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REPORT

Distribution Synchronized Measurements Roadmap

Final Report

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Quanta Technology and Oak Ridge National Laboratory

QUANTA TECHNOLOGY, LLC

4020 Westchase Boulevard, Suite 300, Raleigh, NC 27607 USA

RALEIGH (HQ) | TORONTO | SAN FRANCISCO BAY AREA | SOUTHERN CALIFORNIA | CHICAGO

www.Quanta-Technology.com

Quanta Technology, LLC is a wholly-owned subsidiary of Quanta Services, Inc. (NYSE: PWR)

Report Contributors:

Richard Hunt, Quanta Technology
Julio Romero Aguero, Quanta Technology
Damir Novosel, Quanta Technology
Daniel Brancaccio, Quanta Technology
Eric Udren, Quanta Technology
David Hart, Quanta Technology
Sean Kantra, Quanta Technology
Yi Hu, Quanta Technology
Jean-Christophe Lesieur, Quanta Technology
Lingwei Zhan, ORNL
Yilu Liu, ORNL
Tom King, Jr., ORNL
Christopher J. Bolton, San Diego Gas & Electric
Tariq Rahman, San Diego Gas & Electric
Daniel W. Dietmeyer, San Diego Gas & Electric
Tom O. Bialek, San Diego Gas & Electric

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ABBREVIATIONS AND ACRONYMS

The following abbreviations and acronyms are used in this report:

Abbreviation / Acronym	Definition
AG	application group
AMI	advanced metering infrastructure
AVVC	advanced volt-var control
BCR_i	benefit-cost ratio
CapEx	capital expenditures
ComEd	Commonwealth Edison
Con Edison	Consolidated Edison
CVR	conservation voltage reduction
DER	distributed energy resources
DFR	digital fault recorder
DG	distributed generation
DLSE	distribution linear state estimator
DMS	distribution management system
DOE	Department of Energy
Dominion	Dominion Energy
EMS	energy management system
EV	electric vehicle
FCI	faulted circuit indicator
FCP	falling conductor protection
FDR	frequency disturbance recorder
FIDVR	fault-induced delayed voltage recovery
FLISR	fault location, isolation, and service restoration
FNET	frequency monitoring network
GNSS	global navigation satellite system
GOOSE	generic object-oriented substation events
GPS	global positioning system
Hi-Z	high impedance
IBR	inverter-based resource
IEC	International Electrotechnical Commission
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
IIA	integrated impedance angle
IP	internet protocol

Abbreviation / Acronym	Definition
IT	information technology
LTC	load tap changer
MAIFI	momentary average interruption frequency index
NASPI	North American Synchrophasor Initiative
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NOC	network operations center
OMS	outage management system
OpEx	operational expenditures
ORNL	Oak Ridge National Laboratory
PCC	point of common coupling
PDC	phasor data concentrators
PEV	plug-in electric vehicle
PG&E	Pacific Gas and Electric
PMU	phasor measurement unit
PQ	power quality
PV	photovoltaic
R&D	research and development
R-GOOSE	routable generic object-oriented substation events
RTDMS	real-time distribution management system
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SLA	service level agreement
SMD	synchronized measurement device
SST	solid-state transformer
STTP	streaming telemetry transport protocol
SVS	static var systems
T&D	transmission and distribution
TCP	transfer control protocol
UDP	user datagram protocol
U.S.	United States
V2G	vehicle-to-grid
VR	voltage regulator
VVC	volt-var control
VVO	volt-var optimization
WAMS	wide-area management system
WASA	wide-area situational awareness

EXECUTIVE SUMMARY

Quanta Technology, Oak Ridge National Laboratory, and San Diego Gas & Electric partnered to develop an industry framework and a high-level industry roadmap for deploying distribution synchronized measurements for electrical power system modernization. Benefits of distribution synchronized measurements for better visibility and other applications on the transmission system are also included where appropriate. This project is supported by the U.S. Department of Energy (DOE) to identify the critical distribution synchronized measurement technologies for future U.S. DOE investment. The roadmap is based on a framework and methodology for quantifying benefits and costs for applications and associated infrastructure, and for developing application priorities. The report also provides high-level system architecture to provide the required data availability to support various applications. This methodology and framework can be easily adapted by organizations based on their priorities, experience, knowledge, and needs.

The key technology used is synchronized measurements, including power system quantities such as current, voltage, and frequency, which are precisely and accurately time-synchronized. These measurements have provided unprecedented situational awareness for transmission systems in the last 10 years and are becoming a key sensor technology to address the distribution system's needs. In the last few years, the deployment experiences of San Diego Gas & Electric and other utilities have shown how synchronized measurement technology could play a key role in distribution network modernization.

The business need driving this effort is the vital role that distributed energy resources and electrification in providing the nation with clean energy. The overall project objectives are:

- Provide high-level guidance via the industry roadmap for developing and investing in synchronized measurement technology on distribution circuits considering technical requirements and challenges based on industry input and diverse business needs. This guidance includes the key success factors required to deploy the technology and supports the development of industry standards and guides.
- Provide a methodology to help diverse users prioritize applications and develop customized processes and roadmaps.
- Help vendors design and prioritize product development and develop product and system roadmaps.
- Help the U.S. DOE develop programs to accelerate the grid modernization process and applications using synchronized measurement systems.

This project has been divided into a series of tasks which are reflected in this final report. The first task updated SDG&E's 2012 use cases to address recent industry and technology developments. Using expert business and technical knowledge, these use cases have been clustered into 19 application groups and described in detail. For the second task, the project team interviewed SDG&E, Commonwealth Edison, and Consolidated Edison's business leaders and experts to update the information, including the technology deployment status, and address the broader industry needs and plans. The third task involved a detailed evaluation of application benefits for identified use cases based on business needs. A relative comparison of the cost-effectiveness based on their industry priority, the value of synchronized measurements for each application, and ease of deployment was done for each application group. After this work was completed, the fourth task was to use the results to develop an industry application roadmap that suggests a short-term, mid-term, and long-term implementation schedule of applications for the distribution system that take advantage of synchronized measurements. These updated results and the industry application roadmap have been presented at North American Synchrophasor Initiative meetings to gain additional input to this final report. The final task was to recommend pilots in the near-term based on the critical distribution synchronized measurement applications of the short-term roadmap.

This report documents each task's results, with chapters summarizing the interviews, the industry application roadmap, application group descriptions including relative scoring on benefits and costs, the methodology for determining the benefit-cost ratio and the final results, and a discussion of system architecture. The complete industry interviews and a literature review for the various application groups are included in appendices.

Of special interest is the method used to determine the benefit-cost ratio. The project team has developed a prioritization methodology to assess the high-level relative benefits and costs of each application group. The following eight categories are aligned with typical strategic areas of interest for electric utilities: 1) Resilience and Reliability, 2) Sustainability and Decarbonization, 3) Real-Time Operation, 4) Advanced Planning, 5) Public Safety, 6) Efficiency Improvement, 7) Innovation Potential, and 8) Customer Engagement and Business Potential. The implementation and cost impacts were evaluated based on the following five categories: 1) Complexity, 2) Investment, 3) Risk, 4) Maturity, and 5) Readiness.

Each benefit and cost category is assigned a weight to model its relative importance based on the project team's technical opinion and industry experience. Those weights are customizable and can be updated as needed. The applications were graded for the above benefit and cost categories using a scale from 0 to 10. The results were then used to calculate a benefit-cost ratio to prioritize the application groups. The process also included the high-level system architecture and requirements for each application group.

The application benefit-cost ratio is calculated for all applications on a single plot and is useful for developing short-, mid-, and long-term roadmaps for applications, infrastructure, and processes. However, certain initiatives may be more strategically advantageous than their benefit-cost ratio would imply. (While favorable, they may require significant investments or be extremely complex, etc., or they may not provide significant direct benefits. Nevertheless, they are critical to the successful implementation of other high-priority applications, etc.) Therefore, these types of applications can be deemed strategic for an implementation roadmap and assigned a higher priority than that estimated by the methodology.

Based on this benefit-cost ratio, the top five priority application groups are:

- Advanced microgrid applications and operation
- High-accuracy fault detection and location
- Advanced monitoring of distribution grid
- Improved load shedding schemes
- Wide area visualization

These are use cases with high benefits that fully leverage the availability of synchronized measurements and with only low or medium costs to implement. These specific use cases are identified in the industry application roadmap as the short-term applications to implement. The industry roadmap sorts the remaining applications into a mid-term or long-term application schedule based on the benefit-cost ratio, considering the value of synchronized measurements to the applications and the difficulty in implementing the specific applications. The top five applications are recommended for pilots. The team's first pilot project proposed to the U.S. DOE is to develop, test, and implement novel and comprehensive fault detection and location methodologies while leveraging the existing architecture and expanding it to support other applications.

The weighted costs used in the analysis only address installing a specific application and not the cost of the system architecture necessary to support synchronized measurements from the distribution system. It is expected that this architecture will be similar for most applications other than the number of measurement points required, with similar costs to install. This system architecture must support collecting data from enough sensors to deliver applications while meeting performance requirements for availability and latency. Importantly, the need for synchronized measurement data, based on the benefits identified in this document, shows that equipment vendors of devices such as inverters, reclosers, switch controllers, and power quality meters need to integrate synchronized measurements into their devices. It is important to emphasize that adopting these applications and the infrastructure to support them is more than a technology decision. Adoption requires a plan, organizational structure, and tools to implement, maintain, and enhance the applications and systems. Furthermore, all stakeholders engaged in deploying the technology need to be trained to plan, operate, and maintain infrastructure and applications.

While developing software tools is necessary, an analysis of the applications' requirements shows that most of the applications can be achieved. Distribution systems require monitoring of more points than transmission systems, but existing hardware will allow utilities to develop individual utility roadmaps and deploy infrastructure and hardware for the short-term and in preparation for future applications using existing technology and hardware products.

This document has used "synchronized measurements" to emphasize a need to move the industry beyond phasor measurements. Expanding some applications in this roadmap and developing new applications will require the industry—with U.S. DOE leadership—to invest in further research. It is necessary to protect the investment by building a flexible infrastructure that is relevant for the future. This is particularly important considering other industry trends, including smart cities, rural broadband, areas for high penetration and DER and microgrids, etc. However, the need for further research should not be an impediment to continue building an infrastructure and deploy applications identified in this roadmap.

Developing standards and guides by IEEE, with support from NASPI and NIST, has been a critical factor for successful technology deployment. Information provided in this document, related to system architecture and application and infrastructure requirements, should help IEEE and NASPI-DSTT in this process.

This report's findings support an ongoing industry engagement process charting the course for utilities and their product and system suppliers to create the platform and tools for reliable and economic operation of distribution systems with high penetration of distributed energy resources, storage, electric vehicles, and other emerging influences. The results in this report are based on industry input and expert knowledge. However, utilities and other companies can use the approach in this report to adjust the priority criteria and the resulting roadmap based on their needs and capabilities.

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1 INTRODUCTION

The U.S. power industry is moving toward carbon-neutral system operation in the next 10 to 20 years. Distributed energy resources (DERs) and electrification will be vital in providing the nation with clean energy via the distribution system. Distribution systems have a history of low visibility due to a lack of high-fidelity grid monitoring. Today's distribution system operation relies on a centralized energy supply, predictable feeder configurations and customer load behavior, and outage handling by customer reports or advanced metering infrastructure (AMI), where applicable. Legacy devices and technologies will not support the advanced critical applications to be developed and implemented, and upgrades will require significant effort, investment, and time. To accommodate DERs, we need fundamental changes in distribution network planning, operation, and protection and control methods. Specifically, we need better sensor coverage that provides fast and detailed distribution system operating measurements and information, along with controllable circuit devices using sensor data to control and protect distribution system elements holistically and in real-time. We need to document and close the gaps between the equipment deployed today and what will be required in the future—notably, replacements for inadequate sensors, measurement devices, and control capabilities.

The new advanced sensors and measurement devices must enable new business models, such as distribution system operators and real-time interactions with "prosumers." Synchronized measurements have provided transmission system users with unprecedented situational awareness in the last 10 years (e.g., post-event analysis, model validation, real-time operational support, and advanced protection and control) thanks to their increased report and sampling rates and precise time synchronization of measurements over wide areas. This is a key technology to address the distribution system's low visibility. San Diego Gas & Electric (SDG&E) and Quanta Technology's deployment experience has shown how synchronized measurement technology will play a key role in distribution network modernization.

More than 50 use cases have been identified, and most of them are directly applicable to other utilities.[1] For example, SDG&E successfully developed and deployed a synchronized measurement-based falling conductor protection (FCP) scheme, and a comprehensive roadmap has been developed for large-scale deployment. Oak Ridge National Laboratory (ORNL) has extensive experience in synchronized measurement technologies—especially with high synchronization accuracy, high-speed, low-cost implementations, which are vital for high-fidelity and low-cost distribution system deployments.

This report incorporates information from the updated SDG&E synchronized measurement use cases, feedback from partner utilities on business needs and drivers, and existing and potential use cases. The project team interviewed SDG&E, Commonwealth Edison (ComEd), Consolidated Edison (Con Edison), and Dominion business leaders and experts to update the report for addressing the industry's broader needs.

[1] SDG&E Quanta Use Case High-Level Definitions V 0.12 10/31/2012

It describes a detailed evaluation of application benefits for identified use cases based on business needs to provide high-level relative comparisons of their cost-effectiveness based on their industry priority, the value of synchronized measurements for each application, and ease of deployment. The updated results and roadmap will be presented at a North American Synchrophasor Initiative (NASPI) meeting to gain additional input in preparation for the final industry roadmap.

The document also provides a framework and methodology for quantifying benefits and costs for applications and associated infrastructure, as well as for developing application priorities. It consists of sections addressing applications, a process for prioritizing applications, and the infrastructure and processes needed to deliver these applications. This report is the basis for developing an overall industry roadmap for deploying synchronized measurements for distribution system modernization and identification.

1.1 Background and Objectives

Over the last two decades, electric utilities have placed increasing importance on improving the situational awareness of electric grid behavior to enhance the overall reliability of system operation. They have been prompted by catastrophic events like the 2003 blackout and Superstorm Sandy, as well as the operating challenges of the energy supply's increasing diversity and unpredictability. Most industry leaders have pointed toward the deployment of synchronized measurement technology as the key element for enabling this awareness, and they are making major investments in these measurement systems. The wide-area precision time synchronization of these measurements, provided at a suitable reporting rate and accuracy for the intended application, is essential for identifying the grid's stability and dynamic behavior challenges as it responds to new energy transfer demands, system disturbances, and component outages.

Synchronized measurements refer to measurements taken across the grid with a precise timestamp. The measurements can include but are not limited to frequency, magnitude, phase angle, power, rate of change of frequency, and voltage and current waveforms. Note that accuracy or reporting rate are properties of synchronized measurements that will be defined in application requirements.

Emerging active distribution systems are envisioned to include greater penetration of DERs—photovoltaic (PV), wind, battery energy storage, electric vehicles (EVs), and active consumer participation. Furthermore, the need for outage management and remediation, self-healing, islanding capabilities, faster and more sensitive fault detection, and greater situational awareness of the distribution system's operating state are expected to drive the need for more granular and synchronized data. More than ever before, there is a robust case for the broad-scale deployment of synchronized measurement technology on the distribution grid.

In 2012, SDG&E pioneered synchronized measurement technology on distribution circuits, including phasor measurement units (PMUs) deployed at multiple locations at feeders outside the substation. SDG&E, in partnership with Quanta Technology, LLC, documented an exhaustive list of applications or use cases based on the availability of synchronized measurements and accurate high-speed measurement infrastructure across distribution feeders and substations. The project team developed functional definitions highlighting potential benefits, accessible “low-hanging fruit” opportunities, and technical requirements for the system platform and its data communications-based measurement gathering and processing and control capabilities.

One particular use case from 2012 is a scheme by which synchronized measurements streamed at rates of 30 frames per second or more could be analyzed holistically across a feeder area to detect that a circuit conductor was broken and in the process of falling toward the ground. The measurement system could locate the break and trip adjacent switching devices when the conductor had fallen only a few feet. As a result of this rapid tripping, the broken conductor lands dead and with no risk of a high impedance (Hi-Z) arcing fault. With wildfire ignition risk as a focus for California utilities, SDG&E focused on developing this scheme, with the first installation and demonstration in 2015. Since then, SDG&E has continued to deploy PMUs and supporting communications on 12 kV feeders located in dozens of areas prone to wildfires.

The business case for synchronized measurement systems in distribution is based on more than wildfire risk mitigation. It is also based on a long list of use cases offering the critical capability to operate the distribution system in a coming environment of diverse energy resources and customer reliability expectations. Existing distribution supervisory control and data acquisition (SCADA) will be challenged to provide adequate visibility and control. These use cases have not yet been demonstrated in practice, and questions remain. For instance, what sequence of equipment deployment and application development will best serve the emerging needs of utilities across the United States in the coming years?

The roadmap provides high-level guidance for development and investment while looking at technical requirements and challenges against industry and customer needs. It shows the requirements for successfully deploying synchronized measurement technology and critical applications on the distribution systems of SDG&E and other utilities in other regions with different needs. The roadmap consists of sections addressing applications, prioritizing these applications, and the infrastructure and processes needed to support synchronized measurements. It helps:

- Diverse users prioritize applications and develop processes and their roadmaps.
- Vendors design and prioritize product development and develop their roadmaps.
- The U.S. Department of Energy (DOE) develop programs to accelerate the grid modernization process and applications using synchronized measurement systems.

It also addresses how distribution synchronized measurements could help with better visibility and other applications on the transmission system. Furthermore, the prioritization and roadmap process help recommend pilot programs that identify use cases most valuable to the industry and are “low-hanging fruit” for the near-term achievement of goals.

1.2 Roadmap Development Methodology

The roadmap’s development follows distinct tasks with review gates between the tasks and at the conclusion. These tasks are described in Figure 1-1.

- The first task was to develop the high-level roadmap documentation using cost-benefit analyses of individual use cases based on benchmark cost estimations and interviews with SDG&E stakeholders. SDG&E stakeholders reviewed the high-level roadmap for approval of the approach and agreement on applications prioritization, technical requirements, cost assessment, and relationship development among use cases.
- The second task was for the project team to bring the use case evaluations to a selected panel of utility industry stakeholders from other regions, inquire about current and foreseen distribution system needs and issues, and reevaluate the roadmap in light of these broader needs.
- In the third task, the project team produced and vetted a list of revised applications with explanatory material on individual use cases, system infrastructure requirements, and the ranking and scheduling analysis underlying the proposed roadmap. This step included creating detailed descriptions of applications based on use-case benefits, identifying research and development (R&D) and implementation efforts, and costs for each application, and performing a state-of-the-art review of system technologies. It also included identifying deployment challenges and developing high-level budgetary cost estimates for typical deployment scenarios.
- The next step is to review the draft roadmap to a larger group of industry stakeholders at the 2021 NASPI meeting(s).
- After reviewing the proposed roadmap with broader industry stakeholders, the next task is to finalize the framework and roadmap, including near-, mid-, and long-term priorities for applications, infrastructure, and processes.
- The final step will be to identify pilot programs for critical distributed synchronized measurement applications.

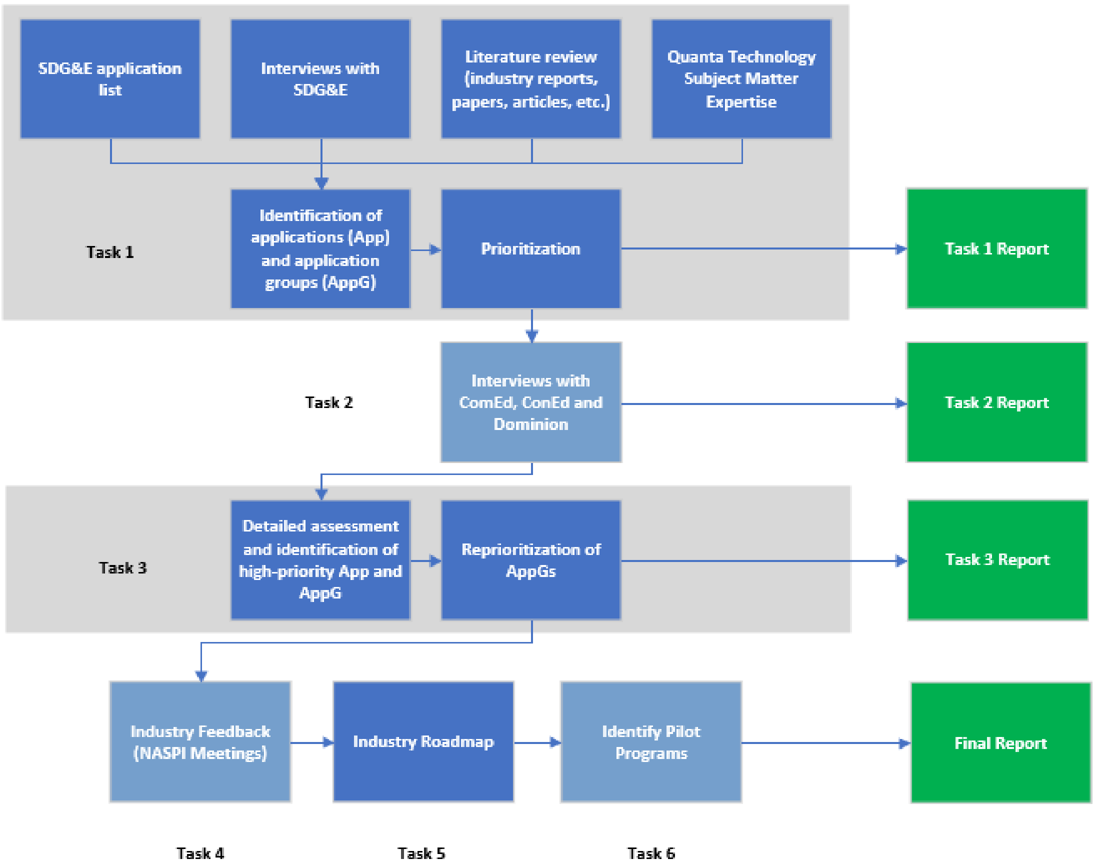

Figure 1-1. Roadmap Development Steps

2 DEFINING DISTRIBUTION SYNCHRONIZED MEASUREMENTS APPLICATIONS

In 2012, Quanta Technology and SDG&E developed a comprehensive list of use cases or applications justifying the future deployment of synchronized measurements and infrastructure on SDG&E's distribution system. This study identified and categorized 54 use cases, which are categorized into the following groups:

- Monitoring: Sixteen use cases
- State assessment: Seven use cases
- Model validation: Six use cases
- Protective schemes—mitigation, enhancement, detection: Fifteen use cases
- Holistic closed-loop control and operational optimization: Ten use cases

The project team used this original list of applications as the starting point to develop the distribution synchronized measurement applications roadmap. The project team's process (see Figure 2-1) included the following steps:

1. Reviewed the original application list.
2. Conducted interviews with stakeholders at SDG&E to understand how key business and technology drivers had changed and collect feedback regarding potential new applications.
3. Used the original application list, results from the interviews at SDG&E, a literature review, and its own experience in this area to develop a draft roadmap that included additional applications. Then, applications were clustered into 19 application groups (AGs) based on similarities of individual applications to facilitate the communication of the roadmap to industry stakeholders.
4. Conducted additional interviews with technical leaders from Con Edison, Dominion, and ComEd to understand the perspective of other industry stakeholders regarding synchronized measurement technologies.
5. Used the results from these additional interviews to prepare the final roadmap described in this document.

Figure 2-1. Development Process for Distribution Synchronized Measurement Applications Roadmap

The remainder of this section summarizes the feedback provided by industry stakeholders from SDG&E, Con Edison, Dominion, and ComEd. It describes the applications and AGs proposed in the distribution synchronized measurement applications roadmap.

2.1 SDG&E Stakeholders Interview Summary

The project team met with groups from several SDG&E business units. Technical experts from protection and control, distribution engineering, and distribution planning and operations shared information on the overarching issues they experience when operating the distribution system and how these issues may be addressed with applications incorporating synchronized measurements.

Given the importance of wildfire risk mitigation in California, SDG&E is very interested in potential applications focused on fire risk mitigation, including detecting falling or downed conductors, Hi-Z fault detection, incipient fault detection, and asset health assessment. All stakeholders interviewed consider these use cases to be most important. Now, SDG&E is accelerating the roll-out of distribution FCP systems in open-loop mode (tripping disabled) to gather dependability and security evidence. The short-to-medium-term goal is to extend the number of feeders covered and enable high-speed tripping.

The visibility of the real-time distribution system's state is another use case raised in all interviews. Increasing DER penetration and transportation electrification, combined with the current deficiency of sensors and overall data-gathering infrastructure on the distribution system, is a concern. Increased synchronized measurement deployments would enable new applications, including richer information for operators, closed-loop protection and control, real-time system model updates, phase identification, and fault location. Predictive analytics based on machine learning and events classification were also topics of interest for the medium-term development horizon.

It has also been identified that sharing business units' plans for synchronized measurement deployment or use across the organization would be beneficial for optimizing deployment and enhancing benefits for business units. This deployment roadmap, supported by a cost-benefit analysis, will be useful for high-level decision-makers in determining how to approach future investments optimally.

Technical experts know that the telecommunications infrastructure will need significant investment to support the widespread deployment of synchronized measurements on the distribution system. Associated costs for network security will also be significant and may present a hurdle for investment and expertise development to overcome. The interviewees also saw challenges related to the requirements for managing massive databases and achieving cultural change. (The Task 1 report was based on the SDG&E interview sessions.)

2.2 Industry Stakeholders Interview Summary

The project team also conducted additional interviews with technical leaders from SDG&E Con Edison, Dominion, and ComEd to understand business and technology drivers and needs. The interviews also helped identify opportunities for synchronized measurement technologies to solve existing and expected challenges and requirements. Moreover, the interviews helped collect general feedback regarding applications of synchronized measurement technologies and specific feedback about potential additions to the original application list. Full interviews are documented in Appendix A: Industry Interviews. The results from those interviews are summarized in Table 2-1 and Table 2-2, describing the perspective of the utility technical leaders in the following areas:

- Utility business and technology drivers and needs
- Synchronized measurement technology benefits
- Utility needs and gaps
- Existing synchronized measurement technology applications
- Planned initiatives and vision
- Barriers and gaps for the adoption of synchronized measurement technology
- Solutions to facilitate adoption
- Experience with synchronized measurement technology
- Recommendations to facilitate technology adoption
- Experience with this technology
- Most valuable information from technology roadmaps

“Grey” boxes represent areas of particular interest for the interviewed utility. The interviews indicated that grid modernization/transformation and DER integration, and related concepts are key drivers for all utilities. Additionally, there are regional drivers specific to every utility. For instance, equipment failure and asset health evaluation is a specific concern at Con Edison, given the features of its distribution system (underground secondary network supplying high-density loads in a large metropolitan area), while power quality (PQ) for large customers is an important concern at Dominion, given that data centers are a significant component of its customer base. Expectedly, key needs at utilities include, among others, safety, DER management, reliability and resilience, PQ, and grid analytics. This is valuable feedback validating the importance of the key applications included in the proposed roadmap.

Results also show that technical leaders agree that a key benefit of synchronized measurement technologies is improved transmission and distribution (T&D) operations. This is particularly important in distribution, where the technology remains incipient and where DER integration is transforming the grid from a passive and relatively predictable system into a highly dynamic and complex network. The operation of this evolving grid requires using high-resolution time-synchronized real-time data.

Table 2-1. Summary of Industry Interviews (Part I)

#	Questions	Utility			
		SDG&E	ConEd	Dominion	ComEd
1	**Drivers and needs**				
	NERC compliance				■
	Risk management of major events				■
	Enhance transmission operation				■
	Grid modernization/transformation			■	■
	DER integration			■	■
	Grid evolution				■
	Power quality for major customers			■	■
	Holistic T&D planning and operations			■	
	Real-time analytics				■
	Equipment failure and asset health management		■		■
	Resilience improvement		■		■
	Public Safety		■		■
2	**Sensing technology benefits**				
	NERC compliance				■
	Risk management of major events				■
	Enhance transmission operation			■	■
	Distribution reliability improvement				■
	Grid evolution				■
	Enhance distribution operation			■	■
	Real-time situational awareness			■	■
	Improve DER integration			■	■
3	**Utility needs and gaps**				
	Safety		■	■	■
	Risk management		■		
	DER management		■	■	■
	Energy storage utilization		■		
	Electrification				■
	T&D system planning				
	T&D system modeling and analysis				■
	Asset management		■		■
	Reliability & resilience			■	■
	Power quality		■	■	■
	Monitoring, protection, automation and control			■	■
	PAC architecture		■		
	Grid analytics			■	■
	Grid evolution				■

Table 2-2. Summary of Industry Interviews (Part II)

#	Questions	Utility			
		SDG&E	ConEd	Dominion	ComEd
4	**Existing synchronized measurement applications**				
	Linear distribution state estimation				
	Microgrid operation				
	Falling conductor protection				
	System reconfiguration (phase angle monitoring)				
5	**Planned initiatives or vision**				
	Microgrid monitoring				
	Critical customer monitoring				
	Real-time situational awareness				
	System reconfiguration (phase angle monitoring)				
	Fault detection and protection				
	Power quality				
6	**Barriers and gaps for adoption**				
	Technology/application maturity				
	Telecommunications requirements				
	Data management/storage needs				
	Cost				
	Business case development				
7	**Solutions to facilitate adoption**				
	Validation of business cases				
8	**Experience with synchronized measurement technology**				
	Positive experience				
	Need for data quality verification				
9	**What can the industry do to faciliate adoption**				
	Demonstration of use cases				
	Large pilot programs				
	Foster innovation before standardization				
10	**Other technologies being explored and experience**				
	Power quality meters				
	Advanced line sensors				
11	**Most valuable information from technology roadmap**				
	Implementing existing roadmap				

Results also show that utilities have implemented or are currently implementing synchronized measurement technologies. Specific applications include linear distribution state estimation for microgrid visibility and operation (ComEd) and phase angle monitoring for system reconfiguration (Con Edison). These utilities intend to continue exploring these and new applications, including critical customer monitoring, real-time situational awareness, and PQ.

Although the overall experience working with these technologies has been positive, challenges remain, particularly in technology costs, data quality verification, and developing and validating business cases. Utility technical leaders also recognize the value and benefits that synchronized measurement technologies provide, but there is a need for the industry to sponsor the demonstration of additional applications via pilot programs that validate business cases and foster innovation in this area. For instance, the development of additional standards can be a consequence (rather than a requisite) of implementing synchronized measurement technologies.

Finally, an important finding is that utilities are interested or have already developed roadmaps to apply synchronized measurement technologies and are exploring other advanced sensor technologies, such as PQ meters and fault circuit indicators. Their interest validates the importance of applications that help improve distribution system monitoring and enable real-time distribution system operations.

This input was considered when developing the proposed technology roadmap described in this document and when updating this report.

2.3 Synchronized Measurement Technology Applications

The project team used SDG&E's original application list, results from the interviews at SDG&E, a literature review, and its own experience to develop a draft roadmap that included additional applications. Applications were clustered into 19 AGs based on similarities of individual applications to facilitate the communication of the roadmap to industry stakeholders. Table 2-3 summarizes how the existing and new applications have been grouped. Subsections appearing after the table give definitions and explanations of these use cases and groupings, as well as a review of the deployment status or industry experience with each of these applications.

2.4 NASPI Distribution Team and Industry Stakeholders Review

The synchrophasor prioritization and roadmap were presented to the NASPI project team for review and comments. NASPI feedback is documented in Appendix C: Feedback from the NASPI Distribution Task Team on the Draft Report. These comments and feedback from the industry stakeholders were used to update the final report.

Table 2-3. Proposed Applications Grouping

ORIGINAL SDG&E PROGRAM AREA (2012)	ORIGINAL SDG&E USE CASE NUMBER (2012)	PROPOSED GROUP NUMBER	PROPOSED APPLICATION GROUP DESCRIPTION	PROPOSED USE CASE NUMBER	NEW USE CASE DESCRIPTION
Monitoring	M-1	AG1	Advanced Volt-VAR Control (AVVC)	A1	Conservation Voltage Reduction (CVR)
Control & Optimization	C-1		Advanced Volt-VAR Control (AVVC)	A2	Volt-VAR Control (VVC) of distribution systems
Control & Optimization	C-8		Advanced Volt-VAR Control (AVVC)	A3	Volt-Var Optimization (VVO)
Monitoring	M-3	AG2	Advanced monitoring of distribution grid	A4	Active and reactive power flow monitoring
Monitoring	M-5		Advanced monitoring of distribution grid	A5	Voltage profile monitoring
Monitoring	M-11		Advanced monitoring of distribution grid	A6	Monitoring of communications system/equipment performance with management metrics
Monitoring	M-12		Advanced monitoring of distribution grid	A7	Frequency monitoring
Monitoring	M-14		Advanced monitoring of distribution grid	A8	Near real-time event monitoring (physical)
New	New		Advanced monitoring of distribution grid	A9	Near real-time event monitoring (cyber)
Monitoring	M-2		Advanced monitoring of distribution grid	A10	Phase angle monitoring for voltages and currents
Monitoring	M-6	AG3	Asset management of critical infrastructure	A11	Power apparatus asset management
New	New		Asset management of critical infrastructure	A12	Power apparatus functional monitoring
Control & Optimization	C-10		Asset management of critical infrastructure	A13	Monitoring and control of critical infrastructure and large customers
New	New		Asset management of critical infrastructure	A14	Underground secondary/spot network monitoring and analysis
Assessment	A-2		Asset management of critical infrastructure	A15	Dynamic rating of distribution assets
Monitoring	M-8	AG4	Wide area visualization	A16	Circuit status dashboards
Monitoring	M-13		Wide area visualization	A17	Integration of customer site FNET information
Monitoring	M-15		Wide area visualization	A18	Improved wide area situational awareness (T&D)
Model Validation	V-6		Wide area visualization	A19	Visualization of dynamic system response
Monitoring	M-4	AG5	DER integration	A20	Monitoring of intermittent DER
Assessment	A-1		DER integration	A21	Voltage impact assessment and mitigation due to high penetration of intermittent energy resources
Scheme Development	S-7		DER integration	A22	Active and reactive reverse power flow management
Control & Optimization	C-2		DER integration	A23	Customer/smart inverter control
Control & Optimization	C-7		DER integration	A24	DER management and energy balancing with energy storage
New	New		DER integration	A25	Load unmasking (behind-the-meter DER)
Assessment	A-6	AG6	Real-time distribution system operation	A26	Distribution state estimation
Control & Optimization	C-6		Real-time distribution system operation	A27	Closed-loop circuit operation
New	New		Real-time distribution system operation	A28	DERMS implementation
New	New		Real-time distribution system operation	A29	Improved demand response

Table 2-3 Cont.

Assessment	A-4	AG7	Enhanced reliability and resilience analysis	A30	Improved distribution reliability analysis	
Assessment	A-5		Enhanced reliability and resilience analysis	A31	Post-mortem analysis	
Monitoring	M-7	AG8	Advanced distribution system planning	A32	Phase identification	
Model Validation	V-1		Advanced distribution system planning	A33	Distribution system computational model validation	
Model Validation	V-2		Advanced distribution system planning	A34	Short circuit study validation	
Model Validation	V-5	AG9	Distribution load, DER, and EV forecasting	A35	Load characterization, load modeling and load forecasting	
New	New		Distribution load, DER, and EV forecasting	A36	DER forecasting	
New	New		Distribution load, DER, and EV forecasting	A37	EV Forecasting	
Assessment	A-7	AG10	Improved stability management	A38	Voltage stability monitoring and control	
Scheme Development	S-15		Improved stability management	A39	Control instablility, hunting, or oscillation detection - voltage, var, switching	
New	New		Improved stability management	A40	Transient stability monitoring and control	
New	New		Improved stability management	A41	Fault Induced Delayed Voltage Recovery (FIDVR) detection	
Scheme Development	S-1	AG11	High-accuracy fault detection and location	A42	Faulted circuit indication	
Scheme Development	S-4		High-accuracy fault detection and location	A43	Incipient fault & failure detection	
Scheme Development	S-9		High-accuracy fault detection and location	A44	High accuracy fault location	
Scheme Development	S-10		High-accuracy fault detection and location	A45	Communications failure location for maintenance dispatch	
Scheme Development	S-12		High-accuracy fault detection and location	A46	High impedance fault location	
Scheme Development	S-13		High-accuracy fault detection and location	A47	Open conductor fault detection	
Scheme Development	S-2		High-accuracy fault detection and location	A48	Falling conductor protection	
Scheme Development	S-8	AG12	Advanced distribution protection and control	A49	Reclosing assistance for fast circuit recovery after fault	
New	New		Advanced distribution protection and control	A50	Current differential protection of feeder sections	
New	New		Advanced distribution protection and control	A51	Adaptive protection of distribution systems	
Control & Optimization	C-3	AG13	Advanced microgrid applications and operation	A52	Planned islanding and restoration of microgrids	
New	New		Advanced microgrid applications and operation	A53	Advanced protection of microgrids	
New	New		Advanced microgrid applications and operation	A54	Advanced distribution system topology, automation and control (holonic grids)	
Scheme Development	S-3		Advanced microgrid applications and operation	A55	Islanding detection for distributed generation (anti-islanding scheme)	
Scheme Development	S-5	AG14	Improved load shedding schemes	A56	Improved load shedding schemes - frequency	
Scheme Development	S-6		Improved load shedding schemes	A57	Improved load shedding schemes - voltage	
New	New		Improved load shedding schemes	A58	Improved load shedding schemes - load flow based	
Control & Optimization	C-4		Improved load shedding schemes	A59	Load shedding real time compensative arming to balance 1547 compliant PV	
Scheme Development	S-11	AG15	Advanced distribution automation	A60	Load transfer and load balancing	
Control & Optimization	C-5		Advanced distribution automation	A61	Self-healing and enhanced FLISR operation	

Table 2-3 Cont.

Assessment	A-3	AG16	Technical and commercial loss reduction	A62	Circuit loss minimization
Scheme Development	S-14		Technical and commercial loss reduction	A63	Energy accounting
New	New		Technical and commercial loss reduction	A64	Techical and commercial loss identification, calculation and reduction
New	New	AG17	Monitoring and control of electric transportation infrastructure	A65	Monitoring and control of electric transportation infrastructure
New	New		Monitoring and control of electric transportation infrastructure	A66	Vehicle-to-Grid (V2G) monitoring and control
Control & Optimization	C-9	AG18	Integrated resource, transmission and distribution system planning and analysis	A67	Running sub-transmission (69 kV) and distribution in parallel
New	New		Integrated resource, transmission and distribution system planning and analysis	A68	Integrated resource, transmission and distribution system planning and analysis
Monitoring	M-9	AG19	Power quality assessment and analysis	A69	Harmonics measurement
New	New		Power quality assessment and analysis	A70	Voltage sag and swell measurement
New	New		Power quality assessment and analysis	A71	Flicker measurement
New	New		Power quality assessment and analysis	A72	Voltage and current imbalance measurement
New	New		Power quality assessment and analysis	A73	Short-duration interruption measurement
New	New		Power quality assessment and analysis	A74	Harmonic state estimation/diagnosis
New	New		Power quality assessment and analysis	A75	Primary meter customer (e.g major customer monitoring -power quality)

3 INDUSTRY ROADMAPS

3.1 Application Roadmap

One of the key results of this report is a timeline for the successful implementation of applications that can use synchronized measurements to improve distribution system performance. This timeline is driven by various factors and criteria tied to the relative benefit, cost, and reliance on synchronized measurements to achieve a high accuracy result. The Industry Application Roadmap can be seen in Figure 3-1.

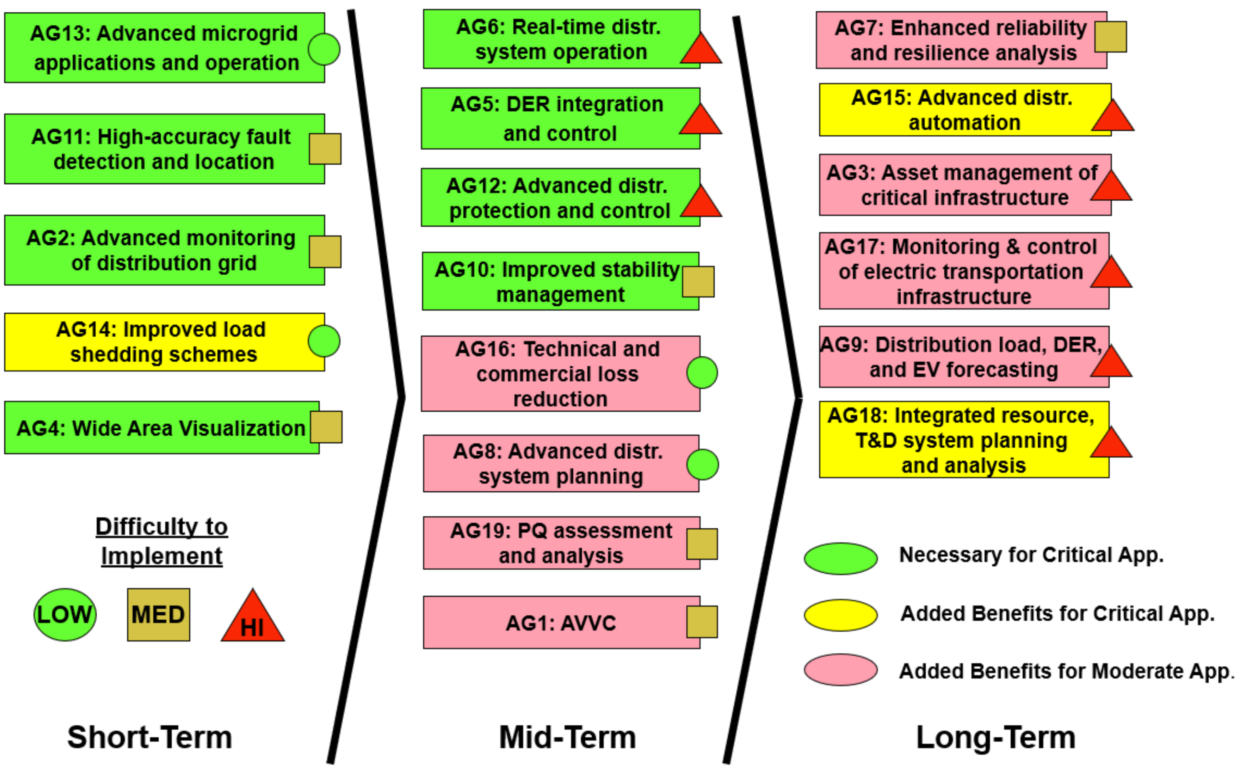

Figure 3-1. Industry Application Roadmap

This report prioritizes the AGs based on a benefit-cost ratio (BCR_i) scoring that is described in Chapter 5. The roadmap for implementing the AGs uses this prioritization and other factors to define a short-, medium-, and long-term timeline for implementing these AGs at a typical utility. The AGs identified with a "high" BCR_i in Table 5-5 are the ones to include in the short-term roadmap, as these are groups with high perceived benefits and/or lower costs to implement.

To develop the roadmap further, three key classifications are assigned to each application: Application Priority, Value of Synchronized Measurements, and Difficulty to Implement. The AGs are then classified based on the composite of the individual applications that comprise the group, with additional weighting assigned to the highest importance applications.

Application Priority is a determination of how critical this application is to improved distribution system performance and reflects the benefits as scored in Table 5-3. These numerical values allow the AGs to be sorted as "Critical" or "Moderate," where, in an ideal world, "Critical" applications would be implemented first. However, the cost of implementation and relative maturity of infrastructure or process ultimately influence the timeline for successful deployment.

The "Value of Synchronized Measurements" assesses the impact that synchronized measurements have on a unique application. An AG with a "Necessary" rating for this classifier implies that synchronized measurements are required to implement the underlying applications. An AG that has a rating of "Added Benefit" (notated as "Additional Benefit" in later figures) implies that the application can ultimately be built without synchronized measurements, but substantial enhancement can be accomplished by incorporating synchronized data into the algorithms.

The "Application Priority" and "Value of Synchronized Measurements" classifiers are applied in combination to each AG, resulting in one of three blended classifications in Figure 3-1:

- Necessary for critical app
- Added benefits for critical app
- Added benefits for moderate app

The last classifier, "Difficulty to Implement," is tied to the cost of implementation as scored in Table 5-4. It is essential in grounding the timeline to reality and calculating a relative cost of implementation. Each application is assigned a value of High, Medium, or Low, relating to the relative cost for effective implementation. This results in some lower priority applications transitioning to a short-term timeframe due to a combination of the cost to implement criteria, such as a high level of application maturity, a low level of investment required, or a low level of complexity.

The methodology and analysis that led to Figure 3-1 will be detailed in the subsequent sections.

It is important to emphasize that this roadmap is based on industry input and expert knowledge, addressing all-encompassing industry needs. The overall process, including the framework and the roadmap, can be used by organizations to develop plans to deploy distribution synchronized measurements. However, each organization would need to adjust the priority criteria described in this document based on individual needs and develop its roadmap. This approach could be used by utilities, ISOs, vendors, research organizations, and any organization developing a roadmap.

3.2 Infrastructure and Process Roadmaps

In addition to the short-, mid-, and long-term application roadmap, it is recommended that each user should develop short-, mid-, and long-term infrastructure and process roadmaps. This document provides information about the overall system architecture to support synchronized measurement applications, including a detailed list of infrastructure and process requirements. In combination with the present state infrastructure (particularly communications and data management), this information could be very beneficial in developing those user-dependent roadmaps.

Figure 3-2 shows a summarized graphical representation of application infrastructure requirements.

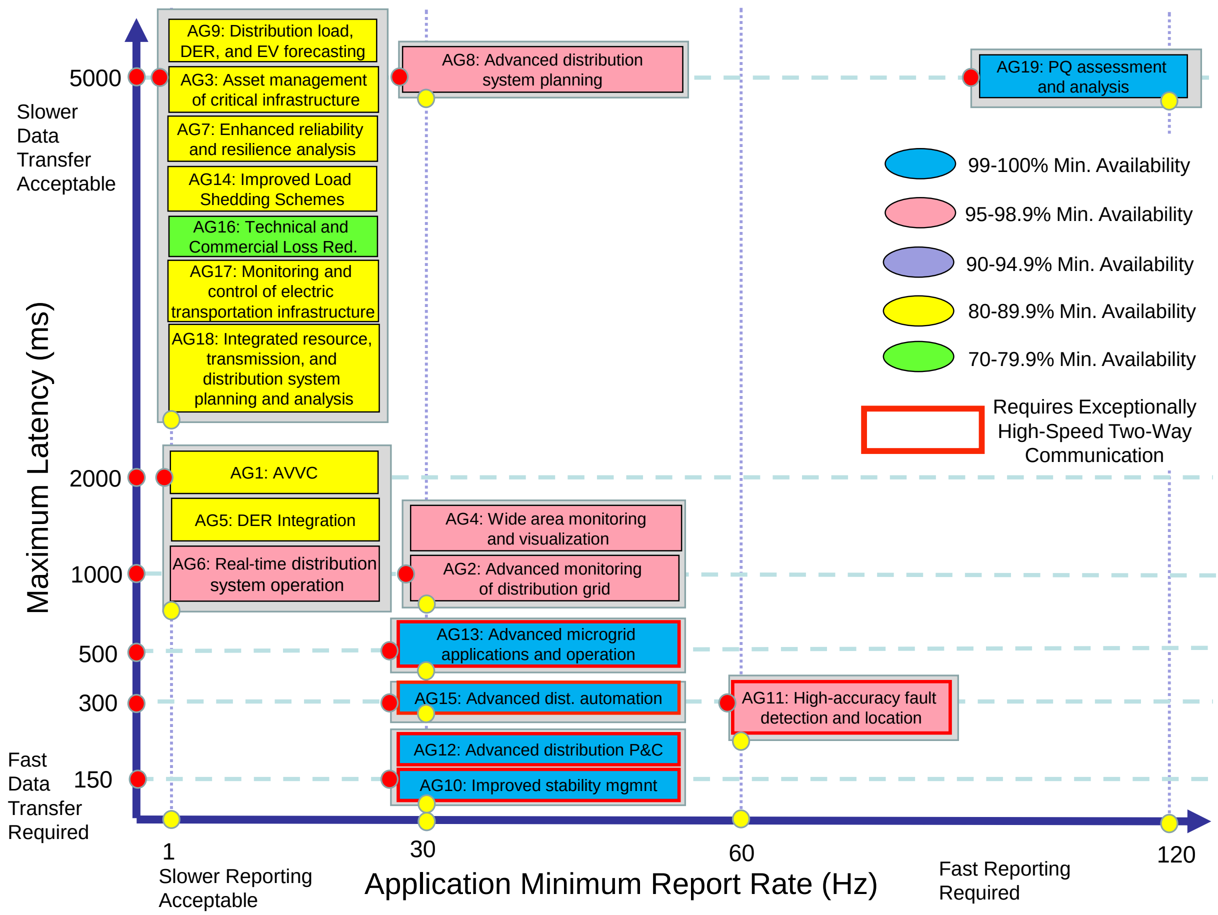

Figure 3-2. Infrastructure Requirements

3.3 Pilot Recommendations

One of the roadmap's goals is to provide guidelines for pilots in the near term based on the critical distribution synchronized measurement applications of the short-term roadmap. Pilots on the top 5 priority AGs are recommended:

- Advanced microgrid applications and operation
- High-accuracy fault detection and location
- Advanced monitoring of distribution grid

- Improved load shedding schemes
- Wide area visualization

The first pilot project proposed to the U.S. DOE by the team is to develop, test, and implement novel and comprehensive fault detection and location methodologies while leveraging the existing architecture and expanding it to support other applications. It also includes evaluating a state estimation-based ground fault detection and location tool. The outcome will be an overarching strategy to maximize the benefits of synchronized measurements for fault detection and location and any additional applications identified during this pilot.

4 DETAILED ANALYSIS OF DISTRIBUTION SYNCHRONIZED MEASUREMENTS APPLICATIONS

This section includes a detailed evaluation of application benefits for identified use cases based on business needs. It provides the following information to each AG:

- High-level summary.
- Deployment status in the industry.
- Importance of applications and synchronized measurements to achieve identified benefits. It also shows graphically how critical each application is, what value synchronized measurements provide, and how difficult it is to implement each application. This information provides the basis for developing an easy-to-review overall industry short-, mid-, and long-term roadmap.
- Quantified high-level benefits to help with the overall prioritization.
- System and product requirements such as accuracy, availability, latency, sampling rate, and reporting rate, as well as quantified high-level costs to help with the overall prioritization.
- State-of-the-art review of system technologies, including literature search and R&D efforts.

The information above is needed to provide high-level relative comparisons of their cost-effectiveness based on their industry priority, the value of synchronized measurements for each application, and ease of deployment.

High-level benefits are rated on a scale of 1 (least beneficial) to 10 (most beneficial) for each AG below. High-level costs are rated on a scale of 1 (least costly) to 10 (most costly). Maturity and Readiness are rated on a scale of 1 (least mature/ready, most costly) to 10 (most mature/ready, least costly).

The description of each AG lists the general performance requirements for synchronized measurement data in a table. The tables may list performance requirements for "synchronized measurement data," that is, an explicitly time-synchronized phasor measurement. The tables may also list the performance requirements for other data such as metering data, instantaneous data, oscillography, and other similar data that should be time-synchronized but are not explicitly synchronized phasor data.

4.1 AG1: Advanced Volt-Var Control

4.1.1 High-Level Summary of Application

Voltage and reactive power control in distribution systems have become more complex with the growing penetration of DERs (e.g., rooftop PVs, EV loads, and interactions with new programs like conservation voltage reduction [CVR]). Traditional voltage control systems rely on slow-acting electromechanical devices installed on the primary feeder. These systems are less than optimal as distribution transitions towards a more dynamic grid. Advanced volt-var control (AVVC) technologies like smart inverters and other distributed secondary-side voltage regulation devices are perceived to be the key enabling technologies for meeting future smart grid requirements, such as effective voltage control and the ability for seamless integration of DER. Despite the complex nature of the distribution system and limited numbers of regulating equipment, the traditional approaches of volt-var control (VVC) have provided satisfactory performance (so far). However, the growing installation levels of DER using smart inverters, fast-charging EV loads, and their associated dynamics are now challenging VVC in ways that only can be addressed by deploying higher report rate synchronized measurement systems. AVVC includes the following use cases:

- A1—Conservation voltage reduction: Most existing CVR implementations rely on bellwether revenue meters to report voltage measurements every 15 minutes. The voltage measurements are used to control distribution substation transformer tap changers. A control system based on this technology is usable but slow and can result in transformer tap changer early failure. Also, the design can introduce problems over a wide area due to the single feeder nature of the feedback system. Using higher report rate measurements synchronized across the feeder enables delivered voltage levels to be more constant to all customers. Synchronized measurements can also be used to determine suitable feeder candidates for CVR.[2]
- A2—Volt-var control of distribution systems: Volt/VAR optimization and control is an advanced function that determines the best set of control actions for all voltage regulating devices and var control devices to achieve one or more specified operating objectives without violating any of the fundamental operating constraints (high/low voltage limits, load limits, etc.). There are multiple schemes deployed for VVC, including automated capacitor switching for localized control. Adding high report rate measurements synchronized across the feeder would improve the granularity of the actual real-time system status allowing for finer controls. The improvement over traditional VVC will have to be tested to determine cost justification.
- A3—Volt-var optimization (VVO): VVO is the general term for several techniques to improve distribution system efficiencies by managing power factor. As with CVR and VVC, systems are already deployed using traditional non-synchronized measurement devices (non-SMDs). These systems have been shown to work, but it is estimated that a high report rate of measurements synchronized across the feeder allows for smoother and quicker reacting controls system-wide, reducing losses, and providing better voltage control for customers.

4.1.2 Deployment Status in the Industry

Utilities are deploying traditional CVR, VVC, and VVO using automation and manual controls. The addition of synchronized high report rate measurement devices will have to be tested to determine cost vs. benefit.

[2] Synchrophasors for Distribution Applications, Power and Energy Automation Conference, Spokane, Washington, March 26–28, 2013. https://cms-cdn.selinc.com/assets/Literature/Publications/Technical%20Papers/6561_SynchrophasorsDistribution_RM_20121030_Web.pdf?v=20191011-220136

4.1.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Synchronized measurements provide the following benefits:

- Providing more accurate information on the level of VVO benefits.
- Determining feeder voltage protection settings voltage limit constraints.
- Enabling on-peak and off-peak substation optimization settings for large customers.
- Determining settings for switched capacitors within the specified limits.
- Controlling capacitor bank or static var compensator setpoints.
- Controlling generator and inverter reactive power setpoints.
- Optimizing power factor near real-time.
- Increasing visibility into system operating parameters and greater control to optimize energy-efficient and reliable electricity delivery.
- Predicting voltage volatility due to increasing penetration of intermittent renewable generation sources and increasing diversity and variability of loads.

In general, synchronizing measurements across the feeder would provide additional benefits but may not be critical for those applications.

Figure 4-1 presents the value of synchronized measurements for AVVC.

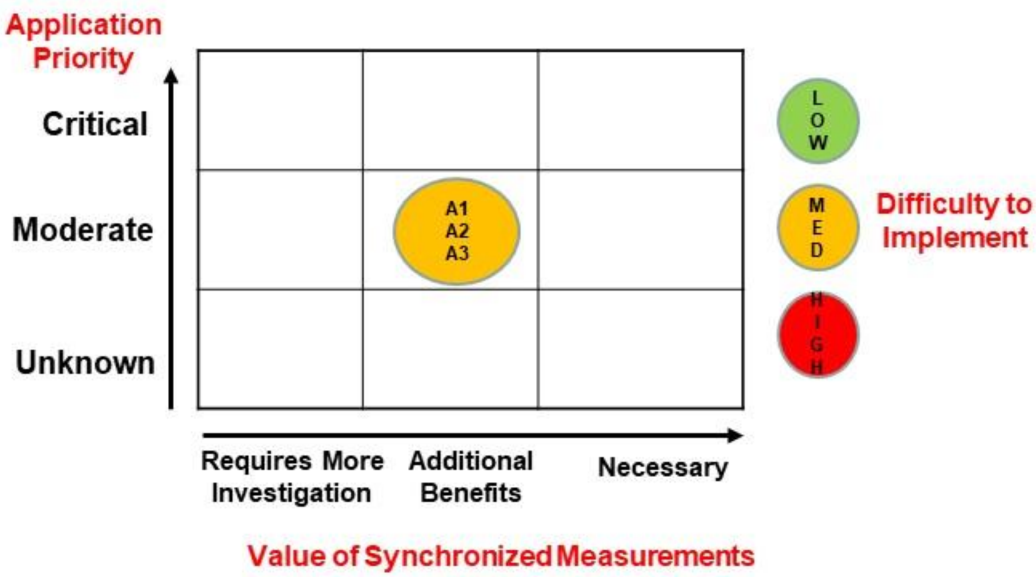

Figure 4-1. Value of Synchronized Measurements for AVVC (AG1)

4.1.4 Quantified Benefits

High-level application benefits of synchronized measurements for AVVC:

- Efficiency improvement (6)
- Customer engagement and business potential (6)
- Real-time operation (5)
- Sustainability and decarbonization (5)
- Advanced planning and asset management (5)
- Innovation potential (4)
- Resilience and reliability (4)
- Public safety (3)

The intent of AVVC is the efficient operation of distribution feeders, and synchronized measurements improve this efficiency to ensure a consistent voltage profile across each feeder. A consistent, quality voltage profile improves customer satisfaction and the real-time operation of the distribution system.

4.1.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for AVVC applications:

- Readiness of the utility and utility personnel to adopt (7)
- Maturity of possible solutions (7)
- Investment required to implement (6)
- Complexity of the solution (4)
- Risk of failure (3)

The cost drivers for VVC are the lack of mature solutions, as existing VVC methods must be adapted for 1) synchronized measurements and numerous new control points on the system, and 2) the investment required for installing the measurement points, communications infrastructure, along with the costs and efforts of algorithm development.

All applications will require multiple synchronized measurement points per feeder. The majority of these applications (especially the applications that provide the most benefits) will require using synchronized measurement data from multiple points on each distribution feeder where the application is provided.

The specific performance requirements for AVVC are presented in Table 4-1.

Table 4-1. Specific Performance Requirements for AVVC

Requirement	Synchronized Measurement Data	Other Synchronized Data
Measurement accuracy	1% total vector error	±5% error
Availability	95%	80%
Latency	2000 ms	2000 ms
Sampling rate	Device sampling rate	Device sampling rate

Requirement	Synchronized Measurement Data	Other Synchronized Data
Reporting rate	Minimum 10 Hz	1 Hz

4.2 AG2: Advanced Monitoring of the Distribution Grid

4.2.1 High-Level Summary of Application

Advanced monitoring of the distribution grid involves using applications that provide real-time information about the distribution system beyond the basic information available from the substation. Advanced monitoring becomes necessary as distribution systems evolve from passive radial circuits with unidirectional power flows to complex active meshed networks where power flow magnitudes and direction are driven by the operation of DERs, new apparatus types, and electrification connections. To address this evolution, it is necessary to assess the effectiveness of existing distribution system designs, identify areas for improvement, and propose sustainable solutions.

The assessment's objective is to collect synchronized voltage and current measurement data from strategic locations on distribution circuits at a central processing location. Advanced monitoring requires rapid value updates to monitor the real-time status of the distribution system.

This advanced monitoring includes the following use cases:

- A4—Active and reactive power flow monitoring: Using advanced measurement data to identify potential design improvements to account for increased penetration of DERs, microgrids, and distribution flexible alternating current transmission system devices.
- A5—Voltage profile monitoring: Using voltage measurements to develop a circuit voltage profile, identifying PQ issues, using key data to show the effectiveness of VVC and AVVC applications.
- A6—Monitoring of communications system/equipment performance with management metrics: Using measurement intelligent electronic device (IED) reports to track the performance of the communications network used for advanced monitoring and other distribution system applications.
- A7—Frequency monitoring: Measuring frequency behavior on distribution circuits to understand the impact of DERs.
- A8—Near real-time event monitoring (physical): Increasing the frequency of data collection from the impacted circuits to monitor the fast-changing conditions when a significant operating event is detected. The distribution grid topology can be monitored and updated as events occur.
- A9—Near real-time event monitoring (cyber): Using and comparing measurements from across distribution circuits as a method to cross-check data integrity and using the distribution system's state to verify the consistency of specific data streams and validate control.
- A10—Phase angle monitoring for voltages and currents: Using current and voltage phase angles along a distribution circuit to evaluate circuit operation and analyze power flow around VRs, capacitor banks, and DERs.

4.2.2 Deployment Status in the Industry

Some advanced monitoring use cases are implemented on SDG&E circuits as a byproduct of installing FCP. ComEd has deployed distribution synchronized measurements for DER monitoring as part of implementing its 2015 technology roadmap. The initial focus has been on the Bronzeville Microgrid[3] (see AG13) for situational awareness and control.

4.2.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Advanced monitoring of the distribution grid uses real-time measurements to understand the state of distribution circuits—not just equipment status, but also the impact of DERs and meshed networks on load flows, frequency, system stability, and other performance concerns. The need to do active and reactive power flow measurements, phase angle measurements, frequency measurements, and voltage profiles for entire circuits requires the use of precise, synchronized measurements from multiple points on every monitored distribution circuit. This type of monitoring will become critical to understand the distribution system's performance as inverter-based resources (IBRs) and meshed networks become more prevalent.

Figure 4-2 presents the value of synchronized measurements for advanced monitoring of the distribution grid.

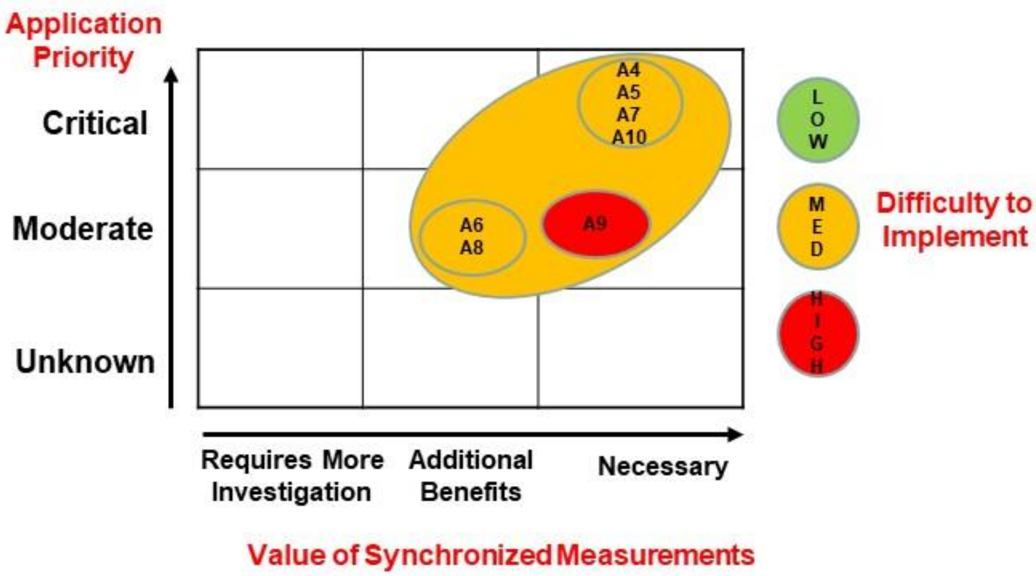

Figure 4-2. Value of Synchronized Measurements for Advanced Monitoring of the Distribution Grid (AG2)

[3] P. Pabst, H. Chen, Synchronized Measurements in Distribution Systems, Mar. 2021, https://www.naspi.org/sites/default/files/2021-04/20210331_naspi_webinar_comed.pdf

4.2.4 Quantified Benefits

High-level application benefits of synchronized measurements for advanced monitoring of the distribution grid:

- Real-time operation (8)
- Efficiency improvement (8)
- Resilience and reliability (7)
- Sustainability and decarbonization (6)
- Advanced planning and asset management (6)
- Public safety (6)
- Innovation potential (6)
- Customer engagement and business potential (5)

Real-time operation is the obvious benefit, as more comprehensive, synchronized data is available for system operations, and the impact of DERs, network configuration, and load flows can be instantly seen in distribution management systems (DMSs). Monitoring system parameters will aid in resilience and reliability by using this data to identify circuit performance during normal and post-event operating scenarios. Also, monitoring system parameters will improve efficiency by identifying circuit performance or load problems in real-time while showing the impact of circuit configurations during normal and stressed conditions. Sustainability is enhanced by the ability to measure the impact of renewable resources on individual circuits and the system as a whole. At the same time, planning and asset management are improved by having a comprehensive view of circuit and system performance to help prioritize areas of improvement. Advanced monitoring can improve public safety by supporting faster fault location and system restoration efforts, providing a platform for innovation in distribution system operations, and providing system reliability and performance to support customers.

4.2.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for advanced monitoring applications for the distribution grid:

- Complexity of the system (4)
- Investment required to implement (7)
- Maturity of the solutions and devices (6)
- Risk of failure (3)
- Readiness of the utility and utility personnel to adopt (7)

Measurements can be taken from different locations such as standard outlets, overhead lines through voltage and current transformers, key DER facilities, and distribution substations. Advanced monitoring of the distribution grid will require multiple synchronized measurement points per feeder used at the system level. This is a high-density application in terms of infrastructure requirements.

Suggested performance requirements for advanced monitoring of the distribution grid are presented in Table 4-2.

Table 4-2. Specific Performance Requirements for Advanced Monitoring of the Distribution Grid

Requirement	Synchronized Measurement Data	Other Synchronized Data
Measurement accuracy	1% total vector error	±5% error
Availability	95%	95%
Latency	1000 ms	5000 ms
Sampling rate	Device sampling rate, minimum 480 Hz	Device sampling rate
Reporting rate	Minimum 30 Hz	1 Hz

Understanding the costs of advanced monitoring is straightforward. The investment is mostly in installing numerous measurement devices, the communications network to transport data, and updating DMSs and algorithms to take advantage of the data. Utility personnel should be ready to adopt this advanced monitoring, as it is mostly an extension of existing distribution management concepts. Solutions are relatively mature, needing only to integrate synchronized measurements into proven applications. These are not complex applications, mostly doing real-time displays and comparisons of values. The risk of failure is low, as monitoring the distribution system simply defaults back to the traditional monitoring presently in use.

4.3 AG3: Asset Management of Critical Infrastructure

4.3.1 High-Level Summary of Application

Asset management of critical infrastructure provides real-time and offline analysis to assess the condition of primary distribution equipment and circuits. Power apparatus along distribution feeders ages and degrades over time. Field personnel lack accurate feedback with evidence of the condition or operating history and may not have time to inspect or test every device. For this reason, some utilities use a "run to failure" approach for managing large fleets of distribution assets like service transformers. Since the deployment of synchronized measurement technology on every single distribution device would be cost-prohibitive, development would need prioritization based on asset and customer criticality. This approach would enhance the reliability and resilience of critical infrastructure.

Applying advanced data analytics to advanced current/voltage measurements and equipment operating information makes it possible to:

- Identify abnormal operating conditions
- Implement remedial actions before disruptions happen
- Monitor devices to achieve condition-based maintenance of distribution apparatus and synchronized measurement/protection and control devices
- Drive the adoption of dynamic ratings for equipment

Data collection may be done online (real-time) or offline (on demand), and it can be prioritized based on the specific application. For instance, applications related to life cycle evaluation may require periodic offline data collection and evaluation, while those for system operation may involve real-time monitoring, data collection, and analysis.

Asset management of critical infrastructure includes the following use cases:

- A11—Power apparatus asset management: Measurement devices capture transient, overload, and fault duty data to estimate equipment loss of life while recording outages or device failures.
- A12—Power apparatus functional monitoring: IEDs located on the distribution circuit can interface with primary equipment to capture the timing of open and close operations, record operation counts, and identify abnormal operating patterns.
- A13—Monitoring and control of critical infrastructure and large customers: Ensuring reliable supply to vital facilities, such as fast service restoration during outages, delivering premium PQ, and executing control measures to ensure secure system operation.
- A14—Underground secondary/spot network monitoring and analysis: Using measurements of currents and voltages for medium voltage and low voltage networks to identify power flows and equipment failures, especially in the presence of DERs.
- A15—Dynamic rating of distribution assets: Using measurements of currents and voltages in conjunction with weather data to calculate dynamic thermal ratings of stressed distribution assets, particularly of substation transformers and main circuits, in an offline or real-time mode.

4.3.2 Deployment Status in the Industry

Real-time monitoring of critical assets and using data analytics to assess performance, condition, and impact on life cycle are well-known applications of advanced sensor technologies in T&D systems:

- A11 and A12: There are commercial products and solutions to monitor and evaluate the condition of critical assets. Examples include the Intelligent Transmission Asset Monitor[4] developed by Electric Power Group (EPG). This solution uses one model-based and two data-driven methods for failure detection. The model-based method relies on using a substation linear state estimation and compares estimated data to measured synchronized measurement data. This method ignores system events such as line faults and tripped breakers and only detects local events/anomalous data that may indicate an equipment malfunction. The other two methods that detect measurement anomalies that are precursors of equipment failure are the control chart, which calculates the average range of a moving window and comparing it to each new data point, and moving variance, which compares the moving variance to each new data point. These methods have been explored as part of projects sponsored by the U.S. DOE, EPG, American Electric Power, and the National Energy Technology Laboratory.[5]

[4] http://www.electricpowergroup.com/itam.html

[5] N. Nayak, J. Chynoweth, Substation Asset Health Monitoring Using Synchrophasors, Nov. 3, 2020 https://www.naspi.org/sites/default/files/2020-11/06_epg_nayak_substation_health_20201103.pdf

- A13 and A14: Using advanced sensors in distribution systems for critical asset condition assessments (e.g., substation transformers and secondary/spot network systems) is becoming an industry-leading practice.[6,7] Utilities like Con Edison,[8] Public Service Electricity and Gas,[9] Pepco Holdings Inc.,[10] and ComEd[11] have enabled real-time monitoring and control capabilities and implemented network monitoring systems that allow real-time asset condition assessments. Figure 4-3 shows an example of this application for Newark Airport's underground network system. A specific product to do this includes Eaton's VaultGard.[12] However, synchronized measurement is an emerging area where most work has been conducted in R&D and academic efforts.[13] This is discussed in more detail in Appendix B.
- A15: Dynamic rating of transmission lines is a well-known area with commercial products, solutions, and documented industry experiences. For instance, Lindsey's SMARTLINE-DLR and SMARTLINE-TCF[14] use advanced sensors[15] and advanced data analytics to calculate a line's maximum instantaneous current carrying capacity or forecast transmission line capacity in real-time. Additionally, several academic proposals apply synchronized measurement technologies to evaluate dynamic ratings of transmission lines.[16] However, the application of this type of technology to monitor distribution assets is still very new.

[6] R. Harada, Real-Time Remote Monitoring of Sites and Assets – Part I, https://electricenergyonline.com/energy/magazine/1114/article/Real-Time-Remote-Monitoring-of-Sites-and-Assets-Part-I.htm

[7] R. Harada, E. Sotter, Real-Time Remote Monitoring of Sites and Assets – Part II https://electricenergyonline.com/energy/magazine/1144/article/Real-Time-Remote-Monitoring-of-Sites-and-Assets-Part-II.htm

[8] Consolidated Edison Distributed System Implementation Plan https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/distributed-system-implementation-plan.pdf?la=en

[9] D. Blew, PSE&G Monitors Asset Condition, T&D World, Oct. 1, 2014 https://www.tdworld.com/distribution/pseg-monitors-asset-condition

[10] http://www.eatonensc.com/sites/default/files/assets/documents/presentations/2018-presentations/2019 ENSC Presentation RJS.pdf

[11] https://www.tdworld.com/substations/comed-monitors-underground-networks

[12] https://www.eaton.com/EatonCA/ProductsSolutions/Electrical/ProductsandServices/ElectricalDistribution/SecondaryNetworkSolutions/Communications/VaultGard/index.htm

[13] M. Hojabri et. al, A Comprehensive Survey on Phasor Measurement Unit Applications in Distribution Systems, Energies 2019, 12(23), 4552; https://doi.org/10.3390/en12234552

[14] https://lindsey-usa.com/dynamic-line-rating/

[15] https://lindsey-usa.com/sensors/transmission-line-monitor/

[16] F. Gülşen Erdinç et. al, A Comprehensive Overview of Dynamic Line Rating Combined with Other Flexibility Options from an Operational Point of View, Energies 2020, 13(24), 6563 https://www.mdpi.com/1996-1073/13/24/6563

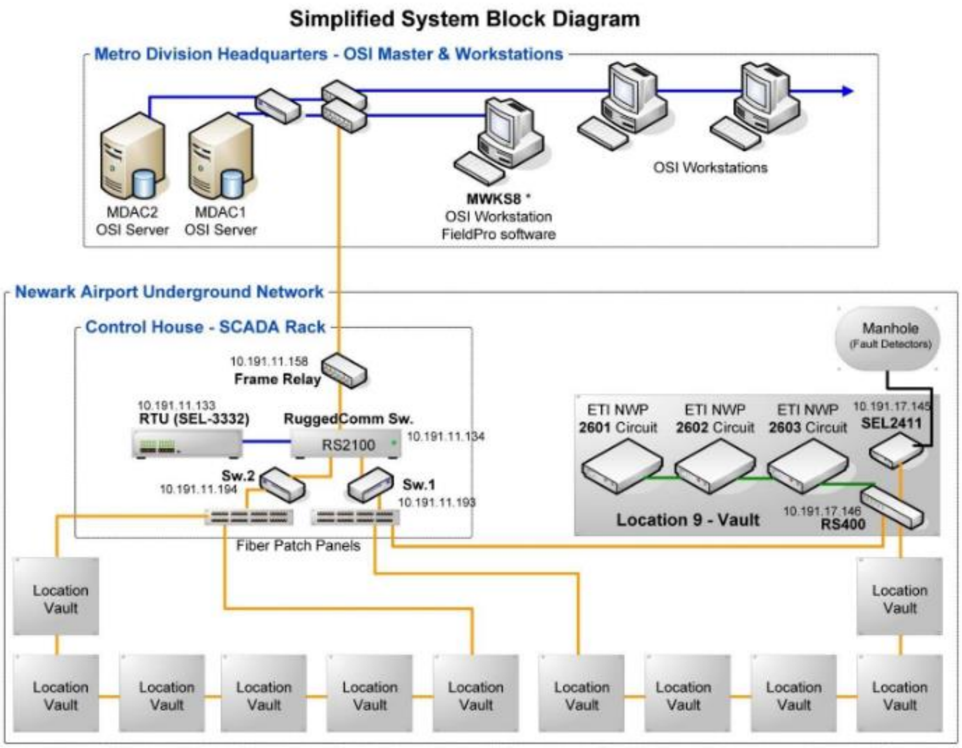

Figure 4-3. Simplified System Block Diagram for Newark Airport Underground Network[17]

4.3.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Asset management of critical infrastructure is very important, especially when it involves critical assets because of the function that they provide (e.g., a transformer that provides service to a hospital) and because of the complexity to identify, repair and restore failures that affect them (e.g., underground secondary networks). Monitoring, control, and awareness of this infrastructure are very important for system operation and overall customer satisfaction, and the industry is actively working on implementing solutions to achieve these objectives. There are commercially available products (e.g., advanced sensors, PQ meters, digital fault recorders [DFRs], etc.) and solutions to monitor asset performance and ratings (including dynamic ratings), either in real-time or on-demand. These products include analytics suites to identify patterns in the data that can be used when evaluating the condition or the likelihood of potential failures (so these potential failures can be addressed preventively).

In this regard, the additional value that synchronized measurements would provide to monitor and evaluate the condition of this type of critical assets (e.g., substation transformers) is incremental when compared to competing technologies. However, for applications that involve monitoring magnitude and phase angles of voltages, currents and power flows of complex grid topologies (e.g., underground secondary/spot networks or primary network systems) or monitoring assets critical for grid operation

[17] D. Blew, Network Monitoring System, Jan. 8, 2019, IEEE Transformer Committee PC57.167 WG, http://grouper.ieee.org/groups/transformers/subcommittees/distr/C57.167/NMS%20PSEG%20pres%20IEEE%20Xfmr%20Jan2019.pdf

(e.g., monitoring voltage magnitudes and phase angles of normally open switches during system reconfiguration), synchronized measurement technologies can provide an added value to conventional sensing technologies. Implementing this type of technology in underground secondary/spot network systems can be highly complex, particularly considering the number of measurements needed, logistical issues, and technology limitations of deploying telecommunications solutions in high-density areas of large cities (considering that secondary networks are generally used in downtown areas).

Figure 4-4 presents the value of synchronized measurements for asset management of critical infrastructure.

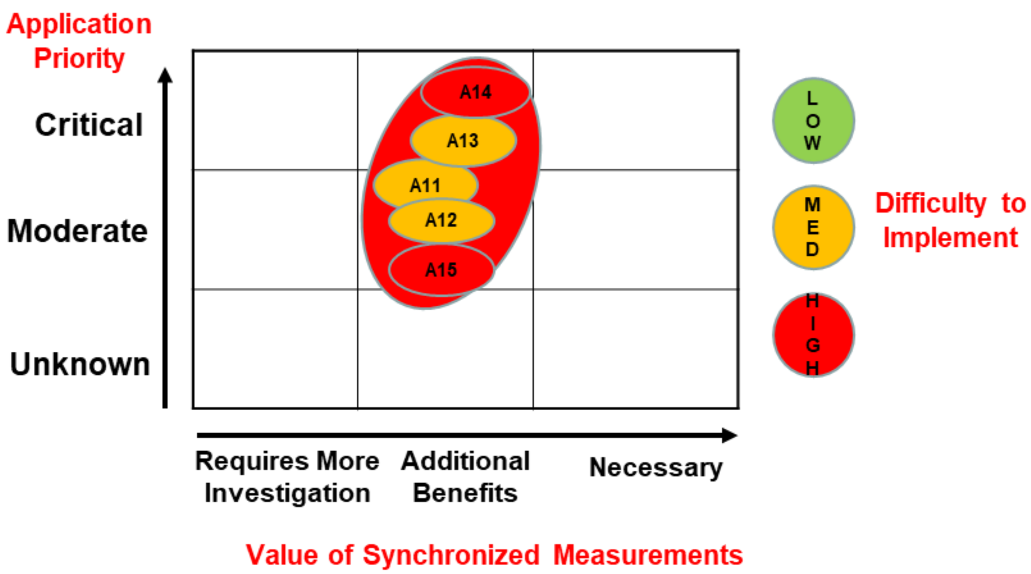

Figure 4-4. Value of Synchronized Measurements for Asset Management of Critical Infrastructure (AG3)[18]

4.3.4 Quantified Benefits

The high-level benefits of synchronized measurements for asset management of critical infrastructure:

- Advanced planning and asset management (7)
- Innovation potential (7)
- Resilience and reliability (7)
- Efficiency improvement (7)
- Public safety (6)
- Real-time operation (5)
- Customer engagement and business potential (5)

[18] D. Blew, Network Monitoring System, Jan. 8, 2019, IEEE Transformer Committee PC57.167 WG, http://grouper.ieee.org/groups/transformers/subcommittees/distr/C57.167/NMS%20PSEG%20pres%20IEEE%20Xfmr%20Jan2019.pdf

- Sustainability and decarbonization (4)

High-level benefits of the application of synchronized measurement technologies for asset management of critical infrastructure include:

- A11 and A12: Understanding asset condition and status in real-time and identifying potential failures can help utilities implement preventive measures (e.g., maintenance, asset replacement, system reconfiguration, etc.) to avoid outages and service interruptions. Quantifiable benefits include 1) avoiding (or reducing) equipment damage and the need for corrective maintenance or emergency asset replacement and associated labor, 2) preventing reliability deterioration, 3) avoiding (or reducing) energy not supplied and respective customer dissatisfaction and complaints, and 4) reducing the time needed for forensic analyses (e.g., root-cause analysis, failure identification, etc.).
- A13 and A14: Monitoring and control of critical infrastructure (including underground secondary/spot networks) and large customers can help utilities prevent, identify, and prevent disruptions that impact reliability, resilience, and PQ of critical customers (e.g., hospitals), customers that require "perfect or premium power" (e.g., data centers), and complex grid configurations (e.g., secondary networks) that are difficult to fault-diagnose and restore. The high-resolution, time-synchronized georeferenced data provided by synchronized measurement technologies helps identify data patterns used to recognize root causes of failures and can help understand and prevent impacts caused by the integration of DER and electric transportation.
- A15: Dynamic rating of distribution assets can help utilities 1) optimize asset utilization (e.g., use additional reserve capacity that utilities may not be aware is available during emergency conditions), 2) defer the upgrade of distribution components considered overloaded when analyzed using fixed ratings or 3) postpone projects intended to relieve capacity (e.g., system reconfiguration to transfer the load to neighbor feeders or substations, or deployment of reactive power compensation).

4.3.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of synchronized measurements for asset management of critical infrastructure:

- Complexity of the system (8)
- Investment required to implement (8)
- Maturity of the solutions and devices (6)
- Risk of failure (4)
- Readiness of the utility and utility personnel to adopt (5)

It is helpful to look at this evaluation in terms of specific applications:

- A11, A12, A13, and A14: Latency and data availability requirements are moderate. Analysis can be done by exception, on-demand, or on an hourly or daily basis, except during operating conditions that are particularly stressful for the T&D grid. Real-time monitoring of critical assets, customers, and secondary/spot networks may be required during extreme weather events (e.g., heat storms) or emergency operations. However, these situations are expected to be the exception rather than the norm. These applications, particularly A14, require a systematic approach to make them effective. The number of measurements needed to implement them will depend on the system size and the assets monitored, but the process can involve hundreds of devices in large systems (e.g., every network transformer in a secondary network system). Therefore, these applications are expected to be more costly and complex to implement.

- A15: Latency and data availability for this application are stringent. It requires the implementation of a highly reliable and low latency telecommunications solution. Data must be collected and transmitted to the control center in real-time, and respective analyses and control actions must also be implemented in real-time. This application would target only a few very specific assets (e.g., substation transformers or selected lines). Therefore, the number of measurements required for implementation would be relatively small compared to applications A11, A12, A13, and A14.

4.4 AG4: Wide-Area Visualization

4.4.1 High-Level Summary of Application

Synchronized measurement technology includes a wide array of monitoring devices, including PMUs. The time synchronization of the measurements is critical to developing and deploying wide-area visualization systems to help utilities and grid operators better manage the electric grid and improve its reliability. PMUs can report as many as 60 measurements per second, while SCADA provides a measurement every 4 s to 10 s with no time synchronization. High report rates from PMUs can be used by applications to detect and display events that SCADA misses, thereby improving visibility into grid conditions and the performance of specific assets such as power generators. PMUs used with high-speed data networks, high-quality data analytics, and active system management can improve reliability, provide environmental benefits, yield cost savings, and increase the electricity grid's efficiency and throughput.

Wide-area visualization includes the following use cases:

- A16—Circuit status dashboards: Time synchronized measurements of voltages and currents at several locations along distribution circuits support real-time indication of voltage and current levels to securely determine energization levels for individual circuits. This information can assist field crews working to solve outage issues and improve safety.
- A17—Integration of customer site FNET information: Frequency monitoring network (FNET) is a wide-area power system frequency measurement system. Using a type of synchronized measurements known as a frequency disturbance recorder (FDR), FNET/GridEye accurately measures power system frequency, voltage, and angle. These measurements can then be used to study various power system phenomena and may play an important role in developing future smart grid technologies. The FNET/GridEye system is currently operated by the Power Information Technology Laboratory at the University of Tennessee, Knoxville, and the ORNL in Oak Ridge, Tennessee.[19]
- A18—Improved wide-area situational awareness (WASA) T&D: Without time-synchronized measurements, it is impossible to achieve accurate wide-area visibility. Synchronized measurement

[19] FNET: http://fnetpublic.utk.edu/

systems deliver near real-time, time-synchronized grid condition data across an entire system or interconnection. This data can be used to create wide-area visibility across the bulk power system in ways that let grid operators understand real-time conditions, identify early evidence of emerging grid problems, and better diagnose, implement, and evaluate remedial actions to protect system reliability. When applied to distribution and transmission, operators can get a clearer picture of the grid and its effect on distribution.

- A19—Visualization of dynamic system response**:** To visualize dynamic system response, a much higher measurement report rate is often required. For example, an oscillation resulting from an improperly configured smart inverter will not be visible when using traditional SCADA measurements.

4.4.2 Deployment Status in the Industry

SDG&E and many other utilities have deployed SMDs suitable for WASA on their transmission networks. These are typically PMUs. Including the distribution networks in the WASA displays would require additional measurement devices at strategic locations on the distribution network to be deployed.

4.4.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Wide-area visualization is the original use case for synchronized measurements focused on the transmission system. The increasing penetration of DERs and microgrids makes visualization of the distribution system important, both to show system status and the dynamic system response due to the use of inverters.

Figure 4-5 presents the value of synchronized measurements for wide-area visualization.

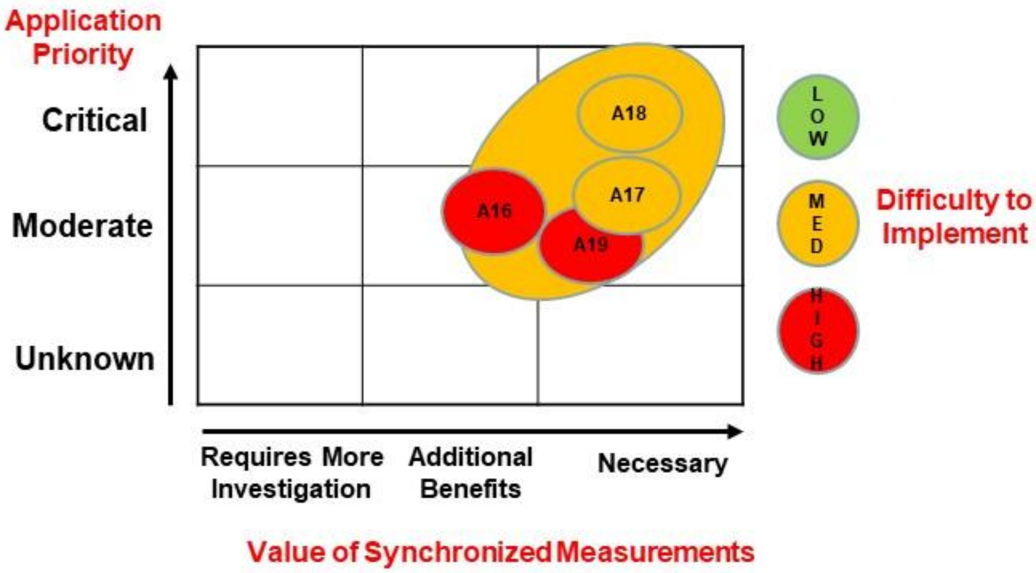

Figure 4-5. Value of Synchronized Measurements for Wide-Area Visualization (AG4)

4.4.4 Quantified Benefits

High-level application benefits of synchronized measurements for wide-area visualization:

- Real-time operation (9)
- Resilience and reliability (8)
- Public safety (7)
- Customer engagement and business potential (7)
- Sustainability and decarbonization (6)
- Advanced planning and asset management (6)
- Innovation potential (6)
- Efficiency improvement (5)

Synchronized measurements are intended to provide wide-area visualization. This total picture of the entire distribution system will benefit real-time operation, as system operators will have a complete picture of the system. Reliability and safety are improved as operating issues are instantly recognized to be acted upon.

4.4.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for wide-area visualization applications:

- Complexity of the solution (6)
- Investment required to implement (7)

- Maturity of possible solutions (6)
- Risk of failure (3)
- Readiness of the utility and utility personnel to adopt (6)

All applications will require at least one synchronized measurement point per feeder. The majority of these applications, especially the most beneficial ones, will require synchronized measurement data from multiple distribution feeders for full visibility.

The specific performance requirements for advanced monitoring of the distribution grid are presented in Table 4-3.

Table 4-3. Specific Performance Requirements for Wide-Area Visualization

Requirement	Synchronized Measurement Data
Measurement accuracy	1% total vector error
Availability	95%
Latency	1000 ms
Sampling rate	Device sampling rate
Reporting rate	Minimum 30 Hz

The cost drivers wide-area visualization are essentially the costs of realizing the solutions. There is a need for numerous sensors on distribution circuits, a need for infrastructure to support these devices and data streams, and a need to upgrade the capabilities of DMSs to handle and display this data. Meeting these needs requires a complex solution and significant technological changes.

4.5 AG5: Advanced DER Integration and Control

4.5.1 High-Level Summary

The advent of fast-acting power generation technologies, such as power electronic-based DERs (e.g., PV and wind) and battery storage, is fundamentally changing distributions systems' design and operation. These sources can produce reverse power flows and rapidly shift circuit voltage profiles, making the operation of conventional voltage control devices (like switched capacitors and VRs) ineffective or unstable. Mitigation schemes for DER's effects on distribution system voltages require fast, precise, and widespread holistic measurements at the point of interconnection and adjacent loads and branches.

These widespread measurements will come from all points of interconnection and other key equipment on the distribution system and will be centrally gathered either at the substation or DMS to facilitate DERs and battery storage integration.

DER integration includes the following use cases:

- A20—Monitoring of intermittent DER: Measuring individual or aggregated DER output in real-time and the impact on circuit power flow.
- A21—Voltage impact assessment and mitigation due to high penetration of intermittent energy resources: Using accurate voltage measurements from several points on a circuit to capture fast-changing voltage phenomena or profiles and integrating these measurements into circuit-wide control solutions.
- A22—Active and reactive reverse power flow management: Determining and controlling the active and reactive power flow magnitudes and direction across a circuit in real-time.
- A23—Customer smart inverter control: Using data streamed from measurement points across the circuit as the basis for a centralized or distributed control system using controllable DER inverters to regulate voltage, dispatch power, and yield a stable response during system disturbances.
- A24—DER management and energy balancing (energy battery storage): Using accurate, synchronized measurements to manage power and energy transactions of DERs (generation and storage) to maximize overall utilization and limit adverse impacts on circuit PQ.
- A25—Load unmasking (behind-the-meter DER): Using measurements of load information to capture the impact of DERs located beyond the interconnection point on utility circuit voltage profile and load flow.

4.5.2 Deployment Status in the Industry

Some advanced DER integration applications have initial deployments on utility systems. ComEd has deployed distribution synchronized measurements for DER monitoring (see AG2). This deployment also includes a distribution linear state estimator (DLSE), islanding, load and generation balance, re-synchronization, DG/load disaggregation, and asset management and value optimization. The initial focus has been on the Bronzeville Microgrid[20] (see AG13) for situational awareness and control.[21] ComEd is also exploring using a distributed energy resources management system (DERMS) to control smart inverters to prevent reverse power flow through substation transformers under high DER penetration.

4.5.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

DER integration can create a variety of impacts on power distribution systems operations, planning, and design. Data provided by synchronized measurements can be used to identify and understand the drivers and root causes behind these impacts. Data can also be used to design and validate the effectiveness of mitigation measures. Examples of DER impacts include voltage rise, voltage fluctuations, violation of thermal loading limits, reverse power flow, voltage and current imbalance, load masking, etc. These impacts can be highly dynamic due to the variability of DER output (e.g., wind and solar) and grow in complexity as DER proliferation increases (including potential interaction effects among inverter-based

[20] P. Pabst, H. Chen, Synchronized Measurements in Distribution Systems, Mar. 2021, https://www.naspi.org/sites/default/files/2021-04/20210331_naspi_webinar_comed.pdf

[21] B. Kregel, H. Chen, A Journey to Full Distribution Situational Awareness, https://www.naspi.org/sites/default/files/2019-10/03_Success_Chen_Kregel_20191030.pdf

DER). These dynamics make the high-resolution, georeferenced, and time-synchronized capability of synchronized measurement technologies very valuable.

Figure 4-6 presents the value of synchronized measurements for advanced DER integration.

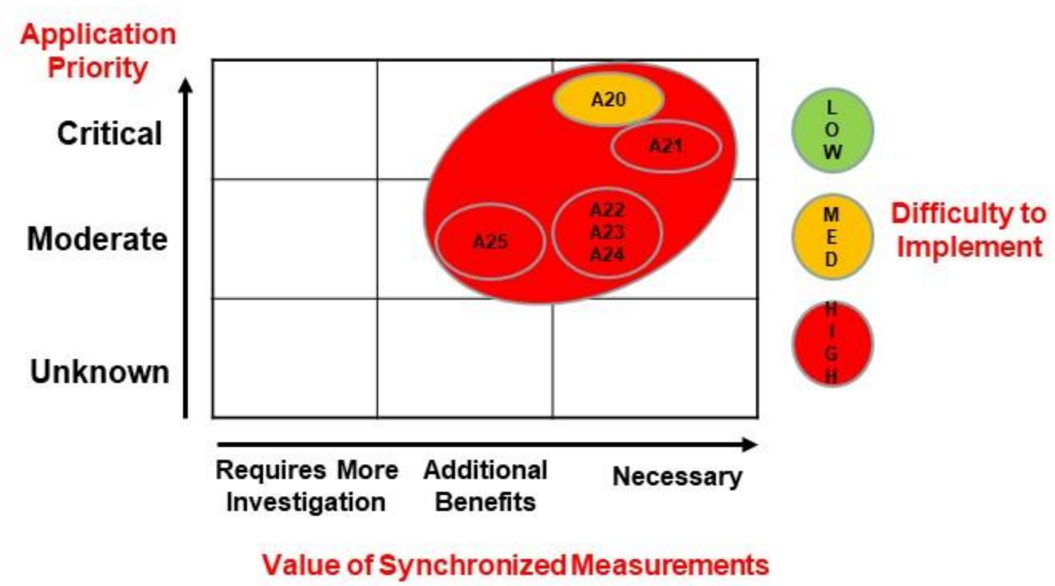

Figure 4-6. Value of Synchronized Measurements for Advanced DER Integration (AG5)

4.5.4 Quantified Benefits

High-level benefits of synchronized measurements for advanced DER integration and control:

- Sustainability and decarbonization (9)
- Innovation potential (8)
- Resilience and reliability (7)
- Real-time operation (7)
- Advanced planning and asset management (7)
- Customer engagement and business potential (7)
- Efficiency improvement (6)
- Public safety (4)

DER integration can have important benefits, including compliance with renewable portfolio standards goals and improved service to end users by mitigating PQ-related issues (e.g., voltage fluctuations, voltage rise, voltage imbalance, etc.). In addition, DER integration supports decarbonization, innovation related to control and operations, system resilience through islanding capabilities, and real-time operations through load support and demand management.

4.5.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for DER Integration and control applications:

- Complexity of the system (7)
- Investment required to implement (7)
- Maturity of the solutions and devices (6)
- Risk of failure (5)
- Readiness of the utility and utility personnel to adopt (5)

Latency and data availability for these applications are stringent. They require the implementation of a highly reliable and low latency telecommunications solution. Data must be collected and transmitted to the control center in real-time. Likewise, analyses and control actions must be implemented in real-time. This application would potentially target hundreds or thousands of DERs. Therefore, the number of measurements required for implementation would be large, and the overall cost of the application would be high. Therefore, this is a high-density system architecture at the distribution feeder. It is also a high-density application at the system level, as data must be collected and processed from every distribution substation.

The suggested performance requirements for advanced DER integration and control are presented in Table 4-4.

Table 4-4. Specific Performance Requirements for Advanced DER Integration and Control

Requirement	Synchronized Measurement Data	Other Synchronized Data
Measurement accuracy	1% total vector error	±5% error
Availability	80%	95%
Latency	2000 ms	5000 ms
Sampling rate	Device sampling rate	Device sampling rate
Reporting rate	Minimum 30 Hz	1 Hz

4.6 AG6: Real-Time Distribution System Operation

4.6.1 High-Level Summary

Distribution systems are evolving due to increased penetration of DERs and electric transportation, resulting in the need for robust real-time monitoring, protection, automation, and control algorithms that allow operating this highly dynamic system within quality, reliability, efficiency, and security requirements. However, solutions are bounded by physical limitations imposed by radial distribution grids (e.g., circuit capacity and stiffness).

The objective of this application is to use voltage and current data (provided by synchronized measurements deployed at strategic locations along distribution circuits) to operate (monitor and control) the distribution system reliably, including preventing or identifying and mitigating impacts caused by variable DER and electric transportation integration.

Real-time distribution system operation includes the following use cases:

- A26—Distribution state estimation: Using synchronized measurements from distribution circuits combined with available data provided by SCADA, AMI, telemetry monitoring, etc., to conduct state estimation of distribution circuits. DLSE is an improvement on conventional state estimation as it enables linear calculations and improved accuracy using state measurements if full observability is achieved with a sufficient number of synchronized measurements. This application has been successfully implemented in transmission and is now being deployed in distribution. As it will take time to fully deploy synchronized measurements to achieve full observability, hybrid distribution state estimation represents an intermediate solution.
- A27—Closed-loop circuit operation: Using the measurement and comparison of key electric parameters under the closed-loop operation of distribution circuits to understand voltage profiles, load flows, line loading, short circuit duty, especially due to the impact of intermittent DERs.
- A28—DERMS implementation: DERMS is a platform combined with the DMS to operate the distribution system in the presence of aggregated DERs, especially focusing on voltage management, power flow optimization, and local load management.
- A29—Improved demand response: Using measurements of power flows and the capacity of DERs to match system response with DER response high demand periods.

4.6.2 Deployment Status in the Industry

Some applications of real-time distribution system operations are being deployed. Specific examples are:

- A26: Application of synchronized measurement technologies for distribution state estimation is still an emerging area. The most relevant utility industry experience in this area is the distribution linear state estimation project by ComEd in collaboration with V&R Energy. ComEd is undertaking this project to analyze some of its DER-rich areas, including the Bronzeville Microgrid (see Figure 4-8), the Chicago Airport, and the Mendota-Dixon 34.5 kV loop. The DLSE engine relies on a foundational connectivity model of the distribution grid, supplemented by real-time data collected by 46 PMUs deployed at strategic locations. The engine then compares time-synchronized measurements between different PMUs across a feeder or system to calculate active and reactive power flows within a system-level model. The DLSE performs its analysis 60 times per second and provides an estimation of potential future system conditions.[22] Implementation of DLSE and advanced applications based on

[22] B. Kregel, ComEd Engineers Real-Time Situational Awareness, T&D World, Sep. 2020 https://www.tdworld.com/test-and-measurement/article/21138063/comed-engineers-realtime-situational-awareness

DLSE, such as switching event detection, voltage monitoring, etc., are described in[23]. Other functions of interest in this project include 1) observability analysis, 2) bad synchronized measurement data detection and correction, 3) microgrid monitoring, gathering, and reporting, and 4) archiving alarms and metrics, situational awareness visualization, and topology change identification.[24]

Hybrid distribution state estimation has been piloted at Central Hudson utility by V&R Energy and Quanta Technology as part of a project funded by NYSERDA under PON 4094. It uses the RTDS representation of Central Hudson's distribution system and a low-cost DER Gateway prototype. Both SCADA measurements and an IEEE C37.118 stream from virtual PMUs have been fed to the hybrid state estimator. The DER Gateways provide additional inputs through a distributed monitoring platform that interfaces to the distribution state estimator through SCADA. The project explored the use of the hybrid distribution state estimator and the DER gateways to enable advanced distribution applications, namely DER dispatch and thermal constraint management, and enhance FLISR through load-DER disaggregation and support real-time VVC.

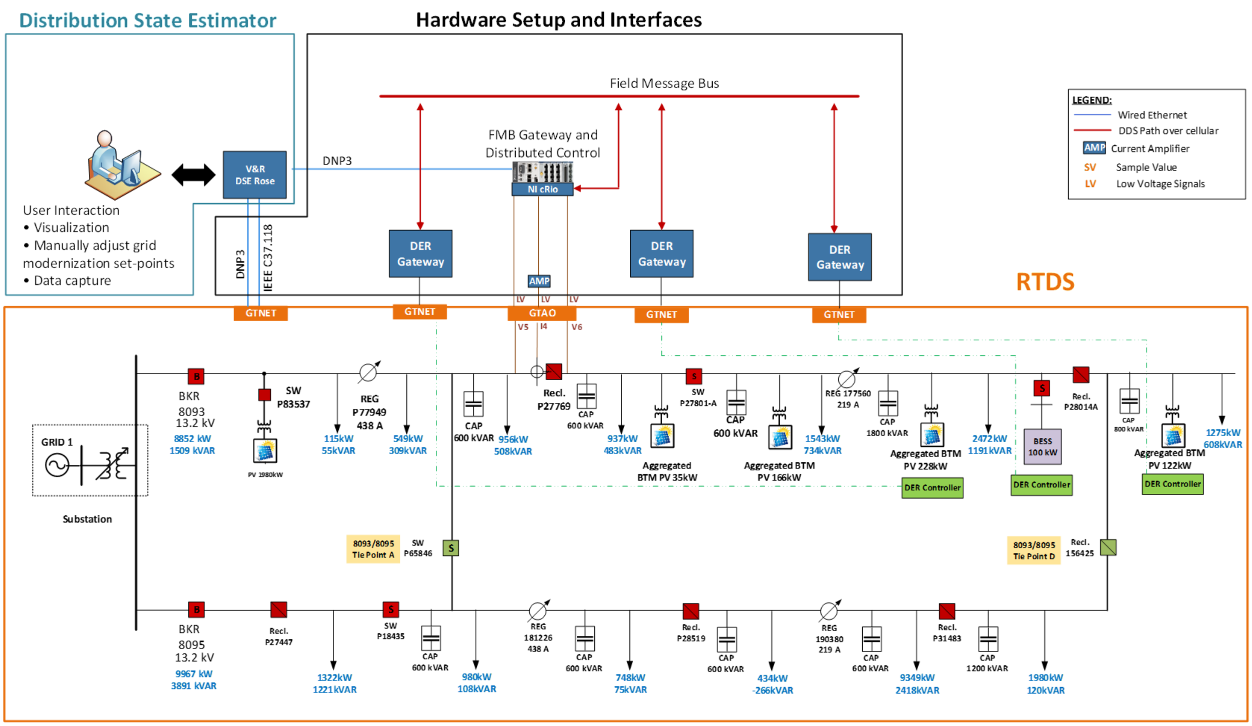

Figure 4-7. Hybrid DLSE Demonstration Set-Up Used in NYSERDA Project

[23] N. Gurung, S.R. Kothandaraman, L. Zhang, H. Chen, F. Rahmatian, M.Y. Vaiman, M.M. Vaiman, M. Povolotskiy, and M. Karpoukhin, "Use of PMU-Based Software Platform to Provide Real-Time Situational Awareness for Bronzeville Community Microgrid", IEEE PES T&D Conference & Exposition, 2020, Chicago, Illinois, 2020TD0343.

[24] P. Pabst, H. Chen, Synchronized Measurements in Distribution Systems, https://www.naspi.org/sites/default/files/2021-04/20210331_naspi_webinar_comed.pdf

- A28: Using synchronized measurements for DERMS is also an emerging area. ComEd is implementing a DERMS as a non-wires alternative to prevent violations of substation transformer maximum reverse power flow due to high adoption levels PV-DG. DERMS monitors transformer loading, DER output, system conditions and will send signals to manage DERs if any system violations occur (see Figure 4-9).

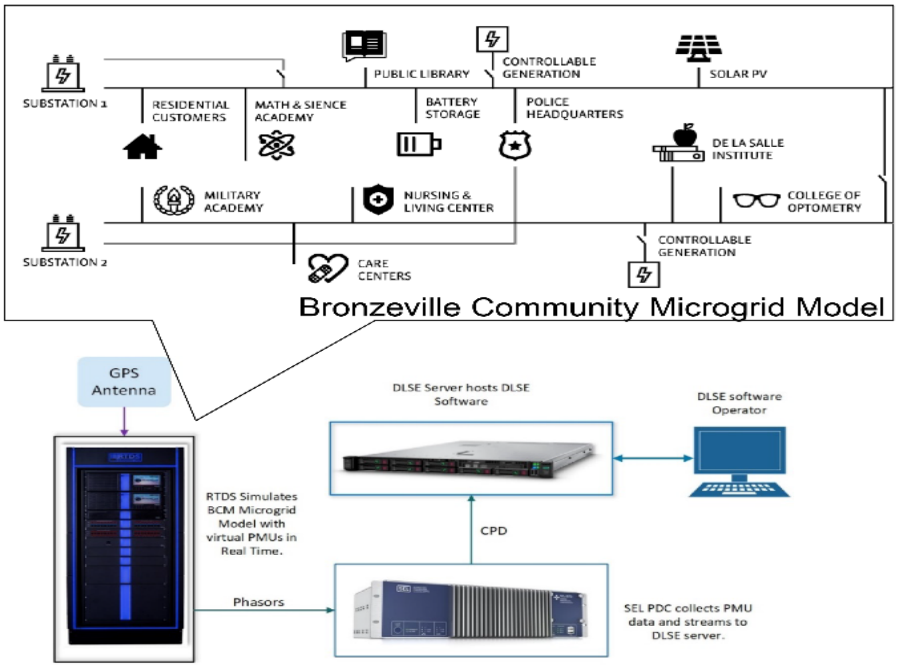

Figure 4-8. DLSE24

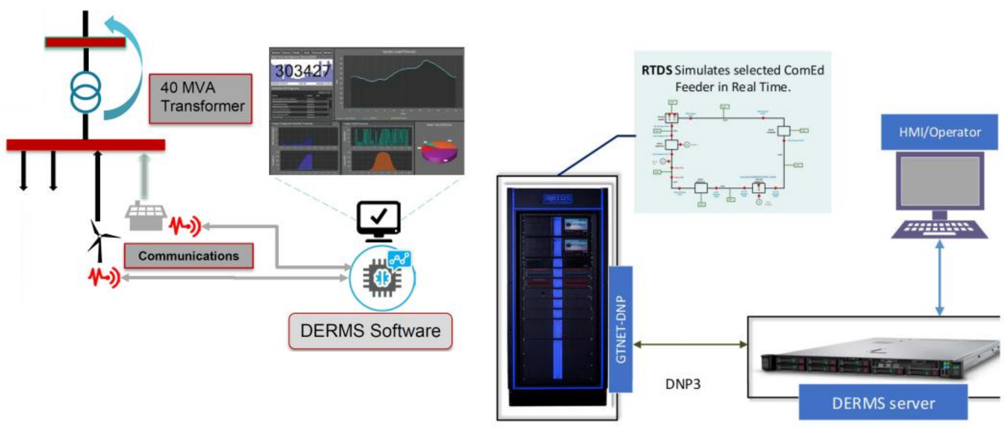

Figure 4-9. DERMS for Renewable DG Integration[24]

4.6.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Real-time distribution system operation is quickly becoming a critical area of modern distribution systems. This change is mainly due to the need to monitor the dynamic behavior of the grid. It is also due to the need to understand how DER may impact key electric variables, so control actions can be implemented to prevent or mitigate them. Real-time distribution system operations can be and have been implemented using conventional measurements and supported by SCADA. SCADA is suitable for traditional distribution systems, which exhibit slow dynamics largely driven by changes in demand and grid reconfiguration (operation of protection, automation, and control systems). However, modern distribution systems with high DER penetration and electric transportation experience more frequent changes and faster dynamics, largely due to DER output variability and widespread use of advanced distribution automation schemes. As discussed above, DLSE and advanced applications based on DLSE have been implemented at ComEd and demonstrate significant benefits of the A26 application.[25,26,27] This important application is not possible without synchronized measurements. As it will take time to fully deploy synchronized measurements to achieve full observability, hybrid distribution state estimation is the basis to effectively supporting grid modernization applications such as fault location, isolation, and service restoration (FLISR), VVO, and dispatch of DER assets.

Furthermore, synchronized measurement technologies at strategic locations and distribution feeders (e.g., substation, reclosers, switches, VRs, capacitor banks, DER units, and large/critical customers) can provide accurate real-time data that can be used to estimate the distribution system's state and enable the implementation of DERMS control actions and advanced demand response. The time-synchronized, georeferenced, and high-resolution capability of synchronized measurement technologies provide unique information to understand distribution system dynamics and implement control actions (e.g., DER curtailment, DER reactive power injection/absorption changes, demand response, etc.).

Synchronized measurement technologies are particularly helpful for proactively reconfiguring complex system grid topologies, especially in systems with high DER penetration and microgrid involvement. For instance, measuring magnitudes/phase angles of voltages/currents helps verify the feasibility of make-before-break switching operations and enables distribution system closed-loop/meshed operation, which is being explored as a solution to increase DER hosting capacity and facilitate integration.[28] Synchronized

[25] M. Heng (Kevin) Chen, "Distribution Linear State Estimator for Increased Situational Awareness and Resilience", IEEE ISGT 2020, February 19, 2020. (Panel session presentation).

[26] M. Vaiman, "PMU-based Real-Time Distribution System Monitoring Platform", IEEE ISGT 2021, February 18, 2021. (Panel session presentation). Available online at https://resourcecenter.ieee-pes.org/conferences/isgt-na/PES_CVS_ISGTNA21_218_600.html.

[27] M. Vaiman and Mohd Khairun Nizam Mohd Sarmin, "Implementing PMU-based Systems for Transmission and Distribution System Analysis", NASPI Working Group Meeting, April 13, 2021. Available on-line at https://www.naspi.org/sites/default/files/2021-04/D1S1_05_vaiman_vrenergy_naspi_20210413.pdf.

[28] M. Davoudi, V. Cecchi, J. Romero Agüero, Evaluation of Meshed Distribution Systems for Increased Penetration of Distributed Generation, CIGRE US National Committee, 2014 Grid of the Future Symposium http://cigre-usnc.org/wp-content/uploads/2015/06/Evaluation-of-Meshed-Distribution-Systems-for-Increased-Penetration-of-Distributed-Generation.pdf

measurement technologies' ability to provide accurate values of voltage phase angles and magnitudes is a unique added value for implementing this type of application.

Figure 4-10 presents the value of synchronized measurements for real-time distribution system operations.

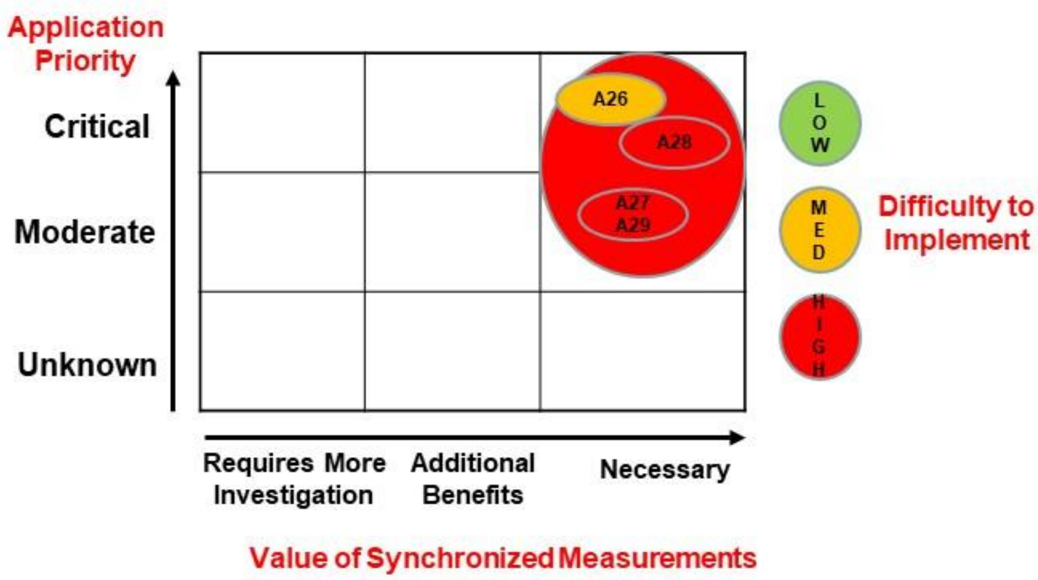

Figure 4-10. Value of Synchronized Measurements for Real-Time Distribution System Operations (AG6)

4.6.4 Quantified Benefits

High-level benefits of synchronized measurements for real-time distribution system operations:

- Real-time operation (9)
- Resilience and reliability (8)
- Public safety (7)
- Efficiency improvement (7)
- Innovation potential (6)
- Sustainability and decarbonization (5)
- Customer engagement and business potential (5)
- Advanced planning and asset management (4)

Synchronized measurements from the distribution system can be used to provide linear state estimation and fully implementing a DERMS system, greatly improving the real-time operations and reliability of the network.

4.6.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for real-time distribution system operation applications:

- Complexity of the system (7)
- Investment required to implement (7)
- Maturity of the solutions and devices (6)
- Risk of failure (5)
- Readiness of the utility and utility personnel to adopt (7)

Regarding the A26 application, deploying DLSE with full observability requires a large number of synchronized measurements. As technology has been deployed in practice, implementation difficulty is related to the infrastructure required (number of devices required and communications). A hybrid distribution state estimator is a good intermediate solution to deploy the technology in the most cost-effective way to achieve benefits.

In general, real-time distribution system operations require implementing a highly reliable and low latency telecommunications solution. Data must be collected and transmitted to the control center in real-time, and respective analyses and control actions must also be implemented in real-time. This application would potentially target hundreds or thousands of devices (e.g., reclosers, switches, DER, large/critical customer loads, etc.). Therefore, the number of measurements required for implementation would be large, and the overall cost of the application would be high.

The suggested performance requirements for real-time distribution system operations are presented in Table 4-5.

Table 4-5. Specific Performance Requirements for Real-Time Distribution System Operations

Requirement	Synchronized Measurement Data	Other Synchronized Data
Measurement accuracy	1% total vector error	±5% error
Availability	95%	90%
Latency	2000 ms	5000 ms
Sampling rate	Device sampling rate	Device sampling rate
Reporting rate	Minimum 30 Hz	1 Hz

4.7 AG7: Enhanced Reliability and Resilience Analysis

4.7.1 High-Level Summary of Application

Distribution reliability analysis is a fundamental component of distribution system planning and critical for ensuring a dependable supply to customers. Modern approaches use outage management system

(OMS) data to calculate circuit reliability indices and failure rates, provide predictive reliability models, and address "what-if" scenarios. Synchronized data from the entire distribution system could provide a holistic and spatial approach to analyzing circuit reliability and resilience. Enhanced reliability and resilience analysis include the following use cases:

- A30—Improved distribution reliability analysis: Using synchronized measurements to monitor the frequency and duration of sustained and momentary service interruptions in distribution circuits to determine system components' failure rates and repair times, calculate reliability indices such as the momentary average interruption frequency index (MAIFI) and the momentary average interruption event frequency index ($MAIFI_E$), and identify pockets of poor reliability.
- A31—Post-mortem analysis: Gathering and analyzing high-resolution, time-synchronized, georeferenced voltage and current magnitudes and phase angles from a distribution feeder during fault and abnormal operating conditions to identify root causes of outages and evaluate protection and control actions' effectiveness.

4.7.2 Deployment Status in the Industry

There has been significant interest in deploying advanced sensors to monitor distribution feeder performance, identify event root causes, pinpoint worst-performing areas, and improve distribution reliability and resilience. Examples of these technologies include advanced sensors and analytics suites by Sentient Energy,[29] Lindsey,[30] Grid 20/20,[31] SEL,[32] Aclara,[33] Digitalgrid,[34] 3M,[35] and others. Utilities like Florida Power and Light,[36] ComEd,[37] Hawaiian Electric,[38] and Pacific Gas and Electric (PG&E)[39] have deployed these sensors through U.S. DOE projects. However, using synchronized measurements in this area is new—existing experiences have been mostly part of R&D projects[40] and are documented and discussed in Appendix B: State of the Art Review of System Technologies.

Figure 4-11 presents an example of a data analytics solution and reliability analysis based on advanced sensor data.

29 https://www.sentient-energy.com/

30 https://lindsey-usa.com/sensors/

31 https://grid2020.com/

32 https://selinc.com/solutions/fault-indicators-and-sensors/

33 https://www.aclara.com/products-and-services/sensors-and-controls/grid-monitoring-platform/mv-sensor/

34 https://digitalgridinc.com/products-and-services/vault-products/sensors/

35 https://www.3m.com/3M/en_US/power-distribution-us/sensored-cable-accessories/

36 https://www.tdworld.com/smart-utility/article/20966142/florida-power-light-orders-20000-distribution-line-sensors

37 https://www.tdworld.com/substations/article/20966646/comed-monitors-underground-networks

38 https://www.bizjournals.com/pacific/news/2018/04/10/heco-grid-study-emphasizes-real-time-data.html

39 https://www.sentient-energy.com/SentientPDFs/Sentient_Case_Study_SAIDI_PGE_v1.pdf

40 https://gmlc.doe.gov/sites/default/files/resources/Sensing%20and%20Measurements%20Overview_Presentation.pdf

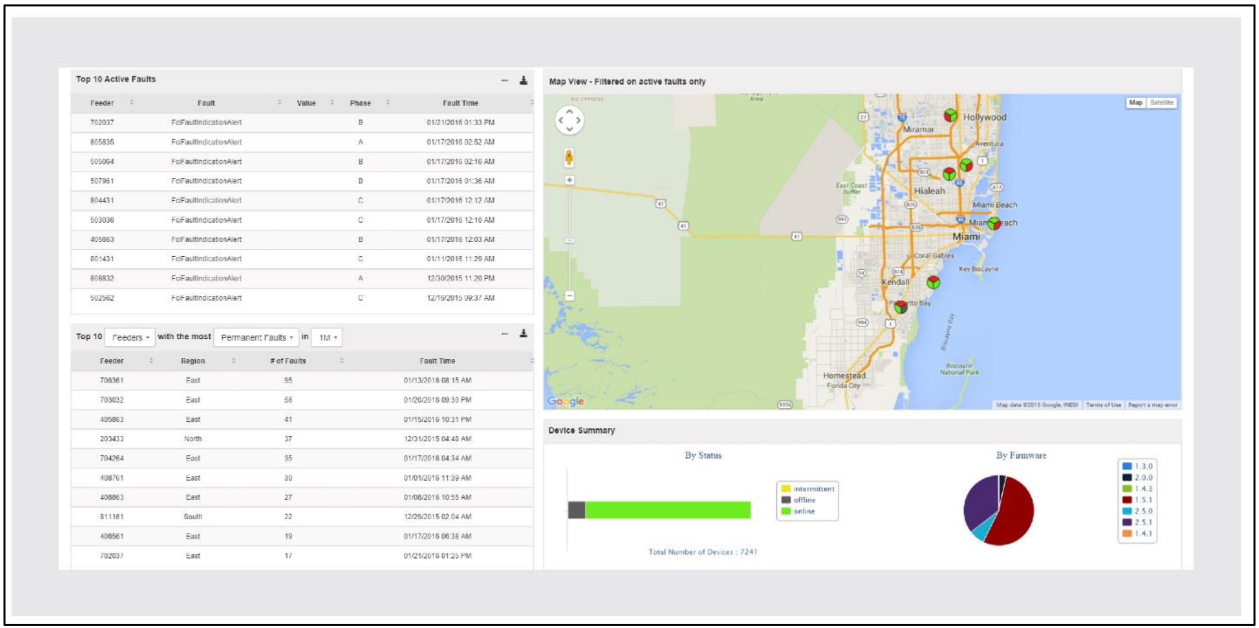

Figure 4-11. Example of Data Analytics Solution and Reliability Analysis Based on Advanced Sensor Data[41]

4.7.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Reliability and resilience analyses are foundational to power distribution planning and engineering. There is increasing interest in using advanced technologies to improve awareness regarding distribution systems' reliability and resilience, particularly at the customer level. Distribution reliability performance is evaluated using well-known indices such as the system average interruption frequency index, the system average interruption duration index, and the customer average interruption duration index. Calculating these indices requires accurate outage and service interruption data, and the deployment of AMI and OMSs has facilitated the collection of this data. However, about 43% of total customers in the United States do not have smart meters,[42] and smart meter deployment is subject to regulatory approval. Therefore, the deployment of advanced sensors is an alternative to address this specific need.

Additionally, collecting data to calculate reliability indices that measure the impact of temporary faults and momentary interruptions (MAIFI and $MAIFI_E$) remains a challenging task for utilities, even for those that have deployed AMI and distribution automation solutions. In this regard, the time-synchronized and georeferenced capability of synchronized measurement technologies can facilitate data collection for these indices and understanding the impact this type of event has on distribution customers and other system components (e.g., reclosers, inverters, etc.). Similarly, the high-resolution capability of these technologies allows capturing voltage and current waveforms and calculating their respective magnitudes and phase angles. This can be valuable information for conducting detailed root-cause and post-mortem analyses and identifying solutions to improve reliability and resilience. However, it is worth noting that

[41] https://www.sentient-energy.com/products/ample-analytics-platform

[42] https://www.smart-energy.com/industry-sectors/smart-meters/smart-metering-in-us-reaches-57-penetration/

similar analyses can be conducted using other advanced sensor technologies, such as DFR, PQ meters, and advanced faulted circuit indicators (FCIs). In this regard, the additional benefits provided by synchronized measurement technologies are incremental and particularly applicable to complex distribution systems with high DER penetration, where georeferenced and time-synchronized data can be valuable to identify features and root causes of outages.

Figure 4-12 presents the value of synchronized measurements for reliability and resilience analysis.

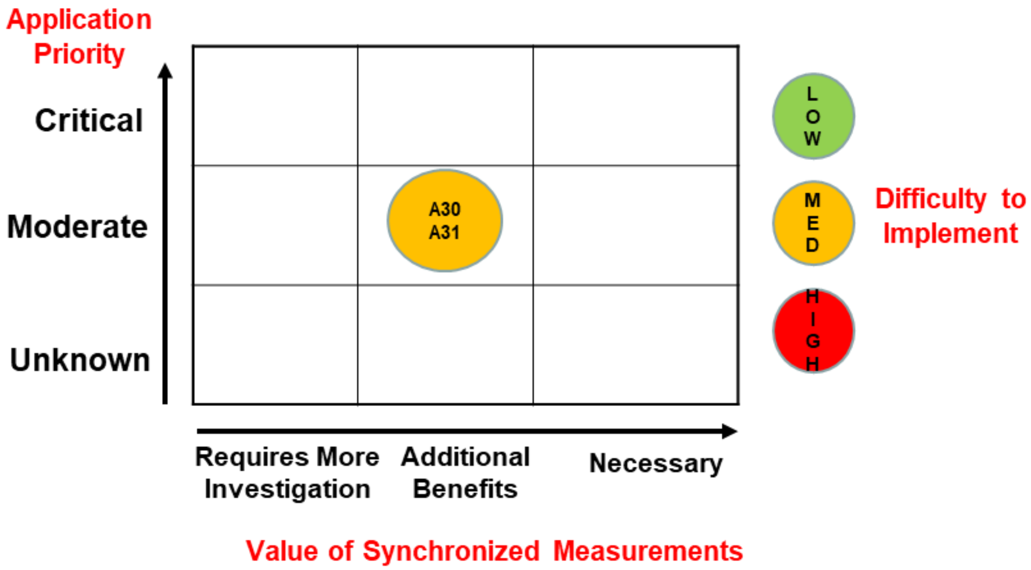

Figure 4-12. Value of Synchronized Measurements for Reliability and Resilience Analysis (AG7)

4.7.4 Quantified Benefits

High-level benefits of synchronized measurements for reliability and resilience analysis:

- Resilience and reliability (6)
- Advanced planning and asset management (6)
- Innovation potential (6)
- Customer engagement and business potential (5)
- Sustainability and decarbonization (4)
- Public safety (4)
- Efficiency improvement (4)
- Real-time operation (3)

High-level benefits of the application of synchronized measurement technologies for reliability and resilience analysis include:

- A30: Greater resolution, accuracy, and spatial granularity of reliability and resilience analyses based on data provided by synchronized measurement technologies can help understand performance at the section- and customer-level. In turn, this understanding can allow investment optimization for improved grid operation. Specific benefits include the ability to 1) calculate customer-level reliability and resilience metrics, 2) calculate indices based on short-duration interruptions, such as MAIFI and $MAIFI_E$, and 3) evaluate impacts of reliability-driven operations practices and advanced technologies, such as three-phase and single-phase reclosing and distribution automation schemes, on the distribution system and DER operations.
- A31: The high resolution, time-synchronized, and georeferenced data provided by synchronized measurement technologies can be particularly valuable for post-mortem and root-cause analyses. The data can help identify the effectiveness and deficiencies of existing operations practices, validate new operations approaches, and identify root causes behind disruptive system events. Specific benefits include evaluating the effectiveness of overcurrent protection philosophies (e.g., fuse saving, fuse tripping), reclosing approaches (e.g., single-phase reclosing and lockout), and automation schemes (e.g., FLISR implementation using reclosers or switches). Other benefits include conducting detailed root-cause analyses to identify outage sources and propose targeted reliability and resilience improvement solutions.

4.7.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for enhanced resilience and reliability analysis applications:

- Complexity (5)
- Required investment (5)
- Technology maturity (5)
- Associated risk (5)
- Organizational readiness (6)

Latency and data availability requirements are moderate. Analyses can be done by exception, on-demand, daily, or offline. These applications, particularly A30, require a systematic approach to make them effective. The number of measurements needed to implement them will depend on system size, availability of AMI and other sensor technologies, and spatial granularity of the analyses, but it can involve hundreds or thousands of sensors (e.g., several sensors per distribution feeder). Therefore, these applications are expected to be costlier and more complex to implement.

4.8 AG8: Advanced Distribution System Planning

4.8.1 High-Level Summary of Application

Distribution system planning uses system models to determine load distribution, voltage profiles, reliability calculations, and short circuit currents based on SCADA data and static information extracted from databases, device nameplates, and other systems. The chances for erroneous data and DER penetration add uncertainty to the planning process. Advanced distribution system planning takes advantage of synchronized voltage and current measurements from distribution circuits to validate system models and to support studies of system modifications that improve performance. Advanced distribution system planning includes the following use cases:

- A32—Phase Identification: Using synchronized measurements from various points on a circuit as a reliable and simple method for phase identification at any location on the circuit.
- A33—Distribution system computational model validation: Verifying the system planning model using high-resolution, synchronized measurements from multiple points along a circuit to verify voltage profile, load distribution or power consumption, and distribution of reactive power flow by comparing to results predicted from computational models.
- A34—Short circuit study validation: Using offline analysis of fault current and voltage data from strategic points along distribution circuits to validate the results of short circuit studies and update or develop more detailed distribution circuit models, accounting in particular for the impact of DER inverters.

4.8.2 Deployment Status in the Industry

There is growing interest in using advanced sensor data for distribution system planning. However, most work in this area involves using modern but more traditional measurement technologies, such as SCADA, AMI, and DFR data.[43,44] The use of synchronized measurements in this area remains incipient, and existing experiences have been mostly part of R&D projects conducted by academia and national laboratories.[45,46,47,48,49,50,51] These uses include synchronized measurements for phase identification, as shown in Figure 4-13, and validation of distribution system parameters (e.g., line impedance) and fault currents calculated in short circuit studies. Additional discussion on this topic is in Appendix B: State of the Art Review of System Technologies.

[43] B.K. Seal, M.F. McGranaghan, Automatic identification of service phase for electric utility customers, 2011 IEEE Power and Energy Society General Meeting https://doi.org/10.1109/PES.2011.6039623

[44] H. Pezeshki, P. Wolfs, Correlation based method for phase identification in a three phase LV distribution network, 2012 22nd Australasian Universities Power Engineering Conference (AUPEC) https://ieeexplore.ieee.org/document/6360284

[45] Y. Liu, et. al, Distribution-Level Phasor Measurement Units Application to Composite Load Model Validation, 2019 North American Power Symposium (NAPS), https://doi.org/10.1109/NAPS46351.2019.9000387

[46] M. Bariya, et. al, Guaranteed Phase & Topology Identification in Three Phase Distribution Grids, IEEE Transactions on Smart Grid (Early Access) https://doi.org/10.1109/TSG.2021.3061392

[47] C. Shand et. al, Exploiting massive PMU data analysis for LV distribution network model validation, 2015 50th International Universities Power Engineering Conference (UPEC) https://doi.org/10.1109/UPEC.2015.7339798

[48] C.S. Chen et. al, Design of Phase Identification System to Support Three-Phase Loading Balance of Distribution Feeders, IEEE Transactions on Industry Applications, 2012-01, Vol.48 (1), p.191-198

[49] R.S. Singh et. al, Estimation of Impedance and Susceptance Parameters of a 3-Phase Cable System Using PMU Data, Energies 2019, 12, 4573; https://www.mdpi.com/1996-1073/12/23/4573

[50] M.U. Usman, M.O. Faruque, Validation of a PMU-based fault location identification method for smart distribution network with photovoltaics using real-time data, IET Generation, Transmission & Distribution, 2018, Vol. 12 Issue. 21, pp. 5824-5833, https://ietresearch.onlinelibrary.wiley.com/doi/pdfdirect/10.1049/iet-gtd.2018.6245

[51] T. Dunmore, Experimental studies of a phase identification system for distribution systems, 2010 IEEE PES Transmission and Distribution Conference and Exposition https://doi.org/10.1109/TDC.2010.5484344

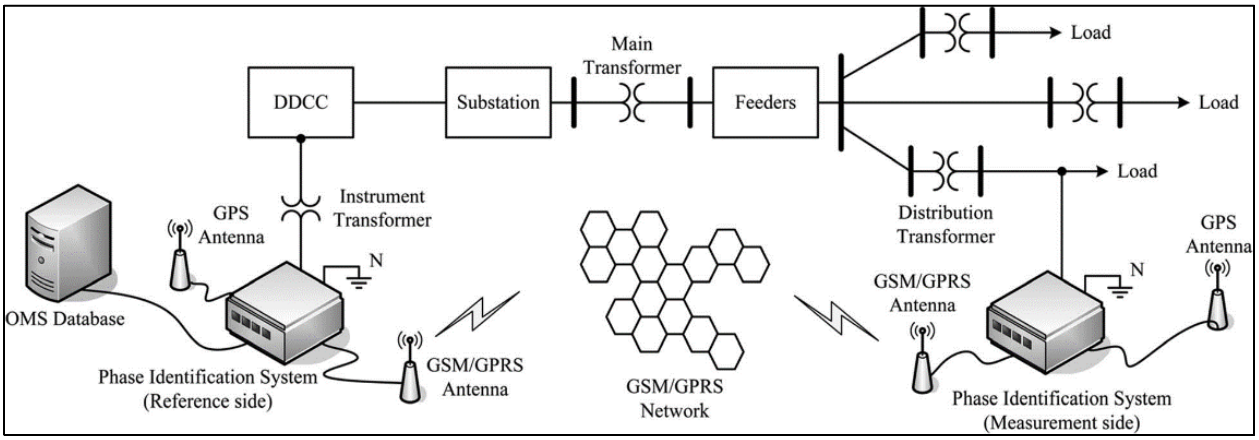

Figure 4-13. Example of Application of Synchronized Measurements for Phase Identification[48]

4.8.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

This section outlines the importance of synchronized measurements for each application.

- A32: Synchronized measurements would provide valuable information about voltage phase angles and phase arrangement on specific feeder locations. Because of the time synchronization capability, phase angle measurements are either absolute (using universal angle) or relative to a pre-specified reference point. Hence, phase angle measurements will identify which conductor represents each phase (A, B, or C). If phases are not connected in a designated order during equipment installations, phasors will be reported with improper sequences, or phase angles will deviate from expected values. Using reported phase angles, the connection order can be revised to obtain correct measurements. Comparing conductor order and voltage phase angles at specific feeder sites can allow identifying phases for locations between two synchronized measurements.
- A33: Synchronized measurements at various strategic locations across a distribution feeder would provide valuable data to determine load distribution, voltage profiles and validate parameters (e.g., line impedance, etc.) of distribution system models. Synchronized measurements installed close to DER facilities would allow validating power flow values and potential voltage fluctuations in these feeder locations. Load distribution and aggregation on different branches and phases would be estimated with higher accuracy. The status of voltage control devices (e.g., tap positions of LTCs and line VRs and capacitor bank status) would be directly monitored and incorporated in the model validation process. The high-resolution capability of synchronized measurements would also help identify fast-acting phenomena associated with load and generation changes and capture the impact of renewable DG intermittency on modeling.
- A34: The high-resolution, time-synchronized, and georeferenced data provided by synchronized measurements would allow validating results of short circuit studies. This is very valuable to improve the accuracy and effectiveness of other applications, such as fault location, protection, and FLISR operation, as well as for planning activities (e.g., equipment specification, distribution automation, protection coordination, and reliability analyses), particularly in distribution systems with high penetration of DER, which have multiple fault current sources. This type of validation can also be

conducted using other types of advanced sensors and meters, such as DFR. In this regard, synchronized measurements provide an incremental value to competing technologies.

Figure 4-14 presents the value of synchronized measurements for advanced distribution system planning.

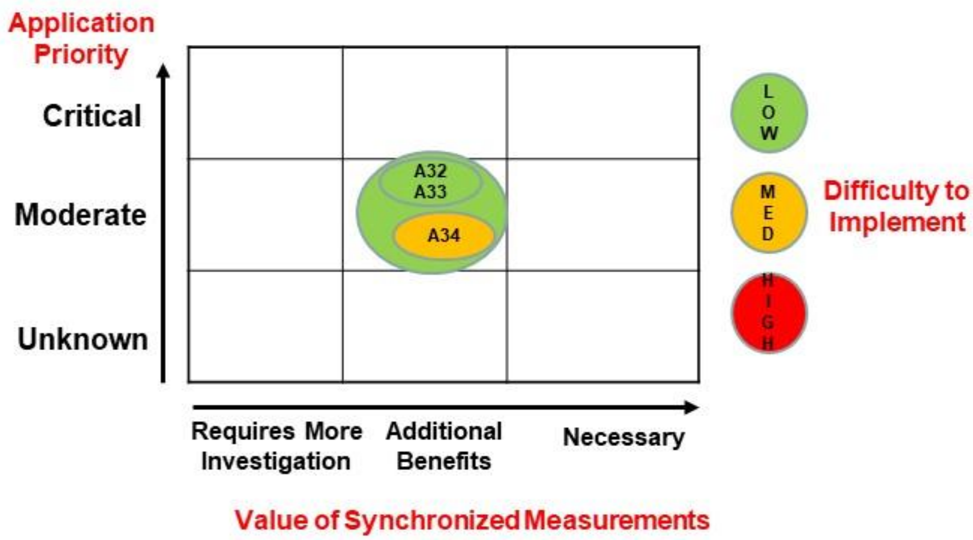

Figure 4-14. Value of Synchronized Measurements for Advanced Distribution System Planning (AG8)

4.8.4 Quantified Benefits

High-level application benefits of synchronized measurements for advanced distribution system planning:

- Advanced planning and asset management (7)
- Resilience and reliability (6)
- Efficiency improvement (6)
- Innovation potential (6)
- Sustainability and decarbonization (5)
- Customer engagement and business potential (4)
- Real-time operation (2)
- Public safety (2)

High-level benefits of applying synchronized measurement technologies for advanced distribution system planning include:

- A32: Using synchronized measurements would 1) eliminate hazards to utility personnel during line work while providing greater value-added benefits due to saving money and time on crew work, 2) enhance the load placement and distribution among phases to improve the voltage and power flow balancing of a feeder, 3) reduce feeder losses, 4) enhance system mapping and information as part of GIS systems, and 5) eliminate the need for feeder de-energization or reduce downtime.

- A33**:** Accurate computational models of feeders and substations are foundational to proper distribution systems analysis, engineering, planning, and operations. Some critical activities relying on precise computational models include capacity planning, load forecasting, voltage regulation, system protection, reliability, efficiency analyses, etc. Measured data provided by PMUs can be used to validate and calibrate computational models. In turn, these models will increase the accuracy of the results calculated by simulation software and lead to direct economic benefits derived from improved system design, planning, operation, and control. This is conceptually shown in Figure 4-15 for the specific case of distribution system operation and control applications.[52]
- A34: Validation of short circuit studies is important for various planning activities, including equipment specification (e.g., ratings and fault duty specification), design and implementation of distribution automation solutions such as FLISR, protection coordination, and reliability analysis. Synchronized measurements would help verify and improve the accuracy of short circuit studies, and therefore, the effectiveness of associated planning activities—particularly in distribution systems with high DER penetration, which have multiples sources of fault current and more complex topologies than traditional feeders.

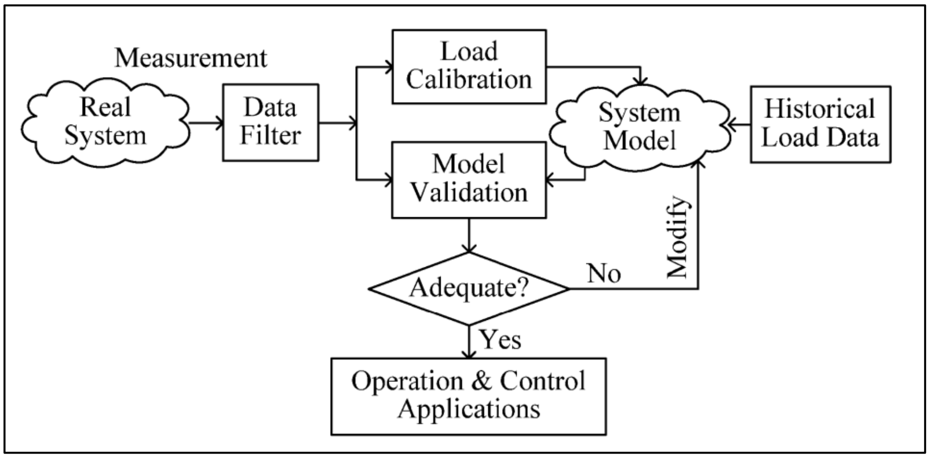

Figure 4-15. Example of Distribution System Model Validation and Calibration[52]

4.8.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for advanced distribution system planning applications:

- Complexity (4)
- Required investment (4)

[52] Y. Liang, K.S. Tam, R. Broadwater, Load Calibration and Model Validation Methodologies for Power Distribution Systems, IEEE Transactions on Power Systems, Vol. 25, No. 3. Aug. 2010

- Technology maturity (5)
- Risk (5)
- Organizational readiness (5)

Latency and data availability requirements are moderate, and planning analyses are generally performed offline (on demand). These applications generally require a systematic approach to make them effective. The number of measurements needed to implement them will depend on the system size, availability of AMI, DFR, and other sensor technologies, and the analyses' spatial granularity, but they can involve hundreds or thousands of sensors (e.g., several sensors per distribution feeder). However, these applications are not expected to be the main driver behind implementing a synchronized measurements roadmap. Instead, they are likely to complement others that need synchronized measurements to be implemented and provide significant benefits to existing technologies. In that regard, when implemented with those primary applications, the marginal cost associated with these applications is expected to be moderate.

4.9 AG9: Distribution Load, DER, and EV Forecasting

4.9.1 High-Level Summary

Load forecasting is a vital distribution planning process. Load forecasting estimates the timing, location, and rate of change of distribution system load growth. Its results are used to identify and plan distribution system upgrades and expansions. Due to the proliferation of DERs and EVs, the distribution grid's increasingly dynamic nature has created interest in implementing short-term load and DER forecasting algorithms, which require load characterization (e.g., determine load sensitivity with respect to voltage and frequency), and in understanding the impact of external variables (e.g., temperature, irradiance) on both, load and DER production.

Load and DER forecasting can take advantage of high sampling rates and time-synchronized data from distribution circuits and substations to improve the accuracy of the models and the required historical data. This type of detailed modeling can help improve the accuracy of short- and long-term forecasting algorithms.

Distribution load, DER, and EV forecasting include the following use cases:

- A35—Load characterization, load modeling, and load forecasting: Using synchronized load data collected from key locations along distribution feeders to validate and fine-tune load models and evaluate if the models accurately describe the dynamic behavior of distribution loads. Using peak load information recorded by SMDs for peak and spatial load forecasting purposes, including validation of weather normalization methods and load dependency concerning external variables (e.g., temperature, humidity, etc.).
- A36—DER forecasting: Modeling and forecasting DER output and its dependency relative to external variables (e.g., temperature, irradiance, wind speed, humidity, etc.) to predict the availability and impact of DERs on distribution circuits.

- A37—EV forecasting: Modeling and forecasting EV load and its dependency with respect to internal variables (active and reactive power sensitivity relevant to changes in voltage and frequency) and external variables (e.g., temperature, irradiance, wind speed, humidity, etc.) to predict the impact of EVs on distribution circuit loading.

4.9.2 Deployment Status

While there are several distribution synchronized measurement deployments for monitoring, no documented projects use synchronized measurements to enhance short- and/or long-term load, DER, and EV forecasting.

4.9.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Using synchronized measurements provides high-resolution, time-synchronized, and georeferenced data of loads and DER outputs. These measurements can be used with data about external (e.g., temperature, irradiance, wind speed, humidity) and internal variables (e.g., voltage, frequency) to develop more accurate short- and long-term forecasts. These forecasts can enhance real-time operation and distribution planning activities, including capacity planning. Figure 4-16 presents the value of synchronized measurements for distribution load, DER, and EV forecasting.

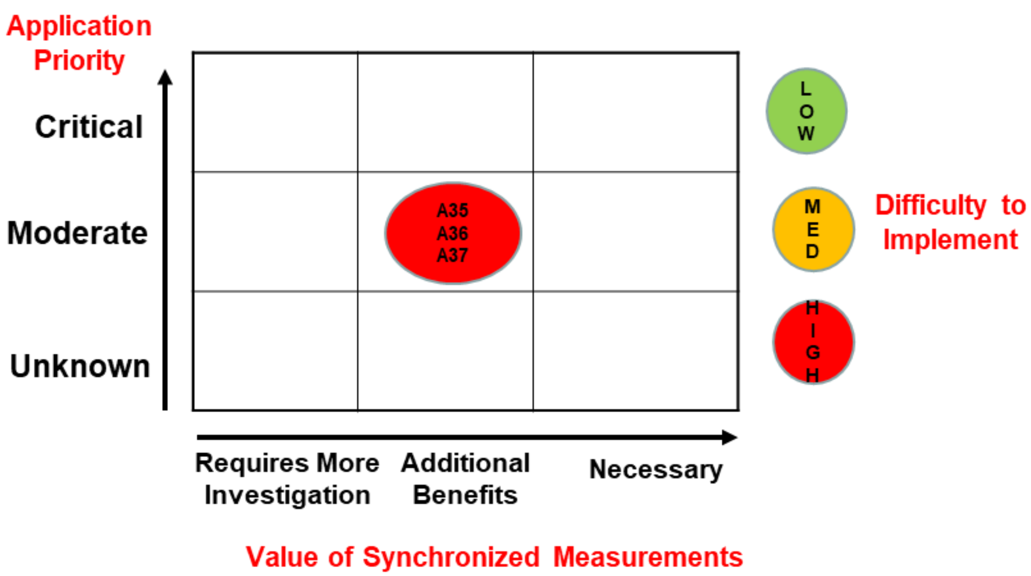

Figure 4-16. Value of Synchronized Measurements for Distribution Load, DER, and EV Forecasting (AG9)

4.9.4 Quantified Benefits

Primary benefits for all applications are in areas related to load improvement, DER, and EV models for system analysis and load forecasting. Applications A35, A36, and A37 provide a complete model of the distribution grid.

High-level benefits of synchronized measurements for distribution load, DER, and EV forecasting:

- Sustainability and decarbonization (7)
- Advanced planning and asset management (7)
- Efficiency improvement (6)
- Resilience and reliability (6)
- Customer engagement and business potential (6)
- Real-time operation (5)
- Innovation potential (5)
- Public safety (2)

Applications A36 and A37 offer immediate benefits for studies and load forecasting to identify system impacts of DER and EV sites. These applications should be the focus for initial pilots. Application A35 requires much more effort due to the number of points to be monitored.

4.9.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for load, DER, and EV forecasting applications:

- Complexity of the system (7)
- Investment required to implement (7)
- Maturity of the solutions and devices (4)
- Risk of failure (5)
- Readiness of the utility and utility personnel to adopt (4)

Latency and minimum report rates for applications A35, A36, and A37 are not as stringent as for other real-time applications. For these applications, a minimum report rate of 1 report per second, availability of 80%, and latency of 5000 ms is required. These applications require a systemic approach with a higher cost, while applications A36 and A37 could be implemented strategically at DER and EV sites to improve model validation and forecasting. This application requires communication between field measurement devices and a central system.

4.10 AG10: Improved Stability Management

4.10.1 High-Level Summary

DERs and electrical storage proliferation impact the maximum loading and transfer capability limits of existing feeders and substations, resulting in possible voltage and transient stability issues. Renewable DERs and electrical storage are IBRs that do not have an inertial response and do not provide fault current levels as synchronous generators. While frequency response and the impact of fault current levels are discussed for other AGs, this section focuses on the distribution and transmission systems' voltage and transient stability issues. For example, a fault on the transmission system can cause voltage dips that affect IBRs, creating system oscillations that need to be damped. Systems with a very high level of IBRs may require technologies such as synchronous condensers and static var systems (SVS). Furthermore, increased penetration of DERs can help supply increased circuit loading. At the same time, a sudden loss of DERs due to a disturbance can lead to voltage collapse affecting both T&D systems. Therefore, it is critical to perform offline and online evaluations of voltage collapse margins for planning and operations activities.

Another issue is the fault-induced delayed voltage recovery (FIDVR) phenomenon. This is a voltage condition initiated by a transmission, sub-transmission, or distribution fault and characterized by stalling of induction motors, initial voltage recovery after the clearing of a fault to less than 90% of pre-contingency voltage, and slow voltage recovery of more than 2 s to expected post-contingency steady-state voltage levels. FIDVR is caused by constant torque induction motor loads (mostly by residential air-conditioner single-phase motors), which stall in response to low voltages. The stalled motors draw excessive reactive power from the grid. When the motor thermal overload protection trips, the voltage may significantly overshoot the nominal voltage, particularly if capacitor banks remain in service. This situation can further aggravate system conditions and cause a cascading system failure. A severe event can result in fast voltage collapse.

Synchronized measurements for improved stability management use high sampling rate synchronized measurements from the distribution system as an input to the offline analysis of voltage and transient stability margins. Eventually, this can be an online analysis as part of a control loop to address possible stability issues.

Improved stability management includes the following use cases:

- A38: Using synchronized data gathered from distribution circuits combined with other utility data sources and systems to evaluate T&D voltage stability margins for distribution circuits with large penetration of DER. Identify a need to switch on and off synchronous condensers and SVS or initiate any other measure (e.g., load shedding).
- A39: Analyzing measurements from across the feeder, looking for oscillatory or erratically varying components of voltage and current signals over a wide range of frequencies (e.g., 0.01 Hz to 15 Hz) that indicate unforeseen control interactions. Identify a need to switch on and off synchronous condensers and SVS or initiate any other measure (e.g., load shedding).
- A40: Using phasor measurements from distribution circuits combined with other utility data sources and systems to evaluate transient stability, especially as DERs with grid-forming IBRs increasingly deliver active and reactive power support.
- A41: Using time-synchronized voltage measurements on the distribution system to profile and detect delayed voltage recovery after a fault event and initiate or prevent unnecessary control actions such as adding reactive sources or initiating spatial load shedding. It is necessary to distinguish between FIDVR and voltage instability. For the former case, switching on the reactive power resources before motors trip would exacerbate the voltage overshoot and worsen the situation.

4.10.2 Deployment Status

Stability management methods using measurement- and model-based methods and tools have been implemented in transmission and could be deployed in distribution if those issues occur. The distribution-based FIDVR phenomenon needs to be further investigated. The deployment status of applications is summarized as follows:

- A38 and A41: Improved stability management, such as real-time voltage instability detection (RVII), has been implemented at TNB Malaysia, piloted at PG&E and SCE[53], and plans to be implemented at SDG&E.
- A39 and A40: Several proven transmission tools for oscillation and transient stability detection methods are extensively used globally that could be implemented and tested for conditions with high penetration of DER and storage. However, they have not been used to monitor distribution circuits and take actions at the distribution level.

4.10.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Synchronized measurements are critical for addressing stability and FIDVR issues. Each application is addressed below:

- A38: Using RVII or similar technology for online, fast detection of voltage stability margins could be useful for fast-developing voltage instability. It could help both the operators and/or could be implemented as part of the automated scheme.
- A39 and A40: Using proven transmission tools for oscillation detection or oscillation and transient stability detection is recommended. As in transmission, it is not possible to detect oscillations without using synchronized measurements.
- A41: Using RVII or similar technology for online, fast detection between FIDVR or voltage instability is a very useful application to prevent unnecessary switching on reactive power resources.

Figure 4-17 presents the value of synchronized measurements for improved stability management.

[53] M. Glavic, D. Novosel, E. Heredia, D. Kosterev, A. Salazar, F. Habibi-Ashrafi, M. Donnelly, “See It Fast to Keep Calm,” IEEE Power and Energy Magazine, July/August 2012.

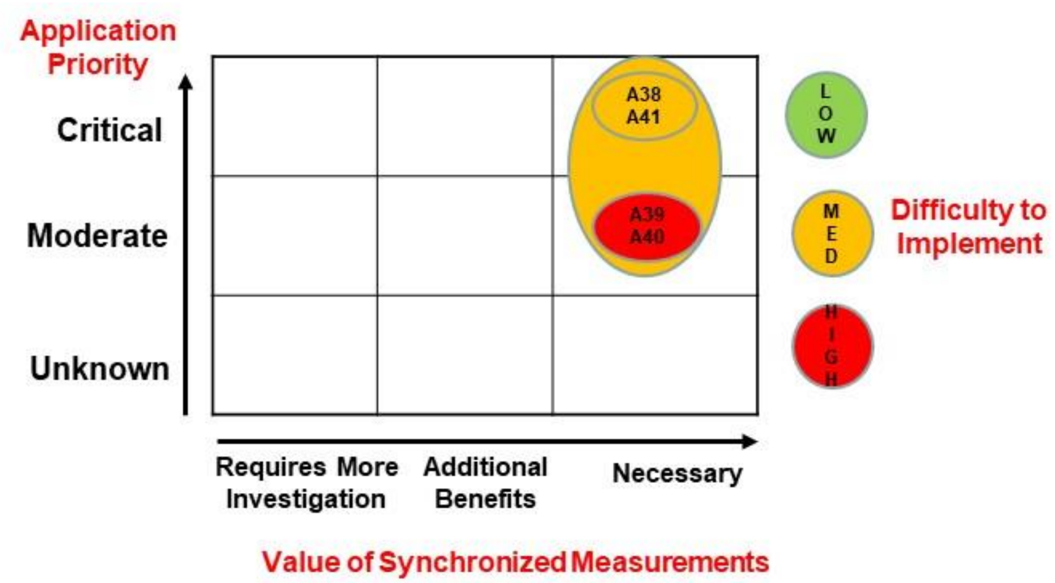

Figure 4-17. Value of Synchronized Measurements for Improved Stability Management (AG10)

4.10.4 Quantified Benefits

A primary benefit for all applications is preventing power system outages and blackouts caused by large penetration of IBRs. Applications A38 and A41 have better-defined control actions and corresponding benefits than applications A39 and A40, which require more investigation.

High-level application benefits of synchronized measurements for improved stability management:

- Real-time operation (9)
- Resilience and reliability (7)
- Innovation potential (7)
- Sustainability and decarbonization (4)
- Public safety (4)
- Efficiency improvement (4)
- Advanced planning and asset management (3)
- Customer engagement and business potential (3)

Stability management provided with synchronized measurements will directly address real-time operations and the distribution system's reliability by calculating stability margins, transient stability, and monitoring feeder voltage profiles.

4.10.5 System and Product Requirements, including Estimated System Costs

High-level evaluation of deploying synchronized measurements for stability management applications (focusing on A38 and A41 as initial applications):

- Complexity of the system (5)
- Investment required to implement (5)
- Maturity of the solutions and devices (5)
- Risk of failure (5)
- Readiness of the utility and utility personnel to adopt (5)

Latency and data availability for applications A39 and A40 is more stringent, while applications A38 and A41 could be implemented in a more distributed way, reducing communication requirements. More investigations need to be done to identify how many measurements would be required to address the need.

High-level requirements for each application are:

- For applications A38 and A41, a minimum report rate of 30 reports per second, availability of 95%, and latency of 500 ms.
- For applications A39 and A40, a minimum report rate of 30 reports per second, availability of 99%, and latency of 150 ms.
- For applications A39 and A40, a systematic (centralized) approach with higher cost, while applications A38 and A41 could be implemented distributed out to distribution substations.
- For applications A38 and A41, synchronized measurements at selected monitoring sites.
- For applications A39 and A40, synchronized measurements across the system.
- Communications architecture is located between field measurement devices and substation(s) and between the substation(s) and the central system.

The specific performance requirements for improved stability management are presented in Table 4-6.

Table 4-6. Specific Performance Requirements for Improved Stability Management

Requirement	A38 and A41	A39 and A40
Measurement accuracy	1% Total vector error	1% Total vector error
Availability	95%	99%
Latency	500 ms	150 ms
Sampling rate	Device sampling rate	Device sampling rate
Reporting rate	30 Hz	30 Hz

4.11 AG11: High-Accuracy Fault Detection and Location

4.11.1 High-Level Summary of Application

A fault-induced outage or service interruption condition requires the dispatch of repair crews to locate and fix the problem. Traditional dispatch only provides basic information like the status of protective and switching devices and OMS data to locate the problem on the circuit. This information may help locate outages (e.g., downstream from a specific device) but may not be enough to accurately identify the actual fault location. Modern microprocessor-based relays and reclosers can estimate the distance to the fault location by analyzing fault current data. However, given the topology of the distribution grid, there may be more than one location that matches the calculated distance.

Moreover, fault impedance uncertainty may impact the accuracy of the calculation. Modern distribution automation applications, such as FLISR, can locate faults and restore service by isolating fault locations between two open devices and transferring customers in healthy sections to neighbor feeders via ties. However, FLISR schemes can be less effective in long radial feeders, serving sparse loads, such as those common in rural areas, where locating faults can be time-consuming and involves miles of overhead lines. Modern OMSs process this information, along with last-gasp messages from AMI systems and customer trouble calls, to triangulate and select the most likely fault location. This process is established at utilities. However, collecting and processing all this information may require several minutes and is subject to uncertainties related to fault current magnitude (fault impedance), especially in areas where it is comparable to pre-fault (load) current. Methods for fault location in T&D systems are described in *C37.114-2014 - IEEE Guide for Determining Fault Location on AC Transmission and Distribution Lines*.[54]

The use of time-synchronized measurements is an alternative to increasing the accuracy and speed of this process. High-accuracy fault detection and location develops the ability to triangulate and locate the problem with multiple time-synchronized measurements and by collecting circuit data for multiple enterprise uses. It then quickly presents these results to maintenance dispatchers and field crews. Modern microprocessor-based relays and reclosers,[55] which are the main advanced protective devices used in distribution systems, have synchronized measurement functionalities. These functionalities facilitate the implementation of this type of application.

High-accuracy fault detection and location includes the following use cases:

- A42—Faulted circuit indication: High-resolution measurements of voltages and currents at several locations along distribution circuits support fast indication of fault location direction. This estimation occurs through patrolling and gathering data records from measurement devices or online via remote polling and processing of measurement data points by an operational data gathering system that supports operator interaction with field crews.

[54] C37.114-2014 - IEEE Guide for Determining Fault Location on AC Transmission and Distribution Lines https://ieeexplore.ieee.org/document/7024095

[55] https://selinc.com/products/751/docs/, https://selinc.com/products/651RA/docs/

- A43—Incipient fault and failure detection: Analyzing time-synchronized measurements, with triggering and recording of data showing abnormalities. Offline pattern recognition and signature analysis of records can identify field apparatus that has degraded to impending failure.
- A44—High accuracy fault location: Collecting synchronized high sampling rate measurements recorded during faults, along with instantaneous sample value oscillographic records plus relay and recloser fault location values. The complete dataset is processed through fault location tools and algorithms to yield accurate problem location, including identifying the branch, location on the branch, and phase(s) affected, with a timely presentation of the results to maintenance dispatch and field personnel.
- A45—Communications failure location for maintenance dispatch: Monitoring communications exchanges among measurement devices located on the distribution circuit for errors such as packet loss, abnormal error rates, or outage of reporting exchange. Problem indications can be evaluated across topological information and algorithms to notify maintenance personnel of the communications problem's most likely location and cause.
- A46—High impedance fault location: Hi-Z fault detection is extended by using distinct differences in electrical voltage and current signatures upstream and downstream from the fault to identify the existence of a Hi-Z fault such as downed conductors.
- A47—Open-conductor fault detection: Detecting sudden changes in active and reactive power flows measured at various points along the circuit indicating open conductors or switching phase devices, providing alarms or isolation control signals.
- A48—Falling conductor protection: Using the pattern of shifts in synchronized voltage and current measurements from various points on the distribution circuit in a combination of algorithms to detect that a circuit conductor has broken and is in the process of falling to de-energize the broken circuit conductor section after it has fallen only a few feet, well before the conductor contacts the ground to create a Hi-Z fault.

4.11.2 Deployment Status in the Industry

SDG&E and many other utilities deploy FCIs and advanced sensors to help with fault location. Some FCIs require line patrolling and inspection to verify a visual and/or audible activation signal, while newer devices support radio communications and remote or automated access to verify activation. Modern FCIs also support advanced sensing capabilities, such as current magnitude measurements and fault current waveform (oscillography) capture.[56] Existing FCIs do not support precision measurement synchronization.

SDG&E does not deploy high-accuracy fault detection and location. FCP was invented during the SDG&E distribution synchronized measurement development program and applied on multiple distribution circuits in demonstration mode. Numerous additional deployments are planned in the coming year for high fire-risk areas.

[56] https://www.sentient-energy.com/solutions/fault-detection

4.11.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Accurate fault location and detection are critical activities to ensure reliable and safe power delivery to customers. There are numerous proposals for fault location and detection, and they have become a standard function of most modern protective devices. However, many of these proposals and products were developed for radial distribution feeders. Hence, as distribution systems evolve into active and dynamic networks with high DER penetration levels, new challenges such as transient and voltage stability concerns emerge, requiring new fault location and detection algorithms. Additionally, as customer reliance on electric power grows, societal expectations regarding high levels of reliability and resilience will continue increasing. Therefore, fast service restoration times (necessitating accurate and fast fault detection/location) are required in the event of a fault. Within this context, this application has a moderate-to-critical priority and is expected to provide additional benefits (e.g., accuracy) to existing methodologies and solutions.

Figure 4-18 presents the value of synchronized measurements for high-accuracy fault detection and location.

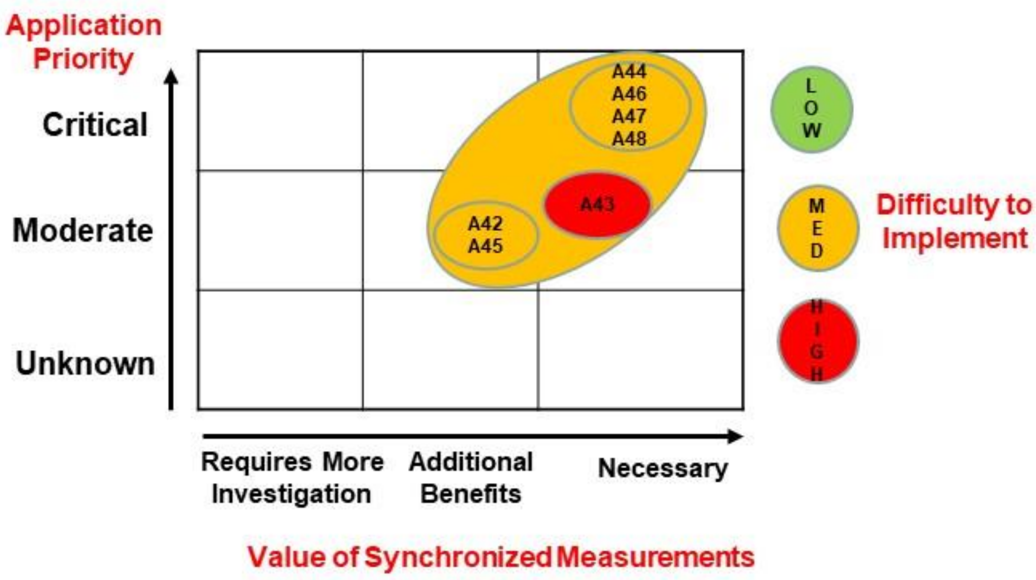

Figure 4-18. Value of Synchronized Measurements for High-Accuracy Fault Detection and Location (AG11)

4.11.4 Quantified Benefits

High-level application benefits of synchronized measurements for high-accuracy fault detection and location:

- Public safety (9)
- Efficiency improvement (8)
- Resilience and reliability (8)

- Real-time operation (8)
- Innovation potential (7)
- Customer engagement and business potential (7)
- Advanced planning and asset management (6)
- Sustainability and decarbonization (4)

A significant benefit is in public safety. FCP and open-conductor fault detection increase the overall safety of the distribution system by detecting broken or downed overhead lines before arcing faults occur. Combining these preventive techniques with better fault location improves safety even more through fast identification and repair of faulted equipment and line segments. Resilience and reliability, along with real-time operations, improve through system operators knowing when and where faults occur. Operators can dispatch crews directly to fix the problem and return all system elements to service as quickly as possible. This rapid fault location and identification also improves operating efficiency by reducing the need for line patrols and other manual fault-locating techniques. Innovation potential is the estimation of the ease of adopting advanced fault locations. The potential is high, as the application techniques and tools are well defined and only need access to more precise data. A more reliable system, where faults and failed equipment are identified faster, leads to better service. It also provides business opportunities as third-party power producers and customers become more willing to integrate into the utility system.

4.11.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for advanced fault detection applications:

- Complexity of the system (4)
- Investment required to implement (7)
- Maturity of the solutions and devices (6)
- Risk of failure (4)
- Readiness of the utility and utility personnel to adopt (5)

All advanced fault location applications will require multiple synchronized measurement points per feeder, with most of these applications requiring the use of synchronized measurements data from multiple points on each distribution feeder. Therefore, this is a high-density system architecture, with 10 or more measurement points per distribution feeder. It is also a high-density application at the system level, as data must be collected and processed from every distribution substation. Processing the data and advanced fault location algorithms will occur at the substation and system levels. Device control commands will be issued at the substation level. Alarm and fault location indications will be presented at the system level.

The specific performance requirements for advanced fault location applications are presented in Table 4-7.

Table 4-7. Specific Performance Requirements for Advanced Fault Location Applications

Requirement	Synchronized Measurements Data	Other Synchronized Data
Measurement accuracy	1% total vector error	±5% error
Availability	99.9%	95%
Latency	300 ms	5000 ms
Sampling rate	Device sampling rate	Device sampling rate, 3840 Hz or better preferred for oscillographic data
Reporting rate	Minimum 60 samples/s, 120 samples/s is preferable	1 Hz

Advanced fault location is straightforward in all these areas. The complexity is mostly in the need to collect data from numerous locations on the distribution system. Most applications are based on existing, proven techniques and algorithms that simply must be expanded or updated for more comprehensive data. The investment is mostly in installing field equipment, especially communications, application development, and rollout and training.

The biggest risk around advanced fault detection is also around its greatest benefit—public safety. If these applications do not work as expected, utilities will continue to face the same risks related to property damage and public safety as they do today.

4.12 AG12: Advanced Distribution Protection and Control

4.12.1 High-Level Summary of Application

Distribution protection is traditionally based on radial feeders and predictable short circuit current levels related to the fault location. Distribution protection elements, including protective relays, line reclosers, and fuses, are non-directional. They operate based on levels of short circuit current and are coordinated to provide reliability. DER penetration converts radial feeders into interactive networks. This may significantly alter the available fault current at the substation circuit breaker and along the feeder. It may have a changing impact based on the moment-to-moment capacity of the connected DERs. Impacts can include the performance of reclosing, reduced coordination between protective devices, desensitizing protective devices, nuisance fuse blowing, the failure of fuse saving schemes, and nuisance tripping due to a reverse power flow through the non-directional protection elements. As a result, traditional overcurrent-based protection schemes may not be reliable, resulting in a failure to clear faults or incorrect clearing of un-faulted segments.

Advanced distribution protection and control uses synchronized measurements from the distribution circuits to correctly identify faults and faulted segments, even with reduced short circuit current levels.

Advanced distribution protection and control includes the following use cases:

- A49—Reclosing assistance for fast circuit recovery after fault: Reclosing schemes must account for the presence of DERs so as not to reclose out-of-phase with the DER. Instead of simply adding time delays, reclosing assistance uses phase angle and voltage information from the circuit section downstream of a recloser to estimate the exact fault clearing time and determine the proper reclosing time for fast circuit recovery.
- A50—Current differential protection of feeder sections: Current differential protection provides reliable and selective protection to feeder segments even with reduced fault currents and different power flows. Current differential protection is implemented by gathering synchronized current measurements from sections of the distribution circuit combined with differential algorithms in protection devices located on the feeder.

A51—Adaptive protection of distribution systems: Using synchronized measurements to indicate the DER presence, combined with forecasting and system models, allows algorithms to calculate the ideal protection settings for feeder relays and reclosers, including coordination, based on actual operating conditions, and to change the protection settings to match actual short circuit levels available on the feeder. In addition, if a relay or circuit breaker misoperates, synchronized measurements can be used to initiate preventative or backup protection. The protection part normally deals with the fault location identification and isolation by sending the trip commands. The control subsystems handle the secondary (centralized) control of dispatchable resources in the feeder to leverage the post-fault voltage stability. For example, synchronized measurement data can be analyzed to 1) predict the system states immediately after the fault isolation, 2) determine the new setpoints of dispatchable resources or switch their controllers, and 3) update protection settings based on system conditions.

4.12.2 Deployment Status in the Industry

Advanced distribution protection and control is not deployed at SDG&E.

4.12.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Reliable protection that quickly detects and isolates faulted equipment and limits outages to just the faulted equipment is critical to ensure reliable and safe power delivery to customers. Distribution protection systems have been designed around radial distribution feeders and high levels of short circuit current. However, as distribution systems evolve into active and dynamic networks, with high-penetration levels of DERs, issues such as reduced and unpredictable levels of short circuit currents and reverse power flows on the distribution feeders are emerging. Therefore, the distribution protection must be updated and dynamically adaptive for this new uncertain operating situation. Additionally, customer and societal expectations regarding high levels of reliability and resilience will continue increasing. Therefore, faster service restoration times in the event of a fault are also required. This application has moderate-to-critical priority within this context and is expected to provide additional benefits (e.g., protection dependability and protection security) over existing methodologies and solutions.

Figure 4-19 presents the value of synchronized measurements for advanced distribution protection and control.

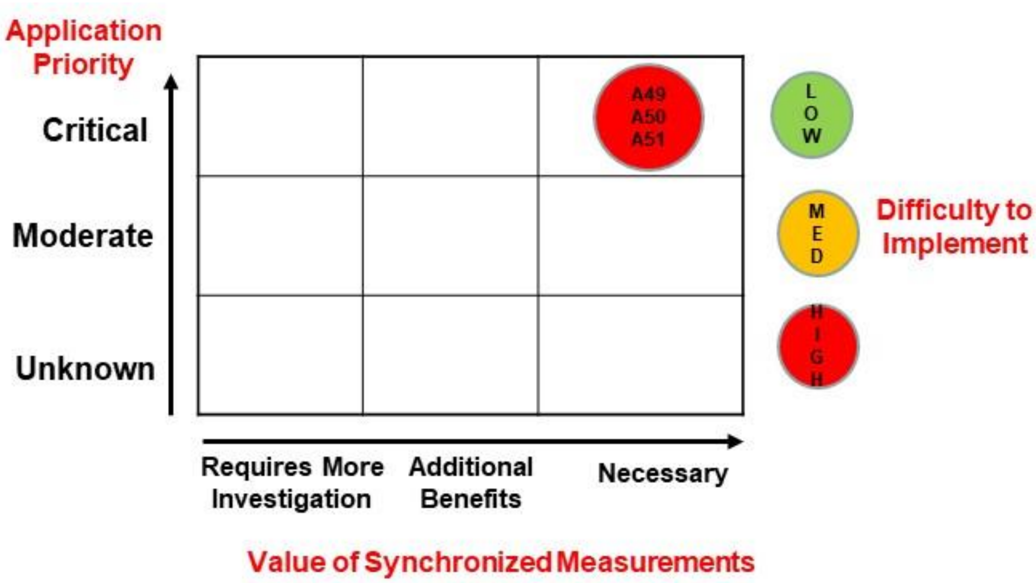

Figure 4-19. Value of Synchronized Measurements for Advanced Distribution Protection and Control (AG12)

4.12.4 Quantified Benefits

High-level benefits of synchronized measurements for advanced distribution protection and control:

- Public safety (9)
- Resilience and reliability (8)
- Real-time operation (8)
- Sustainability and decarbonization (7)
- Innovation potential (7)
- Customer engagement and business potential (5)
- Efficiency improvement (4)
- Advanced planning and asset management (2)

Public safety is the most significant benefit, as reliable detection and isolation of faulted circuit elements are still achieved even when the available capacity of DERs impacts short circuit currents. Resilience and reliability benefit from isolating the correct faulted equipment during all operating scenarios and maintaining the coordination of protection devices, including proper reclosing cycles. Real-time operation also benefits, as protection settings and protection coordination (including reclosing cycles) will be correct for the short circuit current and DER capacity present on the system. The algorithms and methods to deliver advanced distribution protection use existing methods enhanced with synchronized measurements. Therefore, the innovation potential is quite high. A distribution protection system that can operate reliably with the high penetration of DERs will allow for larger penetration of DER and will result in better customer satisfaction.

4.12.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for advanced distribution protection applications:

- Complexity of the system (7)
- Investment required to implement (7)
- Maturity of the solutions and devices (5)
- Risk of failure (5)
- Readiness of the utility and utility personnel to adopt (5)

Advanced distribution protection requires multiple synchronized measurement points per feeder, with most of these applications needing synchronized measurements data from multiple points on each distribution feeder. This is likely a "medium density" system architecture at the distribution substation, with several measurement points per feeder. It is a low-density application at the system level, as most data collection, algorithms, and processing will occur in the substation or on the circuit feeders. The algorithms to determine dynamic protection settings may take place at the substation or system level.

The specific performance requirements for advanced distribution protection applications are presented in Table 4-8.

Table 4-8. Specific Performance Requirements for Advanced Distribution Protection Applications

Requirement	Synchronized Measurements Data	Other Synchronized Data
Measurement accuracy	1% total vector error	±5% error
Availability	99.9%	95%
Latency	150 ms	5000 ms
Sampling rate	Device sampling rate	Device sampling rate
Reporting rate	60 Hz	1 Hz

These applications are somewhat complex. There is a need to collect data from numerous locations on the distribution system and push control commands to multiple devices on each feeder. There is significant engineering effort in determining and implementing the algorithms for reclosing assistance and dynamic protection settings. The investment required is somewhat high, mostly for installing field equipment, application development, rollout, and training. As described, the solutions are mature, as they are based on existing algorithms and techniques. The most technically innovative application is dynamic protection settings, which initially will be rules-based to adapt settings based on pre-determined scenarios.

There are some risks with advanced distribution protection. One risk is the operating speed of differential protection. Other risks are the reliable adaption of reclosing coordination and protection settings for system conditions. Failures of these algorithms means that utilities will face the same risks of degraded protection system performance and reliability with large DER penetration. The limiting factor to utility readiness is understanding how to implement differential protection and dynamic protection settings on distribution feeders.

4.13 AG13: Advanced Microgrid Applications and Operation

4.13.1 High-Level Summary of Application

Microgrids are small-scale power grids and are normally connected to the larger grid. They typically incorporate DER such as wind, solar, energy storage systems, and controllable loads in a combination that can operate in an isolated and self-sustaining mode when a grid connection is unavailable. Microgrids are characterized by bidirectional power flows, flexible modes of operation, and variable short circuit currents that drop drastically when the microgrid is disconnected from the larger utility grid. Microgrids have operating challenges, such as control of islanded operations. Fault protection based on short circuit currents from the utility grid must be supplanted with voltage and directional protection that isolates faults when the microgrid is islanded.

Advanced microgrid applications use synchronized high sampling rate measurements at the interconnection point and throughout, combined with control systems and dedicated algorithms, to enable the microgrid's reliable operation in grid-connected and islanded modes.

Advanced microgrid operation and applications include the following use cases:

- A52—Planned islanding and restoration of microgrids: Using synchronized measurements to initiate disconnection from the grid during contingencies causing PQ issues or when there is a grid supply outage. Control system measurements from around the microgrid are used to sustain the island load-generation balance, closely control island operation, and restore the island after recovery of the main grid.
- A53—Advanced protection of microgrids: Using synchronized high sampling rate measurements for current differential protection, directional or voltage-based protection, and adaptive behavior of advanced distribution protection and control applications.
- A54—Advanced distribution system topology, automation, and control: Using synchronized measurements in a service-oriented architecture combined with communications to operate a distribution system composed of many DERs and loads with autonomy and self-management of DER sources, recursive aggregation, and dynamic reconfiguration of the distribution network based on actual time-varying conditions.
- A55—Anti-islanding detection for DERs (anti-islanding scheme): Installing SMDs at the interconnection points for DERs on distribution systems to detect a sudden change in phase angle of the bus voltages at a DER location for the substation voltage and force disconnection of the DER from the grid.

4.13.2 Deployment Status in the Industry

Microgrid applications utilize other technologies to provide reliable operation, such as real-time distribution operation applications (AG6) and advanced distribution automation applications (AG15). Deployment of those particular applications is described in their respective sections. This section focuses on the overall deployment of microgrids. Advanced microgrid applications and operations are deployed at the ComEd Bronzeville Microgrid in Chicago, IL[57,58], and on a limited scale in SDG&E demonstration installations (Borrego Springs). Presently, 27 PMUs are deployed at the Bronzeville Microgrid for situational awareness and control[59].

4.13.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Microgrids are requiring all the operational control and protection of the larger grid. Microgrids are in some ways more complex than the larger grid, as the sources of capacity are likely to be smaller, more numerous, inverter-based, and combined with large numbers of controllable loads. Also, the microgrid must be able to operate in combination with and separated from the larger grid. Synchronized measurements are the key to applications that support the successful operation of microgrids.

Islanding and restoration (A52 and A55) are simple and effective ways of using synchronized measurements. Figure 3.22 shows an example of application A52 for islanding and restoration.

[57] https://www.naspi.org/sites/default/files/2021-04/20210331_naspi_webinar_comed.pdf

[58] P. Pabst, H. Chen, Synchronized Measurements in Distribution Systems, Mar. 2021, https://www.naspi.org/sites/default/files/2021-04/20210331_naspi_webinar_comed.pdf

[59] B. Kregel, H. Chen, A Journey to Full Distribution Situational Awareness, https://www.naspi.org/sites/default/files/2019-10/03_Success_Chen_Kregel_20191030.pdf

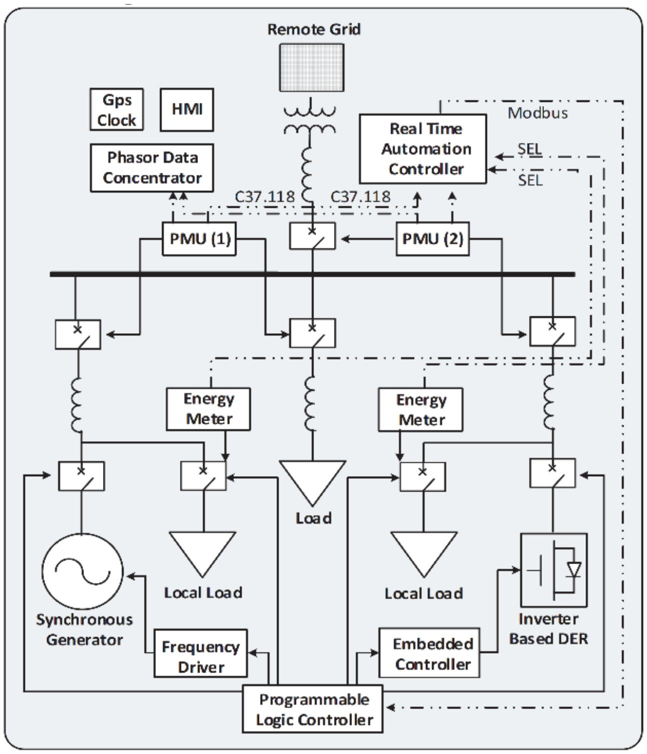

Figure 3-20. Example of Microgrid Architecture Using PMUs to Support Automated Islanding and Resynchronization[60]

Figure 4-21 presents the value of synchronized measurements for advanced microgrid applications and operation.

[60] M. Cintuglu at. al, Microgrid Automation Assisted by Synchrophasors, Proceedings of 2015 IEEE Power & Energy Society Innovative Smart Grid Technologies Conference (ISGT) https://doi.org/10.1109/ISGT.2015.7131857

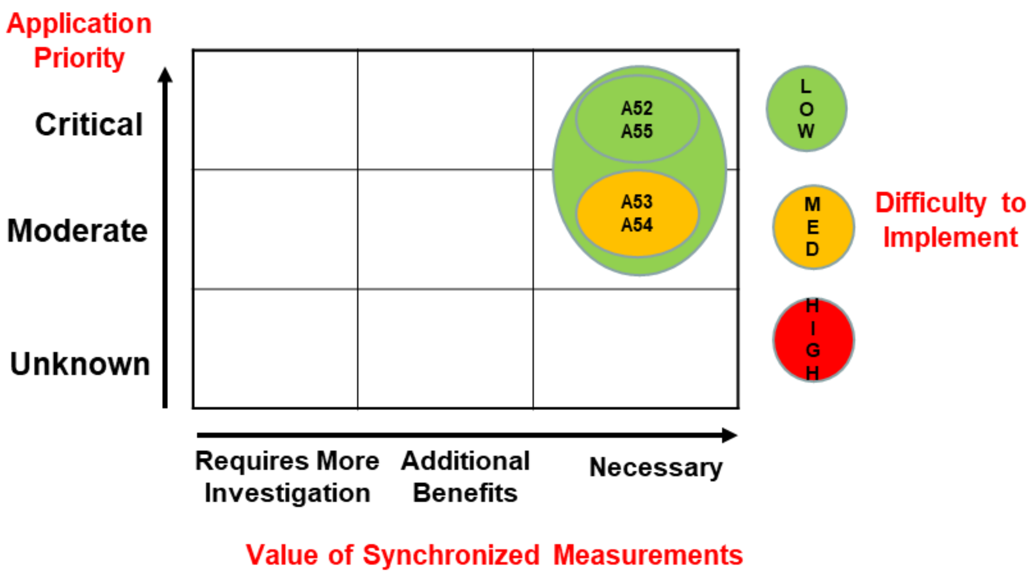

Figure 4-21. Value of Synchronized Measurements for Advanced Microgrid Applications and Operation (AG13)

4.13.4 Quantified Benefits

High-level benefits of synchronized measurements for advanced microgrid applications and operation:

- Sustainability and decarbonization (8)
- Resilience and reliability (8)
- Real-time operation (7)
- Customer engagement and business potential (7)
- Innovation potential (7)
- Public safety (5)
- Advanced planning and asset management (4)
- Efficiency improvement (4)

The obvious benefits of microgrids are reliability and resilience. Unlike the regular grid, which is in a stressed or damaged condition, microgrids maintain service independently. Microgrids aim to achieve decarbonization and sustainability by using renewable resources as efficiently and practically as possible. This efficiency reduces the need for traditional sources of generation.

The concepts of microgrids, microgrid control, protection of microgrids, and islanding detection are relatively new. Tools and application principles are still being developed, providing an opportunity for innovation. Microgrids are also very beneficial for customer relations as a goal of microgrids is to provide a reliable electrical system that relies on renewable resources.

4.13.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for advanced microgrid applications and operations:

- Complexity of the system (5)
- Investment required (5)
- Maturity of solutions (7)
- Risk of failure (5)
- Readiness of utility personnel to adopt (6)

Islanding and restoration (A52 and A55) using synchronized measurements are simple to implement as they do not require many measurements, and angle accuracy is not critical. For islanding detection, it is only important to detect if the microgrid is connected or not.

Advanced microgrid applications and operations require multiple synchronized measurement points in the microgrid, with most of these applications needing synchronized measurement data from multiple locations. At a minimum, synchronized measurement data will be required from every grid interconnection point at every significant DER resource. This is likely to be a "medium density" system architecture in terms of communication requirements. Most data collection, algorithms, and processing will occur in the microgrid at a microgrid controller location.

The specific performance requirements for advanced microgrid applications are presented in Table 4-9.

Table 4-9. Specific Performance Requirements for Advanced Microgrid Applications

Requirement	Synchronized Measurement Data	Other Synchronized Data
Measurement accuracy	1% total vector error	±5% error
Availability	99%	95%
Latency	500 ms	5000 ms
Sampling rate	Device sampling rate	Device sampling rate
Reporting rate	30 Hz	1 Hz

Complexity is based on the need to manage the interconnection between the microgrid and the larger grid, managing all the internal IBRs and control loads, ensuring reliability and performance are maintained, and the continuously varying availability of resources and loads. This requires a microgrid controller to run different applications for reliability and performance in parallel and requires retrieving a large amount of synchronized data. The investment is partly in application development (as many of these applications are new) and partly in the system's installation (including the SMDs and the communications infrastructure needed to retrieve the data). Other costs, such as the risk of adopting microgrid controls, the maturity of solutions, and the willingness of utilities to adopt advanced microgrid applications, are all relatively low.

4.14 AG14: Improved Load Shedding Schemes

4.14.1 High-Level Summary

Load shedding schemes comprise a group of applications based on voltage, current, and frequency measurements, which take remedial action according to a regional plan to avoid system collapse under the loss of generation sources or loading stresses. Load shedding has historically been based on regional frequency-based or voltage-based plans. However, the changing generation mix will eventually demand additional high-speed local shedding schemes based on locally detected imbalances or measurement trajectories. Shedding has been typically performed by distribution feeder underfrequency or undervoltage load shedding relays or by communicated shedding command from a location where a voltage or frequency collapse has been detected. One of the major shortcomings of such a legacy scheme is that the load expected to be shed for a particular feeder is based on nominal load rather than on a real-time measurement. If real-time measurements are available, they are typically limited to the feeder head location without any granular visibility of the loads or sources downstream. As a result, DER supplying loads without islanding capability may mask the true impact of circuit load shedding actions.

Load shedding schemes can be improved by placing measurements at each feeder's switching location, measuring each branch's load flow, and communicating values to a control location. An advanced load shedding scheme continuously tabulates which devices can be operated to achieve an assured target load shed for the feeder and keep these updated lists prepared for use if any frequency or voltage setpoint operates. This approach yields a wide range of benefits, including the ability to selectively shed var consuming loads on a particular feeder without interrupting critical loads, DERs, or capacitors banks during the shedding operation.

Improved load shedding schemes include the following use cases:

- A56—Improved load shedding schemes – frequency: Using advanced measurement data and return control paths to optimize frequency-triggered load shedding schemes.
- A57—Improved load shedding schemes – voltage: Same as A56 but for voltage-triggered load shedding schemes. In addition, a more accurate impedance-based scheme could be deployed (e.g., real-time voltage instability indicator). Detection of voltage instability condition is described in more detail in the A38 application.
- A58—Improved load shedding schemes – load flow-based: Improved schemes are based on the load flow information and the real-time value of the load assigned for shedding. As load value changes, the value assigned based on planning off-line studies may not correspond to the actual value. This may result in a load shed too small or too large, affecting the frequency recovery. Calculating the load value in real-time and adaptively adjusting load to be shed in prescribed frequency steps optimizes the amount to be shed and assures optimal frequency recovery.
- A59—Load shedding real-time compensative arming to balance IEEE 1547 compliant PV: Using advanced measurement data and return control paths to improve load shedding accuracy to achieve

target values and avoid unnecessary disconnection of PVs. This use case avoids dropping feeders with DER whose net load consumption from the grid is insignificant in achieving load shedding targets or supporting the grid via reverse flow.

4.14.2 Deployment Status

Improved load shedding applications are currently partially deployed.[61]

4.14.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

These applications are critical. The recent 2021 Texas power blackout shows that optimizing load shedding amounts based on real-time data is important. It is also important to automate the process to speed up the recovery. The importance of synchronized measurements to align load data provides additional benefits but may not be necessary to deploy those improved schemes.

Figure 4-22 presents the value of synchronized measurements for improved load shedding schemes.

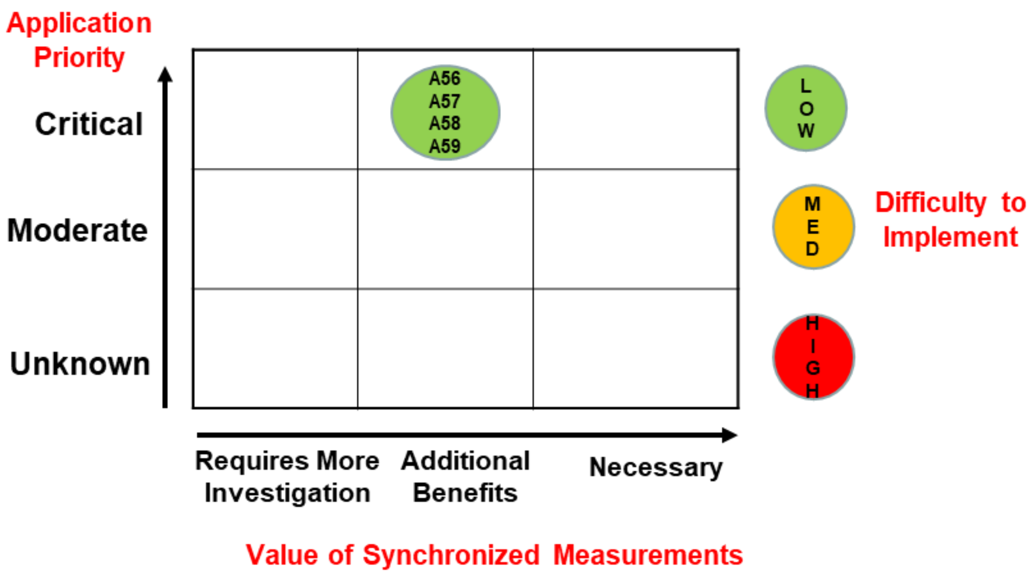

Figure 4-22. Value of Synchronized Measurements for Improved Load Shedding Schemes (AG14)

4.14.4 Quantified Benefits

Improved load shedding schemes are critical to prevent blackouts as systems are more stressed due to climate change and renewable generation penetration. Synchronized measurements would provide additional benefits through accurate and synchronized measurements in real-time. However, the main benefit would be to use synchronized data to analyze the disturbance post-mortem.

[61] D. Andersson; P. Elmersson; A. Juntti; Z. Gajic; D. Karlsson, "Intelligent load shedding to counteract power system instability," IEEE/PES T&D Conference Latin America , April 2004.

High-level application benefits of synchronized measurements for improved load shedding schemes:

- Real-time operation (7)
- Resilience and reliability (7)
- Efficiency improvement (6)
- Innovation potential (6)
- Customer engagement and business potential (6)
- Sustainability and decarbonization (4)
- Advanced planning and asset management (4)
- Public safety (4)

Using synchronized measurements will improve and fine-tune load shedding schemes, improving the system's real-time operation and a more resilient system during abnormal operating conditions.

4.14.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for improved load shedding applications:

- Complexity of the system (5)
- Investment required to implement (5)
- Maturity of the solutions and devices (7)
- Risk of failure (3)
- Readiness of the utility and utility personnel to adopt (5)

The cost of implementation is medium and is based on the number of monitoring sites. Synchronized measurements at all monitoring sites where the load is planned to be shed are required. Communications architecture is required between field measurement devices and substations and between substations and the central system.

The requirements are medium as there may be no need for fast real-time data. However, there is a need to monitor many load-switching locations for granular visibility. Therefore, a reporting rate of 1 report per second, availability of 80%, and latency of 5000 ms is sufficient.

4.15 AG15: Advanced Distribution Automation

4.15.1 High-Level Summary

Distribution automation is generally used to remediate situations such as overloading system components, excessive losses, low-voltage violations, voltage unbalances, and spurious tripping of overcurrent protection when the unbalance might be extreme. A common practice to mitigate these problems is to transfer customer loads among neighboring circuits and circuit phases using distribution automation. A similar reconfiguration process can also be initiated as part of a FLISR scheme after the feeder's faulted section has been isolated.

These operations are generally not using real-time data. Rather, they use the distribution equipment's daily or seasonal load profiles to assess the receiving feeder's reserve capacity. In practice, given the uncertainties of this process, load transfers may not be optimal or cause further unbalance or overloading problems. Advanced distribution automation leveraging real-time power flow information from PMUs at key locations (circuit breakers, reclosers, switches, and DER sites) can improve pre-event or offline load allocation, online state estimation, and service restoration processes with the balanced operation and efficient utilization of available circuit capacity during normal and emergency conditions.

For FLISR applications, in addition to improved reserve capacity and dynamic ratings of distribution assets, fault location is more accurate, allowing for the optimized use of the field workforce during emergency conditions. Advanced distribution automation uses synchronized voltage and current measurements from locations across the distribution system circuit or area, streamed at a rate of many measurement-sets per second to a central assessment and control platform, to estimate the best course of actions for load transfer and selection and sequence of operation of switching devices for service restorations. It requires a return control path to each circuit switching device included in the holistic control strategy and model.

Distribution automation includes the following use cases:

- A60—Load transfer and load balancing: Using data from PMUs at strategic locations on the feeder to increase real-time awareness and facilitate proactive distribution grid reconfiguration (load transfers to between feeders and substations) to address system needs (e.g., defer upgrades, address voltage regulation issues, etc.) and identify voltage/current imbalance issues and target remedial control actions.
- A61—Self-healing and enhanced FLISR operation: Using synchronized high-rate measurements and return control paths to improve the accuracy of fault location and service restoration performance of FLISR.

4.15.2 Deployment Status in the Industry

Distribution automation is a foundational component of grid modernization and smart grid initiatives. It involves a variety of technologies to improve system performance, reliability, and resilience. The most common distribution automation technologies include FLISR and VVO. FLISR has received significant attention in the last decade, with numerous implementations and thousands of smart devices (reclosers, switches, sensors, controllers, etc.) deployed at utilities such as ComEd,[62] CenterPoint, Duke Energy, and Con Edison[63].

Although FLISR is already a mature technology, there is increasing interest in evaluating the potential impacts, interactions, and benefits of FLISR on DER and microgrid integration, including the use of these resources for intentional islanding operation and resynchronization to minimize impacts of contingencies.

[62] https://www.tdworld.com/grid-innovations/distribution/article/20964750/comed-rolls-out-modern-infrastructure

[63] https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf

[64] A similar experience has been reported recently in the literature covering the Bronzeville Microgrid in Chicago, IL.[65] However, the use of synchronized measurement technologies within the context of FLISR in radial distribution feeders remains incipient.

4.15.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Modern distribution automation schemes, such as FLISR, involve three distinct steps, 1) fault location, 2) fault isolation (e.g., using nearest normally closed automated devices located immediately upstream and downstream from the fault location), and 3) service restoration (transfer healthy sections of faulted feeder—located downstream from the fault—to neighbor feeders via normally open ties). Synchronized measurement technologies can provide additional benefits to enhance each stage of the FLISR process.

DER integration may introduce additional challenges to consider. For instance, during a contingency condition and depending upon the control system logic and automation technology, FLISR schemes may rely on pre-fault load data measured in real-time by line reclosers to determine the feasibility of switching operations (including load transfers to neighbor feeders and substations) to reconfigure the grid (isolate faulted sections and restore service to customers located in healthy sections of a feeder).[66] The interconnection of a utility-scale DER system may "mask" the pre-fault load in a distribution automation scheme zone, which may lead to the execution of an otherwise unfeasible load transfer operation. Since DER systems will cease to energize and trip no more than 2 s after feeder de-energization, a large load may be mistakenly transferred to a neighboring feeder or substation. This mistaken transfer may create operational problems (e.g., temporary overloads), although loading within the transferred section may return to the pre-fault values once the DER system reconnects.

Synchronized measurement technologies located at reclosers and DER units can provide accurate real-time data that allow the "unmasking" of pre-fault loads within a distribution automation scheme zone and correctly assessing the feasibility of a load transfer and reconfiguration alternative in real-time. Additional synchronized measurements deployed along distribution feeders can also provide voltage and current data that can be used to verify the feasibility of an alternative configuration from the point of view of voltage regulation. These objectives can also be accomplished using conventional measurements, making the benefits of synchronized measurement technologies incremental (i.e., enhancing existing approaches).

Figure 4-23 presents the value of synchronized measurements for advanced distribution automation.

[64] M. Hojabri et. al, A Comprehensive Survey on Phasor Measurement Unit Applications in Distribution Systems, Energies 2019, 12, 4552, http://dx.doi.org/10.3390/en12234552

[65] https://www.naspi.org/sites/default/files/2021-04/20210331_naspi_webinar_comed.pdf

[66] https://www.tdworld.com/smart-utility/article/20972125/the-many-faces-of-flisr

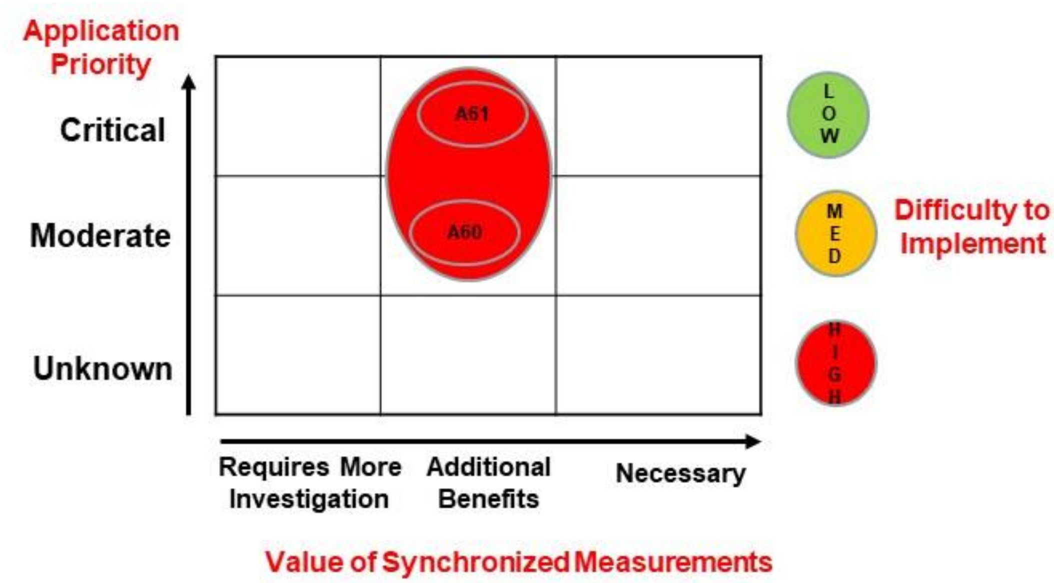

Figure 4-23. Value of Synchronized Measurements for Advanced Distribution Automation (AG15)

Synchronized measurement technologies can be particularly helpful to proactively reconfigure complex system grid topologies, especially in systems with high DER penetration and microgrids. For instance, measuring magnitudes/phase angles of voltages/currents can help verify the feasibility of make-before-break switching operations. This type of operation is important to avoid the short-duration service interruptions required when using break-before-make switching approaches. Make-before-break switching is important to implement proactive distribution system reconfigurations intended to address system needs (e.g., capacity upgrade deferrals, voltage regulation needs, voltage/current imbalance issues, etc.), and reconnection of islanded microgrids to distribution systems (resynchronization). Synchronized measurement technologies' ability to provide accurate values for voltage phase angles and magnitudes is a unique added value for implementing this type of application.

4.15.4 Quantified Benefits

High-level benefits of deploying synchronized measurements for advanced distribution automation applications:

- Resilience and reliability (7)
- Real-time operation (6)
- Efficiency improvement (6)
- Innovation potential (6)
- Public safety (6)
- Sustainability and decarbonization (4)
- Customer engagement and business potential (4)
- Advanced planning and asset management (3)

Benefits for two applications include:

- A60: Supporting the implementation of proactive reconfiguration of distribution systems by providing data to evaluate the feasibility of make-before-break switching operations. Proactive distribution system reconfiguration can help address issues such as reliability and resilience improvement (e.g., temporary grid reconfigurations to withstand weather events), capacity deferral, loss reduction, voltage regulation improvement, and voltage/current balancing via load transfers to neighbor feeders and substations, and DER/microgrid integration.
- A61: Improving the accuracy and effectiveness of the stages of FLISR schemes, which would enhance distribution system reliability and resilience, overall grid flexibility, and the ability to integrate DER and microgrids.

4.15.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for advanced distribution automation applications:

- Complexity of the system (6)
- Investment required to implement (7)
- Maturity of the solutions and devices (6)
- Risk of failure (6)
- Readiness of the utility and utility personnel to adopt (6)

Latency and data availability for these applications are stringent. They require the implementation of a highly reliable and low latency telecommunications solution. Data must be collected and transmitted to the control center in real-time, and respective analyses and control actions also must be implemented in real-time. This application would potentially target hundreds or thousands of devices (e.g., reclosers, switches, DER, etc.). Therefore, the number of measurements required for implementation would be large, and the overall cost of the application would be high.

The specific performance requirements for advanced distribution automation are presented in Table 4-10.

Table 4-10. Specific Performance Requirements for Advanced Distribution Automation

Requirement	Synchronized Measurement Data	Other Synchronized Data
Measurement accuracy	1% total vector error	±5% error
Availability	99%	95%
Latency	300 ms	5000 ms
Sampling rate	Device sampling rate	Device sampling rate
Reporting rate	30 Hz	1 Hz

4.16 AG16: Technical and Commercial Loss Reduction

4.16.1 High-Level Summary of Application

Technical losses are naturally occurring losses (caused by action internal to the power system) and consist mainly of power dissipation in electrical system components such as transmission lines, power transformers, measurement systems, etc. Non-technical losses are the losses that occur due to unidentified, misallocated, or inaccurate energy flows. These losses can be described as electricity that is consumed but not billed. It is important to differentiate this from the electricity that is billed but where the bills are not paid. For non-technical losses, the end-user is unknown, or the amount of energy being consumed is uncertain.

The three main types of non-technical losses are energy theft, unmetered supply errors, and conveyance errors.

Technical and commercial loss reduction includes the following use cases:

- A62— Circuit loss minimization: One common form of energy loss is the result of unbalanced phase loading. This form of energy loss is rare in transmission systems but can occur over time on distribution systems where changes in topology result in unbalance. It can be difficult in complex distribution topologies to determine how the individual phases are distributed to customers. Unbalanced phases result in I^2R losses. Time SMDs can identify the phase and magnitude of a line they are measuring which can aid in root cause analysis.
- A63— Energy accounting: Energy accounting can be accomplished effectively without time-synchronized measurements. This accounting is typically accomplished with a single meter at the output of the transformer connected to a feeder. Time synchronized measurements can add additional value, if determined to be advantageous, to show a more granular view of energy production and consumption.
- A64— Technical and commercial loss identification, calculation, and reduction: For specific areas (i.e., feeders and customers), time-synchronized measurements can be valuable in root cause analysis. Determining causes for the discrepancies between energy delivered and energy billed can be difficult with data collected only from substation feeder meters and customer revenue meters. Having accurately synchronized time-stamped measurements can help find specific conditions that may be short-term in nature that cannot be seen using traditional data collection.

4.16.2 Deployment Status in the Industry

SDG&E and many other utilities have percentages of technical and non-technical losses. After selecting specific feeders where this is thought to be a problem, a pilot should be deployed to determine cost-benefit analysis.

4.16.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Figure 4-24 presents the value of synchronized measurements for technical and commercial loss reduction.

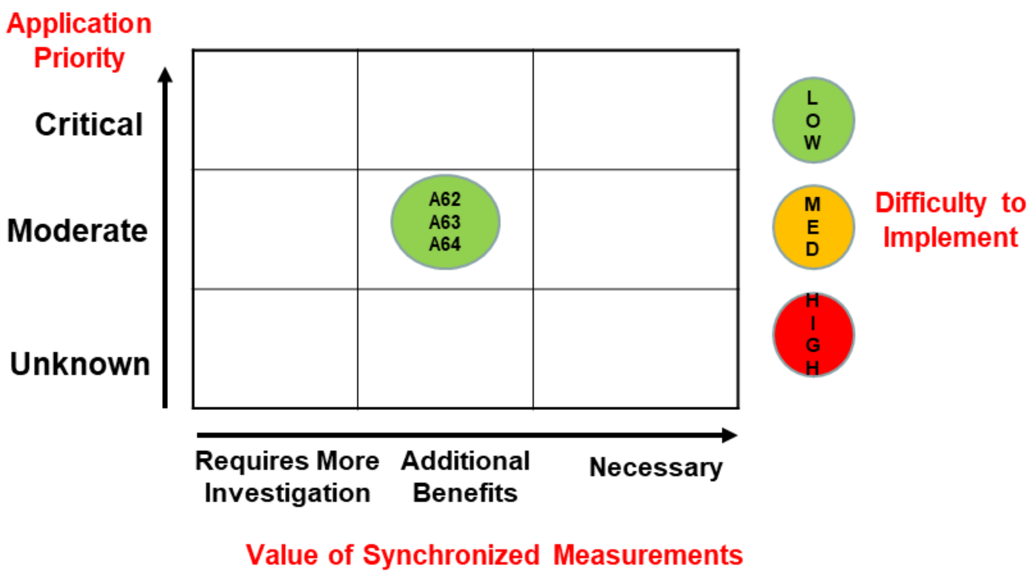

Figure 4-24. Value of Synchronized Measurements for Technical and Commercial Loss Reduction (AG16)

4.16.4 Quantified Benefits

High-level application benefits of synchronized measurements for technical and commercial loss reduction:

- Efficiency improvement (7)
- Customer engagement and business potential (6)
- Sustainability and decarbonization (5)
- Advanced planning and asset management (5)
- Innovation potential (5)
- Real-time operation (4)
- Public safety (3)
- Resilience and reliability (2)

Synchronized measurements can be used to reduce circuit losses, improve root cause analysis of energy billing issues, and provide data to improve customer energy accounting, thereby making the distribution system more efficient.

4.16.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for technical and commercial loss reduction applications:

- Complexity of the system (5)

- Investment required to implement (4)
- Maturity of the solutions and devices (6)
- Risk of failure (3)
- Readiness of the utility and utility personnel to adopt (6)

All applications will require multiple synchronized measurement points per feeder. The majority of these applications (especially applications that provide the most benefits) will require synchronized measurement data from multiple points on each distribution feeder where the application is provided.

4.17 AG17: Monitoring and Control of Electric Transportation Infrastructure

4.17.1 High-Level Summary of Application

Today, there is no longer a debate on whether there will be a future with EVs or not. Recent investments, actions, and an ever-increasing list of EV options being offered by major auto-manufacturers have shifted the debate from "when we will see a future of EVs" to "how do we handle the impact of EVs ." Consumers are also beginning to recognize the advantages of PEVs over conventional vehicles, such as lower lifetime operating costs, better acceleration, and at-home charging. Finally, states and federal agencies are also pushing adoption forward as transportation electrification becomes a pillar in the formation of decarbonization plans and the benefits of emission reductions in levels of smog and health come into focus.

Although there is a great deal of focus on advancements of light-duty vehicles, it is the chargers that have to be monitored . In addition, electric transportation is more than just light-duty vehicles. It also encompasses medium-/heavy-duty vehicles as well. When utilities were first examining charging loads, most charging was conducted at home with a level I charger—where each charger maxed out at under 2 kW. As vehicles increased their range and batteries increased their size, charging levels began to increase, and level II chargers reached 7-10 kW. Currently, the City of San Diego has 57 EV charging stations (68 ports) at 15 locations to make charging more convenient for EV drivers. The locations include destinations like Balboa Park, other parks and recreation centers, libraries, and entertainment districts. These intermittent high current loads on the distribution grid will have a cumulative effect that must be closely monitored.

However, desires to charge vehicles even faster have pushed vehicle chargers to evolve just as fast as the vehicles themselves. DC fast charging offered levels of 50-350kW as charging moves beyond residential homes and into public charging areas. As electrification expands into medium and heavy-duty vehicles, commercial operations need to maintain operations and efficiencies, make fast-chargers the chargers of choice, dramatically increasing loads, their impact on the grid, and the need to monitor and incentivize controls of charger operations across a territory.

Monitoring and control of electric transportation infrastructure include the following use cases:

- A65—Monitoring of electric transportation infrastructure: Synchronized measurements information may be useful for studying the effect charging patterns have on the distribution network. This monitoring is especially useful in areas of low EV charging hosting capacity. The high load caused by the clustered high-power chargers at the commercial operations of distribution centers and freight delivery supply chains will need to be monitored to enable mitigation techniques.

- A66—Vehicle-to-grid (V2G) monitoring and control: V2G is a process where charged vehicles can be used for voltage support during peak load. This application is in the very early stages of defining the use case. There are no deployments of this infrastructure anywhere except test labs. In general, the charged EV would act like any other battery or PV connected behind the meter. If deployed, high report rate synchronized measurements would be important for the control needed to use the stored energy effectively. A detailed report on the state of the art can be found at: https://rmi.org/wp-content/uploads/2017/04/RMI_Electric_Vehicles_as_DERs_Final_V2.pdf.[67]

4.17.2 Deployment Status in the Industry

California has mandates for electrification of heavy-duty segments such as metro buses and freight trucks. For example, SDG&E is deploying EV charging stations throughout San Diego and at their facilities. Logistics and transportation distribution centers will be assessing electrification to meet carbon reduction goals. California has examined the impact of these policies on their grid (study AB 2127[68]) and noted many areas of potential stress. The Transportation Electric Framework, set to be finalized by the end of 2021, lists actions utilities need to take and has moved the need to monitor medium and heavy-duty charger impacts to near-term priorities.

4.17.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Synchronized measurements are not critical for monitoring EV charging but provide added benefits for analyzing the impact of charging on the distribution network and identify mitigation techniques. If V2G becomes viable, monitoring and control using synchronized measurements will provide benefits to control the charging and discharging.

Figure 4-25 presents the value of synchronized measurements for monitoring and control of electric transportation infrastructure.

[67] "Electric Vehicles as Distributed Energy Resources", https://rmi.org/wp-content/uploads/2017/04/RMI_Electric_Vehicles_as_DERs_Final_V2.pdf

[68] California Energy Commission, "Electric Vehicle Charging infrastructure Assessment – AB 2127", https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle-charging-infrastructure-assessment-ab-2127

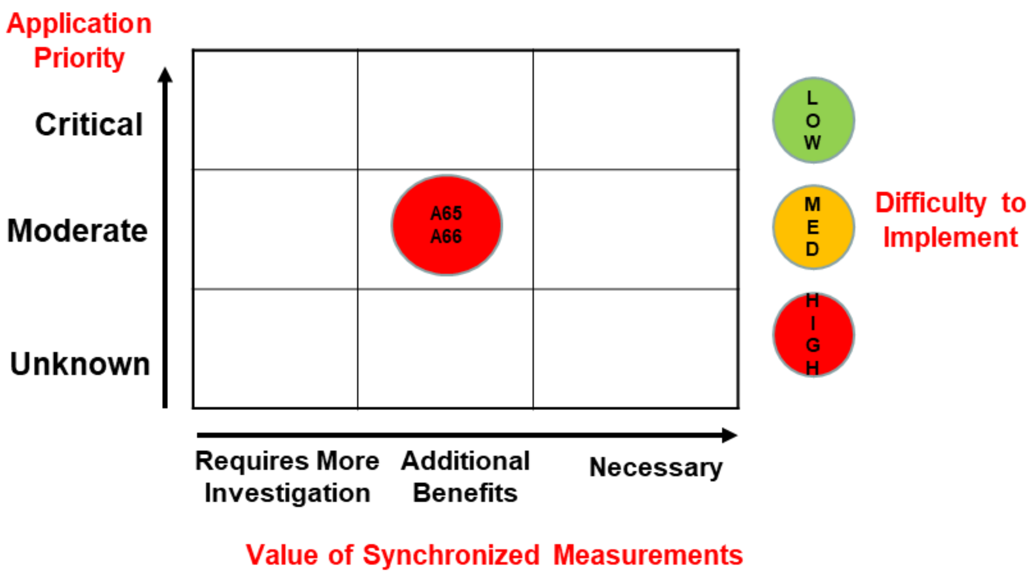

Figure 4-25. Value of Synchronized Measurements for Monitoring and Control of Electric Transportation Infrastructure (AG17)

4.17.4 Quantified Benefits

High-level application benefits of synchronized measurements for monitoring and control of electric transportation infrastructure:

- Sustainability and decarbonization (7)
- Advanced planning and asset management (7)
- Innovation potential (7)
- Customer engagement and business potential (6)
- Resilience and reliability (5)
- Real-time operation (5)
- Efficiency improvement (5)
- Public safety (3)

Synchronized measurements are beneficial to monitor EV infrastructure for sustainability and decarbonization. The important benefit is the ability to see, and manage, real-time reactions from potential grid overloads and use this information to prevent outages due to EV charging.

4.17.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for monitoring and control of electric transportation infrastructure applications:

- Complexity of the system (6)

- Investment required to implement (6)
- Maturity of the solutions and devices (3)
- Risk of failure (4)
- Readiness of the utility and utility personnel to adopt (3)

The costs of electric charging infrastructure are based on the need to communicate directly to the charging devices and the data requirements to handle these measurements. One aspect limiting adoption is utility understanding of the customer needs around EV charging for medium and heavy-duty commercial operations.

This AG requires a minimum report rate of 1 report per second, availability of 80%, and latency of 5000 ms is required. It also requires communication between field measurement devices and a central system. Application may have more demanding requirements for charging controls, e.g., a higher reporting rate.

4.18 AG18: Integrated Resource, Transmission, and Distribution System Planning and Operations

4.18.1 High-Level Summary

The modernization of the T&D grids—driven by recent technology innovations, societal aspirations for clean energy, and increasing vulnerabilities from climate change—requires closer coordination and integration in the planning and operation across the electricity value chain. It has become increasingly important to plan and operate the system holistically in the present and ever-changing environment. This holistic operation includes inverter-based DERs and storage, as well as electrification of the transportation sector. Furthermore, steady-state and dynamic planning processes need to be integrated with protection coordination as the grid becomes more dynamic with high-penetration of DERs.

Modern T&D planning requires accurate models for distribution, including inverter-based generation. Distribution networks no longer behave as passive loads and should not be modeled as such due to the following:

- Drastically changed daily load curve
- Weather conditions with major impacts on consumption and DG
- Circuits exhibiting very different dynamic characteristics

Furthermore, meaningful transmission planning must also include distribution load forecasting and DER and electrification forecasting.

From the T&D operation perspective, distribution has a history of low visibility and relies heavily on predictable feeder and customer load behavior. In conclusion, the operation of a large portion of DERs, both connected to distribution networks and behind-the-meter, are not available to T&D planners and invisible to T&D operators. As synchronized measurements provide accurate information about the phase angles and magnitudes of distribution circuit voltages and currents, they are valuable to support the planning and operation of meshed networks and parallel operation of 69 kV circuits with adjacent distribution and sub-transmission circuits. This information is necessary for T&D planners and operators to address coordinated T&D planning and operations.

Integrated resource, transmission, and distribution system planning and analysis include the following use cases:

- A67—Meshed networks and running sub-transmission (69 kV) and distribution in parallel: Using data from synchronized measurements on the distribution system both for planning and for control schemes to support meshed network operation and parallel operation of 69 kV and adjacent circuits.
- A68—Integrated resource, transmission, and distribution system planning and analysis: Gathering synchronized measurements from adjacent sub-T&D circuits to study and plan interactions and adequacy of T&D system infrastructure for operating scenarios, including heavy penetration of DER in either or both systems. It enables better visibility of the overall system.

4.18.2 Deployment Status

The use of synchronized measurements for integrated resource, transmission, and distribution system planning and analysis is not deployed in the industry.

4.18.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

Synchronized measurements are helpful in control schemes to support meshed network operation and parallel operation of 69 kV and adjacent circuits but are not necessary and provide additional benefits. However, planning and operating integrated T&D grids will require synchronized measurements to achieve the necessary grid visibility and enable accurate system modeling.

Figure 4-26 presents the value of synchronized measurements for integrated resource, transmission, and distribution system planning and operations.

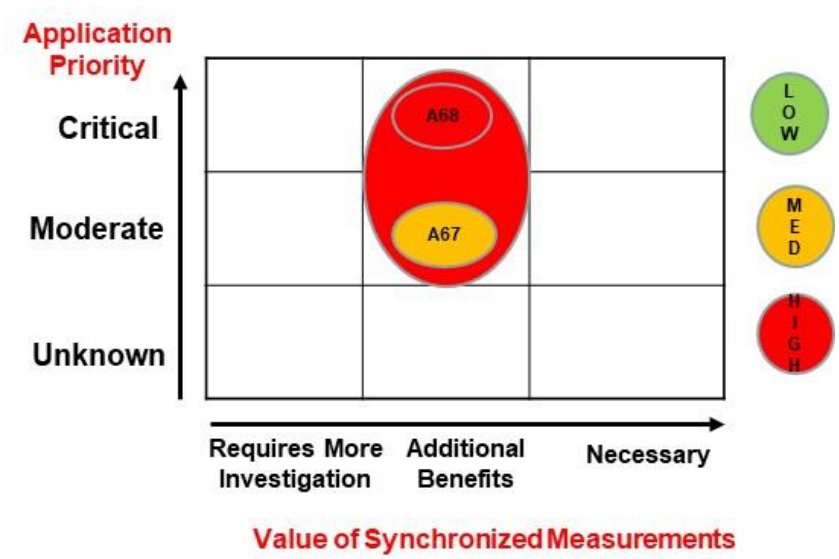

Figure 4-26. Value of Synchronized Measurements for Integrated Resource, Transmission, and Distribution System Planning and Operations (AG18)

4.18.4 Quantified Benefits

High-level application benefits of synchronized measurements for integrated resource, transmission, and distribution system planning and operations:

- Advanced planning and asset management (7)
- Efficiency improvement (7)
- Resilience and reliability (6)
- Sustainability and decarbonization (6)
- Innovation potential (6)
- Customer engagement and business potential (4)
- Real-time operation (4)
- Public safety (3)

Improved visibility and control with distribution circuit monitoring and accurate models or equivalents are essential for modern T&D planning and operation. Synchronized measurements will play a critical role in developing models and provide visibility of DERs to both T&D planners and operators. They are required to provide increased information exchange and control action coordination between transmission grid and distribution networks for the reliable operation of both.

4.18.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for integrated resource, transmission, and distribution system planning and operations applications:

- Complexity of the system (8)
- Investment required to implement (8)
- Maturity of the solutions and devices (3)
- Risk of failure (4)
- Readiness of the utility and utility personnel to adopt (2)

The requirements are medium as there may not be a need for fast real-time data. However, there is a need to monitor many load-switching locations for granular visibility. Reporting rates of 1 report per second, availability of 80%, and latency of 5000 ms are sufficient.

The cost of implementation is high due to a need to have many monitoring sites and the communications architecture between field measurement devices and substations and between substations and the central system.

4.19 AG19: Power Quality Assessment and Analysis

4.19.1 High-Level Summary of Application

PQ issues include harmonic distortion, voltage sags and swells, flicker, brief dips or interruptions, and transients. These behaviors are problematic, but especially for circuits or customers with sensitive loads. The widespread use of electronic and information technology (IT) equipment, the proliferation of inverter-based DG (e.g., PV), and EV charging systems will require more comprehensive monitoring and evaluation of PQ indices in distribution systems. The growing number of sensitive loads and the increased reliability and PQ demanded by commercial and residential customers will expand the need to capture, assess, and mitigate PQ issues.

PMUs can play an important role in providing the required data to characterize and mitigate PQ phenomena observable in high-speed power-frequency voltages and current signals. While power-frequency synchronized measurements mask harmonics and wave distortion, some developers have proposed the inclusion of new harmonic synchronized measurements, which can be captured as snapshots to indicate the direction of harmonic or distortion power flow and thus point to the sources. Momentary and transient events are captured by a PQ meter function incorporated in the synchronized measurement system. The data can be used to calculate PQ indices at key customer sites with sensitive loads and for distribution system locations overall. The data stored by PMUs can be downloaded and processed offline to compute PQ indices, identify issues, propose mitigation measures, evaluate the effectiveness of PQ improvement projects, and meet regulatory reporting requirements. Moreover, if real-time data or snapshot-streaming communications facilities and data processing resources are in place, data from PMUs can be used in online system operations to identify PQ issues (e.g., flicker) and execute control operations to alleviate them.

PQ assessment and analysis includes the following use cases:

- A69—Harmonic measurements: Streaming updates or captures of harmonic component magnitudes and angular relationships for trending levels and alarming for excessive harmonics.

- A70—Voltage sag and swell measurement: Capturing and profiling out-of-range voltage disturbances following IEEE industry or other situationally-driven stability standards.
- A71—Flicker measurement: Capturing and profiling flicker incidences following IEEE industry or other situationally driven observability and process impact standards.
- A72—Voltage and current imbalance measurement: Capturing and profiling unsymmetrical operation of three-phase distribution system segments to identify and correct causes.
- A73—Short-duration interruption measurement: Capturing and profiling short dips or interruptions resulting from external faults or switching operations can upset critical customer processes.
- A74—Harmonic state estimation and diagnosis: Using harmonic phasor measurements from specially designed PMUs to identify the sources of offending harmonics by directional harmonic power flows.
- A75—Primary meter customer monitoring of PQ: Integrating customer PQ meter data with data circuit data gathered by the utility to profile service PQ and diagnose causes of PQ problems.

4.19.2 Deployment Status in the Industry

SDG&E has broadly deployed PQ meters in distribution substations for the previously listed assessments and predictive detection of impending apparatus failures by noise signature. Some synchronized measurement-enabled PQ meters have been deployed on circuits with synchronized measurements and falling-conductor detection.

4.19.3 Importance of Applications and Synchronized Measurements to Achieve Benefits

The PQ performance of the distribution system is becoming more important as more sensitive electronic loads, IBRs, and EVs are connected to the system. One significant interest is the cumulative impact of IBRs and EVs on the total harmonic distortion on the distribution system. Therefore, capturing PQ data and calculating PQ indices will be more important. Synchronized measurements can improve the measurement of some of the PQ indices, especially total harmonic distortion. These applications are only a low to moderate priority in improving distribution system operations, except for specific situations.

Figure 4-27 presents the value of synchronized measurements for PQ assessment and analysis.

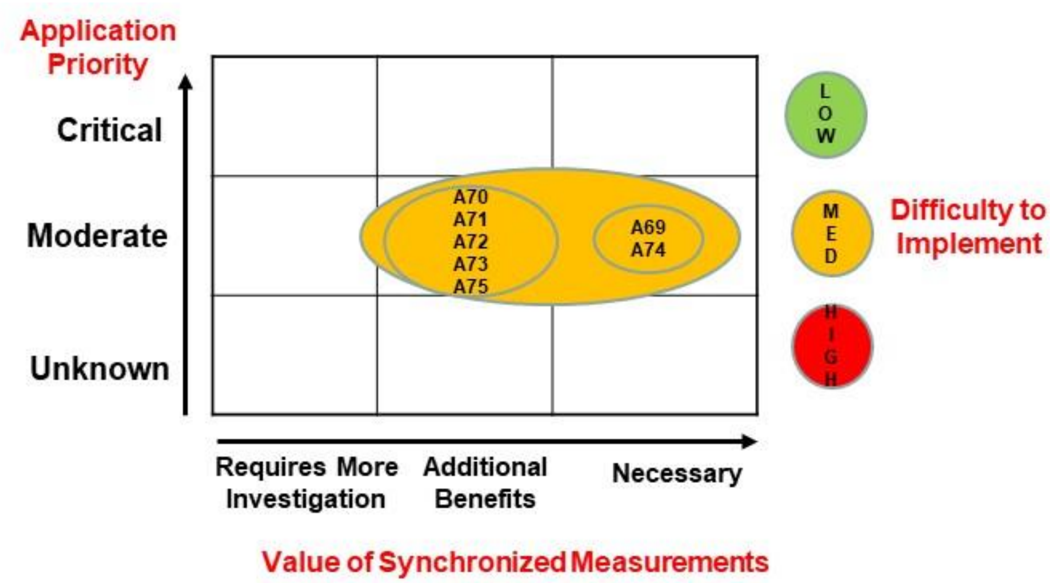

Figure 4-27. Value of Synchronized Measurements for PQ Assessment and Analysis (AG19)

4.19.4 Quantified Benefits

High-level application benefits of synchronized measurements for PQ assessment and analysis:

- Customer engagement and business potential (7)
- Advanced planning and asset management (6)
- Resilience and reliability (6)
- Innovation potential (6)
- Sustainability and decarbonization (5)
- Real-time operation (5)
- Efficiency improvement (5)
- Public safety (2)

The benefit to customer engagement is the ability to use the PQ indices at customer locations to identify problems and suggest possible system improvements. The same data can be used to develop innovative solutions to maintain PQ at specific sites and across the entire system, such as with system-wide harmonics monitoring. PQ data can also be used as an input to operators and operating decisions and be beneficial to system planning to help identify problem areas and with prioritization.

4.19.5 System and Product Requirements, Including Estimated System Costs

High-level evaluation of deploying synchronized measurements for PQ assessment and analysis applications:

- Complexity of the system (5)
- Investment required to implement (6)
- Maturity of solutions and devices (7)
- Risk of failure (2)
- Readiness of the utility and utility personnel to adopt (5)

PQ assessment and analysis application will require measurements from critical loads at specific points on distribution circuits. Therefore, this is a medium-density architecture in terms of the number of points and communications. Most data can be retrieved from PQ devices, and only some specific synchronized measurement data must be streamed continuously. Many measurements will use dedicated PQ devices. However, it is expected that over time manufacturers of intelligent circuit devices such as PMUs, capacitor bank controllers, and inverters will incorporate PQ measurements as core functionality.

The specific performance requirements for PQ assessment and analysis applications are presented in Table 4-11.

Table 4-11. Specific Performance Requirements for PQ Assessment and Analysis Applications

Requirement	Synchronized Measurement Data	Other Synchronized Data
Measurement accuracy	1% total vector error	±5% error
Availability	99.9%	99%
Latency	5000 ms	5000 ms
Sampling rate	Device sampling rate	Device sampling rate, 15,360 Hz or better preferred
Reporting rate	120 Hz	1 Hz

The cost around maturity is driven by the need to collect and integrate large amounts of PQ data into a common system for analysis and assessment, and then develop the tools and systems needed to analyze the data. The investment is in developing algorithms and installing and maintaining the measurement devices and communications system. Utility personnel are already familiar with PQ measurements and their uses and should be able to adopt these applications quickly. The complexity of installing a PQ system is mostly in project work to identify locations and install the system components.

5 PRIORITIZATION OF DISTRIBUTION SYNCHRONIZED MEASUREMENT APPLICATIONS

5.1 Prioritization Methodology

The project team developed a prioritization methodology to assess the relative benefits and costs of each synchronized measurement technology AG. The AGs are the foundational components of the roadmap and consist of a group of related use cases. Each AG's relative benefits and costs were evaluated using an expert knowledge-based approach with strategic categories. These categories are based on overall industry trends and specific areas of interest for electric utilities in North America, including those participating in the interview sessions with the project team. Then, initiatives were graded in each benefit and cost category using a scale from 0 to 10. The project team did the grading using its technical expertise, industry experiences, and understanding of electric utility operations. Thus, the prioritization is based on the needs of a typical utility considering the industry inputs and the team's experience. The grading is an input based on expert knowledge indicating the relative benefit or cost of a specific initiative compared to the roadmap's remaining initiatives. A weighted average approach was used to calculate the overall benefits and costs of each initiative. These results were then used to calculate a BCR_i and prioritize initiatives. The methodology was implemented in Microsoft Excel and customized to include two additional alternative prioritization approaches: 1) Prioritization by application benefit and 2) prioritization by application cost. For an individual utility, the methodology can determine prioritization based on the utility's needs and plans.

5.2 Prioritization Based on Benefit-Cost Ratio

5.2.1 Benefit and Cost Categories

Eight categories were selected to evaluate relative benefits. Each category is aligned with typical strategic areas of interest for electric utilities, where a higher number indicates a higher relative benefit:

1. Resilience and reliability: Relative potential to improve grid resilience and reliability.
2. Sustainability and decarbonization: Relative potential to help achieve sustainability and/or decarbonization objectives.
3. Real-time operation: Relative potential to help improve real-time system operation, awareness, visualization, and control.
4. Advanced planning: Relative potential to enable advanced system planning.
5. Public safety: Relative potential to improve public safety.
6. Efficiency improvement: Relative potential to improve overall system efficiency.
7. Innovation potential: Relative potential to enable adoption of leading industry practices, position utility as an innovator, and/or produce intellectual property.

8. Customer engagement and business potential: Relative potential to help become and/or remain a trusted advisor and create new services and products.

Five categories were selected to evaluate relative costs. “Cost” is used in a broad sense and includes aspects that can impact implementation beyond required investment and operations cost (capital expenditures [CapEx] and operational expenditures [OpEx]), which are generally the main (and sometimes only) elements considered in this type of evaluation. The approach proposed by the project team accounts for other factors that may affect initiative implementation and cost. Using relative scores facilitates modeling intangible and subjective cost elements, as described next:

- Complexity: Relative complexity of implementing an initiative.
- Investment: Relative investment level required for implementing and initiative. This index is intended to assess how costly implementing an initiative might be compared to the roadmap's remaining initiatives.
- Risk: Relative risks and impacts of unsuccessful initiative implementation.
- Maturity: Relative maturity of the concept and technology required for implementing an initiative.
- Readiness: The utility’s familiarity with required concepts and technologies and its organizational readiness to implement and integrate the application in existing processes and activities.

Please note that higher scores for complexity, investment, and risk indicate higher costs, while higher scores for maturity and readiness indicate that the applications are closer to adoption and indicate lower costs.

The investment category is intended to rate the combination of CapEx and OpEx for the specific AG and is a relative measurement between the AGs. CapEx includes 1) the installation and hardware required for measurements and the supporting communications network, 2) the cost of developing and installing the applications, 3) the cost of equipment required to host or support the application, and 4) other upfront costs needed to implement an application or AGs. OpEx is the cost of maintaining this application or AG in service, including 1) monitoring the system and communications networks, 2) the cost of communications bandwidth based on bandwidth requirements, 3) the cost of application and software licenses and maintenance agreements, and 4) the cost of testing and maintenance. The number and types of measurement points will therefore influence the rating of this category, as will the cost to develop and install the application.

The previously described process is based on the high-level system architecture and requirements identified for each AG. The architecture and requirements are described in section 6.

Each benefit-and-cost category was assigned a weight to model its relative importance, as shown in Table 5-1 and Table 5-2. This assignment was based on the project team’s technical opinion and industry experience. However, weights are customizable and can be updated/adjusted to reflect new information if needed.

Table 5-1. Benefit Categories

Benefit Category	Weight
Resilience and reliability	9
Sustainability and decarbonization	7
Real-time operation	8
Advanced planning	6
Public safety	10
Efficiency improvement	5
Innovation potential	2
Customer engagement and business potential	3

Table 5-2. Cost Categories

Cost Category	Weight
Complexity	3
Investment (CapEx and OpEx)[69]	10
Risk	4
Maturity	2
Readiness	1

[69] This category models the total investment needed for asset/infrastructure deployment (CapEx) and operation (OpEx) through its lifecycle. This is generally considered by utilities as the most important factor in estimating overall costs. For this reason, it is assigned the greatest weight in the model. However, this weight can be customized as needed.

5.2.2 Calculation of Benefit-Cost Ratio

The relative summary benefits of each AG were calculated by:

1. Assigning numerical scores (0 to 10) to each benefit category for each specific AG (there are 19 AGs)
2. Calculating a weighted average of the scores of each AG for all benefit categories (Eq.1):

$$SB_i = \frac{\sum_{j=1}^{n} B_{ij} \cdot wb_j}{\sum_{j=1}^{n} wb_j} \quad \text{(Eq.1)}$$

where,

SB_i is the relative summary benefit of AG i (there are 19 AGs)
B_{ij} is the relative benefit of AG i for benefit category j (there are eight benefit categories[70])
wb_j is the relative weight of benefit category j

The relative summary costs of each AG were calculated by:

1. Assigning numerical scores (0 to 10) to each cost category for each specific AG (there are 19 AGs)
2. Calculating a weighted average of the scores of each AG for all cost categories (Eq.2):

$$SC_i = \frac{\sum_{k=1}^{m} C_{ik} \cdot wc_k}{\sum_{k=1}^{m} wc_k} \quad \text{(Eq.2)}$$

where,

SC_i is the summary cost of AG i (there are 19 AGs)
C_{ik} is the relative summary cost of AG i for category k (there are five cost categories[71])[72]
wc_k is the relative weight of cost category k

A BCR_i was then calculated for each AG using the respective summary benefits and costs (Eq.3). The overall process is shown in Figure 5-1. AGs were prioritized from high to low BCR_i. An AG with a high BCR_i is one that, relatively speaking, provides benefits that are significantly greater than its respective costs. AGs with greater BCR_is were given higher priority for implementation.

$$BCR_i = \frac{SB_i}{SC_i} \quad \text{(Eq.3)}$$

[70] The formulation is presented for n benefit categories, n = 8 was used in this project, but the methodology allows to use additional categories

[71] The formulation is presented for m cost categories, m = 5 was used in this project, but the methodology allows to use additional categories

[72] For the maturity and readiness categories, the cost used is (10 – the rating), so a higher number in the rating is a lower cost to implement.

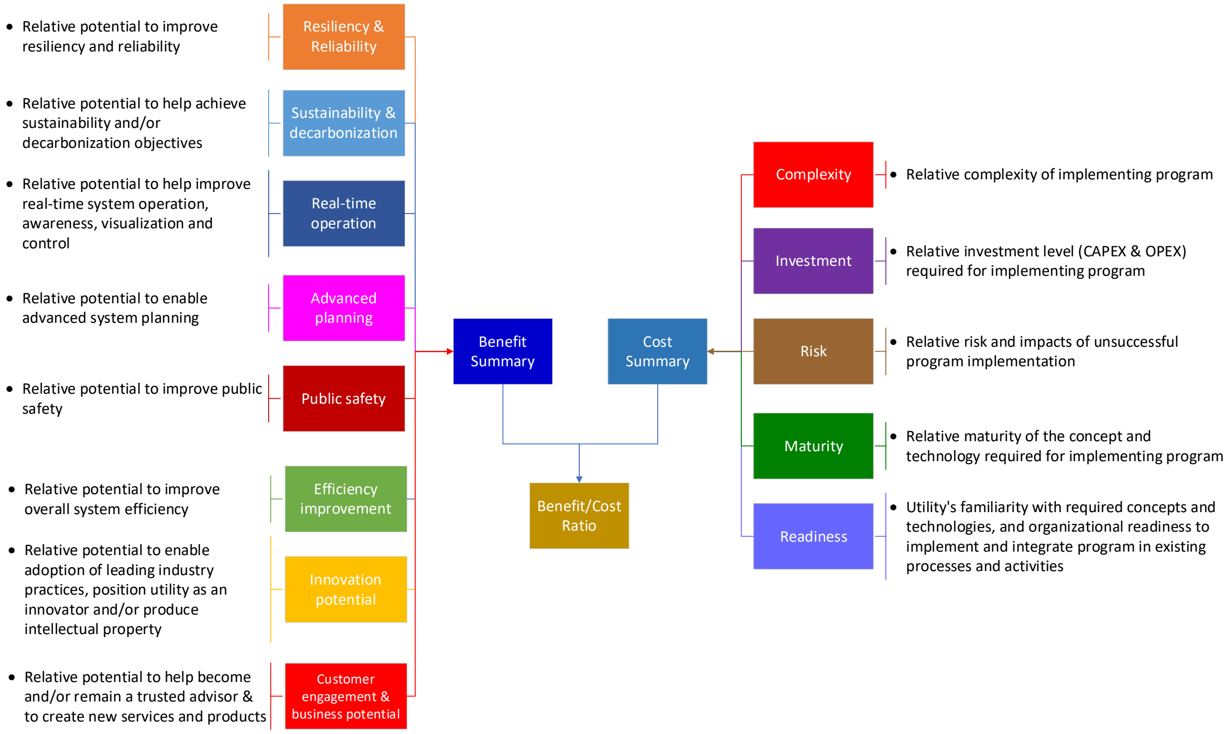

Figure 5-1. Overview of the BCR$_i$ Process

5.3 Prioritization Results

This section presents the results of the prioritization approach. Table 5-3 shows each benefit category's inputs and summary benefit results for the 19 proposed AGs. Category values range from 0 to 10, and the greater the value, the higher the relative benefit of an AG in a specific category. Table 5-4 shows each cost category's inputs and summary cost results for the 19 proposed AGs. Category values range from 0 to 10.

Table 5-3. Results from Benefits Analysis (Relative Benefits by Initiative)

Application Number	Application Description	Relative Benefit								Benefit Summary	Benefit Summary Numerical
		Resilience & Reliability	Sustainability & Decarbonization	Real-Time Operation	Advanced Planning & Asset Mgmt.	Public Safety	Efficiency Improvement	Innovation Potential	Customer Engagement & Bus. Potential		
AG1	AVVC	4	5	5	5	3	6	4	6	MEDIUM	4.54
AG2	Advanced monitoring of distribution grid	7	6	8	6	6	8	6	5	HIGH	6.64
AG3	Asset management of critical infrastructure	7	4	5	7	6	7	7	5	MEDIUM	5.94
AG4	Wide-area visualization	8	6	9	6	7	5	6	7	HIGH	7.00
AG5	DER integration and control	7	9	7	7	4	6	8	7	HIGH	6.62
AG6	Real-time distribution system operation	8	5	9	4	7	7	6	5	HIGH	6.70
AG7	Enhanced reliability and resilience analysis	6	4	3	6	4	4	6	5	MEDIUM	4.58
AG8	Advanced distribution system planning	6	5	2	7	2	6	6	4	MEDIUM	4.42
AG9	Distribution load, DER and EV forecasting	6	7	5	7	2	6	5	6	MEDIUM	5.26
AG10	Improved stability management	7	4	9	3	4	4	7	3	MEDIUM	5.28
AG11	High-accuracy fault detection and location	8	4	8	6	9	8	7	7	HIGH	7.30
AG12	Advanced distribution protection and control	8	7	8	2	9	4	7	5	HIGH	6.72
AG13	Advanced microgrid applications and operation	8	8	7	4	5	4	7	7	HIGH	6.26
AG14	Improved load shedding schemes	7	4	7	4	4	6	6	6	MEDIUM	5.42
AG15	Advanced distribution automation	7	4	6	3	6	6	6	4	MEDIUM	5.42
AG16	Technical and commercial loss reduction	2	5	4	5	3	7	5	6	MEDIUM	4.16
AG17	Monitoring and control of electric transportation infrastructure	5	7	5	7	3	5	7	6	MEDIUM	5.26
AG18	Integrated resource, T&D system planning and analysis	6	6	4	7	3	7	6	4	MEDIUM	5.18
AG19	PQ measurement	6	5	5	6	2	5	6	7	MEDIUM	4.86

Table 5-4. Results from Cost Analysis (Relative Costs by Initiative)

Application Number	Application Description	Relative Cost					Cost Summary	Cost Summary Numerical
		Complexity	Investment (CapEx & OpEx)	Maturity	Risk	Readiness		
AG1	AVVC	4	6	7	3	7	MEDIUM	4.65
AG2	Advanced monitoring of distribution grid	4	7	6	3	7	MEDIUM	5.35
AG3	Asset management of critical infrastructure	8	8	6	4	5	HIGH	6.65
AG4	Wide-area visualization	6	7	6	3	6	MEDIUM	5.70
AG5	DER integration and control	7	7	6	5	5	HIGH	6.10
AG6	Real-time distribution system operation	7	7	6	5	7	HIGH	6.00
AG7	Enhanced reliability and resilience analysis	5	5	5	5	6	MEDIUM	4.95
AG8	Advanced distribution system planning	4	4	5	5	5	LOW	4.35
AG9	Distribution load, DER and EV forecasting	7	7	4	5	4	HIGH	6.55
AG10	Improved stability management	5	5	5	5	5	MEDIUM	5.00
AG11	High-accuracy fault detection and location	4	7	6	4	5	MEDIUM	5.55
AG12	Advanced distribution protection and control	7	7	5	5	5	HIGH	6.30
AG13	Advanced microgrid applications and operation	5	5	7	5	5	LOW	4.60
AG14	Improved load shedding schemes	5	5	7	3	5	LOW	4.40
AG15	Advanced distribution automation	6	7	6	6	6	HIGH	6.00
AG16	Technical and commercial loss reduction	5	4	6	3	6	LOW	4.05
AG17	Monitoring and control of electric transportation infrastructure	6	6	3	4	3	HIGH	6.05
AG18	Integrated resource, T&D system planning and analysis	8	8	3	4	2	HIGH	7.40
AG19	PQ measurement	5	6	7	2	5	MEDIUM	4.80

Table 5-5 and Figure 5-2 show the prioritization method's results based on the BCR_i. The prioritization provides a reference for developing the implementation roadmap. Those projects with the highest BCR_i should have higher priority for implementation. Therefore, they should be implemented first, in the early stages of the roadmap, as long as they are not dependent upon other initiatives' implementation. Prioritization results were used with potential interdependencies among AGs to develop a proposed timeframe for implementation and overall roadmap.

Figure 5-3 provides an alternative way to analyze the prioritization results. The scatter plot shows benefits vs. costs per initiative. It is worth noting that there are initiatives that are deemed beneficial but are also costly (i.e., they require significant investments, are complex, etc.) or that may not provide significant direct benefits but are critical to the successful implementation of other high-priority initiatives. Therefore, these types of initiatives may be deemed strategic for an implementation roadmap, therefore, could be assigned a higher priority than that estimated by the methodology.

As the application cost-benefit ratio is calculated and shown for all applications on a single plot based on infrastructure requirements, it is beneficial for developing short-, mid-, and long-term roadmaps for both applications and infrastructure.

Table 5-5. Results from Prioritization (BCRi) and Implementation Roadmap. High 1.2+, Med. 0.8-1.19, Low .5-.79

Application Number	Application Description	BCR_i	BCR_i Numerical	Priority Number
AG13	Advanced microgrid applications and operation	HIGH	1.36	1
AG11	High-accuracy fault detection and location	HIGH	1.32	2
AG2	Advanced monitoring of distribution grid	HIGH	1.24	3
AG14	Improved load shedding schemes	HIGH	1.23	4
AG4	Wide area visualization	HIGH	1.23	5
AG6	Real-time distribution system operation	MEDIUM	1.12	6
AG5	DER integration and control	MEDIUM	1.09	7
AG12	Advanced distribution protection and control	MEDIUM	1.07	8
AG10	Improved stability management	MEDIUM	1.06	9
AG16	Technical and commercial loss reduction	MEDIUM	1.03	10
AG8	Advanced distribution system planning	MEDIUM	1.02	11
AG19	Power quality measurement	MEDIUM	1.01	12
AG1	Advanced volt-var control	MEDIUM	0.98	13
AG7	Enhanced reliability and resilience analysis	MEDIUM	0.93	14
AG15	Advanced distribution automation	MEDIUM	0.90	15
AG3	Asset management of critical infrastructure	MEDIUM	0.89	16
AG17	Monitoring and control of electric transportation infrastructure	MEDIUM	0.87	17
AG9	Distribution load, DER and EV forecasting	MEDIUM	0.80	18
AG18	Integrated resource, transmission and distribution system planning and analysis	LOW	0.70	19

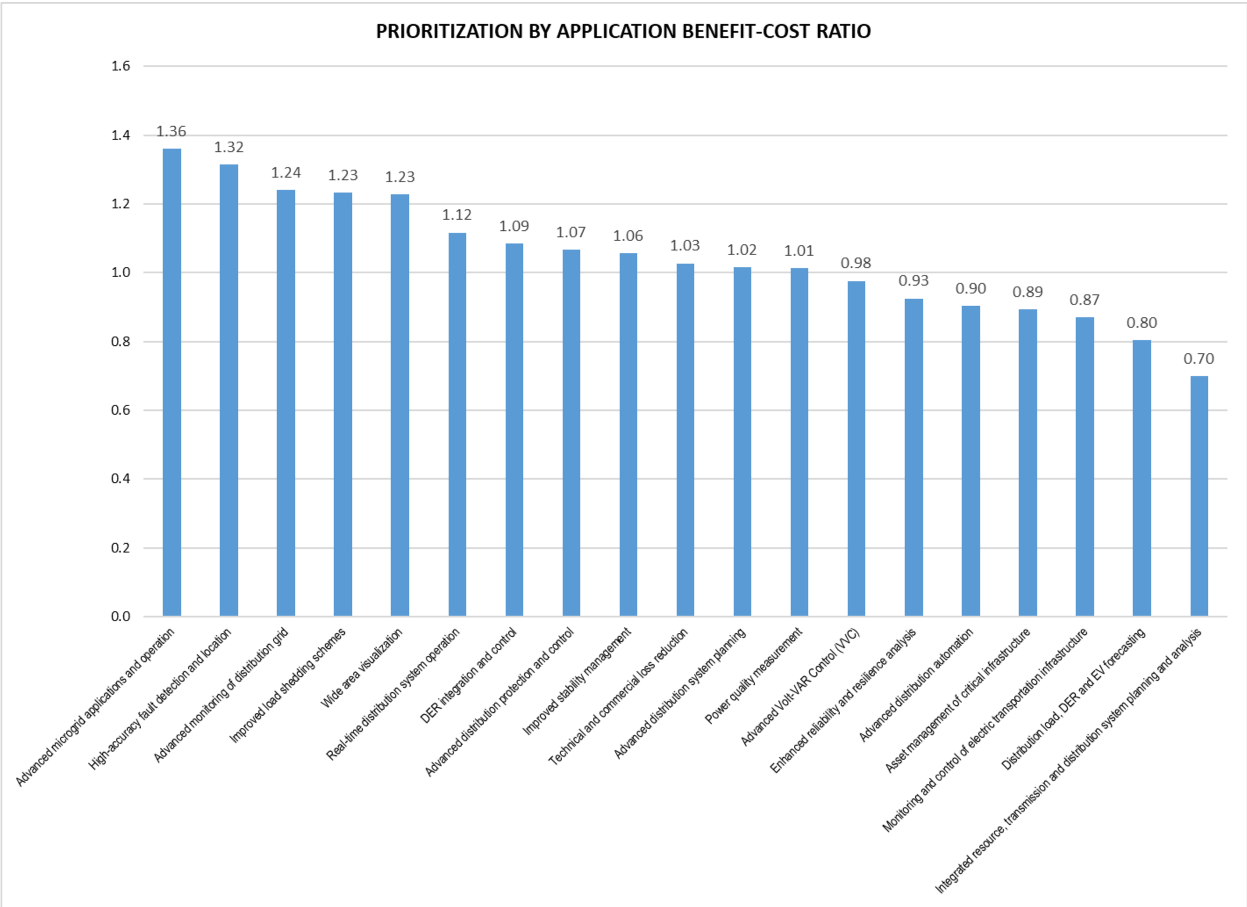

Figure 5-2. Results from Prioritization (Prioritized List of Initiatives Based on BCR_i)

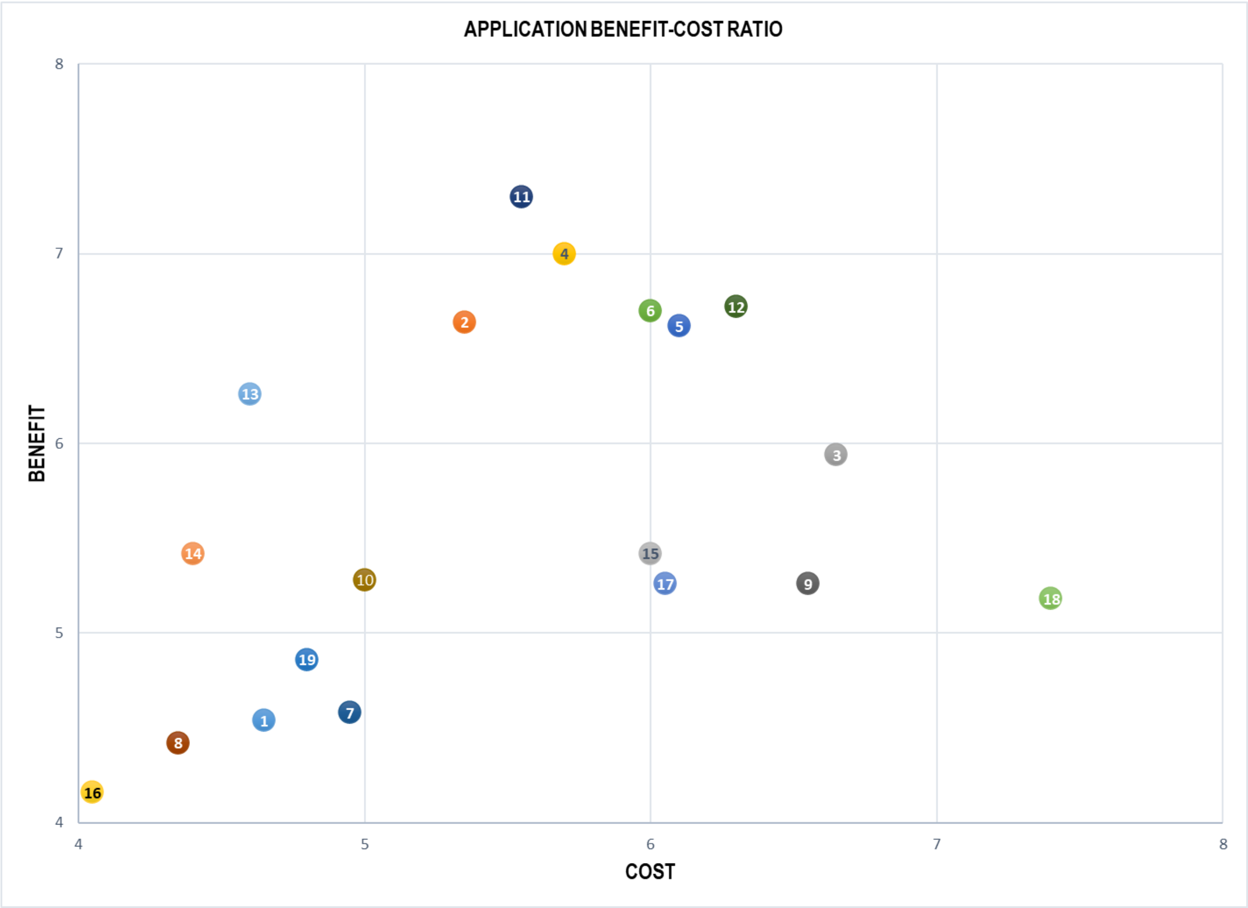

Figure 5-3. Results from Prioritization (BCR_i)

6 SYSTEM ARCHITECTURE TO PROVIDE THE REQUIRED DATA AVAILABILITY TO SUPPORT SYNCHRONIZED MEASUREMENT APPLICATIONS

6.1 Purpose of Architectural Evaluation

The variety of use cases described in section 2 and analyzed for development eligibility in section 5 are not individual and isolated applications to deploy in separate systems. A key principle is that the industry should develop one core platform—one array of SMDs, communications, processing, user data access, and storage—to deploy, manage, and maintain across the distribution system. This core platform can support the attachment of substations, control centers, or centralized processing devices to support groups of use cases.

Each use case (and each grouping of use cases) has specific requirements for 1) how long it can wait for synchronized measurements after the real-time occurrence of the measurements, 2) what rate of measurement updating it needs, 3) what reliability of delivery is acceptable, 4) what sort of return control path is needed, 5) what processing burden must be supported, and 6) what overall access to broader ranges of data is needed. Thus, the roadmap for SMD use case development inherently defines a roadmap for the architecture and technical performance requirements for the single system platform we deploy to support the selected use cases as they are developed.

This section explains the overall architectural concepts of a wide-area distribution synchronized measurement system. It lists example technical performance requirements as a function of which use cases are to be deployed. This presentation will support the definition of requirements, design, and deployment roadmap for the actual synchronized measurement system that will be able to support selected use cases. That platform definition is to be completed after the use case roadmap is finalized.

6.2 Introduction to Synchronized Measurement System Architecture

The high-level system architecture to support synchronized measurements is shown in Figure 6-1. This architecture aims to reliably move these measurements from the source devices to operations and control applications where they will be processed and analyzed. Additionally, this architecture must allow control commands to pass back to the system's devices from these central applications.

The applications using the data determine specific performance requirements, such as data availability, measurement accuracy, and archiving. The communications protocols used to share data and controls for specific applications set requirements on the communications networks. This overall system architecture impacts utility business processes, including design engineering, system support, maintenance, and troubleshooting.

A key enabler of the system architecture is the communications network needed to move synchronized measurements from measuring devices to the applications that acquire, store, and process these measurements. These synchronized measurements typically have a much higher report rate than SCADA measurements. While the report rate is higher, the frequency of the reports is usually constant. Many synchronized measurement systems report time-synchronized measurements 30 times per second. This frequency means, on average, a device transmits a new report every 33.3 ms. This report, or data rate, is relatively new in the energy utility domain. Historically SCADA data rates could be as high as one report per second. However, in most cases, the rate was one measurement every 10 s. Utilities would employ dead-band techniques, only reporting changing data, to reduce this rate further. In some extreme cases, a measurement value may only be reported once per day. Another significant difference between SCADA and synchronized measurements is SCADA measurements are polled while synchronized measurements are published.

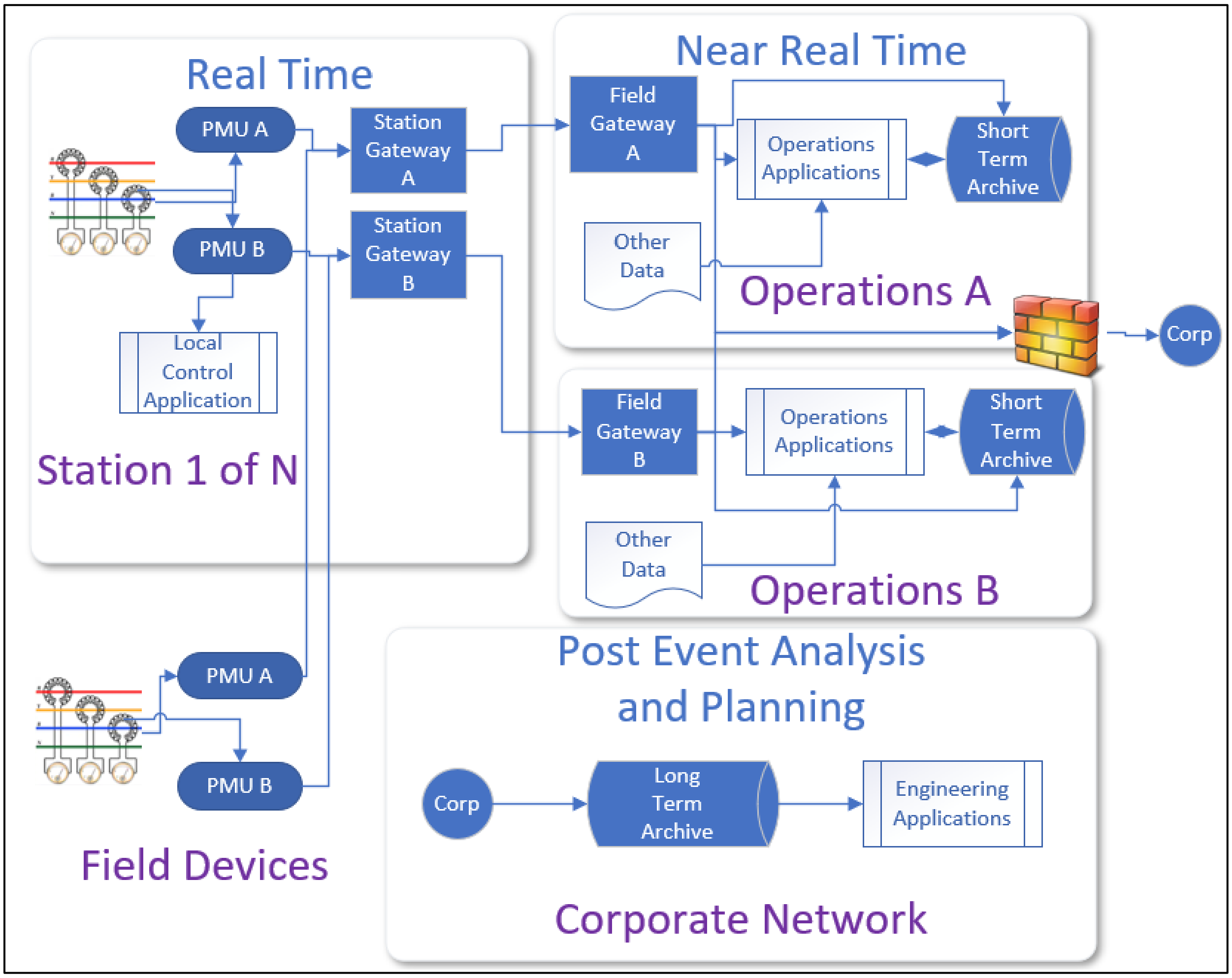

Figure 6-1. High-Level System Architecture

These factors create additional stress on communication and data delivery systems in place at most utilities. However, one benefit to the constant report rate is that communication or other data delivery issues can be immediately detected, and strategically located testing applications can determine some initial steps toward a root cause.

Availability and accuracy are the primary requirements for synchronized measurements to provide value to applications built to perform specific functions using this data. The needs of the specific application will determine the levels of availability and accuracy required.

6.3 Availability

Availability is the ratio of measurements expected by an application at a given report rate vs. the measurements that arrive at the application. For example, an application expecting 60 reports, or data frames, per second would expect 3600 data frames in a minute. Any fewer would bring availability down to less than 100%. Some applications that use synchronized measurements can function with less than 100% availability.

6.3.1 Latency

Latency is part of availability but specifically affects applications that must perform in near real-time. For example, latency is not an issue for archiving synchronized measurement data for use in post-event root cause analysis but is critical for an application like FCP. Most of the latency time is from the communication systems. Latency is directly related to availability. If latency increases beyond a preset threshold, the receiving application or appliance will treat the data frame as if it never arrived.

6.3.2 Redundancy

Redundancy is not specifically required for many synchronized measurement applications. However, redundant architectures can address several issues that directly affect availability. Any redundancy along the data communications path will improve availability in the presence of hardware, firmware, or software failures. Redundancy also permits the shutdown of one redundant path for regular maintenance, patching, and updates while maintaining full system functionality. The maximum improvement in availability will be realized when redundancy is end-to-end, starting from the instrument transformers at the measurement point to the end applications that use the data.

6.4 Accuracy

Accuracy is determined by the actual measurement device and the measurement chain from instrument transformers to the device. The communication architecture does not affect measurement accuracy. Once the device has made a measurement and packaged the data for transmission, the data will arrive at its destination unchanged. If the data change, the communication protocol will flag the data as being changed. However, the communications network's availability and latency can impact the end application's accuracy, depending on how the application accounts for delayed or missing data.

For synchronized measurements, there is a second requirement for accuracy. The measurement device must have an accurate clock to maintain the synchronization of measurements. The accuracy requirement for this clock is dependent on what values are being measured. For example, to measure the phase angles of voltage and current, the clock must be accurate within 25 µs. Accurate device clocks are typically supported by connection to global navigation satellite system (GNSS) clocks that can maintain the clock with accurate signals updated once per second. Maintaining these clocks' accuracy is an important topic, but the overall system architecture assumes accurate, reliable time synchronization is available.

The system architecture should provide some capability to verify the accuracy of the data. Secondary checks for voltage and current magnitudes can be made by comparing the time-synchronized device measurements with traditional SCADA devices. Phase angles can be compared with the results of state estimators. These angular comparisons are only effective when large differences are detected, e.g., a 120-degree difference for a synchronized measurement angle measurement compared to a state estimator indicates incorrect phasing at the measurement device. Some methods of streaming synchronized measurements, such as defined in C37.118-2, provide quality information to indicate to end applications how accurately these measurements are synchronized to a GNSS time standard.

6.5 Archiving

The other key performance requirement for the system architecture is the ability to archive data. There are multiple use cases for historical or post-event analysis, such as fault location, model validation, phase angle monitoring, and oscillation detection. This data's high report rate requires archive systems designed with capabilities selected for the large amounts of data with very high-speed data writing.

The general requirement for archiving depends on the intended use of the data. A short-term archive may be all that is required for applications like advanced distribution protection and control, improved load shedding schemes, or fault location. To use post-fault event analysis as an example, NERC PRC-002-2 disturbance monitoring and reporting requirements require a minimum of 10 days of data storage for synchronized measurements, while many NERC regional coordinating councils require 30 days of storage of synchronized measurements. Therefore, a short-term archive should be expected to store 30 days of synchronized measurement data. For other applications, such as distribution system planning, asset management of critical infrastructure, or distribution load forecasting, years of archived data may be necessary. This longer-term archive will require a robust data historian.

6.5.1 Archive Strategies

Archiving requirements also impact the system architecture, as the size of the archive and the use of the archived data impact operational requirements. Archives used for system-wide data and long-term system performance analysis, requiring years of data storage, should be centrally located on the enterprise network and managed by the enterprise IT team. Smaller archives, such as those for fault analysis that typically require storing only 30 days of data, may be centrally or regionally located.

Archiving requirements also influence the selection of and investment in the archiving tools. A system-wide archive will set certain demands on the historian selected and may result in significant licensing costs. A way to mitigate this cost is taking advantage of or expanding the enterprise license for a historian already in use for other purposes.

Another possibility is to take advantage of open-source historians. Open source provides the ability to distribute multiple instances for little upfront cost. It may be desirable to use different historians for enterprise-wide storage and local control applications based on application requirements.

A short, but not comprehensive, list of historians used in synchronized measurement applications is:

- OSISoft PI Archive

- AVEVA eDNA
- Grid Protection Alliance openHistorian custom B+ Tree
- PingThings Berkeley Tree Database
- GE Phasor Analytics
- SEL proprietary databases
- EPG proprietary
- MS SQL and variants
- Oracle (Time series)
- Small applications like Hadoop, Apache Spark, Apache Storm (stream processing), Ceph, Disco, Google Big Query, etc.

6.6 Using Synchronized Measurements for Real-Time Control

An additional architectural requirement in using synchronized measurements for near real-time system control is to provide an additional high-availability and low-latency communication path for commands. For example, falling conductor detection requires tripping and full de-energization well before the conductor approaches objects beneath it (less than 1 s after the line breaks). Both the data delivery for situational processing and the returning signal to de-energize must have very low communications latencies to achieve this speed.

6.7 Communication Protocols

The communication protocol can affect the availability and latency of synchronized measurements. Protocols that use large monolithic data aggregations put additional strain on network communications which can result in lower availability. Understanding some of the performance aspects and limitations of these protocols is necessary for developing the system architecture. All protocols are packet-based and can use existing enterprise communication networks such as synchronous optical networks (SONET) and multiprotocol label switching (MPLS).

The three possible protocols to stream synchronized measurements are 1) IEEE C37.118.2-2011, 2) IEC 61850-8-1 Routable Sampled Values (R-SV), and 3) IEEE 2664 Streaming Telemetry Transport Protocol (STTP). Each is discussed in sections 6.7.1, 6.7.2, and 6.7.3.

6.7.1 IEEE C37.118.2-2011

IEEE C37.118 is the most widely used protocol to stream synchronized measurements, as it has been in use the longest. All synchronized measurement products support the original (2005) version of C37.118, and vendors are adding support for the latest (2011) version. The protocol is simple and efficient in sending synchronized measurement and frequency data, and it uses the least amount of bandwidth possible without compression. Data frames optionally include support for equipment and signal names up to 256 characters. C37.118 supports transfer control protocol/internet protocol (IP) and user datagram protocol (UDP)/IP transport methods, with both methods in common use.

C37.118 has a few drawbacks. Concentrated data frames from PDCs can get large, therefore consuming bandwidth. The C37.118 standard has limitations on the maximum number of synchronized measurement data streams that can be aggregated into one data frame, which could limit applicability to some distribution applications.[73] More importantly, C37.118 has no inherent cybersecurity protocols, which will become a limitation as synchronized measurements are used for system operating and control functions.

6.7.2 IEC 61850-8-1 Routable Sample Values

IEC 61850-8-1 defines methods to map synchronized measurement data into the IEC 61850 Standard object modeling. Synchronized measurements are mapped into R-SV and routable generic object-oriented substation events (R-GOOSE) messages sent through IP networks using multicast messaging. Using IEC 61850 to publish synchronized measurements addresses cybersecurity through encryption and authentication methods defined in the IEC 62351 Standards. Under IEC 61850, routable sample values and R-GOOSE messages are rebroadcast to ensure reliable transmission.

Using routable sample values results in larger data frames than C37.118, but good architecture practices can mitigate the impact. To date, the bigger application drawbacks are limited vendor support and the computational burden of packet authentication in communications interfaces.

6.7.3 IEEE 2664 Streaming Telemetry Transport Protocol

IEEE 2664 STTP is a new standard under development. It attempts to address issues that other protocols have with bandwidth, scalability, and security. STTP uses publish/subscribe communications, where publishers control accessibility for individual subscribers. Security is based on Transport Layer Security authentication and encryption protocol. The development of STTP was funded, in part, by the U.S. DOE to transfer data, including time-series synchronized measurement data and data for status and control actions.

Vendor support is a limitation to STTP, as the IEEE 2664 is still under development. Only SEL, Grid Protection Alliance, and EPG offer support for STTP.

6.7.4 Communications Protocols for Control Actions

Control commands will be sent over the same communications network as that used for synchronized measurements. These commands can use any of the typical SCADA protocols or methods. These can be field bus protocols such as Modbus, traditional SCADA protocols such as DNP3, newer methods such as IEC 61850 GOOSE messaging or IEC 61850-90-5 R-GOOSE messages, or distribution specific protocols such as openFMB. During protocol selection and system design, it is important to recognize that some protocols use IP addressing and are routable while others are not. For example, generic object-oriented substation events messaging has many advantages but will require a private communications network because it cannot be routed.

[73] Y. Hu., V. Gharpure, "Overcoming standard limitations in synchrophasor systems," 2014 IEEE PES T&D Conference and Exposition, April 2014, Chicago, IL

6.8 Details

6.8.1 Application Requirements

The system architecture for synchronized measurements will be determined, in part, by the applications' needs using these system measurements. Applications will have different data availability requirements, maximum latencies of receiving the data, and minimum reporting rates. Based on the possible applications described in this report, typical values are shown in Table 6-1.

Table 6-1. Typical Values for Minimum Availability, Maximum Latency, and Minimum Report Rate

Proposed Group Number	Application Group	Minimum Availability %	Max. Latency (ms)	Min. Report Rate (Hz)
AG1	AVVC	80	2000	1
AG2	Advanced monitoring of distribution grid	95	1000	30
AG3	Asset management of critical infrastructure	80	5000	1
AG4	Wide-area monitoring and visualization	95	1000	30
AG5	DER integration	80	2000	1
AG6	Real-time distribution system operation	95	2000	1
AG7	Enhanced reliability and resilience analysis	80	5000	1
AG8	Advanced distribution system planning	95	5000	30
AG9	Distribution load, DER, and EV forecasting	80	5000	1
AG10	Improved stability management	99	150	30
AG11	High-accuracy fault detection and location	99.9	300	60
AG12	Advanced distribution protection and control	99.9	150	30
AG13	Advanced microgrid applications and operation	99	500	30
AG14	Improved load shedding schemes	80	5000	1
AG15	Advanced distribution automation	99	300	30
AG16	Technical and commercial loss reduction	70	5000	1
AG17	Monitoring and control of electric transportation infrastructure	80	5000	1
AG18	Integrated resource, transmission, and distribution system planning and analysis	80	5000	1
AG19	PQ assessment and analysis	99.9	5000	120

6.8.2 Business Processes

Adopting synchronized measurements as part of distribution system operations will impact many business areas. However, acquiring these measurements and the supporting architecture is essentially an extension of existing SCADA systems. Therefore, this new architecture should be built on top of existing business processes used around SCADA.

SCADA already collects synchronized data by polling devices for low-resolution data. Synchronized measurements are essentially the same data continuously provided, but explicitly synchronized at a higher sampling rate and can provide accurate phase angle measurements. Also, synchronized measurements will be provided by more devices and devices located on the distribution feeders. Synchronized measurements should be retrieved in coordination with existing SCADA data, as many of the advanced control applications use high-resolution synchronized measurement and traditional SCADA data.

Integrating the new synchronized measurements into a utility's SCADA processes can tap into existing internal support teams for existing EMS and DMS applications. These support teams should be engaged to help design and deploy new applications and system architecture, understand these applications' uses and intent, and assist with personnel training.

The architecture to support and synchronize measurements in operating the distribution system cuts across many utility groups. As a result, it is important to identify the groups responsible for different system parts and activities. These groups may include corporate IT, system operators, SCADA, system protection, substation technicians, and field operators. The people in these groups will need training in system use and maintenance, and this training will need to be developed specifically for their needs. For instance, engineers will need to know how to design and specify the system and system components. Operators will need to know how synchronized measurements impact situational awareness and control actions across the distribution system. Field personnel will need to know how to install, maintain, and troubleshoot the system's various components.

6.9 Maintenance

It is important to maintain the infrastructure after deploying the system architecture to support the synchronized measurement applications. This will require implementing business processes, establishing service level agreements (SLAs) with various business units, and creating dashboards and job aids to help with root cause analysis of events where availability or accuracy of data was not maintained.

6.9.1 Business Processes and Service Level Agreements

Business processes and developing SLAs will include determining the different business units' responsibilities in the utility and basing the SLAs on the specific application requirements. These processes will determine the deployment sequence of various resources to correct problems identified either by the applications' users or automated tracking applications. There may be several individual business units involved in different applications.

6.9.2 Dashboards and Job Aids

The time-synchronized, high-frequency fixed report rate of time-synchronized data measurement delivery lends itself well to a dashboard display that can notify responsible parties in near real-time when problems occur. Events such as limited availability, communications channel loss, device failures, and data transit times can be alarmed and annunciated.

6.9.2.1 Dashboards

A typical dashboard display is shown in Figure 6-2. This display shows the availability of different synchronized measurement streams and alerts when the availability of a stream drops below alarm levels.

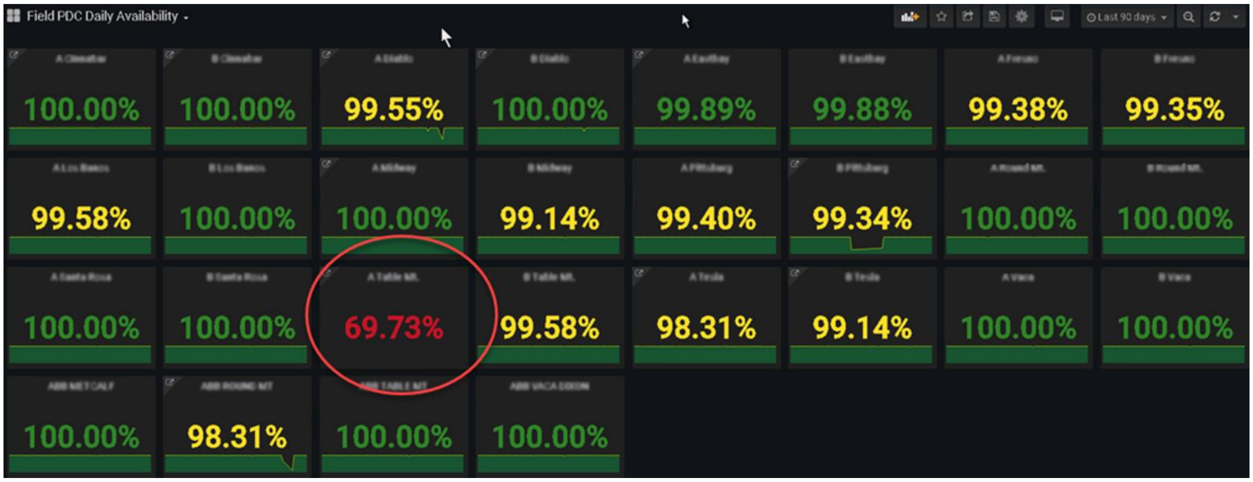

Figure 6-2. Typical Availability Dashboard

6.9.2.2 Job Aids

One example of a training need is understanding how the system architecture affects the availability of statistics. Problems in one part of the system may propagate into other areas while obscuring the root cause. The simple architecture of Figure 6-3 shows an example.

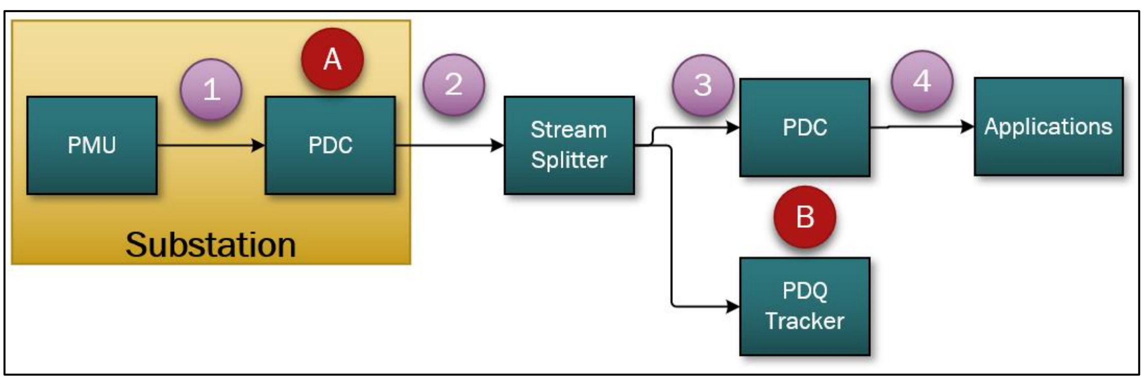

Figure 6-3. Simple System Architecture

Figure 6-2 raises alarms to system operators when the data availability drops below application limits. Engineers will need to analyze the root cause of this data loss. One tool counts how many synchronized measurement samples arrive each minute and looks for variations (Figure 6-4).

Figure 6-4. Data Sample Frequency Analysis

One possible case is that availability issues from measurement devices at location 1 appear as data errors from PDC A at location 2. This situation should be straightforward to diagnose.

Another case is that availability issues of the communications network at location 2 will appear as data errors in the data from PDC B at location 4. In this case, it will be necessary to diagnose where the availability issues occur in the communications if this is either before or after the router of location 3. However, in this case, the PDCs hide the data availability problems. Because of network availability at location 2, PDC B will consider the data from all PMUs connected to PDC A to have the same availability issues and data errors.

In this example, expanding the gaps in the data indicates no samples were received for several minutes. The lack of samples necessitates further analysis and probably indicates a router issue or a timed process overloading the network.

Another approach is to look for communications errors between a PMU and a PDC, as seen on the PDC's output. An example is a simple data error count (see Figure 6-5). In this example, there are 4407 data errors spread out over an entire day, typical of UDP communications.

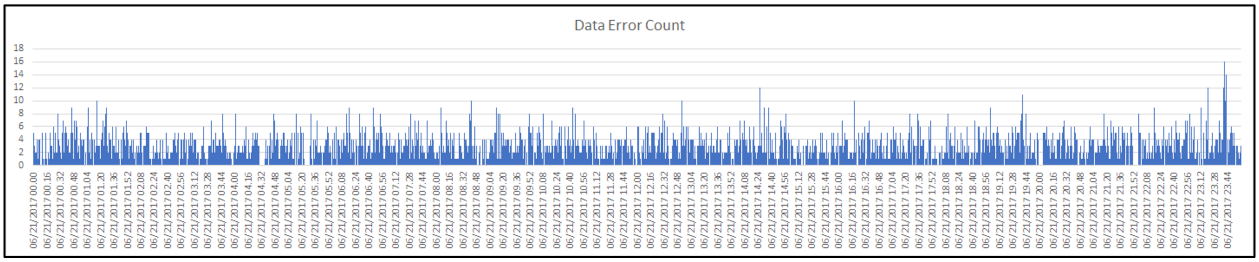

Figure 6-5. Data Error Count Example

6.9.3 Condition Monitoring and Alarming of PMUs, Communications Devices and Functions, and Processing

Sustainable widespread deployment of synchronized measurement infrastructure requires that each device monitor its functional integrity by active or repetitive "heartbeat" methods and report by alarm, with specific cause indications as available. It is not practical and may be disruptive for users to conduct periodic testing of devices or systems. Some use cases in section 2 specify monitoring functions for the synchronized measurement system and its components. This effort may include reaching into the operation of associated power apparatus and monitoring some aspects of its condition, which benefits distribution asset management overall.

6.10 Deployment Considerations

Actual requirements for deploying the infrastructure to support advanced synchronized measurement applications for distribution systems have been mentioned throughout section 6. The following items are suggestions for successful deployment.

Each area of the infrastructure may be deployed and maintained by different business units. Therefore, it is important to bring stakeholders from each unit into the process as early as possible.

6.10.1 SCADA Technicians

There are already employees at a utility familiar with deploying and maintaining measurement devices for collecting SCADA data (for example, relays and meters). These same people should be trained and be responsible for deploying and maintaining SMDs.

6.10.2 Network Support

Most utilities will have a network operations center (NOC). This group is responsible for maintaining communications between field devices and control centers. Typically, SMDs will have a higher report rate than non-synchronized devices. Network support techs will have to be made aware of increased bandwidth requirements. The fact that the data from synchronized devices are accurately time-stamped can make troubleshooting issues easier, but the increased data report rate is harder on network equipment. It is important to put SLAs in place with the NOC that meet the requirements of the specific applications deployed.

6.10.3 Distribution Applications Support

New applications brought into the control centers will have to be supported. Utilities already have business units to support existing applications. The employees supporting applications in the control room will have to be trained to support the new applications based on synchronized measurements.

6.10.4 Accurate Real-Time Clock Distribution

In some cases, there may be no business unit at a utility responsible for accurate time-of-day clock data distribution. Typically, corporate networks can "make do" with standard network time protocol. This standard is not accurate enough for synchronized measurements. Other more accurate methods, such as real-time clocks based on GPS signals, will be required. If no business unit exists for this requirement, one will have to be created and integrated into the company.

6.10.5 Dispatchers

As with any new applications, adding applications based on SMDs will require that control center dispatchers be trained on their use. Also, new business processes will need to be defined and documented. Finally, if the applications lead to control operations or automated control actions, policies will have to be implemented to support these actions.

7 CONCLUSIONS

With support from the U.S. DOE, Quanta Technology, ORNL, and SDG&E partnered to develop a framework and a high-level deployment roadmap for power distribution synchronized measurements. The result of this project is the industry application roadmap described in Chapter 3. The collective expertise of the project team was used to rate each AG based on the benefits of the applications and the cost to implement these applications. Benefits and costs used weighted scores based on multiple criteria. These weighted scores were then used to calculate a BCR_i to provide a relative application ranking. The scoring and ranking methodology for the applications is described in this report. This framework is intended to be customized for an individual utility to identify high potential synchronized measurement-based applications of value to their system based on needs, requirements, expertise, and capabilities.

7.1 Industry Application Roadmap

Figure 3-1's industry application roadmap is based on the BCR_i and other criteria, such as the value of synchronized measurements to the proposed application and the difficulty of implementing the application. The starting point of this industry roadmap is the ranking of Table 5-5, showing the AGs ranked from the highest to lowest BCR_i.

7.1.1 Short-Term Priority Applications

Based on this scoring, five AGs have a "high" BCR_i. These AGs become the short-term priority for implementation in the roadmap. They are:

- Advanced microgrid applications and operation
- High-accuracy fault detection and location
- Advanced monitoring of distribution grid
- Improved load shedding schemes
- Wide area visualization

Except for improved load shedding, these use cases have high benefits and only medium implementation costs. Improved load shedding has fairly high benefits but is rated as inexpensive to implement. The individual component benefits that drive these ratings tend to be of direct interest to utility operations. They include system resilience and reliability, real-time operations, public safety, customer engagement, and business potential. Other than investment cost, the most common individual component of the cost drivers is the maturity of the individual solutions.

7.1.2 Mid-Term Priority Applications

The AGs shown in the roadmap as a mid-term priority for implementation are applications that provide high benefits with a higher average cost to implement (compared to the other AGs), or they provide average benefits (compared to the other AGs) with a low cost to implement. The other three AGs rated with high benefits are advanced distribution protection and control, real-time distribution system operation, and DER integration and control. It is relatively intuitive that these are AGs where synchronized measurements will have a great benefit, as they directly address changing requirements for the distribution system. However, these are relatively more complex applications to deliver than the high-priority ones, requiring significant development and overall system and process maturity before implementation.

7.1.3 Long-Term Priority Applications

The applications with a long-term priority tend to be those with relatively average benefits and a high cost to implement. Applications such as monitoring and control of electric transportation infrastructure and distribution load, DER, and EV forecasting, for example, have some benefit for distribution system performance, but the complexity to implement solutions is high, and the maturity of possible solutions is very low, making these applications difficult and therefore costly to implement.

7.2 Practical Takeaways of the Industry Roadmap

The roadmap developed in this report is based on the project team and utilities expertise and knowledge. However, drivers, capabilities, benefits, and costs will vary for every utility. A utility with large DER penetration will see more benefits from some applications than others. Utilities that already manage tightly integrated communications and data infrastructure will have lower implementation costs than those which do not. Utilities will have their own understanding of their company's risks and of the readiness to adopt solutions. However, any utility can determine their BCR_i using this model and framework with the weighted scoring method described in Chapter 5.

A point to emphasize is that the costs used to rank these applications include the standalone investment necessary to provide that individual application. Therefore, these costs only cover application and algorithm development, along with actual implementation and rollout. System architecture and communications infrastructure costs are assumed to be relatively common between AGs, as all applications need to collect, process, store, and analyze large amounts of data from the distribution system. However, since many of the AGs use the same measurements, infrastructure, and communications, installing the first application will reduce the cost of the second application.

While developing software tools is required, analysis of the applications' requirements shows that most applications can be achieved with existing technology and hardware products. Although the distribution systems require monitoring of more points than transmission, existing hardware will allow utilities to develop individual utility roadmaps and deploy infrastructure and hardware for the short-term and in preparation for future applications. Enabling the functionality into the distribution automation, capacitor banks and other devices would be a good step in anticipation of deploying applications identified in this roadmap.

This document has used "synchronized measurements" to emphasize a need to move the industry beyond phasor measurements. Expanding some applications in this roadmap and developing new applications will require the industry—with U.S. DOE leadership—to invest in further research. It is necessary to protect the investment by building a flexible infrastructure that is relevant for the future. This is particularly important considering other industry trends, including smart cities, rural broadband, areas for high penetration and DER and microgrids, etc. However, the need for further research should not be an impediment to continue building an infrastructure and deploy applications identified in this roadmap.

Finally, IEEE and NASPI-DSTT are in the process of creating standards and guides for distribution synchronized measurement, which has been a critical factor for successful technology deployment. Information provided in this document, related to system architecture and application and infrastructure requirements, should provide help with these guides.

7.2.1 Vendor Roadmap

While it is expected that this roadmap and framework are most valuable to utilities, it also provides value for equipment vendors and solution providers. Understanding these applications and their needs should drive industry solution development. As the value of synchronized measurements and the need for large numbers of synchronized measurement points on the distribution system are demonstrated, manufacturers of equipment such as smart inverters, recloser controllers, line sensors, and other circuit devices will likely add synchronized measurement capabilities.

7.2.2 Pilot Programs

The results from this work are helpful for recommending pilots in the near-term based on the critical distribution synchronized measurement applications of the short-term roadmap. Pilots for the top five priority AGs are recommended.

The first pilot project proposed to the U.S. DOE by the team is to develop, test, and implement a novel and comprehensive fault detection and location methodology while leveraging the existing architecture and expanding it to support other applications. The outcome will be an overarching strategy to maximize the benefits of synchronized measurements for fault detection and location.

7.3 Infrastructure and Process

This report makes clear that numerous viable applications using synchronized measurements can be adopted on the distribution system. However, to adopt these applications requires a strategic investment in infrastructure, system architecture, and processes—essentially, a great deal of change management. These applications are based on acquiring large amounts of time-critical data that require significant bandwidth and are from numerous points on the distribution system. Significant thought/planning should be given to system architecture, including availability requirements, accuracy requirements, and data archiving needs. This architecture requires a communications infrastructure that is more robust and capable than what is likely to exist for the distribution system. The architecture also includes system databases and data repositories, where strategies can range from "data lakes" that collect all data or individual repositories for each specific application need.

It is important to emphasize that adopting these applications and the infrastructure to support them is more than a technology decision. Adoption requires a plan, organizational structure, and tools to implement, maintain, and enhance the applications and systems. This plan should define an organizational structure to support these applications and indicate the operating groups and roles responsible and accountable for application design, communications infrastructure, and data archiving and storage. It should also cover necessary maintenance, repair, support, and diagnostics, and cover the tools/processes for monitoring, alarming, and diagnosing systems and applications.

A very important element of the overall process is training. All stakeholders engaged in deploying the technology need to be trained to plan, operate, and maintain infrastructure and applications.

It is also recommended that each user should develop short-, mid-, and long-term infrastructure and process roadmaps in addition to the application roadmap.

APPENDIX A: INDUSTRY INTERVIEWS

Industry Survey for ORNL Project – SDG&E

Distribution System Synchronized Measurement Technology Deployment

Initial Survey Questions

January 13, 2021

Respondent(s):
Nick Moran and Chris Bolton, - Interviewed December 7, 2020
Tom Bialek – Interviewed November 30, 2020
Tariq Rahman, Dan Dietmeyer – interviewed December 1, 2020
Beverly Raposa, Dan Bedell, Cory Mitsui – Interviewed January 13, 2021
Christian Henderson and Fidel Castro – interviewed December 10, 2020

1) What are your overarching business, regulatory, policy, and technical drivers or needs and gaps?

   Need to distinguish between the short-term and long-term needs of this technology.

   Short-term needs:

   Prevent and mitigate wildfires (falling conductor), be more proactive than reactive. Need awareness and prioritization to carry out load curtailment in extreme weather or fire conditions and 'micro issues' – special local events. Measurement & control of overloaded circuits because of public safety power shutoff (PSPS) in the backcountry. Visibility was an issue last summer with the current SCADA system in place. Not having proper visibility is making control actions more difficult. Having large-scale contingency emergency plans in place for the above is a major concern. Having better data may facilitate the handling of emergency situations (see PSPS) and require less staff. Also, the need for incipient fault detection, how to detect before equipment catastrophically fails, have detailed granular information about circuits.

   Long-term needs:

   Investment in other parts of the system to get smarter about detecting what may fail and making sure the model of the system is accurate and up to date. Visibility to other components, the impact of the integration of solar, energy storage, system stability. Better ADS functionality for the new distribution SCADA system that can adjust and control thousands of devices. Need model and accurate analog values for fault location algorithms (including laterals) and FLISR. Fault Location currently done using data coming from SCADA. Ensuring that data is validated. Data mapping consistency is a need as well.

   The long-term need is the monitoring of residential PV, DER, small generators with accurate power flow – even the new SCADA is challenged. Better model reflecting actual system condition (phase identification, switch positions, etc.) and power flow accuracy concerns. There are lots of single-phase & phase-phase loads. Phasing is important and difficult yet not well understood. Getting proper visibility and phase identification would be ideal sooner rather than later. Need visibility of new customer generation output, as well as control. Who controls and how to control the dispatchable load? Also, how to build a system of control, especially for BESS, and to get real-time information to state estimator.

The importance of system stability, addressing how distribution may affect transmission and vice versa. Due to the integration of inverter-based resources in distribution systems replacing transmission resources, the distribution operational situation will have a huge impact on transmission operations. Increased visibility is necessary for both T&D systems.

Real-world examples provided by SDG&E:

- Outside parties are connecting 25 MW of generation at distribution substations that were not designed for these energy flows.
- DER is triggering Remedial Action Schemes (RAS) designed before DER was installed. [Side question – has DER undermined the very nature of the system problem the RAS was designed to mitigate? Is it still valid? What new RAS analytics are needed now?]
- We need to be able to manage the situation when a cloud passes over the system while many EVs are plugged in and charging.

a) Share thoughts of **needs and gaps** triggered by this list of impacted business areas. Which of the following are most important in your work situation?

i) Safety (employee and public)

Safety can be improved by the use of synchronized measurement data. Control algorithms could be written to assist in alerting system operators, engineers, and utility maintenance teams with event-based alerts or slow trending issues that are indicative of imminent equipment failure.

Synchronized measurements can be used for fault location aspect and faster identification of downed conductors or other fault conditions to reduce fire and safety threats.

ii) Risk management; fire risk

Accelerate the deployment of synchronized measurement systems to identify and isolate broken conductors as part of the Falling Conductor Protection program, as part of SDG&E's WMP plan. Also, use faster fault location and identification of downed conductors or other fault conditions to reduce fire/safety threats.

iii) Managing Distributed Energy Resources (DER) in transmission and distribution operations

Same comment as for distribution operations or power quality below.

iv) Load and DER forecasting

Same as the comment on power quality below.

v) Energy storage utilization

Same as the comment on power quality below, but synchronized measurement will be pretty useful for Energy Storage units dispatchable by the ISO or controlled by SD&E for localized microgrid operation such as Borrego Springs.

vi) Electrification (e.g., EVs and infrastructure; fossil fuel energy displacement in buildings) for decarbonization and climate change

Synchronized measurements could be useful for understanding load profiles at charging centers such as Tesla Superchargers, where there is significant load.

vii) T&D system planning

Model validation via synchronized measurement wide-area system snapshots.

viii) System modeling and analysis, both T and D

Same as the comment for T&D system planning below.

ix) Asset management, asset condition monitoring, maintenance

Can be improved by providing synchronized measurement data for voltage and current monitoring of high-value assets like capacitors, inductors, transformers, energy storage, and other such sites.

x) Reliability and resilience hardening

Providing synchronized measurement data across the system at transmission and distribution levels will provide the utility control centers the ability to have new primary sources of data for SCADA applications and relegate traditional SCADA systems to serve as a backup source.

xi) Power quality

Integrate synchronized measurements into areas of distribution circuits close to large inverter-based resources or other typically noisy industrial loads in order to assess the power quality at a basic level. This may require increasing the sampling frequency on PMUs from 30 samples per second (as is done with Falling Conductor Protection) to higher rates such as 60, 120, or 240 samples per second. Evaluate if these sampling rates would even serve PQ metering needs if the harmonic content is beyond the measurable range of PMU's.

xii) System protection, control, monitoring, and automation

Insight into pre-fault, fault, and post-fault oscillography to facilitate event analysis and safe restoration of customer load and fault location. Useful in the observation of resources including synchronous condensers, statcoms, generation, and reactive resources to see their contribution to the stable operation of the system or to identify irregular system oscillations (and specifically undamped modes of oscillation).

xiii) Grid analytics (presentation of operating and event data in forms useful for operators, engineers, planners, and other enterprise stakeholders)

Develop standard operating procedures for operations and the use of PMUs within the control center for the operation of the transmission and distribution systems to facilitate decision-making in outages and irregular system operations (unusual voltage and current profiles, etc.).

xiv) Others (think about what gaps you see that do not follow from any of the above)

Power quality, precursors for failure, 128/256/512 samples per cycle, time-synchronized; wire down, tree contact; better analytics that address many of the above topics. EVs, PVs – SDG&E is blind today. Working with CAISO on IBR response issues, such as how to dispatch IBRs, along with various energy and ancillary services to dispatch. Better modeling. Need a clear vision of how to get to the end result, e.g., how to use relay data in holistic solutions. Can't rely on individual boxes or point-based solutions, must integrate algorithms into the system instead. One system should handle a broad range of functions.

Transmission operations: Wide-Area Supervision Control Software integration into operations control rooms by virtue of Standard Operating Procedures based upon NERC compliance requirements to justify the directives given to the TOP and decided upon by the utility. To provide high-resolution data for oscillography preceding and post faults at every transmission and sub-transmission node across the system.

Distribution operations: Distributed PMUs across distribution circuits at major nodes where circuits branch out have noteworthy industrial, renewable, or energy storage loads where the oscillography, accuracy, and frequency of Synchronized measurement data would benefit supporting the operation and system planning of the distribution system.

b) How could those **drivers or needs and gaps** be addressed by sensing technologies, particularly synchronized measurements, as applied to the distribution system?

System operators cannot identify the problems on the distribution system, so more granular information is needed. PMUs and analytics will play an important role in having an accurate state estimator and enable real-time operation. Deployment of distribution PMUs will be useful to resolve issues in transmission; the high granularity of data is very important to address existing and emerging issues. This granularity must provide the speed and resolution for voltage monitoring applications to give better awareness for overloaded circuit/low voltage and flicker issues that operators now learn about from customer phone calls. Having the measurements and alarms to detect those situations calls is the goal. With more accurate measurements and modeling, the number of curtailment load drop targets could be reduced.

c) What are your company's vision and objectives regarding synchronized measurement technology?

SDG&E is still trying to understand the capabilities of synchronized measurements before developing a strategy. There are use cases, the main ones being falling conductor protection and building the platform that can be used for operations.

d) What are your company's ongoing and planned initiatives regarding synchronized measurement technology (next 5 yrs.)?

Not so many PMUs are deployed at the distribution level as compared to the transmission system. Over the next 5 years, the goal is to have more PMUs for better visibility of the distribution system. The PMUs already available must be integrated into the NMS.

2) In your opinion, what are the main benefits of adopting synchronized measurement technology?

Some benefits are already observed at the transmission level for the ongoing WASA project. The main benefit observed thus far is better system visibility (awareness), enabling new problem-solving solutions to operational challenges. An example of generator fault contribution was provided by Chris B., where the traditional SCADA system would not have an adequate resolution.

Beyond this is the need to study synchronized measurements as one of multiple data sources among several needed. Also, see the use for PQ meters as well. A longer-term vision requires an understanding of the capabilities of the system to get to a full-fledged strategy. Need to build a platform SDG&E can use for distribution operations, including support for a distribution state estimator.

3) What are the barriers or gaps for further adoption of synchronized measurements technology in distribution systems?

The barriers to the installation of synchronized measurement technology in distribution systems include the following. Telecommunications is a big issue; local computing is important to reduce the need for sending large volumes of data. Cybersecurity compliance is a part of this, as data does not flow through traditional pathways and drives the need for more robust networks. Telecom was originally built with data management in mind, so compliance was not a critical element at the time. Now it is important to address this issue. Security needs major financial investment and embedded activities at all levels of design and operation. Telecommunications requirements for radio systems or direct fiber infer costs, including pole replacements, repeater site requirements, and raise the cost of coverage for diverse topography coverage of these circuits.

Management and storage needs can be an issue as the O&M of synchronized measurement systems are not rolled into traditional support models for an organization and fall on the engineering organizations that design and build them until they grow in size enough to require a larger support group. Costs can be a barrier as PMUs are typical features of relays that are installed with other line-side equipment that may drive pole replacement and require the installation of the sensors to support such devices. Business use case development is a barrier as many operations groups question the importance of this data if they are unable to make operational decisions based upon it. Therefore, the importance of working realistic operational use cases in a control room environment will facilitate greater adoption, dependence upon, and support of such systems.

a) Examples to consider are Technology/application maturity; Telecommunications requirements; Data management and storage needs, cost; Business case development.

   Another aspect of the telecommunications infrastructure: The SCADA system is already challenging the existing infrastructure, and more is required for more data.

   Data management - existing SCADA team already at capacity; more data to manage will add to the challenge. Will require a new department or set of resources.

   Deployment costs - all aspects, including maintenance costs.

   Change management - lack of familiarity with PMUs for distribution employees. Need training and culture change.

b) What specific needs do you see with respect to sensor performance – cost, accuracy, or other issues?

c) Synchronized measurement sensors should be able to function with differing levels of accuracy based upon the installation need, no different than equipment classes today. Cost should be reasonable since these devices should benefit from manufacturers achieving economies of scale due to the widespread deployment of the technology on T&D systems worldwide. This will also further encourage design, procurement, and integration of the technology. PMUs need to have tighter integration between the equipment itself and the applications that use them. Naming conventions for signals and terminals, better quality visualization and event snapshot capabilities, ease of use to move between historical and real-time data for differing needs in the industry.

Some existing CTs/PTs are damaged - in addition to new instrument transformers, existing ones may need replacement. Need a better way to manage their condition.

4) What are your observations or experience with synchronized measurement systems or sensor products and vendors – those used in the past and new product entries?

SDG&E has used SEL SynchroWAVe Central, SynchroWAVe Operations, EPG PGDA, and Alstom Phasorpoint/PhasorScope. The only vendor that has a product that is easy to use in operations is SEL. EPG and Alstom have extremely cumbersome applications with regards to historical data observation, which does not bode well for quick analysis of system conditions in a control room. For engineering, off-line analytics EPG and Alstom might be fine, but it is not an enjoyable experience to use the clunky features of the tools. Successful user experience and ease of experience are paramount to the support of the technology.

5) What can the industry do to facilitate the adoption of synchronized measurement technology?

Developing this roadmap is an important step to understand the needs and benefits of synchronized measurements to facilitate adoption.

6) Is your company exploring other similar, competing, or complementary technologies (e.g., advanced fault circuit indicators, other advanced sensors, etc.)? If so, what has been your company's experience thus far?

SDG&E is also using power quality meters and wireless fault indicators (WFIs). With WFIs, operators get fault indication alarms, but engineers are the ones using other available data.

7) What is the status of each use case in the supplied list – or others not in the list?

The one use case truly being deployed is the Falling Conductor Protection program. It is currently being rapidly designed and deployed into all of SDG&E's HFTD Tier 3 and 2 circuits in that order.

Industry Survey for ORNL Project - ConEd

Distribution System Synchronized Measurement Technology Deployment

January 18, 2021

Respondent(s):
Attendees:
David Wang – Distribution Engineering, ConEd
Paul Stergiou- Distribution SCADA Manager, ConEd
Steve (Shutang) You - Researcher at University of Tennessee
Dr. Yilu Liu - ORNL/University of Tennessee
Lingwei Zhan - ORNL
JC Lesieur- QTech
Eric Udren- QTech

1) What are your overarching business, regulatory, policy, and technical **drivers or needs and gaps**?

- Unexpected outages avoidance:
    - ConEd is looking to add sensors on its underground network for partial discharge (PD) detection.
    - This should help alleviate the risk of cascading outages, such as the example provided by Paul where ConEd network was in a situation of N-7.
    - ConEd system is designed to operate reliably under N-2 at worst.
- Time Domain Reflectometry (TDR) was tried and did not work so well.
- PD may not be an optimal solution for underground feeders, given its limited range of effectiveness. ConEd feeders can be 8-10 miles long. The number of sensors required would make this solution difficult to deploy.
- Equipment failure and asset health management:
    - Over 26,000 underground distribution transformers.
    - These transformers are in congested environments (busy streets, restaurants, etc.). Failure can result in public safety issues.
    - Better equipment health assessment monitoring and tools are being explored.

- Moisture intrusion and joint contamination are recurring causes of failure.
- ConEd has proper visibility of feeder and transformer loading and feels confident that most failures are unrelated to overloads.

- The area substation transformer neutrals are grounded through a series reactance. Incipient fault detection and isolation would be valuable for feeders to avoid overvoltage on healthy phases when ground faults occur.

2) How could those **drivers or needs and gaps** be addressed by sensing technologies, particularly synchronized measurements, as applied to the distribution system?

- ConEd is looking at various technologies, including PD detection, and is open to other solutions but does not have a specific answer.

3) Share thoughts of **needs and gaps** triggered by this list of impacted business areas. Which of the following are most important in your work situation?

i) Safety (employee and public)- 1st priority

ii) Risk management; fire risk - 2nd priority

iii) Managing Distributed Energy Resources (DER) in transmission and distribution operations: Phase angle monitoring.

iv) Energy storage utilization: Better monitoring of batteries needed. Issues with communication protocol compatibility. (DNP vs. MODBUS)

v) Asset management, asset condition monitoring, maintenance: Discussed extensively throughout the meeting

vi) Power quality ConEd has installed PQ instrumentation in all the large area substations and in the underground networks. Uses include fault location on underground network feeders, 2nd fault detection, inrush overcurrent detection, sub-cycle detection, long clearing events, and customer support.

vii) Architecture of distribution PAC system – components and communications: IEC 61850 deployed a few years back on the distribution system (outside large substations). Limited usage at this moment outside the large substations.

4) What are the existing applications of synchronized measurements in your company's distribution system? Are there opportunities to leverage already deployed sensors and PMUs to develop further applications to meet some of the needs and gaps identified in question #1?

- Several PMUs have been installed on the transmission system to provide phasor information in real-time. PMUs are also installed in area substations and used anytime there is the need to do network load transfers with tight phase angle requirements [*associated with low impedance networks/ties*].
- This practice arose after 9/11 with the need for transfers among area substations around WTC. Published an article on this in GPS World, "Keeping the Lights On."

- PMUs are installed and removed for as-needed intermesh connections with tight phasing requirements.
- PMUs have been used on the secondary network for phase identification – "All cables are black."
- Post-mortem analysis done through data pull from relay - not done online.

5) What are your company's ongoing and planned initiatives or vision regarding synchronized measurement technology in the distribution system (next 5 yrs.)? Do you have a sense for what are the short-, medium- and longer-term priorities within your organization for the needs, drivers, and potential applications discussed above? If there is no planned initiative in place in your organization, what are the reasons?

    - Deploy more permanent PMUs for phase angle monitoring for load transfers – data is streamed in automatically every second.
    - Interested in technologies that may detect wires down and automatic isolation. Want to know more about SDG&E FCP.

6) What are the barriers or gaps for further adoption of synchronized measurements technology in distribution systems?

    i) Installation cost is an issue in NYC. Monthly communication fees (O&M) could be prohibitive as well.

    ii) Positive Cost-Benefit Analysis could be helpful given the above cost concerns.

7) Is your company exploring other similar, competing, or complementary technologies (e.g., advanced fault circuit indicators, other advanced sensors, etc.) for distribution system applications? If so, what has been your company's experience thus far?

    PD sensors: See details in Q1 answers.

    PQ meters: PQ meters are standard on new substation transformer installation projects - PQ meters have been an asset in identifying issues such as LTC problems and internal faults.

    Deployed SOS sensors in underground vaults to detect and alarm for possible explosive gases.

    Utilize IR cameras to detect hot spots on cables installed in underground structures.

    There is a pilot project underway in which fiber optic sensors are deployed in network transformer windings for measurements, including temperature and vibration.

    There is a pilot project installation of optical voltage sensors on medium-voltage feeders. Traditional PT failures may cause extensive collateral damage due to proximity to other equipment.

Industry Survey for ORNL Project – Dominion Energy

Distribution System Synchronized Measurement Technology Deployment

Dominion Energy

Feb 2, 2021

Matt Gardner, Director of Electric Transmission Operations Engineering
Derek Kou: System planning team, Rick Siepka: Manager Electric Grid Planning team, Pat Gould: Manager Operating Center Application- Owner of Telemetry/SCADA, Penn N Markham: System operation Engineering Transmission
Dr. Yilu Liu, ORNL/University of Tennessee
Lingwei Zhan, ORNL

1) What are your overarching business, regulatory, policy, and technical **drivers or needs and gaps**?

Synchronized measurements are more than just synchronized measurements and must include other measurements in the discussion.

SEL-735 is the Dominion PQ go-to device and has lots of metadata but is not a tool for real-time situational awareness (SA). We need real-time analytics, plus what distribution fault analysis (DFA) is aiming to do, which is predicting problems.

Fault location and PQ – Dominion can have >30 MW solar on a feeder, 3-4 providers on a circuit at multiple sites. Not just PQ is needed, but location and direction of harmonic sources. Point-on-wave (POW) analysis would be able to locate harmonics; phase angle of harmonic relationships point to a location, which needs synchronized measurements capability.

Falling conductor protection is interesting. Dominion is working with TAMU on DFA real-time analysis, and it seems promising.

Data gathering or measurements should be installed in reclosers or sectionalizing switches – integrate with package for field replacements. There are twice as many circuit devices in distribution versus transmission, and a lot of the distribution infrastructure is old. There would be a big benefit to integrating a lot of sensors at affordable prices.

Communication is an issue, with a lot of bandwidth required. 5G could be a potential solution.

Dominion is concerned about dynamics issues and oscillatory behavior in the distribution system that never show up at transmissions due to the installation of PV, which is becoming a system management problem.

Dominion distribution voltage of 34.5 kV is much higher than average – quite broad coverage and almost what some consider transmission. Can this high distribution voltage be leveraged on the system to configure small islands? Most DG/DER over 1 MW is installed with transfer trip. But what if the system is the problem: is it possible to do a bottom-up restoration with DER on distribution? Not just PV, but trash burners, CHP, etc. Beyond this, Dominion wants DFA and microgrid integration. Synching up microgrids for a restoration event is an interesting synchronized measurement application – using the distribution system as a bus for resilience.

Distribution topologies are becoming as complex ad meshed transmission topologies. Distribution has loop schemes, network flows, and meshed configurations. Even at transmission, Dominion has not fully leveraged, making PMUs useful to operators and may be a generation away from doing so at distribution. How to do that is a useful study topic.

One of the ongoing concerns is how to operate the distribution system in a changing environment. For instance, switching operation on the distribution system with DER integration or/and the networked condition is a source of concern. Better visibility and knowledge of system topology (State Estimation) would enable safer and more efficient operation.

The distribution system is not easy to manage due to DERs, storage, electrification, and weather forecasting. 1000 times more coverage (over 2 million customers, 0.5 million service transformers) may be needed compared to transmission system monitoring. This sheer number of nodes and branches on distribution systems could present a challenge for state estimation applications. How to poll all different data together and utilize them while remaining cost-effective is important to the utility.

Distribution system management needs a self-healing tool, quick system restoration, distribution system state estimation, which is important to distribution system Fault Location, Isolation, and Service Restoration (FLISR). For real-time and short-term planning studies such as the simulations of "what if" scenarios (N-1) for coordination, system loading, etc., using real-time data is necessary.

2) How could those **drivers or needs and gaps** be addressed by sensing technologies, particularly synchronized measurements, as applied to the distribution system?

See the responses above. Also, the short-term goal is the utility-scale DERs (1MW above) monitoring.

In the long-term, the utility has a blind spot too small size DERs less than 1MW, thus has limited controllability on these devices (no transfer switch). The right level of measurements (e.g., measurement graduality, number of devices to be deployed) is not easy to determine and needs further study.

3) Share thoughts of **needs and gaps** triggered by this list of impacted business areas. Which of the following are most important in your work situation?

    Dominion sees managing DER in distribution operations, load and DER forecasting, power quality as significant priorities due to the growing about of DER installed on the distribution system.

Network topology detection, state estimation, and phase identification are of most interest. For phase identification, as of today, the main trunk is usually accurate, but the laterals have a high rate of inaccuracy. Sometimes phase will change over time (ex: after storm restoration, there can be phase rotation not reported back).

For instance, right now, the system is managed by planning function, not in real-time. When topology or phase identifications are wrong, FLISR won't converge or won't be accurate.

4) What are the existing applications of synchronized measurements in your company's distribution system? Are there opportunities to leverage already deployed sensors and PMUs to develop further applications to meet some of the needs and gaps identified in question #1?

Distribution system visibility mainly comes from AMI smart meters and by leveraging existing IED devices to gather data. In addition, utility-scale DERs have meters and power quality analyzers. PMUs are only on transmission, and there is a need to provide this data on distribution. Measurements from digital relays are available, but the use is normally only for post-mortem events analysis after pulling time-stamped data from IEDs.

5) What are your company's ongoing and planned initiatives or vision regarding synchronized measurement technology in the distribution system (next 5 yrs.)? Do you have a sense for what are the short-, medium- and longer-term priorities within your organization for the needs, drivers, and potential applications discussed above? If there is no planned initiative in place in your organization, what are the reasons?

AMI data should combine with circuit synchronized measurement and PQ data to yield a holistic analytics picture of distribution performance and situational awareness. These are not separate domains. For example, fault location and outage management; customer PQ issue causes, and remediation.

6) What are the barriers or gaps for further adoption of synchronized measurements technology in distribution systems?

Finding the right number of sensors is of interest to limit the hardware and installation cost. Also, based on the AMI experience on distribution systems, the communication network and data management could be bottlenecks.

7) What can the industry do to facilitate the adoption of synchronized measurement technology in the distribution system?

Large pilot programs that are aggressively funded and are agile or sprint-like could bring a proven winner that others would adopt.

We love standards and see the vision of a unified, consistent approach, but they lag in innovation. Don't worry about standards yet – go make something work first and do standards based on that.

Self-sensing, self-organizing, self-supporting, self-managing systems with analytics that observe and learn. AI-assisted distribution system management could save a lot of labor.

Industry Survey for ORNL Project - ComED

Distribution System Synchronized Measurement Technology Deployment

March 17, 2021

Respondent(s): Commonwealth Edison (ComEd) – Paul Pabst, Heng Chen, Aleksi Paaso

1) What are your overarching business, regulatory, policy, and technical **drivers or needs and gaps**?

- Comply with mandatory NERC reliability standards
- Major risk management of events that impact reliability and resilience (e.g., natural disasters, etc.)
- Enhanced transmission operation
- Meet grid modernization (EIMA) reliability performance requirements
- Evolution to Network Services Provider/Integrator (NSPI)

2) How could those **drivers or needs and gaps** be addressed by sensing technologies, particularly synchronized measurements, as applied to the distribution system?

- The utilization of high resolution, accurate, and reliable synchronized measurement data will help ComEd comply with NERC standards
- Synchronized measurement data can help manage and reduce risks associated with the loss of critical customers, major system loss, and complete system loss
- Synchronized measurement data can also improve transmission system operation and increase overall T&D visibility
- Synchronized measurement data can help ComEd continue improving distribution reliability indices of interest (SAIDI and CAIDI)
- Selected synchronized measurement applications can help achieve ComEd's NSPI vision
- Synchronized measurement applications can help improve distribution system operations and increase system awareness and visibility

3) Share thoughts of **needs and gaps** triggered by this list of impacted business areas. Which of the following are most important in your work situation?

   i) Safety (employee and public)
   ii) Risk management; fire risk
   iii) Managing Distributed Energy Resources (DER) in transmission and distribution operations
   iv) Load and DER forecasting

v) Energy storage utilization

vi) Electrification (e.g., EVs and infrastructure; fossil fuel energy displacement in buildings) for decarbonization and climate change

vii) T&D system planning

viii) System modeling and analysis, both T and D

ix) Asset management, asset condition monitoring, maintenance

x) Reliability and resilience, hardening

xi) Power quality

xii) System protection, control, monitoring, and automation

xiii) Architecture of distribution PAC system – components and communications

xiv) Grid analytics (presentation of operating and event data in forms useful for operators, engineers, planners, and other enterprise stakeholders)

xv) Others (think about what gaps you see that don't follow from any of the above)

All of the above areas are relevant and important for ComEd. The most important ones are i) and x), followed by iii), vi), viii) and xiv).

4) What are the existing applications of synchronized measurements in your company's distribution system? Are there opportunities to leverage already deployed sensors and PMUs to develop further applications to meet some of the needs and gaps identified in question #1?

- ComEd has identified 33 potential distribution synchronized measurement applications. ComEd is currently implementing a distribution linear state estimator working in partnership with V&R, expected benefits from this application include real-time monitoring of DER, DER impact mitigation, and increased resilience

- ComEd has 190 installations of PMUs in 18 substations and 25 micro-PMUs (PSL and Lindsey sensors) in two distribution feeders in Bronzeville (there is a fiber optic backbone). The PMUs outputs are fed into an analytics platform (phasor data concentrator, SPL product, then PI historian).

5) What are your company's ongoing and planned initiatives or vision regarding synchronized measurement technology in the distribution system (next 5 yrs.)? Do you have a sense for what are the short-, medium- and longer-term priorities within your organization for the needs, drivers, and potential applications discussed above? If there is no planned initiative in place in your organization, what are the reasons?

- ComEd is implementing the distribution synchronized measurement high-level implementation roadmap developed in collaboration with Quanta Technology. Roadmap includes 33 applications in 5 areas (DER integration, distribution system operations, WAMPAC, asset management and reliability, and planning and analysis

- ComEd started implementation in 2018 and 2019 with an Initial focus on monitoring microgrids and critical customers (18 substations). In 2020 it added 5 substations and 25 feeder PMUs. After this initial stage, ComEd plans to focus on a software platform for advanced applications and analytics.

6) What are the barriers or gaps for further adoption of synchronized measurements technology in distribution systems?

   i) Technology/application maturity – technology is mature enough

   ii) Telecommunications requirements – fiber optic deployment facilitates this, but there is no fiber everywhere

   iii) Data management and storage needs

   iv) Cost (e.g., measurement instrument, communication, data storage, and management) – Implementation cost is the most critical one. It can be mitigated by the value provided by the application

   v) Business case development

   ComEd considers that all areas are relevant. However, key challenges are ii) cost-effective telecommunications technologies (ComEd is approaching synchronized measurement deployment and applications as one of the benefits derived from its fiber optic deployment initiative) and iv) overall technology cost, which remains high. The latter can be addressed via robust business case development.

7) What is your vision on potential solutions to facilitate the adoption of synchronized measurement technology?

   Validation of use and business cases via field deployment will provide evidence to help justify the implementation of distribution synchronized measurement technology.

8) What are your observations or experience with synchronized measurement systems or sensor products and vendors – those used in the past and new product entries?

   - Positive experience in general, getting value from deployment, exploring closed-loop control (R&D in the lab plus pilot).

   - Detailed data quality check is needed once applications are deployed and functioning.

9) What can the industry do to facilitate the adoption of synchronized measurement technology in the distribution system?

   Demonstration of use cases that can solve problems that cannot be solved with conventional technologies, along with validation of detailed benefit-cost analysis.

10) Is your company exploring other similar, competing, or complementary technologies (e.g., advanced fault circuit indicators, other advanced sensors, etc.) for distribution system applications? If so, what has been your company's experience thus far?

- Yes, ComEd has deployed PQ meters (PSL), advanced line sensors (Sentient), etc.
- Lack of infrastructure (telecommunications, storage, analytics, etc.) remains a challenge for the implementation of these technologies as well.

11) Do you think developing a roadmap of distribution system synchronized measurement technology deployment would help your company to deploy this technology on your distribution system? If so, what are the most valuable information you would like to learn to help your company to deploy this technology?

Yes, ComEd already has a roadmap that is currently implementing.

APPENDIX B: STATE OF THE ART REVIEW OF SYSTEM TECHNOLOGIES

This section provides a review of the current state of technologies that may be used to provide the applications described in this report. The review has been done by AG, and therefore each group has an individual section. The review includes a literature search and a description of R&D efforts.

AG1: Advanced Volt-Var Control

Currently, voltage regulation on the distribution system commonly operates on the order of hours. Operating the voltage regulation more frequently may not be desirable because the load tap changer (LTC) and voltage regulator (VR) have mechanical parts.[74] However, with the increasing penetration of DERs on the distribution system, power inverter-based energy resources could provide VVO in a much higher resolution. In the meantime, the emergence of DERs on the distribution system changes the loading patterns, influencing the performance of volt-var regulation devices. High DER penetration on distribution systems could cause issues like voltage rise, voltage drop, etc.[75,76] Ozdemir et al. [77]developed a voltage-var control method by using historical synchronized measurements on the distribution system to estimate the voltage-to-power sensitivity. The method is completely based on measurements and is agnostic to errors in system parameters. The reactive power of distributed generation (DG) is continuously adjusted at a time step of 15 minutes, and 1% measurement errors are assumed in this study. Based on SCADA measurements, it proposed a supervisory control of the VVC method that searches for the best control settings in real-time, minimizing power loss and providing an optimal global solution with fast computation speed. The voltage-var regulation method uses multiple devices (e.g., LTCs, VRs, capacitors) and operates at a rate of 5-15 minutes. The various VVC methods for DGs and EVs are summarized, and the changes of real-time smart inverter-based VVC recommended by IEEE 1547-2018 are discussed. Voltage control techniques can be classified into four categories: 1) local control, 2) decentralized control, 3) distributed control, and 4) centralized control. Centralized control has better performance, but it requires a reliable communication network with considerable investment in sensors and measurements.

A realistic target for VVO is less than 5 s from measurement to control action[74,78] which recommends that the voltage measurement accuracy is on the order of 0.1 V on a 120 V base. The measurement accuracy and reporting rate requirements of synchronized measurements for voltage-var control applications can be satisfied with existing SMDs. As discussed in Sun et al.,[75] the main challenge of voltage-var control in a centralized control are the reliable communication network and sensor investment, which need considerable investment. Although centralized control with synchronized measurements could have

[74] R. Arghandeh, "Micro-Synchrophasors for Power Distribution Monitoring, a Technology Review", arXiv: 1605:02813, 2016.

[75] H. Sun et al., "Review of Challenges and Research Opportunities for Voltage Control in Smart Grids," in IEEE Transactions on Power Systems, vol. 34, no. 4, pp. 2790-2801, July 2019, doi: 10.1109/TPWRS.2019.2897948

[76] Peng Li, Hongzhi Su, Li Yu, Zhelin Liu, Chengshan Wang, Jianzhong Wu, Voltage Control Method of Distribution Networks Using PMU Based Sensitivity Estimation, Energy Procedia, Volume 158, 2019, Pages 2707-2712.

[77] G. Ozdemir, S. Emiroglu and M. Baran, "Supervisory control for coordinating Volt/Var control devices on a distribution system," 2016 IEEE Power & Energy Society Innovative Smart Grid Technologies Conference (ISGT), Minneapolis, MN, USA, 2016, pp. 1-5.

[78] A. v. Meier, D. Arnold, M. Andersen, R. Arghandeh, and E. Stewart, "Control Applications for Micro-Synchrophasor Measurements," California Institute for Energy and the Environment, Berkeley, CA2014.

better performance,[75] the advantages of using synchronized measurements for voltage-var control over other methods need more study.

AG2: Advanced Monitoring of the Distribution Grid

Advanced grid monitoring for distribution systems relies on well-designed network architecture and data management systems. Gharavi and Hu[79] proposed a scalable synchronized measurement communication network for real-time distribution network monitoring. PMUs communicate with local phasor data concentrators (PDCs) via a wireless local area network, and local PDCs communicate with higher-level PDCs via a local area network with higher bandwidth. A measurement data reduction method is developed to mitigate the bandwidth requirement on the communication network. Bashian et al.[80] proposed an optimal placement of PMUs on distribution systems to achieve full observability of distribution networks. For example, nine PMUs are needed in an IEEE 34-nodes test feeder to achieve full observability.

The communication system is a key monitoring component, particularly for the distribution system, where access to high-speed communication is limited in most areas. Fiber provides high bandwidth but has a high cost. Wireless communication can be used as a cost-effective option and could be the major communication method used for transferring synchronized measurement data to PDCs. Flerchinger et al.[81] tested 3G cellular and wireless serial radio on distribution PMUs. Configuration of the wireless techniques depended on the corresponding applications and the geographic environments. Katsaros et al.[82] developed a low latency communication infrastructure to enhance the currently available power line communication technology with newer high-speed communication links at strategic points. Wireless communication capability supported by local measurement devices is critical due to the nature of distribution circuits that are widely spread, and fiber-optic communication can complement wireless communication for critical measurement nodes that require higher measurement reliability and low latency. Therefore, the future communication network of advanced monitoring for distribution systems could consist of different communication methods (e.g., fiber-optic, 4G/5G, radio frequency, power line carrier, etc.), and R&D efforts are needed to design a flexible and scalable communication network to meet different distribution system needs.

Another critical component of advanced distribution system monitoring is data management and analytics. The University of California, Berkeley developed an agile and scalable data management tool called the "Design and Implementation of a Scalable Synchronized measurement Data Processing

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[79] H. Gharavi and B. Hu, "Scalable Synchrophasors Communication Network Design and Implementation for Real-Time Distributed Generation Grid," in IEEE Transactions on Smart Grid, vol. 6, no. 5, pp. 2539-2550, Sept. 2015, doi: 10.1109/TSG.2015.2424196

[80] A. Bashian, M. Assili and A. Anvari-Moghaddam, "Optimal Placement of PMUs and Related Sensor-based Communication Infrastructures for Full Observability of Distribution Networks," 2020 IEEE Power & Energy Society General Meeting (PESGM), Montreal, QC, Canada, 2020, pp. 1-5, doi: 10.1109/PESGM41954.2020.9281586

[81] B. Flerchinger, R. Ferraro, C. Steeprow, M. Mills-Price and J. W. Knapek, "Field Testing of 3G Cellular and Wireless Serial Radio Communications for Smart Grid Applications," 2016 IEEE Rural Electric Power Conference (REPC), Westminster, CO, USA, 2016, pp. 42-49, doi: 10.1109/REPC.2016.22

[82] K. V. Katsaros, B. Yang, W. K. Chai and G. Pavlou, "Low latency communication infrastructure for synchrophasor applications in distribution networks," 2014 IEEE International Conference on Smart Grid Communications (SmartGridComm), Venice, Italy, 2014, pp. 392-397, doi: 10.1109/SmartGridComm.2014.7007678

System."[83] The existing data management solutions for wide-area management systems (WAMSs) at transmission systems could also be leveraged for distribution system applications.

Various parameters can be monitored in real-time, including active and reactive power, voltage and current magnitude, frequency, phase angle. For example, DGs' active and reactive power can be monitored for central-level voltage regulation and power factor correction.[84] Phase angle measurement across multiple locations can help understand the power flow on the distribution network. It should be noted that waveforms at the distribution level generally contain more noise and harmonics than the transmission system, causing measurement accuracy challenges to distribution measurement devices.[85] Whether the current IEEE synchronized measurement standard is suitable for synchronized measurements at distribution-level measurements remains an open problem, and R&D efforts are needed to better understand the measurement challenges on the distribution system.

AG3: Asset Management

Synchronized measurements can develop dynamic models to estimate the asset health probability of failures and risks. Predictive analysis on the health of grid assets can contribute to an optimized asset management strategy. For example, synchronized measurements can provide a dynamic feeder rating. The static feeder rating is usually computed using the most severe situation, which inevitably underestimates line ratings. A dynamic feeder rating can be achieved using synchronized measurements and ambient environment measurements. The benefits of a dynamic line rating are justified in Safdarian et al.,[86] Raque et al.,[87] and Bilibin et al.,[88] which developed a congestion management application of the distribution network based on dynamic feeder rating. Synchronized measurements can also help detect equipment issues early to prevent costly damage or outages. In Stewart et al.,[89] a distribution transformer's oil leak was inspected by utility personnel with the help of synchronized measurements. Padhee et al.[90] found that the signal-to-noise ratio of synchronized measurements is correlated to transformer failure. Synchronized measurements are useful to detect anomalies in breaker mis-operation, and they help identify the breakers needing inspection.[91] Synchronized measurement data from a

[83] S. K. Michael, P Andersen, Connor Brooks, Alexandra von Meier and David E. Culler, "DISTIL Design and Implementation of a Scalable Synchrophasor Data Processing System," presented at the ACM sigcomm 2015.

[84] H. Sun et al., "Review of Challenges and Research Opportunities for Voltage Control in Smart Grids," in IEEE Transactions on Power Systems, vol. 34, no. 4, pp. 2790-2801, July 2019, doi: 10.1109/TPWRS.2019.2897948

[85] L. Zhan, Y. Liu, J. Culliss, et al., Dynamic single-phase synchronized phase and frequency estimation at the distribution level, IEEE Trans. Smart Grid 6 (July (4)) (2015) 2013–2022.

[86] A. Safdarian, M.Z. Degefa, M. Fotuhi-Firuzabad, et al., Benefits of real-time monitoring to distribution systems: dynamic thermal rating, IEEE Trans. Smart Grid 6 (July (4)) (2015) 2023–2031.

[87] A.N.M.M. Raque, D.S. Shafiullah, P.R. Nguyen, et al., Real-time congestion management in active distribution network based on dynamic thermal overloading cost, Power Systems Computation Conference (PSCC), Genoa, Italy, June 2016.

[88] I. Bilibin, F. Capitanescu, Contributions to thermal constraints management in radial active distribution systems, Electr. Pow. Syst. Res. 111 (2014) 169–176.

[89] E.M. Stewart, C. Roberts, A. Liao, A. von Meier, O. Ardakanian and K. Brady, and A. McEachern, "Predictive distribution component health monitoring with distribution phasor measurement Units."

[90] M. Padhee, A. Pal, and M. Rhodes, "PMU-based online monitoring of critical power system assets."

[91] N. Nirbhavane, "Use of synchrophasors to detect control system and circuit breaker reclosing issues."

distribution feeder is used to analyze capacitor bank operation.[92] Equipment health diagnostics benefit from high-resolution synchronized measurements. However, there are no specific requirements for measurement accuracy.[93]

Besides synchronized measurement data, asset management information systems could use data from different sources such as AMI, geographic information systems (GISs), and SCADA. Over the last decade, utilities have evaluated AMI for asset management, allowing them to monitor asset conditions in near real-time and apply advanced analytic methods to optimize asset lifecycles.[94] The industry's application of synchronized measurements in distribution system asset management is in a very early stage. However, compared to other measurements like AMI, synchronized measurements allow high-resolution and high-speed dynamic modeling of grid assets in real-time across a wide area thanks to highly precise time synchronization. Therefore, synchronized measurements could play a vital and unique role in future grid asset management, enabling dynamic rating to distribution assets and predictive analytics on equipment failures.[95] As grid asset management by synchronized measurements is still at an early stage, main R&D efforts should focus on demonstrating the benefits of synchronized measurements-based grid asset management technology over other emerging asset management approaches such as AMI-based methods.

Furthermore, R&D efforts should be directed toward integrating synchronized measurements with existing data sources such as AMI, GIS, and SCADA and provide a hybrid data-based grid asset management approach. The measurement performance requirement of synchronized measurements for grid asset management is determined by the specific application. However, existing synchronized measurement systems should meet most grid asset management needs because their accuracy, rate, and latency are better than smart meters. However, due to the increasing complexity of distribution systems caused by DERs, reducing the cost of synchronized measurements could be a critical factor for the coverage of grid assets by SMDs.

AG4: Wide-Area Visualization

Relatively few PMUs are deployed on the distribution system for wide-area visualization, and very few grid applications for distribution systems use synchronized measurement data. FNET/GridEye is a low-cost, quickly deployable global positioning system (GPS)-synchronized wide-area frequency measurement network. High dynamic accuracy FDRs measure the power system's frequency, phase angle, and voltage at ordinary 120V outlets.[96] Funded by Advanced Research Projects Agency-Energy, microPMU was developed for distribution system monitoring, and various applications have been developed using

[92] A. Shahsavari et al., "A data-driven analysis of capacitor bank operation at a distribution feeder using micro-PMU data," 2017 IEEE Power & Energy Society Innovative Smart Grid Technologies Conference (ISGT), Washington, DC, USA, 2017, pp. 1-5, doi: 10.1109/ISGT.2017.8085984.

[93] Synchrophasor Monitoring for Distribution Systems, A White Paper by the NASPI Distribution Task Team.

[94] Rethinking Asset Management: Evolving to Analytics-Driven Decisions. https://www.landisgyr.com/webfoo/wp-content/uploads/2017/01/LandisGyr_Rethinking-Asset-Management.pdf

[95] Smart Asset Management, https://www.tdworld.com/grid-innovations/asset-management-service/article/20966761/smart-asset-management

[96] Y. Liu et al., "Wide-Area-Measurement System Development at the Distribution Level: An FNET/GridEye Example," in IEEE Transactions on Power Delivery, vol. 31, no. 2, pp. 721-731, April 2016, doi: 10.1109/TPWRD.2015.2478380.

microPMU measurement data.[97] Rare utilities have deployed PMUs on distribution systems for wide-area visualization purposes. SDG&E streamed synchronized measurement measurements from several circuits in high fire-risk areas, and the data can be viewed with dashboard and client software.

AG5: Advanced DER Integration and Control

Accuracy is important for the DER integration application, and there are no specific requirements for continuity or latency. Papers by von Meier et al.[98] and Hojabri et al.[99] show that voltage and current phasors require a 0.5% total vector error, or a time error of 15.915 µs in a 50 Hz system. Also, the expected sample rate is 50 or 60 reports per second for 50 Hz or 60 Hz systems, and current synchronized measurement technologies can meet these requirements. The likely technical challenge is the data mining and the micro-PMU placement, as discussed in Arghandeh.[100] Significant effort has been made to use PMUs for addressing problems associated with the increasing penetration of DERs, such as the fast-changing voltage profile and reverse power flow issue. These efforts fall into one of two categories:

1. In the first category, distribution PMUs are used to monitor the DER output power. For example, Seyedi et al.[101] proposes a time-series analysis method of synchronized measurement to monitor the variations of DER output power and detect irregular fluctuations. This method is tested on a solar PV system with energy storage and effectively detects and mitigates the ramp-rate solar power fluctuations.
2. In the second category, distribution PMUs are used to design controllers for voltage and frequency regulation and active and reactive power management. For example, the distribution synchronized measurement is used to optimally control the line flows of an unbalanced power distribution network with DERs in Sankur et al[102]. The authors use an extended two-dimensional extremum seeking control paradigm to control the active power and the reactive power simultaneously.

Nowak et al.[103] use distribution synchronized measurement to design a measurement-based optimal DER dispatch method, where the PMUs only need to be installed at a subset of buses. However, they play a central role in the proposed method by estimating a linear sensitivity model from the synchronized data

[97] A. von Meier, E. Stewart, A. McEachern, M. Andersen and L. Mehrmanesh, “Precision Micro-Synchrophasors for Distribution Systems: A Summary of Applications.” IEEE Transactions on Smart Grid, July 2017

[98] von Meier, E. Stewart, A. McEachern, M. Andersen and L. Mehrmanesh, "Precision Micro-Synchrophasors for Distribution Systems: A Summary of Applications," in IEEE Transactions on Smart Grid, vol. 8, no. 6, pp. 2926-2936, Nov. 2017.

[99] M. Hojabri, U. Dersch, A. Papaemmanouil, and P. Bosshart, “A Comprehensive Survey on Phasor Measurement Unit Applications in Distribution Systems,” Energies, vol. 12, no. 23, p. 4552, Nov. 2019.

[100] R. Arghandeh, “Micro-Synchrophasors for Power Distribution Monitoring, a Technology Review,” arXiv, abs/1605.02813, 2016.

[101] Y. Seyedi, H. Karimi and S. Grijalva, "Irregularity Detection in Output Power of Distributed Energy Resources Using PMU Data Analytics in Smart Grids," in IEEE Transactions on Industrial Informatics, vol. 15, no. 4, pp. 2222-2232, April 2019.

[102] M. D. Sankur, R. Dobbe, A. von Meier and D. B. Arnold, "Model-Free Optimal Voltage Phasor Regulation in Unbalanced Distribution Systems," in IEEE Transactions on Smart Grid, vol. 11, no. 1, pp. 884-894, Jan. 2020.

[103] S. Nowak, Y. C. Chen and L. Wang, "Measurement-Based Optimal DER Dispatch With a Recursively Estimated Sensitivity Model," in IEEE Transactions on Power Systems, vol. 35, no. 6, pp. 4792-4802, Nov. 2020.

of voltage and power injections. Sivaranjani et al.[104] studied the application of the distribution PMUs in voltage angle and frequency droop control in interconnected microgrids, focusing on the impact of measurement loss events, which could occur when the GPS signal is unavailable for synchronization.

Rodrigues et al.[105] leveraged the high-resolution and low latency of time-stamped synchronized measurement to design a secondary frequency control method for an islanded microgrid with DERs. The control method uses active information derived from PMUs to adjust generator contributions with an adaptive time-variable droop characteristic. The same authors recently[106] used the distribution synchronized measurements to design a distributed control strategy to improve the frequency and voltage of islanded microgrids with DERs. The designed controller effectively enhanced the dynamic performance of DERs with proven stability and steady-state analysis. Furthermore, it sped up the dynamic process of reaching a steady-state, reducing the frequency nadir and mitigating oscillation, thus greatly improving islanded microgrids' frequency and voltage regulation.

AG6: Real-Time Distribution System Operation

With the rapid development of DERs, robust real-time control algorithms based on time-synchronized measurements are needed to operate the distribution systems reliably.

In addition to references related to practical deployment, many real-time control algorithms using synchronized measurement data have been proposed in the literature. For example, when estimating the state of distribution systems, a hybrid method incorporating SCADA and synchronized measurements is also proposed in Das et al.[107] It provides an accurate estimation method combining SCADA data with limited synchronized measurement data. When synchronized measurement covers the region, the method can estimate the state as frequently as the sampling rate. When the data is limited and a disturbance is unobservable, the method can still accurately track the system dynamics with the SCADA data. Dynamic state estimation methods using only high precision synchronized measurements are proposed as well.

With the growth in deployment density of time-synchronized measurement technology, several dynamic state estimation methods facilitated using purely synchronized measurement data have been proposed. For example, a high accuracy real-time dynamic state estimation tool with fast computational speed was developed by Pulok and Faruque.[108] The authors showed that the drawbacks of SCADA-based state

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[104] S. Sivaranjani, E. Agarwal, V. Gupta, P. Antsaklis and L. Xie, "Distributed Mixed Voltage Angle and Frequency Droop Control of Microgrid Interconnections With Loss of Distribution-PMU Measurements," in IEEE Open Access Journal of Power and Energy, vol. 8, pp. 45-56, 2021.

[105] Y. R. Rodrigues, M. Abdelaziz and L. Wang, "D-PMU Based Secondary Frequency Control for Islanded Microgrids," in IEEE Transactions on Smart Grid, vol. 11, no. 1, pp. 857-872, Jan. 2020.

[106] Y. R. Rodrigues, M. M. A. Abdelaziz and L. Wang, "D-PMU Based Distributed Voltage and Frequency Control for DERs in Islanded Microgrids," in IEEE Transactions on Sustainable Energy, vol. 12, no. 1, pp. 451-468, Jan. 2021.

[107] K. Das, J. Hazra, D. P. Seetharam, R. K. Reddi and A. K. Sinha, "Real-time hybrid state estimation incorporating SCADA and PMU measurements," 2012 3rd IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe), Berlin, Germany, 2012, pp. 1-8.

[108] M. K. H. Pulok and M. O. Faruque, "Real-time dynamic state estimation using synchrophasor data," 2015 North American Power Symposium (NAPS), Charlotte, NC, USA, 2015, pp. 1-6.

estimations are overcome by high precision synchronized measurements and an algorithm using the linear state estimation method with these real-time synchronized measurement data. Zhao et al. [109] presented an even more robust estimation method that takes advantage of an adaptive weight assignment function to dynamically adjust the synchronized measurement weight based on the distance of big unwanted disturbances. This method can monitor a power system under different operating conditions in real-time.

There are other dynamic state estimation methods with different focuses, such as those described by Lin et al., [110,] who presented a robust method for active distribution grids incorporating microgrids. It is formulated as a quadratic programming problem and solved in a decentralized manner to accommodate the autonomous operation mode among microgrids. Zhang et al. [111] added the influence of the distributed generators into consideration, and Ali et al. [112] focused on accurate visualization of microgrid states.

Recent research by Chu et al.[113] proposed a real-time, data-driven method to indicate the state evaluation from massive streaming synchronized measurement data.

AG7: Enhanced Reliability and Resilience Analysis

For this AG, von Meier et al.[114] identifies the requirement of measurement quantity, time resolution, accuracy, and latency for an outage management application, where voltage and current magnitudes measurements are desired, and the 1 s time resolution, 1% error, and 1 s latency have been adequate. Synchronized measurement technologies can meet this requirement, and there are no obvious challenges identified in the literature. In this research, applying synchronized measurements for enhanced reliability and resilience analysis is documented in the footnoted references.[115,116,117,118,119] Mohamed et al.[115]

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[109] J. Zhao et al., "Power System Real-Time Monitoring by Using PMU-Based Robust State Estimation Method," in IEEE Transactions on Smart Grid, vol. 7, no. 1, pp. 300-309, Jan. 2016.

[110] C. Lin, W. Wu and Y. Guo, "Decentralized Robust State Estimation of Active Distribution Grids Incorporating Microgrids Based on PMU Measurements," in IEEE Transactions on Smart Grid, vol. 11, no. 1, pp. 810-820, Jan. 2020

[111] T. Zhang, W. Zhang and P. Yuan, "Distributed Dynamic State Estimation in Active Distribution System Based on Particle Filter," 2018 IEEE Innovative Smart Grid Technologies - Asia (ISGT Asia), Singapore, 2018, pp. 664-668.

[112] I. Ali, M. Huzaifa, O. Ullah, M. A. Aftab and M. Z. Anis, "Real Time Microgrid State Estimation using Phasor Measurement Unit," 2019 International Conference on Power Electronics, Control and Automation (ICPECA), New Delhi, India, 2019, pp. 1-6.

[113] L. Chu, R. Qiu, X. He, Z. Ling and Y. Liu, "Massive Streaming PMU Data Modelling and Analytics in Smart Grid State Evaluation based on Multiple High-Dimensional Covariance Test," in IEEE Transactions on Big Data, vol. 4, no. 1, pp. 55-64, 1 March 2018.

[114] von Meier, E. Stewart, A. McEachern, M. Andersen and L. Mehrmanesh, "Precision Micro-Synchrophasors for Distribution Systems: A Summary of Applications," in IEEE Transactions on Smart Grid, vol. 8, no. 6, pp. 2926-2936, Nov. 2017.

[115] M. A. Mohamed, A. S. Al-Sumaiti, M. Krid, E. M. Awwad and A. Kavousi-Fard, "A Reliability-Oriented Fuzzy Stochastic Framework in Automated Distribution Grids to Allocate u -PMUs," in IEEE Access, vol. 7, pp. 33393-33404, 2019.

[116] A. Shahsavari, A. Sadeghi-Mobarakeh, E. Stewart and H. Mohsenian-Rad, "Distribution grid reliability analysis considering regulation down load resources via micro-PMU data," 2016 IEEE International Conference on Smart Grid Communications (SmartGridComm), Sydney, NSW, Australia, 2016, pp. 472-477.

[117] A. Shahsavari et al., "Distribution Grid Reliability Versus Regulation Market Efficiency: An Analysis Based on Micro-PMU Data," in IEEE Transactions on Smart Grid, vol. 8, no. 6, pp. 2916-2925, Nov. 2017.

[118] S. Kumar, B. Tyagi, V. Kumar and S. Chohan, "Multi-Phase PMU Placement Considering Reliability of Power System Network," 2018 IEEE/PES Transmission and Distribution Conference and Exposition (T&D), Denver, CO, USA, 2018, pp. 1-9

[119] S. Pandey, S. Chanda, A. K. Srivastava and R. O. Hovsapian, "Resilience-Driven Proactive Distribution System Reconfiguration with Synchrophasor Data," in IEEE Transactions on Power Systems, vol. 35, no. 4, pp. 2748-2758, July 2020.

proposed a reliability-oriented stochastic model to optimize customer interruption costs and power losses by placing synchronized measurements in distribution systems. Shahsavari et al.,[116,117] used distribution synchronized measurements to analyze the transient behavior of load when the load resources participate in the frequency regulation. They aggregate these transient load profiles into a three-phase surge current profile to analyze distribution system reliability that considers over-current protection relay devices with different characteristics. The paper suggests that distribution system reliability may be jeopardized if multiple load resources participate in frequency regulation on the same feeder. Kumar et al.[118] aimed to improve distribution system reliability and observability by placing PMUs where each bus's reliability index is defined. These indices are aggregated to an overall system reliability index to determine the synchronized measurement placement. To enhance the distribution system's resilience against extreme weather events or cyber events, Pandey et al.[119] used the distribution synchronized measurements to support proactive control actions such as pre-event network reconfiguration with islanding. In this paper, the distribution synchronized measurements are used to monitor the line flow of power distribution lines. Based on these measurements, distribution system operators can take proactive control actions such as load shifting or load shedding to reduce the line flow to almost zero before the event happens. The method is tested on real feeders and can alleviate the impact of extreme events on the system.

AG8: Advanced Distribution System Planning

This AG mainly involves model validation and topology, and phase identification. For the model validation application, the line segment impedance validation is often discussed in the literature, where the absolute accuracy of all phasors is a limiting factor and should be around 0.0001 PU for a shorter segment.[120] For the model validation of other components, the total vector error of voltage and current phasors are expected to be within 0.5%, and there is no latency and continuity requirement.[120] For the topology detection application,[121] the methods based on time series signatures usually require the voltage phasors with a time resolution of 1 cycle or better, and synchronization is critical. It also has the continuity requirement with a complete history and a latency requirement of 1 s. For topology detection based on source impedance methods, voltage and current phasors are needed, while the other requirements are similar to the methods based on time series signatures. For phase identification,[121] the voltage phase angles are essential, but it only requires the absolute accuracy of phase angle on the order of 1 degree, and there are no requirements on latency or continuity. The current synchronized measurement technology can meet all the requirements in the above applications, and the major technical challenge is

[120] M. Hojabri, U. Dersch, A. Papaemmanouil, and P. Bosshart, “A Comprehensive Survey on Phasor Measurement Unit Applications in Distribution Systems,” Energies, vol. 12, no. 23, p. 4552, Nov. 2019.

[121] von Meier, E. Stewart, A. McEachern, M. Andersen and L. Mehrmanesh, "Precision Micro-Synchrophasors for Distribution Systems: A Summary of Applications," in IEEE Transactions on Smart Grid, vol. 8, no. 6, pp. 2926-2936, Nov. 2017.

the micro-PMU placement, as discussed in Arghandeh.[122] In the research community, the topology and phase identification, and model validation are studied in the footnoted references[123,124,125].

Bariya et al.[123] propose a greedy method for three-phase unbalanced radial distribution systems to achieve joint identification of both phase and topology. The proposed method uses voltage measurement only, either phasors or magnitude but with slightly different performance. The paper assumes PMUs report data at 120 Hz. The method also applies if the resolution is good enough for the measurement to be de-trended to remove inter-nodal corrections. Liu and Etingov[124] use actual micro-PMU measurements from distribution feeders collected by Lawrence Berkley National Laboratory to conduct composite load model validation. The generated load models are calibrated to match the performance with micro-PMUs measurements. Finally, Mahmood et al.[125] use the measurements from real PMUs installed at the campus of École Polytechnique Fédérale de Lausanne in Switzerland to conduct a steady-state model synthesis of real active distribution systems. The measurements from PMUs at many distribution system locations were used to synthesize a three-phase steady-state equivalent model. Also, the paper performed a hardware-in-loop experimental validation of the synchronized measurement-based steady-state model synthesis applications. It demonstrated the ability to produce accurate, equivalent reduced models of those network sections bounded by PMUs.

AG9: Distribution Load, DER, and EV Forecasting

Most of the work in this area has been conducted within the context of R&D projects led by academia and research organizations and mostly applied to the operation of transmission systems. For instance, Tian et al.[126] applied synchronized measurements, a backward-forward sweeping algorithm, and a dynamic neural network to obtain the distribution network's real-time operation state and safety situation. Kurbatsky and Tomin[127] proposed intelligent methods and approaches to solve the problems of monitoring and forecasting of the expected DER operating conditions: 1) Intelligent hybrid approach to short-term forecasting of expected state variables (power flows, voltage magnitude, etc.) based on the combined application of artificial neural networks and the Hilbert-Huang Transform, and 2) intelligent approach to monitoring and forecasting of heavy load and/or emergency conditions based on modem methods of adaptive clustering and factor analysis.

[122] R. Arghandeh, "Micro-Synchrophasors for Power Distribution Monitoring, a Technology Review," arXiv, abs/1605.02813, 2016

[123] M. Bariya, D. Deka and A. von Meier, "Guaranteed Phase & Topology Identification in Three Phase Distribution Grids," in IEEE Transactions on Smart Grid, doi: 10.1109/TSG.2021.3061392.

[124] Y. Liu and P. Etingov, "Distribution-Level Phasor Measurement Units Application to Composite Load Model Validation," 2019 North American Power Symposium (NAPS), Wichita, KS, USA, 2019, pp. 1-6, doi: 10.1109/NAPS46351.2019.9000387.

[125] F. Mahmood, L. Vanfretti, M. Pignati, H. Hooshyar, F. Sossan and M. Paolone, "Experimental Validation of a Steady State Model Synthesis Method for a Three-Phase Unbalanced Active Distribution Network Feeder," in IEEE Access, vol. 6, pp. 4042-4053, 2018, doi: 10.1109/ACCESS.2018.2792320.

[126] S. Tian, et al., "Situation Forecasting Method for Distribution Network Based on Phasor Measurement Unit," 2019 IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC) https://doi.org/10.1109/APPEEC45492.2019.8994472

[127] V.G. Kurbatsky, N.V. Tomin, "Smart system of monitoring and forecasting for electric power systems," 2012 IEEE International Conference on Power System Technology (POWERCON) https://doi.org/10.1109/PowerCon.2012.6401289

AG10: Improved Stability Management

For the stability application, the system frequency and oscillation detection are discussed by von Meier et al.,[128] where the voltage phase angle and synchronization are shown to be essential. Von Meier et al.[128] also pointed out the time resolution requirement of 1 cycle or better, the continuity requirement with complete history, and the latency requirement of sub-second if informing protection is needed. As discussed in Arghandeh,[129] the likely technical challenge for oscillation detection is errors caused by voltage and current transformers.

Using the Thevenin equivalent, Vu and Novosel first reported synchronized measurements for voltage stability detection in transmission[130] [131]. Methods based on this technology are promising for distribution applications, such as the FIDVR detection, which is closely related to voltage stability detection. In addition to the use of RVII for distinguishing between FIDVR and voltage stability (see above), Matavalam et al.[132] also used synchronized measurement to estimate the Thevenin equivalent for long-term voltage stability monitoring and conducted case studies on the combined T&D systems. The idea of the Thevenin equivalent is extended to a three-phase unbalanced distribution system in this paper. Results show that synchronized measurement plays an important role in identifying the regions that cause long-term voltage instability. Chen et al.[133] proposed an analytical method to quantify the impact of local phasor measurement uncertainty on the Thevenin equivalent impedance in voltage stability analysis. Su and Liu[134] used synchronized measurements to estimate the Thevenin equivalent parameters by formulating worst-case and robust least-square problems that consider synchronized measurement uncertainties. Also, the synchronized measurement data was used to simulate and evaluate the FIDVR issue in Abed and Salazar[135] and Reddy and V. Ajjarapu.[136] In Abed and Salazar[135] and Reddy and V. Ajjarapu,[136] the PMUs measurements were used to record the real-time FIDVR events and are further used to calibrate the composite load models. In Abed and Salazar,[135] the authors used voltage measurement from synchronized measurements to calculate a Lyapunov exponent to assess the stability and identify the delayed voltage

[128] von Meier, E. Stewart, A. McEachern, M. Andersen and L. Mehrmanesh, "Precision Micro-Synchrophasors for Distribution Systems: A Summary of Applications," in IEEE Transactions on Smart Grid, vol. 8, no. 6, pp. 2926-2936, Nov. 2017.

[129] R. Arghandeh, "Micro-Synchrophasors for Power Distribution Monitoring, a Technology Review," arXiv, abs/1605.02813, 2016

[130] K. Vu, D. Novosel, M. Begovic, M.M. Saha, "Use of Local Measurements to Estimate Voltage Stability Margin", PICA 1997, Columbus, Ohio, May 1997.

[131] K. Vu and D. Novosel, "Voltage Instability Predictor (VIP) - Method and System for Performing Adaptive Control to Improve Voltage Stability in Power Systems," US Patent No. 6,219,591, April 2001.

[132] A. R. Ramapuram Matavalam, A. Singhal and V. Ajjarapu, "Monitoring Long Term Voltage Instability Due to Distribution and Transmission Interaction Using Unbalanced μ PMU and PMU Measurements," in IEEE Transactions on Smart Grid, vol. 11, no. 1, pp. 873-883, Jan. 2020.

[133] C. Chen, J. Wang, Z. Li, H. Sun and Z. Wang, "PMU Uncertainty Quantification in Voltage Stability Analysis," in IEEE Transactions on Power Systems, vol. 30, no. 4, pp. 2196-2197, July 2015

[134] H. Su and T. Liu, "Robust Thevenin Equivalent Parameter Estimation for Voltage Stability Assessment," in IEEE Transactions on Power Systems, vol. 33, no. 4, pp. 4637-4639, July 2018

[135] N. Abed and A. Salazar, "Simulations and evaluation of FIDVR using PMU data," 2014 IEEE PES General Meeting | Conference & Exposition, National Harbor, MD, USA, 2014, pp. 1-5

[136] A. Reddy and V. Ajjarapu, "PMU based real-time monitoring for delayed voltage response," 2015 North American Power Symposium (NAPS), Charlotte, NC, USA, 2015, pp. 1-6

recovery. Hojabri et al.[137] said that voltage stability monitoring and assessment require a transfer time of 500 ms, which can be met by current synchronized measurement technology.

AG11: High-Accuracy Fault Detection and Location

Brahma[138] proposed a fault location method that uses synchronized measurements of voltage and current to compute the Thevenin equivalents for positive, negative and zero-sequence impedances. The fault location is calculated based on the comparison of voltage differences throughout the circuit. Ren et al.[139] proposed a method using voltage and current phasor measurements. Candidate fault locations are found by iterating every line segment. The final fault location is determined by comparing the voltage phasors for the junction nodes of branches. Din et al.[140] proposed a fault location scheme for aged power cables using phasor measurements from both ends of the cable line. Zhang et al.[141] proposed a graph-based fault location method using a limited number of synchronized measurements. A hierarchical distribution system state estimation approach is developed by integrating graph theory, which is then used to identify the fault location. Pignati et al. [142] proposed fault detection and location method using state estimation results of different and augmented network topologies. Bansal et al.[143] proposed an open and short circuit fault identification method based on Tellegen's theorem. Gholami et al.[144] proposed a state estimation-based method for short circuit fault. Current, voltage and pre-fault state estimation results are needed for this method. Simulation shows this method requires less state estimation execution times. Cui et al. [145] proposed a Hi-Z fault detection and location method based on semi-supervised learning. Zanjani et al.[146] proposed a Hi-Z fault detection method by computing the discrepancy between sampled and estimated data. PMUs of 5000 Hz data rate are used in this work. Kantra et al.[147] proposed a statistical

[137] M. Hojabri, U. Dersch, A. Papaemmanouil, and P. Bosshart, "A Comprehensive Survey on Phasor Measurement Unit Applications in Distribution Systems," Energies, vol. 12, no. 23, p. 4552, Nov. 2019.

[138] Brahma, Sukumar M. "Fault location in power distribution system with penetration of distributed generation." IEEE transactions on power delivery 26.3 (2011): 1545-1553.

[139] Ren, J., S. S. Venkata, and E. Sortomme. "An accurate synchrophasor based fault location method for emerging distribution systems." IEEE Transactions on Power Delivery 29.1 (2013): 297-298.

[140] Din, E. S. T. E., et al. "An PMU double ended fault location scheme for aged power cables." IEEE Power Engineering Society General Meeting, 2005. IEEE, 2005.

[141] Zhang, Ying, Jianhui Wang, and Mohammad E. Khodayar. "Graph-based faulted line identification using micro-PMU data in distribution systems." IEEE Transactions on Smart Grid 11.5 (2020): 3982-3992.

[142] Pignati, Marco, et al. "Fault detection and faulted line identification in active distribution networks using synchrophasors-based real-time state estimation." IEEE Transactions on Power Delivery 32.1 (2016): 381-392.

[143] Bansal, Yashasvi, and Ranjana Sodhi. "PMUs Enabled Tellegen's Theorem-Based Fault Identification Method for Unbalanced Active Distribution Network Using RTDS." IEEE Systems Journal 14.3 (2020): 4567-4578.

[144] Gholami, Mohammad, et al. "Detecting the location of short-circuit faults in active distribution network using PMU-based state estimation." IEEE Transactions on Smart Grid 11.2 (2019): 1396-1406.

[145] Cui, Qiushi, and Yang Weng. "Enhance High Impedance Fault Detection and Location Accuracy via $\mu $-PMUs." IEEE Transactions on Smart Grid 11.1 (2019): 797-809.

[146] Zanjani, Mohsen Ghalei Monfared, Hosein Kazemi Kargar, and Mina Ghalei Monfared Zanjani. "High impedance fault detection of distribution network by phasor measurement units." 2012 proceedings of 17th conference on electrical power distribution. IEEE, 2012.

[147] Kantra, Sean, Hany A. Abdelsalam, and Elham B. Makram. "Application of PMU to detect high impedance fault using statistical analysis." 2016 IEEE Power and Energy Society General Meeting (PESGM). IEEE, 2016.

method to detect Hi-Z fault. O'Brien et al. [148] proposed a falling conductor detection method, which triggers before the conductor hits the ground.

The synchronized measurement data quality is seldom addressed in the literature. Poor data quality generally undermines the performance of statistical methods more significantly than others.[145,147] Data rate is also seldom addressed. Thirty Hz is usually sufficient, with one exception[146] that used 5000 Hz in the experiment. Latency requirement is mostly dependent on the use case. O'Brien et al. [148] required the lowest latency as it aimed to detect the fault before the conductor hit the ground. Different approaches have different requirements for synchronized measurement installation. Most previously mentioned methods require full observability of the system (i.e., synchronized measurements installed at each bus or each side of lines). The accuracy of Gholami et al.[144] is highly dependent on whether synchronized measurements are installed at the desired locations. Pereira et al. proposed a general synchronized measurement placement scheme optimized for fault detection using the Tabu search algorithm.[149] Most methods require massive deployment of PMUs, which is usually not cost-efficient and sometimes impractical. Zhang et al.[141] claimed that they needed fewer synchronized measurements. However, the topology has to be known. Prior knowledge of network topology is another challenge because most methods are not adaptive to a topology change.

AG12: Advanced Distribution Protection and Control

Hooshyar et al.[150] suggested replacing the magnetic distribution transformer with a solid-state transformer (SST) at every node to facilitate DER integration. They proposed an enhanced overcurrent protection scheme that exploits synchronized measurement functionality in SSTs and feeder protective relays. A promising simulation result is presented even with an overall delay of 60 ms in the study. At a 60-frames-per-second reporting rate, each synchronized measurement loads the communication network at 29 kbps.

Kumar et al.[151] proposed a voltage stability index using local phasor values and a corresponding special protection scheme for N-1 contingency at the key node. Brahma et al.[152] developed a protection scheme for a distribution system with high penetration of DG. This scheme is adaptive to temporary and permanent changes in the distribution network. The accuracy depends on the accuracy of synchronized measurement, which can be met with existing devices. Al-Maitah et al.[153] proposed a wide-area

[148] O'Brien, William, et al. "Catching falling conductors in midair—detecting and tripping broken distribution circuit conductors at protection speeds." 2016 69th Annual Conference for Protective Relay Engineers (CPRE). IEEE, 2016.

[149] Pereira, Rodrigo Aparecido Fernandes, Luis Gustavo Wesz Da Silva, and José Roberto Sanches Mantovani. "PMUs optimized allocation using a tabu search algorithm for fault location in electric power distribution system." 2004 IEEE/PES Transmission and Distribution Conference and Exposition: Latin America (IEEE Cat. No. 04EX956). IEEE, 2004.

[150] Hooshyar, Hossein, et al. "PMU-assisted overcurrent protection for distribution feeders employing Solid State Transformers." Sustainable Energy, Grids and Networks 10 (2017): 26-34.

[151] Kumar, Deepa S., J. S. Savier, and S. S. Biju. "Micro-synchrophasor based special protection scheme for distribution system automation in a smart city." Protection and Control of Modern Power Systems 5.1 (2020): 1-14.

[152] Brahma, Sukumar M., and Adly A. Girgis. "Development of adaptive protection scheme for distribution systems with high penetration of distributed generation." IEEE Transactions on power delivery 19.1 (2004): 56-63.

[153] Al-Maitah, Khaled, and Abdullah Al-Odienat. "Wide Area Protection Scheme for Active Distribution Network Aided PMU" 2020 IEEE PES/IAS Power Africa. IEEE, 2020.

distribution protection scheme based on the integrated impedance angle (IIA). This schema can generate tripping signals within 31 ms, given the communication latency is about 8 to 11 ms, specified by IEC 61850. Seyedi and Karimi[154] proposed a data-driven approach for adaptive backup protection and secondary control of DG systems. The protection and control are jointly carried out based on the processing of synchronized measurement datasets and the exchange of protective messages. In this study, the communication delay is assumed to be 25 ms. For advanced distribution protection and control, the requirement for reporting rate can be met with existing synchronized measurements. Communication requirements can also be achieved by complying with the IEC 61850 standard. However, the research does not cover the impact of poor-quality data. As a result, influences from uncertainties caused by measurement noises and communication failures should be investigated.

AG13: Advanced Microgrid Applications and Operation

Shi et al.[155] proposed a DG control strategy for microgrid islanding by estimating the power imbalance in microgrid and adjusting converter interfaced DGs adaptively to compensate. The estimated power imbalance only needs to have the same sign as the true value. In a separate paper, Shi et al.[156] proposed an active control strategy for restoring a microgrid by measuring the phase angle mismatch between the microgrid and the main grid at the point of common coupling (PCC). Sharma et al.[157] developed a methodology that detects the fault in microgrid by monitoring the absolute value of the rate of angle difference between the PCC and the bus nearest to the fault line. The impact of synchronized measurement placement is addressed, but the optimal placement strategy has not been developed.

Sepehrirad et al.[158] proposed a decision tree-based differential relay scheme for differential protection of microgrids. Sharma et al.[159] proposed a new indicator for fault detection, called “integrated impedance angle” or “IIA,” computed by positive sequence components of fault voltage and current phasors. Then an IIA-based microgrid protection scheme is presented. Cintuglu et al.[160] presented a series of synchronized measurement automation applications in microgrids, including protection event analysis, islanding, resynchronization, and remote generation dispatch experiments. Mishra et al.[161] suggested that islanding DGs can be detected by comparing the difference between the grid and load side synchronized

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[154] Seyedi, Younes, and Houshang Karimi. "Coordinated protection and control based on synchrophasor data processing in smart distribution networks." IEEE Transactions on Power Systems 33.1 (2017): 634-645.

[155] Shi, Di, Ratnesh Sharma, and Yanzhu Ye. "Adaptive control of distributed generation for microgrid islanding." IEEE PES ISGT Europe 2013. IEEE, 2013.

[156] Shi, Di, Yusheng Luo, and Ratnesh K. Sharma. "Active synchronization control for microgrid reconnection after islanding." IEEE PES innovative smart grid technologies, Europe. IEEE, 2014.

[157] Sharma, Nikhil Kumar, and Subhransu Ranjan Samantaray. "Assessment of PMU-based wide-area angle criterion for fault detection in microgrid." IET Generation, Transmission & Distribution 13.19 (2019): 4301-4310.

[158] Sepehrirad, Iman, et al. "Intelligent Differential Protection Scheme for Controlled Islanding of Microgrids Based on Decision Tree Technique." Journal of Control, Automation and Electrical Systems 31.5 (2020): 1233-1250.

[159] Sharma, Nikhil Kumar, and Subhransu Ranjan Samantaray. "PMU assisted integrated impedance angle-based microgrid protection scheme." IEEE Transactions on Power Delivery 35.1 (2019): 183-193.

[160] Cintuglu, Mehmet H., Ahmed T. Elsayed, and Osama A. Mohammed. "Microgrid automation assisted by synchrophasors." 2015 IEEE Power & Energy Society Innovative Smart Grid Technologies Conference (ISGT). IEEE, 2015.

[161] Mishra, Manohar, Sheetal Chandak, and Pravat Kumar Rout. "Taxonomy of Islanding detection techniques for distributed generation in microgrid." Renewable Energy Focus 31 (2019): 9-30.

measurement angles with a preset threshold. Thus, a very small non-detection zone can be achieved at a high implementation cost. Various high-performance applications were proposed. However, the impact of microgrid topology change has not been properly discussed. Most of the research was conducted under simulation, and the influence of measurement noises and communication failures needs more study.

AG14: Improved Load Shedding Schemes

Most load shedding strategies using synchronized measurements are related to transmission systems where the existing PMUs can meet the need. Research on applying synchronized measurements on load shedding in the distribution systems is in an early stage. Kumar et al.[162] developed a voltage stability index-based special protection scheme for a radial distribution network in India. Two PMUs were placed at key nodes in a city. More PMUs are needed for the automatic load shedding procedure. In this approach, the network model is needed to analyze the voltage stability for the load shedding strategy. The load shedding strategies on distribution systems using synchronized measurements are not well studied yet. However, the fast emergence of DERs and active loads on distribution networks means that load shedding could happen more frequently on distribution networks, so more R&D efforts are needed to study how the synchronized measurements can benefit load shedding, particularly for the distribution network with high penetration of DERs, battery, and EVs.

AG15: Advanced Distribution Automation

Synchronized measurements can improve the FLISR scheme to 1) improve the accuracy and effectiveness of fault location,[163] 2) improve the effectiveness of protection algorithms used by line reclosers or relays/circuit breakers to detect/isolate faults (e.g., Hi-Z faults),[164] and 3) measure actual ("unmasked") pre-fault load currents needed to assess the feasibility of load transfers in centralized (e.g., advanced DMS-based) automation schemes.[165]

Shi et al.[166] proposed using PMUs for microgrid synchronization. This method eliminates the voltage phase angle difference across the circuit breaker/recloser at the PCC and uses synchronized measurements transmitted via IP communications. Similarly, Aleem et al.[167] demonstrated the microgrid resynchronization process in real-time by using data provided by synchronized measurements. Aftab et al. [168] demonstrated a resynchronization process that relies on the utilization of PMUs to measure

[162] Deepa S. Kumar et al., Micro-synchrophasor based special protection scheme for distribution system automation in a smart city, Protection and Control of Modern Power Systems volume 5, Article number: 9 (2020).

[163] M. Jamei et. al, Phasor Measurement Units Optimal Placement and Performance Limits for Fault Localization, IEEE Journal on Selected Areas in Communications, Vol. 38, No. 1, January 2020, pp. 180-192 https://doi.org/10.1109/JSAC.2019.2951971

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magnitudes and angles of voltages using IEC 61-850-90-5. Finally, Dua et al.[169,170] proposed algorithms for optimal placement of micro-PMUs to ensure distribution grid observability for multiple configurations while defining observability based on various factors, including directly and indirectly monitoring switch node voltages using micro-PMUs, and defining a switch node observability measure.

AG16: Technical and Commercial Loss Reduction

Synchronized measurements can be applied to monitor power systems and provide advanced technical and commercial loss reduction solutions. The literature contains research conducted to improve the estimation of power and energy losses and minimize losses.

As for the real-time estimation of technical transmission losses using the synchronized measurements, related research has been conducted in Tuttelberg and Kilter,[171] Pavičić et al.,[172] and Tuttelberg et al.[173] Tuttelberg and Kilter[171] presented a concept for estimating transmission losses which computes Joule, corona, and inductive losses and capacitive generation based on synchronized measurement data and mathematical expressions as separate components. Then the transmission line loss is calculated as the sum of the above components. Pavičić et al.[172] presented a more advanced concept for real-time transmission line technical losses prediction that combines measurements from electricity meters, SCADA systems, and synchronized measurements. This concept has been experimented with historical data to prove that it is possible to determine technical losses in each transmission line in the current state, leading to further improvements in the planning and procurement of losses. Tuttelberg et al.[173] focused on correcting systematic errors in corona losses. It can further reduce transmission line loss since corona losses are a key component of the total losses. It should be noted that there is rarely related research for distribution systems.

Research has been conducted for commercial losses since traditional meter inspections are not effective in detecting them. Researchers are using time-synchronized measurement technology to solve this problem. For example, Yuan-Liang Lo et al.[174] proposed detecting non-technical losses by searching potential abnormal electricity usage utilizing real-time measurement data. Carquex and Rosenberg[175]

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proposed using power and voltage measurement across time to detect any inconsistency caused by electricity theft. Leite and Mantovani[176] proposed a strategy for detecting and locating non-technical losses in distributed networks. Based on data collected by field devices such as synchronized measurements or IEDs, a multivariate monitoring and control procedure is carried out to detect the possible power losses at distribution transformer terminals. If abnormal power consumption is detected, then the point where commercial losses have occurred will be located.

However, the common challenge for technical loss reduction is identified in Tuttelberg and Kilter[171] and Pavičić et al.[172] The authors pointed out the loss estimation accuracy is hard to determine definitively. The solution to this challenge is to improve the accuracy of measured voltages and currents and improve the estimates of the loss components.

AG17: Monitoring and Control of Electric Transportation Infrastructure

EVs behave either as active loads or as DERs is the concept of V2G technology. Therefore, large-scale EVs with V2G capability connected to the power grid will cause a significant impact on distribution systems. Usman and Faruque[177] reviewed various synchronized measurement technologies in power systems and stated that applying synchronized measurements in V2G technology is a potential research area. It is a potential research area because—with the help of the large-scale deployment of fast-responding frequency measuring devices—the EVs can act as reserve sources against unexpected outages. Sexauer et al.[178] pointed out that high penetration levels of active loads and DERs in the distribution grid can change the traditional grid from a slower-changing radial network to a multi-source dynamic network, and only distribution level PMUs that can provide fast and real-time grid measurements can give the ability to monitor and analyze the dynamic distribution network. Sexauer et al.[178] also discussed how PMUs could play a key role in the future electric transportation infrastructure. Most EVs can only use the power grid to charge their batteries, but with the help of frequency measuring devices with fast communication speed such as PMUs, EVs may also be used as mobile energy storage. Yang et al.[179] further proved that when V2G-capable EVs act as energy resources, they could help load frequency control in an isolated grid. Using the online monitoring data from PMUs, the proposed controller can coordinate the output of EVs and DG and has a robust performance on load frequency control with complex operation situations includes renewable energy generation and continuous load disturbances.

Sexauer et al.[178] and Yang et al.[179] pointed out the current challenge of realizing V2G technology is the delay in communication. Jamroen et al.[180] performed detailed simulations about how communication

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delay impacts EVs charging power control compared to ideal, no-delay situations. Simulation results reveal that communication delays can severely affect the system frequency stabilization due to the mismatch between EVs charging power and the imbalance of generation and load demand. The simulation also reveals that the proposed control algorithm for EVs has unsatisfactory performance. Jamroen et al.[180] continued research on the EV charging control scheme. Kesorn et al.[181] proposed an algorithm considering frequency stabilization in distributed systems, which can handle the impact of communication delays. This EV control scheme observes discrete-time frequency data of the power system through synchronized measurements and calculates frequency deviation using processed data. Mean absolute error of frequency deviation is used to obtain the optimal PI controller gain factor for the EV charging control. The overall communication delay is set as constant 500 ms, which includes the time of synchronized measurement data acquisition, synchronized measurement data transmission, and EVs control signal from the control center to the local EVs. However, this communication delay is set based on the authors' assumption rather than the actual value. Therefore, the communication delay is still a key challenge for future research on the control of electric transportation infrastructure.

AG18: Integrated Resource, Transmission, and Distribution System Planning and Operations

There is no specific literature in this area. There will be significant efforts to incorporate synchronized measurements in T&D planning and operations. Many other applications (listed in this document) are the basis for enabling integrated planning and operation. However, significant R&D efforts are required to identify methodologies and tools to support the A67 and A68 applications.

AG19: Power Quality Assessment and Analysis

There is no specific literature for PQ assessment and analysis using synchronized measurements. There will be some effort to incorporate synchronized measurements in PQ assessment and analysis, especially to identify methodologies and tools to support A69 through A75 applications.

[181] N. Kesorn, A. Pichetjamroen, S. Dechanupaprittha and C. Jamroen, "Optimal PEVs charging control for frequency stabilization considering communication delay in remote microgrid," TENCON 2017 - 2017 IEEE Region 10 Conference, Penang, 2017, pp. 1469-1474, doi: 10.1109/TENCON.2017.8228089.

APPENDIX C: FEEDBACK FROM THE NASPI DISTRIBUTION TASK TEAM ON THE DRAFT REPORT

This section includes the feedback provided to ORNL and Quanta Technology from the NASPI Distribution Task Team. Feedback from the NASPI Distribution Task Team is in blue, and responses/comments from ORNL and Quanta Technology are in *green*.

Feedback contributors include Ahmed Abd Elaziz, Reza Arghandeh, David Laverty, Matthew Rhodes, Younes Seyedi, and Sascha von Meier. (Please accept our apologies if someone is accidentally missing from this list.)

Defining Measurements

It might be useful to include a section early on in the report that defines more clearly the characteristics of "synchronized measurements" to qualify for the applications discussed later.

The bottom of page 2 refers to the synchronized measurements streaming at 30 frames per second that enabled SDG&E's Fallen Conductor application. It should be made explicit that this required complete phasors since the algorithm uses angle differences.

120 and 240 reported frames per second (2 or 4 samples per cycle) are more reasonable numbers for voltage or current phasor measurements.

"Synchronized measurements" could reasonably be taken to mean

(i) synchrophasors with standard accuracy up to 1% TVE

(iii) rms voltage and/or current magnitude values only, delivered at 30, 60, or 120 Hz with time stamping.

(iv) continuous point-on-wave (CPOW) measurements with hundreds of sampled values per cycle

or some other combination of characteristics.

The report is generally based on (i). It may be worthwhile to consider extending the analysis of applications and use cases to the other categories, especially if there are enabled applications that don't overlap.

A definition of synchronized measurements was added in section 1.1.

Transmission vs. Distribution

There could be more discussion of differences in requirements, applications, and industry practices for PMUs in distribution vs. transmission networks.

This document lays great groundwork for distribution application roadmap development, but the one aspect that will limit its use is an understanding of the degree of time-synchronized measurement device deployment needed in distribution to supply the data for these applications. This may be out of the scope of this document, but at least a cursory discussion on the topic with references to recommended distribution time-synchronized measurement devices would be of great benefit.

The degree of synchronized measurements to be deployed on the distribution network has no simple answer. It will be algorithm- and application-specific and is beyond the scope of the report.

Smart Meters

There could be more consideration of smart meters equipped with GPS to provide synchrophasor capabilities. An interesting point re the Smart Meters is that going by the datasheets, the silicon they use probably already has the capability to produce "synchrophasor-like" measurements. This is at the cost of $10s rather than $1000s.

If available in the future, this would be a benefit to some of the use cases. Clarification on the use of existing technology/products and future technology/products has been added to the Executive Summary.

Performance Requirements

The listing of specific performance requirements for each application (measurement accuracy, availability, latency, sampling rate, and reporting rate), along with the more detailed discussion in Appendix B, is very useful. This analysis could prove valuable for the IEEE Distribution PMU Working Group C41.

Hopefully, additional requirements will be clarified in the pilot projects.

Prioritization of Applications

The approach seems reasonable and well thought out in general. It should help identify the juiciest low-hanging fruit for a utility looking into these opportunities. The rough characterization by application priority vs. added value of synchronized measurements is probably more useful than the ranking in Section 5.3 since the numerical ratings end up quite close together. The presentation of the data appropriately makes clear the tradeoffs among the various criteria.

The prioritization is based on the needs of a typical utility. Hopefully, the methodology can be adopted by utilities to define a more specific prioritization.

Section 4.12.1

Another use of synchrophasors and their timing information for supervisory and backup protection applications might be considered: Substation automation units can collect and process the data reported by different PMUs to monitor the operation of local relays and circuit breakers in real-time. If relay malfunction or misoperation of a circuit breaker are detected, then preventive/remedial actions should be launched to prevent power outage. This supervisory process essentially requires a certain degree of coordination between the protection and control subsystems. This coordination can be achieved by

- Processing the timestamps in synchrophasor data streams
- Capturing the fault inception

The protection part normally deals with the fault location identification and isolation by sending the trip commands. The control subsystems handle the secondary (centralized) control of dispatchable resources in the feeder to leverage the post-fault voltage stability. For example, data can be analyzed to:

- Predict the system states immediately after the fault isolation
- Determine the new setpoints of dispatchable resources or switch their controllers

This application was added to section 4.12.1.

System Architecture, Section 6

It would be useful to be more explicit about the expected system architecture for synchrophasor networks, including the location of the device(s) that run the application and analyze the synchrophasor datasets. This topic could perhaps be addressed in more detail in a follow-up report. Relevant questions include:

- Where is the application implemented physically – for example, in a microgrid central controller or a distribution substation? How many or what kinds of communications links are required to deliver the data to the application?
- Is a Phasor Data Concentrator (PDC) used, or some alternative data solution, local or in the cloud? Can a given application run on the PDC or data platform?
- What communication links are required, not just from the individual sensors/PMUs, but connecting to the application?
- Can we process the datasets and make a decision at the edge of the communications network to avoid unnecessary communications and lower the total latency for time-critical protection applications?
- How can different types of cyber-attacks jeopardize the integrity and availability of the synchrophasor datasets received by the application?

Additional application-specific details are expected to be defined in the pilot projects.

Industry Roadmaps, Section 3.1

Distribution Topology Detection can be a short-term goal with low or med difficulty for implementation. (See Figure 3-1).

This was added and clarified under A8 in AG2.

4.12 AG12: Advanced Distribution Protection and Control

Topology detection can also be an application under the Advanced Distribution Protection and Control category.

See above.

Comments on Section 4

Rationale for designing distribution-level PMUs with higher precision requirements compared to transmission PMUs [1]:

- In the distribution grid, the distance between buses is short (in a range from Km to a few meters). Therefore, the voltage drop between buses is small, causing a slight angle change between different buses (less than 0.02 degrees).
- The distribution grid suffers from harmonics, unbalanced conditions, and fast load-changing behavior. So, the Distribution level PMU must be designed with a high reporting rate to record these events and ensure good power quality monitoring.
- Moreover, the R/X ratio in the distribution grid is large. Therefore, the direction of power is not always from the lead to the lag. Accurate analysis is required to evaluate the load flow. As a result, the distribution level PMU is required to be designed with high angle resolution.

Transmission PMUs and distribution PMUs (or uPMUs) on the market today use the same or similar GPS receivers that have 1 pps with 50-100 ns timing accuracy as this translates to a 0.001- 0.002 degree angle precision. Hence transmission and distribution PMUs share the same angle precision because they use the same GPS receiver technology.

The GPS timing error provides a lower limit for phase angle accuracy, but whether the actual phase angle measurement accuracy can achieve the lower limit is determined by many other factors. The circuit noise, angle to digital circuit errors, sampling synchronization error, distortion in grid voltage and current waveforms, and phase angle calculation errors can contribute to phase angle errors.

The distribution applications we evaluated do not require higher angle resolution at the distribution level. However, in the future, some applications may require it. Many distribution-level transients are not best measured by PMUs. Synchronized point on wave would be the recommended measurement for fast transients.

About Sampling Frequency

One thing that must be considered about the DFT principle is that to estimate any phasor of frequency F; the sampling frequency must be greater than 2F. This means that at least three samples are used to provide the sinusoidal wave information. However, this condition does not ensure to adders the required angle resolution. This condition is a minimum requirement. Also, this concept is used for measuring the hth order harmonic [2].

The distribution grid LVS and MVS harmonics content limits are discussed for the 35th -50th order [3-4]. So, in order to calculate this harmonic, the sampling frequency should be at least f_s=(35*3*60-50*3*60)=(6.3-9)KHz.

For the angle resolution of 0.02, the sampling frequency is required to be at least f_s=360^o/0.02=18KHz [5]. The sampling frequency is chosen to be the highest value between the Power quality requirement and the angle resolution requirement, which is 18KHz for angle resolution around 0.02 degrees. Note that practical distribution level PMU by PSL is designed with (25.6-30.72 kHz sampling frequency). This represents an angle resolution of 0.01 degrees as described by the PSL data sheet [6].

Comment 1: Based on 1 and 2, first comment on Table (4.2) where the minimum sampling frequency is selected to be 480 Hz, which is corresponding to 8 samples per cycle and angle resolution 360^o/480=0.75 (approximately the resolution required by the traditional PMU) [7]. In this case, the 3rd harmonics is the maximum order that can be measured. This is not sufficient for power-quality monitoring, and it is better to revise the mentioned sampling rate.

The sampling rate limits the angle reporting rate. However, the angle precision is theoretically limited by GPS time precision. As noted above, most commercial GPS receivers have 1 pps at 50-100ns accuracy. This translates to a 0.001- 0.002 degree angle precision. Again, most transmission and distribution PMUs share the same angle precision because they use the same GPS receiver technology.

Additionally, as discussed in the previous question, a timing error is only a part of the angle measurement errors, the circuit noise, angle to digital circuit errors, sampling synchronization error, distortion in grid voltage and current waveforms, and phase angle calculation errors can contribute to phase angle errors. That being said, GPS timing error provides a lower limit for phase angle accuracy, but whether the actual *phase angle measurement accuracy can achieve the lower limit is determined by many other factors discussed above.*

Power quality measurements, either to monitor high order harmonics or to capture common events such as voltage sags and swells, require a higher sampling rate than normally provided by streaming SMDs. Existing commercial power quality monitors have high sampling frequencies and provide this data through time-synchronized record captures. The applications proposed in this report use synchronized measurements augmented by power quality record captures. Power quality applications can be modified to use streaming synchronized high sampling rate data when the application use case becomes clearly defined, and devices supporting this capability become available.

Comment 2: Table (4.6) I believe the reporting rate should be at least 120Hz since it is used in the transients stability evaluator. This is because transient events may exist for only 0.5 cycles [8-9]. Therefore, the distribution level PMU reporting rate, at this condition, is one measurement per half cycle. The same comment for the reporting rate is presented in Tables (4.7) and (4.8).

Wide area stability applications can utilize the rates in the table. 120 Hz reporting rates tend to be associated with local control functions. Future applications may require higher rates.

Comment 3: Authors mentioned “Latency.” If this word means it is the distribution level PMU response time, then 300 msec is equivalent to 18 cycles. The protection system is going to clear the fault with time between (5-6 cycles) [9]. This means the protection system will take action before the distribution level PMU latency? If I understand this correctly. Same comment for Table (4.8).

Most of the latency time is from communications. If synchronized measurements are needed for time-critical protection decisions, the measurements would be used locally or via a low latency communication network. This clarification was added to Section 6.3.

Comments on Section 5

Comment 4: Each application AG(1-19) requires a different number of synchronized measurements, which affect the number of installed distribution level PMUs. For example, IEEE 33 distribution grid needs 11 units with 20 current channels to perform application AG2 [10]. On the other hand, the number of units is increased to 15 with 28 current channels to perform application AG11 [11]. Based on that, AG11 required a more significant number of synchronized measurements than AG2, which means higher CapEx. However, in Table (5.4), AG2 and AG11 have the same CapEx & OpEx cost value.

A clarification was added to section 5.2.1.

Comment 5: Another important factor in cost evaluation criteria is the application running cost by the installed distribution level PMUs. Installing a larger number of units means higher running and operation costs [10]. More data are sent to the Phasor Data Concentrator, which means a larger amount of GB/Sec and higher communication cost. Additionally, AG11 requires a higher reporting rate which increases the OpEX factor compared with AG2, even if the same number of units is assumed for both applications.

A clarification was added to section 5.2.1.

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