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Factors Affecting PMU Installation Costs

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Executive Summary

Installing synchrophasor systems involve a number of strategic and tactical decisions for which there is little empirical data. This report identifies the major decision points and provides qualitative information regarding cost impacts of those decisions. It also documents some good practices and lessons learned regarding synchrophasor system installations.

Interviews of nine companies that participated in the SGIG/SGDP synchrophasor projects revealed several key drivers of costs for installing PMUs. In order of relative importance, these drivers are:

Communications: The majority of the participants identified communications installations and upgrades as the most significant factor affecting PMU acquisition and installation costs. One utility reported that, absent adequate existing communications, upgrades to communications infrastructure increased the cost of installing PMUs by a factor of seven. However, once a high-speed backbone telecommunications network is installed, the cost of installing additional PMUs is relatively low.

Security: Cybersecurity requirements were the second most significant factor affecting PMU acquisition and installation costs. The participants used two approaches:

- ***Mission-critical systems***. Used for making operational decisions or to drive automatic control actions.
- ***Mission support systems***. Used for monitoring system conditions and for offline capabilities that do not directly affect operations.

Three of the participant utilities built mission-critical synchrophasor systems and designated them as critical cyber assets, complying with the most extensive NERC Critical Infrastructure Protection (CIP) requirements. The remaining participants built mission-support synchrophasor systems that require adherence to a less demanding set of CIP requirements. One utility estimated that deploying a mission-critical PMU system increased its PMU installation costs by a factor of two over the amount required for deploying a mission-support PMU system.

Synchrophasor technology was invented some 30 years ago, but wide-scale deployment of production-grade synchrophasor systems in the United States began only recently, in large part due to funds from the U.S. Department of Energy's (DOE's) Smart Grid Investment Grant (SGIG) Program and Smart Grid Demonstration Program (SGDP), matched by private investment. These programs applied funds made available by the American Recovery and Reinvestment Act of 2009.

<u>Labor:</u> To install and commission PMUs, the participant utilities used two approaches:

- ***Specialized crew.*** Specialized training and tools were provided to a single crew which handled all of the installations (minimizes learning curve).
- ***Decentralized crews.*** Training was provided to technical personnel across the system where PMUs were being deployed (minimizes travel time to and from installation sites).

While labor was a significant cost driver, neither the specialized nor the decentralized crew strategy emerged as a good or lowest cost practice. Rather, the optimum choice between these two approaches depended on the number of miles to be driven by the installers and the number of PMUs to be installed. However, one practice to significantly reduce labor costs is to coordinate PMU installations with other planned substation outages.

<u>Equipment:</u> The final cost driver was the PMU hardware cost; this was typically less than 5% of the total installed synchrophasor system costs.

The average overall cost per PMU (cost for procurement, installation, and commissioning) ranged from $40,000 to $180,000. Synchrophasor systems used for making operational decisions or that drive automatic control actions have the most extensive system requirements and thus incur the highest costs.

Transmission utilities that had prior experience with PMUs were better able to define the functional requirements for their synchrophasor systems. Sharing information through the North American SynchroPhasor Initiative and other forums, however, served to develop and improve good practices across the industry for assessing synchrophasor requirements, developing procurement specifications, installing and commissioning PMUs, and validating PMU data.

With the deployment of synchrophasor technology under the SGIG/SGDP projects, transmission owners and system operators are continuing to gain valuable insight into the deployment of production-grade synchrophasor systems and are seeing value from the increased grid observability they provide. With the data presented in this report, synchrophasor system planners can now develop approaches for each of the major cost drivers to address their specific power system challenges within the financial constraints of their companies.

Factors Affecting PMU Installation Costs

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I. Introduction

A power system must be designed and operated with appropriate reserves and protective equipment to be able to survive contingencies—the sudden unavailability of the largest and most critical generator and transmission line assets. In an effort to share critical assets, and thus improve the reliability of power systems, these systems interconnected into what we know as today's power grid. However, as power systems became interconnected, their complexity grew. Their operation not only became much more difficult, but the consequences of a critical mistake or an unforeseen incident were compounded. Outages didn't just affect a building; in 1965 the country discovered that one misoperation or equipment overload could black out a major portion of North America for an extended time. And when a problem occurs, it can propagate quickly; leaving little time for the system operator to detect the problem and take corrective action.

This, of course, raises the planning question of, "How much reserve and protection is enough?" and the operating question of, "How do I know when I'm in trouble?" Technology advances in sensors, communications, data processing, and computing power have given rise to the "Smart Grid" and promise to significantly advance capabilities associated with power system planning and operations. Achieving discernment from these new technologies has been a key barrier: What is the power system doing, and how is any particular piece of equipment, and the system as a whole, really responding? Supervisory control and data acquisition (SCADA) systems that have been the state-of-the-art for monitoring power systems typically provide data every 2 to 4 seconds. Synchrophasors dramatically advanced that state-of-the-art.

Synchrophasor technologies and systems use monitoring devices called phasor measurement units (PMUs) to measure the instantaneous voltage, current, and frequency at specific locations in an electric power transmission system (or grid)[1]. PMUs convert the measured parameters into phasor values[2], typically 30 or more values per second. PMUs also add a precise time stamp to these phasor values, turning them into synchrophasors. Time stamping allows these phasor values, which are provided by PMUs in different locations and across different power industry organizations, to be correlated and time-aligned and then combined. The resulting information enables transmission grid planners and operators to have a high-resolution "picture" of conditions throughout the grid in real time.

[1] These parameters represent the "heart-beat" and health of the power system. Voltage and current are parameters characterizing the delivery of electric power from generation plants to end-user loads, while frequency is the key indicator of the balance between electric load and generation.

[2] A primer on synchrophasors and phasor values is provided in the report "Synchrophasor Technologies and their Deployment in the Recovery Act Smart Grid Programs" dated August 2013. https://www.smartgrid.gov/recovery_act/program_impacts/applications_synchrophasor_technology

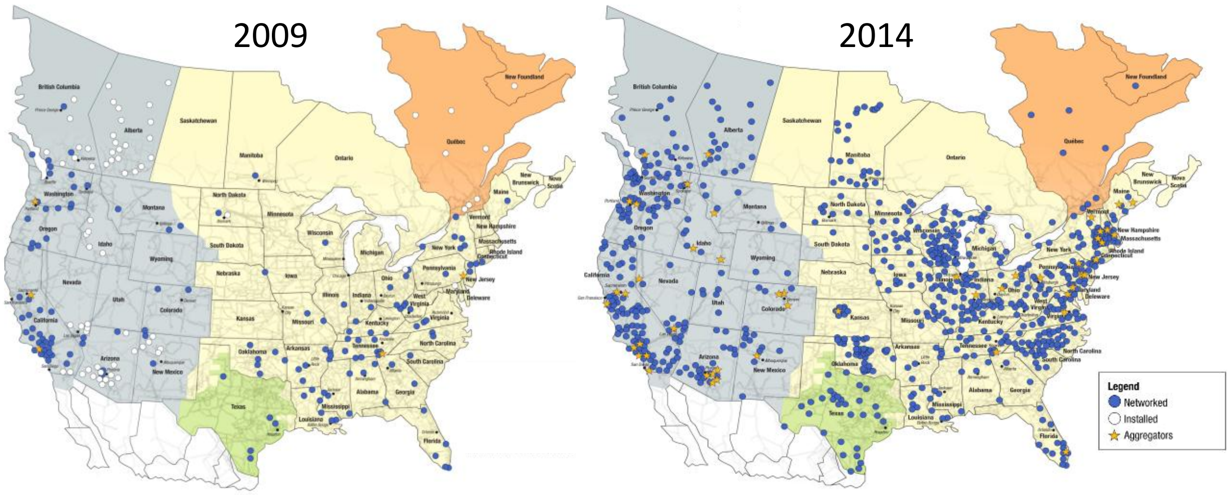
Synchrophasor use has been increasing since 2004, when the U.S.-Canada blackout investigation report recognized that many of North America's major blackouts have been caused by inadequate situational awareness for grid operators, and recommended the use of synchrophasor technology to provide real-time wide-area grid visibility. While synchrophasor technology was invented in the 1980s, its presence in commercial power systems was limited mostly to research applications, so the technology was rarely used in an operational environment. To achieve its potential, synchrophasor technology requires:

- Installation of numerous PMUs to create a "critical mass" of sensors that could truly characterize network operations
- A communications system capable of transmitting large amounts of information at a time scale short enough for it to be useful by system operators
- Data management and handling systems to process large volumes of real-time synchrophasor data
- Applications software to use the synchrophasor information to improve the modeling, forecasting and controls of the grid
- Standards for data and communications to enable sharing of information from PMUs across the grid.

The Smart Grid Investment Grants (SGIG) and Smart Grid Demonstration Projects (SGDP) for synchrophasor and communications systems were funded by the American Recovery and Reinvestment Act (ARRA) of 2009. These projects marked the first time that many transmission utilities had procured and installed modern, production-grade PMUs on an operational scale. These also mark the first time that most independent system operators (ISOs) and regional transmission operators (RTOs) contemplated the use of synchrophasor data applications. Between 2009 and 2014, the federal grants and matching private investments (recipients provided 50% or more cost share) increased the demand for production-grade PMUs and synchrophasor data applications. This, in turn, accelerated the evolution of relevant technical interoperability standards and guidelines.[3] This helped bring the technology into the mainstream of the electric utility industry across the North American grid. Figure 1 shows the increase in PMU deployments from 2009 to 2014.

[3] These include advances in C37.118, IEC 61850, and guidelines written by the NASPI Performance Standards Task Team. Interoperability standards and guidelines are outside the scope of this report. Additional standards and guidance for synchrophasor hardware, information technology and applications are still being developed.

Figure 1. Phasor Measurement Units across North America



Source: North American Synchrophasor Initiative (NASPI)

The required investment for a synchrophasor system is large, but significant additional benefits are realized when numerous interconnected utilities and system operators install PMUs and share their data. Industry cooperation, including technology transfer activities and organizations supported by DOE, has been crucial in spurring the implementation and facilitating the operation of synchrophasors. The North American Synchrophasor Initiative (NASPI) was established as a platform for industry collaboration to improve power system reliability and visibility through wide area measurement and control using synchrophasor technology. It is a collaborative effort between the U.S. Department of Energy (DOE); the North American Electric Reliability Corporation (NERC); and North American electric utilities, vendors, consultants, federal and private researchers and academics. NASPI activities are funded by DOE, facilitated by the Electric Power Research Institute (EPRI), and supported by NERC and the voluntary efforts of many industry members and experts.

DOE and private sector efforts, including NASPI, have developed and improved best practices for assessing a transmission utility's synchrophasor requirements (capabilities and location), developing procurement specifications, installing and commissioning PMUs, and validating PMU data[4]. Such practices reduce the cost (in equipment and personnel) and time needed to implement and commission a synchrophasor system.

As SGIG/SGDP grant recipients installed or enhanced synchrophasor systems, it was apparent that there were numerous types of PMUs available, with associated differences in costs and communications requirements as well as variances in the effort needed for installation and

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[4] For example: Zhang, Q., et al, "PMU Data Validation at ISO New England," IEEE 978-1-4799-1303-9/13, Institute of Electrical and Electronics Engineers, 2013. This work was supported by the U.S. Department of Energy under Grant DOE-FOA 0000058 ARRA.

commissioning. Users' choice of the equipment and supporting infrastructure depends on the anticipated uses of the synchrophasor data (applications) and the characteristics and capabilities of existing sensors and communications systems. The objective of this report is to provide guidance and "lessons learned" to the utility industry that will facilitate future PMU installations and reduce their costs. This report addresses those objectives by delineating the options, key characteristics, and aspects of the evaluation process in order to help transmission utilities select the most appropriate synchrophasor technologies and designs.

Overview

This study explores the high level requirements and cost determinants of synchrophasor procurement and installation in the SGIG/SGDP synchrophasor projects. The scope of the study examines the costs to procure, install, and commission synchrophasors to the point where the PMUs are obtaining and reporting data[5]. Based on interviews with several of the SGIG and SGDP award recipients, this study reviews the basic cost elements of synchrophasor technology, cost determinants based on functional needs and characteristics of existing assets and infrastructure, methods used by grant recipients to select technologies and lower final costs, lessons learned, and best practices identified through the course of the projects.

This report is not intended to provide a robust quantitative analysis of specific or detailed cost data. It is difficult to analyze and document the SGIG/SGDP projects' synchrophasor costs in a systematic way. When the SGIG/SGDP projects were undertaken, PMUs were still a relatively new technology with few standardized specifications and practices or guidelines for PMU placement, installation, communications, commissioning, or use. In addition, each of the ARRA synchrophasor projects had different goals and considerations for its project based on the specifics of their electric power systems, and each kept cost records based on internal processes.

Study Participants

Information for this study came from interviews of several of the larger SGIG/SGDP award recipients and through review of presentations delivered at the NASPI Work Group meetings. The companies interviewed for this study were chosen because of their historical participation in the NASPI community and because they have been leaders in sharing observations and insights about the factors affecting PMU installation costs. The utilities contributing to this report are listed in Table 1. Further information on these DOE projects can be found on the SmartGrid.gov website[6].

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[5]"Installed" PMU costs cover what is necessary to have PMUs that are functioning properly and reporting their data. This includes planning and design, engineering, hardware (i.e., PMU device), labor, infrastructure, and commissioning (i.e., making sure the PMUs are operating and their data are accurate).

[6] https://smartgrid.gov/recovery_act/project_information/?f[0]=im_field_project_type%3A5170

Table 1. SGIG/SGDP Recipients that Contributed to this Study

NERC Regions	Entity	DOE Project
Western Electricity Coordinating Council (WECC)	Bonneville Power Administration (BPA) [7]	WECC SGIG DE-OE0000364
	Idaho Power Company (Idaho Power)	SGIG DE-OE0000243
	Pacific Gas and Electric Company (PG&E)[8]	WECC SGIG DE-OE0000364
SERC Reliability Corporation	Duke Energy Carolinas (Duke)	SGIG DE-OE0000374
	Entergy Corporation (Entergy)	SGIG DE-OE0000375
Midwest Reliability Corporation, Reliability First Corporation	Midcontinent ISO (MISO)	SGIG DE-OE0000369
	American Transmission Company (ATC) [9]	SGIG PMU DE-OE0000362
	Manitoba Hydro[10]	MISO SGIG DE-OE0000369
Texas Reliability Entity	Oncor Electric Delivery Company	CCET[11] SGDP DE-OE0000194

[7] BPA is a partner and sub-recipient in the Western Electric Coordinating Council (WECC) SGIG project.

[8] PG&E is a sub-recipient partner in the Western Electric Coordinating Council (WECC) SGIG project.

[9] ATC is a transmission owner, member of MISO, and a grant recipient. ATC received SGIG funds from DOE to install PMUs and PMU data applications. ATC also received SGIG OE0000363 to install communications. MISO is also a grant recipient, and also received funds from DOE to install PMU data applications and coordinate applications and communications with its member partners.

[10] Manitoba Hydro is a Canadian company and a member of MISO. Manitoba Hydro installed PMUs during MISO's SGIG synchrophasor project. Manitoba Hydro's synchrophasor system is integrated into the MISO synchrophasor system, as they are all part of the Eastern Interconnection.

[11] The Center for the Commercialization of Electric Technologies (CCET) was a primary recipient of SGDP funding. The CCET project collaborated with Texas utilities to install PMUs. Oncor is one of the participant utilities.

II. PMU Census

The projects funded with SGIG and SGDP monies and matching private funds installed 1,400 PMUs to date. This section summarizes approximate numbers of PMUs installed by the participant utilities before, during, and after formal completion of the implementation phase of the ARRA projects. The pre-project PMU counts give insight into the level of experience that each transmission utility had with PMU technology before they began their Smart Grid projects. The post-project PMU additions indicate that some of the utilities found more value than expected (i.e., found more uses for PMU data than originally planned) in their newly installed synchrophasor systems and decided to install more PMUs.

Number of Production-Grade PMUs Installed

Table 2 indicates the number of PMUs fielded by the participant utilities before, during, and after the SGIG/SGDP projects. The columns within Table 2 describe the PMU count as follows:

- Number of PMUs in service before the SGIG and SGDP projects.
- Number of PMUs installed under the utility's original SGIG/SGDP scope of work.
- Number of PMUs added to the original scope of work. These PMUs were added within the original projects' funding levels.
- Number of PMUs added to the system beyond the project scope. These are PMUs purchased and installed by utilities after completion of the implementation phase of their SGIG and SGDP projects. They were completely utility-funded.

Participant utilities planned the number and locations of their PMUs to serve specific synchrophasor goals and uses. For instance, if the utility intended to use synchrophasor data for on-going power plant model validation, more PMUs would be installed at the points of interconnection with large generators. A project designed to facilitate wide-area situational awareness and develop operational alarms and alerts would site more PMUs at key substations across its service area and encourage its neighbors to do the same. Several of the participant utilities shared their PMU location studies and plans with NASPI members, and NASPI developed a guidance document on PMU siting informed by these analyses.[12] In addition, the NERC Regional Reliability Coordinators assisted in preparing advisory type criteria such as

[12] See J. Chow, L. Beard, M. Patel et al., "Guidelines for Siting Phasor Measurement Units," June 2011, at https://www.naspi.org/File.aspx?fileID=518; WECC, "PMU Placement Criteria, Draft 2.0," October 15, 2009, at https://www.wecc.biz/committees/JSWG/111209/Lists/Minutes/1/PMU%20Placement%20Criteria.pdf; V. Madani, M. Parashar et al, "PMU placement considerations -- a roadmap for optimal PMU placement," IEEE Power Systems Conference & Exposition, March 20-23, 2011; and two presentations at the NASPI June 9, 2010 Work Group meeting, at https://www.naspi.org/File.aspx?fileID=103.

PMU location considerations. DOE, the National Institute of Standards and Technology (NIST), and NASPI's Performance and Standards Task Team developed industry guidelines regarding nomenclature, conformance, installation, and commissioning of production-grade PMU systems.

Table 2. Approximate Number of PMUs Installed in the Study Group

Recipient	Before SGIG/SGDP Project	Original SGIG/SGDP Scope	Added to SGIG/SGDP Scope	Installed after SGIG/SGDP
BPA	25[13]	130	0	0[14]
Idaho Power	2	8	0	16
PG&E	10[15]	150	0	0
Duke	10	103	0	15
Entergy	21[16]	45	0	17[17]
MISO	15	144[18]	74[19]	0
ATC	20[20]	49	10[21]	0
Manitoba Hydro	1	6[22]	26[23]	2
Oncor (CCET)	0	9	8	0

[13] BPA installed approximately 25 research-grade PMUs prior to the SGIG projects. These PMUs are no longer in service.

[14] BPA will install 5 PMUs in 2015 followed by 5 to 8 PMUs a year through 2019. BPA's primary driver for all PMU installations is long-term and short-term planning. They have done work in model validation and have used PMUs to identify and fix governor-modeling issues, to refine system models, and to perform other functions.

[15] PG&E installed approximately 10 PMUs for experimental purposes. Five of the experimental PMUs were networked for data sharing. These 10 PMUs are not included in PG&E's count of production-level devices installed during and after the SGIG project.

[16] Entergy installed 21 PMUs prior to their SGIG project. Those installed under the SGIG replaced these PMUs.

[17] Entergy will install 3 PMUs in 2014 to support voltage stability monitoring in Entergy's western region. An additional 14 PMUs will be installed from 2014 to 2015.

[18] In addition to these 144 PMUs, 6 were provided to Manitoba Hydro.

[19] In addition to these 74 PMUs, 26 were provided to Manitoba Hydro and 10 to ATC.

[20] ATC had a project that started prior to their SGIG to install 53 PMUs. 20 of these PMUs were in service leading into the SGIG project. The remaining 33 PMUs were installed at the same time the SGIG projects were underway.

[21] ATC is a partner in the MISO SGIG project, which funded these 10 PMUs.

[22] Manitoba Hydro participated in the MISO SGIG project.

[23] Manitoba Hydro participated in the MISO SGIG project.

Post SGIG/SGDP Installations

The participant utilities planned a base level of PMU coverage for their portions of the bulk electric system. Several of these utilities found sufficient value in their newly installed synchrophasor systems to justify installing more PMUs after the SGIG/SGDP projects were completed. These post-project installations were funded solely by the utilities. Table 3 summarizes the reasons behind these additional PMU investments. In some cases, the additional PMUs improved coverage in portions of the grid prone to disturbances. For example, Idaho Power planning engineers initiated placement of additional PMUs at select generating stations to measure the extent, if any, to which these stations drive oscillations[24] currently observed on their system. PMUs were also added to enable specific synchrophasor applications. For instance, Entergy installed additional PMUs to support its voltage stability application and Manitoba Hydro added PMUs at specific generation facilities for generator model validation.

Table 3. Grant Recipients that have Installed Additional PMUs beyond SGIG/SGDP Scope

Recipient	Additional PMUs Installed	Reason for Installing Additional PMUs
Idaho Power	16	Idaho Power added 5 PMUs under the WECC Western Interconnection Synchrophasor Program (WISP) and 11 more using internal funds to enhance coverage. Idaho Power plans to install at least 5 more PMUs at generating facilities to identify oscillation sources on their system.
Duke	15	Duke installed 15 PMUs to enhance the coverage provided by its SGIG project. Duke's Operations and Planning departments identified specific locations for these PMUs.
Entergy	17	Entergy is installing 3 more PMUs to support a voltage stability application and upgrading 14 existing digital fault recorders (DFRs) to include PMU functionality to enhance coverage.
Manitoba Hydro	2	Manitoba Hydro added 2 PMUs to increase the number of channels at one substation (an SGIG PMU already existed at the location). The additional units enhance the system built under the SGIG project to facilitate model validation, support convergence of the state estimator, and support convergence of calculations by the energy management system (EMS).

[24] Low-frequency oscillations occur when an individual or group of generators swing against other generators operating synchronously on the same system, caused by power transfers and high-speed, automatic turbine controls attempting to maintain an exact frequency. http://www.nerc.com/docs/oc/rapirtf/RAPIR%20final%20101710.pdf

III. Major Drivers of PMU Acquisition and Installation Costs

This study examined the costs expended in the SGIG and SGDP synchrophasor projects to procure, install and commission PMUs and necessary infrastructure to the point where the PMUs were collecting and reporting accurate data. The elements of installed costs included not only the hardware cost of the PMU device (usually less than 5% of total installed system cost); but also the costs to design the system (specifications, drawings, data network design); installation costs; costs to transmit and manage the large amounts of data collected by the PMUs; and the resources needed to commission the PMU system, to validate the data collected. The participant utilities reported a consistent set of drivers for PMU installed costs, but the relative impacts of each driver varied from project to project because each utility differed in:

- Technical objectives for the PMU system based on power system challenges to be addressed
- Power system generation and transmission assets
- Power system asset configurations/topologies and geographic size
- System management philosophies and procedures
- Existing information and telecommunications network infrastructures.

The DOE Funding Opportunity Announcements for the SGIG and SGDP (DE-FOA-0000058 and DE-FOA-0000036, respectively) gave significant leeway to the applicants to propose PMU devices and systems that would prove to be used and useful in their unique settings.

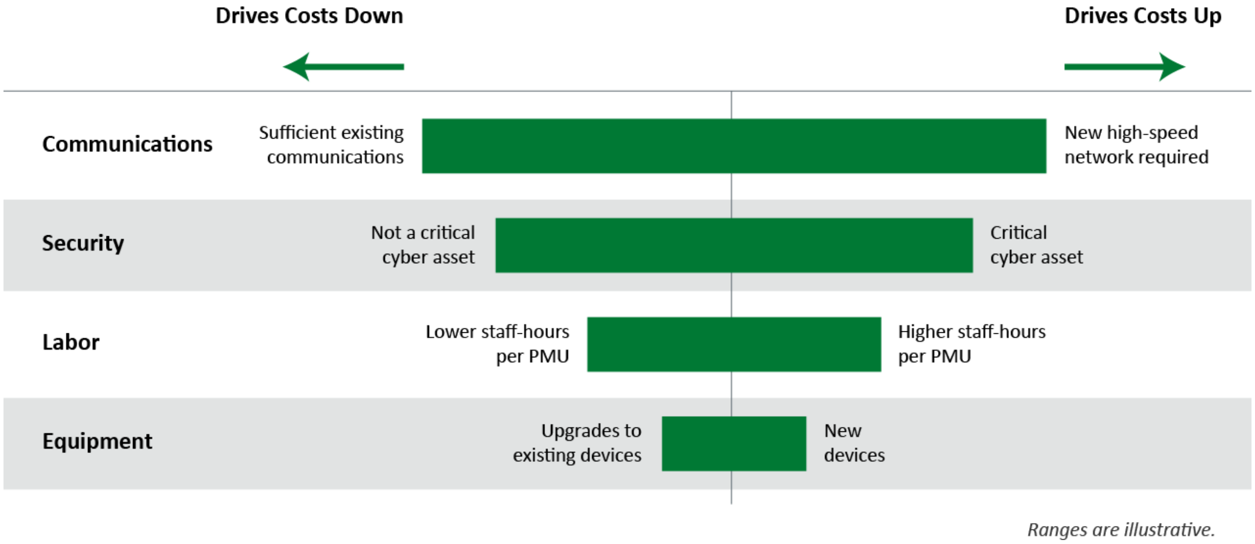
The major cost drivers for PMU acquisition and installation are listed in Table 4. They are listed in order of those with the most influence on total installed costs for PMUs. Thus, the capabilities of the communications infrastructure required to support synchrophasors and the degree to which the utility's existing communications systems could meet those requirements, were the most important determinants of the installed PMU system cost.

Table 4. Major Drivers of PMU Acquisition and Installation Cost

Major Cost Drivers	Description
Communications	Additions or upgrades to the communications infrastructure: • Media and electronics linking these sites to one another • Electronics at the PMU sites and control centers
Security	Equipment and development of procedures to meet Critical Infrastructure Protection (CIP) requirements. There were two basic approaches: • **Mission-critical synchrophasor systems.** These are to be used to make operational decisions or real-time control. • **Mission-support synchrophasor systems.** These do not provide real-time input to operations or applications.
Labor	Installation crew and support engineer labor to design and perform installation and commissioning of PMUs and related equipment and systems. Two labor deployment strategies emerged: • **Specialized crew.** Specialized training and tools were provided to one crew which handled all the installations (minimizes learning curve). • **Decentralized crews.** Training was provided to technical personnel across the system where PMUs were being deployed (minimizes crew travel time).
Equipment	Hardware components, including PMUs, required for building and operating the synchrophasor system. These fell into three basic approaches: • Deployment of new stand-alone phasor measurement units • Replacement of existing digital relays or digital fault recorders with plug-compatible new equipment with PMU functionality (does not require changes to substation wiring or instrument transformers) • Upgrading software/firmware in existing digital relays or digital fault recorders to enable PMU functionality.

In the process of interviewing the participant utilities, some cost trends became evident. However, differences among utility systems, practices, and synchrophasor applications prevent quantifying the precise extent to which each cost driver impacts the installed cost per PMU. The installed cost is the total cost for purchasing and installing a PMU. These costs include planning and design, engineering, hardware (i.e., PMU device), labor, infrastructure, and commissioning costs. Figure 2 provides a qualitative indication of these cost trends presented in order of relative impact.

Figure 2. Major PMU Acquisition and Installation Cost Drivers and their Relative Impacts



Each of these cost drivers is discussed in the following sub-sections, and a more detailed list of cost elements is presented in Appendix B.

The major cost drivers are inter-related, so decisions in one area affect each of the other areas to some extent. For example, decisions on security provisions can affect the labor and equipment categories, as security provisions require more engineering expertise (labor) and redundant, security-specific hardware (equipment), and often increase the requirements and costs of communications networks.

Each utility assessed their synchrophasor requirements: What applications were needed? Were these real-time (system control and situational awareness) or planning-related (model validation and post-event analysis)? The results of that assessment determined which technology and architecture options were chosen. Some PMUs measure only a few values; others measure a dozen or more. Many of the participant utilities purchased new stand-alone PMU units, but several utilities were able to upgrade existing digital relays or digital fault recorders already installed on their systems. To help guide the selection process, PG&E and BPA conducted extensive functional and interoperability testing of commercially available PMUs and upgradeable relays to determine their conformance to PMU technical standards[25] (existing and in development). In the end, these tests provided assurance that the PMU devices and systems deployed had the capability to accurately measure physical quantities and calculate the specific grid parameters for their synchrophasor-based applications. The installed cost of PMUs varied amongst the participant utilities according to functionality and complexity of their synchrophasor systems. The variance is reflected in the installed costs reported by the participant utilities, which

[25] IEEE C37.118 and IEC 61850 are examples of technical standards that relate to PMUs.

ranges from $40,000 to $180,000. BPA and PG&E, both members of WECC, had costs that at least doubled that of the other participant utilities. This is not surprising, when one considers the number and complexity of WECC's synchrophasor applications.

Another factor is whether the PMU data is used to make operating decisions. BPA installed PMUs for both mission-critical (trusted to make operating decisions) and mission support (used to support operating decisions with validation from trusted systems) applications. It found that the mission-critical PMUs cost twice as much than the mission-support PMUs. Table 5 shows the synchrophasor applications each participant utility planned to implement.

A more complete discussions of PMUs as an element of synchrophasor system costs is presented in Section IV.

Table 5. Planned Synchrophasor Applications of SGIG/SGDP Recipients

Functions	Projects						
	ATC (ATC is also part of MISO)	CCET (includes ONCOR)	Duke Energy	Entergy	Idaho Power	Midwest ISO (includes Manitoba Hydro)	WECC (includes BPA and PG&E)
REAL-TIME APPLICATIONS							
Oscillation detection			✓	✓	✓	✓	✓
Phase angle monitoring	✓	✓		✓	✓		✓
Frequency event detection	✓	✓				✓	✓
Voltage stability monitoring	✓	✓		✓	✓	✓	✓
Event management, alarm, restoration	✓						✓
General event detection	✓	✓		✓		✓	✓
Islanding detection	✓						✓
Wide area awareness/visibility	✓	✓	✓	✓	✓	✓	✓
Wide Area Control							✓
STUDY MODE APPLICATIONS							
Model validation & improvement	✓	✓			✓	✓	✓
State estimation model improvement	✓	✓	✓	✓		✓	✓
Power plant model improvement		✓			✓		✓
Post event analysis	✓	✓	✓	✓	✓		✓
Operator training		✓					✓

In addition to acquisition and installation costs, there are costs associated with operating and maintaining synchrophasor systems including:

- Development of applications to transform synchrophasor data into actionable information for system engineers and operators
- Training and education to make utility staff aware that the tools exist and enable them to use the tools effectively
- Management of the equipment and communications networks to make sure they work reliably.

Although not an installation cost, applications development was the highest cost that PG&E reported for its synchrophasor project. This was followed by the cost for analytics required to validate counter-intuitive information because the newly available synchrophasor data presented many surprises to system operators and planners. Because the focus of this report is on acquisition and installation cost drivers, discussion of the applications development and operations and maintenance (O&M) cost drivers is not included in this report.

Communications

The majority of the participant utilities identified communications installations and upgrades as the most significant factor affecting PMU acquisition and installation costs. One utility reported that, absent adequate existing communications, upgrades to communications infrastructure increased the cost of installing PMUs by a factor of seven. However, once a high-speed backbone telecommunications network is installed, the communications cost for additional PMUs is relatively low. Synchrophasor communications costs include:

- Telecommunications networks and components (repeaters, towers, etc.) linking sites to one another
- Electronic devices installed at the PMU sites and control centers.

Synchrophasor systems have latency, data quality, and bandwidth requirements that surpass other grid-monitoring systems. Before the SGIG/SGDP projects, few transmission utilities had high speed communications at every node in their systems and had varying degrees of communications readiness relative to the bandwidth required to support synchrophasor systems. Because of the significant costs, communications requirements were a major factor for selecting the location of the PMUs for many of the participant utilities, who followed two major site selection strategies:

- ***Function-dominant approach:*** Identify locations that meet utilities' needs relative to the desired synchrophasor data applications, including location choices driven by regional or NERC criteria. Then upgrade the communications infrastructure as necessary to support the applications being deployed.
- ***Site-dominant approach:*** Identify locations with communications infrastructure sufficient to support the applications being deployed. From this set of stations, select the locations that best meet the utility's needs as driven by regional and/or NERC disturbance recorder placement criteria.

A third approach emerged, which is a hybrid of the two listed above. One utility identified locations with the most adequate communications available (albeit not sufficient to support conventionally configured PMUs). It then configured the PMUs to provide the best service they could within the restricted communications limits. Even at a reduced quality, this approach provided practical experience in deploying PMUs and familiarity with the PMU data, so the utility could develop a fact-based business case for future PMU system upgrades.

Utilities with existing high bandwidth communications were able to take a function-dominant approach. Since they had already made the strategic investment in communications infrastructure, they were able to make optimum coverage of the electric grid their primary driver for site selection.

The site-dominant approach was taken by those participant utilities with limited communications capability. They restricted installations only to sites having sufficient communications and accepted that the coverage of their grid would be limited.

PG&E[26] and BPA designed and deployed their synchrophasor systems to serve mission-critical grid operations use, including (for BPA) anticipating automated protection and control actions after the PMU system's performance is validated on their system. While both utilities had existing communications across much of their systems, some enhancements were needed to achieve the level of redundancy and/or bandwidth required for a synchrophasor system supporting real-time operations and control.

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[26] PG&E stated that its ultimate network solution (and associated cost) was driven by the number of PMUs installed, the volume of data produced and transported, the types of data streaming from different PMUs, the types of applications implemented, the type and amount of data transported to control centers, and the ongoing testing of various firewall rules.[27] The PG&E Synchrophasor network is engineered using multicast streaming between the redundant PMUs and two diverse Control Centers. Multicast utilizes the Internet Group Management Protocol (IGMP), which is a communications protocol used by hosts and adjacent routers on IP networks to establish multicast group memberships.

BPA upgraded its network switches and routers to meet its cybersecurity requirements. Both BPA and PG&E[27] installed redundant communication paths for PMU data transport. This aspect of the project is discussed in the Security subsection of this report.

ATC required extensive upgrades to its communications infrastructure. To that end, ATC received one SGIG award to build a transmission data communications network and a second award to install PMUs. The communications project installed fiber optic lines and other components of communications infrastructure to integrate 140 substations within the ATC system. With adequate communications in place, ATC was able to focus on installing PMUs at locations its engineers believed would provide the best coverage of the electric system.[28] Duke also made significant upgrades to its communications infrastructure to handle synchrophasor data transport. Duke reports that these upgrades increased the installed cost by more than seven times the amount that would have been required had synchrophasor-worthy communications already existed.

Entergy and Manitoba Hydro both had extensive communications networks available, yet they still took a site-dominant approach. Both made existing communications a prerequisite for selecting a site for PMU installation.

Oncor took the hybrid approach. Oncor indicated that communications upgrades could have been the highest cost element of its synchrophasor system. In order to avoid those costs, Oncor installed PMUs at sites that had pre-existing communications capability even though the communications systems would not support the requirements for conventionally configured PMUs. Oncor reduced the bandwidth requirements of its synchrophasor system by lowering reporting rates and reducing the number of channels delivered by each PMU, allowing them to stay within the limits of the existing communications equipment. Oncor indicated that this arrangement was sufficient for the demonstration system undertaken in 2009, but acknowledged that a communications system upgrade will be required to support future production-grade synchrophasor system deployment.

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[27] The PG&E Synchrophasor network is engineered using multicast streaming between the redundant PMUs and two diverse Control Centers. Multicast utilizes the Internet Group Management Protocol (IGMP), which is a communications protocol used by hosts and adjacent routers on IP networks to establish multicast group memberships.

[28] In this report, the ATC PMU costs do not include the communications upgrades funded through a separate SGIG project. Since the cost of ATC's communications upgrades support its SCADA and other operations-related systems as well as its synchrophasor system, it is not possible to allocate the cost of those communications upgrades per PMU. Additionally, the communications system upgrades are a one-time cost that will support future PMU installations.[29] NERC Critical Infrastructure Protection compliance website: http://www.nerc.com/pa/CI/Comp/Pages/default.aspx. NERC continues to update CIP requirements in response to evolving threats and technology capabilities.

Security

The majority of the participant utilities identified cybersecurity requirements as a significant factor affecting PMU acquisition and installation costs, with two clear security strategy trends:

- Mission-critical PMU system
- Mission-support PMU system.

In either case, systems were designed, built, and operated in accordance with the NERC Critical Infrastructure Protection (CIP)[29] requirements appropriate to their intended use. One utility estimated that deploying a mission-critical PMU system increased its PMU installation costs by a factor of two over the amount required for deploying a mission-support PMU system.

From the inception of these projects, DOE required the SGIG/SGDP synchrophasor grant recipients to develop and implement cybersecurity plans to protect the integrity of their synchrophasor systems and data produced by these systems. Each recipient's progress towards achieving the goals in its cybersecurity plans was monitored by DOE throughout the duration of the projects. These cybersecurity plans developed by each recipient included compliance with the requirements of the NERC CIP standards.

Level of Requirements

Since each system is unique, CIP requirements require that asset owners exercise engineering judgment in declaring whether or not synchrophasor system elements should be considered as critical cyber assets, whether or not to apply that categorization to their entire synchrophasor system (PMUs as well as communications), and what security protections to implement. The asset owner's intended use of a synchrophasor system then dictates the level of CIP requirements that must be followed.

For mission-critical systems, data are used to make operating decisions or to drive automatic control actions. Because the consequences of bad data can be severe, mission-critical synchrophasor systems are subject to the most demanding CIP requirements. In contrast, mission-support systems require adherence to a less demanding set of CIP requirements.

The cost of implementing security varies significantly across the industry depending on the applications deployed, the particulars of each company's data systems, the nature of the

[29] NERC Critical Infrastructure Protection compliance website: http://www.nerc.com/pa/CI/Comp/Pages/default.aspx. NERC continues to update CIP requirements in response to evolving threats and technology capabilities.

company's CIP-compliance plans, and the degree to which the data will be trusted for manual or automated operational decisions.

Three of the participant utilities built mission-critical PMU systems and designated them as critical cyber assets, complying with the most demanding CIP requirements. These cases revealed that achieving CIP compliant synchrophasor systems for mission critical services is a major driver of the installed cost.

The remaining participant utilities built mission-support PMU systems, choosing to focus on deploying synchrophasor systems for monitoring and offline capabilities that do not directly affect critical operations. Cost was a major factor in making this designation.

The utilities with significant PMU experience before the SGIG grants were more likely to designate their systems as mission-critical. It can be argued that their historical operational experience provided empirical data upon which an informed business case could be made for the higher cost of investing in a mission-critical system. Those utilities' operators and planners could cite specific instances where the technology had already been used to solve specific technical problems and could more easily extrapolate to the technology's potential and future reliance on synchrophasor technology for operations, control and protection.

Specific Security Cost Experiences

Most of the substations chosen for PMU installation had pre-established security perimeters, protecting critical cyber assets by restricting physical access. However, in some cases, the physical perimeter required upgrades to protect PMUs and PMU-related equipment. PG&E installed card readers at a few sites to support PMU installations. Entergy installed its PMUs, global positioning system (GPS) clocks, telecommunications devices, and computers within secured equipment cabinets (which essentially serve as vaults).

Figure 3. Entergy Secure Phasor Cabinet, Front View (left) and Interior View (right)

Source: Angela Nelson

Securing communications networks and providing data encryption were also significant costs. BPA installed two synchrophasor systems: one mission-critical system and one mission-support system. The mission-critical system is intended for operational decision-making, alarming, and wide-area controls. It was thus designated as a critical cyber asset. The mission-support system is intended for engineering studies and model validation rather than for control or operational decision-making. Appropriately, the communications infrastructure for the latter synchrophasor system did not provide the same level of redundancy as the critical system. Nevertheless, the data from both types of installations are firewalled at the control center, but only the data from the critical PMUs are sent to the Peak Reliability Coordinator and shared with other Western Interconnection Synchrophasor Project (WISP) partners and used at BPA for situational awareness and future remedial action schemes (RAS)[30] controls. BPA indicated that the cost of building the mission-critical synchrophasor system was much higher than the cost of the mission-support system. The additional costs included network switches and routers that met requirements, as well as the cost of providing redundant communications paths.

Most of the SGIG PMUs installed within BPA substations (120 total) are capable of being used for future RAS controls. To make this possible, BPA installed redundant PMUs and high performance substation routers within each substation. Before being used for controls, each of

[30]Remedial Action Scheme (RAS): An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying. (NERC: Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards)

these sites will have a physical security perimeter and electronic security perimeter that meets CIP requirements. The data from each redundant PMU are encrypted and transmitted on dedicated communication links to the primary and alternate control centers; there are two independent links to each control center. Several of BPA's substations were upgraded to accommodate these demanding telecommunications performance needs, which in turn, required upgrades to substation battery banks and air conditioning systems. These system requirements were implemented across BPA's geographically large system to enable BPA to easily add in additional PMU measurement and control points as needed in the future. All of these high performance and security requirements more than doubled the installed cost of PMU installation over that for the non-critical system.

PG&E also upgraded telecommunication equipment to meet CIP requirements. PG&E conducted extensive advance testing of PMU, phasor data concentrator (PDC), and clock hardware options to determine whether individual products were in compliance with NERC's then-recommended practices before the company made its final equipment choices. PG&E also conducted some intrusion detection testing on its synchrophasor system elements before field rollout.

Idaho Power chose to build a mission-support system, and thus did not classify its synchrophasor system as a critical cyber asset. However, Idaho Power does interface with WISP, and has put an intrusion detection tool at the WISP data collection point. This strategy protects WISP data, which is considered a critical cyber asset.

Labor

The participant utilities report that labor was a significant cost factor for installing and commissioning PMUs with two trends in labor deployment strategy emerging:

- ***Specialized crew.*** Specialized training and tools were provided to one crew, which handled all the installations (minimizes learning curve).
- ***Decentralized crews.*** Training was provided to technical personnel across the system where PMUs were being deployed (minimizes travel time to and from installation sites).

While labor was a significant cost driver, neither the specialized nor the decentralized crew strategy emerged as a "best" or lowest cost practice. Rather, the optimum choice between these two approaches depended upon:

- The extent of the geographical territory (the distance to be covered by installers)
- The number of PMUs installed.

One important practice to reduce labor costs is to coordinate PMU installations with other planned substation activities. Perhaps more importantly, coordinating with other planned substation activities resulted in fewer maintenance outages.

The cost impact reflected the labor hours for crews and engineers, including travel time for the installation crews. Labor efforts varied widely across the participant utilities, reflecting the number of PMUs installed, distance to the sites, installation methods, and the experience level of the crew with PMU installations or upgrades. Participant utilities who installed or upgraded 50 or more PMUs generally established a standardized process for PMU installation; this shortened the work time required and thus tended to reduce labor costs.

Installation Crew Training

Most of the participating utilities trained dedicated crews to perform all PMU installations. These crews were able to leverage lessons learned from previous installations to improve work efficiency and speed. The utilities reported that it only took completing the first few installations before crews became more proficient and faster in performing quality work at the PMU installation sites.

ATC, a MISO member, installed approximately 20 PMUs before its SGIG project began. These installations were protection relays with PMU capabilities that were configured by protection engineers. However, installations under the grant were a mix of digital fault recorder (DFR) upgrades and stand-alone PMUs. Because many of these installations were not associated with protection relays, a different set of field personnel had to install and configure the equipment. These crews had no previous experience installing or configuring PMUs, so their initial tasks took longer and cost more. ATC noted that its first 5 or 10 installations were the most expensive, but those costs fell significantly over time, and later installations cost half as much.

Best Practices: Remote Access

Prior to Entergy's SGIG Award, Entergy had to dispatch a technician to a substation to power cycle/service a PMU. The person-hours consumed in driving to these remote sites — often half a day of travel to perform a 10 minute task — made the cost of maintaining the synchrophasor system initially very high. Today, substation computers allow Entergy to change settings or reset PMUs remotely within minutes. Entergy noted that as the synchrophasor systems expand, remote management is necessary to perform firmware upgrades and patch management, change settings, and identify/address PMU operational issues. Entergy has also developed methods for the equipment to alert staff when it is experiencing problems or security issues.

PG&E combined dedicated crews with local crews to install PMUs. During the installation process, the dedicated crews trained the local crews so that they understood the ongoing O&M requirements for the synchrophasor system. PG&E's installation crews had a minimum of four persons consisting of two field personnel, a network technician, and an engineer. Support engineers and managers were also available by phone to support the field crews.

Utilities that span large geographic areas experienced significant expenditures for time spent by installation crews driving to remote sites, forcing a trade-off between experience-based crew efficiencies and increases in travel time. Idaho Power and Manitoba Hydro both cover large service areas and chose experience-based efficiencies over travel cost. Idaho Power indicated that labor costs accounted for approximately 50% of the installed cost of synchrophasors in their SGIG project. They noted significant cost in travel time and lodging costs for crews performing installations at remote substations.

Task Coordination

Establishing line or bus outages to perform equipment installations is a labor-intensive task for utilities. PG&E found that a significant portion of the implementation process involves clearances[31], preparing test procedures, and restoration of the cleared equipment back to service. Another aspect of the clearance coordination process is that high voltage equipment clearances have a different impact than network clearances. Each type of clearance has to be carefully evaluated. Studies are required to assess grid operation without the asset(s) and plans need to be made to survive a contingency without the asset(s) available. For example, a network upgrade at a substation may involve loss of visibility of the station, that is, the station is not visible during the clearance window to the human-machine interface at the control center nor to the automated control devices. If there is no redundant network path, the utility may need to deploy operating personnel to physically staff the substation during the PMU installation period in order to assure that the substation can be operated if necessary. Resources must be planned for and associated alternative solution costs (i.e., the costs of staffing a station during the equipment clearance windows) need to be considered, as these costs can significantly increase the synchrophasor system installation budget.

Even with a trained crew doing the installation, the asset owner must assure that there is appropriate engineering oversight, validation of proper terminations, validation of data flows, and confirmation of alarms during and after the installation. All of these require attention from specialized individuals whose availability might be scarce and whose time can add to the overall cost of system installation.

[31] High voltage equipment clearance is the process of temporarily de-energizing substation power equipment for the purpose of performing work. Network clearance temporarily takes information technology out of service for the purpose of performing work.

Oncor scheduled PMU installations together with other planned tasks to be performed by a local crew. Oncor gave these crews instructions on how to install GPS clocks and make configuration changes to existing and purchased equipment.

In some situations, the next planned outage for a particular utility may occur outside of the project timeframe. In these cases, the installation must be delayed, another planned outage requested, or safety-permitting, installation can sometimes be performed on live components. Duke requested planned outages for the purpose of installing its SGIG PMUs. However, at its most critical sites, the PMU installation work orders were held off until the next previously planned outages (i.e., outages that were scheduled to accommodate non-PMU work orders).

BPA had an aggressive timeframe to meet project expectations. Because this did not allow enough time for new outage requests, they coordinated with planned outages when possible, or, when safe, installed PMU equipment while the station equipment was energized. This complicated the installation effort, but BPA indicated that its crews became adept at evaluating the available options and performing the work over multiple site visits when necessary.

As the above examples make clear, many elements of labor costs are particular to the needs and characteristics of the synchrophasor project and sites. BPA initially installed PMUs at three sites in order to learn the process. In this way, BPA learned that new instrument transformer cables needed to be run from the substation yard to the control house. The principal component for these costs was labor.

Hardware Effects on Labor Costs

Installation of PMUs, PDCs, GPS clocks, and computers within a substation site entails connections to current transformers (CTs) and potential transformers (PTs), telecommunications, and possible serial communications. These tasks can be complex and time-consuming when it comes to wiring and validating connections to each device. Some of the participant utilities developed internal specifications for hardware configuration to streamline the installation process.

Idaho Power, Entergy, and BPA each standardized specifications for their PMU hardware cabinets. Entergy used a secure cabinet as part of its CIP compliance (see the Security section). BPA indicated that while there was still new wiring required for every new PMU in a substation, they used a “wiring template” which reduced installation time. BPA had its equipment and telecommunications cabinets built by a contractor, tested off-site, then shipped the cabinets to the installation site so the crew was only required to make the connections between the cabinet and the PMU. Entergy also had its secure phasor cabinets built and tested locally and then shipped to the installation sites.

Equipment

The choice of PMU devices turned out to be among the lowest cost drivers for the participant utilities. Each grant recipient developed unique requirements for PMU installations based on familiarity with vendor hardware, intended uses for the synchrophasor data, operational philosophy, and CIP compliance plans. Three equipment strategies emerged:

- Acquire and install new stand-alone phasor measurement units.
- Replace existing digital relays or DFRs with plug-compatible new equipment that has PMU functionality (which does not require changes to substation wiring or instrument transformers).
- Upgrade software/firmware in existing digital relays or digital fault recorders to enable PMU functionality.

Some of the participant utilities used a combination of these strategies.

Adding PMU capabilities to an existing piece of equipment, thus creating a dual function device, has distinct advantages compared to installing stand-alone PMUs. Dual-function devices leverage multiple functions within a single installation, reducing the amount of incremental labor and equipment required to produce engineering drawings and make wiring connections. DFRs are a prime example of devices that can be upgraded to add PMU functionality. A single DFR can often process as many measurements as two or three stand-alone PMUs. In cases where firmware upgrades were not feasible, an existing device could be retrofitted with a new dual-function device by the same manufacturer. However, if dual-function devices are not already installed, or are not available for upgrades and/or retrofit, then stand-alone PMUs become a more attractive option.

PG&E Experience

PG&E reported costs breakdowns for the installation of new PMUs and device upgrades. The installed cost for a new PMU is approximately $270K. In contrast, the cost of upgrading a device is approximately $90K. The bulk of the cost differential is associated with Engineering (Substation and Telecommunication) new installation vs. updating existing information, plus the cost to perform installation of new equipment including the extent of equipment clearance. For new installations, much larger equipment clearance is needed as opposed to clearing the device to upgrade with PMU capability. Once the infrastructure is in place to support PMUs, the cost of installing additional PMUs is approximately 35% of these initial costs. (The cost shown in Figure 6 is an average installed cost for PG&E, where approximately 80% of the installations are site upgrades – substation and information technology).

Those utilities that chose to upgrade existing devices generally reported much lower PMU installation costs than those that installed new PMUs. Manitoba Hydro purchased upgraded DFRs with PMU functionality as a retrofit option. In this case, old DFRs were simply replaced with new ones without changing wiring configurations within the substations. Manitoba Hydro estimated that its cost of purchasing and installing DFR retrofits was approximately one-third that of stand-alone devices. Costs were higher at sites without pre-existing DFRs because the DFR installation required new wiring and connections to the communications network.

PG&E and ATC used a combination of dual-function devices and stand-alone units. PG&E indicates that approximately 80% of their PMU installations under the SGIG project were upgrades to dual-function devices. PG&E tested a number of equipment upgrade candidates and firmware upgrade options within its POC facility to determine which of the available upgrade candidates would best meet its performance and implementation requirements, and worked out the upgrade procedures before sending crews out into the field. Like Manitoba Hydro, PG&E reports that upgrades to dual-function devices were performed at close to one-third the price of installing stand-alone PMUs. Counter to the general trend, ATC indicated that their DFR upgrades did not result in cost savings because their firmware upgrades were more complicated than anticipated.

Best Practices: Proof of Concept Testing Facility

PG&E developed a proof of concept (POC) facility for testing, process development, equipment trouble-shooting, and data impairment tests prior to field installation. The POC allowed PG&E to learn and address many lessons prior to field deployment. The POC also provided the opportunity for industry participation in development of the related smart grid standards such as IEEE C 37.243 and C 37.244, and IEC 61850-90-5 and allowed industry engagement in conformance and interoperability testing. Based on insights learned in the POC, PG&E developed procedures and training for its field crews before the start of field installations. As part of the project plans, PG&E identified two pilot field installations and used those site installations to identify field implementation challenges. Those challenges were addressed and worked out in the POC facility and then integrated into the overall deployment plans. PG&E used the POC process to test its entire synchrophasor supply chain. PG&E also leveraged the POC facility to design, test and integrate new synchrophasor data-based control center tools and to test those tools user interfaces.

Figure 4. Proof of Concept Test Facility

Source: PG&E

Ancillary equipment is the hardware required to support PMU operation, apart from the PMU itself. Such equipment includes GPS clocks, PDCs, network switches and routers, cabinets and computers. The cost of this equipment is generally low relative to the installed cost.

Utilities Leverage Existing Sensors

PMUs are attached to potential transformers (PTs) and current transformers (CTs), which sense power line voltages and currents, then attenuate the signals to levels that monitoring devices can safely process.

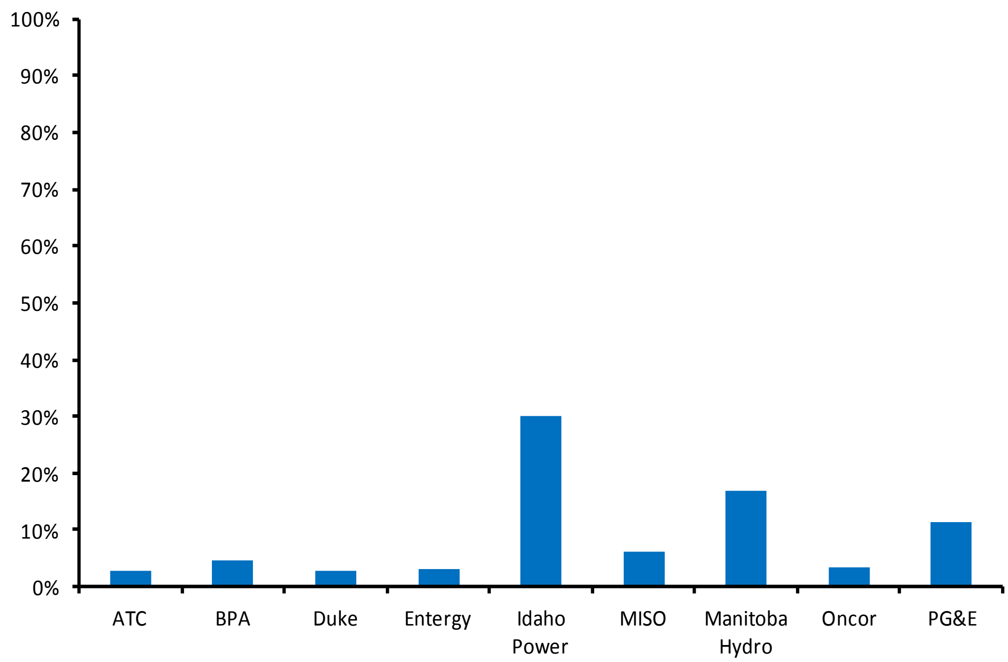
"We used existing PTs and CTs for all of our PMU installations. The purchase, installation, and configuration of new PTs and CTs would have more than doubled project costs."

– Manitoba Hydro

IV. PMUs as an Element of Synchrophasor System Cost

Figure 5 shows that the average purchase cost of a PMU device as a percentage of the average overall installed costs (purchase, installation, and commissioning) was small, usually less than 10%. ATC, BPA, Duke, Entergy, PG&E, and Oncor indicated purchase costs of less than 5% of the overall installed costs. In the case of Idaho Power and Manitoba Hydro, that number appears to be larger only because the average overall installed costs were relatively low.

Figure 5. Average Cost of PMU Device Compared to Average Installed PMU Cost

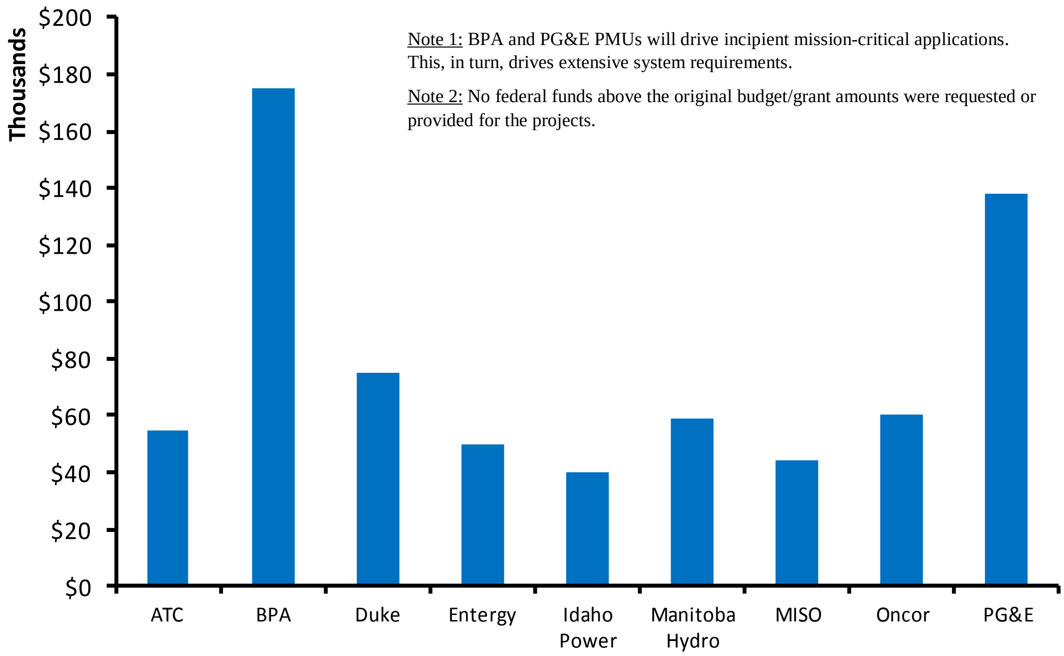


Regarding overall cost per PMU, Figure 6 (below) shows average costs of PMU purchase, installation, and commissioning for the participant utilities. While the costs of PMU installation vary widely among these utilities, several project-specific factors affect installed cost (as previously discussed).

However, the major determinants of the overall costs were 1) the existing infrastructure to support synchrophasor systems and 2) the applications and capabilities associated with each synchrophasor system. Table 5 illustrates the variations in functionality for each utility's synchrophasor system.

As an illustrative example of the value of having synchrophasor-ready infrastructure, PG&E provided cost breakdowns for the installation of new PMUs and devices upgrades. It stated that once the infrastructure is in place to support PMUs, the cost of installing additional PMUs is approximately 35% of these initial costs.

Figure 6. Average Overall Cost per PMU (for Procurement, Installation, and Commissioning) under Grant Funding



WECC provides an example of the dependence of reported synchrophasor system costs on functionality. BPA had installed research-grade PMUs in the early 1990s and had 25 research-grade PMUs operating on its research telecommunications network before preparing its SGIG proposal. While these PMUs allowed engineers at BPA to evaluate the technology, the research-grade equipment was not reliable or precise enough for production-grade operation. To achieve a production-grade synchrophasor system under the SGIG project that could provide mission-critical services, BPA had to improve its equipment and communications system to make it more reliable and secure. These factors and others, including installing instrument transformer cables, culminated in costs that more than doubled those of the research-grade PMUs. As shown in Table 5, BPA and PG&E (as WECC members) implemented production-grade synchrophasor systems with a high degree of functionality with extensive capabilities. Their prior experience with research-grade PMUs enabled them to formulate a business case that justified investing in these advanced synchrophasor applications. PG&E reported that its cost of implementing advanced applications was the largest cost element of its synchrophasor system.

Another factor is that prior experience with PMUs helped many participant utilities procure and install synchrophasor technology more cost effectively. For example, Entergy had installed several production-grade PMUs before 2009, and had eight years of experience with placement and installation of PMUs. Entergy designed its SGIG project to leverage these initiatives and expertise realized from its early PMU projects.

However, for several of the participant utilities, the SGIG and SGDP projects were their first experiences with PMUs. The funding provided by SGIG and SGDP helped them gain experience that will facilitate future PMU installations and synchrophasor system enhancements. Through DOE-sponsored technology transfer activities such as NASPI, the entire industry will benefit from the "lessons learned" by the ARRA co-funded projects.

V. Conclusion

The average overall costs per PMU (cost of procurement, installation, and commissioning) range between $40,000 and $180,000. However, not all PMUs, or the infrastructure required to support them, are equivalent. Simple "cost per PMU" calculations do not reflect differences among utilities in required phasor data concentrators, communications infrastructure upgrades, applications costs, staff training needs, and physical substation constraints to installing PMUs. The PMU device itself can vary in complexity, although the device cost alone is usually not significant; generally, PMU device costs were approximately 5% of the installed cost reported by the participant utilities. Based on the experiences reported by the nine participant utilities, this report offers insights into the strategic decisions and practices that influenced the costs of PMU installation.

Interviews with the utilities revealed several themes explaining how project design, procurement, and installation decisions drove total installed costs of PMUs. Specifically, each utility's plans for how to use the synchrophasor system drove their choices with respect to communications requirements, security requirements, how to manage installation crews, and equipment requirements. Those factors collectively determined the ultimate cost of PMU acquisition and installation.

Communications upgrades for the new synchrophasor systems were identified by the participant utilities as the largest cost driver, and one that required significant strategic planning. From a practical standpoint, substation communications capabilities range from almost non-existent available bandwidth (usually in older substations) to high-bandwidth fiber-optic connectivity. One utility reports that installing PMUs in a substation that requires communications network upgrades, rather than in a substation with pre-existing fiber connectivity, increases the project cost by a factor of more than two.

Participant utilities identified security requirements as the second largest cost driver. DOE required all of the grant recipients to provide a cybersecurity plan as they were installing production-grade systems, many of which may support control room analytics and automated protection schemes in a few years. Some of the utilities chose to designate their synchrophasor systems as critical cyber assets and implemented the CIP requirements necessary to make these assets compliant, while the other utilities deferred the critical asset designation and were able to implement a reduced level of CIP requirements to achieve their goals for CIP compliance. The data show that the cost to build a critical synchrophasor system can be up to three times the cost of a system that is intended for non-critical functions.

The participant utilities identified labor as a significant cost element of installed costs. However, the projects reporting have so many variations in system design, device choice, and installation practice that it is impossible to reach any sweeping conclusions about which labor, training, and crew management strategies were most effective.

One approach was to use one (or very few) specialized crews to handle all the installations. The advantage of this approach is that the crews “move up the learning curve” with each subsequent installation as they become more familiar with the tasks. The disadvantage of this approach is that specialized, experienced crews may have to travel over longer distances. This cost penalty increases in proportion to the size of the service territory, as the time savings from experience are offset by time required to travel to remote installation sites.

The alternate approach was to use local crews to do PMU installations, provided they have some training, procedures, and checklists to assure that they could do the job effectively. The advantage of this approach is that the local crews know the nuances of the local substations and do not need to travel long distances to perform quick tasks. On the other hand, skilled crews that have never done a PMU installation may take longer to complete the task properly than a crew with extensive PMU installation experience.

Whether using a new crew or an experienced one, the participant utilities agreed that PMU installations are more efficient when the PMU installations are coordinated and scheduled with other work orders within a substation. Thus, the asset is not taken out of service solely for the PMU installation. If the PMU installation is assigned to crews that are already on-site performing other work, this minimizes incremental travel and set-up time for the PMU installation. This has the added logistical benefit of reducing the number of outage requests—a major advantage in situations where systems are highly utilized and outages require long lead times to obtain. One utility had an aggressive timeframe to meet project expectations that did not allow enough time for new outage requests, so they coordinated with planned outages when possible, or, when safe, installed equipment in an energized substation.

Equipment was the last factor mentioned by the participant utilities. The typical cost of PMU devices was less than 5% of the installed cost. (This includes acquisition and installation.) However, in one case a utility’s PMU device was about 30% of the installed costs because its infrastructure costs were very low, and its total installed costs were at the low end of the range reported by the participating utilities. Phasor measurement functionality is built into many digital relays, DFRs, and other dual-function devices. The key decision regarding equipment is whether to field stand-alone PMUs or to enable the PMU functionality in dual-function devices that are already installed in the field.

A common observation was that prior experience with PMUs led to:

- More precision in specifying synchrophasor applications’ goals and hardware performance requirements

- Better understanding of the cost drivers, which improved capability to trade off costs versus capabilities when deciding among options
- More cost-effective and efficient approaches to employee training and crew selection for PMU installations.

The SGIG/SGDP projects have provided recipients with experience and infrastructure that are expected to facilitate future PMU installations. DOE supports many activities that will also communicate the lessons learned from these ARRA-funded synchrophasor projects throughout the industry, resulting in widespread cost and project efficiency benefits. These technology transfer activities include documenting the results from the ARRA projects, preparing synchrophasor case studies that demonstrate how the technology will be used, and supporting industry users groups and information sharing organizations, such as NASPI. Furthermore, DOE will continue to support the development of synchrophasor applications. As an example, DE-FOA-0000970, "Pre-Commercial Synchrophasor Research and Demonstration," is advancing software applications for synchrophasor data from pre-commercial status to commercial grade for implementation by utility partners.

Appendix A

Elements of Synchrophasor Systems

Synchrophasor systems produce high-resolution measurements of voltages and currents and deliver the information for immediate use and storage for later use. A representative synchrophasor system within a substation is shown in Figure 7.

Figure 7. Example Synchrophasor System Installation within a Substation

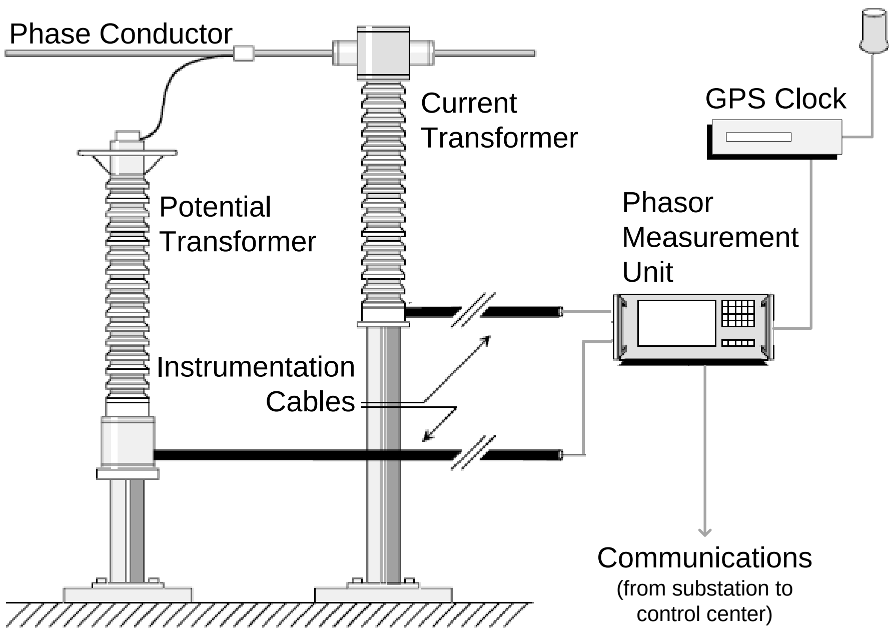
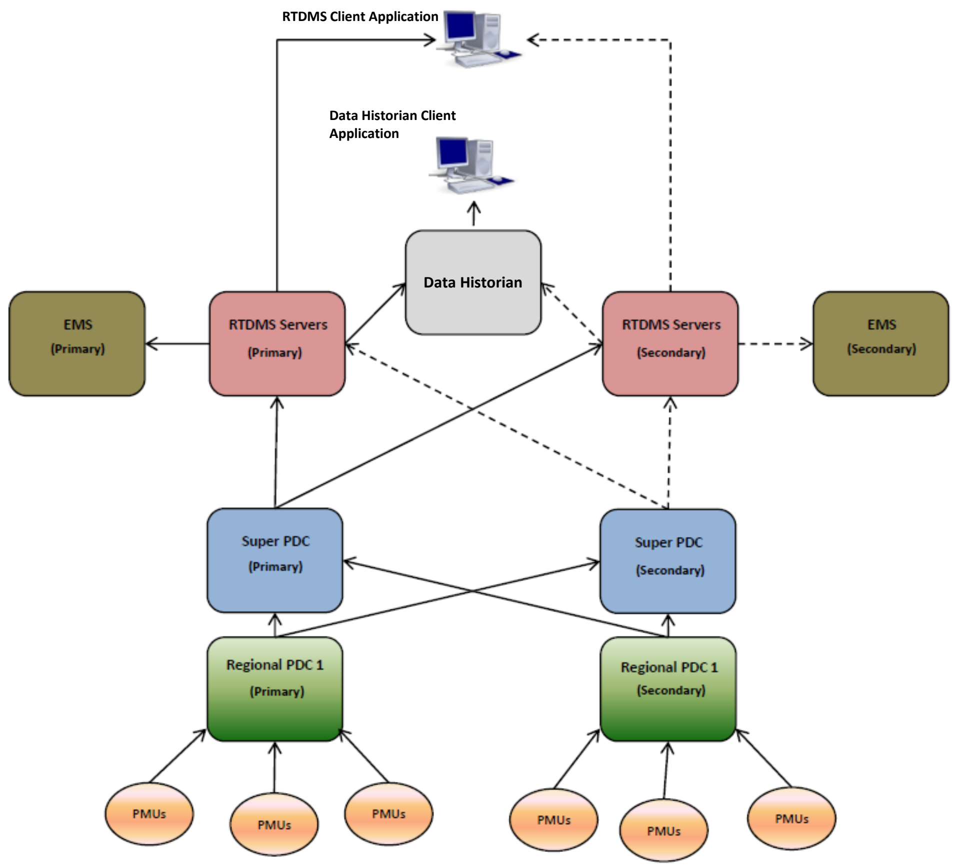


Figure 8 provides an example of how synchrophasor data is delivered from substations, through PDCs, to control centers that house applications, data historians, and energy management systems.

The combination of all elements in Figure 7 and Figure 8 describes a complete synchrophasor system. These basic elements are common to all synchrophasor systems, although specific configuration and implementation details of such systems reflect the design philosophies and needs of each utility and its system partners.

Figure 8. Synchrophasor Data Flow Diagram (Provided by Duke Energy Carolinas)



Key elements of synchrophasor systems include[32]:

- ***Phasor Measurement Units (PMUs)*** are the primary component in synchrophasor systems. PMUs calculate voltage and current phasors based on digital sampling of alternating current (AC) waveforms and a precise time signal provided by a GPS clock. A PMU reports its phasor calculations at rates up to 240 times per second. PMUs installed within North America are typically configured to report at rates of 30 times per second.
- ***Instrument Transformers*** include current transformers (CTs), potential transformers (PTs), and coupling capacitor voltage transformers (CCVTs). These devices are installed directly on the phase conductors to sense power system currents and voltages, and attenuate the signals to levels safe for measurement.

[32] More complete synchrophasor system element descriptions are available in "Real-Time Application of Synchrophasors for Improving Reliability" (RAPIR), North American Electric Reliability Corporation (NERC), 10/18/2010. http://www.nerc.com/docs/oc/rapirtf/RAPIR%20final%20101710.pdf

- ***Global Positioning System (GPS) clocks*** are precise-time clocks synchronized to Universal Time using GPS, which provide timing signals to the PMUs. Because of various GPS physical and cyber vulnerabilities, NASPI encourages the use of back-up or alternate non-GPS time synchronization options such as in-PMU back-up clocks and network time distribution to supplement GPS-based timing sources.
- ***Communications*** transport the digital information from the PMU to the location where the data will be used and/or stored for later use. Communications are typically provided through a utility-owned and operated wide-area network (WAN) but can be any digital transport system that offers acceptable security and availability.
- ***Phasor Data Concentrators (PDCs)*** receive and time-synchronize phasor data from multiple PMUs to produce a real-time, time-aligned output data stream. A PDC can exchange phasor data with PDCs at other locations. Through the use of multiple PDCs, multiple layers of data concentration can be implemented within an individual synchrophasor data system.
- ***Data storage*** comprises systems that store synchrophasor data and make it conveniently available for after-the-fact analysis. Data storage can be integrated into a PDC, a stand-alone data historian, a traditional data base system.
- ***Applications*** process data for visualization, real-time analysis, and after-the-fact analysis. Examples include the following applications:
  - Oscillation detection
  - Phase angle monitoring
  - Frequency event detection
  - Voltage stability monitoring
  - Islanding detection
  - Model validation and improvement
  - Post-event analysis
  - Operator training.

Key elements in the data flow diagram (Figure 8) include:

- ***Phasor measurement unit (PMU)*** is previously defined as a key component of synchrophasor systems.
- ***Phasor data concentrator*** is previously defined as a key component of synchrophasor systems. The descriptors regional and super designate the location and function of the PDC in the system architecture.
- ***Real-time dynamics monitoring system (RTDMS)*** is a synchrophasor-based application that provides real-time visualization of power system dynamics and situational awareness.

- ***Energy management system (EMS)*** is a system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system[33].
- ***Data Historian*** manages and stores high volumes of data, including synchrophasor data.
- ***Client applications*** provide user access to RTDMS and other system applications.

While this report focuses principally on the SGIG and SGDP recipients' costs and experiences relevant to PMU acquisition and installation, those costs can be a small proportion of the total synchrophasor system—both in terms of initial implementation and over its entire lifecycle. The system owner's plans for intended system use—which synchrophasor applications will be adopted—drive initial PMU acquisition and installation costs and the design and lifecycle costs for the entire synchrophasor system.

As noted previously, synchrophasor systems that will be used to support real-time grid operations or automated controls require a significantly higher level of data availability and data integrity than systems that are intended to deliver data for planning and off-line applications. Full, long-term integration of a synchrophasor system will ultimately transform the entire transmission system management and workflow. Thus, key factors affecting the overall cost of a synchrophasor system are driven by the owner's intended plans for system use and may include:

1. Whether the system is intended to support real-time operations and automated control uses, or mission support uses (e.g., wide-area situational awareness) and off-line planning applications.

2. The owner's determination of the appropriate level of physical and cybersecurity and device redundancy that is required and appropriate—today and in the future—for the current and planned uses of the synchrophasor system.

3. What level of communications system quality, speed, and availability is required to support the current and intended uses of the synchrophasor system, and whether the physical and business infrastructure already exists to support those communications requirements. The system owner's partnerships and data-sharing commitments will affect communications requirements, as will the availability and cost of qualified third-party communications providers.

4. Whether the synchrophasor data applications are already mature and production-grade, or require further development and testing. Development of the analytics and algorithms for critical grid relationships is challenging and can require extensive research. Using those analytics in software creation and design and implementation of effective user interfaces can be time-consuming and costly, as is the process of integrating new tools into the

[33] Source: http://en.wikipedia.org/wiki/Energy_management_system

engineering and real-time control room environments. As examples of new applications developed for the SGIG synchrophasor projects, PG&E and Entergy developed production-grade tools for post-event analysis, COMTRADE[34] file use, and several real-time operational tools, and BPA developed and tested automated tools for power plant model validation and oscillation detection. Entergy as well, implemented tools for wide-area voltage stability and oscillation monitoring, integrated PMUs into an off-line state estimator, developed and implemented phasor data exchange gateways, and implemented a state of the art visualization system for wide-area monitoring.

5. Costs incurred for initial and on-going training for operating and engineering personnel to use the new systems and applications effectively. PG&E reports that training for its dispatchers and operators was a significant cost of rolling out its production-grade synchrophasor system.

6. Costs incurred for initial and lifecycle support for engineering and maintenance personnel to maintain the system hardware. This can require changes to business relationships across the company, establishing the equivalent of Service-Level Agreements for the synchrophasor system.

7. Because most synchrophasor systems are intended to exchange data with other grid partners, it can be difficult to effect such exchange if those partners do not establish early agreements with respect to data exchange and format requirements before designing their system hardware and communications plans. Recent synchrophasor data standards such as IEEE 37.118.90-5-1 and -2 make this easier by establishing common specifications and expectations for all participants. To the degree that technical interoperability standards or security standards have not yet been adopted to address relevant synchrophasor applications or interactions, system costs will be higher as individual projects understand with developing these tools on their own.

8. Use of synchrophasor technology in conjunction with other real-time operation tools will require developing substantive new operational procedures, which must meet NERC documentation guidelines. Such procedures require extensive testing (off-line and in actual practice) before they can be formally adopted and documented.

[34] Common Format for Transient Data Exchange for power systems (COMTRADE) is a file format for storing oscillography and status data for transient power system disturbances. http://en.wikipedia.org/wiki/Comtrade

Appendix B

Contributing Cost Elements for PMU Installation

- Once initial device and communications requirements have been identified, performing testing and planning to determine which equipment meets those requirements (e.g., which new PMU or relay upgrade option or which telecommunications methods and providers can meet the data latency, availability, and accuracy requirements) and whether all of the hardware, software and communications options are reliably interoperable.
- Connecting a new PMU up to the specific points on the grid that it will be monitoring, usually with multiple PMUs installed per substation.
- Using a software upgrade to convert an already-installed, PMU-capable digital relay or disturbance recorder into a PMU.
- Configuring the PMU.
- Testing all of the physical connections from the grid to the PMU to be sure that they are working properly.
- Installing a GPS antenna and connection from the antenna to each PMU and PDC installed at the site.
- Installing any necessary communications extensions or upgrades required to stream PMU data in real-time to external PDCs and historians.
- Installing any additional routers or servers or other PDC equipment needed to support the PMUs within the host location.
- Installing any physical security measures (equipment vault, physical site access restrictions, etc.) deemed appropriate for the site and the owner's chosen security posture.
- Running tests and other commissioning activities in the field to determine that everything was installed correctly and is working properly to measure, collect, and deliver data effectively from the host site through the communications system to the receiving PDC.
- Providing real-time technical support from information technology, communications, protection engineers and field supervision staff to the field crews to handle any problems that arise.
- Developing and formalizing procedures and guidelines for all of the above.
- Training field and support technical support staff on all of the above.
- Traveling to and from the installation sites, including time and field expenses.

Contributing Cost Elements for Operating and Maintaining Synchrophasor Systems

- ***Application development and testing*** – Production grade tools for post event analysis, COMTRADE file use, and several real-time operational tools needed to be developed.

- ***Model validation and contingency analysis*** – EMS model validation with PMU superimposed data for line voltage connected data, contingency analysis models, reactive margin indication tools, and impact of observability on the data analytic tools.

- ***Deployment of advanced tools for real-time operation*** – Rules, policies, and recommendations for advanced applications need to be fully vetted. Tools cannot be used as basis for their actions. The use of PMU applications require a comprehensive process to become fully integrated in the operational process and implemented as an integral part of the operators set of rules and established procedures for real-time system management.

- ***Lifecycle management*** – Maintaining and upgrading equipment firmware, replacement of aging devices, and equipment repair and testing.

- ***Personnel training*** – Training utility staff is an important factor in terms of bringing visibility to synchrophasors as a tool and achieving vestment by engineers and operators. Training includes development of training programs for synchrophasor uses and applications.