Diagnostic Applications for Micro-Synchrophasor Measurements

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1. Introduction

The purpose of this report is to articulate and justify the preliminary selection of diagnostic applications for data from micro-synchrophasors (μPMUs) in electric power distribution systems that will be further studied and developed within the scope of the three-year ARPA-e award titled *Micro-synchrophasors for Distribution Systems.* The present report is an expanded and updated version of the draft report submitted in October 2013.

The research team's thinking about selecting applications for μPMU data has evolved substantially since the beginning of the project.

The initial set of five diagnostic applications from our proposal included
- unintentional island detection
- reverse power flow detection
- diagnosis of fault-induced delayed voltage recovery (FIDVR)
- oscillation detection
- fault location and high-impedance fault detection.

This set represented a sample across possible end uses that varied across several dimensions:
- likely level of difficulty with respect to the phase angle measurement required
- likely advantage afforded by phase angle as compared to conventional approaches
- likely opportunities for field testing
- likely difficulty of writing algorithms for implementation
- likely interest level and sense of urgency among utilities.

Through conversations within our team, with other academic colleagues and with our utility contacts and candidate project partners, we then expanded the range of applications to encompass a broader set of possibilities. This process served to make sure we hadn't overlooked any promising opportunities, and to stimulate thinking among our utility colleagues. The expanded set included a list of approximately 40 distinct applications.

The last step in the process was the down-selection from the expanded list.
This down-selection was guided by

- literature review and conversations with industry colleagues to better understand conventional alternatives to μPMU-based approaches and thus estimate the comparative advantage;
- circuit modeling and simulation to better understand the requirements for phase angle measurements to support difficult applications (in particular, fault location and high-impedance fault detection);
- the expression of interest by utilities, and our assessment of the likelihood of field exploration; and
- consideration of how applications, initially considered as individual stand-alone functions, are in fact related to each other.

The down-selection process has followed a somewhat different rationale than we envisioned at the outset: First, the technical requirements for phase angle measurement to enable diagnostic applications does not appear to be a crucial selection criterion, since we believe these requirements can likely be met for all applications under consideration. Second, it has become clear that we must consider applications, including the particular data and algorithms that will support them, in terms of their functional relationships to each other, rather than as a list of independent items.

The latter point led to a reorganization and mapping of our applications list, evolving it from a serial listing into a hierarchical and functional spectrum. When considering how specific applications would actually be performed, it became clear that some simpler applications would be subsumed by others; conversely, some applications are dependent upon or enabled by others.

Since the draft report, our team has been continuing work on developing algorithms for state estimation, topology detection, and fault location. We have not encountered any surprises that would cause us to question or revise the selection of applications for further study as presented in the draft report. During this period, we have also collected and begun to analyze the first actual voltage angle measurements from µPMUs in the field. While the team confronted several challenges associated with extracting the angle at the desired accuracy, we believe that the crucial problems have been successfully overcome at this time, and we see no reason to doubt the feasibility in principle of using µPMU measurements for the selected applications.

Accordingly, following an overview of the expanded application list, Chapter 2 of this report discusses the functional grouping of applications and identifies three foundational applications, namely, topology detection, state estimation, and dynamic circuit behavior monitoring. It also outlines the interests and priorities of partner utilities with regard to these applications. Chapter 3 discusses technical requirements for the three foundational applications, supporting the conclusion that data resolution needs do not constrain our selection of diagnostic applications at this time. Chapter 4 elaborates on the relationship between the foundational and the subsumed and advanced or derivative applications. Chapter 5 discusses the key applications selected for further study, particularly in view of conventional alternatives with which µPMU-based applications will compete. This chapter emphasizes the theoretical and practical challenges we have identified so far, and presents some of our team's work-in-progress on developing applications. Chapter 6 briefly summarizes challenges and competing alternatives for additional applications. Chapter 7 concludes this report.

2. Applications and Functional Grouping

2.1 Expanded List by Utility Organizational Domain

An expanded inventory of potential µPMU applications in distribution systems is shown (in no particular order) in Figures 1–3, grouped and color-coded in terms of the traditional utility domains that would be primarily supported in each case.

These domains are

- monitoring and diagnostics
- operation and control, and
- planning.

The first domain, monitoring and diagnostics, is fundamental to both of the others. Generally speaking, electric grid operation and control is concerned with physical actions taken on time scales from sub-second to hours under a set of given constraints, while planning is concerned with investments made on the time scale of years to alter the applicable constraints. Monitoring and diagnostics enable operation and planning by providing situational awareness of the state of the power system, ranging from transient and dynamic behavior (sub-second scale) and steady-state operating conditions (seconds to hours) to expectations for design conditions in the future (days to years).

Following Figures 1, 2 and 3 is a brief explanation of what we mean by each application. Some µPMU applications turn out to straddle the traditional domain boundaries. Also, there are naturally some overlaps between and among the labels of these applications; the intent was to capture a range of points that might trigger particular interest or insights. We will not discuss the (green) planning and (red) control applications in further detail in this report, but provide a glossary for context.

Several noteworthy diagnostic applications that we had not identified at the outset of our research project but that emerged from our initial study and conversations with utilities were

- topology status verification
- phase identification and balancing
- performance characterization of inverters
- unmasking load and generation behind net meters.

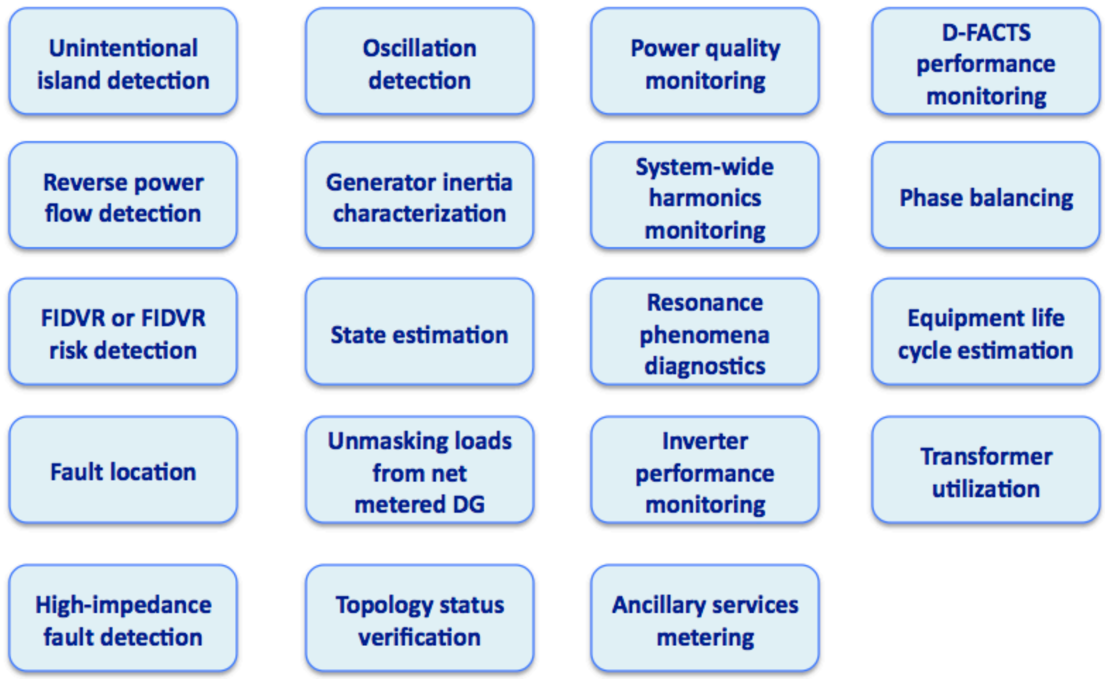

Figure 1. μPMU monitoring and diagnostics applications

Unintentional island detection: This was discussed in our original project proposal. The idea is to quickly and reliably recognize a potentially unsafe situation where a set of generators and loads have separated from the grid but continue to energize their local portion of the network.

Reverse power flow detection: Discussed in original project proposal. The idea is to identify, or anticipate, when power flows in reverse direction on a radial distribution feeder, potentially threatening the safe coordination of protection systems such as circuit breaker relays, and potentially disrupting voltage regulation.

FIDVR or FIDVR risk detection: Fault-induced delayed voltage recovery (FIDVR) detection is discussed in the original project proposal. We added the possible anticipation of FIDVR, which would hinge on identifying in near real-time the varying contribution to total customer load from devices such as single-phase induction motors in residential and small commercial air conditioners that pose an increased risk of FIDVR.

Fault location: Discussed in original project proposal. The idea is to infer the actual geographical location of a fault on a distribution feeder to within a small circuit section (compared to the distance between protective devices) by using recorded measurements of voltage angle before and during the fault, and interpreting these in the context of a circuit model.

High-impedance fault detection: Discussed in original project proposal. The idea is to recognize the dangerous condition where an object such as a downed power line makes an unintentional connection with the ground, but does not draw sufficient current to trip a protective device (since it mimicks a legitimate load). Undetected high-impedance faults are extremely dangerous because they pose both electrocution and fire hazards.

Oscillation detection: Discussed in original project proposal. The idea is to detect power oscillations on distribution systems, including sub-synchronous oscillations known to exist on transmission systems and high-frequency oscillations that may or may not occur as a result of power exchange between and among distributed energy resources.

Generator inertia characterization: Discussed in original project proposal. The idea is to qualify and quantify the behavior of inverters in relation to stabilizing system a.c. frequency and damping disturbances in power angle or frequency.

State estimation: State estimation means identifying as closely as possible, from available network models and empirical measurements, the operating state of an a.c. system in real-time. This state is completely described if the two state variables that drive real and reactive power flow – namely, voltage magnitude and phase angle – are known or computed for every node in the network, given connectivity and impedances of network branches. The µPMU measurements would explicitly provide these state variables to directly feed into a Distributed State Estimator (DSE), which in turn may provide information to a Distribution Management System (DMS).

Unmasking loads from net metered DG: Currently, most renewable generation on the distribution system is net-metered; therefore, it is not possible to tell exactly how much generation is on-line "masking" the load behind the net meter. Estimating the real-time levels of renewables vs. loads would allow for better anticipation of changes in the net load, by separately forecasting the load and generation, and for assessing the system's risk exposure to sudden generation loss. At the aggregate level, this information is of interest to system operators for evaluating stability margins and damping levels in the system.

Topology status verification: Detecting or confirming the actual status (open or closed) of field switches whose indicators may be unavailable remotely or considered unreliable. This deceptively simple application was brought to our attention by utilities, who are often hampered in their efforts to reconfigure distribution circuits (e.g. for service restoration after an outage, or for safely accommodating certain configurations of distributed generation and load) by uncertainty about the actual connectivity of their grid at a given moment.

Power Quality Monitoring: This means measuring and recording deviations from "pure" 60-Hz sinusoidal waveforms of current and voltage. This includes harmonics, noise, frequency deviations, voltage sags and surges, phase imbalances, transients, momentary interruptions (< 5 sec).

System-wide harmonics monitoring: The nonlinear characteristics of distributed energy resources, including various inverters and loads such as electric vehicle chargers, can cause harmonic distortion in power system voltages and currents. Harmonics can result in excessive thermal losses, overload network components (e.g. neutral conductors), and cause premature aging and failure in power system devices (e.g. transformers). Beyond local power quality that impacts the performance of customer loads, the concern here is with the propagation of harmonics throughout the primary distribution system.

Resonance phenomena diagnostics: Analysis of the behavior of different oscillation modes, e.g. damping of oscillations at different frequencies, will reveal the extent to which resonance phenomena exist on distribution circuits. These may include ferroresonance between conventional inductive and capacitive components, or oscillations involving inverters or other solid-state devices.

Inverter performance monitoring: Observation of inverter real and reactive power output at very small time scale relative to line voltage, frequency and angle. Of particular interest is the response to abnormal and transient conditions. Angle measurement will make it possible to validate the performance of advanced inverters designed to compensate for transients.

Ancillary services metering: If and when distributed resources, individually or in aggregate, are remunerated for ancillary services to the grid, their performance could be independently validated with µPMU measurements.

D-FACTS performance monitoring: This unfortunate acronym for "distributed flexible a.c. transmission systems" refers to solid-state devices that actively regulate real and reactive power flow on network branches. Implementation of FACTS devices to date is small in number but big in importance for transmission system operation; D-FACTS is still nearly unheard of in utility practice. If and when such devices are implemented in distribution systems, µPMUs could provide performance validation as well as supervisory control.

Phase identification and balancing: The goal is to assign loads about equally to the individual three phases of the distribution circuit. Phase balancing results in neutral current and loss reduction with increased overall efficiency. At present, many utilities do not have records of phase connectivity, or which single-phase loads are connected to A, B or C. Direct phase angle measurement with a portable device on the secondary distribution system would be a uniquely quick and easy way to ascertain this.

Equipment life cycle estimation: By empirically measuring the impedance of system components such as conductors and transformers, it should be possible to estimate their functional age, anticipate imminent failures before they occcur, and prioritize replacements. This is particularly relevant for underground cable conductors that are inaccessible and expensive to replace.

Transformer utilization: Distribution transformer loading is often unknown, but plays a vital role in service reliability. Continual monitoring can assure that each transformer operates within its nominal kVA capacity and also inform life cycle estimates and replacement priorities.

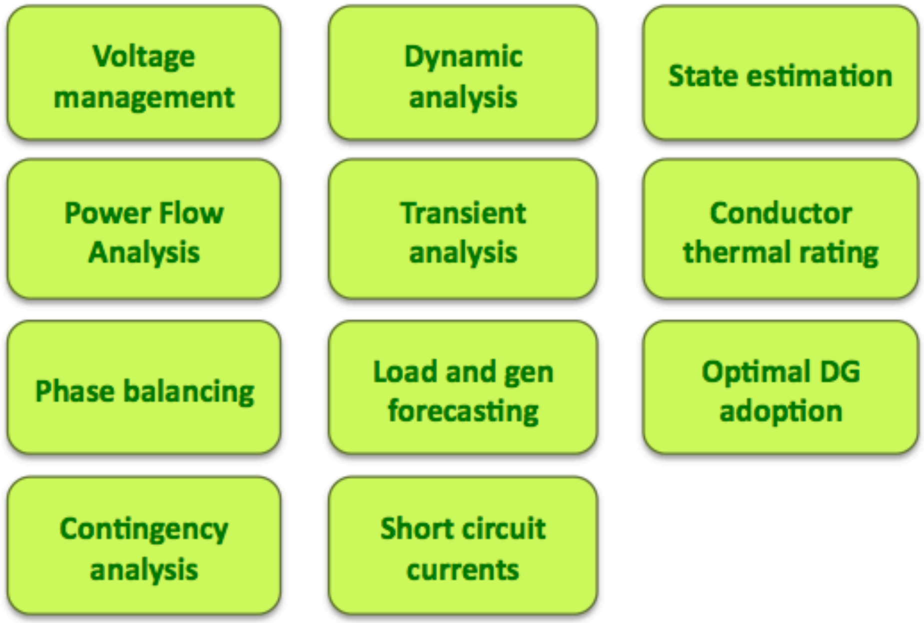

Figure 2. µPMU planning applications

Voltage management refers to the planning decisions (for example, placement and sizing of capacitor banks) intended to assure that the voltage drop along a distribution feeder can be held within ±5% tolerance from beginning to end, under a foreseeable range of loading conditions.

Power flow analysis and *State estimation,* as applications in the planning context, mean estimating steady-state line and equipment loadings under expected load growth, or growth of distributed energy resources.

Dynamic and *transient analysis* refers to phenomena that occur on shorter time scales, as the system transitions between steady states or operates in a highly variable condition. One objective in the planning context is to assure the ability of the system to withstand and ride through a foreseeable range of disturbances without safety hazards, equipment damage or service interruptions; at the same time, of course, one wishes to prevent large transients from occurring in the first place.

Short-circuit currents are estimated for a range of fault scenarios to inform protective relay settings and assure the adequacy of protective devices (such as circuit breakers, fuses, and reclosers).

Conductor thermal rating must be selected according to anticipated future loading.

Phase balancing in the planning context means choosing the appropriate phase connection for single-phase lateral feeders so as to balance loads on the three phases.

Contingency analysis means identifying the tolerance of the system with respect to equipment outages and other untoward events – specifically, which contingency events would result in the loss of service for customers. While security planning at the transmission level stipulates an N-1 or better criterion, meaning that not even a worst-case single event would result in any loss of load, radial distribution systems do not offer the redundancy that could provide N-1 security. Nevertheless, the goal is to make planning decisions that will minimize the probability of customer outages under a range of plausible contingency scenarios.

Load and generation forecasting is central to planning efforts. Forecasting would be supported by detailed knowledge of the present composition of loads and distributed resources.

Opimal DG adoption refers to the siting of distributed generation so as to avoid adverse impacts (such as voltage regulation or protection coordination problems) and enhance distributed benefits (such as congestion relief and loss reduction) where possible. Both positive and negative impacts of DG are highly location specific, and estimating these impacts depends on a detailed understanding of a particular distribution circuit's behavior.

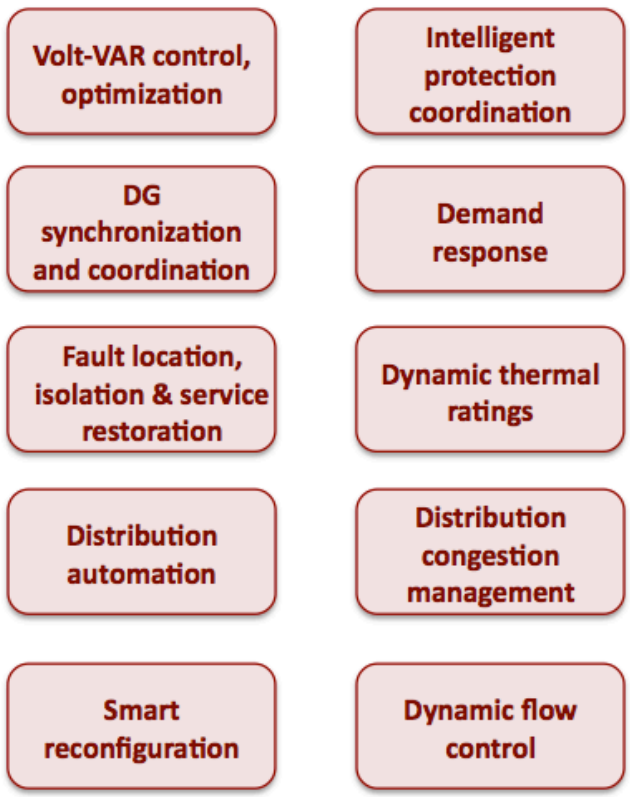

Figure 3. µPMU operation and control applications

Volt-VAR control and optimization refers to the coordinated operation of various voltage regulation devices and reactive power sources to not only maintain voltages within tolerance, but achieve other optimization objectives such as minimizing line losses or reducing customer electric energy consumption (as in conservation voltage reduction or CVR).

Fault location, isolation and service restoration (FLISR) refers to an information and control system that integrates field measurements (such as device status and AMI data) and geographic information to accelerate safe switching operations for restoring service to customers after a fault. (It is noteworthy that in many areas, utilities still rely on telephone calls from customers to identify outages and their geographic extent.)

Distribution automation and *Smart reconfiguration* are related and overlapping functionalities that encompass a range of strategies to change circuit topology in real-time, in pursuit of various optimization goals (including automated service restoration, improved equipment utilization, and loss minimization).

Protection coordination refers to the response thresholds, sensitivities and relative timing among different protective devices on a circuit (fuses, breakers, reclosers) under a range of possible fault conditions. *Intelligent* here means that the protection coordination takes into account specific operating conditions in real-time, and device responses may be adaptive to conditions.

Dynamic thermal rating means adjusting the permissible loading of conductors and other devices according to environmental conditions, especially air temperature and wind speed.

Distribution congestion management means taking actions to change circuit topology, and conceivably also control loads or distributed resoruces so as to avoid overloading equipment.

Dynamic power flow control adjusts or routes power through a particular link by actively reconstructing the a.c. waveform with solid-state switching devices (see D-FACTS above), effectively changing the impedance of a network branch.

Optimal DG operation entails adjusting real and reactive power output of distributed generators or storage units in response to transmision or distribution system needs in real-time.

Demand response means the active control of loads in response to price or other signals representing system needs in real-time (for example, load peak reduction or frequency regulation).

Microgrid operation means coordinating and dispatching resources on a microgrid – that is, an islandable subset of a distribution system – to balance real and reactive power, thus controlling frequency and voltage.

Intentional islanding or separation from the remainder of the grid becomes an option if and when a microgrid can balance its own generation and loads, if protection systems are safely coordinated for the islanded condition, and if there is a strategy for unproblematic re-synchronization with the larger grid at a later time.

2.2 Utility Partners' Interests and Desired Applications

Our team conducted meetings with each of prospective partner utilities and research organizations to explore applications for µPMU measurements that would be interesting to them, for two reasons: first, to generate commitment on their part to collaborate on the project, and second, to inform our efforts in PE6 toward commercialization. While we do not wish our strategic thinking about future synchrophasor applications to be constrained by today's short-term concerns of utilities, we nevertheless aim to have at least one practical use case for each utility that is sufficiently compelling and immediate to inspire their active participation, while lending plausible support to our technology-to-market strategy.

Our conversations with utilities revealed that basic functions such as topology detection, state estimation and the characterization of generation and loads – which could be called "tools" rather than "applications" although we decided against introducing new terminology – are worthy of being considered as applications in their own right, and will likely provide tangible value in and of themselves.

Other applications from the above list encountered different degrees of resonance with different utilities, in accordance with the particularities of their geography, circuit characteristics, and renewable penetration levels. Table 1 summarizes the diagnostic applications that emerged highest on the priority list in conversation with each utility. Note that this table when presented at the February site visit originally included Pennsylvania PPL, with whom we have not executed an MOU; the fourth utility slot has since been filled with Hawaiian Electric Company (HECO).

Table 1: Summary of Utility Partners Preference for µPMU Measurement Applications

	Diagnostic Applications	Additional Research Objectives
UCB/LBNL	Load characterization	Networking, data visualization Model validation
NREL	DG characterization State estimation	Model validation Visualization
UCSD	DG/Load characterization Topology (island) detection	Dynamic and transient analysis Explore control applications
SMUD	State estimation (reverse power flow)	Model validation Visualization
SCE	DG/Load characterization	Dynamic and transient analysis FIDVR analysis and prediction Oscillation detection
Southern	Topology detection Fault detection and location State estimation	Model validation
HECO	State estimation DG Characterization	Oscillation Detection Model validation

After a number of meeting and discussions with utilities, we articulated a set of scenarios and use cases for each utility partner, which are currently being reviewed by our utility colleagues. By *scenario*, we mean a description of a set of conditions that can occur in an application. A *use case* means a user-visible function that is an element of the scenario.

2.2.1. Proposed Scenarios and Use Cases for HECO

Application 1: State Estimation/Topology Detection

Scenario: A distribution feeder has a high penetration of distributed PV

Use Case #1: Detecting small net current
Load on the feeder of interest is low, while PV generation is high. A fault occurs on feeder 2; need to perform switching and confirm PV is disconnected beforehand. µPMU can measure direction of flow and very small currents to ensure the generation source is isolated.

Use Case #2: Model Validation
A developer wishes to interconnect a large PV site to either feeder 1 or 2. The impact and interconnection analysis will be based upon the SynerGEE Electric planning model. The analysis shows a high potential for backfeed and transformer overloads during peak PV output times due to PV on both feeders. The model also showed potential for power quality issues and need for extra voltage support. The impedance of the system was estimated from the GIS data. µPMU data is used to determine the accuracy of the estimated impedance data based on the advanced age of the equipment on the feeder. µPMU data on both feeders can determine the power quality impact of the existing PV locations, and use this data to validate the base case SynerGEE model and the model voltage profiles. The expected operation of existing voltage regulation equipment can also be validated, and optimal operation scenarios proposed to the PV developer and utility, based upon a correct model.

Application 2: Dynamic behavior characterization

Scenario: A distribution feeder has a high penetration of distributed PV

Use Case #3: The distribution operators have little visibility of the renewable penetration in specific areas. µPMU data will provide a better estimate of how much power is being generated by net metered PV, and what impacts it might have that require operator attention (e.g. stability issues in the distribution system that occur because of reduced generator inertia, increased need for voltage support, or changes in system requirements).

2.2.2. Proposed Scenarios and Use Cases for SCE

Application 1: Load Characterization & Observation of Dynamic Behavior

Scenario: San Onofre Nuclear Generating Station (SONGS) is a major generator recently retired. In the event of a transmission overload on a hot summer day, there is a need to reduce load within the local region near SONGS. SCE is planning to use Demand Response (DR) for management of load in the area with the reconfigured transmission feed and generation profile.

Use Case #1: The operators have little visibility of the availability of Demand Response in specific areas. µPMU data will indicate the aggregate load on a specific distribution circuit (or section thereof) before and after a DR signal has been issued. This allows the utility to validate that DR has been performed as requested, without need to refer to a load baseline. Observation of the load before and during the DR will also support better estimates of the DR response obtainable in the future.

Use Case #2: The implications for stability due to replacing the high-inertia SONGS generator with local distributed resources, including DG and DR, are not yet known. Micro-PMUs will monitor dynamic behaviors or stability issues in the distribution system that could be associated with reduced generator inertia in the area which may increase the need for local voltage support. The µPMU data may also provide clues about the amount of load masked by DG behind the meter.

Application 2: FIDVR Detection (includes load characterization)

Scenario: In the SCE region there is an area with high potential for Fault Induced Delayed Voltage Recovery (FIDVR) events due to high temperatures and high penetration of certain air conditioners, whose single-phase induction motors that can stall in response to even brief voltage sags (as are typical, e.g., when a fault occurs on a neighboring feeder). There is an existing measured potential for FIDVR by the original PQube models.

Use Case #3: µPMU measurements would provide a better characterization of the load in the area, including an estimate of the penetration of the type of air conditioners at risk of stalling. This would allow the utility to determine a risk factor for FIDVR. Unique short-term changes in voltage angle may also allow the prediction of an imminent event.

2.2.3. Proposed Scenarios and Use Cases for SMUD

Application 1: Reverse power flow with high renewable penetration

Scenario: A feeder has a 1MW PV site and a 500 kW dairy digester that generates when sufficient fuel is available. The feeder is long, rural and has little existing measurement devices. The load is primarily agricultural. The same substation transformer feeds a second feeder with no DG.

Use Case #1: Load on the feeder of interest is low, PV is high and the dairy digester is running at full output. Load on the second feeder is high. Voltage on feeder two is low, voltage on feeder one is high/adequate. There is a need to correct the voltage on feeder 1 while maintaining conditions on the high PV feeder, utility can decide to curtail PV or DG to allow transformer to raise voltage on feeder 2. Need to understand voltage along length of line to maintain profile with voltage control actions. uPMU can measure the direction of flow and voltage at selected points along the line and enable a correct decision to be made on how to manage the voltage along both lines.

Use Case #2: Fault on feeder 2, need to perform switching and confirm PV is disconnected beforehand. uPMU can measure direction of flow, and very small current readings and ensure is disconnected.

Application 2: Model Validation

Scenario: A feeder has a 1MW PV site and a 500 kW dairy digester that generates when sufficient fuel is available. The feeder is long, rural and has little existing measurement devices. The load is primarily agricultural. The same substation transformer feeds a second feeder with no DG.

Use Case #3: A developer wishes to interconnect a large PV site to either feeder 1 or 2. The impact and interconnection analysis will be based upon the SynerGEE Electric planning model. The analysis shows a high potential for backfeed and transformer overloads during peak PV output times due to PV on both feeders. The model also showed potential for power quality issues and need for extra voltage support. The impedance of the system was estimated from the GIS data. µPMU data is used to determine the accuracy of the estimated impedance data based on the advanced age of the equipment on the feeder. µPMU data on both feeders can determine the power quality impact of the existing PV locations, and use this data to validate the base case SynerGEE model, the model voltage profiles and expected operation of existing regulation equipment can also be validated and optimal operation scenarios proposed to the PV developer and utility based upon a correct model.

Application 3: Microgrid Monitoring

Scenario: SMUD has a microgrid on a feeder close to the Customer Relations Center in Sacramento. The microgrid has potential for intentional and unintentional islanding.

Use Case #4: In the event of microgrid islanding or re-synchronization, there is potential for transient and dynamic events impacting firstly equipment operation and secondly performance of the microgrid components. µPMU data will enable better visibility, characterization and potentially prevention of transient events.

2.2.4. Proposed Scenarios and Use cased for Southern

Application 1: Topology Detection

Scenario: Following a major storm, there are scattered outages throughout the area. Some circuit sections have been isolated and await repair of physical damage from fallen trees. Meanwhile, operators intend to restore service to as many customers as possible on undamaged feeder sections.

Use Case #1: An undamaged feeder section is to be restored by closing a tie switch, transferring load to an adjacent feeder. To assure this operation can be safely performed, the status of all switches or sectionalizers on the adjacent feeder must be determined, but reliable SCADA data is not available from all field devices. µPMU measurements are analyzed to provide conclusive evidence as to the actual status of each point of connectivity in near real-time.

Application 2: Model Validation

Scenario: The utility is conducting a planning study to determine the ability of load tap changers, voltage regulators and capacitor banks to maintain the desired voltage profile on a long distribution feeder. Voltage profiles under different regulation strategies are observed in a simulation environment based on a digital model of the circuit.

Use Case #2: The circuit model may or may not accurately reflect the impedances of all line devices. Micro-PMU measurements at different locations on the circuit provide an independent calculation of the actual impedance between two points.

Application 3: Fault Detection and Location

Scenario: A vehicle hits a rural distribution utility power pole about two-thirds of the way down a radial feeder and one line (e.g., one phase of the 3-phase, 12 kV service) falls to the ground. The other two phases remain connected and operating somewhat normally. Protective devices do not trip.

Use Case #3: Substation monitoring does not recognize an event because the high-impedance fault doesn't appreciably change the feeder load measured at the substation. However, AMI meters on that phase lose power, indicating an outage of some type has occurred. Micro-PMUs (and/or line sensors) are used to monitor conditions on all three phases at various locations along the feeder and indicate a phase-to-ground fault due to very low voltages occurring on Phase B, allowing operators to safely isolate the faulted section.

Use Case #4: The phase-to-ground fault is presumed somewhere on the now isolated feeder section that is several miles long. Measurements from micro-PMUs on either side of the fault provide a narrower estimate of the position along the feeder where the fault occurred. As a result, a smaller section can be isolated, and linemen can be sent to location by the most direct route.

3. Data Requirements for Applications

3.1. Dimensions of Data Requirements

The various applications will differ in the quantity, quality, and timeliness of measurement data they require. It is important to distinguish the following dimensions of data requirements:

- *Sampling rate*

The sampling rate of the µPMU is set at 512 samples per cycle (approx. 30 kHz). This is overkill for measuring the voltage phase angle of the fundamental, but the objective here is to characterize power quality including harmonics, which can mean both magnitude and phase angle of each harmonic. For example, the 31st harmonic of a 60 Hz fundamental would be sampled at about 16 times per cycle.

- *Angular resolution*

Angular resolution means how small a time difference between reference points (e.g. zero crossing or peak) on the voltage waveform at different measurement locations, translated into units of angle, can be discriminated. This hinges on the precision and accuracy of the time stamp assigned to the voltage measurement at each µPMU. (Note that angular resolution is not directly related to the sampling rate.) Based on previous reports under Program Element 1, we expect to obtain an angular resolution on the order of 0.01 degrees.

- *Spatial resolution*

Spatial resolution refers to how closely the µPMUs must be placed on a distribution circuit in order to permit interpolation or appropriate inferences about the conditions at locations not directly measured. Related to spatial resolution, but distinct from the issue of proximity of µPMUs to each other, is the placement of µPMUs in network topological terms, i.e. at nodes or branch points.

- *Data transfer rate*

While all measurements are stored in a circular buffer on the µPMU device, options for exporting data in real-time via ethernet or wireless communications range from firehose mode to arbitrarily sparse data selections at long intervals, and reports triggered by exceptional measurements. The most data-hungry applications will determine the settings for a given µPMU (perhaps under consideration of the cost of data transmission).

- *Communication latency*

Since measurements are time-stamped at the device, the time lag introduced by signal processing and travel between µPMU locations and data aggregation nodes does not impact the accuracy of angle measurements. However, the usefulness of µPMU data for certain purposes will depend on timeliness of receipt.

- *Continuity*

Momentary or longer interruptions of the data stream from µPMUs could be an issue for some applications.

3.2. Requirements for Applications

The three fundamental types of observations – topology, steady-state circuit behavior, and dynamic circuit behavior – have distinct technical requirements for µPMU measurements, in terms of both data reporting and device placement.

Circuit topology or connectivity has only modest requirements for angle data, since the goal is only to discriminate between zero and nonzero power flow on a particular branch. It should be nearly trivial if µPMUs are located directly on opposite sides of a switch. Depending on the number of operable switches compared to the number of µPMUs placed around the network, however, inferring zero or nonzero flow on a more distant branch will be more difficult and will benefit from strategic placement. We would not expect this diagnosis to be very urgent – that is, it would inform other operations taken on time scales of seconds or minutes – unless immediate action is required, as in the case of de-energizing an unintentional island.

Steady-state circuit behavior deals with averages over at least multiple cycles, and more likely seconds, and therefore does not require high sampling rates. The desired precision of power flow estimation, along with the uncertainty in other variables, will determine the required angular resolution. Steady-state behavior also includes power quality dimensions such as harmonics, which will require greater bandwidth than fundamental angle alone.

Dynamic circuit behavior involves the fastest-changing quantities and will therefore make use of the higher sampling rates. During transient events it will be desirable to transmit very detailed, high-resolution data, but not necessarily always; report by exception is a likely communication strategy.

It is worth noting the relationship between high-frequency phenomena to be monitored, and the effective distance range of measurement due to signal attenuation. Since the impedance of conductors and other network components increases linearly with frequency ($X = \omega L$), variations in the waveform at higher frequencies will tend to diminish more rapidly in magnitude over distance. This means that denser placement of µPMUs may become important for dynamic monitoring, especially of specific subjects such as inverters and loads.

Table 2 presents a comparison of different types of observations in terms of the various dimensions of data requirements.

Table 2. Data Requirements

	Sampling rate (per cycle)	Angle resolution (milli-deg)	Spatial resolution (placement)	Data volume (bandwidth)	Communication speed
Topology/Connectivity	1	50-300	sparse but selective	low	low, except for island detection
Steady-state circuit behavior	1-2	10-300	sparse	medium but continuous	typically low but depends on application
Dynamic circuit behavior	2-512	10-50	dense	high but could be intermittent	typically high but depends on application

The angle resolution estimates come from simulations for different distribution line length and impedances as presented in the Task 1.1.1 report. The sampling rates refer to the frequency of interest in the measurement signal and how fast this signal is expected to change.

None of the applications under consideration appear to require greater resolution than should be achievable, as indicated by the initial performance tests of the µPMU. In some cases (for example, fault location) the ultimate performance of our algorithms will hinge on the angle resolution our measurements can reliably produce, but there is no prohibitive requirement that would disqualify any of the applications on our list from useful further study. (Note that once we consider control applications, technical requirements including data resolution and communication latencies may again become more salient.)

3.3. Case Study for Benchmarking Measurement Error Propagation

A simple three-bus system with time-varying distributed generation and loads was used for an initial simulation case study to estimate the impact of measurement error from µPMUs. Beginning with a basic power flow analysis, we would like to understand the effect of an error in *measured* voltage magnitudes and angles at buses (presumed to be equipped with µPMUs) on *calculated* real and reactive power flows. Figure 4 depicts the three-bus circuit diagram used for the basic power flow analysis.

The system inputs are illustrated in Figure 5, which includes bus types and network parameters.
Network parameters:

Base Voltage: 12kV
Base Power: 750 kVA
Bus 1: Slack Bus, voltage controlled to 1 per unit (p.u.), angle set to 0 deg
Bus 2: Load Bus, PV generation 500kW, spring pattern, Household load, 400kW, weekday pattern
Bus 3: Load Bus, PV generation 1000kW, spring pattern, Industrial load 600kW, weekday pattern

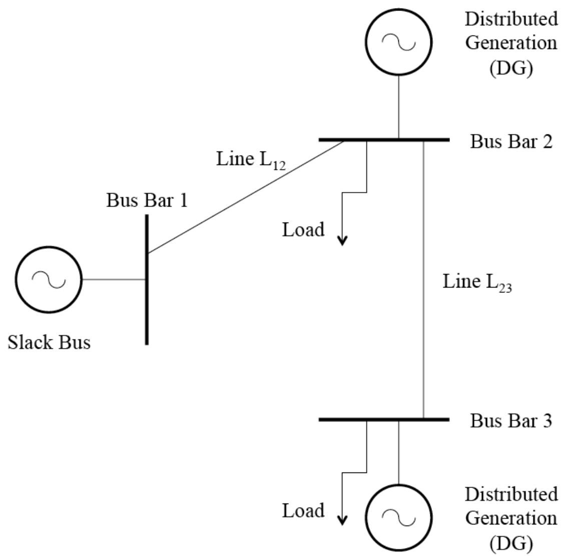

Figure 4. Case study circuit diagram

Cell Nomenclature	
Input Cell	*Explanatory*
Calculation	Note

Input

Specify the bus type, if load and/or generation applies to the bus, and which case to be analyzed

Buses	Bus Type	Load	Load Case	Generation	DG Case
Bus 1	Slack Bus (Vθ)	No	No Load	Yes	Vθ
Bus 2	Load Bus (PQ)	Yes	PQ1	Yes	DG2
Bus 3	Load Bus (PQ)	Yes	PQ2	Yes	DG6

Specify the line parameters

Lines	Line status	Length [km]	R' [Ω/km]	X' [Ω/km]	R [p.u.]	X [p.u.]	R/X
L12	closed	10	0.224	0.254	0.011666667	0.013229167	0.881889764
L23	closed	6	0.224	0.254	0.007	0.0079375	0.881889764
L31	open	8	0.224	0.254	0.009333333	0.010583333	0.881889764
		*	**	**			

Select Base Voltage and Base Power. P.u. values in inport sheets are calculated based on this base voltage/power

Base Values	U_B [kV]	S_B [kVA]	Z_B [Ω]
Grid	12	750	192

Figure 5. Bus Types and Network Parameters

Initially, a power flow calculation is performed for the three-bus system to calculate the precise voltage magnitudes and angles (V and θ) that are consistent with specified load and generation. To simulate voltage measurement data on each bus, a small amount of random Gaussian noise is added to each voltage bus magnitude and phase angle values (± 1 milli-p.u for voltage magnitude and ± 10 milli-degrees for voltage angle). Figure 6 illustrates the noisy voltage magnitudes and phase angle time-series values.

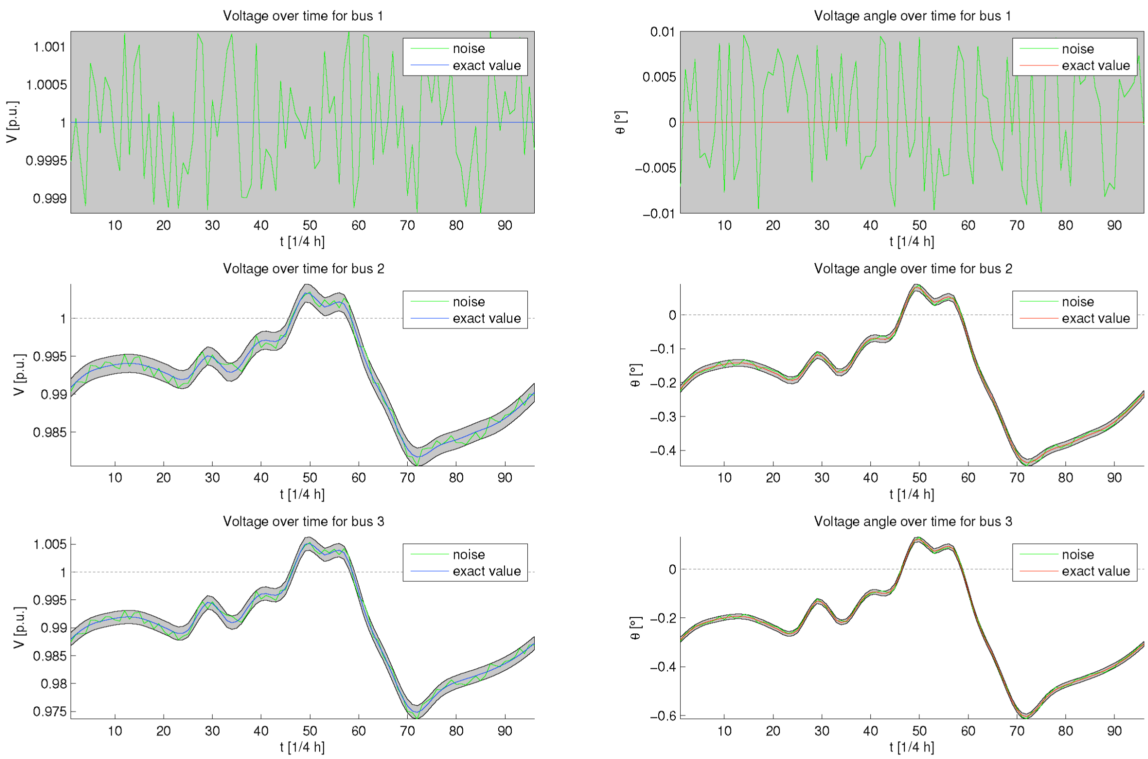

Figure 6. Voltage magnitude and angle with added noise
(± 1milli-p.u for magnitude and ± 10 milli-degrees for angle)

Real and reactive power for each bus is re-calculated based on these simulated noisy bus voltage values, and compared to the "actual" real and reactive power that was the starting point for the analysis. Figure 7 shows the real and reactive power values for three buses.

Naturally, the stipulated measurement error in V and θ propagates as an error in calculating circuit parameters at other buses. Figure 8 shows the error in calculating net real and reactive power values (where "net" refers to the difference between generation and load at each bus) from the noisy simulated voltage measurements: specifically, it plots the difference between the original ("actual") P and Q, and the re-calculated P and Q from the noisy voltages. The scale on the first graph in Figure 8, for Bus 1, extends to $+10^{-3}$ and -1.5×10^{-3} p.u.; the exponent on the vertical scale of the graphs for Bus 2 and 3 is 10^{-4}.

The preliminary conclusion from the exercise on this small system is that the error propagates about as expected, consistent within the same order of magnitude. Bus real and reactive power is sensitive to voltage magnitude and angle as it should be, but no undue magnification of error seems to be occurring. Thus, it is permissible to think about the requirements for µPMU measurement accuracy of various diagnostic applications in terms of a per-unit accuracy requirement for quantities including current, real and reactive power, with an implied roughly linear relationship. Our next step is to extend this analysis to a larger distribution network, and ultimately to examine the effect of measurement errors on *estimated* state variables at other buses without instrumentation.

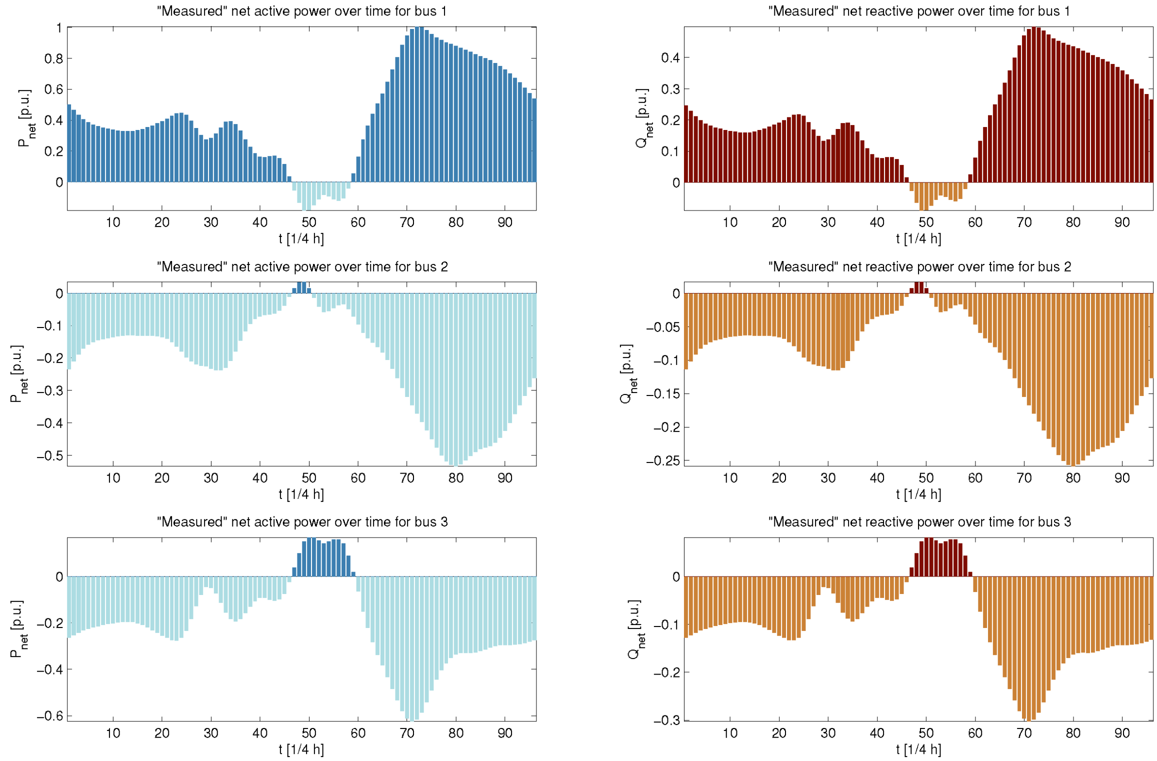

Figure 7. Net power per bus with noisy voltage magnitude and phase angle

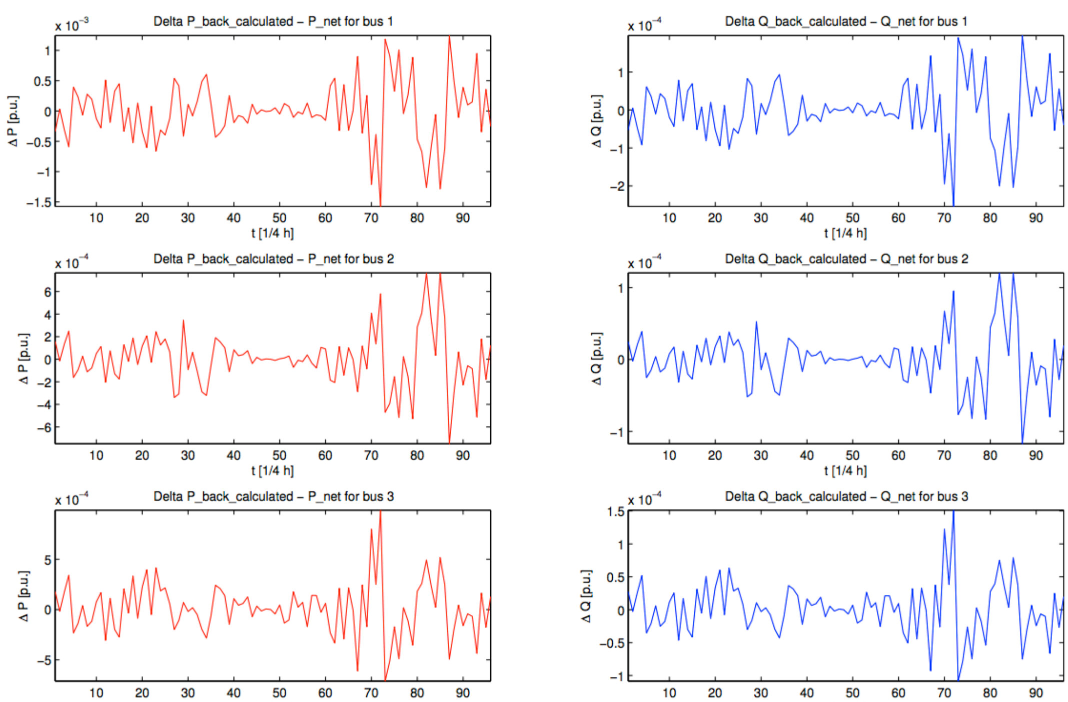

Figure 8. Error propagation in power calculated from noisy V and θ measurements

4. Functional Organization of Applications

This approach centers on the question, "What would it actually take to accomplish the specific tasks implied by the various μPMU applications?" The concern here is not so much with the capabilities of the μPMU and the communications network to provide raw data, but with the analytic steps that must be performed in selecting, processing and interpreting relevant data. On this basis, we organize applications in a hierarchical manner, starting from the literal reading and interpretation of measurements, which then enables further inferences about variables not directly measured, and ultimately evaluating this information to make decisions within different specific contexts.

Essentially, there are three types of observations of circuit conditions that are either directly measured by μPMUs or inferred from the raw μPMU measurements, and that support the foundational applications of μPMU data:

(1) *Topology or connectivity* describes which nodes of the circuit are connected to each other.

(2) *Steady-state behavior* refers to voltage magnitude and angle (and optionally, current magnitude and angle) averaged over time intervals greater than a cycle, typically at least on the order of seconds.

(3) *Dynamic behavior* refers to changing voltage magnitude and angle (optionally, current magnitude and angle) with particular regard to variations on the sub-second and sub-cycle time scale, as the system changes from one steady operating state to another or during temporary excursions or transients.

4.1. Foundational Applications

Topology Detection makes explicit the open/closed status of switches at known locations. Knowledge of the correct topology is necessary for computing power flows on a network based on measurements. It might be assumed that switch status and thus topology is known prior to μPMU measurements (i.e. if switches are instrumented with SCADA), but in fact this information may be spotty, and utilities told us that ascertaining the actual topology with μPMUs would constitute a valuable application in and of itself. Although connectivity is not directly sensed by μPMUs, it can be inferred from the phase angle difference between points on opposite sides of a switch. The number and proximity of μPMU-equipped nodes relative to operable switches that will be required to reliably ascertain switch status, given other uncertainties such as real-time loads, will be investigated in the context of state estimation.

State Estimation combines knowledge of system topology and steady-state behavior, i.e. voltages and currents or real and reactive power flows. The objective of state estimation is to identify the steady-state voltage magnitudes and angles at each bus in a network, which completely characterizes the operating state of the system – meaning the real and reactive power flows on every link, as well as power injected into or withdrawn from each bus.

For reasons discussed in more detail Chapter 4, state estimation for distribution systems is substantially more difficult than in transmission. However, if distribution systems are to be thoroughly understood and actively managed, at least an approximate knowledge of the steady-state operating condition in real-time is a precondition for interpreting specific information about particular devices or particular incidents, and to inform control actions aimed at optimizing the behavior of the system as a whole. In this sense, state estimation will be the foundation for most other applications of μPMU data. It may well be impractical to perform a complete state estimation in the rigorous sense of estimating voltage magnitude and angle at every bus for a distribution circuit (considering that every distribution transformer would technically constitute a bus). A more realistic objective is to produce a (quasi-) real-time representation of conditions that includes the correct topology and voltage magnitudes and angles at key nodes, from which branch flows and interpolated node variables can be derived, and to limit the analysis to an appropriate local subset of the larger network. Depending on the use case, one may wish to examine all the circuits from one substation, a single distribution circuit, feeder, or just an individual feeder branch, which should be faster and easier than a complete state estimation for a larger network. We might call such a rudimentary state estimator a *Fast Local Observability Analysis Tool* (yielding the fortuitous acronym *FLOAT*).

Dynamic Circuit Monitoring might also be called "shark detection." It builds on large amounts of empirical measurements, from which relevant phenomena are to be identified. "Relevant phenomena" here would include those that represent potential concerns with regard to safety, efficiency, and reliability of the power system. In some cases (such as large voltage transients), phenomena emerge very obviously from time-series data of sufficiently high resolution. Others (such as distinct oscillation modes and their damping levels) may require some data mining and teasing out. This application does not yet have fully articulated use cases, because it is not yet known what might be observed when distribution circuits are scrutinized at unprecedented levels. Nevertheless, dynamic observation will be essential for further characterization of loads, generators and other active devices.

4.2. Subsumed Applications

Unintentional island detection is a special case of topology detection that applies to situations where the open switch in question connects two parts of the network that can be independently energized from different sources, rather than being energized through different pathways to the transmission network (i.e. substation). Topology detection is the more general formulation of the problem of identifying, based on phase angle differences, the closest or most direct electrical connection between any two nodes. An island is the special case where no connection exists at all. We presume that in the islanded case, some drift of phase angle can be observed (unless generation and load are *precisely* matched on the island, which becomes increasingly improbable with the degree of match). In the general case, the phase angle between nodes would be expected to hold steady, and topology must be inferred from the comparison of phase angles at a larger number of nodes. A working hypothesis is that if we can solve the general problem of detecting connectivity, we ought to be able to detect islands readily.

Oscillation detection is a subset of dynamic phenomena that might be captured through dynamic circuit behavior monitoring.

Reverse power flow detection is subsumed within state estimation.

4.3. Advanced or Derivative Applications

An effective way to bring state estimation to life would be a *visualization tool* analogous to the angle contour map used by FNET (http://fnetpublic.utk.edu/).

Load and DG Characterization will draw on the observation of both steady-state and dynamic circuit behavior. At present, resources to be characterized will mainly include loads and PV inverters, but the data analysis techniques should also be applicable to distributed storage units and novel solid-state devices (such as solid-state transformers, volt-VAR controllers, or D-FACTS).

Load and inverter characterization provide the necessary basis for a range of further advanced applications that are of immediate interest to utilities. Specifically, *FIDVR prediction or risk diagnosis* would depend on recognizing a particular type of air conditioning loads, and estimating their contribution at a given time.

The *Unmasking* of load with distributed generation behind net meters will likely draw on voltage and current signatures (such as harmonics or transients during on-off switching) that have been identified and associated with loads and generators, as well as correlation with sunshine data.

Fault location draws on all three types of observations: topology, steady-state conditions, and dynamic circuit behavior. Our ability to locate a fault to within a narrow distance range is constrained by our limited knowledge of the pre-fault operating state, in particular the loads. Thus, we expect that state estimation and load characterization will constitute important modules within the fault location algorithm.

High-Impedance fault detection will draw on our ability to identify and locate faults, and well as load characterization, because the key for high-impedance fault detection is to distinguish the fault from a legitimate load. In a sense, the high-impedance fault can be considered a special case of a load to be characterized – but one whose location and time of occurrence is unknown.

The hierarchical and functional relationship among these and other applications is illustrated in the tree diagram in Figure 9. Since this report is focused on diagnostic applications, Figure 10 shows an abridged version of the tree diagram with applications related to diagnostics and monitoring.

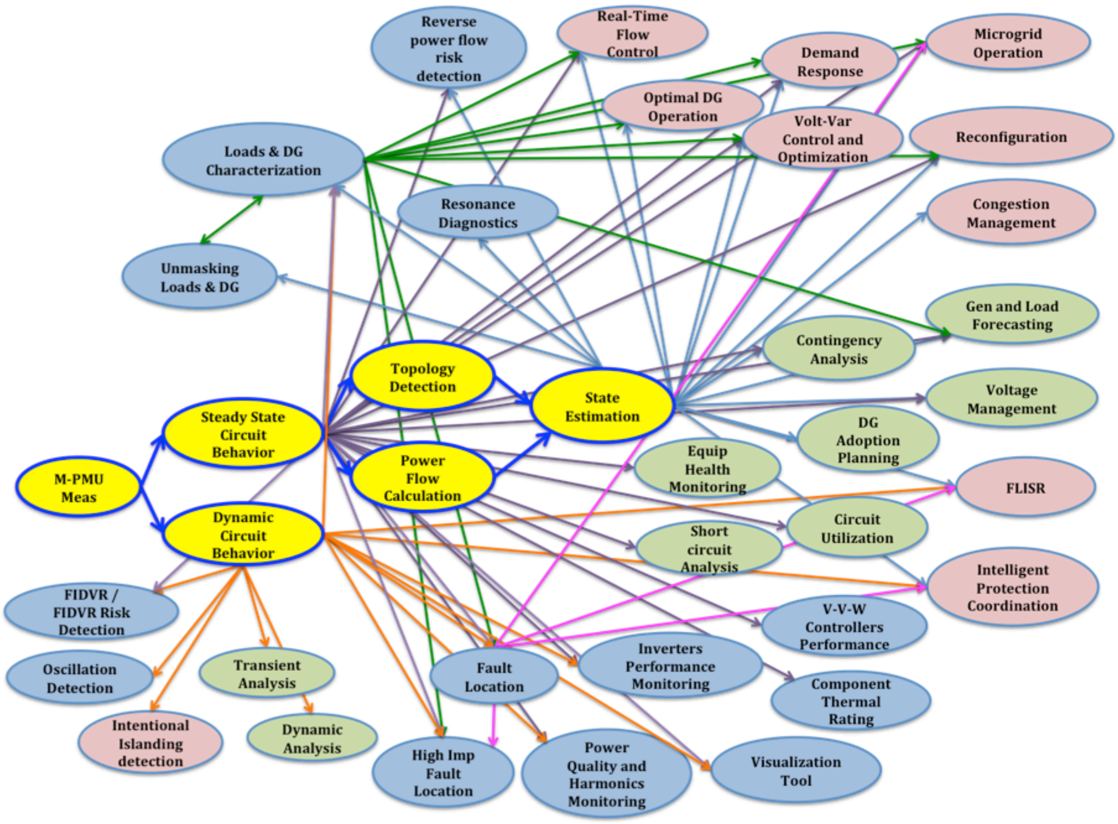

Figure 9. Tree diagram of μPMU applications

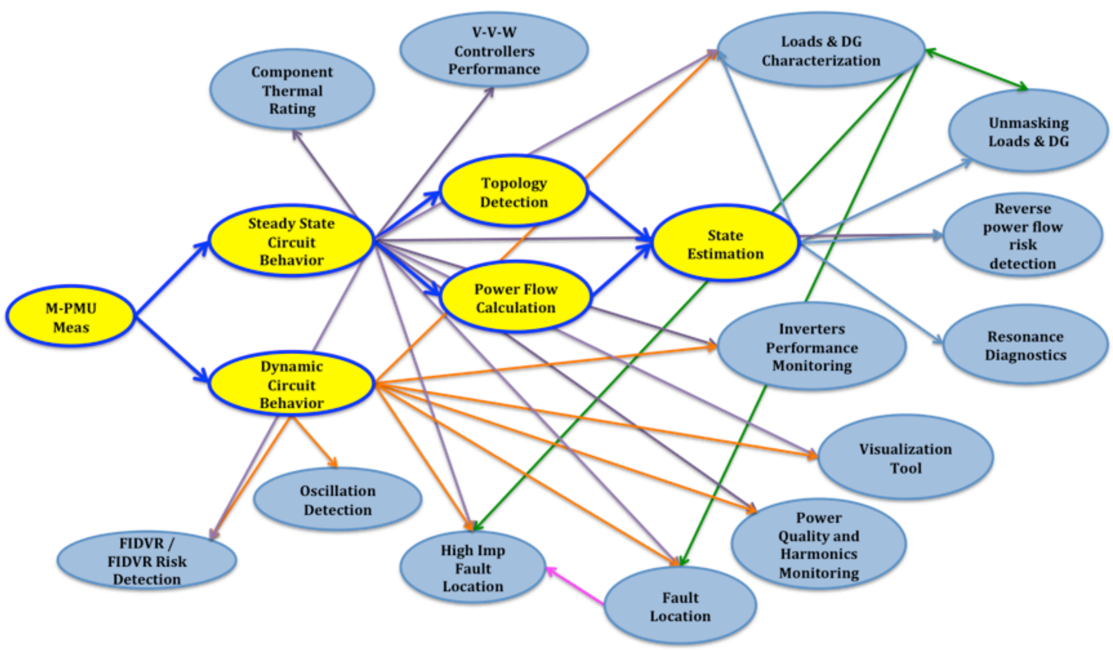

Figure 10. Abridged tree diagram of μPMU diagnostic and monitoring applications

5. Challenges and Competing Alternatives for Selected Applications

THIS CHAPTER CONTAINS CONFIDENTIAL INFORMATION

5.1. Topology Detection (including Island Detection)

5.1.1. Overview of Topology Detection in Distribution Networks

There is currently no practical method for ascertaining distribution network topology or connectivity independently of direct status indication from switchable devices. As of 2013, most U.S. utilities have substation circuit breakers equipped with supervisory control and data acquisition (SCADA) that allows distribution operators to observe their open/closed status and actuate them remotely from a control center. Out in the field, however, line devices and tie switches between feeders may not all be instrumented with SCADA and telecommunications. Even when these switches do report their status remotely, there is an extremely high price for any uncertainty: one missing, delayed or erroneous report can directly lead to consequential switching errors, including fatalities. Therefore, utilities are interested in possible means of corroborating or augmenting available SCADA reports.

Island detection is the one special case of topology detection for which alternative methods have in fact been developed, owing to vital safety concerns and the need to take immediate action. Three approaches to island detection are commonly known: local passive, local active, and communication-based or wide-area. Island detection based on synchrophasor measurements falls in the third category, because it hinges on comparing measurements at locations on and off the island.

5.1.2. Phase Angle Measurements for Topology Detection

Voltage phase angle promises a uniquely different way to assess connectivity, completely independent from querying devices themselves, by comparing the measured against the expected angle differences between nodes for the open and closed state of a switch. The working hypothesis is that these angle differences are sufficiently distinct that either the open or closed switch status can be ruled inconsistent with measurement, for a reasonable range of μPMU placements. Placement strategy will be an essential part of the algorithm development for this application.

Criteria for island detection techniques include speed, sensitivity, selectivity, and cost. Sensitivity means having only a very small subset of possible conditions (combinations of frequency and df/dt) fall into the “non-detection zone” where an island cannot be recognized, usually if generation and load on the island happen to be exactly matched. Selectivity means avoiding false trips due to other electrical events that locally distort power quality. Communication-based techniques generally are more sensitive and selective than local methods, but also more costly. Their speed is constrained by communications. An alternative to PMU measurements is power line carrier communications (PLCC). A combination of local and communication-based methods affords the greatest sensitivity.

The angular resolution requirement for island detection is modest and essentially a non-issue, as it is easily met by conventional PMUs. Simulations described in the literature illustrate various scenarios with different slip frequencies (i.e., the rate at which voltage angle on the island separates from the main grid) depending on how closely generation and load are matched; even in very closely matched cases, slip frequencies are on the order 1 Hz, or six degrees per cycle. This confirms our intuition that communication latency is far more important than angular resolution for this application.

According to IEEE 1547, the maximum operation delay, which includes island detection latency and tripping time, is 2 seconds. This standard is readily met by a variety of communication technologies. The potential advantage of µPMU-based island detection would lie in a superior combination of the above criteria. However, there is not much sense of urgency among utilities for developing this application, because situations where islanding is likely to occur (i.e. microgrids and settings with extremely high penetrations of DG) are still quite rare.

Our ongoing work is to study the more detailed conditions in which we can detect topology errors throughout distribution networks using µPMU data. More precisely, we plan to investigate the impact of phase angle measurements on the topology error detectability conditions. We expect that the phase angle measurements play a key role in relaxing the necessary conditions for guaranteeing the detectability. We are also in the process of developing a method that exactly localizes any topology errors if the detectability holds. On the other hand, we may need to place additional µPMUs to improve the detectability if a critical topology error is not detectable. Therefore, another important future work is to design an intelligent algorithm for an optimal placement of micro PMUs.

Our team has worked on developing efficient algorithms to identify switch status or to detect topology errors given µPMU measurement and psuedo-measurement data in a way that systematically overcomes the combinatorial nature of the problem. We have explored several possible avenues for this analysis. One initially promising approach was to convert the discrete open/closed states of operable switches into continuous variables that would allow the most likely network topology under a given set of measurements to be identified by way of an optimization algorithm. However, there is no guarantee that this method will be applicable to all cases of interest. Our important observation is that the optimal switch status consistent with the data is not, in general, unique. (For example, if two alternate network paths connecting a pair of µPMUs happen to have the same impedance, it is difficult to distinguish which one of the two paths is open.) This fact suggests that there are situations in which we are not capable of detecting topology errors, regardless of the quality of measurement from µPMUs.

This non-determinism of optimal switch status has inspired us to investigate the theoretical foundation of the identifiability of switch status, given µPMU measurement data. Specifically, the key questions are:
(1) Given a particular network topology and placement of µPMUs, is it possible to uniquely determine the optimal switch status?
(2) Given the network topology, what is the minimum number of µPMUs and their placement under which we can uniquely determine the optimal switch status?
The answers to these questions should advance the development of intelligent algorithms for guaranteed topology error detection, as well as informing µPMU placement. Our starting point is the earlier work by Wu and Liu [9] that posed the question, if there is an error in the presumed network topology, how would this be mathematically detectable? Our team is presently working to characterize the conditions under which the topology can be uniquely determined, and specify when it cannot. The detectability of topology errors is further discussed in Appendix A.

In principle, if any topology error were detectable, a solution would be guaranteed, since it is possible to examine a maximum of 2^N presumed network topologies (where N is the number of switches) until one is found with no error. The number of presumed topologies that require examination should in fact be less, not only because some of the 2^N possibilities can be eliminated as implausible, but because possible topologies can be ranked or examined in sequence using graph trace analysis (GTA), as employed in the ISM-DEW software (see PE3 report on Modeling Tools).

5.2 State Estimation

5.2.1. Overview of State Estimation in Distribution Networks

The objective of state estimation is to identify the steady-state voltage magnitudes and angles at each bus in a network, which completely characterizes the operating state of the system – meaning the real and reactive power flows on every link, as well as power injected into or withdrawn from each bus. In transmission networks, the real and reactive power injections are generally known, while the voltage angles are unknown and must be computed through a (surprisingly laborious) iterative numerical approximation. This power flow calculation assumes that the topology of the network and the physical characteristics of all the branches are known exactly. In practice, not enough information is reliably available to produce a complete and accurate picture of power flow for a large network in (quasi-) real-time.

The state estimator is an application that combines information from a variety of sources to make the best educated guess about the state of the system at any point in time. These information sources include empirical voltage magnitude and current measurements at certain nodes (though perhaps not at every bus), from connectivity status indicators (which may not be available for every switch or breaker, or may be outdated or inaccurate), and from mathematical relationships such as Kirchhoff's current and voltage laws that must hold true for every node and every loop in the network. Transmission state estimators are typically updated every several seconds, and are considered quite computationally intensive.

Analogous to transmission, Distribution State Estimation (DSE) uses available measurements to calculate the unknown system parameters where measurements are not available. However, DSE is not part of today's common industry practice: it is more difficult than transmission, and historically there has been no need for it. Indeed, the adoption of transmission state estimation techniques in distribution network shows some accuracy limitations.

However, the State Estimation techniques typically adopted at the transmission level cannot be easily applied at the distribution level, due to some structural differences [1]. While the radial structure of distribution systems allows for certain simplifications, it also removes the redundancy afforded by Kirchhoff's laws – in other words, the estimate for one node can not be corroborated by estimates at neighboring nodes. The reactance-resistance ratio (X/R) of distribution lines are less than X/R of typical transmission lines. Distribution system measurements are also fraught with more noise from which the angle signal must be extracted. Furthermore, there are many more points where loads connect, that each effectively constitutes a bus or network node. Yet the number of available empirical data points as compared to the number of network nodes is much smaller in distribution than in transmission, given that AMI meter data are not communicated in real-time. Moreover, the three-phase transmission systems exhibits balanced characteristics that can be represented just using a single-phase model. On the contrary in distribution systems, the strong penetration of distributed generation (DG) sources, the dual load-generator and dynamic behavior and the several kind of loads, lead to unbalanced conditions that require an explicit analysis of all three phases in state estimation.

5.2.2. Phase Angle Measurements for State Estimation in Distribution Networks

The most common method presented in the literature to solve the distribution system state estimation in distribution networks problem is based on a nonlinear Weight Least Squares (WLS) optimization, with formulations similar to that used for transmission networks [2]. In particular, using nodal voltage magnitudes and phases as state variables (possibly extended to the case of the three-phase networks [3]), the WLS approach relies on the iterative solution of a nonlinear algebraic system, which is progressively linearized around the estimated state, until the estimation error is less than a selected threshold.

Such a system is solved using a Jacobian matrix, whose elements are the derivatives (i.e. sensitivities with respect to the state variables) of different types of measurements such as real and reactive power injections, real and reactive power flow, branch current and/or voltage measurements. It is sometimes convenient to express complex phasors such as nodal voltages or branch currents in terms of real and imaginary parts rather than magnitudes and angle (i.e., in rectangular rather than polar coordinates); this approach is used in [4], and a revised version of such an estimator is reported in [5]. A fast and decoupled version of an estimator based on branch currents is described in [6].

Synchrophasor data have the potential to facilitate the objective of the state estimation by providing an explicit empirical measurement of system states (voltage magnitude and phase angle). There has been some indication in the literature that DSE performance can be improved with the inclusion of synchrophasor measurements by using the WLS or branch-current methods [7],[8]. However, the integration of PMU measurements into distribution state estimators still presents substantial challenges unique to distribution systems, which we intend to address in our work.

If we were at liberty to instrument every node in the network with a highly accurate and reliable sensor, the state estimation problem would become trivial. In transmission system state estimation, the emphasis is on identifying erroneous measurements, based on the assumption that some measurements (even if poor or unreliable) are available from each node. In realistic distribution systems, the starting point is much more difficult: we have to assume that many nodes are not instrumented at all, and that other nodes have only outdated information. Thus, our µPMU-based state estimation scheme will draw on a limited number of µPMUs. To compensate for the small number of measurements as compared to the number of network nodes, we aim to develop several approximation techniques to enhance network observability. (In control theory, *observability* indicates how well the internal states of a system can be inferred from knowledge of its external outputs. For power systems, network observability means the capability to calculate the internal system state – i.e., voltage magnitudes and phase angles – based on a given set of measurements. Observability depends on the number of measurement devices as well as their placements. Specifically, we are exploring the use of pseudo-measurements, meter data where available, and load clustering. A detailed physical model of the distribution network is also necessary.

By pseudo-measurements, we mean computed numerical values to take the place of empirical, physical measurements. The computation is performed on the basis of available historical information and some appropriate statistical analysis. For example, SCADA or customer meter data might be available from certain nodes at 15-minute intervals over a historical time period, but not in real-time. From this historical record, and given available correlated information such as time of day and temperature, a pseudo-measurement for a quantity (voltage, current, real or reactive power) at a particular node would be computed and entered into the state estimator as a best guess of the value a physical measurement at the present time might yield. Our next step in developing pseudo-measurements will be an off-line time-series analysis of sample historical meter data to gauge the potential (and computational effort) for converting these into useful pseudo-measurements. Even if our ability to perform what essentially amounts to load forecasting at high spatial resolution turns out to be very weak, the expectation is that pseudo-measurements will at least provide some confidence bounds for the DSE solution.

Another technique for dealing with the lack of real-time information about loads is spatial clustering. By this we mean representing multiple nodes as a single node for estimation purposes, effectively aggregating all the loads at these buses, collapsing circuit branches where necessary, and thus losing any differentiation between them. In a sense, pseudo-measurements sacrifice temporal resolution for the sake of a robust estimate, while clustering sacrifices spatial resolution.

A key hurdle and innovative aspect of our approach is to introduce topology detection as an interactive component of our state estimation process. This means that we do not assume the network topology is known with certainty at the outset, but that we impose the additional burden of verifying that the connectivity is consistent with the estimated state. Our approach to solving the topology detection problem is described in Section 5.1 above; our intent is to integrate the topology detection algorithm seamlessly within the state estimation process.

In general, the mixture of µPMU measurements and pseudo-measurements in the measurement vector would suggest the need for a nonlinear state estimation algorithm. However, we are examining the potential to process µPMU measurements via a linear algorithm, and have been exploring the limitations of such an approach. Specifically, we propose to use an approximated network model that provides a linear relation between the power loads and the currents. Although in principle this model could provide less precise estimates than WLS, the computational effort is much less and it can be performed much faster. Therefore, such a method would lend itself to on-line state estimation, or situations where repetitive estimations need to be performed (e.g., for different presumptive topologies).

As shown in Appendix A, we have examined the error in the voltage phasor estimation introduced by the linear model; unsurprisingly, it seems to work well if voltage drop between the feeder head and any other node of the network is relatively small, i.e. the voltage at all nodes is close to the nominal value. This approximation shares some similarities with the d.c. model approximation for power flow analysis. It also coincides with the voltage calculation obtained by running a single iteration in the well-known backward/forward sweep method for the load-flow analysis for distribution systems [10]. Numerical simulations on realistic distributions networks provided by IEEE grid tests, seem to indicate that such linear approximation is sufficiently realistic [11]. If the linearization proves unsatisfactory, an alternative approach is a multi-stage DSE, where the first stage is the nonlinear state estimation with conventional measurements and the second stage a linear state estimation with µPMU measurements. Appendix A presents the preliminary state estimation model and inputs in mathematical terms.

In sum, the distribution state estimation problem presents a tension between the quality of available data, speed of performing the computation, and the accuracy of the solution. Data quality in turn means accurate circuit models, and most important the instrumentation provided on a network: how many sensors are installed, how good their measurements are, and how frequently their reports are accessible. We strive to identify the extent to which high measurement quality from a limited number of µPMUs might compensate for the sparsity of their placement, and for the lacking quality of other input data such as loads.

To perform the functions discussed above, our proposed distribution state estimator has four key components or blocks, which are illustrated in Figure 11:
(1) *Topology Detection*
(2) *System Observability Analysis*
(3) *Bad Data Detection*
(4) Distribution *State Estimators*

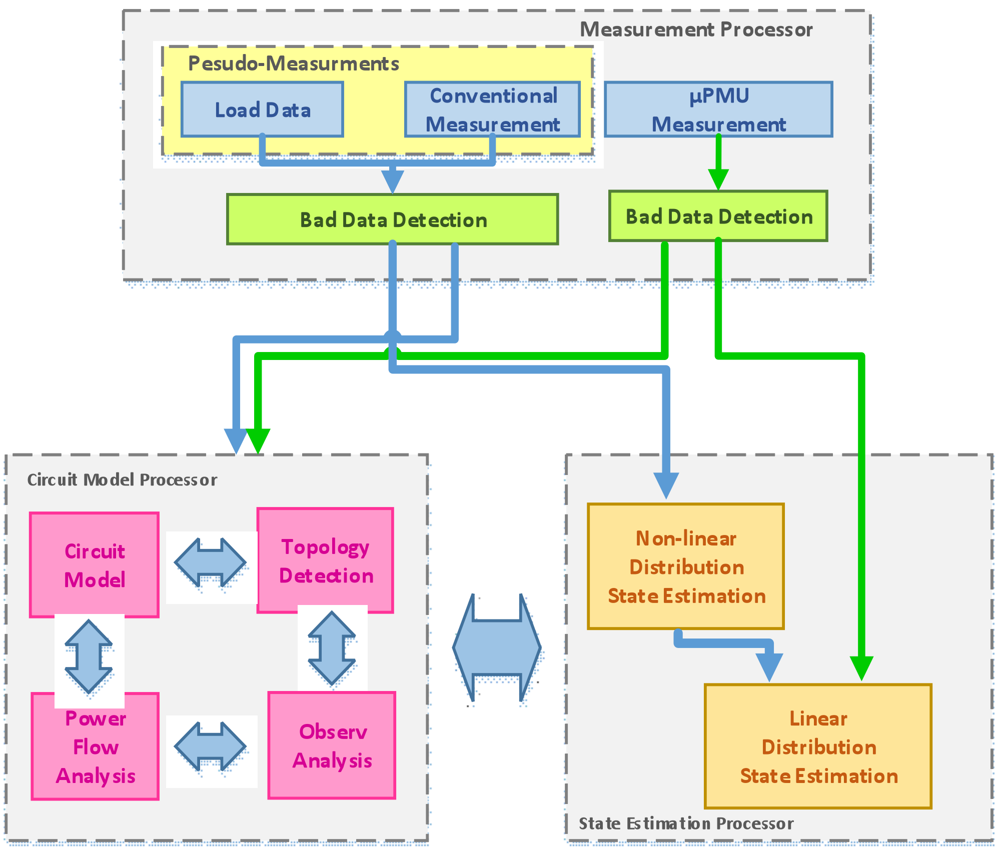

Figure 11. Distribution State Estimation Block Diagram

5.3. Fault /High Impedance Fault Location

5.3.1. Overview of Fault Location in Distribution Networks

Intelligent fault location has received considerable academic study, and various algorithms have been proposed, but few automatic fault location systems are running in the United States. The oldest method of fault location essentially consists of mapping phone calls of customers who are experiencing outages to determine where to send crews to start looking. More effective systems in use are based on using data from relays to identify the section of the feeder that contains the fault. These systems are limited by the density of protection devices and often provide location on the order of 1,000 ft. This 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 improve location of the fault, but require many devices to get a precise fault location.

Commercial systems that integrate data from line sensors, detailed feeder models, and substation measurements exist, notably from Schweitzer Engineering Labs, and have been demonstrated to provide accuracy on the order of tens of feet. It is unclear exactly what is preventing the widespread deployment of such systems, but a key hurdle may lie in the difficulties of integrating different data streams and system models that vary between, and even within, utilities. These systems also use a high density of line sensors that could present significant costs.

Methods for high-impedance fault detection exist, but are generally expensive and necessarily imperfect. Commercial detection algorithms analyze harmonic and non-harmonic currents at high frequencies (GE), use wavelets and statistical methods (ABB), or the rate of change of current (SEL) to recognize arcing downed lines.

Existing methods of fault location vary in complexity and in feasibility. The traditional brute force method consists of obtaining an initial estimate of the location of a fault from mapping customer outages, performing switching operations, and then sending repair crews to visually inspect long sections of line [12]. While reliable and easily performed, this method is antiquated and prolongs outage time. This method has been improved by overhead visual fault indicators that allow repair crews to more quickly cruise a line and locate the fault, but still requires visual inspection as well as the need for the installation of many devices [13]. This kind of system can be improved in speed and accuracy by incorporating wireless sensors to relay information to line crews and eliminate much of the time spent on visual inspection. Though these types systems can be accurate and informative, they require wide deployment of sensors, communication infrastructure, and data storage and processing.

Another class of fault location systems, often referred to as travelling wave methods, relies on high sampling rate, synchronized measurements to calculate the location of the fault [14]. This type of approach involves using signal processing techniques (particularly wavelet transforms) to identify the time at which the disturbance from a fault is observed. Because the time for the signal to propagate from the disturbance to the measurement equipment is a function of the distance from the fault, the difference in observed disturbance times at different synchronized measurement devices can be used to locate the fault [15]. This approach has been augmented for teed networks [16] and for networks that are instrumented with more than two synchronized voltage measurement devices [17]. Another wave based approach is presented in [18] that is specifically tailored for tree structured distribution systems with distributed generation and makes use of the difference in arrival times of reflected waves rather than synchronized measurements. These techniques have been shown to be highly accurate and robust to variations in system conditions (including loading and distributed generation) as they are not dependent on any assumptions about the system besides the topology and line parameters. However, because the waves propagate at close to the speed of light, 1 km of distance corresponds to roughly 3.3 μs of time difference. This means that in order to obtain reasonable accuracy for distribution systems, sampling frequencies on the order of 10 MHz are required. These high sampling rates makes the enabling equipment more costly, making them more appropriate for transmission systems.

A third class of fault location systems for distribution networks, which are broadly known as impedance based methods, involve calculations using line impedances and observed changes in voltage and current at the substation [19]. These methods vary in subtle ways, but the general approach is to use pre-fault and post-fault voltage and current measurements to estimate the fault loop impedance, which depends upon the location of the fault. A comprehensive review of some of the more cited impedance based approaches is given in [20] and a comparison of the performance of the leading algorithms is presented in [21]. These methods demonstrate accurate results in the simulation environment, but their accuracy degrades the further the fault is from the substation, and for moderately high impedance faults (100 W) [20], which are common on distribution feeders [21]. In addition, there are a number of uncertainties that are difficult to model and compensate for in distribution faults [22]. This makes it necessary to carefully examine the assumptions in a simulation in order to judge accuracy.

In established impedance-based methods, uncertainties in load modeling are especially significant. Distribution feeders will generally have multiple load taps in between the substation and the fault, as well as many loads beyond the fault, which can cause significant error if not accurately compensated for [7]. Distribution earth fault impedance exhibits a bimodal distribution with low impedance faults ranging on the order of magnitude of 10 to 100 W and high impedance faults ranging from 10 to 100kW [21]. Even a low impedance fault draws a current such that it does not completely dominate the load currents, making it necessary to compensate for load currents when calculating fault current. This is a difficult task, as the change in load currents due to the voltage drop from faults must be estimated and is not well understood. The simulations and algorithms presented in [21] rely on the use of static load models such as the ZIP polynomial model described in [22]. Not only do real loads have a wide variety of voltage to power characteristics [23] making it difficult to estimate the load model for a given feeder, but it is unclear how well these static models represent actual loads for voltage levels under a fault that differ significantly from normal operating levels. One of the potentially major sources of error in substation based impedance methods is that there are no measurements taken beyond the fault; instead they rely on static load models to estimate the behavior of these downstream loads.

The other class of fault location algorithm is essentially based-on machine learning techniques. A large number of fault scenarios are simulated to create a database of fault events. Observed fault events are then compared to the database to localize the fault to high precision. The weakness of this type of system is that it requires highly detailed system models and has been limited in empirical verification. There is much uncertainty in the distribution system, particularly around load and distributed generation characterization and in the dynamic response of the system to fault events that are difficult to model, that the effectiveness of such systems is difficult to assess without field tests.

5.3.2. Phase Angle Measurements for Fault Location

High-precision measurement devices and pulse generators can be used for fault location as well. They are most useful for underground cables, where it is difficult for crews to patrol a line. The devices send pulses down sections of cables and analyze the resulting waveforms to estimate the fault location. These devices have good accuracy, but they do not sense high-impedance faults well. The major drawback is that the expensive equipment is highly specialized and is not useful for any other applications besides fault location. Typically the cost is only justifiable for underground systems, where there are no other fast alternatives for fault location.

PMUs have experienced rapid growth in transmission systems to almost 100% coverage, largely because of the range of applications they support [26] [27]. A fault location approach based on PMU data differs from the specialized fault indicator networks and wave sensors described above by leveraging a technology that has other applications and a readily available data stream; i.e. the cost of instrumentation need not be justified by fast fault location alone. The proposed algorithm uses pre- and post-fault voltage magnitude and phase at the substation and remote PMUs, as well as current measurements at the substation and an imprecise system model in order to pinpoint a fault in less than a minute. The addition of PMU data to substation current measurements improves upon traditional impedance methods by measuring the behavior of the system on both sides of the fault, making the location estimate more robust to the distance of the fault from the substation, variations in system conditions, and uncertainties in system models. In addition to the incorporation of remote measurements, a novel method of load aggregation is used that improves accuracy for higher impedance faults.

The algorithm presented in Appendix B is designed for shunt faults occurring on lines that are instrumented by a PMU on either end, such that the fault occurs between the two PMUs. In practice, this would mean faults that occur on the primary distribution system. Fast location of these faults is especially important because, unlike faults that can be isolated on laterals, these faults will affect the most downstream customers. Faults that occur on laterals that are not instrumented can be located to the branch point using the proposed algorithm in order to identify the faulted lateral; and then any of the established single end impedance measurement methods can be used to estimate the location of the fault on the lateral.

The proposed fault location algorithm is described by the following process:

1. Identify the type of fault and which phases are affected.
2. Select the PMU at the substation and one of the remote PMUs
3. Starting at the substation, iterate over each line segment connecting the two PMUs. Assume a fault on that line segment and calculate the fault distance. If the calculated distance is greater than the line length, continue to the next line segment. If not, the fault is located according to these two PMUs.
4. Repeat steps 2 and 3 for each remote PMU.
5. Resolve the multiple location estimates from each PMU to a single estimate of the fault location.

The possibility of improved fault location with voltage angle is suggested by our initial modeling exercises, which indicate that angle (as measured at one end of a faulted line section) is more sensitive to fault location than voltage magnitude – that is, the measurement at a fixed μPMU location varies more (by at least an order of magnitude) as the location of the fault is moved. This effect is especially pronounced for faults with higher impedances, whose voltage magnitude effects rapidly diminish with distance to measuring location. The specific research challenges for high impedance fault location and its algorithm are further detailed in Appendix B.

5.4. Characterization of Loads and Distributed Generation

5.4.1. Overview of DG and Load Characterization

There are innumerable ways to measure and analyze the electrical operating characteristics of circuit devices, including loads and generators. In the power distribution context, the most common questions would be concerned with load profiles (on the scale of minutes or hours), generator variability (seconds to minutes), current and voltage harmonics injected by either loads or generators and propagated through the distribution network (by definition on the sub-cycle scale), and the response of loads or generators to changes in voltage (at ay time scale).

For example, an important topic of recent study in the area of load characterization is the response of different loads to changes in voltage, whether in the context of assessing attainable energy savings from Conservation Voltage Reduction (CVR) [22], or understanding the impacts of unintentional voltage transients [28].

The earlier generation PSL PQube, a high-resolution power quality recorder *without* the capability to perform phase angle measurements, could be considered a standard reference technology for measuring the actual behavior of loads or generators. Devices like the PQube can measure current and/or voltage magnitude with various degrees of accuracy and at various sampling rates, e.g. 256 samples per cycle for the earlier PQube. The purpose of identifying harmonic content up to about the 30^{th} harmonic, or plotting time-series graphs of voltage, current, power or frequency during transient events, is well served by such standard power quality instrumentation.

5.4.2. Phase Angle Measurements for DG and Load Characterization

Synchrophasor measurements introduce two unique capabilities to device characterization. First, voltage angle promises the ability to infer power flows from a greater distance than voltage magnitude, at least in theory. This is because angle is more closely related to real power propagation in the circuit, while voltage magnitude varies substantially over short distances and correlates more with reactive power flow. The important novelty here is that it may be possible to characterize the behavior of devices without having to connect a monitor immediately adjacent to them.

Second, µPMUs introduce the ability to directly observe dynamic response in terms of oscillations of voltage angle. For rotating generators, there is an expectation that frequency and angle excursions will be met with a distinct pattern of damped harmonic oscillation. Inverters, since they have no mechanical inertia, will respond differently to such excursions. It is important to understand these responses, not only in the interest of avoiding adverse interactions (such as the inadvertent creation or amplification of oscillations), but because an opportunity may exist to recruit inverters for grid stability services by programming them to behave in particularly desirable ways. However, identifying and then validating these behaviors first requires direct measurement.

We do not yet know how different types of loads and generators will appear when scrutinized in this manner, as there are no reliable models to draw upon. Even in the steady-state, many loads behave differently than one might expect: for example, the real and reactive power consumption of nonlinear loads such as LCD television sets could increase or decrease with voltage, depending on the manufacturer [22]; air conditioner motors may have different voltage thresholds for stalling; and a remarkable range of real and reactive power consumption can be observed as test loads are subjected to a 50% voltage sag in the laboratory [28]. Because so little is known about the actual behavior of devices beyond the idealized a.c. environment, our development of load and DG characterization will be very much driven by empirical data.

6. Challenges and Competing Alternatives for Further Applications

6.1. Visualization Tool

The concept of a visualization tool to illustrate the system's operating state in terms of voltage angle is based on the angle contour map developed by FNET (http://fnetpublic.utk.edu/). While the color gradations on the transmission-level contour map are in steps of ten degrees of angle, for a distribution map they might be 0.1° per step. Additional features could include (i) the option to view voltage magnitude contours rather than angle, (ii) an overlaid circuit diagram showing topology, and (iii) an explicit representation of the three phases in an imbalanced model.

A preliminary conversation with the individual who programmed the FNET graphics suggests that the idea of angle contour visualization ought to be workable in general. The difficulty here is likely in the details. The three-phase representation poses a substantial challenge not only computationally but visually. Also, a key question is how many layers of information need to be integrated into the same application to make it most useful to operators. Ideally, voltage magnitude and angle contours could be overlaid on existing maps, such as are being used in advanced fault location, isolation and service restoration (FLISR) systems. Ideally, too, all available status information from line devices would be imported and compared against the topology detection from µPMU measurements. Yet the alignment and coordination of various databases is known to be a major, time-consuming problem for utilities – and one we cannot presume to address within the scope of this project. In principle, though, angle visualization for distribution systems would be a unique contribution toward supporting situational awareness that could be integrated with other tools in the future.

6.2. Dynamic Circuit Monitoring (including Oscillation Detection)

Conventional means for observing dynamic and transient phenomena on electrical circuits include power quality instruments with a range of refinement in measurement resolution and sampling rate, and associated cost. At present, no commercially available power quality recorder measures voltage phase angle, or claims to detect power oscillations on distribution systems. A prototype device developed by NREL, the Distribution Monitoring Unit (DMU), does have a GPS antenna and measures phase angle, but only to an accuracy on the order of one degree.

The main commercial competition for "distribution synchrophasors" at this time consists of PMU-equipped relays (such as the Schweitzer SEL-351), but these are designed for installation at substations, not for studying dynamic phenomena out on distribution circuits. All SEL Phasor Measurement Units claim "Class 1 accuracy according to IEEE Std C37.118.1-2011," meaning 1% Total Vector Error or about 0.57 degree accuracy, which is consistent with studying transmission system phenomena. Another caveat is cost, since the retail prices for PMU relays do not include communications networking and auxiliary components such as separate time bases and phasor data concentrators.

6.3. FIDVR Risk Detection

While the occurrence of fault-induced delayed voltage recovery (FIDVR) can be readily identified through voltage magnitude measurements after the fact, there is currently no way to anticipate or predict the phenomenon, other than the awareness that a circuit is generally at risk due to climate zone, current weather, and the presence of switched capacitor banks. The challenge for anticipating FIDVR with µPMU data would lie in the successful mining of dynamic circuit monitoring data for clues about the load composition in real-time, and specifically identifying the contribution from single-phase air conditioning compressor motors.

6.4. Unmasking Load and Distributed Generation

There is presently no way to remotely disaggregate loads and generation sources behind a net meter; the only alternative is to physically monitor at points behind the meter. Such monitoring may be prohibitive for both economic and legal reasons. Therefore, utilities concerned about the uncertainty and variability introduced by high penetrations of net metered DG are very interested in non-invasive diagnostics to tease apart how much load is being offset by generation. The challenges to accomplishing this with µPMU measurements reside in the data analysis to identify characteristic "fingerprints" of loads and generators, likely by correlating electrical measurements with other information such as local solar irradiance.

7. Conclusion

While all of the above considerations are important factors in the down-selection of applications, our key consideration is to prioritize and develop the most fundamental, enabling applications first, drawing on the functional mapping in Chapter 2. The reasoning is as follows:

(1) Foundational applications will have to work no matter which of the many possible advanced or derivative applications are ultimately developed, or which particular use cases are to be addressed.

(2) The technical requirements of the foundational applications in terms of data quality and quantity will likely apply to other applications built upon or derived from them.

(3) By developing a small number of essential enabling applications we are opening the broadest range of options to develop advanced and derivative applications in the future, including control applications.

Consistent with this approach, our conversations with utilities revealed that basic functions such as topology detection, state estimation and the characterization of generation and loads – which could be called "tools" rather than "applications" although we decided against introducing new terminology – are worthy of being considered as applications in their own right, and will likely provide tangible value in and of themselves.

We propose, then, to prioritize the three foundational applications for further development:

- ***Topology detection***
- ***State estimation***
- ***Dynamic circuit monitoring***

If the associated effort turns out to be reasonable, we hope to illustrate state estimation with a ***visualization tool***, but completion of such a tool is not a prerequisite for developing other advanced applications of interest.

Observation of steady-state and dynamic behaviors will create an empirical basis for ***Load and DG characterization***, which we believe to be on the critical path toward any of the more advanced applications below.

We are presently continuing our research on ***topology detection*** techniques based on combining µPMU data with other available measurements. Topology detection is an important and innovative component of distribution state estimation, especially in radial distribution networks with lack of redundancy, where most researchers assume the topology or connectivity to be known with certainty. We look forward to reporting about our progress with various techniques, including non-linear optimization and graph-theory based solutions, as well as the inherent limitations.

Alongside this effort, we are in the process of developing ***distribution state estimation*** techniques based on µPMU data, which can also make use of a potpourri of other measurements if and when these are available. Like eschewing the popular assumption of a perfectly certain network topology, this approach reflects an important reality of distribution operations: namely, the amount, granularity and reliability of available circuit data can vary considerably. A robust and practical approach to distribution state estimation should neither rely on the assumption that every node is instrumented, nor miss the opportunity to leverage any useful available information, however imperfect.

As discussed above, a crucial step in our work is to understand the role of different sources of error. There are four important categories of error for state estimation:
1. Measurement error from µPMUs;
2. Errors in the network model (such as connectivity or impedances);
3. Errors in pseudo-measurements (such as forecast loads); and
4. Error introduced by mathematical approximation (specifically, linearized power flow).

Because these errors interact, it is impossible at this point to specify a threshold of µPMU accuracy that would support an adequate job of state estimation. What we can say with relative confidence is that of the above four types of errors, µPMU measurement error is likely to be the smallest (and indeed the least of our worries). The overall error in the state estimation will almost surely be dominated by pseudo-measurements, so the limitation on the practicality of a µPMU-based DSE will depend more on the density of deployment than the performance of the individual instrument. We look forward to characterizing these relationships more explicitly through simulations. In sum, our objective is to develop a robust state estimation approach that is suited to leveraging information from different sources of non-uniform quality, thereby increasing the observability and transparency of distribution networks to the greatest extent practical in a given situation.

We also plan to continue to investigate ***fault location,*** at least until we can reach a more definitive conclusion about its challenges and limitations, based on field data. So far, fault location appears to be difficult but promising. Its successful implementation on an IEEE 123 bus model confirms its capability in principle. However, its actual performance will depend on a combination of topology detection, state estimation, and especially load characterization. The four categories of error for state estimation also apply to fault location, and again the loads are a crucial source of uncertainty. We plan to run more realistic scenarios for fault simulation to test the algorithm under a broader range of conditions. The beauty of pursuing this application is that on the one hand, it is an opportunity to take maximum advantage of the capabilities the µPMU has to offer, while on the other hand, there is a relatively soft threshold for failure: even partial success in narrowing down the location of some faults is probably better than nothing.

By prioritizing the foundational applications and proceeding to ***dynamic load and DG characterization***, we preserve the option of developing any of the more advanced applications, namely:

- ***High-impedance fault detection***
- ***FIDVR prediction***
- ***Unmasking load/DG***

None of these advanced applications are prerequisites for the others, making them a lower priority for this project.

Table 3 below summarizes the key attributes of our candidate applications. We note the main competing conventional strategies, the likely advantage afforded by measuring voltage angle explicitly, the likely technical challenges to be encountered in developing each application, and the preliminary interest level indicated by utilities. We favored those applications that are uniquely enabled by voltage angle measurement, or at least promise a significant advantage over conventional techniques; those whose technical challenges we expect to be able to overcome; and those in which our prospective utility partners indicate the highest level of interest.

Table 3: Summary of Attributes of Candidate Applications

Diagnostic Application	Competing conventional strategies	Likely advantage of voltage angle	Likely technical challenges	Utility interest level
Unintentional island detection	inverter-based, various	possibly faster, greater sensitivity and selectivity, possibly less expensive	easy	low
oscillation detection	none	unique	medium	low
Reverse power flow detection	detect with PQ sensor (V mag, I mag & angle)	may extrapolate to locations not directly monitored	algorithm using minimal placement	moderate
FIDVR detection	detected with V mag	possibly less expensive, faster	easy	moderate
FIDVR prediction	none	may be unique	unsure	moderate
Fault location	various	possibly better accuracy, i.e. locate fault more closely with δ	need high resolution, fast data	high
High-impedance fault detection	various, difficult	possibly better sensitivity and selectivity with δ	unsure	high
Topology detection	direct SCADA on switches	possibly fewer measurement points, independent validation	algorithm using minimal placement	high
State estimation	computation based on V mag measurements	possibly fewer measurement points, better accuracy, faster convergence	algorithm using minimal placement	moderate
Dynamic circuit monitoring	high-resolution PQ instruments, none for δ	uniquely capture oscillations, damping	data mining for relevant phenomena	high
Load and DG characterization	limited observation with PQ instruments	uniquely capture dynamic behaviors	data mining, proximity to subject	high
Unmasking load/DG	none	may be unique	unsure	high

Based on the analysis and discussion in this report, we conclude that **"the angular resolution and communication requirements for one or more applications are consistent with demonstrated or expected performance by µPnet,"** as stipulated in Project Milestone 4.1.2. While algorithms for topology detection and state estimation pose various analytic challenges, the requirements of these applications in terms of angular resolution, data volume and communication speed of µPMU measurements are consistent with what we expect from our network, and indeed with what we have begun to demonstrate at the pilot site. Fault location and dynamic characterization of loads and distributed generation generally impose more stringent requirements. Our initial simulations suggest that useful progress can be made on the problem of fault location with the angular resolution that µPMUs can provide. The value of µPMU measurements for dynamic characterization will have to be judged based on a sufficient volume of empirical field data, whose collection we eagerly anticipate.

Additional Publications

The following are related publications by our CIEE research team and collaborators. In [29-30], a brief review of different proposed application for µPMUs ispresented. In [31], a linear state estimation based on the µPMU is proposed. This approach may be computationally advantageous compared to conventional, non-linear state estimation algorithms. In [32], we propose a new approach for distribution network topology detection with time-series µPMU measurements. The analysis in [33-35] shows the phasor-based method for harmonic analysis in distribution networks using phase angle measurements.

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