Metric #13: Advanced Measurement Systems

M.13.1.0 Introduction and Background

A Wide Area Measurement System (WAMS) describes an advanced-technology infrastructure that is designed to develop and integrate measurement-based information into the grid-management process. The overall infrastructure encompasses measurement facilities, operational support, and data utilization. WAMS measurement facilities that communicate data sampled typically 30 times per second or more are designed to augment those of conventional SCADA over which measurements are "refreshed" at a much slower rate, e.g., once every 4 seconds. Currently used as a complementary system, a WAMS is expressly designed to enhance the operator's real-time "situational awareness," which is necessary for safe and reliable grid operation.[1] In the future, WAMS technologies are expected to be incrementally incorporated into the actual control system of the grid.[2]

WAMS technologies incorporate highly accurate time-synchronized measurements. For example, one type of device known as the phasor measurement unit (PMU) utilizes accurate timing signals transmitted by Global Positioning System (GPS) satellites to determine relative phase angle differences between different locations in the grid. An additional benefit of this instrument class is that the data can be networked to form a wide area view of the overall power system operation.

WAMS has evolved over the past two decades to provide the following functions:[3]

- Real-time observation of system performance
- Early detection of system problems
- Real-time determination of transmission capacities
- Analysis of system behavior, especially major disturbances
- Special tests and measurements, for purposes such as
  - Special investigation of system dynamic performance
  - Validation and refinement of planning models
  - Commissioning or re-certification of major control systems
  - Calibration and refinement of measurement facilities
- Refinement of planning, operation, and control processes essential to best use of transmission assets.

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[1]Hauer JF and JG DeSteese. 2007. *Descriptive Model of a Generic WAMS*. PNNL-17138, Pacific Northwest National Laboratory, Richland, Washington. Accessed October 16, 2008, at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17138.pdf

[2]Hadley MD, JB McBride, TW Edgar, LR O'Neil, and JD Johnson. 2007. *Securing Wide Area Measurement Systems*. PNNL 17116, Pacific Northwest National Laboratory, Richland, Washington.

[3]Hauer JF, WA Mittelstadt, KE Martin, JW Burns, and H Lee. 2006. *Best Practices to Improve Power System Dynamic Performance and Reduce Risk of Cascading Blackouts: Monitoring of System Dynamic Performance*. IEEE Power Engineering Society Task Force on Best Practices to Minimize Blackout Risk. IEEE Power Engineering Society, New York.

Information collected from WAMS is often used to support post-mortem investigations of large-scale blackouts. The disturbance-monitoring function is characterized by large signals and relatively short event records. In addition, precursors to the actual disturbance are often only found in WAMS data, that uniquely provides long records containing small signals with high bandwidth. With complex processing (such as correlation analysis of multiple records) and direct motioning of phase voltages and currents, early warnings of emerging trouble can be found.[4]

IEDs, such as digital fault recorders (DFR) and microprocessor-based protective relays, provide another valuable source of data for establishing an accurate and detailed sequence of events, particularly during the cascading phase of the blackout when events are occurring rapidly.[5]

Digital fault recorders and protective relays are high-speed instruments installed in substations that are designed to measure faults, and in the case of protective relays, act on that information to trip circuit breakers to protect assets from becoming damaged. By capturing the waveform of a fault, detailed information regarding the nature and location of the fault can be calculated, and the proper response of the protective relays and circuit breakers can be confirmed. These devices gather high-speed data and are (usually) synchronized to an accurate time standard. When a large-scale system disturbance occurs, they are an invaluable source of data that is used to support the investigation process, particularly in establishing the timing of events, or confirming the cause of the relay action and breaker trip.

The Common Format for Transient Data Exchange (COMTRADE), IEEE Standard C37.111, is a widely used example of a digital data format for oscillography. Most classes of IEDs that capture high-speed data can export their data in the COMTRADE format. However, the investigation team's access to this data can often be cumbersome. Therefore, it is preferable to consider these issues proactively so that delays during the investigation process can be minimized.

The goal set by DOE[6] in its Report to Congress on the 5-year plan for electric power distribution and transmission was for the grid planners and operators to have the techniques, tools, and technologies needed to operate a smart, reliable grid by 2014. In 2006, real-time data collection was limited to about 100 sensors of various types. The report set an objective of another 100 transmission level sensors by 2009 and deployment of at least 100 distribution-level sensors by 2012.

M.13.2.0 Description of Metric and Measurable Elements

The measurable elements for this metric include:

(Metric 13) the total number of advanced measurement devices: the total number of measurement devices that are networked and are providing useful information at the transmission and distribution levels.

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[4]Hauer et al. 2006.

[5]Dagle JE. 2006. "Postmortem Analysis of Power Grid Blackouts - The Role of Measurement Systems." *IEEE Power & Energy Magazine* 4(5):30-35. Available at http://www.ieee.org/organizations/pes/public/2006/sep/index.html

[6]U.S. Department of Energy (DOE). August 2006. *Five-Year Program Plan for Fiscal Years 2008 to 2012 for Electric Transmission and Distribution Programs. Report to Congress Pursuant to Section 925 of Energy Policy Act of 2005*. DOE, Washington, D.C. Accessed October 16, 2008, at: http://www.oe.energy.gov/DocumentsandMedia/Section_925_Final.pdf

M.13.3.0 Deployment Trends and Projections

There are approximately 165 PMUs installed in late 2008. In the eastern interconnection, there are 104 PMUs with 89 networked and 61 PMUs in the western interconnection.[7] One trade source indicates there were 150 PMUs installed in early 2008 within the eastern and western interconnections[8] up from the 100 PMUs indicated in 2006.[9] Installed and networked PMUs have been increasing as 35 PMUs were installed by June 2006 in the Eastern Interconnection while only 20 PMUs were installed and networked as of January 2006.[10] A study completed by Northeastern University[11] indicated that between 721 and 1300 PMUs would be necessary to address a complete set of applications envisioned for the Entergy network. However, fewer PMUs can provide sufficient information for wide-area visibility for situational awareness of the grid. A NERC technical committee report indicated that at least 500 phasor measurement units would be required to adequately monitor the grid.[12]

Interviews concerning the current prevalence of phasor measurement units and digital fault recorders were conducted for this report (see Annex B). The interviews indicated that 14 of the 21 companies surveyed had altogether 50-75 phasor measurement units, and 10 of the companies had digital fault recorders, 2800-3200 units, altogether. The remaining companies did not report possessing either item. The companies surveyed represent between 200 and 250 GW of substation capacity and between 170 and 190 GW of peak load.

M.13.3.1 Associated Stakeholders

Advanced measurement systems primarily affect transmission providers, distribution service providers and end-users, but they will also reliability coordinators and products and services suppliers. In more detail, they are:

- Transmission providers: need to understand the business case for deploying advanced measurement technology and properly quantify the benefits of this technology to enhance the reliability of the power system.

- Reliability coordinators and the North American Electric Reliability Corporation (NERC) have roles in ensuring grid reliability. They will also need to understand the business case for deployment of the advanced measurement systems.

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[7]Dagle, JE. September 20, 2008. Personal Communications (email) stating the number of PMUs.
[8]Galvan F, L Beard, J Minnicucci, and P Overholt. 2008. "Phasors Monitor Grid Conditions." *Transmission and Distribution World*. Accessed October 16, 2008, at http://tdworld.com/overhead_transmission/phasors_monitor_grid_conditions/.
[9]DOE 2006. *Five-Year Program Plan for Fiscal Years 2008 to 2012 for Electric Transmission and Distribution Programs.*
[10]Widergren SE, Z Huang, JE Dagle. January, 2007. "Electric System-wide Measurements: North American Directions." In *Proceedings of the 40th Hawaii International Conference on System Sciences (HICSS 40), January 3-6, 2007*. Accessed November 24, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=4076613&isnumber=4076362
[11]Galvan F, L Beard, J Minnicucci, and P Overholt. 2008. "Phasors Monitor Grid Conditions." *Transmission and Distribution World*. Accessed October 16, 2008, at http://tdworld.com/overhead_transmission/phasors_monitor_grid_conditions/.
[12]North American Energy Reliability Council (NERC). May 2007. "Technology Committee Minutes May 1, 2007." Accessed September 4, 2008 at: http://www.nerc.com/docs/bot/bottc/TC_0507m_Draft.pdf.

- Distribution service providers will benefit from better customer relations associated with the enhanced grid reliability.

- End users (residential, commercial and industrial) have a stake in anything that could affect power system reliability.

- Products and services suppliers have a role in helping to educate the industry about the need for advanced systems and continued development of the technology.

- Local, state and federal energy policymakers all have a stake in ensuring the reliability of the grid, which has been a significant force behind the U.S. economic engine.

M.13.3.2 Regional Influences

While the basic technology is being deployed throughout the world, there are key regional differences that drive the applications that are sought from advanced measurement technologies. Measuring interregional electromechanical oscillations fueled the early development of WAMS in the western interconnection. First appearing in the grid in the early 1970s when the Northwest region was connected to California through the Pacific Intertie transmission projects, these oscillations were a continuing source of reliability concern and factored prominently in the August 10, 1996 blackout.

Driven by stability considerations, and in an earlier regulatory environment, utilities within the western interconnection made significant progress in the development of monitoring facilities for examining system behavior. This development is a collective response to their shared needs for measurement-based information about system characteristics, model fidelity, and operational performance.[13,14]

Data from WAMS was instrumental in the investigation of that blackout and continues to be a source of knowledge and insight into the western interconnection dynamic behavior. Spiegel et al.[15] indicated there are 54 PMUs integrated across the western interconnection.

Data from PMUs were also instrumental while investigating the August 14, 2003 blackout that affected large portions of the Northeastern United States and Canada. More importantly, the blackout investigation report cited lack of situational awareness as one of the root causes that contributed to the blackout.

The North American SynchroPhasor Initiative (NASPI) is a joint DOE and NERC program to help facilitate the deployment of time-synchronized measurements, including particularly PMUs, throughout North America. NASPI embodies a vision where value is delivered within the operations and planning

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[13]Western States Coordinating Council (WSCC). 1990. *Evaluation of Low Frequency System Response: Study Results and Recommendations*. Report of the WSCC 0.7 Hz Oscillation Ad Hoc Work Group to the WSCC Technical Studies Subcommittee, September 1990.

[14]Hauer JF and JR Hunt (in association with the WSCC System Oscillations Work Groups). 1996. *Extending the Realism of Planning Models for the Western North America Power System*. V Symposium of Specialists in Electric Operational and Expansion Planning (SEPOPE), May 19-24, 1996, Recife, PE, Brazil.

[15]Spiegel L, S Lee, and M Deming. 2007. *Review of Research Projects for Managing Electric Transmission Uncertainty*. Public Interest Energy Research (PIER) TRP Policy Advisory Committee Meeting and California Energy Commission Staff Workshop.

environment using new interregional information and measurement systems. The effort is closely coordinated with industry.[16,17]

Figure M.13.1 shows, as of 2007, the existing and planned PMU deployment locations in North America. There are many PMUs installed that are not networked across organizations not shown on the map, with many more projected in the future.

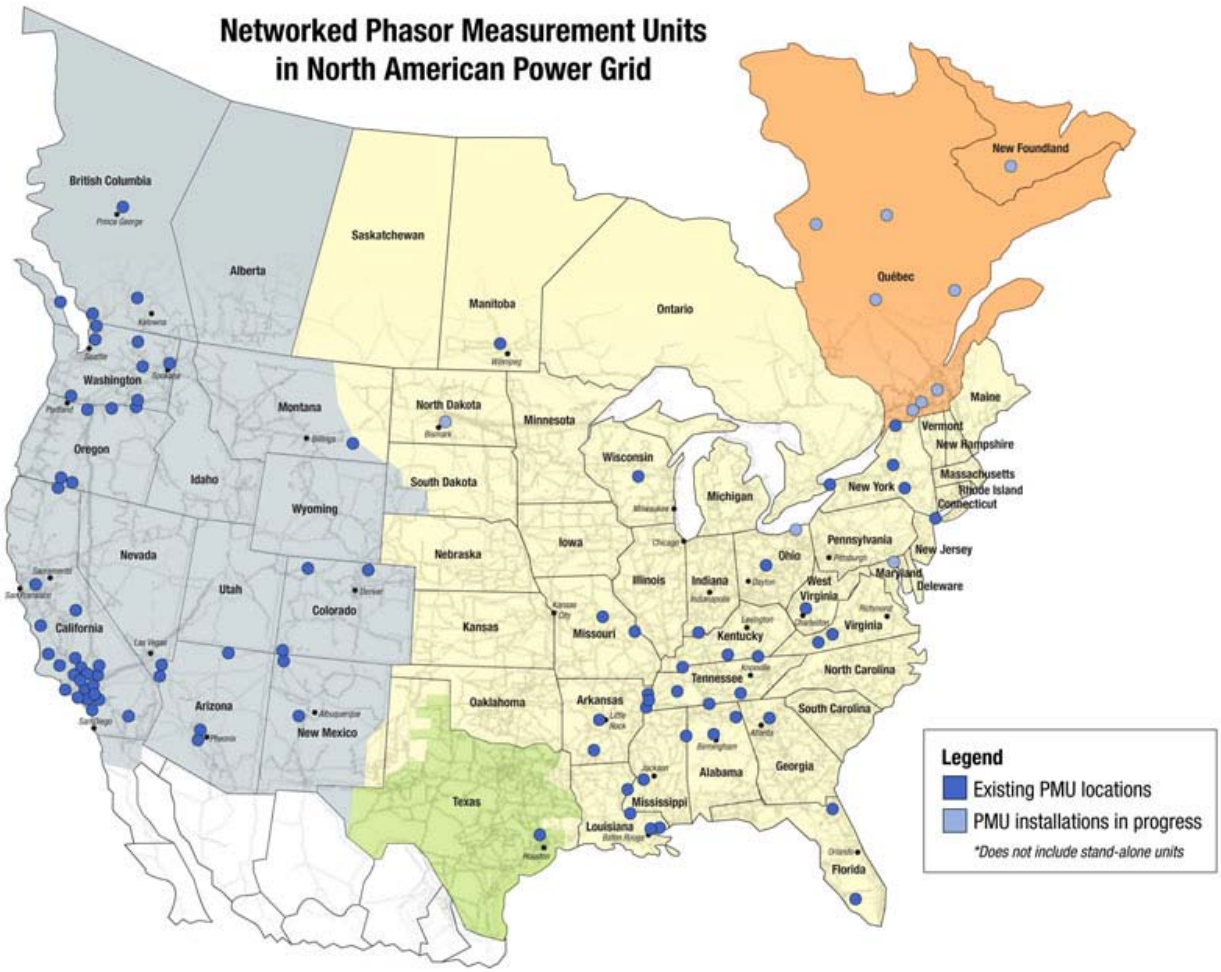

Figure M.13.1. Networked Phasor Measurement Units in the North American Power Grid[18]

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[16]Dagle JF. 2008. "North American SynchroPhasor Initiative." *Proceedings of the 41st Hawaii International Conference on System Sciences - 2008.* Accessed November 24, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=4438868&isnumber=4438696

[17]NASPI 2008. *North American SynchroPhasor Initiative*. Accessed November 24, 2008 at http://www.naspi.org/. Last Updated September 2008.

[18](EIOC) Electricity Infrastructure Operations Center. *North American SynchroPhasor Initiative*. U.S. Department of Energy and Pacific Northwest National Laboratory. Accessed November 24,2008 at http://eioc.pnl.gov/research/synchrophasor.stm / . Last updated July 2008.

M.13.4.0 Challenges to Deployment

The primary challenge to deployment is capturing the business case that advanced measurement technologies provide sufficient benefits beyond more traditional measurement technologies to justify their incremental cost. Primary challenges to deployment include the measurement equipment, networking infrastructure, interoperability and data sharing issues, and applications such as improved visualization tools and other decision-support systems.

As it relates to smart-grid applications, there will undoubtedly be much more raw data available from the smart-grid equipment, but integrating and managing this information will be a significant challenge.

M.13.4.1 Technical Challenges

Primary technical challenges to deployment include the measurement equipment and the communication and networking infrastructure. Another technical challenge is interoperability and standardization. A third primary challenge is improved applications, such as visualization tools that can help operators cope with the increased flow of information associated with the installation of advanced measurement technology.[19,20,21]

Another issue is the degree to which actual phasor data will be shared among utilities and with others. Analysis is needed to identify potential smart-grid applications that rely on phasor data and to assess whether existing coverage is sufficient for the application. There is still a need to assess the usefulness of small signal-stability algorithms and expand them to include mode shapes and determine remedial actions associated with the signals.[22] Weekes and Walker[23] also point out seven different types of organizations that are required to install PMUs: information technology, plant engineering, protection maintenance, protection technicians, communication engineering, commissioning, and transmission services. These all need to be coordinated effectively by management for successful and efficient installation.

Additional work on the measurement technologies themselves is warranted. According to Weekes and Walker,[24] different PMUs give different results for the same measurement input.

M.13.4.2 Business and Financial Challenges

A 2006 survey indicated that nearly 59 percent of utilities do not use and have no plans to use WAMS

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[19]DOE 2006. *Five-Year Program Plan for Fiscal Years 2008 to 2012 for Electric Transmission and Distribution Programs.*

[20]Dagle JE, 2008. "North American SynchroPhasor Initiative." 41st annual Hawaii International Conference on System Sciences.

[21]Weekes M.A and K Walker. 2007. "PMU Challenges and Performance Issues." 2007 IEEE Power Engineering Society General Meeting. Institute of Electrical and Electronics Engineers, Piscataway, New York. Accessed October 16, 2008, at http://ieeexplore.ieee.org/iel5/4275198/4275199/04275770.pdf?tp=&isnumber=&arnumber=4275770.

[22]Spiegel L, S Lee, and M Deming. 2007. "Review of Research Projects for Managing Electric Transmission Uncertainty." Public Interest Energy Research (PIER) TRP Policy Advisory Committee Meeting and California Energy Commission Staff Workshop.

[23]Weekes and Walker 2007.

[24]Weekes and Walker 2007.

as opposed to 67 percent respondents in a 2004 survey.[25] Although the trend is an improvement in terms of utilities that find advanced measurement systems beneficial, it indicates that a large percentage of utilities do not see the benefits outweighing the costs associated with the purchase and installation of advanced sensors.

The August 14, 2003 blackout underscored the need for more reliable situational awareness. More than 50 million people were affected by the blackout with estimated economic losses in the United States were estimated at $4 to $10 billion while 61,800 MW of capacity was lost.[26]

M.13.5.0 Metric Recommendations

The advanced measurement systems metric emphasizes wide area measurements; however, future reports should consider distribution sensor systems aimed at such problems as power quality. The number of installed and networked PMUs should be regularly collected and published each year. Currently the information was assembled through questions to people involved in the North American Synchro-Phasor Initiative.

There are two potential metrics that could be helpful in describing progress for Advanced System Measurement. The two metrics are,

1. *(Metric 13.b) the percentage of substations possessing advanced measurement technology*: the percentage of substations in the U.S. of various voltage and power ratings possessing advanced measurement technology that are networked and are providing useful information;.

2. *(Metric 13.c) the number of applications supported by these various measurement technologies:* the number of applications being supported by these various measurement technologies to support either enhanced system reliability or effective operations.

Currently no data are available for the two metrics: the percentage of substations possessing advanced measurement technology and the applications supported by these various measurement technologies.

[25]Newton CW. 2007. "Highlights from the North American Study of Electric Power Utilities Protection and Control Management and Staff." *Electric Energy T&D Magazine* 3(11):16-23. Accessed October 16, 2008, at http://www.electricenergyonline.com/article.asp?m=9&mag=43&article=319.

[26]U.S. Department of Energy (DOE) and Natural Resources Canada. April 2004. "U.S.-Canada Power System Outage Task Force: *Final Report on the August 14th Blackout in the United States and Canada.*" Accessed 11/21/2008 at https://reports.energy.gov/