Sensor Network Issues for Advanced Power Grids

Version 1.7

December 2017

JD Taft

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December 2017

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Abstract

The traditional techniques for distribution grid data acquisition are facing challenges that are structural in nature as the number of end points providing data increases due to new functionality associated with grid modernization, meaning the centralized hub and spoke model for SCADA is becoming inadequate for future large scale systems. These challenges may be addressed with distributed intelligence architectures, but to do so requires an understanding of sensing and measurement principles that apply to the class of systems represented by electric grids and other structured dynamic environments.

These principles include the extension of system state and observability to full scale electric distribution systems, which means that these concepts must be integrated with utility communication networking. Consequently, the measurement system designer must also understand how appropriate sensor network architecture principles apply to the distribution system data acquisition problem.

This paper describes the principles system state and observability as applied to power grids, as well as describing observability strategy and sensor allocation guidelines.

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1.0 Introduction

Utility measurement and control systems and data processing systems have traditionally been centralized in nature. Grid control systems typically reside in control or operations centers and rely upon low complexity communications to field devices and systems. There are a few distributed control systems for utility applications, including a wireless mesh system for performing fault isolation using peer-to-peer communications among devices on feeder circuits outside of the substations. In addition, certain protection schemes involve substation-to-substation communication and local processing. In general however, centralized systems are the rule for electric grids. Both utilities and makers of various grid control systems have recognized the value of decentralized and distributed intelligence, especially at the distribution level. We recognize that decentralized intelligence is the use of embedded digital processing and communications in a physically dispersed, multi-element environment (specifically the power grid infrastructure but physical networks in general) and distributed intelligence is the use of decentralized intelligence in such a way that the various elements *cooperate in solving a common problem*. This distinction is important in that it implies that distributed intelligence can involve peer-to-peer communication that is generally not be present in decentralized intelligence.

In the area of sensing, measurement and data acquisition, key issues are:

- Observability and system state – key concepts that can be used to guide the design of sensor systems for physical systems with topological structure and system dynamics
- Sensing and measurement – determination of quantities to be sensed, type and location of sensors, and resulting signal characteristics
- Data acquisition – collection of sensor data, sensor data transport
- Sensor network architecture – elements, structure, and external properties of sensor networks
- Communications for sensor networks

These considerations and the increasing complexity of modern power grids lead to the conclusion that the electric utility engaged in grid modernization must consider creating an *observability strategy* to guide the implementation of sensing for modern grid operation. Such a strategy must, as always, draw upon the detailed knowledge of the system in question on the part of the engineers who know it best. But it must also apply tools and concepts drawn from control theory, communication networking, sensor networking, optimization, and recent developments in sensing for power grids to develop a systematic approach to providing the needed measurements in a cost-effective and manageable way. Ultimately, this is a technical tool to help address risk associated with investment in sensing and measurement as part of the grid control architecture.

2.0 Observability and System State

One view of observability is that it is temporal, geospatial, and topological awareness of all grid variables and assets. This definition is intuitive, but does not give us much in the way of analytical tools to work with for developing a grid measurement system. A more formal definition of observability is the ability for any combination of system state and inputs to determine the system state in a finite time using only measurement of system outputs.[1]

We review the definition of state in order to define observability for distribution grids. While this effort is driven by developments at the distribution level, the definitions will be quite general. State is the minimum set of values (state variables) that describe the instantaneous condition of a dynamic system. State variables may be continuous (physical systems), discrete (logical systems and processes), or stochastic (such as Markov model states). For many types of systems and for linear systems in particular, the mathematics of state are well defined in the context of differential equation solutions of system dynamics. State has the property that future state of a dynamic system is completely defined by the present state and system inputs only. Knowledge of past state trajectory or past inputs is not necessary. Mathematically, we describe state for dynamic systems as:

$$d\mathbf{x}/dt = \mathbf{F}[\mathbf{x}(t),\mathbf{u}(t)]$$

for continuous time systems and

$$\mathbf{x}(k+1) = \mathbf{A}[\mathbf{x}(k),\mathbf{u}(k)]$$

for discrete time systems, where **F** and **A** represent system dynamics models, **x** is system state and **u** is the system input.[2]

For electric transmission systems with known or assumed models, a snapshot-based process using a set of sparse state variable measurements, a system model, and a mathematically intense solution method (weighted least squares, linear programming, Newton-Raphson iteration, etc.) performs what is widely known as transmission *state estimation.*[3] More recently, linear state estimation methods have been introduced for transmission system to speed calculations. State estimation for distribution grids involves a number of complications that do not exist at the transmission level. These include the fact that distribution circuits operate almost always in a time-varying unbalanced mode so that estimates must be made for all three phases independently; actual connectivity can be poorly known so that models typically used in state estimation would not be sufficiently accurate to use the results; and circuit-switched configuration changes can change topology in between the time of a state estimate and the time that actions based on that estimate are taken. Consequently, it can be helpful to rely more on *state measurement* and less on state estimation in the distribution case whenever we can arrange for the necessary instrumentation. The need to provide grid state for control purposes leads to the need for observability and therefore sensing and measurement architecture.

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[1] G. Franklin, J. D. Powell, and A. Emani-Naeini, Feedback Control of Dynamic Systems, 6th Edition, Pearson Higher Education, Upper Saddle River, NJ, 2010.
[2] Paul M. DeRusso, Rob J. Roy, and Charles M. Close, State Variables for Engineers, John Wiley and Sons, New York, 1965.
[3] M Filho, et. al., Bibliography on Power State Estimation (1968-1989), IEEE Transactions On Power Systems, August 1990, pp. 950-961.

For linear systems, knowledge of a system model enables one to determine the observability of the system. For linear systems with known state models, the deterministic state estimation process is known as a Luenberger observer.[4] Some control engineers prefer the term estimator for this because the term observer tends to imply direct measurement of states. For the stochastic control problem with random noise in both states and measurements, under linear quadratic Gaussian assumptions, the observer is known as a Kalman filter.[5]

The concept of state applies equally well for logical systems with discrete states. The open/closed or on/off states of switches are prime examples and state transition diagrams and matrices are used to describe discrete system behavior. Logical systems are often described by state transition diagrams but these can be converted to discrete state transition tables,[6] analogous to the state transition matrices **F** and **A** in the linear versions of equations above.

For discrete stochastic variables we may employ the concept of stochastic state as embodied in (possibly hidden) Markov models, where the observed statistical behavior relates to an underlying stochastic state model.[7] A Markov model is a state model where transitions from state to state are described by probabilities rather than deterministic dynamics. A matrix of transition probabilities plays the part of the state transition matrix for deterministic systems. The Markov model concept is a useful mechanism to represent power quality as an element of grid state.

For power grid observability, it is useful to employ an extended distribution grid state definition, where we augment the power state (voltage, current, real power, reactive power) view of grid state with additional elements, such circuit parameters, storage charge state, Demand Response Available Capacity (DRAC) and forecasted capacities and grid technical losses.

For power grids, *extended state* is a collection of variables that fall into several categories, plus a set of adjuncts in the form of forecasts and various derived quantities of interest. Some of the primary grid state groups and adjuncts are:

Electrical State – the extension of power state to the entire extended grid (transmission, distribution, and prosumer domains); includes standard power state, energy state for storage, instantaneous demand, and DER available capacity and invoked capacity.

Component State – instantaneous condition of grid components, including value of model parameters, component health, thermal state, mechanical state (e.g. cable tension and sag), and operating state (in or out of service, setting or set point, fault condition, etc.).

Topological State – connectivity of grid networks (electrical, communications, control and coordination); also includes topological location of connected grid and prosumer components which are crucial for planning and control.

Building State – not strictly part of grid state but useful for both building control and for grid interface in building-to-grid applications.

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[4] D. G. Luenberger, Observing the State of a Linear System, IEEE Transactions On Military Electronics, MIL-8, 1964.
[5] Andrew P. Sage and Chelsea C. White III, Optimum Systems Control 2nd Ed., Prentice-Hall, New Jersey, 1977.
[6] Frederick J. Hill and Gerald R. Peterson, Switching Theory and Logical Design, 2nd Edition, John Wiley and Sons, New York, 1974.
[7] Jia Li, Hidden Markov Model, The Pennsylvania State University, available online: sites.*stat.psu.edu/~jiali/course/stat597e/notes2/hmm.pdf.*

Ambient State – also not part of grid state but these exogenous factors (solar flux, wind, precipitation, etc.) are closely related to grid operation and control and so are included in the extended grid state definition.

Convergent Network States – As indicated in the Grid Architecture work, various other networks have or are converging with grids, necessitating availability of state variables for these networks as part of extended grid state.

Estimators, Modelers, Markets, Analytics and Forecasters – a variety of elements that are not state variables but are nonetheless important to modern grid operation are produced as the output of a variety of tools and applications. These elements, such as wind, solar, and DER availability forecasts, congestion, locational marginal process, etc., are often driven by both grid state variables and measurements used to derive grid state. They are treated as adjuncts to extended grid state.

Since knowledge of grid state is fundamental to most grid control and management applications, determination of state is vital. This leads us to focus on grid state determination.

We use the term grid state *determination* (as opposed to estimation) for the process involved on a power grid, since we may measure some grid power states directly, or we may make measurements from which state elements can be calculated or estimated, or we may use a mix of measured and estimated states. In the case of power grids, we want to know the grid state on a moment to moment basis, since this information is the foundation of many advanced grid functions and capabilities. Determining extended grid state is a multi-stage process, comprising:

- Sensing, measurement and data acquisition – the basic processes of obtaining raw grid data, with conversion from analog to digital form
- Filtering, linearization, scaling, and units conversion – conversion and processing of raw digital data from uncompensated integer counts to compensated, linearized values, scaled to engineering or physical quantity units as opposed to dimensionless integers
- Representation – conversion of physical variables into forms suitable for analysis and use in control in any of several domains: time, frequency, geospatial, or electrical distance from a reference points such as a substation
- State formation – construction of actual grid state elements; may involve several computational processes such as extraction of parameters from data sets, estimation where necessary, and then assembly and aggregation of grid state elements
- Distribution and persistence – grid state elements must be made available to various decision and control processes, and may have to be persisted in any of several tiers of data storage, depending on the various uses for the data

Aggregation may occur at several levels. Raw instantaneous voltage or current samples may be aggregated into records so that they can be processed into Root-Mean-Square (RMS) values and also analyzed for harmonic content. At another scale, we may aggregate voltage samples taken at various points in a meter network into a voltage profile as a function of electrical distance for a feeder. If we have meters that can measure real and reactive power, we can aggregate values to determine power flows at various points on a feeder and may do likewise with DRAC values. We may aggregate current and power flows from points to feeder segments to feeder sections to substations to transmission lines to service areas to control areas.

We may characterize state in various ways by representing state variables in any of four domains: time, frequency, geospatial, and electrical distance and may calculate various measures to assist in extracting meaning from state variables (example: calculating power factor from real and reactive power). Transforming state variables in various ways reveals information (example: converting phasors to symmetrical components) that make implementations of various grid applications straightforward. Figure 1 illustrates a state determination process flow. In a distributed implementation, the filtering, linearization, units conversion and even validation steps may be moved earlier in the chain (closer to the measurement sources).

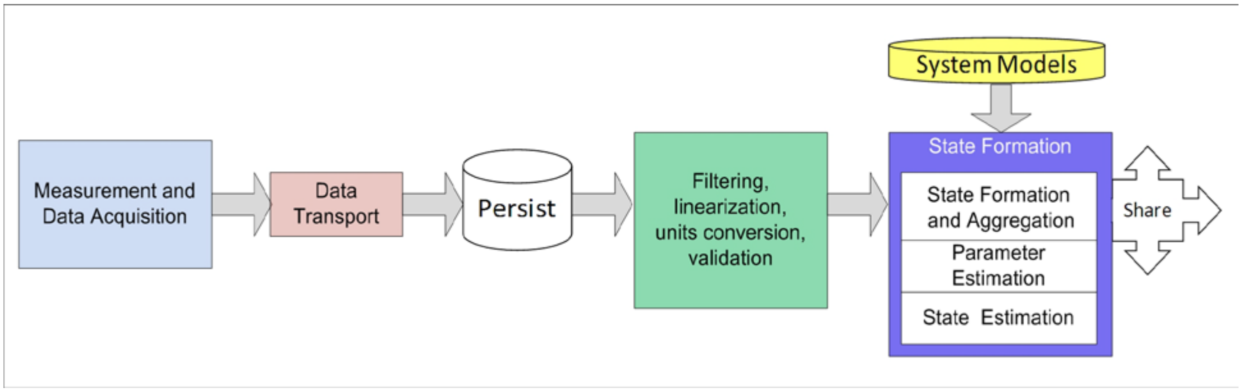

Figure 1. Grid State Determination Process

The concept of grid state is extremely useful for grid data management and control. Consequently, the *determination* of grid state is a crucial advanced grid process. Due to the complexity of distribution grids and the cost of sensor installation, implementing proper grid state determination is not a trivial exercise. For each feeder, we must create a grid sensing strategy that, when aggregated across the whole system, results in a sensor network design for the entire grid. The strategy is necessary to ensure that sufficient measurement is done to provide grid state determination, while minimizing the total cost of the sensor network (including not just material costs but also installation and service labor).

The complexity of modern grids is such that real concerns are arising about the limits of observability. Coupling through the grid complicates the observation process, but more importantly, unstructured additions to power grids can cause a degree of architectural chaos that makes the determination of grid state a challenge. This lack of structure combined with severe complexity appears to place limits on achievable observability. This problem can be combated by regularizing grid and control system structure so that it is not prohibitively expensive to provide the sensing and data processing necessary to achieve the observability required to drive decision and control.

3.0 Sensing and Measurement for Power Grids

The design of a sensing network for a modern power grid should be viewed and formulated as an optimization problem. Fundamentally, we wish to minimize CapEx while managing (bounding) OpEx over a time horizon and yet ensure that observability requirements are met. This can be formulated mathematically; the solution requires the use of sophisticated mathematical and software tools. Such optimizations have been performed to determine best locations for reclosers to maximize reliability, and best locations for PMUs on transmission systems, among other goals. Here we suggest a more practical route – the use of guidelines and design rules. Before introducing the set of guidelines for developing an observability strategy (which leads to a sensor network design), we must cover some additional material.

Keep in mind that there are actually multiple types of networks involved in the modern power grid: in addition to the electric grid, we have communications networks, financial (markets) networks, control and coordination networks, and social networks. We may consider that there is also a sensor sub-network that serves several of the primary networks. Here we are concerned with sensing for the electric grid and its connection to grid control.

3.1 Power Grid Transducers and Smart Sensors

Power grids use a wide array of sensing devices, including sensing built into grid control devices, as well as explicit sensors. A key tradeoff for sensor network design has been the use of many low costs sensors (example: Faulted Circuit Indicators or FCIs) vs. the use of a smaller number of high end sensors (example: multi-variable line sensors). At the highest end are the phasor measurement units (PMUs) used on transmission systems to provide synchronized phasor measurement, but which are being introduced at the distribution level. As modern grid complexity increases, the move toward synchronized measurement necessitated by advanced control requirements leads to the use of high end sensors on distribution feeders. Despite this trend, it is still valid to consider the use of low end sensors and in the more sophisticated approaches, to employ a mix of sensor types. Part of the observability strategy issue is to determine the mix of sensors to be used for a particular system. Smart line sensors and advanced meters are two logical options for distribution grid power state sensing.

3.2 Basic Sensor Functionality

A smart sensor is one that contains a physical parameter transducer, means to convert analog sensor signals to digital form, a digital processor, with memory, embedded software, possibly downloaded applications, and digital communications capability. Present line sensors are usually implemented as a combination of a set of line transducers and a Remote Terminal Unit (RTU) with embedded processing capability, as well as one of more communication interfaces.

A typical configuration of a distribution power line electrical sensor would use three signal channels for phase voltage waveform measurement, three channels for phase current waveform measurement, one channel for neutral current measurement, and one channel for temperature measurement. Voltage and current waveforms should be sampled at 128 or more samples per cycle.[1] Signal channels must include analog anti-aliasing filters. Simultaneous sample/holds are preferred because some processing functions are concerned with relative phase. Raw sensors should be accurate to 0.5% of full scale and have analog bandwidths of at least 10 kHz.

[1] IEEE Std 1159-2009 IEEE Recommended Practice for Monitoring Electric Power Quality. Available online.

The smart sensor platform must contain at least one digital processor with sufficient processing capacity and memory to support local data acquisition, digital signal processing, and digital communications. This platform must be capable of receiving downloaded applications and of performing bi-directional communications over various communication media and with various protocols. It must provide data security functions including:

- Encryption
- Identification
- Authentication
- Non-repudiation
- Tamper detection/prevention

The smart sensor should support IPv6-enabled digital communications. It should support standard protocols for network routing, timing (IEEE 1588[2]), and management (SNMP[3] for example).

It is useful for the sensors to support Transducer Electronic Data Sheets (TEDS[4]), to provide management of sensor –specific information so that multiple applications, data collection engines, or controls can access the sensor without need to access a bottle-neck central data collection system to obtain calibrated data.

3.3 Meters as Sensors

When a utility has or will be deploying an Advanced Meter Infrastructure (AMI) system, it is logical to consider how this meter system may be used as a grid sensor network. Many residential meters are capable of sensing and reporting secondary voltage in addition to usage data. Newer Commercial and Industrial (C&I) meters have significant capabilities for measuring and reporting real and reactive power, power factor, voltage sags, and harmonics in voltage and current.

When an AMI system is in place, careful selection of meters that are approximately evenly spaced along a distribution feeder (in terms of distribution transformer electrical distance from the substation) can enable the determination of feeder voltage profiles, which would be valuable in voltage regulation. In addition, instant voltage readings ("pings") should enable rapid determination of outage extent and restoration progress. Rapid voltage reading could also enable operational verification for grid devices such as switched, reclosers, and capacitors, by providing voltage values just before and just after device command issuance. Those meters that can record voltage sags or compute harmonics in power waveforms could be used to measure power quality state elements. All of these functions have in fact been tried with AMI and C&I meter systems.

In practice, past residential meter systems have not proven to be the all-encompassing sensor fabrics for power grids that many have desired them to be. There are several reasons for this:

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[2] IEEE Standards Association, IEEE Std 1588 – Standard for a Precision Clock Synchronization Protocol for Networked Measurement and Control Systems, 2011, available online: http://standards.ieee.org/findstds/interps/1588-2008.html.

[3] Simple Network Management Protocol

[4] NIST, IEEE P1451 Smart Transducer Interface Standard, see http://www.nist.gov/el/isd/ieee/ieee1451.cfm, and available online at http://www.ieee.org/index.html.

- Residential meters were designed for lowest cost and so did not have advanced sensing capabilities; this means that they did not measure many of the useful quantities needed for grid state determination; in some cases, the existing measurement were not made in a useful manner
- Meter communication networks have often been designed only to support usage reporting and so do not have the bandwidth and latency capabilities to support operation as a grid sensor network; this means that the meters could not provide sensor-type data fast enough to be useful for any but the slowest (read: old style) distribution automation control systems
- Meter communication protocols until recently did not support sensor-like operation, having been developed from a usage reporting point of view; consequently it is normally necessary to go through the meter data collection head end to obtain any meter data, including voltage readings; full IPv6 stacks in the meters can alleviate this
- Meter installation databases generally relate geospatial and customer information to the meter, but there is often no well-documented relationship to power grid connectivity; however power grid connectivity is the context in which sensed data must be interpreted
- Residential meter systems and their communication networks can take very long time periods to re-converge upon partial or complete power restoration, so the meters do not come online fast enough to report grid state information that would be useful for restoration operations or grid control during restoration
- Wireless mesh-based meter communications networks are “lossy”, meaning that they are unreliable in terms of message packet delivery; this is not a problem for usage reporting, but is a severe problem for control system support
- Older residential meters do not have a strong notion of time, so that time-synchronized measurements, important for control system operation, are not possible with those meters

For meters to be useful for any but the simplest distribution automation functions, these issues must be remedied. This means, reliable communications, efficient communication protocols and interfaces, IPv6 support, support for time synchronization via IEEE 1588 time service, synchronized sampling capability, and sensor-grade measurement functions for more than just recording energy usage. Newer generation meters remedy many of these shortcomings but their associated communication networks still fall short in terms of performance for use in protection and control.

The presence of DG such as solar PV systems that can inject power into distribution grids, or storage that can do the same presents issues for the distribution utility, both in terms of grid state and in terms of energy metering and settlement. Net energy metering (NEM) has been applied to the latter but is being phased out. In terms of grid state, NEM does not resolve the measurement problem, which includes the need to understand actual load, not just apparent (net) load. A solution for this is for the utility to make use of *production meters* that measure the energy flow for the DG or DS unit separately from the energy usage for the actual load. The requirement for use of production meters can be included in the connection agreement or grid code.

4.0 Data Acquisition

Power grid devices and sensors operate in one or more of four data acquisition modes:

- Polling – a polling master queries the device, which response with the most recent values of the specified data points; polling is usually on a regular schedule and data size per query is modest
- Streaming – sensor sends a continuous stream of data, once streaming is initiated, until streaming is terminated by command or abnormal exit condition
- Interrogation of stored files – the device maintains a log or data file; upon query, it transmits the log or file to the master; differs from polling in terms of data size per query and frequency/regularity of the query
- Asynchronous event message – the device uses internal processing to detect a specific condition indicated by the data and spontaneously sends an event message to the master or any subscribing system; the event can be when the data changes by a specified amount report by exception) or the event can be an internal clock signal or countdown so that the messages are sent on a regular basis, but initiated by the sensor, not a central controller. The message may or may not contain actual sensor data relevant to the event;

Polling is common in grid control systems, but report by exception is used in some systems to reduce data volumes and therefore communication line bandwidth. Streaming is common for advanced sensors such as PMU-based wide area measurement systems (WAMS). Interrogation of stored data files is common for meters and for data loggers and grid devices that collect records on a power waveform-triggered basis. Asynchronous event messages are becoming more common in devices that contain significant local processing and are therefore able to detect and report events.

Collection of the data in large scale systems presents issues of cycle time, data bursting, and sample skew. In the typical round-robin scanning approach taken by many standard SCADA[1] systems, the time skew between first and last samples represents an issue for control systems that is insignificant when the scan cycle time is short compared to system dynamics, but as dynamics in increase in bandwidth with advanced regulation and stabilization, and as the number of sensing points increases, the sample time skew problem becomes significant.

In a control system where distributed endpoints are free-running and each is updating its measurement(s) asynchronously, round robin collection of the data can result in time skew among samples. This can cause a degradation of accuracy in creating state estimates from the data samples, with resultant degradation of control performance. For many control systems, especially those used in power systems, multiple sensors provide data from widely separated locations. Figure 2 shows a model for multiple measurement delays, plus a control output delay. The diagram illustrates a basic feedback control with multiple sensor inputs. Given that the sensors are in different locations, they will have differing network latencies in transporting the sensed data to the controller. In addition, the control command will experience a transport delay in reaching the final control element.

[1] Supervisory Control and Data Acquisition

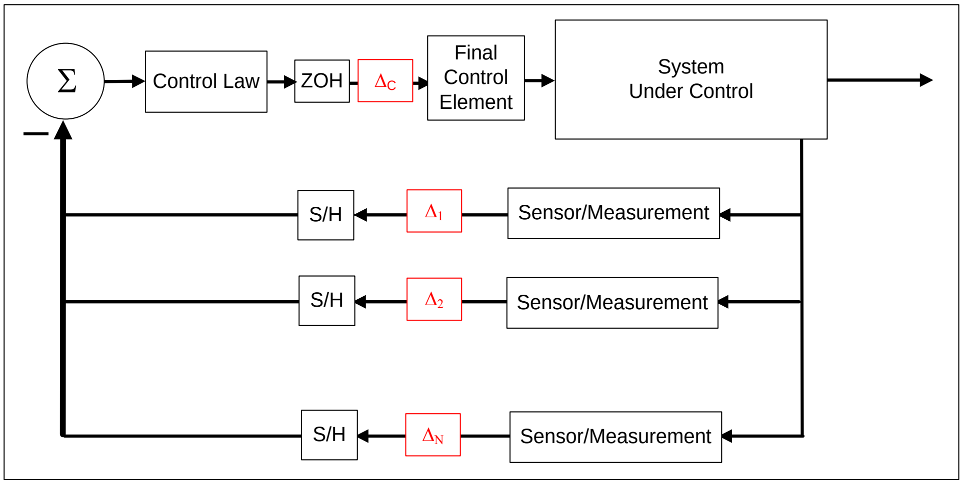

Figure 2. Multi-Sensor Sample Skew Model for Closed Loop Control

Exact analysis of such systems is complex, so it is helpful to take the approach of bounding maximum skew. For a multi-output control system, this can be even more complex, since we would also need to model a set of output control delays. Bounding this time effectively specifies a time window in which the complete set of measurements must be made and gathered. The skew model is needed when dealing with SCADA and with controls that need multiple sensor feedback inputs. An example of the latter is using two PMUs as input to a FACTS controller for modal power oscillation damping on transmission systems.

Sensors could perform synchronized measurement using IEEE 1588 as the means to synchronize clocks, driven from GPS or other master timing sources; the data acquisition system must be capable of collecting all of the samples in a time window short enough to be completed before the next sampling cycle begins. This becomes increasingly difficult as the number of sensing endpoints increases, leading to the need to replace centralized polling with multiple parallel data collection engines or other approaches.

4.1 Distributed Data Acquisition

Distribution SCADA has traditionally been structured as a simple hub-and spoke centralized network. As more smart devices are deployed and as latency requirements move ever lower, the advantages of a distributed SCADA approach become evident. In such an approach, multiple data collection engines are deployed throughout the distribution grid. This is fundamentally different from the logical distributed data collection approach used by some EMS where multiple front end communication engines are located in a single control center. Such an approach is properly viewed as distributed, but has the disadvantage of still using a hub-and-spoke network structure. In the geographically distributed approach, the data collection engines are moved out of the control center and into other places in the power system. These places can be the transmission and primary distribution substations, but we can go further and place smaller data collection engines at tactical locations on distribution feeders. In such an approach, there is more mesh-like peer-to-peer data flow, which can relieve the need to have a very large data pipe into the control center. Figure 3 illustrates such an approach.

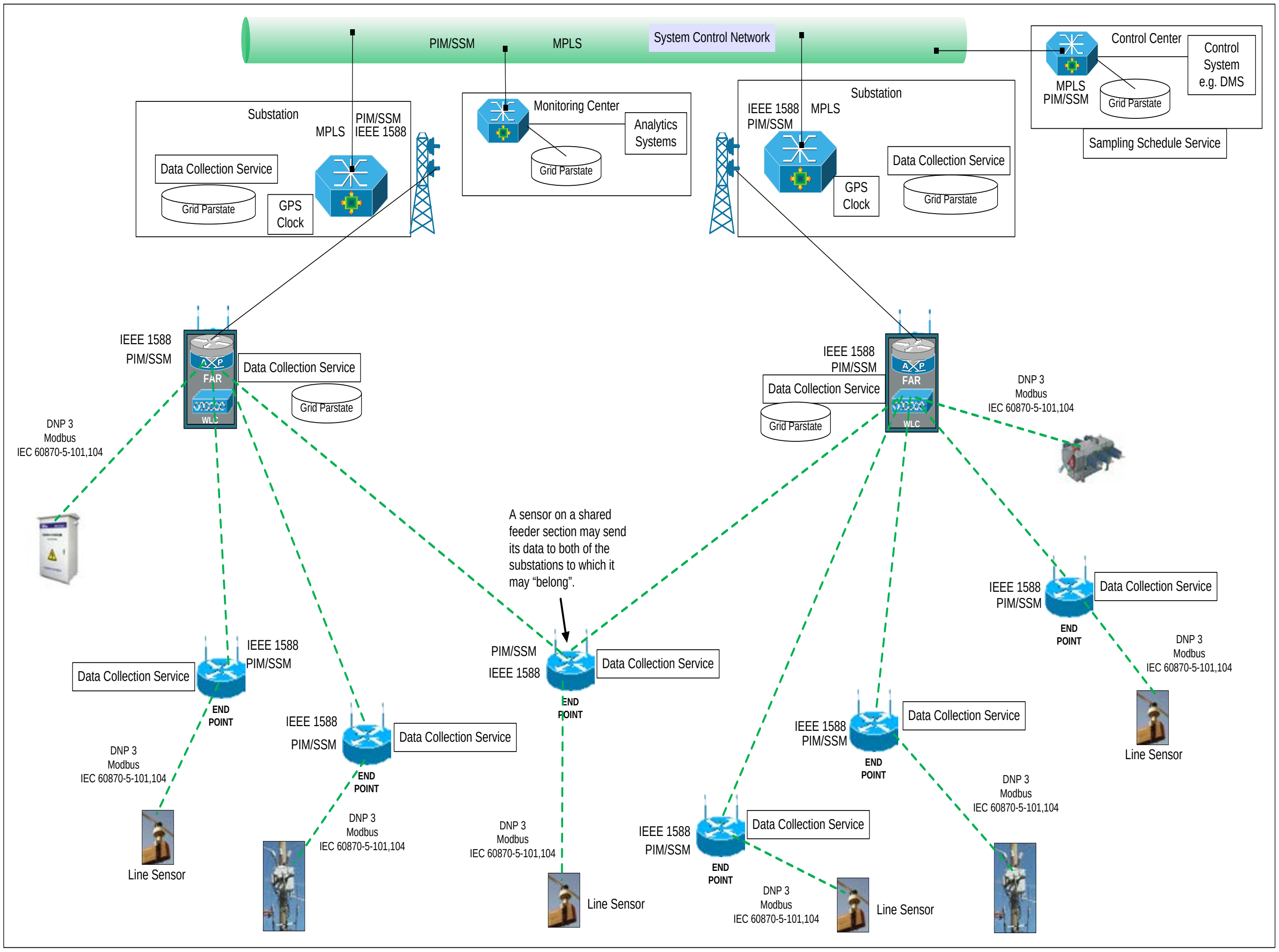

Figure 3. Distributed Data Collection Architecture Example

Given that control systems are moving toward distributed implementations, it is logical that data collection from distribution grids will be aggregated at the primary distribution substations, with some amount of that data being passed along to the control centers as well. Two methods of sensor and grid state data management are especially attractive in this environment and both make use of advanced communication network protocols:

1. True distributed database – in this method, each data collection node maintains an in-memory database of its portion of the grid state (which we refer to as partial state or parstate); data is not duplicated across nodes; when an application queries a node for grid state data, if that data resides on another node, the distributed data base serializes the query, sends it to the node containing the data, receives the response and serves it up without the application needing to know the details of how the data was managed; this method relies upon peer-to-peer communication among the nodes to enable database operation, which can easily be supported in IPv6 networks

2. Network-based publish and subscribe – this method uses IP-Multicast, and specifically Source Specific Multicast (SSM) to turn the communication network into a publish and subscribe mechanism in which any authorized process can subscribe to data from any publishing source; the communication network takes care of optimal packet supplication in the case of multiple subscribers

so that packet flooding does not occur; this method has been applied to managing PMU data flows on transmission level Wide Area Measurement System networks.[2]

Such methods were not practical in past Distribution Automation designs but availability of modern IPv6-based communication networks and grid devices makes these approaches feasible and attractive.

Architectural Insight

The change from centralized to distributed control is driven in part by technological feasibility but more by the penetration of edge (distribution–connected) devices and sub-systems and the potential scale of such penetration. **The scalability issue** affects everything from control algorithms to data acquisition modes to communication network architecture and design. The location of intelligence (computing capacity and software) throughout the grid means that the simple hub-and spoke/centralized control and optimization model must change. While there are views that a completely "flat" distributed model with no structure is appropriate, in fact the hub-and-spoke model can be transformed into a network of hub-and-spoke structures, with the advantage that the properties of such an arrangement can be rigorously understood and much existing knowledge regarding operation of hub-and-spoke systems can be updated and used. This multi-scale network of structures approach accommodates a number of existing approaches to large scale systems, including aggregation of distribution data to distribution substations.

A downside of this approach is that the complexity of communication at the distribution level increases, and so potentially does the volume (due to peer-to-peer communication). Also, existing sensor systems that use central data collection engines must be restructured to accommodate distributed architecture.

[2] Cisco, "PMU Networking with IP Multicast," available online at http://www.cisco.com/en/US/prod/collateral/routers/ps10967/ps10977/whitepaper_c11-697665.html.

5.0 Sensor Network Logical Architecture

Sensor networks generally have a logical architecture, over above communication network protocols and topologies. The logical architecture addresses the issues of query mode, programming, communication modes, information abstraction, and logical structure.

Query modes – the query mode describes how sensors respond to data queries. The set of query modes includes:

- Scan mode – sensors are polled for simple point lists; most commonly used in utility systems (e.g. Remote Terminal Unit DNP3 slaves)
- Database mode – sensors act as a database; support queries (requires a sensor operating system, sensor query language and/or middleware)[1]
- Active network mode – agents execute sensing tasks cooperatively[2]
  - Client/server – agents post data to a server; other agents act a clients to obtain data via the service
  - Meetings – agents exchange information in peer groups or sub-groups at specified times
  - Blackboards – common areas were data can be posted by any agent, then scanned by others for relevance

Node programming model – methods by which software/firmware is downloaded to sensor nodes

- Collectively programmed
  - Sensor middleware – requires a layer of software that consumes node resources, thus severely limiting application software size
  - Viral programming – files are passed from node to node; very difficult to ensure if and when all nodes are updated
- Individually programmed
  - Fixed firmware – rarely use as this method lacks flexibility and requires great cost to upgrade since each box must be touched
  - Remote download – widely used for meters and other devices; the issue here is both the time to upgrade a large number of devices and the cost if a service provider network with data-based tariffs is used

Information abstraction model – the information abstraction model describes how much processing will be applied at the sensor level before the sensor reports outputs. The information abstraction models include:

- Send raw data samples – the simplest approach but also the highest volume data when waveforms are involved; this is used more for asset monitoring telemetry (e.g. power transformer top oil temperature) but has a key use case in differential protection, where the IEC 61850 Sample Values (SV) mode comes into play

[1] C. Jaikaeo, et. al., "Querying and Tasking of Sensor Networks," SPIE's 14th Annual International Symposium on Aerospace/Defense Sensing, Simulation, Control (Digitization of the Battlespace V), Orlando, Fla, April 26-27, 2000.
[2] G. Cabri, et. al., "MARS: A Programmable Coordination Architecture for Mobil Agents," IEEE Internet Computing, Jul-Aug, 2000, pp. 216-35.

- Send characterizations
  - Send parameters and analytics – this is widely used in smart sensors and provides a type of data compression since it extracts useful information from a body of raw sensor data (e.g. converting a set of waveform samples to RMS voltage, RMS current, real power and reactive power)
  - Send decisions and classifications – an even more compressed version of parameters and analytics reporting

Of course, it is quite possible and proper to design sensor systems that make use of more than one of these modes.

We note that for Multi-Agent Systems (MAS) grid state may be propagated via what is known in the MAS field as "belief sharing", or it may be propagated by letting agents observe the actions of other agents (decisions and classifications in our case). Both methods have limitations in that each node's view of grid state gradually converges to what is expected to be correct values assuming that state is essentially static, but is known that the second method has especially severe limitations.[3]

5.1 Sensor Virtualization

The term "sensor virtualization" has been used in several ways. In this paper it means the use of software or network services to allow more than one sensing node to act collectively as an abstract sensor, with unnecessary physical details hidden from application software that uses the sensor.[4] Sensor virtualization can be applied to reduce the cost of smart sensors in distribution grids by sharing computation capabilities for multiple physical transducers. This is especially valuable when deploying synchrophasor measurement capability on distribution feeders, where the cost of traditional PMUs would be excessive. In some models, sensor network middleware is needed to implement the virtual sensor functions, but in practice network services could provide the requisite capabilities without the burden of a middleware layer. Figure 4 illustrates this concept, where multiple transducers coupled with digitizing capabilities acquire the necessary power waveform data, which is then streamed to a network node where computations transform waveforms to phasors. Applications can access the computation node, which can appear as one or several PMUs. Since the exposed logical interface conceals physical details, the application does not need any knowledge of the individual nodes that connect to transducers, or the transducers themselves.

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[3] Petar M. Djuric and Yunlong Wang, Evolution of Social Belief in Multiagent Systems, Proc. IEEE Workshop on Statistical Signal Processing, Nice, France, 2011, pp. 353-356

[4] Anura P. Jayasumana, et. al., "Virtual Sensor Networks – A Resource Efficient Approach for Concurrent Applications," IEEE Computer Society International Conference on Information Technology, 2007.

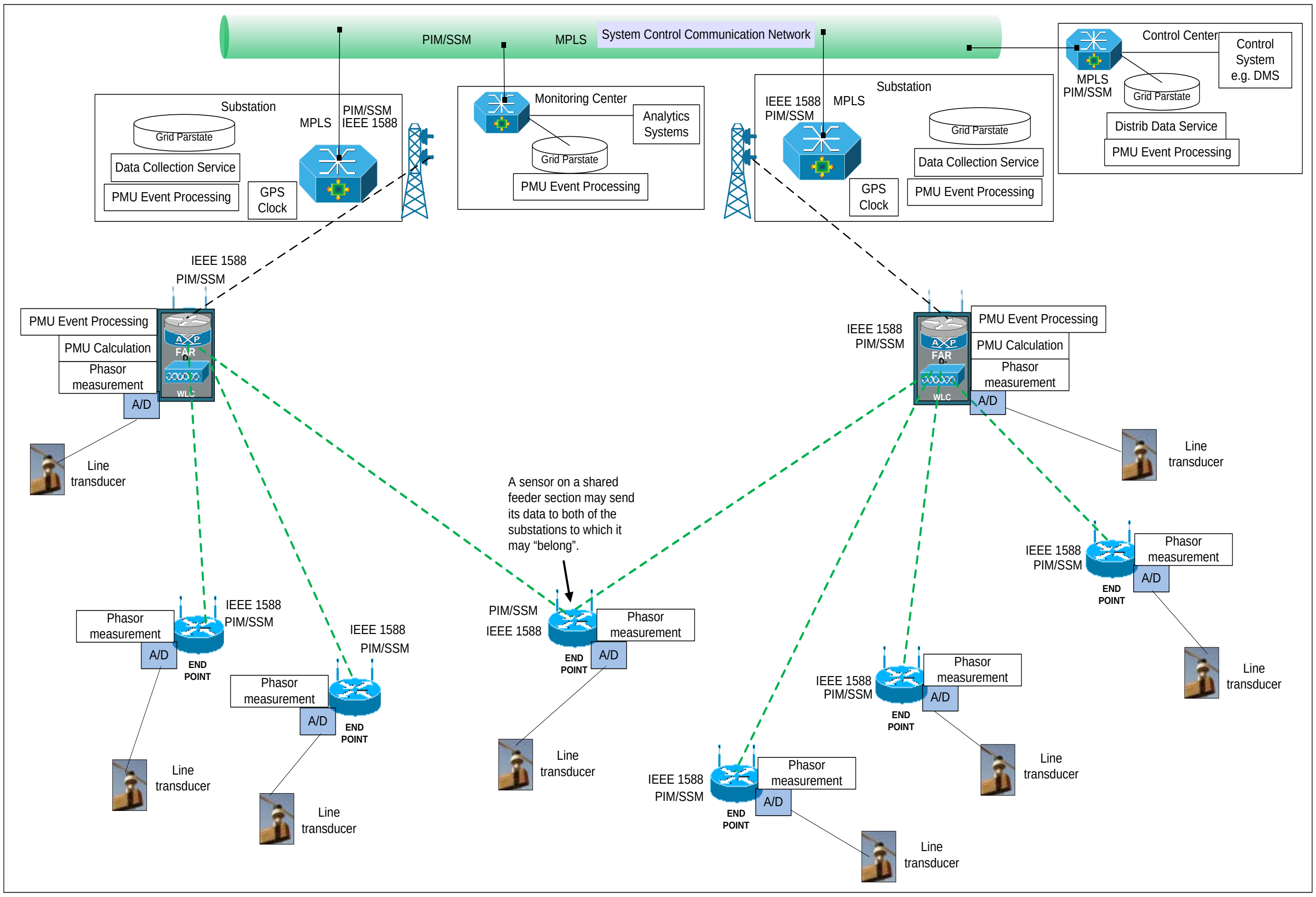

Figure 4. Distribution Level Virtual PMU Network

The next section discusses certain networking issues for sensors. This is a subset of general networking architecture issues for power grids.[5]

[5] J. Taft, et. al., Cisco GridBlocks Architecture: A Reference for Utility Network Design, Cisco, April 2012, available online at http://www.cisco.com/web/strategy/energy/gridblocks_architecture.html.

6.0 Selected Issues for Power Grid Sensor Communications Networks

Communication networks are crucial elements of advanced grids, and can help or hinder, depending on the nature of the communication technology and the grid functional and performance requirements. Among the key parameters are:

- Bandwidth
- Latency
- Burst response
- Average throughput as a function of number of endpoints
- Network structure
- Reconvergence time after a fault or outage

Bandwidth is the obvious criterion, but quite often bandwidth requirements are underestimated due to a lack of understanding of the analytics and applications that will make use of data being transported from sensors to usage points. The most common mistake is to ignore data and analytics associated with the high end sensors that may be used in a smart distribution grid. These sensors and the applications that use them involve much higher bandwidths than traditional SCADA sensing points, as they produce significant data on each power cycle (20 msec in Europeans style grids, 16.67 msec in North American style grids). Such devices can produce more data flow per feeder than the meters or any other sensors. In some control architectures, this data must flow to the substations for processing and consumption rather than to a control center; hence the per-feeder consideration.

Substations are another major source of high data rate flows due to the number and sophistication of the sensors they can contain. Depending on the number and kind of devices involved, substations may have bandwidth requirements that range from 64 kbps to as much as 50 Mbps. Data may flow to control centers or to peer substations through system control networks that may be physically separate from local area (distribution level) networks.

Latency matters because some grid functions and therefore analytics are “real time”, meaning that the results must be produced from newly sensed data and delivered for action within strict time constraints. The bounding latency may be as little as a few power cycles for the fastest functions; it may be a dozen cycles for slightly slower functions; it may be sub-second, or sub-minute for others; finally, there are analytics for which the bounding latency is so large that for all practical purposes they are not “real time” at all. Some communication networks have more than sufficient latency for grid data and analytics, but have excessive latencies. This is usually due to the network having a multi-hop architecture, something that is very common in wireless mesh networks. This issue is also a problem with some Power Line Communication (PLC) and most Broadband over Power Line (BPL) systems.

Burst response matters because many grid devices produce data in bursts and floods, rather than in steady streams. Such bursts occur in response to faults and outages, for example. They can be generated by smart meter systems due to momentary voltage sags on feeder circuits and then again in response to restoration of normal voltage, for example. A communication network that has sufficient bandwidth for steady state data flows can lose data due to buffer overflows during data bursts. Since the bursts in an advanced grid system usually occur when something critical is happening, loss of such data can constitute a crucial grid failure. With some protocols and devices, burst peaks can be 100x the steady state data rates.

Average throughput as a function of the number of endpoints matters because grid systems are built incrementally and are incrementally loaded with new endpoints. A network that provides adequate bandwidth and latency initially can become unacceptable as endpoints are added (this is especially a hazard for networks initially designed to carry AMI traffic, and then re-purposed to carry distribution automation traffic in addition to the original AMI load). The reason is that there is a threshold effect for average response time that causes the network performance to degrade dramatically when the "knee" of the average throughput curve is reached by increasing the number of endpoint devices using the network. As the number of endpoints increases, the average time to deliver messages increases, as does the amount of queuing necessary to prevent message loss.[1] The delivery time knee effect is illustrated Figure 5.

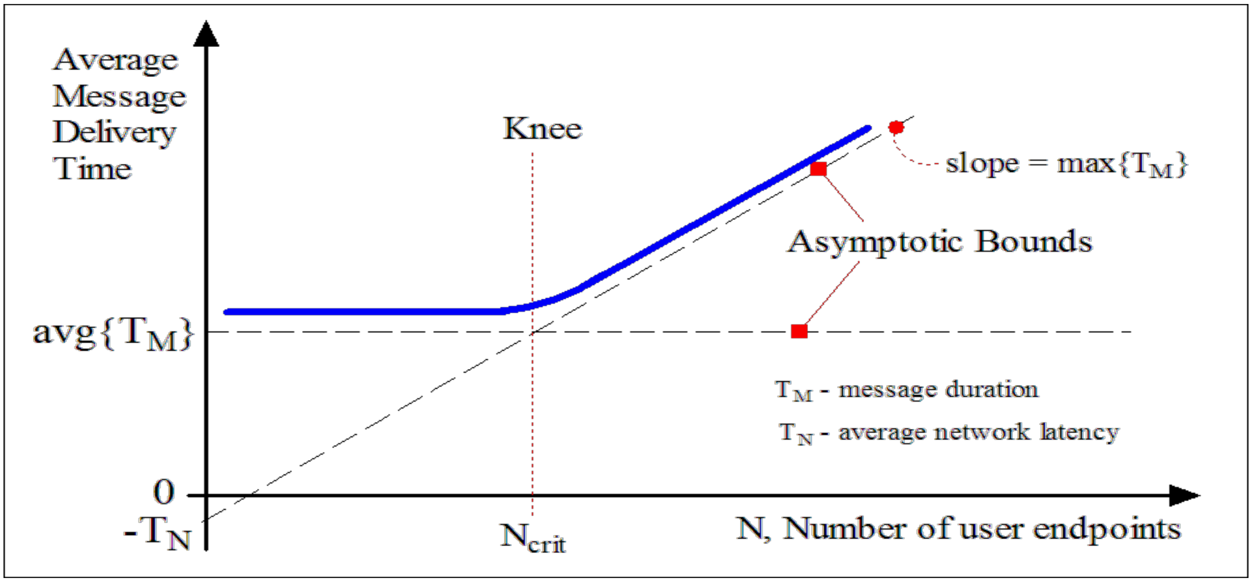

Figure 5. Average Message Delivery Time Knee Effect

Additional factors to be considered for wireless networks include coverage and, in the case of wireless mesh networks, re-convergence. When a wireless mesh network is disrupted, by say, a power failure, it must re-converge to a configuration that allows message packet forwarding. Some mesh networks re-converge slowly, and worse, some have problems re-converging at all under pathological topologies. Such topologies are the result of the mesh network physical layout and can occur unpredictably. Even without pathological topologies, mesh networks may have unacceptably long re-convergence times due to excessively long beacon intervals and other internal settings.

Ultimately, the characteristics of the communication network must be taken into account when developing the observability strategy. If the communication system is legacy, then it may well place limits on observability. For that matter, a new communication network may do the same. When bottlenecking is a significant possibility, alternatives include:

- Data compression at the point of measurement or elsewhere in the data transport path
- Use of distributed analytics to extract and preserve information while reducing data volume

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[1] Raj Jain, Art of Computer Systems Performance Analysis Techniques for Experimental Design, Measurements, Simulation and Modeling, Wiley Computer Publishing, 1991. See Chapter 33, available online at http://www.scribd.com/doc/86318410/231/CHAPTER-33-OPERATIONAL-LAWS

The consequences of these approaches are increases in the computation power at endpoints, potential additional data security issues, and new requirements for management of distributed software and smart devices.

7.0 Observability Strategy

Sensing and measurement support multiple purposes in the grid environment and this applies equally as well to many other systems characterized by either geographic dispersal, or large numbers of ends points, especially when some form of control is required. Consequently, the sensing system design can be quite complex, involving issues such as physical parameter selection, sensor mix and placement optimization, measurement type and sample rate, data conversion, sensor calibration, and compensation for non-ideal sensor characteristics.

We may divide sensor networks into three classes:

- Type 1: those for which there is a physical presence but no particular underlying structure (such as battlefield surveillance networks)
- Type 2: those for which there is an underlying structured physical system (such as power grid sensor networks)
- Type 3: those for which there is no relevant physical system but there is a cyber-system, such as with social networks

Type 1 networks usually must provide general coverage of a target zone or area and so the topological concept of homology groups becomes a useful tool to determine coverage gaps,[1] which is a key issue with most applications involving Type 1 sensor networks. We will not discuss such networks any further here as they are not very useful in the utility setting. However, the concepts of homology groups and topology as tools for determining sufficient sensing for grid state determination are worth pursuing.

With Type 2 networks, we may take another approach based on the topological structure of the underlying physical system and the concept of system state. This means we do not need to resort to the concept of ad hoc randomly distributed meshes for Type 1 sensor networks. Instead, for Type 2 networks, we employ the ideas of system state and observability, combined with an understanding of how the sensor data will be used to create an *observability strategy*. Such a strategy has several elements to it, as Figure 6 illustrates.

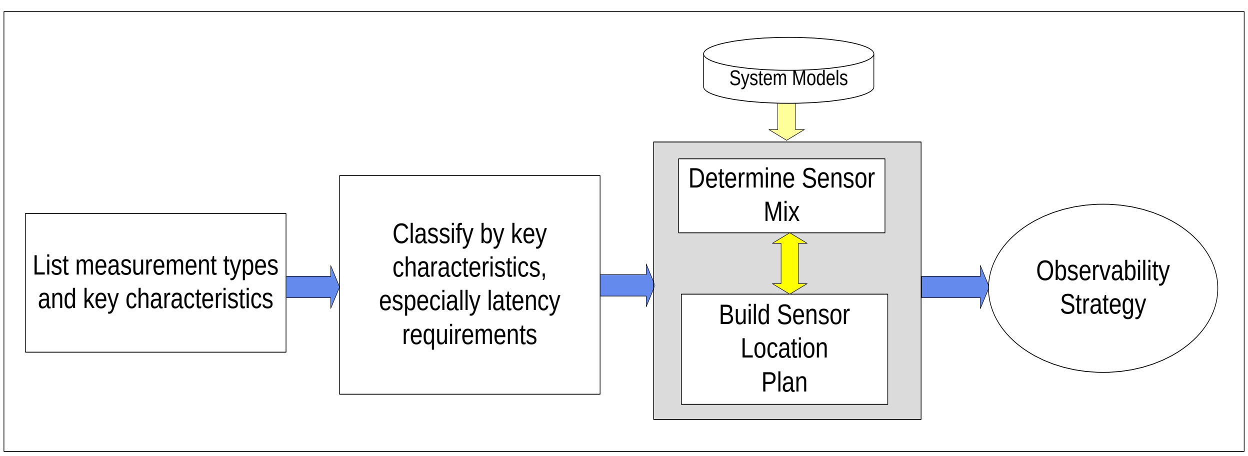

Figure 6. Type 2 Grid Observability Strategy Process Flow

[1] Vin De Silva and Robert Ghrist, Coverage in Sensor Networks via Persistent Homology, Algebraic and Geometric Topology, 7 (2007), pp 339 – 358. Available online at msp.org/agt/2007/07/agt-2007-07-016s.pdf.

The major elements of the strategy development process (simplified here) are:

- List measurement types and characteristics – a preliminary step to catalog all of the measurements needed to support grid observability; characteristics are needed for the next step
- Classify data by key characteristics – this step determines necessary constraints by allocating sensors to support various processes in the data latency hierarchy; in combination with grid structure
- Determine sensor mix and build sensor location plan – these two processes must often be done iteratively with each other; the issue here is a tradeoff between using large numbers of simple sensors and smaller numbers of more capable an expensive sensors; this is the essence of the optimization problem – by applying knowledge of the system being instrumented and computing the costs associated with the configuration at each iteration, one may arrive at a converged solution with reasonable assurance that the solution is good, if not absolutely optimal. If optimality is desired, use of tools such as mixed integer nonlinear programming may be employed.

Note that the process for Type 2 networks makes use of system models. In the case of power grids, this means the electrical topology of the grid, along with the inherent physical laws (Ohm's Law, Kirchhoff's Voltage Law, and Kirchhoff's Current Law) as well as the mathematical properties of planar graphs (Tellegen's Theorem, network duality, etc.). In practice we do not need high density sensor meshes for power grids; instead, by applying knowledge of the physical nature of the grid, we can achieve significant economies by using limited numbers of well-placed sensors to obtain grid state. This is a key point to understand about grid state determination.

Architectural Insight

Distribution grid topology is the framework in which every piece of data and every control action *must* be interpreted. At the planning level, it is the structure that underlies sensor network architecture and can be used to determine the minimum level of sensing necessary to determine grid state. At the operational level, it is the context for every measurement and every action. Lack of accurate and up-to-date grid topology limits the effectiveness of advanced grid functions.

For social (Type 3) networks, the concept of state is not well defined, despite considerable recent research activity in the area. We can, however, outline a few items of interest. One is the formation of communities within a social networking system, sometimes referred to as clusters or cliques. This requires the discovery of logical connectivity, which parallels the power grid issue of electrical connectivity discovery; here we should make a distinction between social networking services, and the actual social networks that form on them. Various techniques are being explored to detect the existence of communities to measure their extents. The research on this is spread over a wide variety of disciplines.[2,3] It is not clear that specific criteria exist for determining the state of a social network as of this writing.

Other activity has focused on understanding social network dynamics, as measured via economic activity like online bidding and other resource allocation and cooperation/competition interactions, using information theory and game theory as tools.[4] Another approach to social networks has been to mine them for information as if they constitute sensor networks themselves. An experimental effort in this

[2] M.E.J. Newman and M. Girvan, Finding and Evaluating Community Structure in Networks, Physics Rev E, vol. 69, no. 2, 2004.
[3] M. Rosvall and C. T. Bergstrom, An Information-Theoretic Framework for Resolving Community Structure in Complex Networks, Proc. Nat. Acad. Sci. USA, vol. 104, No. 18, pp. 7327-731, 2007.
[4] Yan Chen and K. J. Ray Liu, Understanding Microeconomic Behaviors in Social Networking, IEEE Signal Processing Magazine, March 2012, pp. 53-64.

direction is being carried out by the US Geologic Survey in attempting to use Twitter to detect and locate earthquakes.[5]

It is clear that social networks are part of the multi-network convergence involved in grid evolution, but more remains to be done to fully exploit this for measurement purposes.

7.1 Sensor Allocation

A key aspect of observability strategy and resultant sensor network design is the allocation of sensors: determination of appropriate sensors types and selecting the number and locations of the sensors. If sensors, sensor communications networks, and installation were all negligible cost, then one might just over-instrument a grid. However, this certainly not the case and even if the sensors were free, the cost to install them at arbitrarily high density would be prohibitive. This leads to a significant issue of sensor allocation optimization, which leads back to the use of the structural properties of Type 2 sensor networks.

7.1.1 Transmission

Transmission grid state has traditionally been estimated from a system model and a sparse set of physical variable measurements. More recently, PMUs have been added to the transmission grids in North America and other countries for a variety of purposes but including improvement of grid observability. A number of studies have been carried out on optimal number and placement of PMUs on transmission systems. This has led to a rough design guideline that is suitable for observability strategy purposes: PMUs are needed on 1/3 of the buses in a transmission system to ensure complete observability.[6],[7] One must still carry out the design and optimization process to determine the actual locations of these PMUs, but the guideline provides a key number. Engineers may decide that additional PMUs are needed or useful, so the guideline is just a starting point for the transmission observability strategy, and engineering knowledge of the system under consideration plus additional analysis may be need to handle unique cases.

7.1.2 Distribution

Observability for distribution grids is fundamentally a more difficult issue than for transmission for all but the simplest radial systems. Complicating factors include feeder branches and laterals, unbalanced circuits, poorly documented circuits, large numbers of attached loads and devices and, in the case of feeders with inter-ties, time-varying circuit topology. In general, circuit topology and device electrical connectivity may be poorly (incompletely or inaccurately or both) known. These issues make state estimation more difficult than for transmission systems, so it is necessary to rely more upon state measurement and less on estimation.

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[5] See the USGS website page at http://recovery.doi.gov/press/us-geological-survey-twitter-earthquake-detector-ted/.

[6] Baldwin, T.L., Mili, L., Boisen, M. B., Jr., Adapa, R., "Power System Observability with Minimal Phasor Measurement Placement". *Power Systems, IEEE Transactions on*, 1993, p. 707-715.

[7] Mudassir A. Maniar, et. al., Optimal Location of Phasor Measurement Unit for Complete Network Observability of Power System, Global Research Analysis, International, March 2013. Available online.: http://worldwidejournals.com/gra//file.php?val=March_2013_1363598665_05d91_27.pdf

Sensors for distribution grids may be organized into three tiers. The top tier includes feeder sensing devices such as waveform recorders, digital relays, and PMUs located in the primary distribution substations. This tier also contains sensing for some asset monitoring and power quality measurement.

The second tier includes devices located on feeders outside of the primary substations. We shall consider six classes of devices at this tier:

1. Binary devices, such as Faulted Circuit Indicators (FCIs) – these devices indicate events such as the passage of a fault current at the sensing point

2. Line sensors – use analog transducers and digital processing to extract parameters from voltage and current waveforms, but measurements are not synchronized across the system

3. Distribution PMUs – distribution level phasor measurement units that extract current and voltage phasors that are synchronized across the system

4. Waveform recorders – these devices record waveforms with much denser sampling than other sensors, in order to capture high speed transient and high order harmonic information. Devices include power quality monitors and transient event recorders. They may record continually or may be triggered by grid events to retain a window of waveform data leading up to, including, and trailing the event.

5. Grid device controllers – many grid devices such as capacitor banks have controllers that have electrical sensing capabilities; they may be useful as sensing devices when they can be networked to the communication system

6. DER instrumentation packages – Solar PV and other DER can provide information ranging from grid state variables to real time and forecasted DER availability and local environmental conditions; most of these must be networked via the internet since utility networks do not have the means to accommodate them

Note that while some DER providers have suggested that third-party-owned DER could provide all necessary grid state sensing and even eliminate the need for distribution utilities to have distribution communicate networks, this is in fact not a valid option. That is because the third party would have an agency problem, meaning that the third party would not take responsibility or accountability for grid reliability as the distribution utility does and would leave the utility at a loss if the private sector company decided to leave the business.[8]

The third tier includes devices connected to the feeder secondary, such as meters and frequency disturbance monitors. From an architectural standpoint, the use of meters as a sensor fabric presents some issues. Generally, the only way to access voltages from meters is to interface at the meter data collection engine (DCE), normally located in the control center, but in some cases may actually be in the enterprise data center. If the meter data is being used for control in a centralized control environment, having the meter DCE in the control center is acceptable; having it in the enterprise data center is problematic. If control is distributed to the primary substations, then use of the meter data in any low latency control application is somewhat problematic unless the meters are individually addressable without the need to go through the meter DCE.

[8] JD Taft, Roles and Responsibilities for Distribution Grids: DER Sensing and Communication Networks, available online: https://gridarchitecture.pnnl.gov/media/advanced/Roles_and_Responsibilities_for_Dist_Sensing_final.pdf

Architectural Insight

Residential meters that use central DCEs are bottlenecked in terms of use as sensor networks for grid operations. The implementation of IPv6 at the meter level (not just at the DCE interface level) is a key change that can enable such meters to participate in distribution sensor networks.

For European distribution grids, both the Medium Voltage (MV) circuits and Low Voltage (LV) circuits may be accessed at secondary distribution stations in most cases. Therefore, sensing elements for both can reside in the secondary station equipment house, but with perhaps some sensors still distributed along the MV and LV feeders outside of the distribution station houses to aid in fault localization. In the case where communication to devices on the LV grid is via power line communication (PLC), a special problem exists in that the communication physical layer can be disrupted by a fault that we wish to detect, characterize, locate, and isolate using that selfsame physical layer for communication with the sensors and control devices.

7.2 Distribution Grid Topological State (Electrical Connectivity) Representation

Distribution grids present special problems in terms of topological state. Such state information is crucial because it is the context in which grid data, events and control commands must be interpreted. The problems arise because unlike transmission grids, "as-built" topology for distribution grids is often not completely or accurately known. In addition, distribution grid topology can be dynamic, such as in the cases where feeders are partially meshed or are tied to other feeders for reliability reasons. In such cases, circuit switches, sectionalizers, or reclosers may be operated to change the topology and such changes can be frequent. Consequently, data flows in a given circuit section can reverse, as can voltage rises and drops. With the advent of Distributed Generation (DG) penetration on distribution feeders, power flow reversals and loops can occur, impacting protection and Volt/VAr regulation.

Due to grid switching, a feeder section may "belong" to more than one feeder or substation at different times. This raises several issues: how to obtain real time circuit topology, how to represent power state for such sections (since power state must refer to circuit topology), and how to handle distributed sensor data acquisition (which of the several distributed DCEs should collect the data from a section that can belong to more than one substation, for example).

The issue of circuit topology determination is one of the hidden issues for distribution grid modernization, because it can undermine much of the advanced capabilities that grids are intended to achieve and yet the issue is often not discussed or included in the modernization process. Furthermore, it is not sufficient to have topological state on a current operational data basis (meaning the present value). This is because data may not always be interpreted or acted upon immediately. If there is a process delay, circuit topology may change in between the time the data or event message was generated and the time when the data is processed or the time that a control command is issued. Therefore, past values of topological state are also needed in order to provide the correct context for the data, whereas present or possibly even future values are needed to provide context for control commands.

One method of providing the multiple versions of topology that are needed for advanced grid control is to capture the state changes of grid switches, reclosers, sectionalizers, and inter-ties in a time series database and then use a topology processor to reconstruct topology for any required present or past time. The collection of these state transitions is often problematic because the switching device may not report back its state and also because the device may malfunction. In addition, not all switching devices are automatic – many distribution grids contain large numbers of manually-operated switches. Capture of state transitions for such devices is problematic, but can be resolved with a degree of line sensing designed to provide measurement of power state variables that allow automatic inference of the switch state transitions (by sensing changes in line voltage or current flow). If switch state transition determination is an issue, then an aspect of observability strategy should be to include means to sense those changes.

7.3 Example Sensing Strategies

The following tables contain elements of a number of strategies for power grid observability. These can be used to assemble key portions of an overall observability strategy and sensor network design.

Table 1. Strategy Set 1: Power State Determination

1.0	Strategy	Description
1.1	Sparse SCADA sampling	Standard method for old-style SCADA; use a very limited number of sensing points (one or two per feeder); for more detailed sensing, three to five per feeder is normally sufficient, but consider Figure 9 below to deal with branches and laterals
1.2	Synchrophasor sampling	Deploy PMUs at the feeder head end in the primary substation, as well as at three to five points along the feeder
1.3	Premises meter sampling	Use addressable meters to provide voltage profiles along a feeder – 10 to 20 meters are sufficient, but plan to have alternates in case a given meter does not communicate on demand
1.4	Heterogeneous sampling	Use a mixture of sensor types to assemble grid state, including line sensors, PMUs, meters
1.5	Rollup and aggregation	Aggregate point level grid state measurements into section, feeder, substation level state elements by a combining power summations with head end voltage readings; currents may be summed provided every branch is accounted for
1.6	DG Power Flow Monitoring	Monitor power flow at the Point of Coupling on the grid side for distributed generation; alternate – obtain the data from the DG controller
1.7	DS energy state	Obtain state of charge of distributed storage units from DS controllers
1.7	DR Available Capacity	Estimate available DR capacity for the next market period based on statistical models and available behavioral data
1.8	Circuit parameters via PMUs	Use PMUs in a pair-wise fashion to estimate circuit parameters for the circuit segment between the PMUs; care must be taken on distribution circuits as phase shifts can be quite small and measurements can be noisy – the resultant calculations can be ill-conditioned
1.9	Circuit parameters via meters	The same idea as above, but using only meter measurements – the problem is that where meters do not measure phase angle (usually the case) only magnitude calculations are possible

1.0	Strategy	Description
1.10	Technical loss determination	Use line sensor/ PMU data and possibly premises meter data to estimate technical losses; may be done on a segment to segment basis and then aggregated
1.11	Premises sub-metering	Use sub-metering points to make detailed measurements of premises power state for B2G control integration. Usually a very large number of measurement points will be used for commercial and industrial buildings; for residences, fewer will be used except when they are incorporated into "smart appliances", etc.

Table 2. Strategy Set 2: Fault State Determination: Fault Classification and Location

2.0	Strategy	Description
2.1	Feeder level via substation relays	Breaker status indicates presence of a fault and which feeder is involved
2.2	Section level via fault currents	Detection of fault currents via either FCIs or via line sensing can locate fault to the section (or segment if sensors locations do not align with feeder sections)
2.3	Distance to fault 1: from substation	Some relays calculate electrical distance to the fault; on distribution circuits this can be ambiguous due to branches and laterals; also accuracy drops off with distance
2.4	Distance to fault 2: from distributed sensors	Using sensor spaced along the feeder can improve fault location accuracy, since some sensors will be closer to the fault than the substation is, unless the fault is quite near the substation
2.5	Branch disambiguation 1: via FCIs	By noting which FCIs are tripped, it is possible to disambiguate branching issues (i.e. the branch with the fault must have a tripped FCI)
2.6	Branch disambiguation 2: via lateral fuses	Same idea as 2.5, but using fuse states where they are available to eliminate laterals that did not see the fault current
2.7	Branch disambiguation 3: via line sensors	Same idea as 2.5 but using data from line sensors instead of FCIs, for those strategies that use sparse line sensors instead of dense FCIs
2.8	Branch disambiguation 4: Via meters	Same idea as 2.5, but using meters, only for cases where a lateral fuse blow clears the fault, leaving the meters behind the fault without voltage after the fuse blow
2.9	Open phase faults 1: via meters	When no backfeed is present, open phase faults may be located by determining which meters have lost voltage; the first meter without voltage is beyond the fault
2.10	Open phase faults 2: via phasors	Negative sequence over current indicates a potential open phase fault
2.11	Direction to flicker source	Analysis of line sensor waveforms can indicate direction to the flicker source so use of multiple sensors can bracket the source location

Table 3. Strategy Set 3: Device State Determination: Operational Effectiveness Verification

3.0	Strategy	Description
3.1	Device feedback	Some devices provide state feedback via communication interfaces
3.2	Line sensor monitoring	Line sensors near grid devices can detect changes in line voltage and current to verify device operation
3.3	Meter monitoring	Same idea as in 3.2, but using meters

Table 4. Strategy Set 4: Outage State Determination

4.0	Strategy	Description
4.1	Call system input	Combine call system data with grid topological state information to determine grid outage state
4.2	Fault isolation system input	Use information from the fault isolation subsystem combined with grid topological state to determine outage state
4.3	Breaker operation	Use information from the substation breakers (relays, actually) combined with grid topological state to determine outage state
4.4	Meter Power Outage Notification (PON) and Power Restoration Notification (PRN) events	Use information from the PON and PRN messages generated by the meters combined with grid topological state to determine outage state
4.5	Line sensor events	Use information from the line sensors combined with grid topological state to determine outage state
4.6	Multi-source correlation	Combine all of the above to determine outage state; note that in all cases, grid topological state is needed to interpret sensor data

Table 5. Strategy Set 5: Topological State Determination

5.0	Strategy	Description
5.1	Base connectivity extraction	Obtain "as-built" base topology from the GIS, OMS, or DMS
5.2	As-operated connectivity from DMS/OMS	Modify base topology with real time connectivity information from DMS/OMS when available
5.3	Direct switch state monitoring	Modify base topology with real time connectivity information obtained directly from addressable grid switching elements when available (problem: some switches are manually operated)
5.4	Indirect switch state determination	Make use of Strategy 3.2 to obtain switch state changes for manually operated switches (or any other switches or that matter)

Table 6. Strategy Set 6: Power Quality Determination

6.0	Strategy	Description
6.1	Voltage-based measures	Use waveform analysis on data from voltage line sensors or PMUs
6.2	Current-based measures	Use waveform analysis on data from current line sensors or PMUs
6.3	Frequency-based measures	Use waveform analysis on data from line sensors or PMUs or Fnet-type frequency disturbance monitors

Table 7. Strategy Set 7: Thermal State Determination

7.0	Strategy	Description
7.1	Device temperature and hot spot monitoring	Take temperature values directly from built-in device temperature monitors
7.2	Circuit temperature profile monitoring	Use embedded distributed temperature sensing such as optical scattering in fiber to measure and monitor cable temperature profile and hot spots; alternately, use lines sensors with built-in temperature sensing to temperature samples at discrete locations
7.3	Circuit average temperature estimation	Use multi-PMU data or measure cable sag to estimate average circuit temperature
7.4	Circuit hot spot estimation	Use voltage and current profiles built up from near real time meter data to estimate circuit hot spots

Using sub-strategies such as those listed above, we can build observability strategies that lead to sensor network architectures in a straightforward manner. It is clear that developing observability strategies for distribution systems is a complex problem, one that would benefit greatly from the development of tools to be used at the planning stage to help determine what types of grid sensors to deploy, where, and in what densities, and how to combine them with legacy sensing. Such tools should also support sensor network optimization, meaning minimize sensor cost for a given level of observability or maximize observability for a given sensor budget.

Once the observability strategy is set and the sensor allocation guidelines have been specified, it is a straightforward if tedious task to allocate the sensors on each feeder. Due to the variability that can be encountered on distribution circuits, special cases will arise and will need engineering judgment to resolve. An understanding of observability principles and active guidelines, combined with the engineers' knowledge of the system at hand, make this a manageable task.

8.0 Final Comments

The design of sensing networks and measurement systems for Ultra Large Scale (ULS) systems such as power grids involves complications that do not arise in ordinary systems. For those ULS systems that have an underlying physical system with topological structure and system dynamics (common characteristics), we can take advantage of the control theoretic concepts of system state and observability to optimize sensor system designs. In such cases, it is not necessary to resort to randomly distributed ad hoc sensor networks. We can design sensor networks with fewer sensors than in the ad hoc case, with no loss of information.

Drawing upon experience from use of sensor networks in a number of fields, we can define additional architectural properties in the categories of programming, communication modes, information abstraction, and logical structure. The combination of these principles with the system state and observability concepts provides a foundation for sensor network design for physical networks.

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