Synchro-Phasor Data Conditioning and Validation Project

Phase 1, Task 1 Report

Review of existing infrastructure systems, administrative processes, and data validation schemes, methods and algorithms

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EXECUTIVE SUMMARY

This report presents the results of Phase 1, Task 1 of the Synchro-Phasor Data Conditioning and Validation Project. The task required a "Review of existing infrastructure systems, administrative processes, and data validation schemes, methods and algorithms." Electric Power Group, LLC (EPG) carried out this task by (1) conducting interviews with utilities; (2) reviewing literature describing synchrophasor systems; and, (3) drawing upon EPG experience with these systems. The intent was to interview all utility recipients of Smart Grid Investment Grant (SGIG) projects, many of their coordinating partners, and other utilities with synchrophasor systems. EPG prepared a survey form that covered all aspects of phasor measurement systems, from planning to O&M. EPG completed 20 surveys, 17 by interview and 3 that were filled in by a utility. Several of the SGIG grant recipients did not participate, even though they were invited to do so. The responses from the 20 surveys formed consistent patterns, so were sufficient for this report. The findings are summarized below:

Project Management: Management of the smaller projects is being handled by 1 or 2 people who coordinated the various organizations in design, installation, and testing. These leader(s) continue to validate measurements and coordinate repairs. Several felt overworked, as this was on top of other existing duties. Larger projects, such as at the independent system operator (ISO) level, usually are being managed by a team, each of whom managed a segment of the project. Since equipment is installed and operated by transmission operators (TO) under the ISO, the ISO was required to provide guidance and requirements for the equipment and systems that would be deployed. The ISO also formed organizing groups among their TOs to coordinate the ongoing work. Several TOs under an ISO project were only participating because of ISO request and had little interest of their own in the project.

System Design: All of the installations were set up as real-time systems, where data is sent from phasor measurement units (PMUs) in substations directly to control centers. In most cases there was more than one level of data transport, where data went first to a TO control center and then to the ISO control center. Field communications was more of a problem than

communications from TO control center to ISO control centers as many substations have limited bandwidth. Between control centers, there was plenty of leased bandwidth available.

PMU Selection and Deployment Location: The choice of PMU was generally left to the TO installing the equipment. In most cases, PMUs were chosen for convenience, cost, or familiarity with vendor rather than performance. The most popular PMUs were dual-function protective relays, followed by dual-function digital fault recorders (DFRs). In some cases relays were used as a PMU only to simplify O&M. The choice of stations for PMUs and the signals to be measured were largely determined by the ISO. These focused on key transmission points, but included many generation sites too. In many cases the TO installed PMUs at locations where they already had good communications and dual-function equipment.

Security: System security ranged from "experimental"--completely separate from other operational functions--to fully North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) compliant. There is a high awareness of the NERC CIP requirements, so implementation carefully took this into account. The NERC CIP requirements focus on administrative processes – access control, passwords etc. Most systems are being implemented with these requirements in mind so at some point they can become part of operations without being completely rebuilt.

Testing and Calibration: Most PMUs were installed without individual testing or calibration. The measurement was validated in some cases with measurements made in the substation and in others by comparison at the TO or ISO control center by comparison with Supervisory Control and Data Acquisition (SCADA) measurements.

Documentation: Documentation usually followed the normal procedure for similar substation, network, and control center equipment. Explicit phasor system documentation was very individualized, ranging from spreadsheets to MicroStation.

Data Validation: Data validation was very limited. Most utilities did no on-line validation; the ones that did used what the vendor supplied with another product such as a phasor data concentrator (PDC) or visualization. Several had plans to add or improve their data quality monitoring systems.

O & M: Most utilities have not gotten to the stage of maintenance or planning for PMU replacement. They expected to use the same kind of calibration/testing cycle as is used for relays or DFRs, which are similar equipment.

Data Archiving and Analysis: Most utilities have systems in place to save data for analysis, but no real plans to analyze the data. The ISOs have system visualization applications, and

several have complete plans for sharing with their TOs. Many TOs, however, do not have visualization systems nor see a need to have them. Many utilities have existing systems or plans for integration of phasor data with SCADA data. A few use phasors in state estimation. A few use the data for system analysis, model validation, and generator certification.

Performance: Most utilities reported reasonable success with their systems. All had some learning curve problems such as getting consistent router and firewall settings and signal naming coordination. Equipment failures were near zero and system reliability as high as 99.96% was reported. The majority of problems seemed to be in communications and some applications such as PDCs that failed. A number of phasor products from PMUs to displays have had some growing pains with occasional failures.

Data Use: A number of utilities have ideas about what they would like to do with phasor data, ranging from parameter estimation to real-time controls. Most anticipate installing more PMUs in phased programs and by purchasing products for other programs, like relay replacement, with dual use equipment that can be used with phasor systems. While many were not sure what benefit they were going to get from these systems, their interest and hopes were high.

Recommendations: Based on these findings and specific comments from survey participants, the following key points indicate areas that need further attention:

1. Utilities need to plan for sufficient staff and establish process to keep these systems fully operational as they become more integrated into utility operations.
2. More thorough installation validation is needed to assure systems are initially operating correctly and measurements are accurately reported.
3. On-line data validation and management needs improvement to assure the systems can be operated and maintained for their full capability.
4. More applications, both off-line and real-time, are needed to extract the full potential and advantages of this technology.

The next task (Task 2) of this project will address the first two issues with a “best practices” report. Then Task 3 will focus on data validation as indicated in the third bullet. Utilities, vendors, and industry organizations need to address application development and integration into utility functions.

CHAPTER 1 – INTRODUCTION

This report summarizes the findings of "Review of existing infrastructure systems, administrative processes, and data validation schemes, methods and algorithms." The review was comprised of three principal tracks:

1. Survey organizations such as transmission owners and independent system operators with existing synchrophasor systems to catalog current practice. This survey included all phases of these systems from planning to Operation & Maintenance. It focused primarily on Smart Grid Investment Grant (SGIG) projects, but included all that had significant development and would share their experience.
2. Literature review of synchrophasor systems, data validation methods, error checking and detection, and data repair techniques.
3. EPG experience and methods of data validation, filtering and repair. This included experience with users and other companies providing synchrophasor products.

The EPG project team surveyed 20 utility organizations representing a cross section of synchrophasor project participants as follows:

- ISOs working through TOs for implementation 3
- TOs installing PMUs on the basis of ISO/RTO request 4
- TOs installing PMUs based on their own and ISO/RTO requirements 13
- Project size: large (>100 PMUs) – 3; medium (20-99 PMUs) – 8; small (<19 PMUs 9

Note that a geographically small utility may have a large number of PMUs as they use several PMUs in a station and cover stations thoroughly. Conversely a geographically large utility may have few PMUs if they are installed at only large substations.

The surveys were based on a questionnaire prepared by EPG designed to cover all aspects of their synchrophasor projects. To minimize the time required by the utility, most of the surveys were conducted by phone. However, three surveys were completed by the utility and submitted. These survey forms formed the backbone of present developments among SGIG and other North American projects. This information was supplemented by the literature searches, particularly North American Synchro-Phasor Initiative (NASPI) meeting presentations and reports. Document searches also included the Institute of Electrical and Electronics Engineers (IEEE) publication database.

CHAPTER 2 – LITERATURE REVIEW and SURVEY HIGHLIGHTS

This section presents interesting and noteworthy observations from surveys and literature reviews. It is divided into subsections that roughly follow the rest of the report. This is intended to present interesting comments and to highlight findings.

1. System and Project Administration

a. Participants seemed to range from a team that was highly involved with synchrophasor technology to a single project manager that was just getting the assigned job done.
b. Some smaller projects were run by one or two people who handled the work as a special assignment in addition to their regular duties. Their dedication contributed greatly to the success of the project, but they often found it difficult to keep up.
c. Most project management was informal as the projects are in a development phase and the needs are not well established.
d. Documentation in most of the power companies either follows their traditional standard method for this type of equipment or is informally kept by the project groups. There is little documentation or change record specifically for the phasor system.

2. Infrastructure Planning and Development

a. The PMU selection process was mostly left to the TO. Some TOs researched PMUs or implemented testing programs, but most chose PMUs based on convenience, cost, or confidence in a particular vendor. Dual function devices like relays or DFRs were the most popular PMUs.
b. The system architecture was simple and straight-forward in most the phasor systems, with PMUs in substations sending data over a single communication path to a PDC at the TO control center. But one of the TOs is implementing a fully redundant system with dual PMUs sending data in parallel to independent control centers.
c. The choice of PMU location and signals to measure was largely left to the ISO coordinating the project.
d. The measurement data was not validated and there appear to be no plans to validate on a periodic basis. Common practice is to perform a random manual check or one-time comparison to establish comparability.
e. The communications network is mostly shared with SCADA and other corporate traffic. In some cases, PMU data occupies a small portion of the bandwidth and

there are no sharing issues; in other cases, the number of phasors had to be limited to prevent overload.

f. NERC security requirements for synchrophasors are the same as for SCADA when used in operations. Most utilities were installing systems with less security controls as they will not be immediately used for operation, but have designed the system so it can easily be upgraded for that use.
g. Some utilities have a criterion to have PMU at any new generation to meet NERC requirements to verify the generators parameters and validate generator models.

3. Data Validation Schemes

a. Most utilities do not employ an on-line data validation scheme beyond what is provided in their PMUs, PDCs, data storage, and visualization applications.
b. Data validation is generally limited to one-time or periodic comparison with SCADA readings and sanity checks.
c. Most utilities anticipate improvement in data validation through vendors' solutions and a few with in-house data checks.

4. Current Experience

a. Overall experience has been good with one utility reporting reliability approaching 99.99% as measured by data loss.
b. One utility noted that at any given time, given their large number of PMUs in service (over 150) they can expect something would be wrong with data from one or more PMUs.
c. Most utilities have not planned maintenance schedules but generally expect to follow the same schedules as used for relays and DFRs.
d. A number of utilities already have synchrophasor data going into the EMS. A few are using the data in state estimation.
e. Most of the problems are configuration and connection related, basic learning curve type problems. The second biggest problem area is failure of applications which are vendor growing pains as they develop new and customized applications. Many of the start-up issues can be traced to company specific IT practices (firewalls, ports, communications etc.)

5. Future Plans

a. Most utilities plan additional PMU deployments. Many have included PMU capability in requirements for new and replacement equipment.

b. ISOs and reliability monitors hope to cover all extra high voltage (EHV) systems at 230 kV and higher for grid-wide visibility. Some utilities hope to cover large areas of lower voltage transmission as well.
c. Most utilities expressed interest in better visibility and monitoring systems, though several did not see a benefit in the systems currently available.
d. Several utilities expressed interest in applications to perform special functions such as calculating dynamic line loading, island detection, and fault location.

CHAPTER 3 – ADMINISTRATIVE PROCESSES – CURRENT PRACTICES

This chapter includes the information gathered about synchrophasor measurement system administrative process. All the information was provided by SGIG participants and synchrophasor system owners from the survey, and it covered the following three aspects:

- Administrative Management Structure.
- Administration Communication.
- System Access and Responsibility for Making System Changes.

1. Management Structure:

Administrative management is structured in a couple of different ways, depending on company's size, work relationships, cooperative arrangements between TO and ISO, project needs, etc. For instance some companies found it more beneficial to have a single person in charge to lead and administer the full project. In other cases, there is a group of people representing different disciplines that share leadership. The methods that we found are detailed in the below paragraphs.

In the first approach, there is one key person as an administrator or a manager who is responsible for all of major tasks: managing the system such as PDC and relay settings, configurations, displays, communication, etc. The administrator directs several engineers who are responsible for their respective department. The administrator handles issues directly by himself/herself or with concerned departments, and field technicians when the problems or issues occur. In most cases, the people involved are representatives from typical work flow groups such as relay/metering, data communication, information technology (IT) and applications support, operation, system protection and control, etc. These groups usually include the data users, either directly or through association. For most of companies, this administrator is from one of the departments or groups mentioned above.

The second approach is with one management group leading the project and working directly with various departments such as protection and control, communication, operations, and IT. The group is composed of a representative from each of several departments. The representative arranges for work that will be carried out within their own department. For example, if the operations group encounters a problem, they refer it to their representative in the management group who in turn refers the problem to the appropriate group.

In addition to the approaches mentioned above, at some companies the administrative management structure is not defined or formulated. The project work is assigned to staff in the respective departments, such as relay and communications. The individual parts are completed but there is no central management of the project. The project staff may cooperate to solve problems.

The numbers of respondents using each approach are shown in Table 1 below.

Management Types	Number of Respondents
One key person as an administrator	6
One management group leading the project	12
Not defined well	1
Not specified	1

Table 1 – Summary of Project Management Approaches

2. Administration Communication

The communication between users and administration indicates how the users provide feedback to administration for their needs and concerns under the presence of a group or person. The majority of users are from control centers, planning/engineering groups or design departments which is considered as the user core team.

For the participants who have years of experience or large-scale projects regarding synchrophasor system, the communication is done through a detailed process model per activity, task, and need with a group of experts involved in the process as approvers, reviewers, and others specifically interested on the particular subject. Experts assigned to each group are supposed to share knowledge with other groups. The expert also collects information, shares knowledge, and provides feedback to the management during the meetings.

However, for companies with newly started synchrophasor projects or whose projects are still in development stage, the user groups are usually small and communicate via emails, informal phone calls, and face-to-face meetings. Engineers use the data for fault and event analysis in some incidents, and observations and concerns are brought directly to the administrative manager. There is no formal problem notification or resolution record.

A few participating companies plan to install on-line system monitoring applications. Currently there are no on-line application users in these companies, so the personnel in charge of the project reviews daily reports that are automatically generated by other applications. If any problems are discovered, the manager reaches out to the appropriate people to solve problems.

For the companies having off-line applications, there are some post-event analysts using recorded data and following up on data gaps. They contact engineers for adding new PMUs, getting signals improved, etc. Much of the problem feedback comes from automated PDC alarms such as PDC logging through syslog or similar resource and ISOs. Additionally, if a problem is identified, there is a rule as to how the problem resolution is processed. ISO raises the issue and then communicates the issue to the TO who proceeds to identify and resolve it.

The approaches discussed above are summarized in Table 2 below.

Company State	Features	Number of Respondents
Companies with years of experience or large-scale synchrophasor project	Have detailed rules/procedures/process models to resolve issues	4
	The leaders of each related group represent/collect/share feedback during their routine meetings	
Companies with the project newly started	Contact with others directly face to face	11
	Informal verbal and email communications	
	No special process/procedures	
	No formal problem notification/resolution records	
Companies with the project in plan/development stage	No specific users yet	4
Not specified		1

Table 2 – Summary of user-project team communication

Another specific area of communication is in configuration management. Information needs to be shared among administrative, maintenance, and user groups. This is particularly important

when separate parties own or operate parts of the measurement system such as PMUs, communication systems, PDCs and other data processing equipment. Two approaches were mentioned by respondents, though in all cases the common form of communication is email or phone calls.

One approach is having a specific organization responsible for all setting information and sharing that with others as needed. For example, the TO has access to devices and will maintain settings, but may do so at the requrest of an ISO. Even within a TO a specific group such as the system protection group may be responsible for all settings and maintenance. Other groups, e.g., communication group, may be requested to assist in problem resolution.

Another approach is that each group—substation equipment, communications, and IT—manage their own equipment including settings. This requires clear processes and procedures for each part of the system that everybody follows. It also requires ongoing coordination. For example, when the ISO observes a problem they have to contact a TO for resolution since it is the TO that has access to the PMU equipment. Table 3 summarizes these approaches.

Configuration Management Approaches	Number of Respondents
An organization is responsible for configuration	3
Individual groups take responsibility for their own application areas following a procedure that every group follows	4
Not specified	13

Table 3 – Communication Methods for Coordinating PMU and System Configuration

3. System Access and Responsibility for Making System Changes

The designation of organizations and staff that have system access and the responsibility to manage the system are based on company specific practices that vary from company to company. Basically the group in charge of each synchrophasor component has access to and manages that equipment. System protection has access to and manages devices such as relays, DFRs, PMUs, and substation PDCs. Field technicians also have access to PMUs and can handle configuration as well as maintenance. Communication from the substation to the control center is usually managed by a communication group. An IT group handles networks in the control center and sometimes to the field as well. The administrator manages configuration changes by directing the work of the groups. This division of work was consistent across the 12 respondents who detailed this activity.

An example of a TO with defined access responsibilities follows. The planning group has access to data at the PDC level and at the ISO application level for real-time and historical look-back.

The operations group has access to ISO applications for viewing synchrophasor data in real-time and historical look-back. The TO system protection group has responsibility for designating PMU parameter settings. The relay services group has responsibility for applying settings to the PMUs.

In some cases, an ISO directs all PMU work; the TOs do not make any changes unless directed by the ISO. In other cases, the TO works on the equipment as they find necessary and keeps the ISO informed. The TO has access to equipment and does repair, setting changes, etc., so the ISO must work through the TO.

Most companies document system changes, though some of them do not use formal or official report keeping. For example, some track significant issues with spreadsheets. Some ISOs make name changes, so the TOs that are involved do not keep a record of these changes.

CHAPTER 4 – INFRASTRUCTURE PLANNING, DEVELOPMENT, and IMPLEMENTATION

1. System Design:

a. System architecture

The system architecture is pretty simple in most of the power companies. The system architecture follows the basic pattern of collecting into larger data sets from the measurement point to successively higher level organizations. At the first level, PMUs in substations send data to a PDC in the control center (CC) for the TO using communications either owned or leased by the TO. In some cases, the TO uses a substation PDC to gather data from several PMUs at the substation into a single stream which is sent to the CC. In other cases data is streamed directly from each PMU. One of the TOs is implementing a fully redundant system using dual PMUs sending data to independent CCs. Others do not have redundant communications from the substation to the CC. In most cases the TO will forward the data to a regional organization such as an Independent System Operator (ISO) or regional entity like the Western Electric Coordinating Council (WECC). The regional organization uses a PDC to collect the data into a comprehensive set covering the whole region. Figures 1 and 2 drawn from NASPI presentations illustrate typical schemes with and without redundancy.

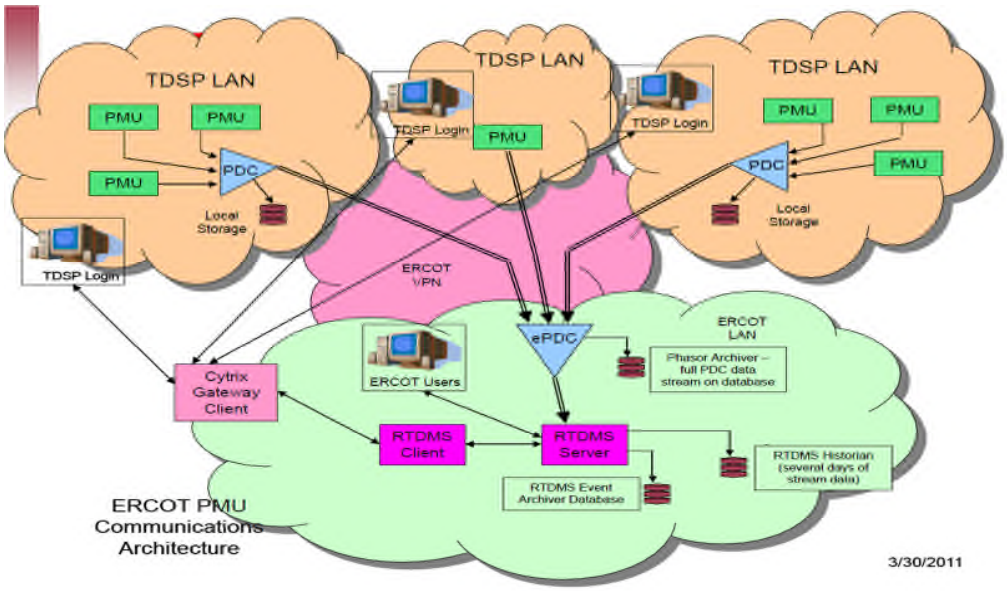

Figure 1. Typical architecture without redundancy

Reference: "Debugging PDC to PDC data flows," NASPI June 2011

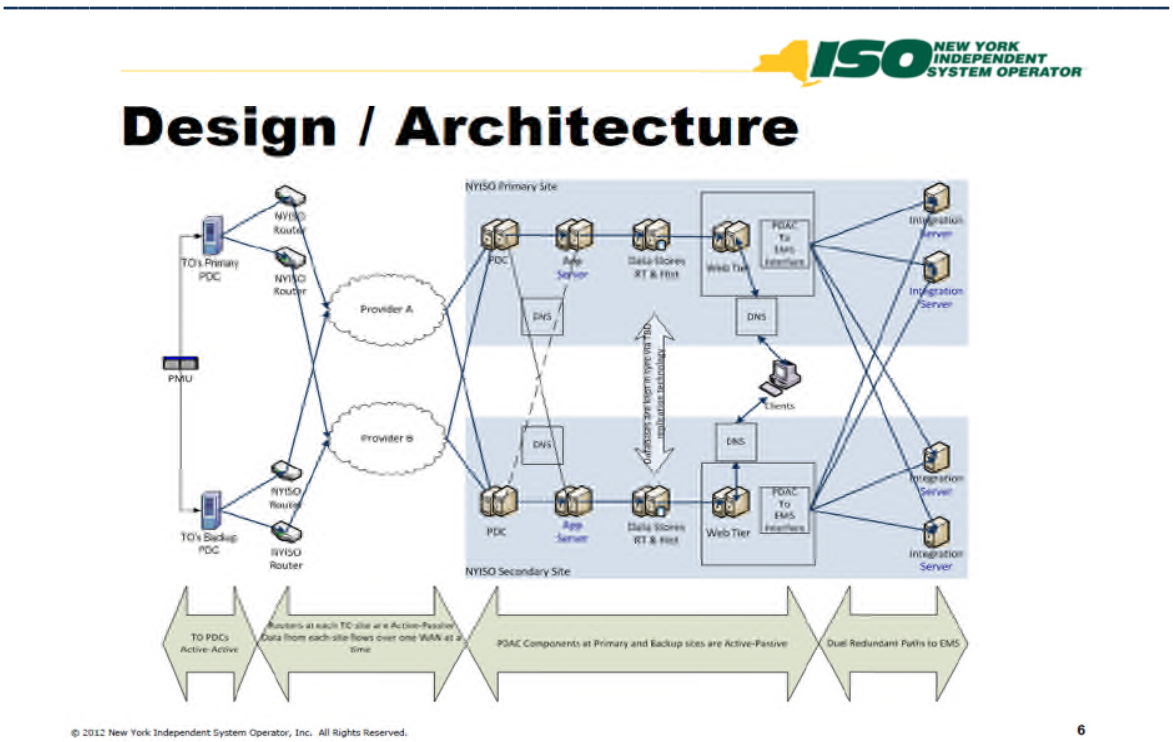

Figure 2. Example of architecture showing full redundancy from the PMU to ISO

Reference: "NYISO SGIG Project Design," NASPI meeting, October 2012

Once gathered and correlated into a synchronized data set by a PDC, the data is stored or/and fed into real-time applications. The PDCs are capable of sending multiple simultaneous data streams to different applications with each stream tailored to the application needs. These applications include:

i. Data file writers – archiving data for analysis (simple and accessible).
ii. Database/Historian – Archiving data for analysis (easier to use than files but less compact).
iii. EMS system – For validation of SCADA data, state estimation, alarming.
iv. Visualization applications – for situational awareness and alarms.
v. Operations applications – For dynamic stability monitoring such as ROSE (by VR energy).
vi. Other PDCs – ISOs, specialty applications.

Nearly all TOs and ISOs archive data for 30 or more days. Many of them use simple visualization such as strip-chart type displays, and most of the larger operators use more comprehensive visualization such as Real Time Dynamics Monitoring System[1] (RTDMS®), eTerravision, or Phasor Point. A few are reporting data into the Energy Management System (EMS), though this effort is in initial stages.

The system architecture found in the literature reviews are similar to the architectures found in the surveys. The architecture diagrams presented consist of a PDC collecting data from different sources such as PMUs, substation PDCs, and clustered PDCs. The data flow is integrated into the EMS applications at very low resolution for events, alarming, and state estimation. But usually higher resolution is used for archiving for engineering analysis, real-time visualization and wide-area monitoring applications. These end user applications are at substation level, control center level, and regional organization level. The historical data is archived for 12- to 24-months for long term analysis.

b. PMU placement

Early projects, such as the EPRI-WSCC projects (1992-1995), had specific placement goals since it was a control project. The WECC Disturbance Monitoring Working Group (DMWG) came up with specific criteria in 2002 including:

- Major transmission interconnections.
- Generation sites of 500 MW or larger.

[1] ®Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060259, and US Patent 8,401,710. All rights reserved.

- Control system sites (SVC, DC terminal, etc.).

The initial SGIG placement of PMUs was focused on locations that could take advantage of the existing measurement capability such as in-service protection (control) relays and DFRs with PMU functionality in substations which had sufficient communications infrastructure. This proved limiting due to practical difficulties. In some cases, expansion of the communication infrastructure was required to support PMU data traffic. In other cases there was insufficient rack space or firmware upgrades were required.

The subsequent placement of PMUs was further extended based on the proposal for candidate sites by the ISOs and certain key stations selected by the planning department. These choices included coverage of substations with Remedial Action Schemes (RAS), previous experience, and lessons learned from historical events and blackouts. The TOs provided feedback on the feasibility options and signals to monitor which helped the ISOs create a list. The PMU installation was then shortlisted based on the practical difficulties related to the construction and maintenance process, infrastructure requirement and deadline to complete the projects. If an ideally located substation lacks the required infrastructure, then the next nearest substation having the infrastructure could be chosen as the location for PMU placement.

The most common criteria for PMU placement are to have coverage on all high voltage buses greater than 345 kV. Some utilities also have plans to extend placement to distribution voltage levels because of known problems such as oscillations. A sampling of the PMU placement criterion from the surveyed utilities includes:

i. New generation of any type.
ii. Generation location greater than 100 MW.
iii. Load centers greater than 1000 MW.
iv. All new lines.
v. Wind farms and renewable generation connections.
vi. Transmission line paths greater than 1500 MW.
vii. High Voltage Direct Current (HVDC) terminals, Static VAR Compensator (SVC) locations.
viii. Generator transformers and step down transformers.
ix. Adjacent buses in the same substation.
x. Substation with more than one voltage level.
xi. Metropolitan areas.

PMU placement is also driven by a number of application needs. Situational awareness applications need full grid visibility. Integration into the EMS system to know the voltages and angles at the buses during outage or during the unavailability of EMS data to the control center or when the state estimator does not solve is another interesting criteria for PMU placement. A PMU at a generation site allows validating generator models as required by NERC. Several utilities are requiring PMU installation for this purpose. A method of calibrating Potential Transformer/Current Transformer (PT/CT) devices using PMUs has been developed; it requires a tree of measurements which dictates PMU placement. A few universities have developed methods for optimal PMU placement in a high voltage network. One such program evaluated PMU placement using a cost function. Integer Linear Programming (ILP) was used to minimize the objective PMU cost function to ensure topological observability. Several variants were presented as well.

c. Synchrophasor component selection (PMU and PDC)

For most utilities, the PMU selection process was simpler than the PMU placement process. The measurement devices used in the field were dual function DFRs or relays and stand-alone PMUs. The ISOs usually take responsibility to identify the PMU locations but leave PMU selection to the TO. The TOs choose PMUs that comply with C37.118 requirements and other technical specifications defined by the TO and/or ISO. The TO's selection may also be based on competitive bids. A few TOs and universities developed PMU testing programs for PMU selection. Testing program results were shared with vendors to correct errors. The vendors benefited in terms of improvements in their PMUs.

PMU functionality in line relays was most frequently used, which eased the selection process. Additional hardware requirements, software bugs, testing cost for the PMU functions, and PMU calibration were some issues associated with dual function line relays. It was noted that testing PMU functions for acceptance test required the relay to be out of service; in some cases this would leave the line un-protected, so the line had to be out of service also. One TO originally also planned to use their DFRs for PMUs, but unfortunately they did not work to standards, so they switched to relays. Some of the PMUs mentioned in the survey include the Macrodyne 1690, SEL relays (487E, 351A, 421D, etc), GE L90, ABB RES670, Mehta Tech DFRs (TR2000 & TR 2500), ERLphase Tesla DFR, and Qualitrol IDM DFR.

Most TOs use only one central PDC to minimize the investment cost, and simplify maintenance, infrastructure, and communications. A few utilities use a substation PDC to gather data from several PMUs at the substation into a single stream, more to manage change configuration control and to minimize firewall/traffic issues than data compression. However, most utilities do not use a substation PDC to simplify installations and minimize

latency. Some of the PDCs mentioned by users include SEL (SEL 3306, SEL 3373, etc.), EPG's *enhanced* PDC (*e*PDC), or OpenPDC and Psymetrics PDC.

d. Signals to be measured

Usually the regional organization/ISO defined the signals (line and bus) to be monitored. WISP (WECC) and Midwest Independent System Operator (MISO) designated which signals are required at each substation. Sometimes it was left to the TO's decision. In some cases, signal selection was opportunistic, simply taking signals that are available. Usually more than one PMU was required to monitor all the circuits in a particular substation. Signals were rarely chosen for redundancy since overall coverage is scant.

Signal measurement is limited by number of input channels on the PMU. Each voltage and current input requires three channels (one for each phase). On the output side, most PMUs can send individual phase phasors as well as frequency and status. Signal selection can be further limited by the communication bandwidth. One TO reported that a 56kb/s circuit can handle one PMU stream and multiple PMUs can push the requirement to 500kb/s or more. Analog and digital signals can also be added to the PMU stream but this is not often used.

e. Communications

The communications are determined by TOs to meet ISO requirements and concerns. The communications network is often shared with SCADA and other corporate traffic. The communications networks originally were serial but are now mostly upgraded to Internet Protocol (IP), used over mostly microwave or fiber optic communication. Fiber optic communication has become very common because of lower cost and more bandwidth. There is still a lot of microwave and Telco provided wire circuits. Some TOs have their own communications and use that, others lease communications from a service provider.

Synchronous Optical Networking (SONET) and frame relay is probably the most common communication protocol used between the substation and the TO control center. Some new installations use Multiprotocol Label Switching (MPLS). From the TO to ISO, MPLS is probably the most common followed by SONET and carrier Ethernet. In all cases, the IP protocol is used for the point to point protocol.

TCP is the most commonly used IP method. It is easy to use, gives enough information to assure the devices are connecting, and is considered reliable. Virtual Priviate Networks (VPNs) are frequently used over the Wide Area Network (WAN) portion to protect the data stream. IP Multicast (One-to-many) is preferred in some cases to reduce network loads. But the use of VPN tunnels and/or firewalls can also inhibit the use of IP multicasting and IT

departments generally do not like the management problems of multicasting. Alternatively, individual unicast streams can be used to direct synchrophasor traffic to each head-end system.

A number of TOs and ISOs found specific issues that had to be resolved in ways specific to their communication capability. These examples include:

- At one TO, most of the substations are served with 56kb/s circuits. Most of the bandwidth is reserved for SCADA and security information. A single PMU data occupies a small portion of the bandwidth, but more PMUs cannot be added without adding communication circuits.
- A TO reported that the signals from the PMUs are being sent in two different data streams independently of each other for full redundancy purposes. Some substations require two PMUs for full coverage. Therefore, redundancy requires four PMUs in a substation and thus 8 output streams out of substation. Each data stream is assigned one-third of T1 (1.544 Mbps).
- A bandwidth and latency study was conducted on the WISP architecture sharing data from one PDC to another. Latency and bandwidth correlation was examined using dedicated communications links and shared communication links. It was found that the latency increases with low bandwidth and with additional authentication security information using dedicated links. The latency increased by 3 milliseconds with codes required for authentication. For shared communication links, the latency was variable but there was a small increase in average latency with code required for authentication.
- It was determined that latency also varies with time alignment of data streams at source and at destination.

A few calculators were used to estimate the bandwidth required for the scope of work. Bandwidth requirement depends upon a number of factors such as network protocols, number of phasors measured at each substation, sample measurement rate, data format (integer vs. floating point) and PDC locations.

f. Overall system security

Any data systems that are used as a part of power system operations are considered a critical cyber asset and are required to adhere to NERC CIP standards. Most of the phasor systems being built today are not included in operations and are therefore exempt. Many of the phasor systems are being implemented with these standards in mind, but it is purely dependent on the TO installing the system. These security requirements are similar to that of SCADA, with same security, confidentiality, and authentication levels as per NERC

guidelines. Some ISOs also require the overall system security to comply with the cyber security plan approved by the Department of Energy (DOE).

Usually the substation is considered a secure zone with firewall at the interface. Data must be protected such as by encryption when sent out of the substation to firewalls at incoming data concentrator connections at the TO and ISO control centers. This can be done with a VPN over any communication system. Since Multiprotocol Label Switching (MPLS) provides its own encapsulation, some users accept that as security between end points.

2. System Installation and Measurement Validation

Installation and validation procedures varied widely. Some TOs simply activated the PMU function in existing relays and used that without calibration or tests. Others test each PMU for functionality before installing and check the measurement carefully in the station. None of them calibrated each PMU before installation or using precise signals after installation. Most TOs accept factory calibration of the PMUs by the vendor. In a few cases, a Doble relay test set is used to check units for reasonable measurement before and/or after installation. Typically the measurement capability of line relays, with added PMU functionality, was tested as a relay when it was initially installed and not validated at the output for PMU measurements. Most PMUs are tested for communication of data streaming to the PDC in coordination with the ISO.

Most ISOs have a process to capture the data for quick validation before accepting the data stream in the PDC server. Some ISOs also perform a detailed validation. One of the TOs reported that 5-10 minutes of data are downloaded remotely and made to run through automated scripts. The automated scripts focused on validation algorithm to perform sanity checks using quality flags and data availability.

The measurements are validated against other measurements available in the substation, TO control center, and the ISO control center. Most of the ISOs and TOs don't have an on-line validation scheme at present but have on-going procedures. The measurement validations revealed errors in devices, bad physical connections, software issues, and discrepancies with other sources of data. A two-step approach was usually taken to validate the measurements.

i. After installation of PMUs, the measurements were sometimes compared with:
   a. Substation data – using relay data, metered data and side-by-side comparison of dual-bus substation.
   b. Control center data - EMS data and State estimator (SE) results.
   c. DFRs and redundant PMU streams.

ii. After measurement validation with data sources, the second step addressed many issues as enumerated below:
   a. Wrong ratios, polarity errors, line identification errors, naming errors, bad clocks, poor connections, firewall issues, firmware upgrade, inconsistent naming procedure, configuration problem at the PMU and PDC level, scale factors and errors in SCADA data.
   b. The settings/adjustments/configuration changes were required to be made in conjunction with the issues related to measurement validation.

ISOs check the data quality and provide feedback to TOs. Most of the TOs rely on the ISOs to validate the data for detailed analysis. If there is a discrepancy in the data, the TOs resolve the issue, probably with a visit to the substation to make appropriate changes.

The measurement data is usually not validated on a periodic basis. A random manual check or one-time comparison is initiated to establish comparability. However, one TO reported that validation with EMS data is planned for every 5-years.

For test, PMU has been introduced into the state estimator at the control center and difference in percentage error is calculated using measured and estimated data with and without phasor measurements. The accuracy of error improved using phasor measurements. The improvement on state estimation usually depends on:

i. PMU locations.
ii. Number of PMU devices.
iii. Calibration of PMU devices.
iv. PMU measurement accuracy.
v. Related SCADA data accuracy.
vi. Synchronization between PMU data & SCADA snapshots.

	BEFORE INSTALLATION		
	Test PMU type according to standards or specifications	Test all PMUs received for specs or calibration	Accept vendor stated qualification and factory calibration
Number of ISO respondents	0	0	1
Number of TO respondents	1	1	14

	AFTER INSTALLATION	
	Validate measurements at substation with test equipment or meters	Validate measurements at control center with SCADA or state estimator
Number of ISO respondents		3 (100%)
Number of TO respondents	8	14

Table 4 – Summary of PMU unit testing and installation validation

Table 4 summarizes the PMU qualification and installation validation process. It is clear that respondents depend on the PMU vendors to produce and deliver quality products according to specifications rather than independently test and calibrate. Measurement validation after installation is fairly consistent, though it should be 100%. Generally, utilities anticipate automation of the measurement comparison and validation process through vendor solutions. The automated process could perform periodic comparison between the measurement data and SE solution every few minutes; perform sanity checks on the data availability and detailed availability check using status flags.

3. Documentation

The documentation for synchrophasor systems varies widely among companies. In many cases, the standard methods for documentation including system diagrams, station rack and wiring prints, and inventory lists. In this way, synchrophasor systems are treated as any other installed equipment. In other utilities documentation is informal and each group/department in the system administration usually maintains their own documentation and record of changes. Most of the companies keep track of changes made using the registered details in the installed software and configuration files. A few companies do not maintain formal records or official reports; however, they have some informal documentation such as spreadsheets. Sometimes a record of issues resolved is part of the standard work flow procedure of the operating order. There is no standard naming convention for the PMU signals and hence difficult to keep record of these changes. The different types of repositories used in the industry are as follows:

i. Overall physical drawings or web-based document of the system architecture and implementation plan.
ii. Overall physical drawings of PDC centric plan (Includes server, software, communication and other information).
iii. Spreadsheet listings.
iv. Microsoft documents and projects, web-based SharePoint.

v. Manual Registry files to track signal name change and other detailed information. (Automation is an on-going process).
vi. Micro station diagrams in PDF format.
vii. Auto-cad files.
viii. Visio Diagrams.
ix. Normal printouts.
x. Other documents, depending on devices and software applications.

The most common types of repositories used for documentation were standard Microsoft office products and PDFs. The rest of the respondents reported that they either accepted the information available in the configuration of equipment and applications as a source of documentation or used the existing utility documents and databases.

Table 5 below shows the breakdown of these types.

Documentation Process	Number of respondents
Documentation using standard file format like PDF, spreadsheets, PPT etc.	9
Documentation using the existing utility type formats and databases	8
Documentation using the configuration of equipment and applications	3

Table 5 – Use of documentation types of respondent

Most of the documentation at present is done similar to the EMS and relay documentation. The physical diagrams have more detailed information about the system compared to the written documentation.

The details that need to be documented were found to be available at various sources and listed in table 6 below.

#	Documentation Details	Source of information
1	Signal source information and parameters (PT/CT types, ratios, calibration, etc)	✓ Partially obtained from local devices ✓ Relay diagrams ✓ Relay database
2	PMU installation information and settings (# PMUs, vendor, # phasors, types, filtering, window, data rate, etc)	✓ Mostly hidden in the ePDC configuration file ✓ Substation Spreadsheet ✓ Device documentation (manual and charts)
3	Communication identification and parameters (Communication type, Intermediary stations of communications, architecture/layout of	✓ Maintained by communication group

	intermediary stations, etc)	
4	PDC and other processing equipment parameters, specifications, settings, redundancy	✓ ePDC Config files placed in running servers ✓ Backed up on the other servers
5	Application list, settings, location of servers and data flow	✓ Maintained by IT Network Group
6	Security information (Data sharing, Application sharing with outside parties)	✓ Cyber security plan documentation
7	Initial and periodic maintenance check and test results	✓ Periodic maintenance of operating system and security patches to the servers, no specific documentation available

Table 6 – Documentation Source List

CHAPTER 5 – DATA VALIDATION SCHEMES, METHODS, and ALGORITHMS

This chapter covers information gathered about data validation. As used in this context, data validation covers all aspects of confirming that data received at any given point accurately represents the quantity that is expected. Data errors may be caused by:

1. Data corrupted by the measuring device.
2. Data errors caused by communication problems.
3. Accuracy lower than expected.
4. Measurement timing in error.
5. Data label incorrect (wrong data is indicated).
6. Data delayed – too late to be used by the application.
7. Data scaling in error.
8. Data representation incorrect (fixed-floating, rectangular-polar).

The research is divided into three sections: 1) survey responses; 2) literature reviews; and, 3) EPG experience. The survey showed most utilities rely on vendor produced solutions and there was little in the literature on this topic. Hence, most information on this topic in this report comes from EPG experience.

1. Survey Response

The surveys produced a wide variety of responses. The utilities with a longer history of phasor system deployment tended to have more comprehensive data monitoring systems. Several utilities that have deployed PMUs at the request of an ISO had no on-line monitoring. Most utilities that were concerned with system and data monitoring only had plans to do so and did not have systems actually deployed. Most of the deployed data quality applications are part of a vendor provided system such as a PDC, visualization, or data analysis application. Most of these do not include alarming, and if they do, it is not used.

Table 7 summarizes these findings in terms of error detection and notification.

Data error detection & notification	Number of respondents
No error detection	5
Error detection only when data processed	6
Error detection on line, no alarm or notification	4
Error detection on line, alarm/notification by EMS	3
Error detection on line, alarm/notification by Email	2

Table 7 – Data error detection and notification scheme usage

The data validation section of the survey considers:

- Data validation schemes.
- Alarms and other notifications of errors or problem conditions.
- Actions that are taken when an error is discovered.
- Work flow for problem resolution.
- Routine maintenance.
- Plans for upgrade or replacements.

These issues are discussed in the following paragraphs.

Data validation schemes used by utilities are usually those provided by vendors in their own products, such as in a PDC or analysis package. Several utilities reported development of their own products. The schemes in products provide statistics on number of lost packets, time and data errors, visual indication of which inputs are bad, and some filtering of bad data. A few also include alarm notifications by email or reports to EMS, however these features were not always enabled. Most of these schemes are based on the data quality flags imbedded in the data (part of the C37.118 data packet). As Table 1 shows, most respondents do not use real-time notification of data problems. However several reported that they have plans to upgrade their monitoring and notification in the future. This emphasizes the fact these systems and their owners are new to the technology and are in an early stage of development.

Alarm or other notification of data and system problems is generally left to the data user. In cases where the prime user is the ISO, several TOs do not do any error detection. Some users do spot checks of data, such as a daily review of the number of records in the data store or looking at snapshots over the day. Other users only find data problems when they examine data during an analysis. A few rely on observing the visual indications from time to time. Only 25% have a regular alarm plan that either uses notification by email or through the EMS. Of these, the type of notifications varies. Typically the PMU is a device like a relay or DFR and these have a failure indication tied into the EMS. In addition, the PDC or other application in the control center may be tied into the EMS or network management. The alarm reporting is not specifically tied to the phasor functions. However, in two cases, the alarming is specifically related to the phasor system and covers most common phasor system problems. As in the case of error detection, several utilities are working on comprehensive reporting systems either on their own or in conjunction with a university.

Most phasor systems are small and governed by a small group. In most cases, the group is composed of representatives from typical work flow groups such as the IT, relay/metering, and communications groups. These groups usually include the data users, either directly or through association. Problem notification is handled by phone, email, and direct personal contact. Problem resolution is usually an ad-hoc process based on experience. The key system contact or manager will contact the appropriate person to look into and correct the most likely cause. With a little experience, this approach seems to work fine for most respondents. In many cases a record is kept of the problem and its resolution. Again, many of the systems are incomplete and problem discovery and resolution is considered to be part of the implementation process, so are not documented as maintenance.

2. Literature Review

There is very little literature that describes data validation techniques, particularly on-line systems that could be used for phasor measurements. Traditionally, data validation has been an after the fact study using detailed instrument calibration and comparison of results among measurement sources. Errors were then corrected for reporting. Systems needing validation in real-time used a careful calibration chain and perhaps dual or triple feeds for redundancy. State estimation is another validation technique that uses over determined equations to validate data and reduce error.

Until recently, state estimation was too processor intensive to be called real-time, typically requiring several minutes to produce an output. But now with a small system to reduce and estimate, it could be done in real-time. This principle is used for the Super Calibrator concept developed at Georgia Tech. It does a state estimation for a single substation. It inputs a complete set of time tagged measurements from sensors in the substation. These measurements can include phasors as well as other Root Mean Squared (RMS) measurements such as voltage, frequency, and power. It uses a substation model to estimate measurement errors and corrects the data before forwarding to the control center or other data consumers.

Other reports and papers describe investigations and measurements on data availability. One report describes a statistical method to validate data: the mean is calculated and then data that falls too far from the mean is declared invalid. Another report points out that since CCVT accuracy is typically only 0.6%, different measurements from the same bus can show 6 kV differences. Performance reports typically anticipate 99.99% availability, but actual experience is only 35% to 90%. While it is early in the cycle for solving problems, these reports show phasor measurement systems have a significant way to go.

Another recent study reported success predicting the next complex value given the three previous measurements using a polynomial predictor. This takes advantage of the fact that most power system phenomena have a bandwidth much lower than the typical phasor estimation rate of 20-60/s. This approach should be usable in real-time, at least on a limited number of signals.

3. EPG Experience

EPG has dealt with data quality issues since it started working with synchrophasor measurements in 2002. EPG incorporates extensive data validation schemes in its *e*PDC, visualization, and analysis applications. EPG also has worked with a wide variety of users analyzing and resolving data problems. This background and the resulting knowledge will be summarized in the following paragraphs. Detailed application of these principles will be presented in the Best Practices report, which will be completed in the next stage of this project.

Most data problems are detectable, some using flags intrinsic to the data, some by comparisons with known benchmarks or other data items in the same set, and others only by using independent comparisons. Here data validation will be treated in three categories:

1. Data timing, measurement, and corruption.
2. Measurement thresholds and comparisons.
3. Data identification, accuracy, and modifications.

The first category includes errors that are detectable by the measurement and communication systems independent of the data itself. Most synchrophasor data communication use the IEEE C37.118 data format, which includes a status word with each data packet that has indicators for:

1. Valid data in packet.
2. PMU error.
3. Timing synchronization.
4. Data alignment by timetag or local time.
5. Data modification from the original.
6. Time quality.
7. Length of time with bad time quality.

These indicators are included with each data frame (sample) and should be included with that data through all processing and storage.

The PMU can detect internal problems such as a corrupted program, memory failure or A/D converter problem through self-checking algorithms. It should report unresolved problems with the error bit and should set the data invalid flag if the data could be in error.

Timing is provided through Global Positioning System (GPS) or a timing system such as IEEE 1588. These systems can determine accuracy levels and communicate that to the PMU. If the timing accuracy drops below the required level, the PMU should set the time-synchronization error flag.

Network communication systems have their own packet and message validation codes. In most cases, the communication system will simply discard corrupted data. In case it doesn't, the Cyclic Redundancy Code (CRC) on each C37.118 message provides a validation directly to the receiving application. If the receiving application detects a CRC error, it should not use the data and set the invalid flag so the data will not be used by any succeeding application.

Most phasor data systems gather data from several PMUs with a PDC. The PDC time-aligns the data and sends it to other applications. If the PDC receives data with a CRC error, it should set the invalid flag and place the corrupted data in the appropriate data slot or replace the data with blank data. In all cases, the invalid flag alerts users that the data is bad. If it receives data that either will not align due to an obvious timetag error or with the time error flag set, it can assign a local timetag ("by arrival"), set the flag warning that the data has a local timetag, and place the data in the data set using that timetag. If it is reprocessing data such as down or up sampling, it can set the data modification flag to any data sample it changes, so other applications will know the sample contains un-measured data. It should retain other error flags that are in the received data. The PDC will very likely perform additional functions and needs to mark the data accordingly.

Any application can check these status flags and use the data accordingly. If we assume that communication corrupted data will be discarded—and thus treated as missing data—then these flags constitute the first element of data validation. The second element consists of logical limits, thresholds, and intrinsic comparisons. These require knowing something about the data and what it represents.

For example, consider a voltage measurement. If it is from a 500 kV bus, we know that the power system will not be operable if the voltage is 800 or 200 kV. So we can assign limits, say 350 and 650, such that if the voltage is outside of this range, it is a data error and the reading can be flagged or discarded. However it is possible to get such a value during a fault or switching. So we probably should have a wider range that is allowed for a few sample periods. This type of data validation can be employed in processing or applications, but

generally should be limited to end use since there can be exceptional cases that violate general rules or may be valuable in deciphering unusual cases.

Frequency is another measurement that can be limited based on known conditions. High and low limits can be applied based on reasonable ranges of the power system. As with voltage, exceptional conditions occur, so it is advisable to store the full range of data. Current is more difficult to quantify since there is rarely a specific operable range.

Some relationships can also be used to validate measurements. Frequency is commonly derived from a voltage measurement input. If the voltage becomes too low, the PMU will not be able to get a good frequency measurement. A threshold on the voltage measurement can be used to flag the frequency as invalid. The digital indication inputs to the PMU can also be used to flag measurement errors, such as indicating line breaker is open so the PT or CT will not be energized.

The third category of data validation methods includes items that cannot be validated intrinsically or with basic measurement knowledge. If a voltage or current measurement is incorrectly identified or scaled, the user has no way to know that it is wrong without comparison with another measurement. All measurements should be validated by comparison with other measurements. In some cases this will be a calibration, where the comparison is with a highly accurate measurement made with a certifiable instrument. In others it will be only validation where the comparison is with an accepted and trusted measurement.

The first place to make these validations is in the substation using installed meters or portable test instrumentation. True calibration has to be done there. The next place is at the TO control center using comparable SCADA measurements or metering reports. These may not be high accuracy, but are highly accepted. Finally, comparisons can be made at regional or ISO levels to look at wider area considerations. State estimation gives accurate results and includes inter-substation phase angles, so provides a reliable reference. With careful methodology, all measurements can be validated.

EPG has worked with many users on data validation and other data quality issues. The biggest problems seem to be failure to check out installations initially and then not using the flags, check words, and other indicators to assure the data is valid. Many problems such as signal identification and scaling can be resolved with very basic checkout procedures. Other issues such as timing signals that do not indicate loss of sync do not cause problems initially but have caused significant disruption later on. Users that display, alarm, and analyze data while ignoring validation indications do so at their own peril. This has caused problems for users at various times.

Unusual problems will crop up even with the most careful system deployment. In one case, EPG found a PMU that had an oscillation in the frequency measurement. In another, there was an A/D converter that failed for one phase input so the positive sequence measurement dropped by one-third. In yet another, the scaling resistor became intermittent so occasionally a voltage measurement appeared approximately 15% too high. And in further case, the GPS clock became unsynchronized and ran fast, the PMU did not detect the change, and the PMU data drove the combined data stream out of lock with other PMUs. Ultimately a data user should always be on the alert for measurements that just do not look right.

EPG has experience with data validation both in developing applications and in supporting users. The approaches outlined above have been used in varying degrees and found to be successful. There will always be unusual situations that come up that are not detected by these methods. While the goal of this project is to come up with more comprehensive data validation for both initial system deployment and ongoing operation, it also should flag odd conditions that do not meet a specific criterion. This work will be forthcoming in the next stages.

CHAPTER 6 – CURRENT EXPERIENCE and FUTURE PLANNING

This chapter covers information gathered about survey respondents' current experience and future plans.

Eleven out of 20 survey respondents indicate that the PMU installation went as planned and on schedule, although with issues which varied from utility to utility. There were some 'learning curves' involved in the installation and configuration of the equipment. Two respondents reported that training they received on the device usage, configuration, and settings changes during the factory acceptance tests helped them during installation. The current experience and future plans are detailed in the following sub-sections:

a. Phasor measurement system reliability.
b. Routine maintenance.
c. Planned additional PMU installations.
d. EMS integration.
e. Synchrophasor application deployment.
f. Problems Encountered.

The current experience and future plans are described in detailed for each section below.

1. Phasor measurement system reliability

Results are mixed with nine respondents satisfied with their project so far while some are experiencing difficulties. Data availability percentage is used as a measure for system reliability. The current system reliability percentage provided by the survey respondents ranges from 90% to 99.96%. One of the respondents mentioned that during the early phases system reliability was poor, but as the issues were understood and resolved, system reliability gradually improved. One ISO has a system reliability target of more than 99.99% which they hope to achieve in the near future as systems become more robust and reliable.

2. Routine Maintenance

Routine maintenance has not reached a high degree of concern since most systems are not yet fully implemented. A PMU is similar to a relay or a DFR and is often a function within one of these devices. Consequently most utilities plan to treat their PMUs the same as these devices for installation, operation, and maintenance programs. Most respondents (14) expect to use the same maintenance schedule and routine as for relay and DFR equipment, which is on a 3-7 year cycle, although one utility foresees more frequent maintenance requirements from the ISO. This maintenance is typically planned around the normal DFR/relay routine, and therefore PMU functions may not be completely tested. However one utility plans an annual validation of the equipment and some others plan to look at the output of PMU measurements. Two of the utilities replied that any application-related maintenance would be carried out at the ISO level. One utility would follow exception based maintenance rather than having a routine maintenance plan for synchrophasor network. Another small utility has no defined maintenance plan for PMUs other than installing quarterly patches on PDCs and servers.

Communications to the control center from the substation is usually handled by a communications group. Maintenance for communications network follows the usual maintenance schedule. The IT group manages maintenance of PDC, visualization, archiving, and other control center applications including local network communications. This includes routine checking and monitoring the host computers, routers, and switches for problems. Some respondents mentioned participating in firmware upgrade programs with vendors to keep their PMUs up to date. Additional software maintenance requirements would be upgrades related to application support, IT infrastructure and standards compliance. One utility plans to have the standard life-cycle asset management plan for PMUs which will indicate replacement requirement at a given point.

a. Planned additional PMU Installations

Several North American utilities have active plans to install additional PMUs in the near future. To put into perspective, one utility plans to increase the number of PMUs installed from 5 at present to approximately 40 within 5-6 years. Their motivation for adding more PMUs is improved wide-area visibility. The higher voltage level substations get more priority for PMU installation. Hence, most of the utilities plan to install PMUs at all the remaining Extra High Voltage (EHV) substations or at any new EHV substations. The second priority for the utilities is to install PMUs at important 345 kV and 230 kV substations (existing or planned) with lesser priority for lower voltage levels (<230 kV). One utility surveyed plans to cover around one-third of its 138 kV network in near future. A few utilities may expand the installation of PMUs to distribution system in long term depending upon requirements and budget allocations.

The PMU placement at substations and the lines/buses to be monitored are most often dictated and defined by the respective ISO or reliability coordinator such as WECC. In these cases, the regional group proposes or recommends the PMU locations for the member utilities. However several utilities are planning more deployments for their own benefits and in addition to the regional requirements. In this case, the utility planning departments determine PMU locations, signals to monitor, and deployment schedule.

New deployments focus on monitoring system dynamics. Many of the utilities are planning to deploy PMUs at the major generation plants (output more than 100 MW; for some utilities as low as 20 MW) enabling the system operators to observe power system dynamics at generators in real-time and planning department to verify the generator parameters and validate the models. Additionally, the utilities with significant wind power generation in their territory have plans in place to install PMUs at the point of interface (POI) with the transmission grid. PMU data can be used to analyze the effect of wind generation on system frequency and voltage. Some utilities would like to have PMUs on all major tie lines with neighboring utilities and on the regularly stressed transmission lines within their service territory. Still others plan to install PMUs at HVDC substations and substations with existing FACTS devices such as SVCs. One utility with radial distribution system noted that switching can cause islanding; therefore it would like to have visibility across the radial system using phase angles. Yet another utility noted that there is a WECC requirement to recertify all the generators above 20 MW for the dynamic characteristics related to the generator models. This recertification can be done using real-time visualization of PMUs; hence the utility plans to install PMUs at all such locations. It was recommended that utilities received data from neighboring utilities for better visibility.

Another motivation for installing new PMUs is to replace obsolete PMUs, relays and DFRs that do not conform to the present standards. Some utilities planning to retire old relays

would replace them with those having PMU capability. Similarly, some other utilities would be replacing old DFRs with PMU-enabled DFRs. In such cases, the usual relay/DFR replacement schedule would be followed, rather than taking into account any PMU placement schedule. One of the utilities has plans to replace and redefine its complete synchrophasor system.

Some utilities have no expansion planned for their synchrophasor system. However, they would be adding the PMU functionality to any new relays installed in their substations in the future so the capability would be available if it is needed.

b. EMS Integration

A large number of utilities and ISOs have plans to integrate phasor measurement systems to their EMS systems. As with data problem detection applications, many of the survey participants look to vendors for EMS interfacing and integration solutions. The integration of phasor data with EMS will serve to supplement the traditional SCADA systems and also validate measurements from SCADA. Such applications can be used for a variety of uses such as angle separation warning prior to switching. Some of the utilities are currently sending limited phasor data such as phase angle, voltage, power and frequency signals to the EMS and plan to send complete data as and when the application capabilities increase in future. Many of the utilities plan to use phasor data for state estimation (SE), including hybrid, distributed, and linear SE. Some comparison has already been done between phasor data and SE and the results have been good. One utility in the survey noted that they plan to use linear SE with phasor data and switch to non-linear SE as an alternate when the GPS sync is lost. Many of the utilities are planning to integrate phasor data to SE through PI. Most of the utilities with plans for SE integration plan to down-sample and send 1-4 samples/second of phasor data to SE. Universities are also playing a big role in the development of these novel applications, working in collaboration with industry. While the ability now exists to incorporate phasor data into EMS applications, some companies do not have any immediate plans to move forward with this type of integration due to budget limitations and cyber security compliance concerns.

Table 8 summarizes survey responses of the integration of phasor data with EMS systems.

Number of companies having linked phasor measurement system to EMS	5
Number of companies with plans to link phasor measurement system to EMS	7
Number of companies with no plans to link phasor measurement system to EMS	3

Table 8 – Integration of phasor data into the EMS

c. Synchrophasor application deployment

Synchrophasor applications are here defined as tools that provide usable information from synchrophasor data. All applications at this point are computer programs. These can be generally categorized as real-time result oriented, archiving, and off-line analysis. Real-time applications range from situational awareness type for operations to hard real-time for automatic control and protection. Archiving applications record data in files, historians, or databases. Off-line analysis uses archived data for detailed system and performance analysis. Some of the applications either reported in use or anticipated in the future include:

Real time:

1. System visualization.
2. Islanding detection.
3. Event detection.
4. Situational awareness alarms.
5. Line monitoring.
6. Fault Location.
7. Error Monitor and Notification.
8. Data Quality Monitoring System.
9. Data Error Detection and Correction.
10. Validation of Models in Real-time.
11. Improved State Estimation.
12. Wide Area Reactive Control.
13. Power Flow Control.
14. On-line Measurement and Model Based Stability Assessment.
15. Protection.

Off-line analysis:

1. System performance analysis.
2. Parameter Validation.
3. Line Rating analysis.
4. Model Validation.
5. Planning Support.
6. Islanding Planning.

Most of the survey respondents expressed an interest in applications for the data and in acquiring applications for their own use. Real-time visualization was commonly mentioned, probably because this type of application is widely used to demonstrate synchrophasor capability. However, relatively few respondents are actively using this type of application. Some seem to prefer using a reduced data set reported to the EMS for alarms and operation support. Archiving is widely used as most respondents save data to a historian, database, or files. Many also do some kind of analysis based on this data.

These results are summarized in Table 9.

Application type	Currently using	Plan to use	No plans
Situational awareness (visualization)	2	6	4
Alarms/analysis using EMS	1	8	4
Archiving	16	2	4
Off-line analysis	15	4	4

Table 9 – Survey respondent synchrophasor application use (not all respondents reported on this)

Survey participants also stressed the need to have phasor data streams from neighboring utilities and better coordination between them and the ISOs. Phasor data is an effective way to bring together a wide-area view of the grid, and data sharing is the only way to make this happen.

Another fact that emerged from the survey is the need to have good training for engineers and operators who would be using the phasor data in the future. Without this, the benefit of these systems will not be utilized.

Some utility companies are planning more development on phasor measurement systems for their own benefits in addition to ISO or other requirements. For instance, one company has a plan for in-house development of a data quality monitoring system and is also exploring the possibility of hybrid systems such as on-line measurement based and model based stability assessment. Several utilities mentioned collaboration with universities for application development and improvement. They also mentioned that universities themselves are developing synchrophasor applications.

Besides measurement and monitoring, some companies are also aiming at developing software for control. There were discussions about wide-area control, power flow control, and planning support. However none of them had a budget or plan yet.

d. Problems Encountered

Utilities dealt with problems both at technical level as well as administrative level. Generally the problems were in learning about the system components and their idiosyncrasies. For example, compatibility issues between components (ex. PMUs and routers, PMUs and GPS devices, etc.) were uncovered. In some cases these required vendor involvement to resolve the issue. There were very few reported component failures, such as PMUs, PDCs, local PCs, servers, switches, routers, cables etc. The impact and time to resolve problems varied from utility to utility. Issues regarding data availability, data quality and data accessibility have surfaced consistently during the surveys. Several utilities mentioned working on the tradeoff between latency and loss of data due to limitations of the communication network. One utility noted that it is expected that something would be wrong at any given time with the large number of PMUs they have in service.

Some important issues reported and key observations are listed below:

1. Problems related to changing device settings/firmware.
2. Issues with phasor data availability in off-line system.
3. Confusion in migration from older “dst” file format to newer “COMTRADE” file format.
4. There were issues with installing DFRs with PMU capability, as their configuration is different from that of other PMUs.
5. One utility surveyed noted that they should have kept the new project focused on PMUs only, instead of reconfiguring/upgrading communications as well; which made the project complicated.
6. Some of the data loss problems were attributed to the communications system. One particular example involves transmitting data from analog modems over to the digital microwave network, which caused data loss. There have been problems with dropouts from WiMax and Ethernet network. Additionally, many of the utilities surveyed would like to have more bandwidth than what they have at present.
7. Naming convention differences between TO and ISO caused confusion. Some PDCs do not support name translations.
8. There have been problems of PDC crashing and PDCs getting locked up which requires resetting. There were problems with PDC to PDC communication and lack of remote PDC access made configuration difficult.
9. Two survey respondents pointed out they did not have enough resources or personnel to make full use of this technology. They recommended a designated synchrophasor team, because the people working on synchrophasors have multiple tasks going on and have trouble keeping up. This lack of resources leads to delayed response when issues come up. One utility noted that more people are needed during the learning curve with fewer people required afterwards.

10. One utility said they would like to measure only positive sequence and possibly negative sequence signals, not all the three phase phasors (as they do now), to save bandwidth.
11. One of the utilities pointed out that having *external* shunts on some of the devices made PMU installation easier; as the circuit did not have to be taken out during installation (*internal* PMU shunts require breaking the CT circuit for installation).
12. One utility recommended that since synchrophasor technology has its own special characteristics, proper training to the users beforehand is essential for the success of the project. This way people working on the project can engage in more effective communication between ISO and TO. Also helpful would be an official synchrophasor project and team, which would make the project easier to track.
13. The PDC should detect data problems and send automated email notifications to the users.
14. There should be notification about PMU service status so someone receiving data understands when the PMU is under test or out of service.

CHAPTER 7 – CONCLUSIONS

This report is an assessment of the current state of the art of synchrophasor systems in North America. It is drawn from direct utility surveys, published literature, and EPG experience. Development is robust and well distributed across the whole continent. The SGIG process has had a very large impact to spur deployments, adding new infrastructure and encouraging coordination through ISOs and reliability organizations. However the projects are new and most are not fully operational. Several areas will need more attention as these projects mature.

Most of the projects are managed by a small group representing the substation, communication and control center aspects of the project. Several reported being pressed to meet the demands of the project and keep up their other department work as well. Most did not have a clear plan for how the project would be staffed once the implementation phase is past. Utilities need to be planning for sufficient staff and process to keep these systems fully operational as they become more integrated into utility operations.

Most utilities did no PMU testing or other examination of their performance. They did not check the actual measurement calibration when they were installed. Most TOs only validated the measurement by comparison with SCADA, but some did no checking at all. While the SCADA comparisons will at least validate the installation, the high PMU accuracy is nullified without careful calibration procedures. At a minimum, spot checking of PMU calibration and some checking of the measurement at the substation would assure that PMUs measurements are at a level consistent with the overall system potential.

Very few utilities employ on-line error detection. Even if the installation is validated, it is necessary to monitor the data to detect changes or failures. The object of this study is data validation and conditioning, which could be highly useful based on this survey.

The principal open question seems to be how these systems and the data will be used. This study showed there are few utilities actively using real-time phasor data. Most are archiving data and many use the data in some type of off line analysis. However, the off-line work appeared to be of very limited scope, with many only looking at strip charts occasionally. Many are expecting to make use of real-time data, so this will be the developing area. It appears most utilities are looking to vendor solutions, so it will be incumbent on developers to come up with products that enhance utility real-time operations.

APPENDICES

Appendix A – Surveyed Utilities

The following utilities participated in the survey, either by interview or submitting a filled in survey.

1. Alberta Electric System Operator.
2. Ameren.
3. American Electric Power.
4. American Transmission Company.
5. Arizona Public Service.
6. Baltimore Gas and Electric.
7. BC Hydro.
8. Bonneville Power Administration.
9. Dominion Power.
10. Idaho Power Company.
11. ISO-New England.
12. Los Angeles Department of Water and Power.
13. Manitoba Hydro.
14. New York Power Authority.
15. ONCOR.
16. Oklahoma Gas and Electric.
17. PEPCO.
18. PJM Interconnection, Inc.
19. Salt River Project.
20. Southern California Edison.

Appendix B – Documents Reviewed for Study

The majority of documents with relevant information were in the NASPI document repositories which can be found on the Web at https://www.naspi.org/meeting. A total of 345 NASPI documents and 29 IEEE and other technical papers were reviewed. The following lists are the documents that were found to be directly relevant to this study and were used in preparation of the report.

NASPI and WECC Presentations

1. "ABB WAMS Capabilities -Synchrophasor Enhanced State Estimator," NASPI Bellevue 2008.
2. "AREVA Activities Related to SynchroPhasorMeasurements," NASPI Bellevue 2008.
3. "Methods of Optimal PMU Placement, Machine Internal State Estimation and Voltage stability and Adaptive distance relaying," NASPI Charlotte 2008.
4. "GridStat and the NASPInet Data Bus Concept," NASPI Charlotte 2008.
5. "Modeling NASPInet Data Flows," NASPI Charlotte 2008.
6. "Distributed State Estimator at U.S. Virgin Islands," NASPI New Orleans 2008.
7. "PG&E Phasor Data System," NASPI New Orleans 2008.
8. Enhancement of State Estimation Results using Phasor Measurements," NASPI New Orleans 2008.
9. "Distributed State Estimator -SuperCalibratorApproachDelivering Accurate and Reliable ata to All," NASPI Sacremento NASPI 2009.
10. "NIST interoperability standards update," Oct 2009
11. "Synchrophasors: Questions from systems perspective," NASPI June 2010
12. "Dynamic performance requirements for phasor measurement units," NASPI Feb 2010
13. "NASPInet and standards development," NASPI Feb 2010
14. "Debugging PDC to PDC data flows," NASPI June 2011
15. "Synchrophasor based tracking three-phase state estimator and its applications," NASPI Oct 2011
16. "Lessons from the field: Dominion," NASPI Oct 2011
17. "American Transmission Company-Lessons from the field," NASPI Oct 2011
18. "Performance Monitoring and Model Validation of Power Plants," NASPI Sacramento 2009.
19. "Lessons from the field: Dominion," NASPI 2011.
20. "Synchrophasor Based Tracking Three-Phase State Estimator and its Applications," NASPI 2011.
21. "A Novel Disturbance Recording and Playback Scheme via a Distributed Dynamic State Estimator," North American SynchroPhasor Initiative (NASPI) meeting, February 2012.
22. "Accuracy of Line Parameters Calculation from Synchrophasor Data in Steady State and During Contingencies," NASPI meeting, February 2012.

23. "Analysis of Synchronization and Accuracy of PMU Measurements in an Operational Power System," NASPI meeting, February 2012.
24. "Fast Real-Time Oscillation Detection," NASPI meeting, February 2012.
25. "Modeling the Delay in Signal Transmission for SynchroPhasor Based Power System Controllers," NASPI meeting, February 2012.
26. "Oscillation Use Cases," NASPI meeting, February 2012.
27. "PMU Time Source Security," NASPI meeting, February 2012.
28. "Synchrophasor State Estimation with Error Correction," NASPI meeting, February 2012.
29. "The Virginia Tech PMU and PDC Test System," NASPI meeting, February 2012.
30. "Three-phase Instrument Transformer Calibration with Synchronized Phasor Measurements," NASPI meeting, February 2012.
31. "How to Manage and Use Synchrophasor Data in a Meaningful Way in Real Time Environments," NASPI meeting, June 2012.
32. "Advanced Analytics and Visualization of PMU Data," NASPI meeting, June 2012.
33. "Overcoming Technical Challenges of Synchrophasor Data," NASPI meeting, June 2012.
34. "PG&E Synchrophasor Project Communication and Data Quality of issues," NASPI meeting, October 2012.
35. "MISO Communication and Data Quality Issues," NASPI meeting, October 2012.
36. "NYISO SGIG Project Design," NASPI meeting, October 2012.
37. "PJM Design Goals for Data & Systems," NASPI meeting, October 2012.
38. "PMU Based Real-Time Oscillation Monitoring," NASPI meeting, February 2013.
39. "Synchrophasor-Based Power System Control in Central America," NASPI meeting, February 2013
40. "Linear State Estimator and Synchrophasor Data Conditioning and Validation," Jim Thorp WECC WISP January 2013

Technical papers

1. Q. B. Dam, S. Mohagheghi, R. H. Alaileh, G. K. Stefopoulos, G. J. Cokkinides and A.P.S. Meliopoulos, "A laboratory setup for relay and GPS-synchronized equipment transient testing," IEEE Power and Energy Society General Meeting-Conversion and Delivery of Electrical Energy in the 21st Century, pp. 1-8, 2008

2. R. Sodhi, S.C. Srivastava and S.N. Singh, "A transient monitor to reflect the quality of
3. Synchrophasors," IEEE Power and Energy Society General Meeting, pp. 1-6, 2010

4. M. Karimi-Ghartemani, M. Mojiri, A. Bakhshai and P. Jain, “A phasor measurement algorithm based on phase-locked loop,” IEEE PES Transmission and Distribution Conference and Exposition (T&D), pp. 1-6, 2012

5. M. Kokalj, M. Lindic, B. Voljc, B. Pinter, Z. Svetik and R. Lapuh, “High accuracy signal parameter estimation algorithm for calibration of PMU devices,” Conference on Precision Electromagnetic Measurements (CPEM), pp. 288 – 289, 2012

6. R. Garcia-Valle, G. Yang, K. E. Martin, A. H. Nielsen and J. Østergaard, “DTU PMU laboratory development – testing and validation,” IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT Europe), pp. 1-6, 2010

Appendix C – Questionnaire used for utility survey

Data Conditioning and Validation Questionnaire

All questions refer to your synchrophasor measurement system and related applications.

1. System Design

What design criteria was used for the system including:

a. System architecture
b. PMU placement
c. PMU selection
d. Signals (phasors) to be measured
e. Communication types, requirement and performance (reliability, bandwidth, latency)
f. Overall system security

2. System Administration

a. What is the system management structure (system design, implementation and operations)? Include sub-groups and activity roles.
b. How do the users provide feedback to system administration for their needs and concerns?
c. Who (organizations & staff) has access to what parts of the system? Who is responsible to make the changes to the system? How are users notified?
d. When separate parties own or operate parts of the system, what is the process for communication of configuration, setting, parameter, or naming changes?
e. Is there a record of changes made, challenges faced, resolution concluded during each configuration change?

3. System Implementation (Installation & Measurement validation)

a. Were the PMUs tested before installation?
    a. Every unit or just a sample unit?
    b. Was each unit calibrated?
b. Once installed, were the PMUs tested?
    a. Use test equipment to inject precise signals or only use power system signals (in-service tests)?
c. Were the PMU measurements validated against other measurements in the following locations?
    i. Substation
    ii. TO control center
    iii. ISO control center
    - ✓ What measurements in each location were used to validate the PMU measurements?
    - ✓ Were the PMU measurements compared with state estimator at TO and ISO control center?
    - ✓ After validation, were there any PMU settings/adjustments/configuration changes required?

4. Operational data validation systems (routine and trouble resolution)

a. What kinds of on-line monitor functions/applications/indicators are installed now or planned for future to detect data problems?

b. Key features of the data validation functions -
   i. Do they use quality flags imbedded in the data?
   ii. Do they perform sanity checks for certain measurements (voltage mag, etc)?
   iii. Do they check databases between different parts of the system within the operating console? Do they also check database between the operating console and the PMU/PDC from other TO's?

c. What action do they take if an error is detected?
   i. Visual alarms and/or audible alarms? Flag data record? Do they send alarms to central processing (EMS or system monitor)?
   ii. If there is a procedure to determine the likely cause of the data problems, describe the process/work flow of data problem determination?

d. What are the techniques used for bad data filtering or repair after errors are detected?

e. How is each type of problem handled? Ie, is sync errors handled differently from invalid data?

f. Is there any data fill-in or repair techniques being used? If so, what are they? Are they effective?

g. System problem resolution –
   i. What is the procedure for notification (who is on the notification chain, what information is communicated, what is the line of authority, etc.)
   ii. Are there any written or on-line guidelines for determining the problem and action to be taken? Is there an intelligent application analyzing the problem and suggesting methods for resolution?

h. Are there on-line monitor functions/applications/indicators included in any other real-time applications?
   i. Real-time visualization? Real-time event detection (oscillation, line flow limits, etc)?
   ii. Real-time control remedial schemes/actions (during a generator drop, capacitor switching)?
   iii. Off-line operational analysis? Off-line planning studies?

i. Is routine maintenance of the system planned? If so, what is the plan?

j. Is there a plan for upgrades or replacement of system of components? If so, what is it?

5. Documentation

a. Is there a documentation plan for the existing phasor system and its architecture?

b. Does the documentation include the following details
   i. Signal source information and parameters (PT/CT types, ratios, calibration, etc)
   ii. PMU installation information and settings (# PMUs, vendor, # phasors, types, filtering, window, data rate, etc)
   iii. Communication identification and parameters (Communication type, Intermediary stations of communications, architecture/layout of intermediary stations, etc)
   iv. PDC and other processing equipment parameters, specifications, settings, redundancy
   v. Application list, settings, location of servers and data flow

vi. Security information (Data sharing, Application sharing with outside parties)
vii. Initial and periodic maintenance check and test results

6. Current experience
a. Do you find that installations went as planned? What would you do differently?
b. What is your system reliability experience so far?
c. What is your data loss rate? Component failures?
d. Other problems?

7. Future plans
a. Is there a plan for installing more PMUs in the future? Does this have a priority list?
b. Are there any additional applications planned for future to detect data problems?
c. Are there applications you have thought of or would like to see using synchrophasor data?
d. If there is any existing/future plan to link the phasor measurement system to the EMS? If already integrated, describe the integration methodology and how long it has been active?

8. Further comments from participants
a. Are there any additional comments/feedback/changes/wishes to be made regarding your system?
b. Apart from the roster of questions, is there any distinct procedure/plan/process adopted regarding PMU location, PMU type, communications, central facilities and application deployment.
c. What is the most successful part of your phasor project? (system design, implementation and operations)
d. What is the lease successful part of the project or problem resolution?
e. What new applications should be incorporated to improve the following
   i. System performance
   ii. Data Conditioning
   iii. Data Validation
   iv. Data Detection and Correction
   v. System Management
f. Would you like your company name to be confidential?
   i. Not be listed at all?
   j. Not be associated with statements you contributed?

[As a matter of policy EPG will not associate any company name with any specific information contained in any report in this project without getting advance permission to do so. EPG does not expect to see the need to mention any company in association with the survey, but if there is something particularly noteworthy, will consider a mention and discuss it with the particular company.]