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Using Micro-Synchrophasor Data for Advanced Distribution Grid Planning and Operations Analysis

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Abstract

This report reviews the potential for distribution-grid phase-angle data that will be available from new micro-synchrophasors (μPMUs) to be utilized in existing distribution-grid planning and operations analysis. This data could augment the current diagnostic capabilities of grid analysis software, used in both planning and operations for applications such as fault location, and provide data for more accurate modeling of the distribution system. μPMUs are new distribution-grid sensors that will advance measurement and diagnostic capabilities and provide improved visibility of the distribution grid, enabling analysis of the grid's increasingly complex loads that include features such as large volumes of distributed generation. Large volumes of DG leads to concerns on continued reliable operation of the grid, due to changing power flow characteristics and active generation, with its own protection and control capabilities. Using μPMU data on change in voltage phase angle between two points in conjunction with new and existing distribution-grid planning and operational tools is expected to enable model validation, state estimation, fault location, and renewable resource/load characterization. Our findings include: data measurement is outstripping the processing capabilities of planning and operational tools; not every tool can visualize a voltage phase-angle measurement to the degree of accuracy measured by advanced sensors, and the degree of accuracy in measurement required for the distribution grid is not defined; solving methods cannot handle the high volumes of data generated by modern sensors, so new models and solving methods (such as graph trace analysis) are needed; standardization of sensor-data communications platforms in planning and applications tools would allow integration of different vendors' sensors and advanced measurement devices. In addition, data from advanced sources such as μPMUs could be used to validate models to improve/ensure accuracy, providing information on normally estimated values such as underground conductor impedance, and characterization of complex loads. Although the input of high-fidelity data to existing tools will be challenging, μPMU data on phase angle (as well as other data from advanced sensors) will be useful for basic operational decisions that are based on a trend of changing data.

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ACRONYMS

AMI	advanced metering infrastructure
CIEE	California Institute for Energy and Environment
DER	distributed energy resources
DG	distributed generation
GIS	geographic information system
GTA	graphical trace analysis
LBNL	Lawrence Berkeley National Laboratory
µPMU	micro-synchrophasor
OMS	outage management system
OPC	object linking and process control
PSL	Power Standards Lab
PV	photovoltaic
SCADA	supervisory control and data acquisition

1 Introduction and Background

The minimal measurement and diagnostic capabilities of today's electric power distribution systems result in operators and planners having little situational awareness of the operating state of their system. This in turn can limit opportunities for grid modernization, including renewable energy integration. With the emergence of distributed energy resources (DER), including distributed generation (DG) and demand response (DR) on the distribution grid, the need is growing for real-time monitoring and quasi-real-time analysis of grid behavior and improved communication of measured data with distribution planning and operations tools.

Distribution planners and operators require high-quality data delivered in a timely manner so that they can make valid choices in both the near and long term. Timeliness will depend on the application of the data; for example, operations require short-term decision making information, while planning may require longer-term calibration data. Data quality will translate directly into power system model accuracy and will directly affect the quality of the results from distribution grid analysis tools. Conversely, the tools may have different accuracy standards than the measured data, and when the data is input this could result in a lack of confidence in either the model or the data. Impact of multiple, different accuracy constraints must be considered when measuring data and performing validation of models and power systems analysis.

The California Institute for Energy and Environment (CIEE) at the University of California, in conjunction with Lawrence Berkeley National Laboratory (LBNL) and Power Standards Lab (PSL), are examining the capacity for micro-synchrophasors (µPMUs) to improve the performance of electric power delivery, through a project funded by the Advanced Research Projects Agency-Energy (ARPA-E) (von Meier et al., 2014). A key element of this activity is determining the capabilities of grid planning and operations software packages to integrate µPMU data and to analyze advanced distribution grid scenarios.

This report reviews the potential for existing distribution planning and operations tools to utilize data from advanced sources, particularly µPMUs, and evaluates the extent to which commercially available, widely used packages for transmission and distribution planning and operations analysis can incorporate and visualize these data.

Advanced data sources such as μPMUs can be used to validate distribution planning models and to improve load, DER and renewable generation characterization and modeling. As greater volumes and sources of real-time data are being integrated into operations, planning tools begin to merge into operational tools for advanced analyses such as fault location, state estimation, and model validation. We review examples of tools that are reported to have these analysis capabilities and assess whether and how μPMU data could be integrated into the tools. We also review how μPMU data can be used to validate models to improve their accuracy.

μPMUs will be demonstrated in selected utility and campus locations. We will use data from this demonstration to determine the accuracy of distribution models provided by utility partners by comparing the tool results to measurements at selected locations. This type of comparison will be essential for validating distribution grid models to ensure that simulation tools accurately represent system behavior.

A key objective of the μPMU demonstration project is to provide evidence of the usefulness of distribution voltage phase angle data. This includes re-creating potentially interesting grid events using validated models. Simulation of events is essential because similar grid events might not occur during the demonstration phase for the measurement devices. Models also help define where data should be collected (i.e., identifying optimal placement of μPMUs) and the volume of data required for various use cases.

This report analyzes commercially available distribution planning and operations tools used in the utility industry and in the applications of the μPMU project. Using empirical measurements in conjunction with modeling and analysis of distribution circuits, we examine the usefulness of phase angle as a state variable and identify the challenges associated with using phase angle data in planning applications.

A companion report, "Software-Based Challenges to Developing the Future Distribution Grid," (Stewart and Kiliccote et al. 2014) describes in general the capabilities of available distribution modeling tools. The current report complements the previous report by specifically reviewing ability of these tools to utilize μPMU data. The initial report developed a review of the state of the art of tools for distribution modeling in general, whereas this report specifically focuses on the use of μPMU data.

As discussed in the first partner report, distribution grid tools must have basic functionality for some or all of the following analyses: steady state, time series, dynamic, protection, and transient. The following tools are discussed here in terms of specific usage in the μPMU applications and data integration needs:

- CymDist (Cooper)
- PSS/Sincal (Siemens PTI)
- DigSilent Power Factory (DigSilent GMBH)
- DEW (EDD)

For applications including state estimation and fault location we will discuss the current industry offerings in the operational realm including ETAP, Alstom E-Terra and Schneider ADMS.

The remainder of this report is organized as follows:

Section 2 discusses measured data sources on the future distribution grid and their integration with existing tools and applications for distribution planning and operations.
Section 3 discusses visualization of advanced measured data in distribution-grid planning and operational applications, i.e., the ability of tools to graphically represent voltage phase-angle measurements.
Section 4 discusses integration of measured and modeled data with distribution planning and operations tools, including the limitations of the tools' solving methods in relation to utilizing these data.
Section 5 discusses accuracy and validation in distribution modeling software and hardware.
Section 6 discusses selected applications of μPMU data, including fault location and state estimation.

2 Measured data availability and needs

Using models for distribution planning requires that they be able to connect to measured data as well as data from other simulation models. During import of a model to a planning tool, various sources are integrated, including geographic information system (GIS) data, customer load data, and equipment data. Substation-level measurements (e.g., SCADA [Supervisory Control and Data Acquisition]) are often used to determine feeder loading and proportionally allocate load to customer locations within the model, as a proportion of distribution transformer size. If customer load is available, from billing information systems, it can often also be allocated as kWh usage at the distribution transformer level. One way that µPMU data could be used is to improve determinations of load size and characteristics; that information could then be used to improve the results of planning models.

The future distribution grid will likely contain large numbers of DG and storage units, including solar photovoltaic (PV), and thus will require different control mechanisms and more complex analysis than are currently employed (Martinez et al. 2011). These new active generation sources introduce new behaviors relevant to system stability and protection characteristics; they also increase the volume of unknown conditions, such as load masked by generation behind a net meter, and make it more difficult to anticipate circuit loading and voltage levels during and after switching operations. Without measuring and characterizing these unknowns there is potential for a decrease in reliability and confidence in the performance of the distribution grid. To date, measured data sources required and available on the future distribution grid include (Martinez et. al. 2011):

- SCADA data
- Distribution line sensors
- Smart metering and advanced metering infrastructure (AMI)
- Weather data

The deployment of µPMUs on the future distribution grid could facilitate a new level of communication and control.

As the distribution grid evolves to accommodate an increasing number of DG and storage installations, the time scales of these generation sources will influence the development of distribution modeling tool analyses, both in the steady state (i.e., at a single point in time) and for transient (i.e., sub-cycle) analyses. (See Stewart and Kiliccote et al. 2014 for a discussion of these types of power system analysis).

2.1 Data Sources

In this section we shall describe some of the common existing data sources in detail and how each of them compares with the data to be available from μPMUs. These are important and relevant to this report because the μPMU should complement and integrate with the existing data sources, while providing a much greater level of resolution and detail. Understanding how these existing data sources are integrated to the existing operations and planning tools will also allow for greater understanding of the challenges of integrating a new data source with shorter measurement time frames.

SCADA data are real-time operational data communicated from a measurement and control point to a utility interface and usually archived for future analysis. SCADA data normally include voltage, amps, real and reactive power flow, and transformer or switch status. SCADA data also include non-operational data or event summaries such as reports or event sequences. SCADA data are typically recorded and transmitted in real-time over 2 to 4 seconds but are often archived on a 5- to 15-minute sample basis.

Line sensor data are acquired from sensors installed on distribution lines. Overhead line sensors are usually used to measure current and disturbance information and communicate wirelessly with the utility. They are often used for fault detection. Some examples include GridSense[1] and Sentient. [2]

AMI includes smart metering and net metering at the customer (residential, commercial and industrial) level. AMI can communicate to a meter data management system such as those

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[1] http://www.gridsense.com/

[2] http://www.sentient-energy.com/

integrated with some power systems applications, e.g., PSS/Sincal (Siemens PTI). Presently, AMI networks are designed for customer billing, DR, net metering, and outage information, allowing customers to see their own demand and utility operators to see customers' status for purposes of outage management. The use of AMI data today is more constrained by communication bandwidth and back-office data management than by the physical capability of the meters. For example, smart meters measure voltage at the customer service entrance, but typically do not communicate that information. Although AMI applications are currently limited, several could be enhanced to collect additional data from customers, including voltage, real and reactive power flow to the grid if DER are present, and power quality. These additional data would enhance the visibility of the distribution grid and its performance in planning and operations applications. Time steps in AMI applications are typically limited to hourly data, but the frequency could be increased (NIST 2010). In future applications, AMI data could also be synchronized with μPMU data locations and SCADA data to provide a fuller, more accurate picture of grid behavior and enable validation of each source.

Weather data includes measured solar irradiance, wind, temperature and humidity. Irradiance data are often used to determine the potential output of utility installed photo-voltaics. Wind speed, temperature and humidity can be used to predict other renewable generation potential, to predict the impact of storms and other weather events, or to inform dynamic ratings of thermally limited equipment such as overhead conductors. Weather data integration with energy management systems and distribution management systems is being demonstrated in places such as Hawaii (Nakafuji et. al 2013).

μPMU sensors are a new information source at the distribution level that can provide voltage and current magnitude measurements at a high sampling rate of 512 samples/cycle (about 30 kHz) and voltage phase angle (enabled by precise GPS time stamping) computed twice per cycle. Thus, μPMUs are capable of providing unique visibility into short-term characteristics of the distribution system. We now consider the time scales of these data sources and where the new measured data source will fit.

2.2 Data Time Scales

Each of the above data sources, like power systems themselves, have inherently different time scales of importance. For example, economic price signaling to DR could be on an hourly basis, but could also inform customer behavior and therefore load in shorter time steps once DR is activated. Weather data for forecasting of short-term variability is on the seconds-to-minutes time scale. Grid and component models require scales from sub-cycle to seconds to hours (**Figure 1**). Future distribution grid planning and management decisions will require knowledge of evolving grid conditions that is collected at many different time scales; therefore, planning and operational software applications will need to be prepared to take in different formats and fidelity.

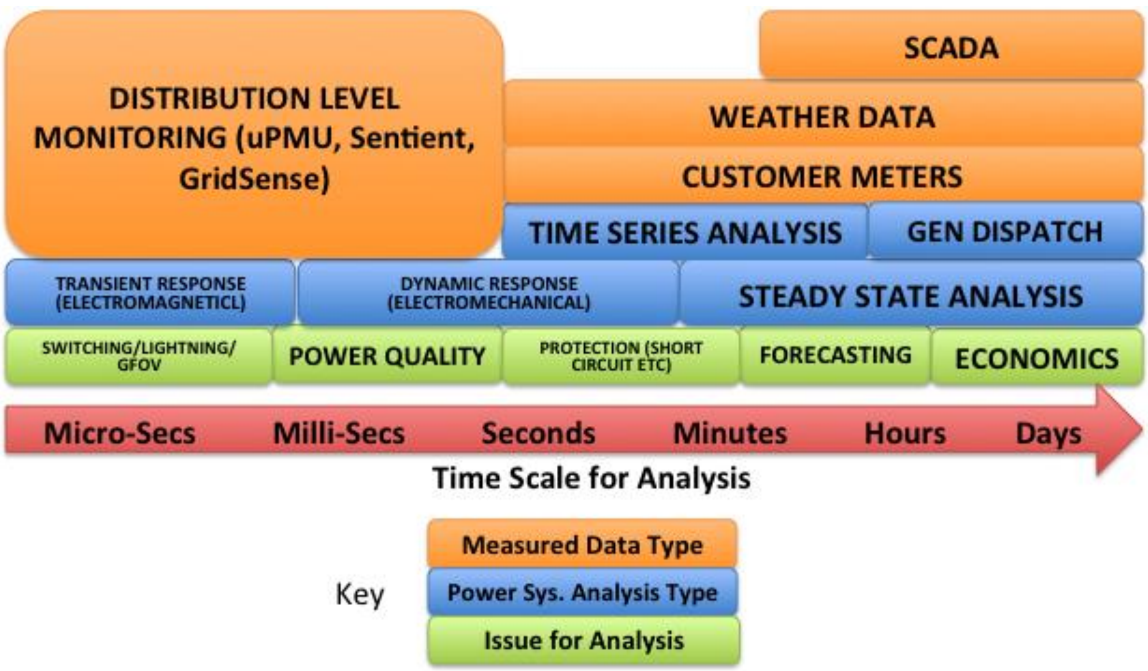

Figure 1. The range of data requirements and time scales at utilities

2.3 Data Quality

Distribution grids lack high-quality measured data from existing data sources, and model validation is an essential use of enhanced measured data. Data quality is defined by the latency, accuracy, ease of use, time-resolution and, most importantly, availability of the data. The cost of distribution sensors is one of the major limiting factors in receiving quality data from the distribution grid. Without a major outage incident on the grid, there is limited motivation for utilities to purchase distribution sensors. In addition, data storage issues limit the fidelity of data collected.

Each of the applications being researched requires a different level of data fidelity. Steady-state circuit behavior, topology detection and state estimation could rely on a sample rate of 1 - 2 samples per cycle, and an angle resolution of 50 to 300 milli-degrees. Dynamic circuit behavior could require 2 to 512 samples a cycle, and an angle resolution of 10 to 50 milli-degrees (von Meier and Arghandeh et al. 2014). Replication of the results in software packages would depend on the application and the basic functionality of the software. Steady-state applications and longer-term dynamics could be visualized in CymDist, DEW, PSS/Sincal and DigSilent PowerFactory. Transient visualization would be limited to packages such as DigSilent, PSS/Sincal and specific transient packages such as PSCAD.

3 Visualization and accuracy of phase angle data in existing planning tools

This section focuses on phase angle data from µPMUs and the ability of distribution-grid analysis tools to graphically represent these data to either the measured degree of accuracy, or the degree of accuracy required for a specific application.

The first consideration is whether voltage phase-angle data can be viewed in the tools' graphical user interface (GUI), or results output. Voltage phase angle is traditionally used in the back end of simulations, since it is mathematically an essential state variable that must be computed at every node for the power flow calculation. However, the voltage phase angle is not always explicitly presented in the GUI, because it has not traditionally been part of distribution system performance analysis in the manner that will now be possible. While dynamic behaviors and topology changes will be captured at the device level, the device measurements may be used in conjunction with models in planning or operations simulation tools to either determine a remedial course of action (say, in the event of an dynamic issue) or to diagnose and reconstruct what events may have caused the observed phase angle change. Another example of augmenting existing simulation tools with phase angle measurements would be the opening of a switch in the network, where a visualization of phase angle could aid significantly in determining switch status (topology detection) or determining permissible switching reconfigurations that will not violate constraints.

The second consideration is whether a tool can render voltage phase-angle data with the degree of precision and accuracy comparable to the measurements collected by the µPMU. Relevant phase angle differences in distribution systems are very small compared to those on transmission systems, i.e. fractions of a degree rather than tens of degrees (Wache et al. 2011). To provide significant information about power flow on distribution circuits, phase angles will likely have to be reported to within ten millidegrees ($1/100^{th}$ of a degree), corresponding to an accuracy or total vector error (TVE) of about 0.2%.

We previously reviewed the capabilities of commonly used distribution planning tools in Stewart and Kiliccote et al. 2014. Of the six tools evaluated, CymDist (Cooper), PSS/Sincal (Siemens PTI), and DigSilent PowerFactory (DigSilent) can represent phase angle in tabular format, but not graphically down to the requisite decimal place. DEW (EDD), can provide voltage and current phase angles, that can be plotted against distance or time. SynerGEE Electric (DNV GL) and ETAP cannot represent phase angle graphically or in tabular form down to the 1/100th decimal place. Further research is required into the accuracy of the simulated data versus the measured data and will be reported on later in the project timeline.

4 Integration of measured and modeled data into tools

As the distribution grid evolves toward more complex loads and more distributed generation, distribution planning and operations functionality are coming together; measured data from the grid itself and from customers form the bridge between planning and operations. Distribution planning may need to account for more dynamic, faster changes to the distribution grid, whereas operations may need to work with a longer time horizon looking into the future, given greater volumes of active resources whose behaviors must be anticipated. Thus, the time scales on which operating and planning decisions are made will no longer be as neatly separated.

We previously (Section 3) discussed the availability of measured data sources for the distribution grid and reviewed whether planning and operations software can visually display the new measured μPMU phase-angle data in simulation results. Following from this, we now discuss how the existing and new data sources, such as the μPMU could be processed within the tools. We also will compare the usage of measured data or device characterization using the μPMU data, versus existing models and statistical data for analysis of distribution grid features and distributed generation.

As a key comparison point for the utilization of μPMU data, we choose the modeling of distributed generation (DG). Within the next 10 years, distribution grids could contain a complex mix of generation, storage, load, demand response (DR), and automated resources all operating on different time scales, creating a growing need for real-time monitoring and quasi- real-time planning analysis of the distribution grid. Of these diverse distributed resources, solar DG has seen the highest penetration levels to date; it also presents unique modeling challenges such as dynamic behaviors and change of power flow direction. We expect that μPMU data can be utilized to provide crucial information about the behavior of DG. Measured data will only be useful, however, if it can be interpreted and utilized effectively in combination with planning tools, which will require new forms of data management and education of tool users.

The current approach to distribution grid planning software development is a combination of accommodating detailed models and approximating representations of key components, such as inverters and loads. This is not an integrated approach and thus cannot address all needs of the future grid. Although some advanced analysis tools have been developed, current tools are in a rudimentary stage relative to the analysis required for a modernized grid. Moreover, the capabilities and appropriate use of these tools for distribution planning are not well understood.

To summarize, the distribution grid models and analysis tools must represent the complex load and DG combinations accurately. These models can either be statistical data inputs or modeled representations of the devices responding to stimuli from the grid. The modeled representations can either be seated within the software package themselves, pre-defined or user defined or they can be external custom models in a separate package called from the base analysis package. Models internal to the software means proprietary formats for each new simulation package and every inverter. Alternately, two new methods being considered are (1) locating the devices models in a more common software platform and linking this to the distribution model; and (2) purely using measured data inputs as a representation of the behavior of a device (Figure 2).

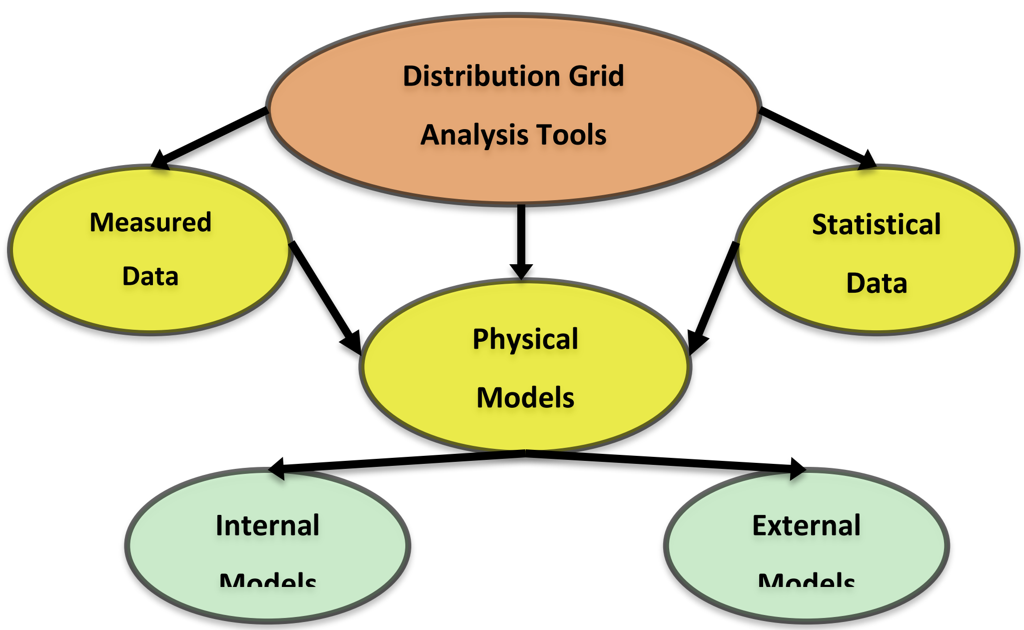

Figure 2. Integration of data sources with distribution modeling tools

Using the tools presented earlier we will use load and inverter modeling as a basis for the ability of commercial tools in these realms for both internal modeling of devices and external data linkages. We will also discuss the ability of the tools to link to measured data and externally modeled components. The following areas are addressed in the subsequent sections:

- Modeling of complex components internal to distribution planning software
- Coupling of external component models
- Integration of measured data for advanced applications

4.1 Modeling of complex components internal to distribution planning software

The modeling of inverters in distribution planning tools is a key example where statistical, modeled and measured data can intersect. While this is not the only example of the necessity of integration of many data sources, we will discuss itas one of the most relevant examples.

Statistical data can be used simply for inverter power output, whereas block diagrams and differential equations can represent complex and often proprietary performance behaviors of the inverters. Measured data can be used either as an input to simulation tools in place of the inverter, or to validate the internally modeled components. We shall now discuss the capabilities of tools to model inverters internally using either statistical or component level models.

Inverter models in power system simulation are widely discussed in the literature (Behnke et al. 2011, Ellis et al. 2012, Ropp et al. 2012, Muljadi et al. 2013). Keller et al. (2010) and Ropp et al. (2012) have analyzed the progress in modeling of inverters in fault current, dynamic and transient realms. We do not repeat the conclusions of these studies but summarize the key issues in each software package for modeling in these realms.

A standard way to model customer-owned solar DG is to represent it as negative load. This is consistent with the physical and contractual arrangement of net metering. However, as

DG penetration levels increase, so do the modeling complexities, requiring dynamic and detailed component models. For example, a negative load model of DG can never cause reverse power flow. This also means that modeling cannot account for DG's protection and control impacts. In the event of a fault, the negative load representation does not show the DG's fault current contribution, nor can DG as a negative load be shown as islanding or tripping during load-shedding and switching operations. But if models cannot simulate what DG can actually do, it is not possible to plan for fully utilizing its capabilities.

While we provide solar inverter modeling as the example of internal component modeling, there are numerous other distributed resource technologies that will require future representation, including EV's, DR and complex loading. Statistical and block modeling may provide some representation, but the proprietary nature of each of the tools and components will result in an awkward multitude of different format models for all the components in each tool. One solution to this problem is to use a tool that can couple with more generic packages such as Simulink. The models can then live in the single format and be called to perform during the simulation.

The key issues for inverter modeling in distribution planning are:

- Representation in steady state, dynamic and transient realms
- Time series and time step capability
- Accuracy of the models
- Combined model types
- Weather data integration
- Potential for integration with external models such as Simulink

We review the tools ability to perform in these key areas in Table 2.

	PSS/Sincal	CymDist	DEW	DigSilent
Steady State	Yes	Yes	Yes	Yes
Fault Current	Yes – impedance based modeling. Integrated models for FC with steady state, protection library available	Yes - impedance based modeling. Integrated models for FC with steady state, protection library available	Yes	Yes – impedance based modeling. Integrated models for FC with steady state, protection lib available
Time Series	Seconds	Seconds	Seconds	Seconds
Control Models	Yes	Yes	Yes	Yes – standard IEEE controller modules
Dynamic	User defined models	Long term dynamics with user defined models	No	IEEE controller modules and user defined models
Transient	Yes	No	No	Yes
Weather/Data Outputs	User input	User input	Linkage to Clean Power Research data	User input
External Interfaces	Matlab/Simulink for Dynamic	Matlab/Simulink for dynamics	Yes for steady state inverter control analysis	Matlab/Simulink for dynamics

Table 2: Capabilities of Distribution Grid Planning Software for inverter modeling

4.2 Integration of measured data for advanced applications

As noted earlier, the diagnostic applications to be investigated for the µPMU data project are state estimation, topology detection, fault location, and model validation. The applications require information from a network of distribution synchrophasor measurement devices that may output two to 20+ data points per distribution feeder at a rate of up to twice per a.c. cycle (120 times per second) . The data will either be stored within the device or communicated directly via Ethernet or wireless cellular network to the utility or analyst. Applications developed through the ARPA-E funded project will use the data to provide information to operators and planners. This information needs to be integrated with existing or new communications systems (not the subject of this report) and other sensor technology; it must also be input to distribution planning and operations tools to support real-time, near real-time, and longer-term planning activities. To accommodate these data, distribution planning and operations tools will need to process large volumes of measurements and potentially run both steady-state and dynamic analyses accounting for grid conditions that vary rapidly because of grid automation, quickly changing renewable energy sources, and demand response. Resiliency and stability in the modernized grid will depend on the measurement and communications of these types of high-fidelity data and the rapid analysis of these data by advanced tools.

Custom operations tools currently accept SCADA data (4 second to 15-minute time steps), weather measurement devices (15-minute to hourly time steps), and AMI data (15-minute to hourly time steps) for outage location and management. In contrast to the SCADA and AMI time steps, µPMU data time steps will be in the range of milliseconds to minutes. The reporting frequency by µPMUs can of course be reduced, but at the expense of leveraging some of their unique capabilities.

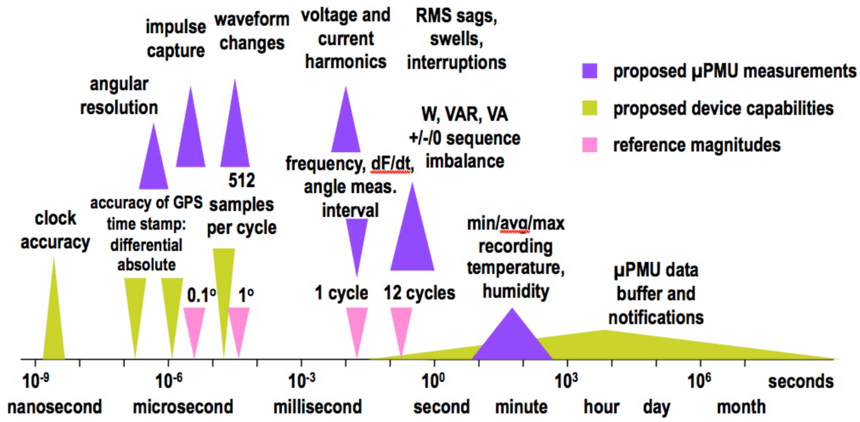

Figure 3. μPMU measurement data time steps

The ability of distribution grid operations and planning tools to accept dynamic and transient data collected in small short steps is not well documented. However, in future grid scenarios, the real-time input of these data may form the backbone of early detection of and response to faults and other operational conditions. In this section, we discuss a number of tools that are used commonly in distribution system planning and that claim to be able to accept data inputs from measured sources.

Currently CymDist Gateway, PSS/Sincal, and DigSilent report that they allow inputs of smart meter/AMI and SCADA data to their advanced planning tools, but the time scales for integration of these data are not indicated. Gateway software from CymDist integrates and extracts information from GIS and enterprise systems to generate the distribution models; but this type of information does not tend to change rapidly or need frequent updating. Gateway reportedly can interface with GIS, AMI and Meter Data Management systems (MDM), Common Information System (CIM), SCADA, distribution management system settings, and Operations Management Systems (OMS) history. Gateway can also perform model validation (as a connectivity check), batch calculations, load allocation, and assignment of protective coordination devices. This is an in-house customizable tool developed for each utility's systems.

For rapid handling of large data sets, such as those that result from AMI measurements, DEW uses protobuf files (i.e., protocol buffers), which is Google's data interchange format. DEW provides an Open Platform Communications (OPC) interface for real-time data and has interfaces to data historians, including PI (Plant Information). Using these technologies, DEW can analyze large data sets, such as one-second solar generation measurements for a year. DEW also has standard SCADA interfaces such as Inter-Control Center Communications Protocol (ICCP).

Although most tools reviewed have an interface to connect to existing measured data sources such as SCADA, their ability to connect to new and custom data sources is either limited or not well documented. Most tools require some customization to receive and use these data, but it is not clear whether high-fidelity data can be handled with existing processing capabilities. This is especially true for inputs that would be updated very frequently, since there is presently very little in the way of installed sensors that provide reporting at rates greater than once every 15 minutes. The use of high-resolution data could limit model convergence, as discussed in the next section below.

4.3 Summary

In Table 3 we summarize the capabilities for data and model integration and computational efficiency for some of the more commonly used packages we have discussed.

Table 3: Capabilities of Distribution Grid Planning Software for model and data integration

	DigSilent	**PSCAD**	**DEW**	**CymDist**	**PSS/ Sincal**
Potential to link to µPMU data	High Potential	Potential	High Potential	Potential	Potential
Data integration potential – other data	AMI, SCADA, CIS, Weather	Unknown	AMI, SCADA, Weather	AMI, SCADA, MDM	AMI, SCADA, CIS, Weather
External component modeling	Yes (Matlab)	No	No	Yes (Matlab)	Yes (Matlab)
Phase Angle Visualization	Yes	Yes	Yes	Yes	Yes
Simulation &					

Processing Constraints					
Detail of inverter Modeling	Highly Detailed component level	Highly Detailed component level	Control models for steady state and time series	Detailed for dynamic analysis	Highly detailed component models
Computation Level	Moderate Speed	Slow Processing	Fast Processing	Moderate Speed	Moderate Speed

As the distribution system evolves and new resources come online, it becomes imperative that these resources are modeled correctly and their impacts on the grid are analyzed. These resources will have mutual impacts and intentional as well as unintentional interactions with others on the grid. These impacts cannot be understood, nor can the deployment of these resources be coordinated in an optimal manner, , using only a single software package; instead, this will require the coupling of numerous packages that individually and accurately model these resources. The coupling can either be through measured or modeled data sources.

Models for inverter dynamic and transient stability are generally proprietary. Although some generic modeling is available, the components' time constants and control loops are unpublished, so detailed modeling will always have inherent estimations and errors. The single-model-source concept, in which the user of simulation software would not need to coordinate among multiple model types (steady state, short circuit, dynamic, transient) to analyze advanced grid conditions, would address the limitations imposed by the current proprietary models.

This generic co-simulation environment may then allow the inclusion of these proprietary models which would benefit both the proprietor, as they seek to continuously analyze and improve their physical model, and the distribution planner, as they attempt to gain a better understanding of the effects of inverters and how these resources can be optimally deployed.

Integration of measured high fidelity data sources such as the μPMU will provide numerous benefits to the distribution grid modeling world. Overall the measured data could replace the need to model many complex aggregated components at the customer and grid level. This measured data could also characterize and represent complex load and generation technologies and grid phenomena not yet realized. Lastly, the data can validate the models being used or allow for more detailed fitting techniques for modeling to be applied.

5 Solving Methods and Data Processing

We discuss above the ability of planning and operations tools to process high-fidelity and existing distribution grid data, which will come from numerous sources on the future grid. To accommodate the large quantities of data that will be generated by the new measurement sources, tools will need efficient methods for processing and solving power flow and other applications. The power flow problem – that is, identifying the complex voltages at each node in the network or currents in each branch, given a set of loads and power injections along with fixed characteristics of the network – is deceptively difficult, because there is no closed-form solution; it requires a numerical iteration process.

There are two methods of solving a power systems network model in operational distribution modeling software packages: graph-based and matrix-based. Aside from DEW, which uses a graph-based approach, the majority of planning tools discussed in this review use the matrix-based approach. Each approach has inherent advantages and disadvantages.

Matrices have traditionally been used for circuit representation and to solve power-flow equations, as they can be more simply translated into programming languages. Matrices have the advantage of being well understood in industry, widely implemented and documented for different functions in commercial transmission analysis software, and later by distribution packages. Usually, iterative power flow solution methods like Newton-

Raphson or Gauss-Seidel are based on power balance equations in the matrix form. The power balance equations include real and imaginary parts of the network admittance matrix **Y**., (Admittance Y is the inverse of the complex impedance Z and accounts for the electrical conductance and well as its imaginary counterpart, the magnetic susceptance, between any two nodes on a circuit.) The size of the admittance matrix **Y** is NxN, where N is the number of system buses. In a realistic power network with thousands of buses, the Y matrix is quite sparse, because each bus is usually connected to few other buses. In distribution networks, both the size and sparsity of the admittance matrix can be much greater than in transmission networks, because of the higher number of nodes and radial structure of distribution networks. (Every distribution transformer constitutes a node, but only adjacent nodes are connected to each other.) Large and sparse network matrices cause algebraic difficulty to find feasible solution for power flow equation sets.

The admittance matrix is also a representation of the network topology. Any single change in any switch status or connectivity between buses (nodes) required updating the whole network admittance matrix (e.g., inserting a zero admittance where a switch between two nodes was opened). The matrix-based network formulation shows a global view of the system. For a large distribution network, updating the matrix is computationally intensive.. However, accuracy and speed of solution are vital features of power flow solvers.

The other school of thought in distribution network modeling comes from graph theory. Here a grid is modeled as a graph G = {V,E} where V ={0,1,...,N} are the ordered nodes, vertices or buses of the grid and E={1,2,...,E} are the ordered edges, lines or conductors of the grid. Each edge has a start node and an end node, and the nodes are used to determine connectivity. That is, two edges that have a node in common are connected.

The graph representation of the network is a local approach: every edge only knows about its neighbors, and there is no need to maintain the large and sparse system admittance matrix.

The DEW software package is the only solution that relies on a graph theory-based approach called graph trace analysis (GTA). GTA is a topology search method that iterates from one node to the neighboring node and updates the network connectivity and physical characteristics like impedance, voltage drop and current flow. In DEW-GTA the system equations can only have knowledge of variables that can be measured at the terminals or boundaries of a component. The GTA power flow method in DEW is naturally distributed and fast without the need for maintaining a large system admittance matrix. It makes it possible to solve the power flow problem in a few seconds.

DEW is an objective oriented modeling tool which its software interface lets users to attach their own algorithms into DEW Integrated System Model (DEW-ISM). This means that algorithms can be added to the model instead of directing data to algorithms outside the model. This is a very important strategy for accommodating smart grid data sets and represents a major paradigm change in the industry.

6 Distribution tool accuracy and measured data accuracy

The preceding sections of this report describe the abilities of current distribution modeling software packages to integrate data from new measurement sources such as µPMUs. We also discussed the likely features of the new data streams that will drive but also support the need for more accurate analysis than is currently performed. Accurate analysis is defined by, for example, how closely a tool's output during a grid event or power flow corresponds to measured, real-world grid behavior. Although a tool may have many advanced features, it is not useful if its model is not accurate. The quality of the data input to the models directly affects the accuracy of the results. Using measured data to validate and calibrate models will dramatically enhance the value of grid analysis tools.

By necessity, some degree of error is accepted in engineering analysis of the distribution system. The Institute of Electrical and Electronics Engineers' (IEEE) standard for accuracy is to within 0.5% for voltage and current output at nodes. As noted earlier, µPMU measurements conform to 0.2% accuracy for power, therefore the sum of the voltage and current measurement errors must be less than 0.2%. Phase angle measurements are reported to be under 1% Total Vector Error (TVE), defined as the square root of the difference squared between the real and imaginary parts of the theoretical actual phasor and the estimated phasor, ratioed to the magnitude of the theoretical phasor (IEEE. 2011 C37.118.1-2011). Thus, there is potential for difficulty in resolving the error between measured and simulated phase angle. The practical impact of errors at these levels is small, but when the percentage error is greater, it can have both economic and technical impacts.

For example, an impact study of the distribution system could indicate a power-quality issue caused by an interconnecting generator (McMorran et al. 2011). A number of items could affect the accuracy of the study results, from conductor type to the source impedance and control strategy for existing equipment. If the study results are erroneous, the utility might require the interconnecting generator to install expensive mitigation equipment that might not actually be necessary, possibly rendering the DG uneconomical. Conversely, the model could err in representing the interconnection as not having a negative impact, which could then result in an unanticipated power quality issue with adverse economic and technical consequences for both customers and the utility. Significant safety impacts could result if, for example, a lack of accurate knowledge of grid topology led field workers to inadvertently switch into an unknown topology and cause an arc flash or overloading. Many such problems would be avoided by validating distribution models with reliable measured data, and this will be a foundational use of the μPMU data to be reported on at a future date.

Errors in distribution operations and planning can be a result of the original data source. Three major contributors to input data error in electrical distribution modeling are discussed in detail in Stewart and Kiliccote et al. (2014):

- GIS data (equipment, conductors)
- Switching and topology reporting
- Customer and load data (aggregate and locational)

With numerous and growing sources of error, validation of models is essential to ensure accurate simulation of the distribution system. We propose in the following a basic initial validation process for the steady state and time series components of the work. Accuracy requirements for the tools following this validation process, and the potential for utilization of the μPMU data will be subsequently reported.

Key validation elements include re-creating steady-state performance, running simulation scenarios for which measured data are available, and locating sources of error. Dynamic measured response and analysis for selected operations can be used with enhanced measurement to determine whether devices are characterized effectively. With future advanced measurement sources providing data, we propose the validation process for distribution models in Figure 4.

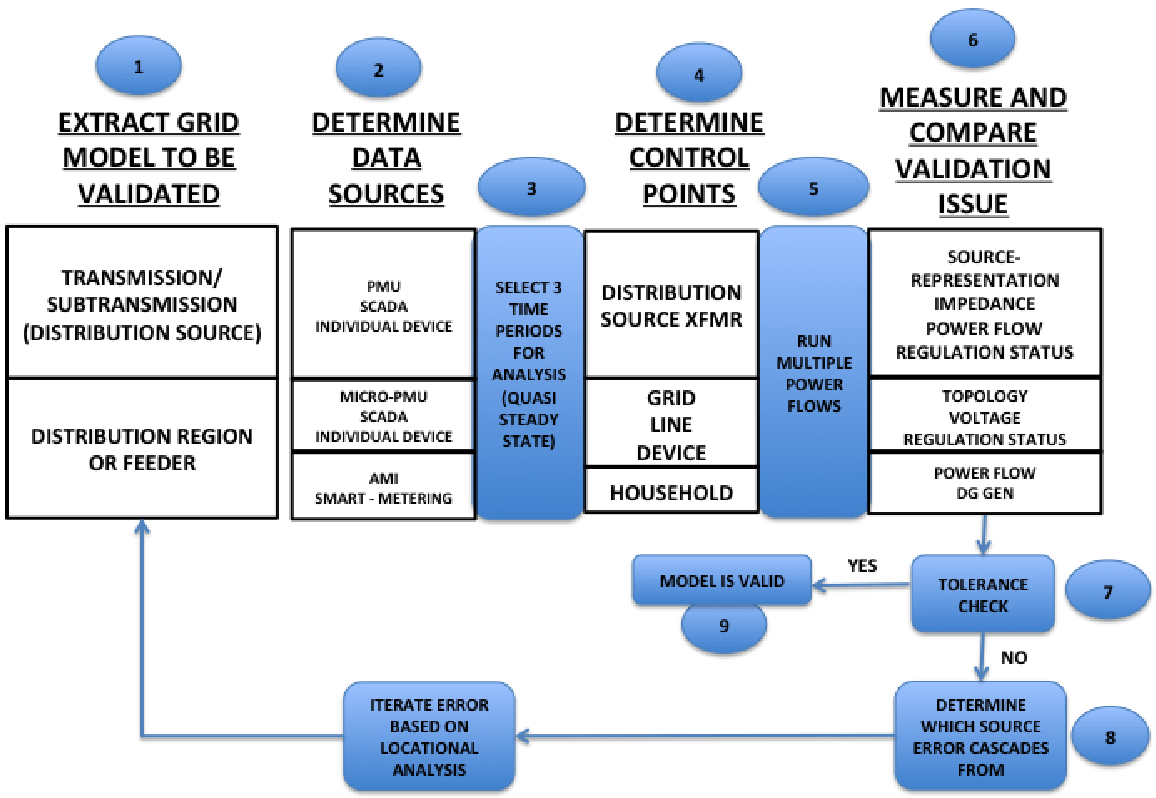

Figure 4. Potential validation process for distribution planning models

In Figure 4 we describe an iterative process for validating distribution models. Initially we extract the model from the GIS database and combine this with customer load data sources. Following this we must determine what measured data sources are available which could be used to validate different points in the model (step 2). At the very minimum we require a measured voltage at both the start and end of the feeder at numerous loading stages, meaning we can determine the impedance is accurate. Further control points (step 3) could include lateral measurements, customer smart metering and voltage regulation device settings (step 4). After running many power flow conditions (step 5), the user can compare if the measured and simulated data at control points is within reasonable tolerance (step 6). Bearing in mind that distribution planning tools report approximately 0.5% accuracy, this would be a reasonable tolerance (step 7). If an error is present the user can determine from the point where it varied past 0.5%, and work backward to determine, for example, the incorrectly modeled conductor segment. Following this the process repeats until we reach the required tolerance.

7 Applications of measured micro-synchrophasor data

Circuit conditions that are either directly measured or inferred from raw µPMU measurements are topology of circuits, steady-state voltage magnitude and angle, and dynamic and transient voltage magnitude and angle. The µPMU project focuses on several diagnostic applications of high-fidelity distribution data, beyond model validation: state estimation, topology detection, fault location, and dynamic circuit behavior monitoring leading to the dynamic characterization of generators and loads. Of these, three applications – namely, topology detection, state estimation (i.e. steady-state power flow) and dynamic circuit monitoring – are considered foundational applications, while dynamic device characterization and fault location build on these foundations and are considered advanced applications (Figure 3).

We review the three foundational applications for µPMU data in commercial distribution systems and briefly discuss these within the context of distribution management system packages that focus on operations.

Measurements of steady-state operating conditions are necessary to create a basic picture of the underlying condition of the circuit, meaning knowledge of the network connectivity and the rms values (i.e. averaged over multiple cycles) of voltages and currents. State estimation provides such a picture given the available input information (e.g. µPMU measurements, SCADA and AMI data) which will likely vary in fidelity and will not include all nodes of the circuit. The steady-state picture of the circuit provides the background for time-varying behaviors that may be superimposed.

Dynamic system behavior and analysis will re-create short-time disturbances (sub-cycle) in system states. Dynamic system behavior monitoring is the basis for applications such as oscillation detection, inverter performance monitoring, and the detection of complex load interactions such as fault-induced delayed voltage recovery (FIDVR). Inverter performance monitoring is also considered a quasi-dynamic or short time-step series analysis.

7.1 State Estimation, Topology Detection, and Operational Distribution Management Systems

Topology detection, model validation, and measured data integration all play key roles in development of state estimation. State estimation is simply a prediction of voltage and current magnitude and angle at all buses or nodes using existing voltage, current, real and reactive power measurements, a network model (e.g. impedances and switch status) and an algorithm that accounts for missing or bad data. This is straightforward to do when there are lots of good data, and becomes dramatically more difficult as reliable and accurate measurements are sparse compared to the number of nodes, as tends to be the case in distribution systems. Transmission-level state estimations are successfully implemented in numerous locations, while state estimation for distribution networks lags behind considerably (Arghandeh and von Meier et al., 2014).

Distributed state estimation (DSE) plays a critical role in a distribution management system (DMS), which is a tool or collection of applications to measure, manage, and control the electricity distribution system from a central operations center. Distribution management systems are at a rudimentary state of implementation in current grid operations, partly because of the lack of good state estimators, which in turn is due to the lack of physical measurements. We hypothesize that μPMU measurement data provide state variables that could considerably advance the accuracy of DSE. As in fault location, there will also be a tradeoff between data quality and required density of physical measurement points (Schenato et al. 2014).
An additional complication for distribution state estimation arises when we cannot be certain of the network representation: specifically, when we must account for the possibility that the open/closed status indicator for a given switch is erroneous. This complication

rarely arises at the transmission level, where SCADA instrumentation is more comprehensive.

A complete state estimation output provides information on switching device status, active and reactive power flows at nodes and branches, load consumption, capacitor bank operation, generator behavior and output, transformer tap position, current flows, and power factor at both sides of each branch; often, a confidence index is also given for the computed solution. State estimation tools should detect bad analog measurements and determine the minimally dependent, critical set of measurements required for accuracy. A detailed, validated physical model of the distribution network is necessary for accurate state estimation. Most utilities use GIS-based circuit models with different levels of accuracy and network component information. Currently, there is no validation of circuit topology in these models. For effective control and operation, utilities must independently maintain correct and updated status of switching devices in the distribution network model – or be subject to a significant error in state estimation

Commercially available state estimation tools that could be informed by μPMU data are grouped either as customized packages provided by vendors (such as ABB or Alstom) or as part of an outage or energy management system. There is a growing trend of coupling state estimation tools with other existing packages for off-line distribution analysis, which is another example of real-time applications (operations) and off-line applications (planning) coming together. The customized packages reviewed are generally adaptations of transmission technology with a fully integrated distribution management system. The technology required to adequately support state estimation, e.g. the number of required monitoring points, measurement quality and communications infrastructure, is often not defined. Vendor-specific measurement technologies may be recommended that do not make interoperability requirements explicit. Customized solutions often refer to balanced-node measurement points and may not accurately account for or estimate system imbalances (Schneider et al. 2010). Cognizant of the limitations imposed on state estimation by scarce measurement data, one vendor who is developing a state estimation application for their distribution software suite has approached our research team regarding the incorporation of μPMU data into their commercial package.

We review the current status of available state estimation and topology identification packages. Although this section considers packages for state estimation as a whole, communications and data requirements in software as well as model validation are essential pieces of a complete and accurate analytical model.

First, we evaluate packages that are normally used for off-line distribution system analysis and that have a state estimation program available. Following this, we discuss custom packages usually provided by vendors in conjunction with distribution management systems. Different packages are normally available or used for state estimation than the commonly used packages for planning reviewed in earlier sections of this report. Our review covers a selection of state estimation packages.

ETAP offers a state estimation and load-distribution package that is reported to processes telemetry data (e.g., from AMI and other advanced metering) to estimate phase angles and magnitudes of bus voltages in power systems. Input of custom data sources is possible, which suggests there is good potential for integrating the μPMU data stream. The data are analyzed for outstanding or obvious errors, and the ETAP tool will identify and report the areas of the network for which there are sufficient data as well as the areas for which there are not sufficient data. In locations where there are no data, measured data from the closest location are used to estimate system voltage and voltage regulation equipment status. ETAP is strong in data consistency and error checking. The literature regarding this package states that a fast convergence solution, within seconds, is possible. Minimum system requirements for measured data points are mentioned but are not quantified and would depend on the system being implemented. ETAP also has a simpler network topology processor available, but the analytical technique used by that tool is unknown.

Cooper offers a partner package for CymDist, CYME server, that performs real-time analytics and distribution state estimation, both balanced and unbalanced. The tool was developed using the same solution engines as CymDist and integrates with EMS, SCADA and DMS systems. This system uses the CymDist database so that operations and planning models can be extracted from the same source. This package reportedly offers a near-real-time and an off-line solution.

The distribution planning tool PSS/Sincal, reviewed in Stewart & Kiliccote et al. 2014, does not offer a state-estimation package, but PTI offers a tool within the same environment that can be coupled with both PSS/Sincal and PSSE, ODMS (Operational Data Management System). ODMS is designed to analyze system security and network modeling using common information model architecture (a standard model being implemented for grid data sources) (IEC 2010). ODMS can perform topology, power-flow, state-estimation, and contingency analyses. Its state estimator uses SCADA data to determine the magnitudes and phase angles across the system. The tool can be used in either real time or a simulation environment. The algorithm will determine the critical number of measurements required to get an accurate solution and provide switch status updates (and correction when control is integrated). ODMS does not offer integration solutions for data from customized sensor applications such as μPMUs or AMI.

DEW and the integrated system model can be used for state estimation. DEW is being used as a real-time state estimator, and the integrated system model includes both transmission and distribution and has more than 365,000 components. DEW has the potential to incorporate data from across a utility, such as SCADA measurements and historical load measurements, coupled with research statistics to predict load for every customer as a function of weather conditions, customer billing class, type of day, and type of month.

DigSilent PowerFactory has a state-estimation package that will take in P, Q, I and V measurements, determine their confidence index, and detect and eliminate bad data. The package can verify system observability, and create proxy data for unobservable regions. The package will utilize monitored data such as SCADA, and system states can be defined by the user, including voltage regulation and generation equipment. The PowerFactory state estimator can support many communication options including OPC and a shared memory interface for interchange with SCADA.

Other packages previously discussed in this report, including SynerGEE Electric, do not offer specific state-estimation packages but do have other features including input options from measured data and sensors that would allow for state estimation applications to be developed using a component object model interface.

The following packages are specific state-estimation packages, often offered coupled with either hardware in the loop or demand-side management.

OPAL-RT offers hardware-in-the-loop and real-time demonstration systems. The system is designed to operate in quasi-real time, which can be 5 to 10 seconds or milliseconds and faster. The hardware-in-the-loop system can be connected to the physical process being evaluated, for example real-time markets (10 minutes), real-time balancing (5 minutes), real-time control (5 to 20 milliseconds), and protection (10 to 50 microseconds). Opal-RT is compatible with Simulink and Matlab models for custom component modeling.

Alstom offers the e-terra platform (Alstom 2014), described as an on-line stability solution that provides network security analysis using state estimation and contingency analysis. The transmission-level system uses synchrophasor-measurement-based approaches and offers a means to validate the results. Immediate application would be for real-time monitoring of power system dynamics to see early warnings of degrading stability margins. The integration of synchrophasor data would improve state estimation by providing actual voltage magnitude and angle phasors to the e-terra platform. The platform is designed to interact with model-based dynamic stability applications also provided by Alstom. Transmission phasor data and stability information are rendered visually. Alstom also offers a renewable operation portal that monitors real-time information, responds to power-balance changes, anticipates incoming potential problems, and recommends remedial action. RER plan, through e-terra, provides a central repository for advanced data processing and alarms, and RER estimation forecasts output for non-telemetered areas and generation control and dispatch to counteract power production imbalances. The system also supports detection and isolation of faults using smart metering, an AMI-based fault location system that relies on reports from multiple measured devices. Finally, Alstom's integrated distribution management system is called e-terra distribution. The system also reports integrated SCADA, distribution management system, and OMS functionality.

Schneider present an Advanced Distribution Management System, demonstrated for integration of advanced distribution energy measurement sources, real time weather, distribution SCADA, and automation measurement. The tools can integrate sources such as MDM, GIS, CIS and home area networks/AMI. With the numerous faster scale data sources already integrated it is understood there is a potential for integration of unbalanced μPMU data sources into the state estimation and real time measurement packages. Schneider's recent acquisition of Telvent gives them advanced knowledge in data source integration and may lead to greater leaps forward in integration of μPMU data.

Based on our review of commercially available programs, we find that the options for distribution-level state estimation using the new high-fidelity μPMU data stream are limited among off-the-shelf products, whose actual capabilities may be less than one could imagine from their high-level descriptions. However, in building on available products, there is considerable opportunity for future expansion of capabilities, especially by way of integrating better measurement data. For state estimation to be useful, model validation and topology detection will need to be significantly enhanced in planning applications, and this validation will need to be transferred to operations. The combination of topology detection and overall model validation as a single stand-alone application verified through commercial distribution planning packages would therefore be a valuable development.

7.2 Fault Location Tools

One of the goals of the μPMU demonstration is to enhance fault location by using recorded measurements of voltage angle before and during the fault and interpreting these in the context of a circuit model. This approach will rely on development of customized applications, integration and manipulation of measured data within a commercial grid modeling tool, and determination of the accuracy of the location itself. It is unlikely that the demonstration systems will experience an actual fault during the demonstration period, so simulation will be an essential feature of the project.

The current basic operations fault location method essentially consists of mapping phone calls of customers who are experiencing outages to determine where to send crews to start visually looking for damaged lines, a tripped pole mounted switch, or other indicative features. Locating underground faults is a much more difficult task, but overhead faults are much more common (S.E.Laboratories 2013). Data from relays can be used to identify the feeder section that contains a fault. The precision of these systems is limited by the density of protection devices, which indicate location to within an accuracy of about 1,000 feet.

This traditional approach has been extended by the development of low-cost line sensors that provide visual indicators and/or wireless communication of the sensing of fault currents. These devices can be deployed at cost-effective densities to help pinpoint fault location, but many devices are required to get a precise fault location.

There are two popular classes of fault location algorithms: machine-learning techniques and measurement and simulation techniques. In machine-learning-based techniques a database is created containing a large number of fault scenarios. Observed fault events are compared to the database to precisely locate the fault. The weakness of this type of system is that it requires a model that has undergone detailed validation, but as discussed in Section 5, such models are lacking in distribution analysis. There is a high degree of uncertainty related to distribution system load and distributed generation characterization as well as the system's dynamic response to fault events. These events are challenging to model, and the effectiveness of such fault location techniques is difficult to assess without field tests.

The second algorithm class uses substation pre- and post-fault voltage and current measurements along with the system model to directly calculate fault location from the observed fault current and voltage dip. The challenge of this method is identification of multiple possible fault locations because of the dispersed, radial distribution system and its dynamic load variation and behavior. Academic studies indicate that both simulation methods are accurate (less than 5% error), but there has been limited verification in the field (Mora et al. 2008, Saha et al. 2002).

Commercial systems that integrate data from line sensors, detailed feeder models, and substation measurements exist, notably from Schweitzer Laboratories (Schweitzer et al. 2010), and have been demonstrated to be accurate to within tens of feet. Wide-scale deployment of these systems is limited, however, possibly because of difficulties in integrating different data communication streams and system network models, which vary between, and even within, utilities. Standardization of data formats for modeling and communication would help address this problem. The required high density of line sensors is also a large expenditure, of which the benefit has not been fully quantified (Lee 2014).

Fault location accuracy depends on electrical model accuracy, and the steady-state validation, because short-circuit analysis will often require the zero-sequence impedances to be modeled (i.e., it is not appropriate to assume a balanced three-phase power flow). Fault location must be integrated with other systems including operations and outage data, the electrical circuit model, and the outage management system, to minimize the volume of sensors and data required. GIS mapping is also essential. Learning from past conditions by means of post-mortem analysis will also enable intelligent reconfiguring of sensing and measurement devices so that it will be easier to locate future faults.

Existing distribution load-flow software, such as SynerGEE and Electric, has reported fault-location analysis options (Short et al. 2009) and GIS coordinated between line segments and nodes. The fault-location analysis simulation in SynerGEE Electric uses the impedance between nodes and historical data as well as Dranetz measurement systems in selected locations to accurately locate faults to within a small percentage distance error.

All fault location tools require high-fidelity models and data inputs from measurement devices. The measurement devices are the key, and each relies on data from a specific set of protection devices rather than line data. These tools, which use power-flow packages such as CymDist and SynerGEE Electric as their bases, require detailed model validation, which also requires detailed measurement data.

Our review of the reported fault-location functionality of some commercially available tools includes CymDist, PSS/Sincal and DEW. CymDist has an add-on package, ASP, which is described as an integrated solution to solve multiple problems, including optimal switching plants and restoration based on high-priority customers. The advanced analysis package allows for zonal protection and restoration schemes. CymDist also has an add-in program for fault location, the short-circuit package available as part of the base, CymFault. CymFault is reported to determine the fault level recorded at a current measuring instrument, relying on integrated communications and historical data, and from these to determine the potential fault locations in the network. The locations are ranked based on probability of accuracy. The selection of locations provided by the tool might reduce the time required to find the location of a fault, but the number of solutions might not improve recovery time. Power Quality (PQ) monitors, such as GridSense Line IQ, have been reportedly integrated with CymDist databases with varying degrees of success (Sabin et al. 2014).

PSS/Sincal provides fault location functionality through an add-on package. The package will reportedly localize a fault at the protection device, determining the precise position of the fault in the supply network based upon impedance of the fault and system. Modern protection devices store the impedance that causes tripping when there is a fault, and these values are used to calculate the position of the fault in the network. These devices would be integrated with PSS/Sincal to communicate data at the time of fault, which would be used to determine its location.

DEW has a fault location application that can be run interactively to help identify locations of momentary faults and can also be run in conjunction with a distribution management system to automatically identify fault locations. The DEW fault location is estimated from pre- and post-fault calculations using the DEW power flow.

All of the above tools rely on physical measurements from line sensors to estimate the location of a fault. Naturally, they assume that only magnitude measurements are available as inputs. It is plausible, however, that the combined measurements of voltage magnitude and phase angle (i.e. complex voltages) along with currents can be readily incorporated into these tools. Furthermore, we hypothesize that by providing the additional measurement information, the accuracy of the location estimate will be improved. This hypothesis is supported by initial simulations with our own fault location algorithm that explicitly depends on voltage phasor measurements (Lee et al. 2014). What is less obvious is the tradeoff between the quality of measurements (i.e. phasor vs. conventional) and the number of line sensors required. We will continue to examine this question in the context of further simulations.

Our focus in this section has been to review commercial packages to locate faults and discuss overall issues pertaining to accurate fault location. Based on available information, we conclude that the combination of a software analysis package connecting to very accurate high-fidelity measured data and a validated distribution model would enhance fault location significantly.

8 Conclusions

Development of grid sensors and analysis methods has increased with the rapid evolution of the distribution grid. There are numerous software options for planning, operations and analysis of the distribution system, but few applications combine advanced data sources and advanced analysis tools.

We reviewed a selection of distribution planning and operations tools for their ability to use new advanced µPMU phase-angle data.

Based on our analysis we conclude that:

- Data measurement is outstripping the processing capabilities of planning and operational tools. The accuracy of planning and operational tools is less than that of the measured data with the integration of courses such as the µPMU. Solving methods cannot handle the high volumes of data generated by modern sensors. New models and solving methods (such as graph trace analysis, implemented by DEW) are needed.

- Not every tool can output a voltage phase-angle measurement to the degree of accuracy measured by advanced sensors. A tool must be able to not only output phase-angle data, but do so to with an accuracy that matches the accuracy of the measurement devices providing the data (e.g., tens of milli-degrees). The traditional error margin of 0.5% is likely an inadequate standard in the context of utilizing high-fidelity measurements. Experimental data will be required to validate the impact of tool error on the analyses performed by utilities.

- Distribution grid data sources are limited; increasing the availability of measured data and its integration into distribution grid modeling tools for validation and other purposes would improve the tools' accuracy and allow for more concentration on developing the tools rather than on their accuracy.

- As the distribution system evolves into a complex, active, controlled, automated resource, the depth of analysis required will evolve also, as will the need for higher-fidelity measurement devices. The applications of measured data will be numerous, including control of the grid, control of generation, improved fault restoration and better utilization of demand response resources.

We identified the following areas for future work:

- Standardization of sensor-data communications platforms in planning and applications tools, allowing integration of different vendors' sensors and advanced measurement devices.
- Increased ability to handle large volumes distribution power-flow data.
- Validation of models that makes use of advanced data sources.

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