energy Commission, PIER Program Energy Commission-500-2012-044..

Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Implementation of Phasor Measurements in San Diego Gas & Electric State Estimator is the final report for the Enhancement of State Estimation Results using Real time Phasor measurement Data project (contract number 500-02-004, work authorization number MR053) conducted by San Diego Gas & Electric and Electric Power Group, LLC. The information from this project contributes to PIER's Energy Systems Research Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-654-4878.

Table of Contents

List of Figures

List of Tables

Abstract

The primary objective of the project was to integrate phasor measurement data into the State Estimator on the Energy Management System of San Diego Gas & Electric with a view to improve the quality of the power system state estimation output. A secondary objective was to demonstrate to what extent the improved state estimates would lead to better congestion management, financial benefits and improved reliability on the South West Power Link and particularly at Miguel (western terminus of South West Power Link). The project demonstrated that Phasor Measurement Unit measurements could be successfully integrated with the conventional power system measurements in the State Estimator without any convergence problems. However, only modest accuracy improvements were observed for a well-tuned State Estimator, such as the San Diego Gas & Electric State Estimator. Tests conducted under different scenarios also indicated that phasor measurements are most beneficial to the State Estimator when the conventional power system measurements aren't reliable or are unavailable altogether. It was also observed that poorly calibrated and heavily weighted phasor measurements can degrade the overall State Estimator accuracy. Given the marginal accuracy improvements, the potential for better optimizing generation dispatch adjustments and congestion management costs on the South West Power Link—purely based on these marginal improvements—is small. Alternate methods therefore need to be explored that either further improve the State Estimator accuracy or directly utilize the phase angle information from the Phasor Measurement Units to reassess the available margins.

Key Words: Phasor measurements, state estimator, wide area measurement systems, reliability.

Executive Summary

Restructuring of the electric industry has led to the formation of larger transmission control areas and larger areas of reliability oversight by grid operators. In addition, the competitive market has increased the level of energy transactions in both California and the interconnected, region-wide system. These developments have introduced greater uncertainty into real-time grid operations, along with increased congestion costs on the grid. This uncertainty demands improved real-time information on actual system conditions that can supplement traditional operating tools and guidelines based on off-line studies.

The operators use either off-line load flow studies or classical weighted least-squared State Estimation results to assess the system security in real time. In off-line load flow studies, real-time data is not used and the results are dependent on modeling assumptions used by the operators. On the other hand, least-squared State Estimation results use real-time telemetered data, such as line flows and voltages at the buses. However, unobservable measurements for parts of the system, variation in measurement accuracy and communication channel anomalies introduce errors in the real-time model.

The recent emergence of Phasor Measurement Unit technology has increased by many orders of magnitude the potential capability for real-time wide-area digital data collection by grid operators. With the advancement in phasor measurement technology, accurate time synchronized measurements of the system state (specifically, magnitude and phase data of the voltage and current) are available. Until now, no phase data has been used in the power system State Estimation. The goal of the project has been to use the phasor data, along with the conventional power system measurements, to improve the quality of the power system state estimates within the San Diego Gas & Electric State Estimator and to verify and quantify the improvement. Applications such as the Real Time Contingency Analysis, which use the State Estimation results, will automatically benefit from improvements to the State Estimator. This will help in reliably assessing the security of the system as well as better managing the congestion on San Diego Gas & Electric’s key transmission lines.

The project successfully demonstrated the utilization of phasor measurements from four Phasor Measurement Units installed at critical substations within the San Diego Gas & Electric State Estimator. For a well-tuned State Estimator (such as the San Diego Gas & Electric State Estimator), only modest improvements in the State Estimation accuracy were observed. However, in cases where the conventional measurements aren’t reliable or are unavailable altogether, the State Estimator gained accuracy and robustness from the additional phasor measurements. More significant accuracy improvements can be expected on systems with poor State Estimator and very few conventional power system measurements.

1.0 Introduction

The origin of modern phasor measurement systems can be traced back to the development of the Symmetrical Component Distance Relay (SCDR) in the early 1970's. However, the fact that the SCDR utilized efficient methods of measuring symmetrical components of voltages and currents proved to be very beneficial for other power system applications. In fact, positive sequence voltages and currents of a network are the backbone of most power system analysis programs: load flow, stability, short circuit, optimum power flow, state estimation, contingency analysis, etc. In early 1980's Global Position System (GPS) satellites were deployed in significant numbers, and it became clear that by using GPS time signals as inputs to the sampling clocks in the measurement system of digital relays one would have a very powerful measurement tool, which would be able to provide very accurate measurements for the analysis of power systems.

The research and development of modern Energy Management Systems (EMS) with wide-area measurement systems started after the 1965 Northeast U.S. blackout. EMS includes Supervisory Control & Data Acquisition (SCADA), inter-utility links and network applications. The network applications mainly consist of State Estimator (SE), Power Flow and Contingency Analysis. Utilities plan and operate the power system under their control using SCADA and inter-utility links to collect local and neighboring system real-time data to monitor and control their portion of the power system. The State Estimator plays a pivotal role to acquire the current state of the power system based on real time measurements and to provide input to the contingency analysis program. But it also comes with issues of robustness, availability, accuracy and maintenance. Phasor measurements can be very useful inputs to the State Estimator to improve its accuracy and robustness.

The electric power grid in the U.S. has evolved from a vertically integrated system to a mixture of regulated and deregulated competitive market systems. Grid oversight is transitioning from local utilities to an assortment of transmission companies, regional Independent System Operators (ISOs) and Regional Transmission Organizations (RTO's). Regulatory and economic pressures have caused new transmission construction to lag the growth in demand. These forces have increased the utilization of the transmission system with a greater number of transactions and power transfers. The result is an operating environment where operators are faced with quick changing and previously unseen power flow patterns and unforeseeable operational conditions with limited information available for real-time operation and decision-making. Reliable electricity supply is continually becoming more essential for society, and blackouts are becoming more and more costly whenever they occur.

In recent years, there have been major blackouts in North America, Europe and Asia. The August 14, 2003 blackout in the Eastern Interconnection impacted 50 million people. Recommendations from the investigation of this blackout carried out by the U.S .—Canadian Power Systems Outage Joint Task Force included the need for wide-area visibility and situational awareness to detect and address problems before they propagate, the use of time synchronized data recorders, and better real-time tools for operators and reliability coordinators. In recent years, utilities in North America have deployed Phasor Measurement Units (PMUs) in their substations to measure the voltage and current phasors (both magnitude and phase angle). These measurements are very accurate and can be used as input to the State Estimator to improve its accuracy and robustness.

This document describes testing and implementation of phasor measurements in San Diego Gas & Electric (SDG&E) Company's State Estimator. Section 2 describes evolution of phasor measurements, Section 3 presents theory of State Estimator with phasor measurements, Section 4 provides the steps in the implementation of phasor measurements in SDG&E-SE, Section 5 presents test results, conclusions and discussion of the results are summarized in Section 6, and Section 7 respectively, and test results in tabular form are given in Appendix 1.

2.0 Evolution Of Phasor Measurements

Phasor Measurement Unit's have their origins amongst the computer relaying developments in the 1960-70's; they are direct descendants of Symmetrical Component Distance Relay's (SCDR's) introduced in the late 1970's.[1,2] Furthermore, the additional ability of time-synchronizing these measurements across the power system to provide a system-wide snapshot across the entire grid on a common reference axis has tremendous potential in power system applications. Sources of synchronization have included pulses, radio, Geostationary Operational Environmental Satellites (GOES), and more recently GPS.
The first PMUs were developed at Virginia Tech in the early 1980's under funding from various agencies such as the U.S Department of Energy (U.S. DOE), Electric Power Research Institute (EPRI), and the U.S. National Science Foundation (NSF). Early prototypes were installed on the Bonneville Power Administration (BPA), American Electric Power (AEP), and New York Power Authority (NYPA) systems. Macrodyne designed and built the first commercial unit based on these original concepts.[3]

One of the first applications of PMUs was event post-mortem analysis. Two major projects demonstrated the utilization of GPS-synchronized power system measurements in North America. In 1992, EPRI sponsored a phasor measurements project using commercially available PMUs to collect GPS-synchronized measurements for analyzing power system problems. In 1995, BPA and the Western Area Power Administration (WAPA), under the U.S. DOE's and EPRI's sponsorship, launched the Wide Area Measurement Systems (WAMS) project to demonstrate the use of GPS-synchronized measurement systems over a large area. The project was timely in that real time measurements taken during the July 2, 1996 and August 10, 1996 power system breakups and blackouts within the Western U.S. proved to be immensely valuable in post analysis and assessment. PMU data was also useful for post-mortem analysis of the August 2003 US blackout.[4]

Phasor measurement based systems, algorithms, and applications have been researched and prototyped in the lab and test environments for the last 20 years, and have reached a level of maturity where they are ready to transition into real time operational environments, providing the industry with new tools and applications to tackle reliability management and operational challenges faced by system operators, reliability coordinators and utility engineers. This has been a major focus of the Eastern Interconnection Phasor Project (now the North American SynchroPhasor Initiative or NASPI)—a U.S. DOE and Consortium for Electric Reliability

---

1 A.G. Phadke, "Synchronized Phasor Measurements – A Historical Overview," IEEE

2 Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES Volume 1, Issue, 6-10 Oct. 2002 Page(s): 476 – 479.

3 Ibid

4 A.G. Phadke, "Synchronized Phasor Measurements," IEEE Computer Applications in Power", April 1993.

Technology Solutions (CERTS) initiative that was started in 2002—to deliver immediate value of phasor technology within North America. The U.S. DOE has funded research of the Real Time Dynamics Monitoring System™ (RTDMS)[5,6], which is currently the primary tool in place to provide visualization and phasor based actionable information in real time to operators and reliability coordinators within the Eastern and Western U.S. Interconnections.

Other applications currently under research and demonstration include feedback control (HVDC controller, Excitation controller, Power System stabilizer, FACTS controller, etc.), and wide-area protection schemes (where the inputs may be derived from protection systems, and outputs of protection systems are used to execute the controls).

State estimation is envisioned as another natural real-time application of PMU's as it directly measures the synchronized positive sequence voltage and currents, thus shifting the emphasis from 'state estimation' to 'state measurement'.[7] Incorporation of phasor measurements in SD&E-SE is the main theme of this document as described in the following section.

---

5 ™Built upon GRID-3P platform. Electric Power Group. U.S. Patent 7,233,843. All rights reserved.

6 I.W. Slutsker, S. Mokhtari, L.A. Jaques, J.M.G. Provost, M.B. Perez, J.B. Sierra, F.G. Gonzalez, J.M.M. Figueroa, "Implementation of phasor measurements in state estimator at Sevillana de Electricidad," Power Industry Computer Application Conference, 1995. Conference Proceedings, 1995, pp. 392 –398.

7 A.G. Phadke, "Synchronized Phasor Measurements – A Historical Overview," IEEE

3.0 State Estimator With Phasor Measurements

A timeline of phasor measurements' developments and their integration in SE was discussed in .[8] This section describes traditional SE and methodology for integrating of phasor measurements in SE used for tests at SDG&E.

3.1. Traditional SE

Basic theory for the Static Power System State Estimation was developed in the 1970's and it has been used in Energy Control Centers for almost three decades.[9] Figure 1 shows a flow diagram of the traditional SE.

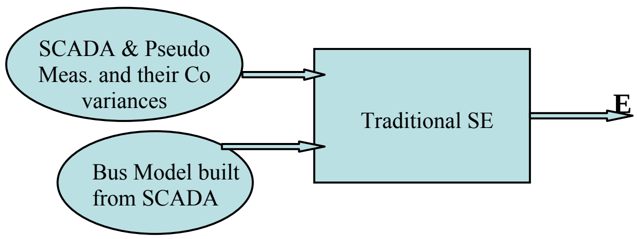


Figure 1. Traditional State Estimator

where:

SCADA Measurements consist of breaker status and tap positions; unit Megawatts (MW), Megavolt Ampere Reactive (MVAR) & voltages; Line & Transformer MW, MVAR & Currents; and Bus Voltages. It also includes measurements from neighboring utilities.

Pseudo Measurements consist of forecasted load and unit output (MW, MVAR), unit voltages and

E is the state vector solution.

The theory of weighted least square (WLS) is very well known, but for completeness, a brief description is given here.[10,11] Equations (1) and (2) below describe the iterative process to find the state vector E or x_{k+1}:

$$\Delta x_k = (H^T R^{-1} H)^{-1} H^T R^{-1} \Delta z_k \qquad (1)$$

and

8 M. Parashar, J. Dyer, T.Bilke, "EIPP Real-Time Dynamics Monitoring System," Proceedings of the 39th Annual Hawaii International Conference, Kauai, Hawaii, January 4-7 2006.

9 C. Martinez, M. Parashar, J. Dyer, J. Coroas, "Phasor Data Requirements for Real Time Wide-Area Monitoring, Control & Protection Applications" EIPP White Paper, Jan. 26, 2005

10 Ibid

11 F.C. Schweppe, "Power System Static State Estimation Part I: Implementation," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-89, No. 1, January 1970, pp. 130- 135.

$$x_{k+1} = x_k + \Delta x_k \quad (2)$$

where $\Delta z_k = [z - h(x_k)]$ is the residual vector, z being the measurement vector, $H= \partial h/ \partial x|_{x= x_k}$ is the measurement Jacobian and suffix k represents value at k^{th} iteration and R is the measurement error covariance matrix. The gain matrix $G= H^T R^{-1} H$ is not inverted; rather, (1) is solved using sparsity techniques involving factorization of G. The more advanced techniques have been developed to factorize this matrix such as the Givens Rotations, which allows wider selection of covariance matrix R elements for a better solution of SE.

After the solution convergence all measurement estimates are calculated and the algorithm performs anomaly (bad data) detection.

The entire network may not be observable by the real time measurement set provided to the state estimator. The following techniques are used to solve the internal (observable) and external (unobservable) portion of the network:

> ***Two-pass SE*** – The network is solved in two steps: internal by WLS and the external by either power flow or by another WLS method.
>
> ***Single-pass SE*** - The entire network is solved by one SE. The network is made observable by adding pseudo measurements for the external system.

Over the years, more sophisticated methods have been developed for anomaly detection, measurements weight assignment, and matrix factorization by researchers, vendors, and utilities. With all these enhancements, traditional-SE still remains the most accurate method of determining the power system state in the Energy Management Systems.

3.2. Integration of Phasor Measurements used with Traditional SE

Traditional SE, as described in Section 3.1, uses SCADA measurements and forecasted pseudo measurements. Synchronized measurements with the same time stamp as SCADA are added to the traditional SE measurements set. Weighted Least Square Algorithm is modified to support the additional phasor measurements. The algorithm requires little changes to incorporate the processing of phasor measurements.[12] The main modification is the addition of new rows to the Jacobian Matrix for participating phasors. These changes also depend on the method of reference selection when phase angle measurements are present. The following are major issues faced by the state estimators in this approach:

- Reference bus selection
- Assigning proper weights to the phasor measurements
- Bad data detection

All these issues are discussed below.

12 A.J. Wood, B. Wollenberg, Power Generation, Operation and Control, John Wiley and Sons, Inc., 2nd edition, 1996.

Traditional state estimation problem is commonly formulated by choosing a reference bus (which is typically the same as the slack bus used for the power flow analysis, but can in general be any bus in the system) and setting its voltage phase angle equal to zero. This also implies that the reference phase angle will be excluded from the state vector and the corresponding column of Jacobian will be removed when building the measurement Jacobian. Different methods for reference selection are described below.

<u>*SE reference bus without a phasor measurement*</u> – In this method a bus without a phasor measurement is selected as the reference bus and "phasor angle differences" are used as measurements. The non-zero terms are added in the Jacobian as shown below:

$$\delta pmu_i - \delta pmu_j = \theta_i - \theta_j \qquad (6)$$

where $i,j=1:N_{pmu}$; $j \neq i$ (i and j are buses with phasor measurements), and

N_{pmu} is the number of PMUs.

θ_i and θ_j are the corresponding SE bus angles for bus i and j respectively.

$\partial(\delta pmu_i - \delta pmu_j)/\partial\theta_i = 1$ is the only non-zero term in i^{th} row and

$\partial(\delta pmu_i - \delta pmu_j)/\partial\theta_j = -1$ in j^{th} row of the Jacobian Matrix.

In the 5 bus example given in Figure 2, bus 1 to 4 has phasor measurements and bus 5 is the reference bus for SE. In this case, equation (6) will have 6 independent angle difference equations for: $\delta pmu_1 - \delta pmu_2$, $\delta pmu_1 - \delta pmu_3$, $\delta pmu_1 - \delta pmu_4$, $\delta pmu_2 - \delta pmu_3$, $\delta pmu_2 - \delta pmu_4$ and $\delta pmu_3 - \delta pmu_4$.

Here, the standard deviation of $\delta pmu_i - \delta pmu_j$ should be used to assign the measurement weight in this formulation. It should also be noted that anomaly detection can be done only on $\delta pmu_i - \delta pmu_j$, and it may not be possible to find the individual phase angle anomalies unless some special methods are developed.

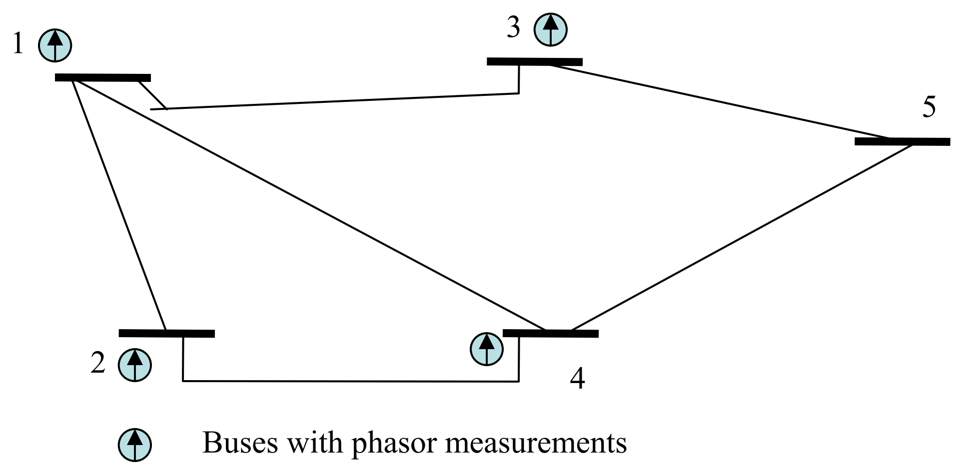


Figure 2. Example for Reference Selection

SE with phasor measurement as a reference bus[13] – This is a special case of the above mentioned technique where a bus with phasor measurement (δpmu_1) is selected as the reference bus and all differences are taken with respect to this angle:

$$\delta pmu_i - \delta pmu_1 = \theta_i - \delta pmu_1 \quad \text{or} \quad \delta pmu_i = \theta_i \qquad \text{for } I = 2: Npmu \tag{7}$$

The Jacobian is modified so that for each other phasor measurement, a partial derivative of phasor measurement with respect to angle variable of its bus is added as the only non-zero term in the row as shown below.

$$\partial \delta pmu_i / \partial \theta_i = 1 \tag{8}$$

Here, the standard deviation $\delta pmu_i = \sqrt{2}\sigma_i$ and appropriate weight can be assigned for the difference where σ_i is the standard deviation of δpmu_i.

In the 5 bus example (Figure 2), if δpmu_1 is selected as the reference then only the following 3 independent equations are added: $\delta pmu_2 = \theta_2$, $\delta pmu_3 = \theta_3$ and $\delta pmu_4 = \theta_4$.

In a method was also developed for error detection at the reference bus.[14] If this measurement is anomaly then it is discarded, the bus with phasor measurement having least residual is selected as the next reference bus and SE is resolved. Siemens Energy management team implemented this method at Spanish utility- Sevillana de Electricidad in 1995.

---

13 A.J. Wood, B. Wollenberg, Power Generation, Operation and Control, John Wiley and Sons, Inc., 2nd edition, 1996.

14 Ali Abur, Eastern Interconnection Phasor Project Working Group Meeting, Chattanooga, TN, April 20, 2005, http://phasors.pnl.gov/Meetings/2005_april/presentations/Abur%20PMU-Placement.pdf.

4.0 Implementation Of Phasor Measurements In SDG&E State Estimator

This section describes phasor measurements locations and integration of these measurements in SD&E-SE.

4.1. Phasor Measurement Locations

There are four Phasor Measurement Units or PMUs (i.e., SEL 421 relays with synchrophasor measurement capabilities) installed at critical substations –Mission 230 kilovolts (kV), Miguel 230 kV, Sycamore Canyon 230 kV, and Miguel 500 kV (a fifth test PMU is also installed in the lab at the Mission 500 kV station). The locations of these PMUs are shown Figure 3. These devices sample analog voltages and currents data in synchronism with a GPS clock, and compute the corresponding phasors required for the improvement in the quality of state estimation.

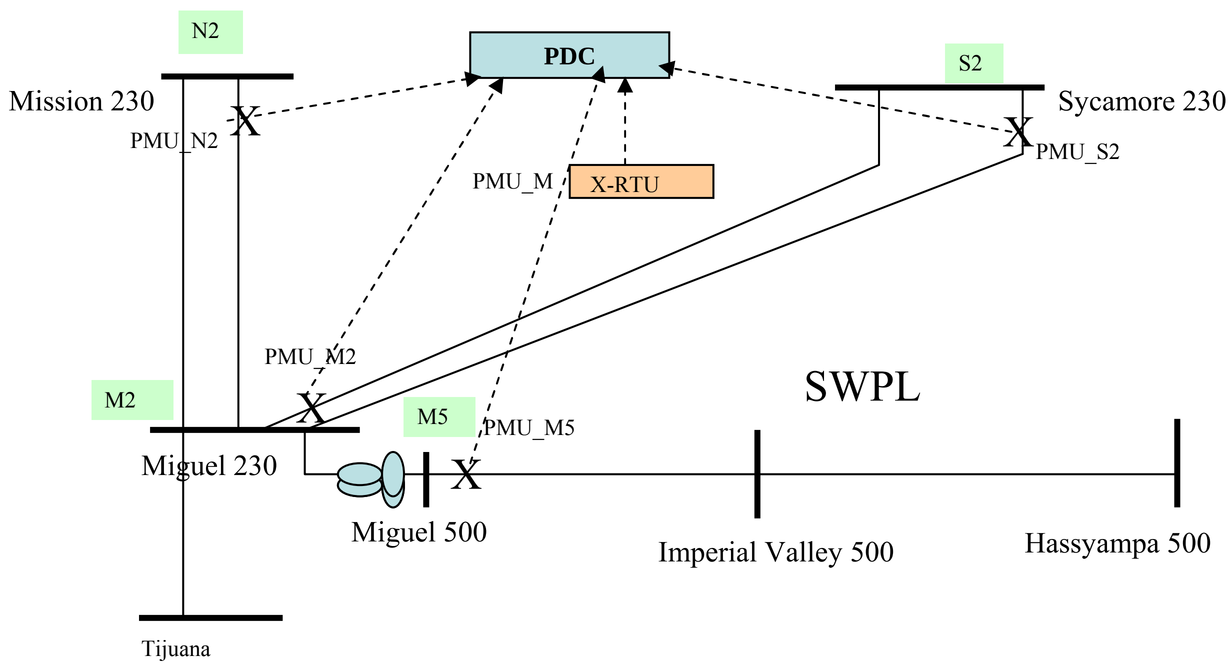


Figure 3. Phasor Measurement Locations in SDG&E

These four PMUs transmit data in real time to the Phasor Data Concentrator (PDC) (SEL 3306) located at the Mission Control Center (MCC) which is a logical unit designed to collect phasor data from all the networked PMUs, align the data based on the timestamps associated with the measurements, and transmit the aggregated synchronized data stream to other applications. This is done at the very high sub-second rate.

Within the overall system architecture, the real-time streaming data from the PDC is archived in the OSIsoft's PI Data Historian that serves as the phasor data repository for the SDG&E Energy

Management System (EMS) and the intermediary gateway for getting in into State Estimator (Figure 4). The necessary PDC-PI interface development was completed by OSIsoft and was successfully tested with the SEL 3306 at the SEL facilities in early March, 2007. In order for this PDC-PI integration to function properly, several minor technicalities had to be considered (such as, PI naming conventions, name tags, data quality tags, etc.) along with the cyber security and firewall related issues associated with the PDC-PI installation and connectivity.

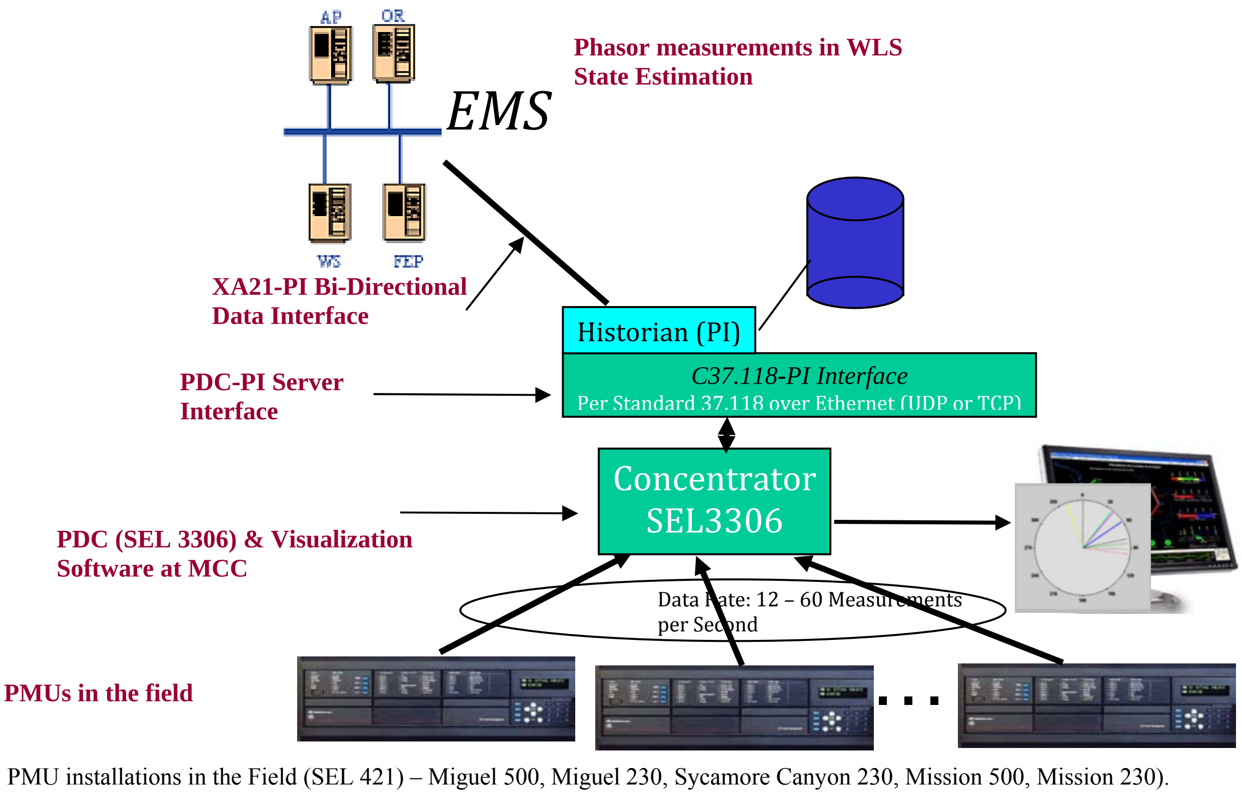


Figure 4. Overall System Architecture

4.2. Integration of Phasors Measurements in SE

The phasor measurements were integrated in SDG&E's GE XA/21 EMS system using a Bi-Directional Data Interface which GE developed to interact with the PI Historian with the following considerations:

- The proposed approach for retrieving from the Data Historian and integrating them within the State Estimation (SE) process is to the RTU functionality.
- The approach tries to utilize existing infrastructure without re-inventing the wheel.
- The system shall be capable of reading up to 100 Phasor measurements at one instance from the external system as often as once a second with a maximum of 10 extraction schedules specified.

- To merge phasor measurements (i.e., voltage angle differences, voltage magnitudes and current magnitudes), the Real-Time Performance Database (PDB) shall be synchronized with the state estimator such that the run of state estimator picks up measurements from a single time stamp. In particular, for each data set, the data reads are based on a pre-specified periodicity on demand, or based on a configured event trigger at which point (1) data with identical timestamps is read across all items in the set, (2) calculations are performed if needed (e.g., angle difference calculations), and (3) the results are stored in the associated XA/21 SCADA points within the Performance Data Base or marked ***non-update*** if the read is unsuccessful.
- The system is also able to block specified applications during this retrieval and writing to the PDB process to preserve time-synchronization and prevent data corruption if these applications were allowed to execute during the data update process.
- The system has the ability to define ***sets*** (or ***groups***) of SCADA points that are to be read from the Data Historian and the periodicity at which a given set is obtained – i.e. "RTU" type data retrieval functionality where the user defines what data is needed and the frequency. Other information associated with each group are the application(s) names that need to be blocked during SCADA point updates, a flag to donate raw or engineering units, a status point reference to allow the activation or deactivation of a group, and an optional phase angle reference point. Each SCADA point includes both input points (i.e., both phasor measurement and associated reference points) and output points (i.e., the angle difference).
- The SE application reads all XA/21 SCADA points from PDB, runs the state estimation process and writes the results back out to the PDB as needed. When the SE is blocked from reading phase angle differences, it shall retry a configurable number of times with a configurable delay between entries. If all these retries are exceeded, then the SE will retrieve all other available analog measurements and continue with the state estimation process. The SE shall mark the calculated phase angle differences as ***Not Used*** for current execution. However, if a try is successful, then all these phasor measurements are processed in the same manner as the other SE measurements.

Note: The above mentioned functionality can be applied to any value stored within the Data Historian and is not just limited to reading WAMS data.

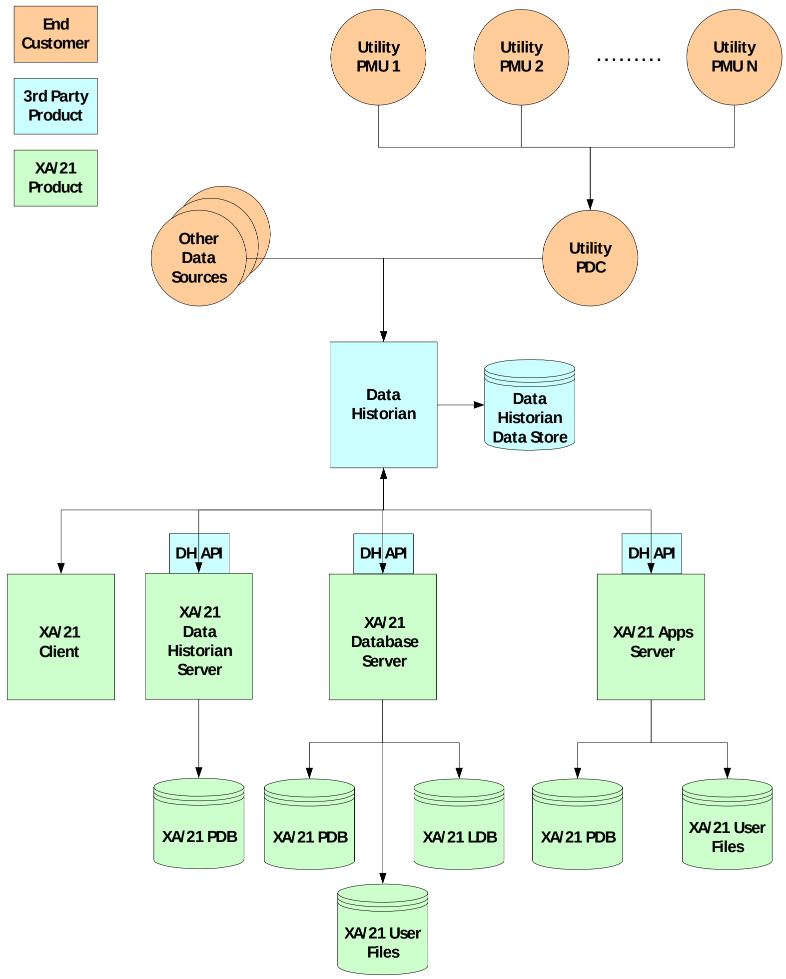


Figure 5. Integration of Phasor measurements with SDG&E SE.

4.3. SE Algorithms with Phasor Measurements for SDG&E

The State Estimator at SDG&E-EMS is a traditional weighted least square method that solves the network in two passes, and originally used SCADA measurements only. The network model consists of 1,775 buses (300 internal, 1,475 external buses) and 2,670 series branches (1,470 lines, 1,100 transformers). For this project, GE also enhanced the SDG&E SE to utilize phasor measurements along with the SCADA measurements by incorporating the methodology described in section 3.2 into their SE.

4.4. Weight Assignments for Phasor Measurements

In the basic state estimator theory a measurement confidence is assigned based on the meter error and the full scale value as follows:

$$3\sigma_i = \text{Full scale value of the meter x \%error/100} \quad (9)$$

where σ_i is the standard deviation of the i^{th} meter error and

The Measurement confidence or weight = $1.0/ (\sigma_i \times \sigma_i)$ (10)

For phasor measurements, maximum error is 1 microsecond which translates to 0.021 degrees and we used σ for phasor measurements 0.1 and 0.03 for testing which corresponds to maximum error of 0.3 and 0.09 degrees respectively.

The original values of sigmas are 1 for 500 kV measurements and for the rest of measurements. For comparison, σs for SCADA measurements were: for 500 kV lines= 12, 230 kV lines=10, 138 kV lines= 5 and 69 kV lines= 4.

5.0 Test Results

This section summarizes the test plan and test results for evaluating the SE performance improvements with phasor measurements.

5.1. Test plan

A test plan with test steps and the test results summary is shown in Table 1.

Table 1- Test Plan Summary

STEP NO.	TEST	TEST RESULTS
1	Ensure phasor measurement data is available in SE.	SE input tables were checked to verify the phasor measurement data.
2	Verify the validity of phasor measurements within state estimator – compare angle differences between SynchroWAVe and SE for a given timestamp.	Tested Successfully- SE angles were found comparable with phasor measurements.
3	Verify that these measurements can be disabled by the user.	Tested Successfully- disabled measurements were not used by SE.
4	Verify that measurements' confidences can be changed by the user.	Tested Successfully- could easily change the measurement confidences for various tests.
5	Run State Estimators under different conditions such as with and without phasors measurements, etc.	Test results are shown in appendix

5.2. Test Results

Table 2 in Appendix 1 shows the test results of SE under various test scenarios. The key observations from these tests are described as follows:

Test 1—with original sigmas of SDG&E (for 500 kV measurements σ =1 and it is 2 for all other measurements) and σ = 0.1 for phasor measurements.

By adding PMU measurements % error on key lines flows goes down by up to 0.39% (for example, on the M5-M2 Transformer, the original error was 0.74%. Incorporating the PMU measurements reduced it to 0.34%).

Test 2—with relaxed sigmas based on meter errors as discussed in section 4.4 so that 3σ =full scale value of the meter x error% and Phasor σ = 0.1.

In this case improvement in error % further improved by up to 0.99% - i.e. the SE further benefits from the PMU measurements when there is lower confidence in the SCADA measurements (for example, on the N2-M3 line, the PMU measurements further reduced the error to 0.54%).

Test 3—sigmas as in test 3 and SCADA measurements blocked at sub-stations with phasor measurements.

In this case maximum improvements in estimates are obtained as expected; %error goes down by up to 3.92% by adding PMU measurements. Hence, at locations where SCADA measurements are unavailable, the PMUs offer the most benefit.

Test 4—SCADA measurement sigmas as in test 3 and phasor measurements σ's = 0.03.

In this case the results improve as well; %error goes down by up to 2.1% by adding PMU measurements - the SE further benefits from the PMU measurements when there is greater confidence in the PMU measurements.

In general, the PMU measurements offer most promise when the reliability of the SCADA measurements is low and/or when SCADA measurements are unavailable.

Additionally, a second set of tests were also conducted. In these tests SE was run with different scenarios such as SCADA+PMUs, SCADA only, PMUs only and no SCADA and no PMUs. These test results are given in APA-Table 3 in Appendix A. It should be noted, however, that there was up to a 0.5 degree error between the SE and the Phase angle measurements. This relatively large discrepancy resulted in larger than expected errors when the PMU measurements were used in the state estimation process, making the overall results of this test inconclusive. The test does demonstrate how inaccuracies in the phasor measurements resulting from poor calibration for example can actually have a negative impact on SE and degrade its overall accuracy.

6.0 Conclusions

From the results of Tables 1, 2, 3 and Test Results of Section 5.2 the following conclusions are drawn:

1. All PMU measurements were successfully integrated with the SCADA measurements for the use in the SDG&E State Estimator and continue to be utilized in daily operations.
2. Using phasor measurements obtained from digital relays with synchrophasor capability yielded comparable State Estimator results but at lower cost than installing new, dedicated PMU's for this purpose.
3. The Traditional State Estimator ran without any convergence problems with phasor measurements.
4. Using a non-PMU reference bus and PMU angle differences as measurements in a traditional-SE gave no problems either in convergence or in accuracy of the solution. SE output was also successfully used by other applications such as Contingency Analysis and Power Flow.
5. State Estimator was run with various weight assignments to SCADA and phasor angle measurements and all results were consistent with slight change in the solution. Accuracy did improve by proper assignment of weights as shown in Tables 2 and 3. However, the improvement in accuracy was not significant as expected. This can be attributed to the small number of phasor measurement locations implemented and/or the effect of adding these measurements to an already well tuned SE at SDG&E.
6. It was observed that the phasor measurements are most beneficial when SCADA measurements aren't reliable (i.e., low confidence in the SCADA measurements) or unavailable altogether. In such scenarios, the SE accuracy and robustness gain from the additional phasor measurements.
7. Poorly calibrated and heavily weighted Phasor Measurements can however degrade the overall SE accuracy.

The overall conclusion is that phasor measurements can easily be integrated with SCADA measurements and used in traditional- SE. Conventional-SE seems to be a preferred method for the integration of phasor measurements in SE by commercial software developers. More tests with well placed PMUs are required to confirm the accuracy results as claimed by researchers that "accuracy of state estimation improves drastically by strategically placing PMUs at 10% of the network buses".[15]

15 Methodologies for Incorporating Phasor Measurements Into state Estimators- a Survey Report submitted by Electric Power Group to California Public Service Commission, January 2008.

7.0 Discussion of Results

The goal of this project was to integrate Phasor measurement data into the State Estimator on the Energy Management System of SDG&E with a view to improve the quality of the power system state estimation output. Many applications, such as the Real Time Contingency Analysis, as well as offline analysis studies use the state estimation results as input. Any improvements to the state's estimation process would therefore automatically benefit downstream applications.

South West Power Link (SWPL) is a major tie line interconnecting SDG&E with major neighboring areas, Arizona Public Utilities, Salt River Project, Imperial Irrigation District and Comisión Federal de Electricidad. Due to inaccurate measurements and modeling errors of the neighboring areas, it is flagged often for congestion, limiting the import capability of SDG&E. Hence, a secondary goal of Phase 2 of the project was to utilize the improved state estimates for SDG&E's system to better optimize generation dispatch adjustments and costs associated with congestion management.

The results from the SE trials with and without phasor measurements suggest that while phasor measurements do improve the accuracy of the SE results, these improvements are in the order of a fraction of a percentage. It was only when the SCADA measurements at PMU locations were blocked that the accuracy improvements were on the order of 1-2%. The implication is that significant accuracy gains with phasor measurements can be expected with PMU installations primarily at locations where there is either poor observability with the conventional SCADA measurements, the SCADA measurements aren't reliable, or those SCADA measurements don't update as often (e.g., measurements from the external system). Some of the reasons for the modest improvements are due to:

- SDG&E being a small system with about 70% metered and observable by SCADA measurements.
- SDG&E's two pass WLS estimator is well tuned and robust providing highly accurate estimates.
- The number of phasor measurements is very small in number.

More significant accuracy improvements would be expected on systems with poor WLS estimators and very less number of SCADA measurements.

Given the small accuracy improvements, the potential for better optimizing generation dispatch adjustments and congestion management costs on the on SWPL purely based on these marginal improvements is small. Alternate methods need to be explored that either further improve the SE accuracy or directly utilize the phase angle information from the PMUs to reassess the available margins. These include:

- Installing additional PMUs to increase the percentage of available phase angle measurements in relation to the conventional SCADA measurements.
- Exploring methodologies for utilizing the current phasor measurements (in addition to the voltage phase angles) that are also available from the PMUs within the SE process.
- Evaluate the possibility of computing margins in terms of phase angles & angle differences across critical corridors rather than the traditional MW flows on these corridors.

8.0 Glossary

Acronym	Definition
AEP	American Electric Power
BPA	Bonneville Power Administration
EMS	Energy Management System
EPRI	Electric Power Research Institute
FACTS	Flexible Alternating Current Transmission Systems
GE	General Electric
GPS	Global Positioning System
GOES	Geostationary Operational Environmental Satellites
HVDC	High Voltage Direct Current
ISO	Independent System Operator
kV	Kilovolt
MCC	Mission Control Center
MVAR	Mega Volt Ampere Reactive
MW	Megawatt
NSF	National Science Foundation
NYPA	New York Power Authority
PDB	Performance Database
PDC	Phasor Data Concentrator
PMU	Phasor Measurement Unit
RTDMS	Real Time Dynamics Monitoring System
RTO	Regional Transmission Organization
SCADA	Supervisory Control & Data Acquisition
SCDR	Symmetrical Component Distance Relay
SDG&E	San Diego Gas & Electric
SE	State Estimator
SEL	Schweitzer Engineering Laboratories

Acronym	Definition
SWPL	South West Power Link
U.S. DOE	United States Department of Energy
WAMS	Wide Area Measurement System
WAPA	Western Area Power Administration
WLS	Weighted Least Square

9.0 References

1. A.G. Phadke, "Synchronized Phasor Measurements – A Historical Overview," IEEE
2. Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES Volume 1, Issue, 6-10 Oct. 2002 Page(s): 476 – 479.
3. A.G. Phadke, "Synchronized Phasor Measurements," IEEE Computer Applications in Power", April 1993.
4. C. Martinez, M. Parashar, J. Dyer, J. Coroas, "Phasor Data Requirements for Real Time Wide-Area Monitoring, Control & Protection Applications" EIPP White Paper, Jan. 26, 2005
5. F.C. Schweppe, "Power System Static State Estimation Part I: Implementation," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-89, No. 1, January 1970, pp. 130-135.
6. A.J. Wood, B. Wollenberg, Power Generation, Operation and Control, John Wiley and Sons, Inc., 2nd edition, 1996.
7. I.W. Slutsker, S. Mokhtari, L.A. Jaques, J.M.G. Provost, M.B. Perez, J.B. Sierra, F.G. Gonzalez, J.M.M. Figueroa, "Implementation of phasor measurements in state estimator at Sevillana de Electricidad," Power Industry Computer Application Conference, 1995. Conference Proceedings, 1995, pp. 392 –398.
8. M. Parashar, J. Dyer, T.Bilke, "EIPP Real-Time Dynamics Monitoring System," Proceedings of the 39th Annual Hawaii International Conference, Kauai, Hawaii, January 4-7 2006.
9. Methodologies for Incorporating Phasor Measurements Into state Estimators- a Survey Report submitted by Electric Power Group to California Public Service Commission, January 2008.
10. Ali Abur, Eastern Interconnection Phasor Project Working Group Meeting, Chattanooga, TN, April 20, 2005, http://phasors.pnl.gov/Meetings/2005_april/presentations/Abur%20PMU-Placement.pdf.

Appendix A
Test Results

APA-Table 2. Test Results 1

SDG&E SE TEST RESULTS WITH AND WITHOUT PHASORS										
	WITH PMU MEASUREMENTS				WITHOUT PMU MEASUREMENTS			ERRORS		
Measurement name	SCADA Measurement	Estimate	PMU meas	PMU estimate	Angle estimate	SCADA Measurement	Estimate	%error with PMU-meas	%error w/o PMU-mes	%error Diff PMU-w/o PMU
TEST 1: MW(line & transformer Original sigmas values), Phasor Measurement sigma=0.1										
N2-M2 line 23	227.76	223.93	-4.88	-4.99		227.76	223.27	1.68	1.97	-0.29
S2-M2-line 21	238.61	233.11	-3.72	-4		238.61	233.06	2.31	2.33	-0.02
S2-M2-line 41	240.04	233.14				240.04	233.14	2.87	2.87	0.00
M5-M2 Trans	766.92	764.29	-5.5	-4.83		766.92	761.28	0.34	0.74	-0.39
TEST 2: sigmas defined from equation:3*sig=full scale value*error% and sigma phasor meas = 0.1										
N2-M2 line 23	221.7	220.51	-4.78	-4.89	-4.84	221.7	218.32	0.54	1.52	-0.99
S2-M2-line 21	223.65	222.76	-3.51	-3.8	-3.77	223.65	220.95	0.40	1.21	-0.81
S2-M2-line 41	224.69	222.79				224.69	220.97	0.85	1.66	-0.81
M5-M2 Trans	772.8	782.93	-5.49	-4.92	-4.87	772.8	775.14	1.31	0.30	1.01
TEST 3: Sigmas as in test 2 and RTU's at ML,MS and MX blocked(not used in SE), phasor sigma=0.1										
N2-M2 line 23	221.7	228.46	-4.78	-5.04	-5.13	221.7	230.72	3.05	4.07	-1.02
S2-M2-line 21	223.65	223.09	-3.51	-3.79	-3.99	223.65	232.97	0.25	4.17	-3.92
S2-M2-line 41	224.69	223.11				224.69	233	0.70	3.70	-3.00
M5-M2 Trans	772.8	789.63	-5.49	-4.95	-4.85	772.8	769.46	2.18	0.43	1.75
TEST 4: MW(line &trans sigma as in test 2) and Phasor sigma=0.03										
N2-M2 line 23	227.76	228.08	-4.88	-5.05		227.76	222.61	0.14	2.26	-2.12
S2-M2-line 21	238.61	234.87	-3.72	-4.08		238.61	233.36	1.57	2.20	-0.63
S2-M2-line 41	240.04	234.84				240.04	233.39	2.17	2.77	-0.60
M5-M2 Trans	766.92	794.65	-5.5	-4.99		766.92	763.53	3.62	0.44	3.17

%errors = abs ((meas-est)/meas)*100

APA-Table 3. Test Results 2

SE TESTING

			PMU+ SCADA		SCADA		PMU		NO SCADA&NO PMUS	
		Meas	Est	%Error	Est	%Error	Est	%Error	Est	%Error
Angles										
	M2 - M5	-5.26	-4.64	-11.79	-4.65	-11.60	-4.64	-11.79	-4.64	-11.79
	S2-M2	-3.68	-3.92	6.52	-3.94	7.07	-3.88	5.43	-3.9	5.98
	S2-M5	-8.94	-8.56	-4.25	-8.59	-3.91	-8.51	-4.81		
	N2-M2	-6.7	-6.84	2.09	-6.86	2.39	-6.82	1.79	-6.84	2.09
	N2-M5	-11.96	-11.48	-4.01	-11.51	-3.76	-11.46	-4.18	-11.48	-4.01
	N2-S2	-3.02	-2.92	-3.31	-2.92	-3.31	-2.94	-2.65	-2.94	-2.65

BRANCH FLOWS

			PMU+ SCADA		SCADA		PMU		NO SCADA&NO PMUS	
Bus	Device	Raw Meas	Est	%Error	Est	%Error	Est	%Error	Est	%Error
M2	M2-M5 Bk 1	778.68	783.87	0.67	784.01	0.68	783.52	0.62	783.65	0.64
	M2-M5 Bk 2	748.44	744.19	-0.57	744.32	-0.55	743.83	-0.62	743.96	-0.60
	M2-S2 ln21	235.46	231.78	-1.56	232.79	-1.13	229.16	-2.68	230.32	-2.18
	M2-S2 ln41	237.67	231.82	-2.46	232.83	-2.04	229.19	-3.57	230.35	-3.08
	N2-M2 ln22	324.21	319.58	-1.43	312.89	-3.49	318.39	-1.80	318.75	-1.68
	N2-M2 ln23	311.59	311.71	0.04	312.01	0.13	310.64	-0.30	310.98	-0.20
	M2-T2 ln40	-92.8	-92.08	-0.78	-93.45	0.70	-91.22	-1.70	-92.63	-0.18
S2	M2-S2 ln21	-236.4	-230.38	-2.55	-231.38	-2.12	-227.79	-3.64	-228.94	-3.16
	M2-S2 ln41	-233.74	-230.44	-1.41	-231.43	-0.99	-227.84	-2.52	-228.99	-2.03
N2	N2-M2 ln22	-316.27	-315.97	-0.09	-316.27	0.00	-314.8	-0.46	-315.15	-0.35
	N2-M2 ln23	-311.08	-307.12	-1.27	-307.4	-1.18	-306.08	-1.61	-306.41	-1.50

No PMU Measurements

Bus	M2	7.56	M5	12.21
	S2	3.62	N2	0.70

NO SCADA & NO PMUs

Bus	M2	7.53	M5	12.17
	S2	3.63	N2	0.69

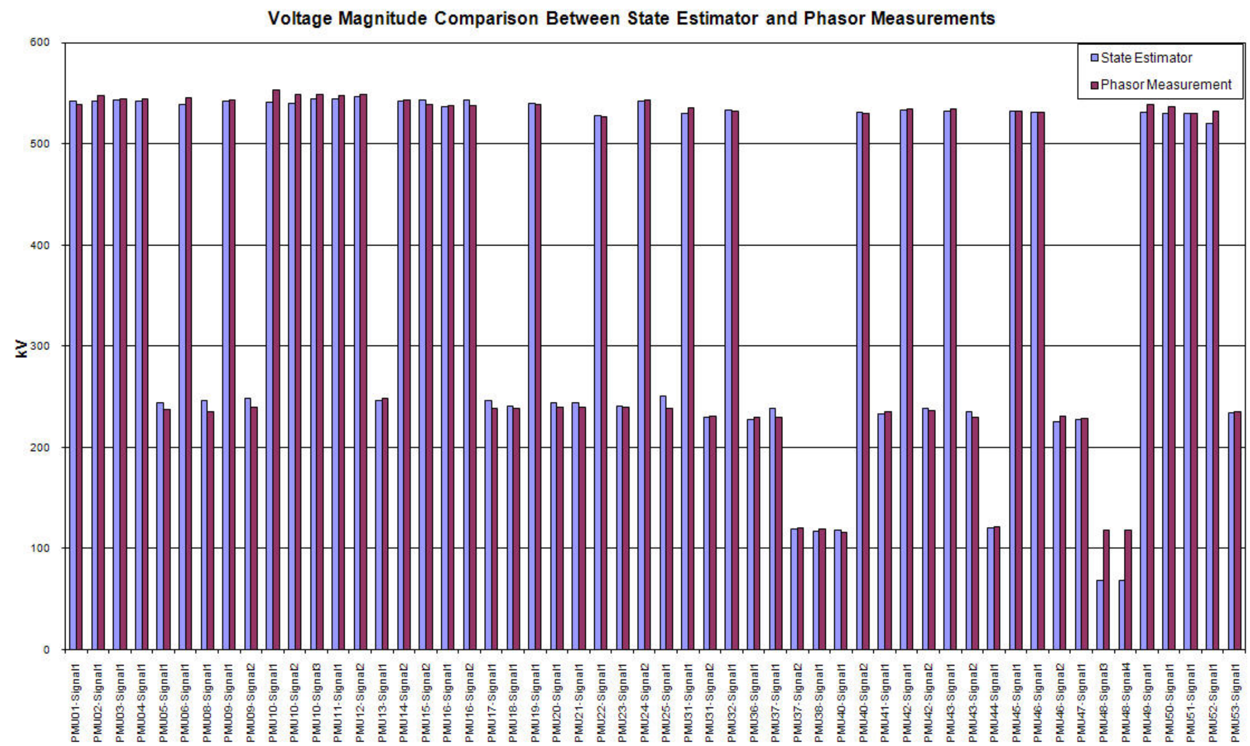
Appendix B
Wide Area Phasor Measurement Comparison

To evaluate an expanded implementation that integrates a larger number of PMUs into a SE with a wider coverage, a WECC-wide comparison of SE snapshot against the Phasor measurements was performed. For this analysis, a phasor data capture containing the complete set of PMU measurements across WECC that are streaming data in real time (~50 PMUs) were used along with a WECC-wide SE snapshot corresponding to the same time instance when the PMU data capture was done. The time instance also corresponded to the peak load condition for that day. To facilitate the comparison, the location that was chosen as the reference bus for PMU phase angle measurements was also used as the reference bus for the SE phase angles. The voltage phase angle and voltage magnitude comparison results are shown in Figure 6. Furthermore, histograms illustrating the mismatch distributions for those comparisons are also shown in Figure 7 *(Note: Aliases have been used for the signal names to preserve the anonymity of the PMU locations).*

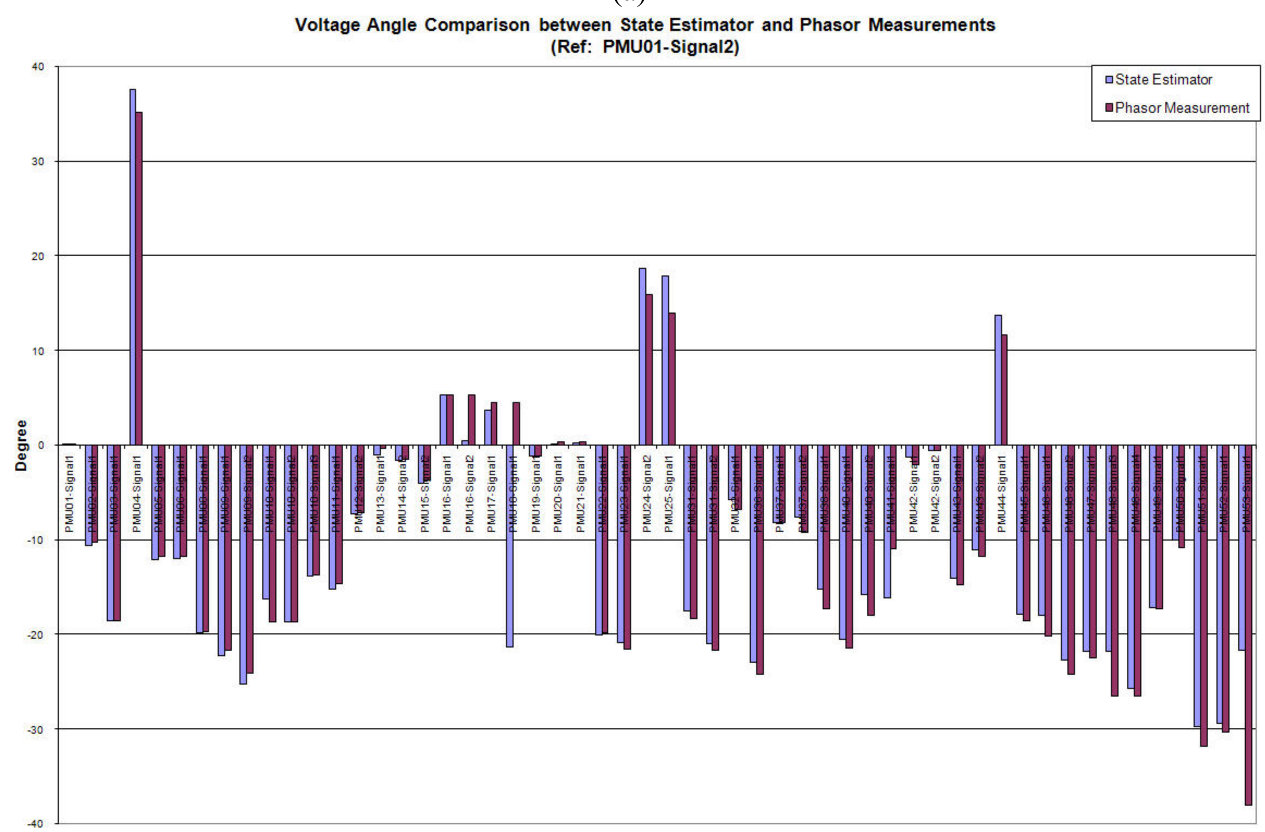
In general, the comparison results show a very close agreement between the PMU measurements and the SE results which speaks to the accuracy of both the WECC phasor network and the SE snapshot. In particular:

- Majority of the PMU voltage magnitudes (39 measurements) were within 0.02 per-unit of the SE results (see Figure 7).
- The two locations where the voltage magnitude mismatch was very significant (~0.7 p.u.) most likely points to incorrect scaling factors that have been suggested for those PMU measurements.
- Majority of the PMU voltage phase angles (35 measurements) were within 1 degree of the SE results (see Figure 7).
- Locations with much larger voltage phase angles were either concentrated within a localized region where the SE modeling perhaps isn't accurate or corresponded to substations at the lower voltage levels where the SE modeling is less detailed.
- The single location where the voltage phase angle mismatch was very significant (~25 degrees) suggests either a PMU wiring discrepancy or an incorrect transformer impedance value in the SE model (the mismatches computed on the high side of that transformer showed much better agreement).

In conclusion, the phasor measurements were found to be very accurate especially since there aren't prone to the modeling inaccuracies that impact traditional SE results. However, as a first step in undertaking a wider implementation of PMU measurement integration into the SE, a comparison of the PMU measurements with the SE snap-shot as was done here should be used to identify locations where the SE model may be inaccurate and needs to be improved. Doing so will guarantee greater benefits when the PMU measurements are directly integrated into the SE process.

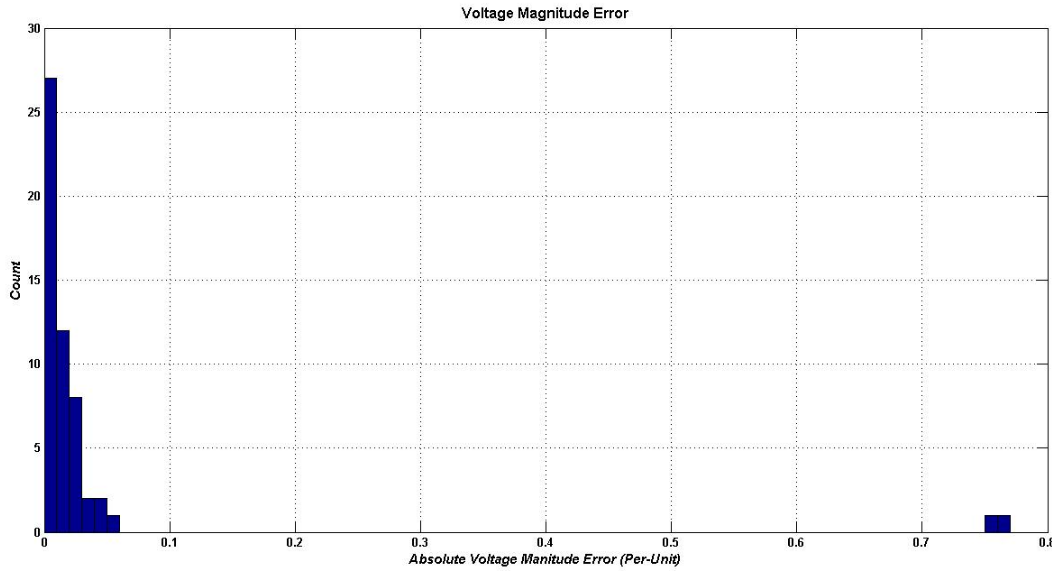


(a)

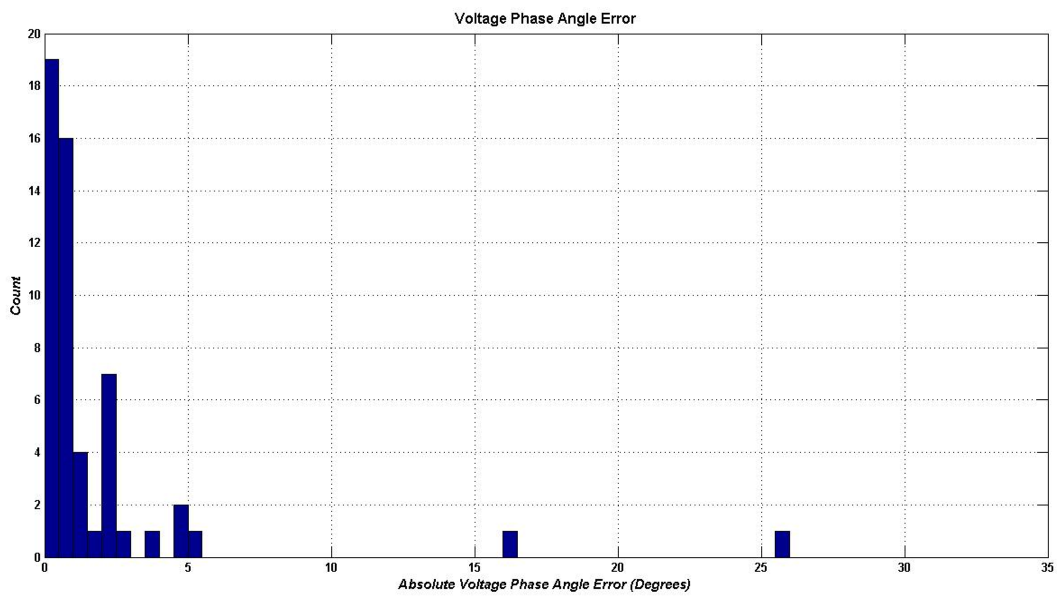


(b)

Figure 6. Comparison of SE snapshot with Phasor measurements: (a) Voltage Magnitude (in kV); (b) Voltage Phase Angle (in degrees).



(a)



(b)

Figure 7. Histogram of the absolute mismatches between SE snapshot with Phasor measurements: (a) Voltage Magnitude (in per-unit); (b) Voltage Phase Angle (in degrees).