

# Precision Micro-Synchrophasors for Distribution Systems: A Summary of Applications

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**Abstract**—This paper describes high-level findings from an innovative network of high-precision phasor measurement units, or micro-PMUs ( $\mu$ PMUs), designed to provide an unprecedented level of visibility for power distribution systems. We present capabilities of the technology developed in the course of a three-year ARPA-E funded project, along with challenges and lessons learned through field deployments in collaboration with multiple electric utilities. Beyond specific applications and use cases for  $\mu$ PMU data studied in the context of this project, this paper discusses a broader range of diagnostic applications that appear promising for future work, especially in the presence of high penetrations of variable distributed energy resources.

**Index Terms**—Phasor measurement units, synchrophasors, voltage measurement, power distribution, smart grids.

## I. INTRODUCTION

Historically, with mostly radial power distribution and one-way power flow, it was only necessary to evaluate the envelope of design conditions, e.g. peak loads or fault currents, rather than continually observe the operating state. But the growth of distributed energy resources introduces variability, uncertainty, and opportunities to recruit diverse resources for grid services, prompting an interest in tools such as advanced sensors and more comprehensive monitoring to better observe, understand and manage the grid at the distribution scale [1]. To address this need, the University of California at Berkeley (UCB), in conjunction with Power Standards Lab (PSL) and Lawrence Berkeley National Lab (LBNL), has worked to develop a high-precision, micro-phasor measurement unit ( $\mu$ PMU) and to study its applications for diagnostic and control purposes in distribution systems.

A  $\mu$ PMU provides ultra-precise, synchronized measurements of voltage (and optionally current) magnitudes and phase angles, or synchrophasors. The  $\mu$ PMU hardware in this project builds on an existing commercial power disturbance recorder capable both of storing and analyzing data locally and of communicating live [2]. The key innovation is a precise time-stamping of measurements via GPS to allow the comparison of phase angles (i.e., the timing of the voltage waveform) at different locations. After developing and testing the  $\mu$ PMU, the project team developed a live network of  $\mu$ PMUs and a powerful time-series database called the

Berkeley Tree Database (BTrDB) [3] to allow for monitoring and visualizing distribution grid behaviors in near real-time. Beyond the pilot test site on the LBNL and UCB campus, several dozen  $\mu$ PMUs were installed on distribution circuits of partnering electric utilities during 2014–2016. The costs of these pilot installations were dominated by the installation labor costs added to the three-year communication costs at 0.5GB per day via cellular modems. The cost of the  $\mu$ PMU instruments themselves, developed for this research project, was approximately \$3,500 per measurement point, optimized for precision research purposes.

The rest of this paper is organized as follows: Section II provides background on synchrophasor technology and the interpretation of PMU measurements. Section III describes the network and database developed to accommodate the rich  $\mu$ PMU data streams. Section IV presents an overview of relevant distribution system applications in both the operations and planning context, providing some illustrative examples and updating recent progress in their development. Section V discusses data quality and limitations in relation to different applications, Section VI introduces an open dataset, and Section VII concludes the paper.

## II. SYNCHROPHASOR TECHNOLOGY

Today, synchrophasors are used almost exclusively to observe transmission systems. Deployment of transmission PMUs has grown dramatically in recent years [4], as synchrophasor data provide unique insights into power flow and angle stability on a.c. networks: they make it possible to directly observe the state variables, voltage magnitude and phase angle at each node, that uniquely determine the operating state of the system through the power flow equations. In transmission systems, where branch impedances are overwhelmingly inductive, real and reactive power flow can be mathematically decoupled to a very good approximation, and real power flow  $P$  between two nodes varies mainly with the voltage angle difference  $\delta$  (that is, the phase shift of the voltage waveform as observed at different locations relative to the same clock), according to the relationship

$$P_{12} \approx \frac{V_1 V_2}{X} \sin \delta_{12} \quad (1)$$

where  $X$  is the line inductance and  $V_1$  and  $V_2$  are the voltage magnitudes. Direct measurement of the state variable

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$\delta$  can not only serve as a proxy for local current measurements (assuming network impedances are known), but can help estimate the system state beyond instrumented nodes, since voltage phasors, unlike currents, are not sensitive to the branch on which they are measured. Moreover, synchrophasors are invaluable for characterizing dynamic behaviors such as oscillations, since it is possible to simultaneously observe position (steady-state phase angle), rate of change of angle (frequency), and rate of change of frequency (ROCOF).

For synchrophasor applications of interest at the transmission level, algorithms compare measurements across large distances, even if the PMUs happen to be installed on distribution circuits—say, at substations, or plugged into 120-V wall outlets [5], [6]. Such analysis provides important insights for wide-area monitoring, including frequency and angle stability, grid oscillation modes and damping, or significant disturbance events [7], [8]. By contrast, this paper addresses applications concerned with power flows on medium-voltage distribution systems to inform *local* decisions. The emphasis here is on comparing data from multiple locations behind the same distribution substation, even if measurements from more distant PMUs are also sometimes drawn on. For example, an algorithm may seek to determine the cause and effects of a fault on a distribution circuit based on voltage and current phasors along the feeder, while checking synchronized data from elsewhere to rule out a disturbance propagated from the transmission side.

Synchrophasor measurements suitable to inform local, distribution-centric analysis are more challenging to make, for several reasons. Because power flows are smaller and distances shorter, voltage phase angle differences of interest are typically two orders of magnitude smaller than those across transmission systems i.e., hundredths to tenths of a degree, not whole or tens of degrees, where a 10 millidegree phase shift at 60Hz is equivalent to  $0.46\mu\text{s}$ . At the same time, magnitude and phase angle signals are small compared to measurement noise and nonrandom measurement errors, and the signal itself typically contains many layers of variation on different time scales that may or may not be of interest for a particular interpretation of the measurement.

Another problem for drawing intelligence from the phasor data here is that distribution networks tend to have significant resistive components, meaning that real and reactive power flow cannot be decoupled and the standard transmission approximation of Eqn. 1 becomes invalid. A better approximation, based on the DistFlow equations for radial systems [9], is given by the pair of equations for voltage magnitudes and angles

$$|V_1|^2 - |V_2|^2 \approx 2(RP + XQ) \quad (2)$$

$$\delta_1 - \delta_2 \approx \frac{XP - RQ}{|V_1||V_2|} \quad (3)$$

where the ratio of inductance  $X$  to resistance  $R$  will determine the sensitivity of real power  $P$  and reactive power  $Q$  to  $V$  and  $\delta$ , respectively [10].

Moreover, since neither loads nor impedances can be assumed equal across all three phases in distribution systems, it may be necessary to use an unbalanced three-phase model,

which adds substantial computational complexity [11]. Because analysis for the unbalanced three-phase case is so unwieldy, its use in practice has been mainly limited to protection studies. With the advent of single-phase generation sources and electric vehicle loads, however, distribution planning and operations will likely see an increasing need to employ three-phase models, along with measurement data from each individual phase.

The  $\mu\text{PMU}$  devices used in this project have reliably measured angle separations as small as  $0.01^\circ$  and voltage magnitudes to within  $10^{-4}$  per-unit. The detailed capabilities of the  $\mu\text{PMU}$  device built by PSL are described in [2], [12]. Devices may be connected directly to single- or three-phase secondary distribution circuits up to 690V, or to the primary (medium-voltage) distribution network by way of transducers such as potential and current transformers (PTs and CTs) that are typically found at distribution substations or line devices.  $\mu\text{PMUs}$  communicate via Ethernet or cellular modem. In the research implementation, each  $\mu\text{PMU}$  streams magnitude and phase angle values for each voltage and current channel at two samples per cycle, or 120 Hz. This paper uses the term “ $\mu\text{PMU}$ ” generically for devices (from any manufacturer) specifically designed to measure distribution-level phase angle separations—i.e., small fractions of a degree—and “PMU” to include devices that meet expectations for the transmission context, with typical accuracies on the order of  $1^\circ$ .

### III. NETWORKING SYSTEM OVERVIEW

The real potential for leveraging phasor data in practical applications lies in clever networking and data management. The ARPA-E project addressed this with an innovative architecture for synchrophasor data analysis on distributed commodity hardware. At the center is an original feature-loaded timeseries store called the Berkeley Tree Database (BTrDB). Able to handle sustained writes and reads exceeding 16 million points per second per cluster node, advanced query functionality and extremely efficient storage, this database enables pioneering analysis and visualization techniques [3].

Leveraging this database, a distillate framework has been created that allows for nimble development of scalable analysis pipelines with strict assurances on result integrity in the face of asynchronous changes in data and out-of-order arrival. This leads to exceptional handling of both real-time and historical data: for instance, over 216 billion raw and 515 billion derived datapoints from 13  $\mu\text{PMUs}$  were archived in as little as 3.9TB [3]; the project’s archives now exceed 100TB. On four large EC2 nodes, BTrDB achieves over 119M queried values per second ( $>10\text{GbE}$  line rate) and over 53M inserted values per second of 8 byte time and 8 byte value pairs, while computing statistical aggregates. It returns results of 2K points summarizing anything from the raw values (9 ms) to 4 billion points (a year) in 100-250ms [13]. We have demonstrated that the system can scale to handle sophisticated analyses and storage for tens of thousands of  $\mu\text{PMUs}$  on commercial off-the-shelf servers [3].

Figure 1 shows the architecture and deployment design for this BTrDB system [13]. Security is addressed in the following

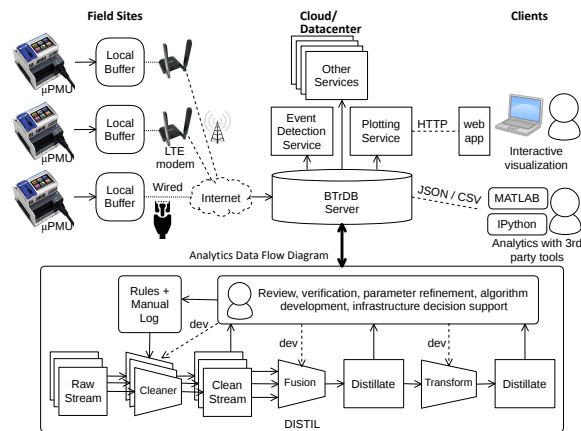


Fig. 1. System architecture overview, adapted from [13]

ways: The plotting service is limited to password-protected user access to the database over an encrypted channel; only data from registered IP addresses or serial numbers is stored; and the  $\mu$ PMU instrument implements a range of secure transfer protocols including SFTP and HTTPS. Additional research is in progress to enhance the security of data transfers from the  $\mu$ PMU instruments to the destination database [14], [15].

With  $\mu$ PMUs installed at multiple places on a distribution feeder (e.g. the substation, the end of the feeder, and key distributed generation equipment), the BTrDB system can support the analysis and operation of an single feeder, many feeders originating at the same substation, or even assist in the detection of transmission-level phenomena [12].

$\mu$ PMUs stream raw data into the database by way of the chunk loader. To enable human-centric analyses, the data is then automatically "distilled" into globally timestamp-aligned clean streams using the GPS lock stream and continually-evolving heuristics for good data. These streams become the inputs for a set of additional algorithms ("distillers") that create a directed data flow graph for a single phase of an individual  $\mu$ PMU. These are repeated for the other phases, and again for each of the other  $\mu$ PMUs [3].

The communication timing can vary and be optimized by application, e.g., once per cycle, once every few seconds, or anomaly-triggered. The data can flow to multiple networking nodes, where each node can be armed with different analytic tools. A networking node can be located on a portable computing station with the proper communication link. The analyzed data can be visualized at the node, sent to users as is or filtered, or sent when a threshold for anomaly detection is met. Examples include a summary sent to the distribution system operator, or a control instruction sent from the networking node to the relevant devices [12].

The networking infrastructure is agnostic to the particular sensor device connecting to it because standard protocols and file formats are employed. A major goal of the BTrDB system is to facilitate the greatest diversity of devices, information, and applications all playing together well in power system operations [12].

#### IV. APPLICATIONS FOR $\mu$ PMU DATA

A broad spectrum of potential distribution system applications could hypothetically be supported by PMU or  $\mu$ PMU data, as has been noted in the literature. [16]–[19]. We distinguish between diagnostic and control applications. Diagnostic applications help operators and planners better understand the present or past condition of the distribution system, which may inform decisions about equipment maintenance, network upgrades or resource interconnection. Control applications inform specific actions to be taken in more or less real-time to directly alter the operating state of the network, including circuit topology reconfigurations, power injections from distributed resources, or demand response. This paper focuses on diagnostics, which are closer to commercial readiness than controls based on PMU data. The overall benefits of ultra-precise, high-resolution and time-synchronized synchrophasor measurements can be summarized as improved situational awareness regarding distribution circuits. Use cases for this type of information range widely and may apply to both operations and planning. Some applications require only high-resolution, time stamped voltage magnitude measurements; some are supported by current measurements (loads); and others (frequency, oscillation and island detection) depend on voltage phase angle data of various accuracy levels. This section provides an overview of specific applications and use cases that have been demonstrated and those that hold future promise.

##### A. Event detection and classification

Our team has used  $\mu$ PMU measurements extensively to detect and explain disturbance events [20]. The diagnostic strength tends to derive more from precision time stamping and very high-resolution magnitude measurements, now comparable across multiple locations, than from calculations explicitly using the phase angle. The  $\mu$ PMU data here present an alternative to distribution system SCADA measurements, which tend to have resolution on the order of several seconds and often are poorly aligned in time with each other. Event detection leverages the inherent high-speed search capability of BTrDB, which makes it possible not only to locate small events inside large data sets, but to iteratively tune search parameters. Use cases span a broad range from identifying and preventing hazardous conditions or equipment damage to helping assign responsibility for disturbances or power quality impacts.

- Voltage sag detection and analysis. The first practical application from our project, developed by LBNL, scans the BTrDB database for voltage sags and notifies users by email [21]. An automated algorithm distinguishes locally caused disturbances on a feeder from those originating elsewhere on the transmission grid, by comparing per-unit voltage sags at multiple locations, as well as changes in current and their precise timing. This analysis can establish, for example, whether a load or generator trip was caused internally, by other nearby devices, or distant sources. The reliability and detail of event classification, along with the ability to locate disturbance origins by

triangulation, will improve with denser deployment of  $\mu$ PMUs and algorithm refinement through learning.

- High-impedance faults. The most important type of local cause for voltage sags are faults with sufficiently high impedance, and thus small current, that do not trip protective devices. High-impedance faults created by animals or arc flashes that are typically invisible to operators can be identified with  $\mu$ PMU measurements, and distinguished from other local voltage sag causes such as motor starts, through the detailed time-series behavior of voltage and current [20].
- Equipment health diagnostics. Our team has demonstrated  $\mu$ PMU-based early diagnosis of a tap changer malfunction on a substation transformer based on analyzing detailed voltage signatures during and after tap change events, enabling timely correction by the utility [20]. Note that voltage phase angle changes can help distinguish tap changes from other magnitude step changes [22]. This application likely extends to many distribution devices with significant potential for economic savings and improved safety.
- Fault location. In theory,  $\mu$ PMU measurements can enhance fault location along circuit sections between protective devices based on estimating the impedance between measurement point and the fault [23]. The expected advantage of high-precision phasor data as compared to SCADA-based techniques is a combination of improved location accuracy and/or fewer sensors, owing to explicit measurement of  $\delta$  and more precise time-alignment of sensor data from different locations.

### B. Topology and Cyber-attack Detection

PMU measurements can be used to confirm the topology of a distribution network, i.e. the open/closed status of switches or breakers. Use cases for topology detection with advanced sensing include situations where SCADA data from remote terminal units are either unavailable or considered unreliable for any reason [24]. Certainty about the actual topology is important for preventing customer outages and constraint violations (e.g. unintentional network loops, unsafe voltage across a switch while closing, high or low customer voltages, excessive load on a circuit section) through subsequent operations. A special case of interest is the detection of cyber-attacks that would deliberately conceal or falsify information, to either mask a physical attack or trick operators into taking actions that inadvertently sabotage the grid. Such attacks could be identified by checking the consistency of SCADA data against independent  $\mu$ PMU data that reside on a separate, independent cyber-network. To escape detection, an attacker would then have to simultaneously attack both networks in perfect coordination, a vastly higher security threshold. Cyber-attacks could also be identified by detecting unexpected operations or topology changes via the physical  $\mu$ PMU measurements alone.

Topology detection algorithms draw on essentially three different approaches, each of which still await extensive testing in the field:

- Residual State Estimation Error. This approach, which depends on absolute measurement accuracy, relates the residual error of the distribution state estimation to a discrepancy between the assumed and the actual network topology. A suitable algorithm can then identify which of a set of possible topologies minimizes the residual error, and is thus the most plausible actual topology [25].
- Time-series Signature of Topology Changes. Rather than scrutinizing the steady operating state under a given topology, this approach focuses on detecting and interpreting the transitions between states, as switches or breakers are being opened or closed. In doing so, it sidesteps the accuracy problem, relying instead on relative changes observable at high sampling rates over time spans on the order of several cycles. In one example of the time-series approach, measurements at different locations on the network are compared against a library of behaviors expected under a set of possible topology transitions [26], [27].
- Source Impedance Method. This approach, which also relies on the time series, is discussed further below. It examines the effective source impedance looking up into the network through step changes in voltage and current phasors that reflect reconfigurations of the circuit topology. Development of this technique is supported by the DOE CEDS project [28].

### C. Model Validation

Beyond the topology status that might change on the order of hours or days, the more permanent physical characteristics and connectivity of a distribution network also require empirical measurement for validation. Because of the high level of detail involved and the cost of verifying information in the field, distribution circuit models are notoriously inaccurate; yet these models form the basis of many essential analyses, especially in the planning context [29]. An important example is the interconnection of distributed solar generation, where a correct model is crucial for the prediction of physical impacts on the circuit. High-precision  $\mu$ PMU measurements of a combination of voltages and currents may confirm, correct, or improve the detail of distribution network models. Specific items of interest include:

- Load models. Detailed time-series measurements of voltage and current at the feeder level can validate and improve analytic tools such as ZIP-models of aggregate load, used to predict load response to voltage changes.
- Generator models. A topic of particular interest is the dynamic response of switch-controlled devices (inverters) to voltage conditions and transient events at fine time scales. The context may be either preventing unintended effects (such as cascading trips) or leveraging these resources for grid services (such as VAR support, harmonic cancellation, transient mitigation, or synthetic inertia).
- Phase (ABC) identification. PMUs allow for relatively straightforward phase identification by direct comparison of phase angles, with the caveat that delta-wye connections shift angles by  $30^\circ$ . Because angle differences

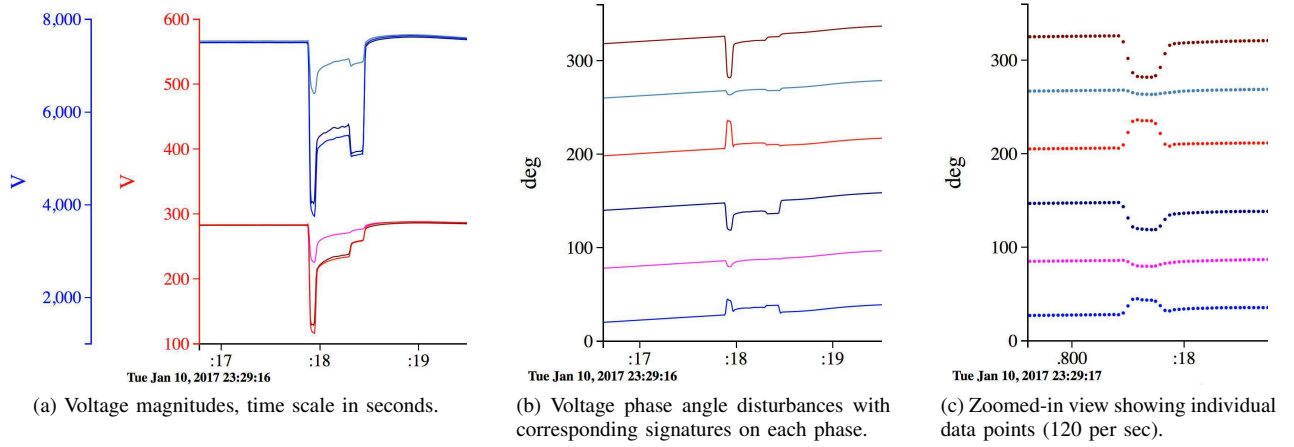


Fig. 2.  $\mu$ PMU voltage measurements on three phases in Berkeley (blue) and Alameda (red).

associated with distribution power flows are much smaller than  $30^\circ$ , it is straightforward to match A,B,C phases on a single feeder by inspection, although this becomes more difficult when reference locations are separated by multiple transformers with unknown configurations or sequencing. A complementary method draws on the time-series to correlate voltage changes on the different phases [30], preferably during large asymmetrical disturbances. This is illustrated by the example in Figure 2, which shows voltage magnitudes and phase angles (relative to the same clock) during an event observed at two Bay Area locations, Berkeley and Alameda, separated by the 115-kV transmission network and multiple transformers. Without any network model information about the phase correspondence between these sites, we can confidently identify it from Figure 2b based on the different shape of the angle disturbance for each phase, despite the matching phases being shifted by  $180^\circ$ . We could have matched Phase 1 between the two locations based on the smaller per-unit magnitude of the voltage sag in Figure 2a, but the association between Phases 2 and 3 by magnitude alone is less conclusive. Using PMU data obviates the need for specific equipment to actively inject a signal for phase identification.

- Line segment impedances. Measurement of both current and voltage phasors at each end of any given line segment or device should, in principle, yield the impedance of that segment through simple application of Ohm's law. We have found this to be surprisingly difficult in practice, as discussed below, since small errors have large impact. A likely path to improving impedance calculations is the application of suitable regression techniques.
- Transformer and other device models. The impedance of any device should be possible to compute in analogous fashion to line segments. The case of transformers is special and interesting because actual impedance varies significantly with load, and this behavior may hold important diagnostic clues for equipment health [20]. Moreover, there is particular interest in developing high-fidelity transformer models to capture voltage magnitude and phase shifts as a function of load, since this would allow

making good inferences about the primary distribution system from convenient and comparatively inexpensive sensor locations (e.g. wall outlets) on the secondary side.

The standard three-phase formulation of Ohm's Law shown in Eqn. 4 for a line segment connecting locations 1 and 2 includes complex terms for the voltage phasor difference between the two locations, the self- and mutual impedances  $Z_{ii}$  and  $Z_{ik}$  of the line segment, and current on each phase (measured at either location).

$$\begin{bmatrix} V_{a,1} - V_{a,2} \\ V_{b,1} - V_{b,2} \\ V_{c,1} - V_{c,2} \end{bmatrix} = \begin{bmatrix} Z_{aa} & Z_{ab} & Z_{ac} \\ Z_{ba} & Z_{bb} & Z_{bc} \\ Z_{ca} & Z_{cb} & Z_{cc} \end{bmatrix} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} \quad (4)$$

For three identical conductors we expect  $Z_{aa} = Z_{bb} = Z_{cc}$  along with  $Z_{ik} = Z_{ki}$ , but since distribution lines are rarely transposed, we cannot assume equal mutual impedances (which depend on geometry). Given values for all the V and I terms from a set of  $\mu$ PMU measurements (6 pairs of voltage and 3 pairs of current magnitude and angle values taken at the same time), we can, in principle, solve for Z.

For the purpose of comparison to circuit model data, it may be desirable to express the voltage, current and impedance terms as symmetrical (zero-, positive-, and negative-sequence) components. One complication for model validation is that the actual geometry and spacing of underground conductors is not readily verifiable. In any case, this approach is highly susceptible to measurement error, considering that a typical voltage drop on such a segment (i.e., our signal) would be on the order of 0.001 to 0.01 p.u. and  $<1^\circ$ , which is similar to the error of a revenue-grade instrument transformer.

One modification, summarized by Eqn. 6, is to consider the line segment impedance  $Z_{segment}$  as the difference between the network source impedances observed from the two end points of the segment during a significant step change of current and voltage.

$$\mathbf{Z}_{loc,t} = \frac{\mathbf{V}_{loc,t} - \mathbf{V}_{loc,t-x}}{\mathbf{I}_{loc,t} - \mathbf{I}_{loc,t-x}} \quad (5)$$

$$\mathbf{Z}_{segment} = \mathbf{Z}_{loc1,t} - \mathbf{Z}_{loc2,t} \quad (6)$$

Equation 5 (written for a single phase in the interest of clarity) shows the source impedance at a single location as

the ratio of differences between pairs of voltage and current measurements taken at time  $t$  and  $t-x$ , where  $x$  should be a small interval (say, on the order of a cycle or several samples) so as to minimize the opportunity for other, external factors to impact voltage, and  $t$  should be chosen such that a significant change in current (and presumably voltage) occurs during  $x$ . Taking the difference between measurements reduces the impact of systematic transducer errors, to the extent that these are stable over the interval  $x$ , and the calculation may be repeated for different times  $t_i$ . This formulation can be expanded into matrix form to account for the unbalanced three-phase case. The algorithm may begin by searching for suitable step change events and conclude by reporting the mean and standard deviation of computed segment impedance values. This example illustrates the peculiar character of distribution-centric as compared to transmission-centric algorithms for utilizing PMU data: namely, an emphasis on techniques for extracting information about very small quantities in the presence of significant noise and uncertainty about basic network properties.

#### D. DG characterization

A critical motivation for increased distribution monitoring is to better understand how distributed generation affects the grid, for purposes of guaranteeing safety and power quality, estimating feeder hosting capacity, and evaluating both costs and benefits associated with distributed resources (such as rooftop solar or larger, commercial PV arrays interconnected at the primary distribution voltage). Key items of local concern include effects on customer voltage and implications for protection systems of reverse power flow. Operators at both the transmission and distribution level also care to better anticipate aggregate net load, DG responses to transients, and exposure of the system to loss of generation. DG characterization may include the following:

- Correlate feeder voltage changes with DG behavior. Voltage volatility may be caused by either loads or variable generation on a circuit, and detailed observations including statistical analyses on various time scales may be needed to determine the actual impacts of DG. BTrDB is a particularly useful platform for this purpose because of its seamless transition through time scales from sub-cycle to years. Use cases include assuring proper service voltage levels, preventing excessive operation (hunting) of legacy voltage regulation equipment, and addressing voltage flicker.
- Detect reverse power flow. Phasor measurements of voltage and current unambiguously identify the direction of power flow, which conventional magnitude-only measurements fail to do. The ability to detect reverse power flow in real-time (and the option take remedial action such as temporary curtailment) should help relieve the need for conservative planning margins in DG interconnection. Figure 3 illustrates power flow reversal due to a large PV array on a cloudy and a sunny day, as seen through the voltage phase angle difference between PV array and substation, which changes sign during the day. Power

flow direction at a single location could also be inferred from the current phase angle relative to voltage, but without capturing power flow on a feeder that may have multiple branches.

- Disaggregate net metered DG from load: When the distribution utility lacks access to separate load and generation telemetry, DG masks an unknown amount of load, which implies greater system exposure to contingencies. Innovative algorithms can leverage available insolation data with  $\mu$ PMU measurements for a high-fidelity estimate of individual PV generation even when not directly metered [20], [31].

#### E. Microgrid Operation

Microgrids hold particular interest in the context of grid resilience. They give occasion for more aggressive operational strategies than typical distribution feeders, such as the following:

- Islanding: deciding when to separate the microgrid from the main grid to operate as a power island. Analytics based on  $\mu$ PMU data may provide better early indication of grid conditions (such as frequency or voltage instability) that warrant intentional islanding for local reliability reasons.
- Load and generation balance: controlling power injections from generation and/or storage to match instantaneous load on the microgrid during islanded operation, and shedding non-critical loads in a deliberate manner when necessary. While essential for balancing a power island, strong local control capabilities may also be used to provide ancillary services to the main grid.
- Resynchronization: reconnecting an islanded microgrid to the main grid. Performing this transition without interruptions or transients requires matching frequency and phase angle across the point of common coupling [32]. One advantage of using PMUs for this purpose is that they need not be co-located with the breaker.

#### F. Distribution State Estimation

State estimation is the process of reconciling available physical measurements (of imperfect accuracy) with mathematical relationships (based on an assumed model) so as to obtain a best-fit estimate of the state variables (voltage magnitude and phase at each node) that uniquely describe power flow throughout the network [33]. This analysis is concerned with (quasi-)steady-state operation over at least several seconds, not transient disturbances or dynamic response. In the transmission context, the condition of redundancy is generally satisfied (i.e. there are at least as many measurements as nodes), so that the focus of state estimation is on correcting erroneous measurements. Distribution networks, while smaller in geographic extent, have much greater numbers of nodes (including essentially every service transformer) that are often without any direct instrumentation. Estimating the operating state of a distribution system thus introduces the challenge of performing some type of extrapolation from

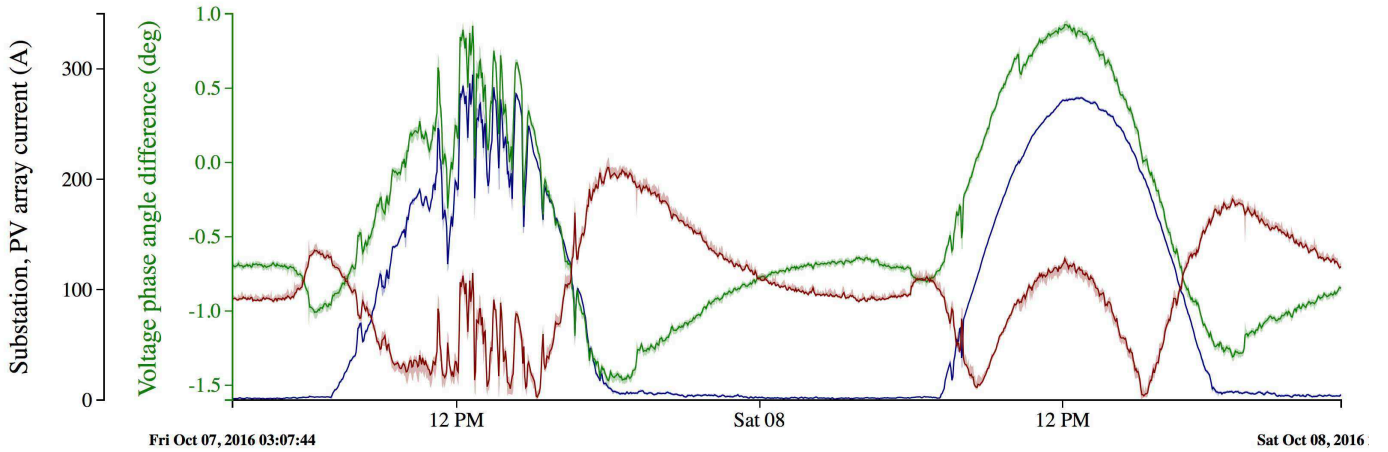


Fig. 3. Voltage phase angle difference (green) between substation and a large PV array on a 12-kV circuit; current injection by the PV array (blue) and net current measured at the substation (brown). The phase angle difference  $\delta$ , a distillate stream in BTrDB, alternately correlates and anti-correlates with net current as the feeder imports and exports power. While the sign of  $\delta$  changes with real power flow, current magnitude does not indicate direction and never crosses zero due to reactive power flow. The  $\delta$  step change in late morning of Oct. 8 is associated with a tap change operation.

available empirical data. A Bayesian approach developed in the context of  $\mu$ PMU research, which uses a linear power flow approximation, makes use of historical information about loads as “pseudo-measurements” and trades off the high precision of  $\mu$ PMU measurements against the number of sensors on a circuit [34]. Irrespective of the particular algorithm used, the success of distribution state estimation is sensitive to the absolute accuracy of voltage magnitude and phase angle measurements obtainable in the field, while accounting for transducer errors. Use cases for distribution state estimation include a broad spectrum of operations and planning decisions that hinge on knowledge of steady-state voltages and power flows throughout a network, including the efficient control of distributed resources.

### G. Phasor-based Control

Control of distributed resources on the basis of  $\mu$ PMU measurements has been confined to the simulation environment so far, but holds interesting promise. The underlying idea is that voltage phasors holistically reflect any changes in the operating state of the system, including generation and load as well as connectivity changes or other contingencies. By tracking a target phasor rather than injecting a predetermined amount of power, a resource can inherently counteract changes occurring elsewhere in the network, requiring fewer measurements and less communication. Explicit phasor measurements also reduce the computational needs for power flow and the dependence of algorithms on potentially inaccurate input data. Use cases for phasor-based control may include managing net power flows, reducing voltage volatility, or matching phasors at tie switches or points of common coupling [35]. To date, our project has developed new linear approximations for the relationship between the measurable phasor profile and P,Q injections that will be suitable as a basis for control [10], and demonstrated the ability to track a reference phasor by simulated inverter control on a small test feeder with significant phase imbalance

[11]. We expect phasor-based control to become an important area of future research.

### H. Transmission versus Distribution Analytics

It is worth reflecting on some fundamental differences between transmission- and distribution-centered use cases and algorithms for PMU data, areas of overlap notwithstanding. The goal is always to provide increased visibility and situational awareness, which can extend both above and below the substation—for example, in detecting and locating the source of disturbance events. However, on the transmission side, PMUs augment extensive telemetry already in place for purposes of power measurements in near real-time. Synchrophasors crucially improve upon these conventional measurements by revealing subtle changes in the time dimension, as seen in oscillations and damping, or studying the relationships among quantities over large distances across the network. Across transmission systems, time-aligned frequency measurements, even without explicit phasor differences, can be highly informative [7]. The key point of interest is the *propagation of changes*, especially the potential of disturbances to cause large outages, while local steady-state quantities are already known to a good approximation.

By contrast, existing SCADA and customer meter data leave vast gaps of knowledge about distribution circuits, where even the physical properties and connectivity of the network itself are often in question. Many of the above distribution system applications are thus concerned with establishing a baseline awareness of the operating state, as much as characterizing departures from it. The goal is often to identify contributions from specific individual sources, and their impacts short distances away. Two resulting difficulties are that the relevant signals to be measured are small, and that algorithms must account for many variables, including unknowns.

## V. DATA REQUIREMENTS AND LIMITATIONS

Our research team has aimed to articulate the requirements that various power distribution-related applications will impose

TABLE I  
EXPECTED DATA REQUIREMENTS FOR DIFFERENT CLASSES OF  $\mu$ PMU APPLICATIONS

Application	Measurement Quantities	Time Resolution	Accuracy	Latency & Continuity
Voltage magnitude profile & variability	Voltage magnitudes crucial, Voltage phase angle useful for recognition of tap changes	1 sec or better resolution is useful, synchronization between & among measurement locations critical	Changes in time of interest, absolute accuracy to 0.5% error adequate	Retain complete history
Awareness of real-time loads	Current magnitudes very useful, V phase angle can be proxy for current iff network impedances are known; current phase angle useful for P,Q decomposition & reverse power flow	1 cycle or better resolution reveals transient behaviors, full time domain characterization with up to 30 kHz sampling of interest to reveal harmonics	Absolute 0.5% error likely adequate	Operationally relevant latency on the order of 1 sec
Outage management	Voltage & current magnitudes	1 sec likely adequate	1% error likely adequate	1 sec latency likely adequate
System frequency & oscillation detection	Voltage phase angle essential	1 cycle or better & synchronization essential	Changes in time, not absolute accuracy of interest, 1% error adequate if stable	Retain complete history; latency requirement may vary, sub-second critical if informing protection
Island detection; Microgrid islanding & resynchronization	Voltage phase angle essential	1 cycle or better resolution	Insensitive to magnitude error, phase angle error stable to $0.01^\circ$	Continuous monitoring, sub-second latency critical if informing protection
Distribution state estimation & SE-based topology detection	Voltage phasors; sensitive to placement & number of sensors; network model & load data important	Synchronization critical	Absolute accuracy on the order of 0.0001 p.u., requires correction for transducer errors	Operationally relevant latency on the order of 1 sec
Topology detection based on time-series signatures	Voltage phasors	1 cycle or better & synchronization critical	Changes in time, not absolute accuracy of interest, 0.5% error adequate if stable	Retain complete history, operationally relevant latency on the order of 1 sec
Topology detection based on source impedance	Voltage & current phasors	1 cycle or better & synchronization critical	Changes in time, not absolute accuracy of interest, 0.5% error adequate if stable	Operationally relevant latency on the order of 1 sec
(ABC) Phase identification	Voltage phase angles essential	1 sec or better for time-series approach; synchronization critical	Absolute accuracy of phase angle on the order of $1^\circ$ likely adequate	No particular need for latency or continuity
Model validation for line segment impedances	Voltage & current phasors	Synchronization critical	Absolute accuracy of all phasors is limiting factor, as good as 0.0001 p.u. for shorter segments	No particular need for latency or continuity
DG Characterization; Transformer, generator & load models	Voltage & current phasors	1 cycle or better reveals dynamic behaviors; synchronization between primary & secondary side of transformer critical	Changes in time, not absolute accuracy of interest, 0.5% error adequate if stable	No particular need for latency or continuity
Event detection & classification	Voltage & current magnitudes adequate for most events, phase angles useful	1 cycle or better, synchronization critical	Changes in time, not absolute accuracy of interest, 0.5% error adequate if stable	Continuous monitoring, operationally relevant latency on the order of 1 sec
Fault location	Voltage & current phasors	1 cycle or better, synchronization critical	Absolute accuracy of all phasors is limiting factor	Continuous monitoring, latency on the order of 1 sec
Phasor-based control	Voltage phasors	1 cycle or better	Absolute accuracy critical for steady-state optimization, but stable errors acceptable for disturbance rejection	Continuous monitoring, latency critical



on the following measurement characteristics: temporal data resolution; absolute and relative measurement accuracy; communication volume, latency and continuity of data transfer; and placement of  $\mu$ PMUs on the distribution circuit. Some of these requirements are summarized in Table I.

With respect to these requirements, a key distinction lies between applications addressing steady-state versus dynamic circuit behaviors. Steady-state applications such as distribution state estimation depend most critically upon comparisons of measurements between different locations made at a single point in time, such as a phase angle difference or a per-unit change in voltage magnitude between two network nodes. Here we require absolute accuracy such that the measurement error is small compared to the signal of interest, perhaps as small as 0.0001 p.u. to discriminate voltages on lightly loaded networks with small impedances. Measurements of absolute quantities for steady-state power flow are thus significantly impacted by transducer errors: even revenue-grade instrument PTs and CTs have magnitude errors up to  $\pm 0.3\%$  and introduce angle shifts on the order of a full degree, much greater than phase angle differences of interest seen along distribution feeders. This concern does not apply to phase identification, where angle differences of interest are much greater than  $1^\circ$ . Table I accordingly reflects the most stringent accuracy requirements in voltage magnitude and angle for state estimation, model validation, fault location, and phasor-based control. Successful development and commercialization of these applications will hinge on effective techniques for transducer calibration.

By contrast, applications that are concerned with dynamic behaviors hinge on the observation of time changes in measurements at a given location, so that only relative accuracy matters, and measurement errors are acceptable if they are stable over time (which we have found to be the case). Instead, for dynamic applications, the temporal resolution becomes more important. Table I thus indicates greater tolerance in the absolute measurement errors for event detection, voltage variability assessment, topology detection, phase identification and DG characterization, as these applications focus on changes in time. A 0.5% magnitude error is still consistent with the accuracy of standard distribution power flow solvers, and 1% seems tolerable where only angle, not magnitude is of interest.

With respect to temporal resolution, we distinguish the sampling rate or granularity of data reporting, versus the accuracy of the time stamp, which provides for synchronization of measurements from different locations. Because the very notions of “rms magnitude” and “phase angle” presume the existence of a sinusoidal waveform, synchrophasor data are only meaningful on a per-cycle basis [36]–[38]. The phasor description is distinct from explicit sampling in the time domain at much higher rates that describes the actual waveform, including harmonics and sub-cycle transients, in what is typically meant by a “power quality measurement.” We generally assume that the power flow of interest through the T&D network is associated with only the fundamental (i.e. 50 or 60 Hz) frequency. Therefore, while power quality measurements benefit from time stamping for the purpose of identifying and comparing disturbance events as observed at

different locations (with precision on the order of a cycle), they do not rely on the ultra-precise time stamping to within fractions of a degree (several orders of magnitude better) needed to identify a comparative phase angle shift. PSL’s device can serve either function: in power quality or “PQube” mode it records 512 samples per cycle in the time domain based on an internal clock, whereas in  $\mu$ PMU mode it computes and records the phasor only twice per cycle but requires a GPS signal for this phasor to be meaningful relative to other locations.

Our team has found that even prior to interpreting phase angles, the mere availability of synchronized rms voltage and current magnitude measurements at 120-Hz granularity across distribution systems provides significantly more insight than conventional SCADA instrumentation, which typically reports at several second intervals and whose time stamps may diverge by seconds or even minutes between locations. Many transient events, including high-impedance faults and responses to switching operations, occur at time scales on the order of cycles and are clearly captured by  $\mu$ PMUs, but are not observed at all by SCADA or misrepresented due to sampling [20]. It is conceivable that a network of much less accurate sensors with a comparatively crude time stamp on the order of a cycle could economically serve the needs of a useful subset of diagnostic applications (including event detection, some forensics, and outage management).

For certain applications such as phase identification and oscillation detection, however, the voltage phase angle provides unique insight. Applications based on calculating power flows over specific network sections—namely, state estimation, SE-based topology detection, validation of network and device models, fault location, and phasor-based control—require some combination of complete voltage and current phasors and complex impedances in order to apply Ohm’s Law. Furthermore, characterization of real-time loads, DG resources, and their impacts on distribution feeders substantially benefits from direct measurement of current angle relative to voltage, which easily reveals power flow direction and distinguishes displacement power factor from the effects of harmonic distortion. These considerations are reflected in the Measurement Quantities column of Table I.

Finally, it is worth noting the distinction between applications that draw on network models in order to interpret and utilize  $\mu$ PMU data, and those that rely purely on direct, empirical measurements. While much of the theoretical development in this field is necessarily predicated on accurate models, the typical shortcomings of available distribution circuit models in practice [29] suggest an advantage for non-model based approaches wherever possible, particularly for control applications [39].

## VI. OPEN $\mu$ PMU DATASET

To facilitate the development of synchrophasor-based applications, a subset of  $\mu$ PMU data from the LBNL campus, along with metadata and circuit model information, is being released for academic use by the research community. This unique “Open  $\mu$ PMU” resource includes three-phase voltage

and current magnitude and angle measurements at 120 Hz from three locations (12-kV substation, feeder, and building transformer) for the period of Oct. 1-Dec. 31, 2015. Data can be downloaded as a raw csv file in bulk (approx. 130GB), or accessed and visualized through the BTrDB plotter, along with instructions, from [powerdata.lbl.gov](http://powerdata.lbl.gov) [40].

## VII. CONCLUSION

High-resolution measurement of voltage and current phasors may offer significant new options for actively managing distribution systems with diverse resources and growing complexity. A plethora of interesting applications in varying states of maturity await further research and development to leverage the opportunities introduced by ultra-high precision  $\mu$ PMU measurements. Because of their versatility, the business case for  $\mu$ PMU sensor networks (much like transmission PMUs) will most likely be made based on the basis of simultaneously supporting multiple needs with a single comprehensive data architecture, in contrast to the traditional approach of justifying dedicated sensors for specific use cases in siloed applications.

Along with the capabilities of new sensor hardware, the novel BTrDB infrastructure means that power system analysis and operation should no longer be constrained by the ability to view, store, and rapidly search large data streams: instead of worrying about what kind of data manipulation is *possible*, the power engineering community may now focus on what is *useful* in practice to do with extremely rich measurement data.

Many applications will be enhanced by the future integration of heterogeneous time-synchronized data [41]. Another key priority is the development of practical techniques for calibrating transducer errors. As work progresses in the nascent field of distribution synchrophasors, we anticipate an increasingly sharp definition of the intersection between what data quality is economically attainable, and what is required by different applications or use cases with demonstrated practical value. Our results so far suggest, reassuringly, that this intersection is not the empty set.

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